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STATE OF CALIFORNIA

Energy Resources Conservation and Development Commission

In the Matter of:	
APPLICATION FOR CERTIFICATION FOR THE PALEN SOLAR ENERGY GENERATING SYSTEM	DOCKET NO. 09-AFC-7

INTERVENOR CENTER FOR BIOLOGICAL DIVERSITY

Exhibit 3113

Testimony of Bill Powers P.E.

Re: Response to May 21, 2014 Committee Order Granting Petitioner's Motion to Reopen the Evidentiary Record and Setting Revised Schedule, Palen Solar Electric Generating System Amendment

Docket 09-AFC-7

Summary of Testimony

The December 2013 PMPD reached the appropriate conclusion in denying the PSEGS project. Higher than anticipated net-metered rooftop PV additions over the next several years brought about by the passage of AB 327 moot the justification that there is a need for a remote solar thermal project at the Palen site. Even without this development, solar PV in any format, either utility-scale PV or large-scale distributed PV on rooftops, is a lower-cost, lower environmental impact alternative than the proposed PSEGS project.

These comments also hold true regarding solar projects equipped with storage. PV equipped with limited battery storage to address the early evening summer peak demand period is substantially more cost-effective than adding thermal storage at PSEGS to achieve the same purpose. PV projects equipped with battery storage in load pockets, such as SCE's LA Basin load pocket, is the most cost-effective application of energy storage. Within the load pocket energy storage would serve the dual purpose of adding to local capacity necessary to meet peak demand, and thereby eliminate the need to procure gas-fired peaking generation to serve the same purpose, while also providing renewable energy storage capability to extend solar energy use into the evening hours.

Qualifications

My qualifications are provided in my prior Testimony and presented in TN-58860 Exhibit 600, and my updated resume is submitted as part of this testimony.

Statement

Powers Engineering has prepared the following comments on the May 21, 2014 Committee Order Granting Petitioner's Motion to Reopen the Evidentiary Record and Setting Revised Schedule, Palen Solar Electric Generating System Amendment. This testimony supplements testimony submitted in this matter on October 5, 2010 and at the California Energy Commission hearing on October 27, 2010.

I. Utility-Scale Solar Alternatives to PSEGS Are Feasible

Both solar trough and utility-scale PV projects are indisputably feasible alternatives to power towers proposed at the PSEGS site.[1] Regarding the feasibility of solar trough technology at the PSEGS site, the PMPD states, and I agree, that both wet-and dry-cooled solar trough technology are fully feasible, and a 250 MW dry-cooled solar trough plant would use no more water than PSEGS:[2]

> In 2008 and 2009, the Energy Commission received AFCs for several renewable energy projects that were proposed to use parabolic trough technology, including the PSPP. Staff is monitoring construction of two of the projects that were licensed by the Energy Commission in September 2010: the Abengoa Mojave Solar Project (AMSP) and the Genesis Solar Energy Project (GSEP). (Ex. 2000, p. 6.1-27.)
>
> AMSP will use wet cooling, and maximum operational water use for the project will total approximately 2,160 AFY. GSEP will use dry cooling, requiring approximately 202 AFY. The proposed PSEGS would require approximately 201 AFY for project operations. (Ex. 2000, p. 6.1-27.)

The PMPD also provides numerous examples of the feasibility of utility-scale PV as an alternative to the proposed PSEG with which I agree. PV projects of this scale are clearly feasible and are being installed across the State including the Desert Sunlight Solar Farm Project in the Chuckwalla Valley and the Topaz Solar Farm Project on the Carrizo Plain.[3] In fact, large scale PV can use less land than the proposed PSEGS per acre. For example, the 250 MW California Valley Solar Ranch Project in San Luis Obispo County is sited on 1,500 acres, equivalent to 1 MW of generation for every 6 acres.[4] In contrast, the

[1] As the PPA is not in the record, I am putting aside the issue of any language in the Brightsource PPA for PSEGS that may be specific to power tower technology which would require that no technology other than power tower could meet such technology specific languages if it exists.
[2] PMPD, p. 2-18.
[3] PMPD, p. 2-28.
[4] PMPD, Table 2, p. 2-29.

proposed 500 MW PSEGS will be located on 3,794 acres,[5] equivalent to 1 MW of generation for every 7.6 acres. Some configurations of utility-scale PV projects use less land area per MW of generation than the proposed PSEGS project.

Operational water use for the PV projects (listed in the Table 2 of PMPD) ranges from approximately 12.4 AFY for the California Valley Solar Ranch Project to approximately 15–22 AFY for the McCoy Solar Energy Project. The PSEGS project would require 201 AFY for project operations.[6] (Ex. 2000, p. 6.1-52.) Even large-scale PV projects use substantially less water than the proposed dry-cooled PSEGS project and provide feasible and superior alternatives the proposed project in my opinion.

II. Distributed Solar Alternatives to PSEGS Are Also Feasible

A. Large-Scale Distributed Rooftop PV

Utility-scale distributed PV is also a demonstrably feasible PV alternative that has been built by SCE and is RPS-eligible. The 2010 RSA for the original Palen Solar Power Project (PSPP) correctly noted that both SCE and PG&E, the two largest investor-owned utilities (IOU) in California, were in the process of constructing large distributed PV projects (p. B.2-62).

The 500 MW SCE urban PV project was approved by the CPUC in June 2009. The 500 MW PG&E distributed PV project was approved by the CPUC in April 2010. These projects are RPS-eligible and will consist of a 250 MW IOU-owned component and a 250 MW third-party component. The power purchase agreement (PPA) between PSEGS and SCE is same type of contract mechanism that has been used by SCE to contract for the 250 MW third-party component of its distributed PV project.[7]

SCE expressed confidence in its March 2008 application to the CPUC for a 250 to 500 MW urban PV project that it can absorb thousands of MW of distributed PV without additional distribution substation infrastructure, stating "SCE's Solar PV Program is targeted at the vast untapped resource of commercial and industrial rooftop space in SCE's service territory"[8] and "SCE has identified numerous potential (rooftop) leasing partners whose portfolios contain several times the amount of roof space needed for even the 500 MW program."[9]

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[5] PMPD, p. 1-1.
[6] PMPD`
[7] Center for Biological Diversity, *Opening Testimony of Bill Powers, P.E. - Application For Certification for the PSPP Solar Power Plant*, Docket No. 09-AFC-7, October 5, 2010. (TN-58860, Exhibit 600)
[8] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, p. 6. (TN-58860, Exhibit 606)
[9] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 44. (TN-58860, Exhibit 606)

SCE stated it has the ability to balance loads at the distribution substation level to avoid having to add additional distribution infrastructure to handle this large influx of distributed PV power.[10] SCE explains:

> "SCE can coordinate the Solar PV Program with customer demand shifting using existing SCE demand reduction programs on the same circuit. This will create more fully utilized distribution circuit assets. Without such coordination, much more distribution equipment may be needed to increase solar PV deployment. SCE is uniquely situated to combine solar PV Program generation, customer demand programs, and advanced distribution circuit design and operation into one unified system. This is more cost-effective than separate and uncoordinated deployment of each element on separate circuits."[11]

SCE also notes that it will be able to remotely control the output from individual PV arrays to prevent overloading distribution substations or affecting grid reliability:[12]

> "The inverter can be configured with custom software to be remotely controlled. This would allow SCE to change the system output based on circuit loads or weather conditions."

As SCE states, "Because these installations will interconnect at the distribution level, they can be brought on line relatively quickly without the need to plan, permit, and construct the transmission lines."[13] This statement was repeated and expanded in the CPUC's June 18, 2009 press release regarding its approval of the 500 MW SCE urban PV project:[14]

> Added Commissioner John A. Bohn, author of the decision, "This decision is a major step forward in diversifying the mix of renewable resources in California and spurring the development of a new market niche for large scale rooftop solar applications. Unlike other generation resources, these projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts. By authorizing both utility-owned and private development of these projects we hope to get the best from both types of ownership structures, promoting competition as well as fostering the rapid development of this nascent market."

The CPUC made a similar observation with its approval of the PG&E 500 MW distributed PV project in April 2010:[15]

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[10] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, pp. 8-9.
[11] Ibid, p. 9. (TN-58860, Exhibit 606)
[12] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 27.
[13] Ibid, p. 6. (TN-58860, Exhibit 606)
[14] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009. (TN-58860, Exhibit 602)
[15] CPUC Press Release – Docket A.09-02-019, *CPUC Approves Solar PV Program for PG&E*, April 22, 2010. (TN-58860, Exhibit 607)

> "This solar development program has many benefits and can help the state meet its aggressive renewable power goals," said CPUC President Michael R. Peevey. "Smaller scale projects can avoid many of the pitfalls that have plagued larger renewable projects in California, including permitting and transmission challenges. Because of this, programs targeting these resources can serve as a valuable complement to the existing Renewables Portfolio Standard program."

The use of the term "smaller scale" in the CPUC press release is a misnomer. Clearly a 500 MW distributed PV project is the same size as the 500 MW proposed PSPP solar thermal project. Individual rooftop PV arrays in a large distributed PV project are functionally equivalent to single rows of reflective mirrors in a solar thermal project. Each rooftop or row is a small contributor to a much bigger whole.

B. Small-Scale: Major Unanticipated Increase in Rooftop PV by Mid-2017

Even though net-metered rooftop PV is not directly RPS-eligible, it does in fact have a direct impact on the quantity of RPS procurement necessary to meet the 33 percent by 2020 target. If rooftop PV displaces electricity that would otherwise be purchased from the grid, the amount of RPS-eligible resources that must be purchased to achieve 33 percent renewables is also reduced.

California's investor-owned utilities (IOUs) are in the process of meeting the California Solar Initiative (CSI) solar PV targets. The IOUs are to have 1,940 MW online by December 2016.[16] This solar capacity is installed on the customer side of the electric meter, on rooftops and parking lots primarily, and is known as "net-metered" solar.

The IOUs' net-metered solar targets increased dramatically with AB 327[17] in October 2013, which enacted Public Utilities Code Section 2827(c)(4)(B) and, established minimum statutory net-metering rooftop solar targets to be met by the IOUs by mid-2017. AB 327 established a statutory mandate to add up to 5,256 MW of solar energy resources in California.

This is a 3,316 MW increase over the 1,940 MW target established for the IOUs by the California Public Utilities Commission (Commission) in D.06-12-033. The IOUs are required by Section 2827(c)(4)(C) to report on a monthly basis their progress in meeting the new minimum solar PV targets by mid-2017. Therefore, at a minimum, the IOUs by law will add 3,316 MW of additional net-metered solar by mid-2017.

Net-metered rooftop solar is not directly RPS-eligible. However, net-metered rooftop solar reduces the amount of grid power that must be supplied by the IOUs to meet demand. One-third of this grid power must be RPS-eligible by 2020. Therefore, even

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[16] Exhibit 3114 CPUC webpage, *About the California Solar Initiative*, last modified January 31, 2014: http://www.cpuc.ca.gov/PUC/energy/Solar/aboutsolar.htm.

[17] Exhibit 3115 Assembly Bill No. 327 (Cal. 2013) https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327

with the unequal accounting of distributed PV under the current system, the addition of 3,316 MW of unanticipated rooftop solar by mid-2017 will have the effect of eliminating the need for approximately 1,100 MW of RPS-eligible solar capacity.[18]

C. *Net-Metered Rooftop PV Qualifies for Use as Tradeable Renewable Energy Credits for RPS Compliance*

CPUC Decision 11-01-025 lifted the stay on the eligibility of net-metered rooftop PV as tradeable renewable energy credits (RECs) available for RPS compliance. The title of January 14, 2011 Decision 11-01-025 is, "*Decision Resolving Petitions for Modification of Decision 10-03-021 Authorizing Use of Renewable Energy Credits for Compliance with the California Renewables Portfolio Standard and Lifting Stay and Moratorium Imposed by Decision 10-05-018*."[19] The CEC subsequently approved as RPS-eligible RECs electricity produced from customer-side distributed generation installations.[20] In practical terms, this means that the entire 3,316 MW of additional rooftop PV to be added by mid-2017 can be converted into RPS capacity through the sale of the RECs associated with this rooftop PV capacity to California IOUs. This is more than six times the 500 MW capacity of PSEGS.

D. *Impact of Higher-Than-Anticipated Distributed PV on RPS Procurement Is Real, CEC Projects No Increase in Electricity Consumption 2014-2024*

The most recent CEC projection of California electricity consumption over the 2014-2024 timeframe forecasts no increase in electricity consumption for the most likely "Mid-Demand Baseline, High-Mid Additional Achievable EE" scenario.[21] In the specific case of SCE territory, consumption is forecast by CEC to decline about 3 percent over the 2014-2024 period.[22] What this means in practical terms is that SCE will require somewhat less RPS-eligible resources in 2024 than in 2014 to meet the 33 percent RPS requirement.

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[18] This assumes a typical net-metered fixed rooftop solar capacity factor of 20 to 21 percent.

[19] Exhibit 3116 See: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/129517.pdf.

[20] See CEC-300-2013-005-ED7-CMF-REV (California Energy Commission's April 2013 "Renewables Portfolio Standard Eligibility Guidebook," seventh edition), p. 63. "Similarly, grid-connected facilities participating in the net-metering tariffs or consuming some or all of the electricity produced by the renewable energy resource onsite and not exporting all of the electricity to the electricity grid may apply for certification to be RPS-eligible, if all eligibility requirements are met for that resource type."

[21] CEC, California Energy Demand 2014-2024 Final Forecast LSE and Balancing Authority Forecasts, Form 1.1c, April 15, 2014. See: http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/LSE_and_Balancing_Authority_Forecasts/.

[22] 2014 bundled and unbundled SCE demand = 86,753 GWh/yr. 2024 bundled and unbundled SCE demand = 83,952 GWh/yr. Net change, 2014 to 2024 = [(83,952 GWh/yr - 86,753 GWh/yr)/ 86,753 GWh/yr] = -3.2 percent (-0.032).

Peak load has also been declining steadily in California Independent System Operator (CAISO) territory, and SCE territory, since 2006.[23] The CAISO one-hour peak load in 2006 was 50,270 MW. The CAISO one-hour peak load in 2013 was 45,097 MW, a 10 percent decline. The SCE one-hour peak load in 2006 was 23,831 MW.[24] The SCE one-hour peak load in 2013 was 22,498 MW,[25] a 6 percent decline.

Therefore, the displacement of RPS capacity needed to meet the 33 percent by 2020 target caused by far larger additions of net-metered rooftop PV than anticipated in CEC forecasts prior to the passage of AB 327 in October 2013 is real displacement that will not be diluted by load growth over time.

III. Battery Storage: 1,325 MW to Be Under Contract by 2020

AB 2514, as codified at Pub. Util. Code Section 2835 et. seq., mandates that investor-owned utilities comply with energy storage targets adopted by the Commission.[26] Public Utilities Code Section 2836(a)(1) directs the Commission to "determine appropriate targets, if any, for each load-serving entity to procure viable and cost-effective energy storage systems to be achieved by December 31, 2015, and December 31, 2020." Section 2836(a)(2) mandates that the Commission adopt procurement targets, if determined to be appropriate, by October 1, 2013. Individual pumped-storage facilities are limited to 50 MW.[27]

The Commission set mandatory energy storage targets for the utilities in Decision D.13-10-040. Decision D.13-10-040 requires that utilities purchase energy storage projects equal to 1 percent of their 2020 annual peak load by 2020,[28] for a total of 1,325 MW across all utilities installed and operational by no later than the end of 2024.[29] Decision D. 13-10-040, orders SCE and PG&E to each purchase 580 MW of energy storage by 2020, and orders SDG&E to purchase 165 MW of energy storage by 2020.[30]

AB 2514 further provides that, once adopted by the Commission, energy storage targets are mandatory and *must* be met by the utilities. Public Utilities Code Section 2837 provides that once energy storage targets are adopted, "[e]ach electrical corporation's renewable energy procurement plan [as required by Public Utilities Code Section 399.11 et. seq.] shall require the utility to procure new energy storage systems that are appropriate to allow the electrical corporation to comply with the energy storage system

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[23] Exhibit 3117 CAISO, *California ISO Peak Load History 1998 through 2013*, January 2, 2014. See: http://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf.
[24] CAISO OASIS "System Load" database, 2006 – 2013. See: http://oasis.caiso.com/mrioasis/logon.do;jsessionid=8C0E842B1B72BE47597C4D0DB2DD1FDC.
[25] Ibid.
[26] Pub. Util. Code Sections 2836(a) and 2837
[27] Exhibit 3118 M. Charles – CPUC, *California's Energy Storage Mandate: Oregon Energy Storage Workshop*, March 19, 2014, p. 12. See: http://www.oregon.gov/energy/docs/Melicia%20Charles_CalPUC.pdf
[28] Exhibit 3119 D.13-10-040, Conclusion of Law 29, at p. 74
[29] Exhibit 3119 D.13-10-040, Conclusion of Law 41, at p. 76
[30] Exhibit 3119 D.13-10-040, Ordering Paragraph 1, at p. 76; Appendix A at p. 2.

procurement targets and policies adopted pursuant to Section 2836." The purposes of this mandatory utility energy storage procurement include:[31]

- Reducing the need for new fossil-fuel powered peaking generation;
- Reducing purchases of electricity generation sources with higher emissions of greenhouse gasses;
- Reducing the demand for electricity during peak periods;
- Avoiding or delaying investments in transmission system upgrades;
- And using energy storage systems to provide the ancillary services otherwise provided by fossil-fuel generating facilities

In meeting the mandatory energy storage requirements adopted by the Commission in D.13-10-040, utilities must comply with Section 2836, which provides that the purposes of energy storage procurement include reducing the need for fossil-fuel powered peaking generation, reducing the need to purchase electricity generation sources with higher greenhouse gas emissions, and using energy storage to provide the ancillary services normally provided by fossil fuel generation.

Areas in California with local capacity requirements, also known as "load pockets," are shown in Figure 1. Energy storage facilities would be most effective in load pockets, like SCE's LA Basin load pocket, where the energy storage could serve to meet local capacity requirements during periods of peak demand and store renewable energy as needed. AB 2514 specifically states that "The purposes of this mandatory utility energy storage procurement include reducing the need for new fossil-fuel powered peaking generation." Gas-fired peaking generation is generally located in load pockets to meet demand in the load pocket under peak demand conditions.

The PSEGS site is outside of the LA Basin load pocket. It would difficult to economically justify authorizing energy storage to be built outside of the load pocket at PSEGS as energy storage at this location would provide no local capacity value for the LA Basin load pocket. The CPUC recently authorized 500 to 700 MW of new supply procurement in SCE's LA Basin load pocket.[32] No energy storage located at PSEGS would count toward meeting this 500 to 700 MW need. However, energy storage located within the LA Basin load pocket would count toward meeting this need and offset the construction of new gas-fired peaking plants in the load pocket.

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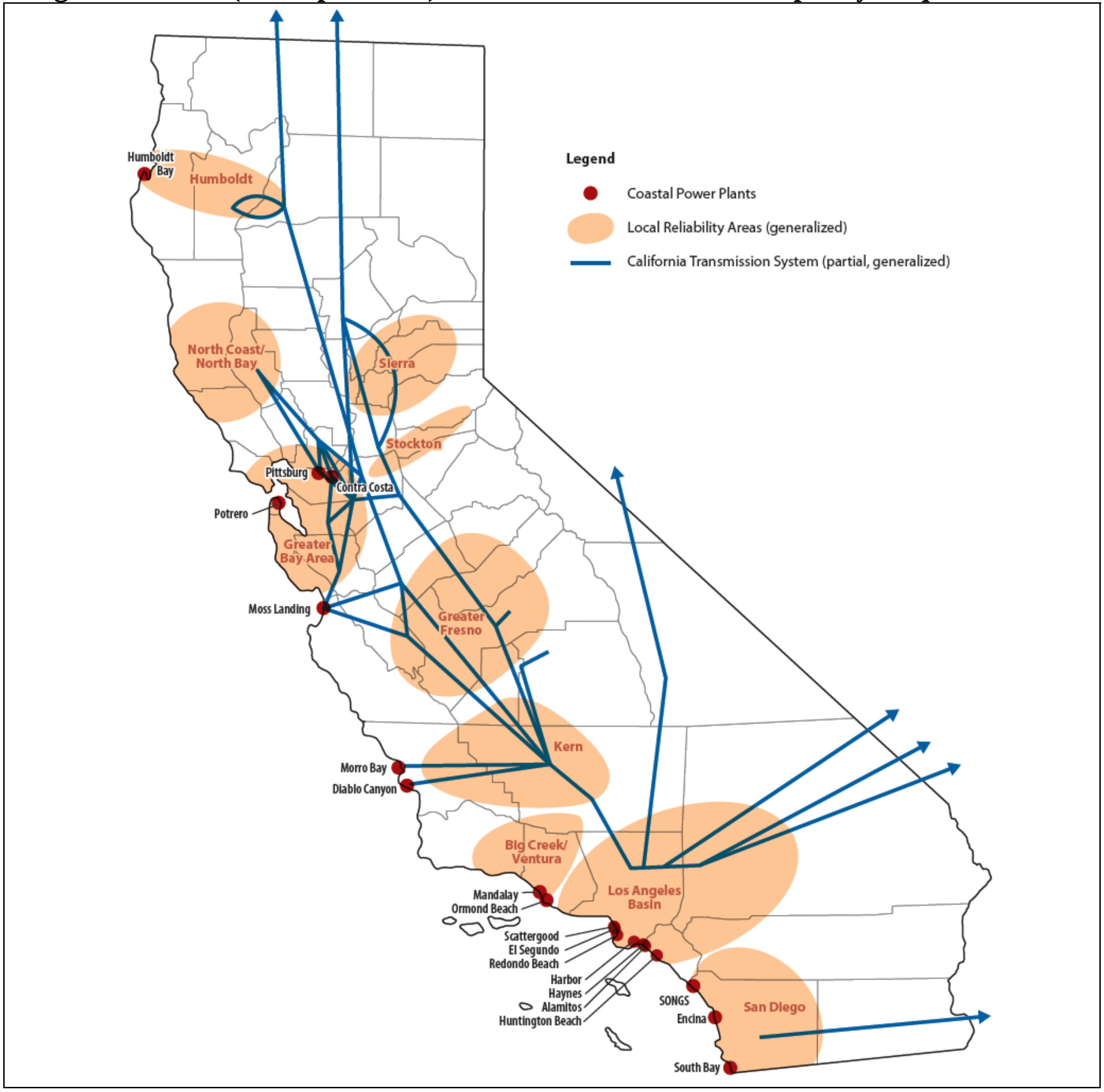
[31] Pub. Util. Code § 2837.
[32] Exhibit 3120 CPUC press release, *CPUC Acts to Ensure Energy Reliability in Southern California*, March 13, 2014: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M088/K989/88989943.PDF

Figure 1. Areas ("load pockets") in California with Local Capacity Requirements[33]



IV. PV and PSEGS Cost Comparison

A. PV Without Battery Storage Versus PSEGS Without Storage

Relatively small PV installations are now being built for less than $2,000/kW. [34]. Current prices for electricity from utility-scale PV power plants in the western U.S. have dropped

[33] Exhibit 3121 ICF Jones & Stokes, *Electric Grid Reliability Impacts for Regulation of Once-Through Cooling in California*, April 2008, Figure 1.

[34] Exhibit 3122 Energy Prospects West, *PNM to Build Four Solar Projects Next Year*, June 10, 2014. "PNM will build four 10-MW photovoltaic solar power projects in 2015. The four projects will cost $79 million to build." Unit cost = $79,000,000/40,000 kW = $1,975/kW.

to approximately $45 to $70 per MWh, or $0.045 to $0.070/kWh.[35] This compares to a power tower capital cost of approximately $5,500/kW without thermal storage at the power tower Ivanpah Solar Electric Generating Station, and an associated cost-of-electricity of approximately $0.17/kWh.[36] In other words, in 2014, the estimated cost of power production from a power tower installation is as much as three to four times greater than utility-scale PV power production at the same location.

It is important to note that the low current cost of PV installations is just as applicable to rooftop installations if these rooftop projects are bundled into a single larger project. For example, the capital cost figure of less than $2,000/kW is for four 10 MW projects.[37] Twenty 500 kW rooftop projects can be bundled as a single 10 MW project, or eighty 500 kW rooftop projects can be bundled as a single 40 MW project, to achieve the economies-of-scale necessary to achieve a capital cost price point at or near $2,000/kW.

B. PV With Battery Storage Versus PSEGS With Storage

Thermal storage is expensive. The estimated average capital cost of a 200-megawatt dry-cooled solar thermal plant with six hours of thermal storage is $7,750/kW, 42 percent more than the capital cost of a solar thermal plant without storage.[38]

Including lead-carbon battery storage to the PV system, or comparable sealed acid gas matt (AGM) lead-acid battery, would add about $500 per kWh to the cost of the PV system.[39] This means that adding three hours of energy storage, sufficient for the PV system to act as a completely reliable early evening peaking power system when electricity demand and power prices are high, would add around $1,500/kW to the PV system cost. The overall system cost of the PV system with three hours of storage would be about $3,500/kW, assuming a current PV system cost without storage of $2,000/kW.

This is much lower than the $7,750/kW capital cost of the solar thermal plant with storage while providing economically "right-sized" energy storage capacity tailored for current and foreseeable energy market conditions.

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[35] Exhibit 3123 Energy Prospects West, *Large-Scale Solar Prices Plummet in the West*, April 1, 2014. Current Prices for electricity from utility-scale photovoltaic (PV) power plants in the western U.S. already have sunk to approximately $45 to $70 per MWh, as reflected in several recently approved power purchase agreements (PPAs) between utilities and developers from California to Texas.

[36] Exhibit 3124 GreenTech Media, *Update: Ivanpah Gets Approval; Construction May Begin Soon*, September 22, 2010. At $5.46/W, and 30% capacity factor, Ivanpah should be producing power for a cost of about $0.17/kWh.

[37] Exhibit 3122 Energy Prospects West, *PNM to Build Four Solar Projects Next Year*, June 10, 2014. "PNM will build four 10-MW photovoltaic solar power projects in 2015. The four projects will cost $79 million to build." Unit cost = $79,000,000/40,000 kW = $1,975/kW.

[38] Renewable Energy Transmission Initiative (California), *RETI Phase 2B Final Report*, May 2010, Table 4-6, p. 4-6. (TN 58860 at Official Notice Requested))

[39] Exhibit 3125 Natural Gas & Electricity Journal, *Federal Government Betting on the Wrong Solar Horse*, December 2010, footnote 11.

V. Conclusion

The December 2013 PMPD denial of the PSEGS project is appropriate because there are better, feasible alternatives. Higher than anticipated net-metered rooftop PV additions over the next several years brought about by the passage of AB 327 moot the justification that there is a need for a remote solar thermal project at the Palen site. Even without this development, solar PV in any format, either utility-scale PV or large-scale distributed PV on rooftops, is a lower-cost, lower environmental impact alternative than the proposed PSEGS project.

These comments also hold true regarding solar projects equipped with storage. PV equipped with limited battery storage to address the early evening summer peak demand period is substantially more cost-effective than adding thermal storage at PSEGS to achieve the same purpose. PV projects equipped with battery storage in load pockets, such as SCE's LA Basin load pocket, is the most cost-effective application of energy storage, as it would serve the dual purpose of adding to local capacity necessary to meet peak demand in the load pocket while also providing renewable energy storage capability.

Declaration of Bill Powers P.E.

Re: Response to May 21, 2014 Committee Order Granting Petitioner's Motion to Reopen the Evidentiary Record and Setting Revised Schedule, Palen Solar Electric Generating System Amendment

Docket 09-AFC-7

I, Bill Powers, declare as follows:

1) I am currently a registered professional mechanical engineer in California with over 30 years of experience in the energy and environmental fields. I am also the owner of Powers Engineering.

2) My relevant professional qualifications and experience are set forth in my previously submitted resume submitted in this matter and the attached testimony and are incorporated herein by reference.

3) I prepared the testimony attached hereto and incorporated herein by reference, responding to the May 21, 2014 Committee Order Granting Petitioner's Motion to Reopen the Evidentiary Record and Setting Revised Schedule, Palen Solar Electric Generating System Amendment

4) I prepared the testimony attached hereto and incorporated herein by reference relating to the proposed Palen Solar Electric Generating System in the Chuckwalla Valley in Riverside County.

5) It is my professional opinion that the attached testimony is true and accurate with respect to the issues that is addressed.

6) I am personally familiar with the facts and conclusions described within the attached testimony and if called as a witness, I could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Bill Powers, P.E.

Dated: June 23, 2014 Signed:

At: San Diego, California

Bill Powers, P.E.

Professional History

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

Education

Master of Public Health – Environmental Sciences, University of North Carolina
Bachelor of Science – Mechanical Engineering, Duke University

Professional Affiliations

Registered Professional Mechanical Engineer, California (Certificate M24518)
American Society of Mechanical Engineers
Air & Waste Management Association

Technical Specialties

Thirty years of experience in:

- Power plant air emission control system and cooling system assessments
- Petroleum refinery air engineering and testing
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Latin America environmental project experience

Power Plant Emission Control and Cooling System Conversion Assessments

LMS100 Gas Turbine Power Plant Air Emissions Control Assessment. Lead engineer to assess Best Available Control Technology (BACT) for four proposed LMS100 gas turbines to be owned and operated by El Paso Electric Company. El Paso Electric proposed NOx and CO emission rates of 2.5 ppm and 6.0 ppm respectively, use of wet cooling tower(s) for intercooler heat rejection, and up to 5,000 hours per year of operation. I identified BACT as equivalent to combined cycle plant levels, 2.0 ppm NO_x and 2.0 ppm CO, due to high operating hour limit., and air cooling with mist augmentation at high ambient temperatures as BACT for PM. The TCEQ Office of Public Interest Council agreed that BACT for the LMS100s should be 2.0 ppm NO_x and 2.0 ppm CO, and that air cooling with mist augmentation should be BACT for PM**.**

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NOx and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ^oF and 13 ^oF were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ^oF and 13 ^oF. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ^oF. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Kentucky Coal-Fired Power Plant – Pulverized Coal vs IGCC. Expert witness in Sierra Club lawsuit against Peabody Coal Company's plan to construct a 1,500 MW pulverized-coal fired power plant in Kentucky. Presented case that Integrated Gasification Combined Cycle (IGCC) is a superior method for producing power from coal, from environmental and energy efficiency perspective, than the proposed pulverized-coal plant. Presented evidence that IGCC is technically feasible and cost competitive with pulverized coal.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Utility Boiler – Best Available NO_x Control System for 525 MW Coal-Fired Circulating Fluidized Bed Boiler Plant. Expert witness in dispute over whether 50 percent NO_x control using selective non-catalytic reduction (SNCR) constituted BACT for a proposed 525 MW circulating fluidized bed (CFB) boiler plant. Presented testimony that SNCR was capable of continuous NO_x reduction of greater than 70 percent on a CFB unit and that tail-end selective catalytic reduction (SCR) was technically feasible and could achieve greater than 90 percent NO_x reduction.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

BP Whiting Refinery Expansion Air Permit. Served as lead engineer on review of netting analysis that resulted in the BP Whiting Refinery Expansion receiving a minor source air permit from the Indiana Department of Environmental Management. Determined that BP Whiting omitted several major sources of emissions, underestimated others, and incorrectly calculated contemporaneous increases and decreases in air emissions. These sources included refinery heaters, flares, coking units, sulfur recovery, and fugitive emissions. These errors and omissions were sufficient in number and magnitude to exceed NSR significance thresholds.

Hyperion Refinery Air Permit. Served as lead engineer on review of BACT determinations in the PSD air permit for the proposed Hyperion Refinery in South Dakota.. BACT review included controls for refinery heaters, cooling systems, fugitive emissions, and greenhouse gases. BACT was identified as SCR for all refinery heaters, use of enclosed ground flare for periodic flare gas emissions from gasification process, and use of leakless fugitive emission components.

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 ^oF and 20 ^oF were evaluated. The annualized cost of the fin-fin air-cooler with a 20 ^oF approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the wide availability of urea on the island. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.
Microturbines – Ronald Reagan Library, Ventura County, California.

Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines will be equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea will be used as the SCR reagent to avoid trigger hazardous material storage requirements. A separate permit will be obtained for the NO_x and CO continuous emissions monitoring systems. The ATCs is pending.

Industrial Boilers – NO_x BACT Evaluation for San Diego County Boilers.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for three industrial boilers to be located in San Diego County. The BACT included the review of low NO_x burners, FGR, SCR, and low temperature oxidation (LTO). State-of-the-art ultra low NO_x burners with a 9 ppm emissions guarantee were selected as NO_x BACT for these units.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.
Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District.
Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling.
Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle “repower” project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month

construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM.
Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM passed the subsequent annual RATA without problems as a result of changes to some of the CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "\$/kwh" and "\$/ton" cost of these control systems was developed in the evaluation.

Gas Turbines – Evaluation of Proposed NO_x Control System to Achieve 3 ppm Limit.
Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol.
Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 ^oF) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Bay Area Smart Energy 2020 Plan . Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County. Report is available online at: http://pacificenvironment.org/-1-87.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The preliminary decision issued by the presiding CEC commissioner in the case recommended denial of the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines. No final decision has yet been issued in the proceeding (as of May 2009).

San Diego Smart Energy 2020 Plan. Author of October 2007 "San Diego Smart Energy 2020," an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy whether, and for grid reliability support. Report at: http://www.etechinternational.org/new_pdfs/smartenergy/52008_SmE2020_2nd.pdf

Development of San Diego Regional Energy Strategy 2030. Participant in the 18-month process in the 2002-2003 timeframe that led to the development of the San Diego Regional Energy Strategy 2030. This document was adopted by the SANDAG Board of Directors in July 2003 and defines strategic energy objectives for the San Diego region, including: 1) in-region power generation increase from 65% of peak demand in 2010 to 75% of peak demand in 2020, 2) 40% renewable power by 2030 with at least half of this power generated in-county, 3) reinforcement of transmission capacity as needed to achieve these objectives. The SANDAG Board of Directors voted unanimously on Nov. 17, 2006 to take no position on the Sunrise Powerlink proposal primarily because it conflicts the Regional Energy Strategy 2030 objective of increased in-region power generation. The Regional Energy Strategy 2030 is online at: http://www.energycenter.org/uploads/Regional_Energy_Strategy_Final_07_16_03.pdf

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.

Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application “templates” for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

BACT Evaluation of Wool Fiberglass Insulation Production Line. Project manager and lead engineer for BACT evaluation of a wool fiberglass insulation production facility. The BACT evaluation was performed as a component of a PSD permit application. The BACT evaluation included a detailed analysis of the available control options for forming, curing and cooling sections of the production line. Binder formulations, wet electrostatic precipitators, wet scrubbers, and thermal oxidizers were evaluated as potential PM_{10} and VOC control options. Low NO_x burner options and combustion control modifications were examined as potential NO_x control techniques for the curing oven burners. Recommendations included use of a proprietary binder formulation to achieve PM_{10} and VOC BACT, and use of low-NO_x burners in the curing ovens to achieve NO_x BACT. The PSD application is currently undergoing review by EPA Region 9.

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions. The cost of these potential PM_{10} RACT controls exceeded regulatory guidelines for cost effectiveness, though testing of modified shield configurations and dense-phase conveying is being conducted under a separate regulatory compliance order.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications. The coater line was equipped with an afterburner for VOC and CO destruction prior to the initiation of the RACT study. It was determined that the afterburner meets or exceeds RACT requirements for the coater line. Significant sources of PM_{10} emissions included the remelt furnaces and the 80-inch hot rolling mill. Chlorine fluxing in the melting and holding furnaces was identified as the principal source of PM_{10} emissions from the remelt furnaces. The facility is in the process of minimizing/eliminating fluxing in the melting furnaces, and exhaust gases generated in holding furnaces during fluxing will be ducted to a baghouse for PM_{10} control. These modifications are being performed under a separate compliance order, and were determined to exceed RACT requirements. A water-based emulsion coolant and inertial separators are currently in use on the 80-inch hot mill for PM_{10} control. Current practices were determined to meet/exceed PM_{10} RACT for the hot mill. Tray tower absorption/recovery systems were also evaluated to control PM_{10} emissions from the hot mill, though it was determined that the technical/cost feasibility of using this approach on an emulsion-based coolant had not yet been adequately demonstrated.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops. Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Preliminary Design of Ambient Air Quality Monitoring Network – Lima, Peru. Project leader for project to prepare specifications for a fourteen station ambient air quality monitoring network for the municipality of Lima, Peru. Network includes four complete gaseous pollutant, particulate, and meteorological parameter monitoring stations, as well as eight PM_{10} and TSP monitoring stations.

Evaluation of Proposed Ambient Air Quality Network Modernization Project – Venezuela. Analyzed a plan to modernize and expand the ambient air monitoring network in Venezuela. Project was performed for the U.S. Trade and Development Agency. Direct interaction with policy makers at the Ministerio del Ambiente y de los Recursos Naturales Renovables (MARNR) in Caracas was a major component of this project.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters.

Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Renewable Energy Resource Assessment Proposal – Panama. Translated and managed winning bid to evaluate wind energy potential in Panama. Direct interaction with the director of development at the national utility monopoly (IRHE) was a key component of this project.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at turbocharger/air cooler assembly plant in Mexicali, Mexico. Source specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish for review by the Mexican federal environmental agency (SEMARNAP).

Air Pollution Control Equipment Retrofit Evaluation – Mexico. Project manager and lead engineer for comprehensive evaluation of air pollution control equipment and industrial ventilation systems in use at assembly plant consisting of four major facilities. Equipment evaluated included fabric filters controlling blast booth emissions, electrostatic precipitator controlling welding fumes, and industrial ventilation systems controlling welding fumes, chemical cleaning tank emissions, and hot combustion gas emissions. Recommendations included modifications to fabric filter cleaning cycle, preventative maintenance program for the electrostatic precipitator, and redesign of the industrial ventilation system exhaust hoods to improve capture efficiency.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at automotive components assembly plant in Acuña, Mexico. Source-specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

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AWARDS

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