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STATE OF CALIFORNIA

Energy Resources Conservation and Development Commission

In the Matter of: APPLICATION FOR CERTIFICATION OF THE PUENTE POWER PROJECT	DOCKET NO. 15-AFC-01

EXHIBIT 7000

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prepared for

Center for Biological Diversity

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I. SUMMARY

- The project objectives listed in the FSA need to be modified to assure a neutral certification process.
- The decline in the demand forecast for the Big Creek/Ventura area has eliminated the justification for the project, making the No Project Alternative feasible and preferred.
- Puente will contribute to increasing GHG emissions from gas-fired generation in California, as less efficient simple cycle gas turbines are operated more frequently.
- The 11 percent capacity factor assumed by Commission staff for CEQA mitigation air emission offsets must be an enforceable cap.
- Emission offsets must be post-baseline, quantifiable emission reductions that benefit the surrounding communities.
- Battery storage is a feasible and cost-effective alternative to Puente that meets all the performance objectives of the proposed project.
- Demand response is a feasible and cost-effective alternative to Puente that meets all the performance objectives of the proposed project.

II. SOME PROJECT OBJECTIVES CAN ONLY BE MET BY PROPOSED PROJECT AND MUST BE DELETED OR MODIFIED

As the project objectives are written in the FSA, only the project exactly as proposed could meet them. Some project objectives go beyond necessary performance criteria that would allow consideration of alternative methods of achieving the performance criteria other than the exact project that is proposed by the Applicant. The performance objectives that need to be deleted or modified as indicated by the following strikethrough edits and bold text additions:[1]

- ~~Fulfill NRG's obligations under its 20-year Resource Adequacy Purchase Agreement (RAPA) with SCE requiring development of a 262-MW nominal net output of newer, more flexible and efficient, natural-gas generationP0F~~
- Provide an efficient, reliable, and predictable power supply ~~by using a simple-cycle, natural-gas- fired combustion turbine~~ to replace the existing once-through cooling (OTC) generation;
- Support the local capacity requirements of the California Independent System Operator (CAISO) Big Creek/Ventura local capacity reliability (LCR) area;
- Develop a ~~262-MW nominal net power-generating plant~~ **resource** that provides operational flexibility with rapid-start and fast-ramping capability;
- Be designed, permitted, built, and commissioned by June 1, 2020;
- Minimize environmental impacts and development costs by developing on an

[1] FSA Part 1, p. 1-3.

existing brownfield site and reusing existing infrastructure, **if a physical resource will be utilized**;
- Site the project on property that has an industrial land use designation with consistent zoning, **if a physical resource will be utilized**.

The California Public Utilities Commission (CPUC) was unambiguous in its December 1, 2016 final approval of the Puente power purchase agreement (PPA) that the existence of a PPA should in no way influence the California Energy Commission's (CEC) independent responsibility to conduct a thorough and neutral certification process. Specifically, the CPUC's final approval of the Puente PPA states:[2]

> Even if contract approval were to improve the overall risk profile for a developer, many more factors go into whether a project ultimately comes to fruition. Further, the CEC has an independent responsibility to conduct a thorough and neutral certification process. And the Commission (CPUC) has been clear that its approval of a power purchase contract should not be used by any parties to influence whether the CEC determines to certify the project and find it CEQA compliant.

The Commission's certification process cannot be "thorough and neutral" if several of a limited number of project objectives in the FSA require the exact project, or a functionally equivalent simple cycle gas turbine project, approved for a PPA by the CPUC. Without project objectives that level the playing field to permit serious scrutiny of all feasible alternatives with the necessary operational characteristics, the Puente certification process will be a rote exercise with a predetermined answer.

III. GRID RELIABILITY JUSTIFICATION FOR PUENTE IS BASED ON OUTDATED 2009 CEC DEMAND FORECAST – CHANGED CIRCUMSTANCES HAVE ELIMINATED NEED FOR THE PROJECT

The grid reliability need that Puente is intended to meet was identified by the CPUC in D.13-02-015, as noted in the FSA.[3] D.13-02-015 states that forecasts used in the CEC's 2009

[2] **Exhibit 7001**: CPUC, *D.16-12-030, Order Modifying Decision (D.) 16-05-050 and Denying Rehearing, As Modified*, December 1, 2016, p. 14.
[3] FSA, p. 4.1-146. "Authorization for Southern California Edison (SCE) to procure natural gas-fired generation or other least-cost (preferred) resources to replace retiring OTC capacity in the Moorpark sub-area of the Big Creek -

Integrated Energy Policy Report (IEPR) were used to determine the local capacity requirement (LCR) authorization for the Big Creek/Ventura LCR.[4] The adopted 2009 California Electricity Demand forecast used in the CEC's 2009 IEPR projected a 1-in-10 year 2020 peak demand in the Big Creek/Ventura Local Capacity Area (LCA) of 5,186 MW.[5] In contrast, the 2016 California Electricity Demand forecast projected a 2020 1-in-10 year peak demand in the Big Creek/Ventura LCA of 4,479 MW.[6] 2020 is the proposed online date for the Puente project. The more current 2016 forecast is approximately 700 MW lower than the 2009 forecast that resulted in an authorization of 215 MW to 290 MW of gas-fired generation in the Big Creek/Ventura LCR in D.13-02-015.

The load growth forecast by the CEC for the Big Creek/Ventura LCA in 2009, which was the basis for the CPUC authorization for the Puente project, never materialized. In the 2016 CEC forecast, which covers the 2016-2027 timeframe, the forecast peak demand for the Big Creek/Ventura LCA in 2016 is 4,547 MW. This is higher than the CEC's peak demand forecast of 4,479 MW for 2020. What is more, the 2016 CEC forecast indicates that peak demand in the Big Creek/Ventura LCA will remain essentially unchanged from 2020 through 2027.[7] The need for Puente, based on the current CEC forecast for 2020 demand, to assure grid reliability in the Big Creek/Ventura LCA is gone. Therefore, the No Project Alternative is feasible.

Ventura LCA was granted in D.13-02-015 (February 13, 2013) in the CPUC's 2012 LTPP proceeding (R.12-03-014). The decision authorized SCE to procure no less than 215 MW and no more than 290 MW."

[4] **Exhibit 7002**: D.13-02-015, p. 119. "Findings of Fact: 1) It is reasonable for the Commission (CPUC) only to consider LCR forecasts by the ISO using renewable portfolio scenarios already in the record of R.10-05-006. 2) It is reasonable to use local capacity studies and power flow modeling from the ISO for LCR forecasting. 3) The ISO used demand forecasts provided by the CEC in its 2009 IEPR, which used 2009 demand forecast data. It is reasonable to use this data for LCR forecasting in this proceeding."

[5] **Exhibit 7003**: California Energy Demand 2010-2020 Staff Revised Forecast, Form 1.5d, Statewide 1-in-10 Net Electricity Peak Demand by Agency and Balancing Authority, December 2009.

[6] **Exhibit 7004**: California Energy Demand Update Forecast, 2016 - 2027, Mid Demand Baseline Case, Mid AAEE Savings, Form 1.5d – Statewide, 1 in 10 Net Electricity Peak Demand by Agency and Balancing Authority (MW), January 2016.

[7] Ibid. 2020 peak demand forecast for Big Creek/Ventura LCR = 4,479 MW. 2027 peak demand forecast for Big Creek/Ventura LCR = 4,472 MW.

IV. PUENTE WILL NOT LOWER GHG FOOTPRINT OF GAS-FIRED GENERATION IN CALIFORNIA OR IN THE WECC

A. Greater Use of Simple Cycle Gas Turbines Like Puente Is Driving Up Greenhouse Gas Emissions from Gas-Fired Generation in California

As the FSA explains, combined cycle units had largely displaced aging coastal steam boilers in California by 2010, seven years ago.[8] Since 2010, the capacity factors of combined cycle units in California have been declining, while the capacity factors of simple cycle gas turbines have been increasing, as shown in Table 1. During this timeframe the capacity factor of aging coastal steam units was relatively stable, at 5.4 percent in 2010 and 5.3 percent in 2014.[9,10] What this means from a GHG emissions standpoint is that lower efficiency simple cycle gas turbines are incrementally displacing the output of higher efficiency combined cycle gas turbines, and more GHG emissions are being emitted on average from gas-fired generation in California.

Table 1. 2010-2014 capacity factors for California combined cycle and simple cycle units[11]

Unit type	Capacity factor (%)				
	2010	2011	2012	2013	2014
Combined cycle	59.9	59.4	57.1	56.0	54.7
Simple cycle	3.2	3.6	4.9	4.7	5.9

This translates into a decline in the thermal efficiency of gas-fired generation in California, which is reflected in a rising "heat rate."[12] As shown in Table 2, the average heat rate of gas-fired power plants in California increased from 7,634 Btu/kWh in 2010 to 7,750 Btu/kWh in 2014. Adding another lower efficiency simple cycle gas turbine, in this case Puente, will

[8] FSA, p. 4.1-148. "In 2001, approximately 74,000 GWh (62.5 percent of natural gas-fired generation) in California was from pre-1980 natural gas-fired steam turbines, combusting an average of 11,268 Btu per kWh (not shown in the figure). By 2010, this share had fallen to approximately 6,000 GWh (5.4 percent); 64.1 percent of natural gas-fired generation was from new combined cycles with an average heat rate of 7,201 Btu per kWh (CEC 2011, also not shown in the figure)."
[9] Ibid, Table 3, p. 4.
[10] FSA, p. 4.1-148.
[11] **Exhibit 7005**: CEC, *Thermal Efficiency of Gas-Fired Generation in California: 2015 Update*, , March 2016, Table 3, p. 4.
[12] Heat rate = the amount of fuel heating value (in Btu) needed to produce a given amount of electricity (in kilowatt-hours).

exacerbate the problem of a rising average gas-fired power plant GHG footprint, per MWh of electricity generation, in California.

Table 2. Average heat rate of natural gas-fired power plants in California and the WECC, 2010 through 2014

Greenhouse Gas Table 5
Weighted Average Heat Rate for Operating Natural Gas-Fired Plants[1] in the WECC and California 2010-2013

Year	Average WECC Heat Rate [2] (MMBtu/MWh)	Average CA Heat Rate [3] (MMBtu/MWh)
2010	7,712	7,634
2011	7,954	7,881
2012	7,841	7,806
2013	7,771	7,666
2014	7,761	7,750

[1] Excludes cogeneration facilities
[2] Compiled from EIA-923 data.
[3] Compiled from Quarterly Fuel and Energy Reports submitted to the California Energy Commission.

That same trend is also evident in the Western Electricity Coordinating Council (WECC). The thermal efficiency of WECC gas-fired generation averaged 7,712 Btu/kWh in 2010, and 7,761 Btu/kWh in 2014 as shown in Table 2. The Puente heat rate is far higher, at 9,819 Btu/kWh,[13] than either the California or WECC average heat rates for gas-fired generation. The more Puente is used, the more Puente will put drive upward the average heat rate of gas-fired generation in California and in the WECC.

B. GHG Footprint of Puente Is Much Greater Than GHG Footprint of SCE Grid Power

Puente will emit 1,149 lb CO_2/MWh.[14] In contrast, SCE grid power emitted only 506 lb CO_2/MWh in 2015.[15] The Puente GHG footprint is more than double the average SCE GHG grid power footprint of 506 lb CO_2/MWh.

This is of particular importance when considering the battery storage alternative to Puente. The electricity stored by the battery will be SCE grid power. As the GHG footprint of SCE grid power declines, the GHG footprint of the electricity stored in the battery also declines.

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[13] Puente heat rate = 2,572,000,000 Btu/hr (FSA, p. 5.3-3) ÷ 262,000 kW net (FSA, p. 5.3-1) = 9,819 Btu/kWh (net).
[14] 9,819 Btu/kWh is equivalent to 9.819 MMBtu/MWh. The CO_2 emission factor per MMBtu = 117 lb CO_2/MMBtu. The CO_2 emission factor for Puente = 117 lb CO_2/MMBtu x 9.819 MMBtu/MWh = 1,149 lb CO_2/MWh.
[15] **Exhibit 7006**: SCE, *2015 Edison International Corporate Responsibility Report*, p. 28, grid power GHG = 0.23 metric tons/MWh.

In contrast, the GHG footprint of Puente will remain fixed at 1,149 lb CO_2/MWh throughout the operational lifetime of the Puente project.

C. Economic Dispatch Based On Heat Rate Cannot Be Presumed – Other Dispatch Considerations Are Overriding Economic Dispatch

The FSA claim that simple cycle gas turbines have certain unique characteristics that merit their more frequent usage, than would be warranted based on fuel efficiency alone when compared to combined cycle units, is unsupported. NRG bid both a conventional combined cycle option and two simple cycle options, the GE Frame 7HA.01 and the LMS100 at the Mandalay site.[16] The LMS100 is significantly more efficient than the GE Frame 7HA.01, 44 percent versus 41 percent.[17] For reasons not explained by the Applicant, SCE selected the least efficient of the two simple-cycle options offered, the GE Frame 7HA.01. Presumably the Applicant proposed a conventional combined cycle project for the site because the combined cycle project could meet the grid reliability and ramping functions defined in the SCE RFO (Request For Offers).[18] The FSA provides hypothetical reasons why a simple cycle unit might be dispatched ahead of a combined cycle unit, despite the much better heat rate of the combined cycle unit. However the explanation rings hollow knowing NRG bid a combined cycle unit for the same duty at the same site.

The FSA gives the following general reasons why a lower efficiency simple cycle unit would be dispatched before a higher efficiency gas-fired unit:[19]

- Gas plants that are very efficient at full output are not necessarily dispatched before less efficient ones.
- Use of this plant to meet contingency needs (e.g., demand on a hot afternoon) may result in less incremental fuel combustion than a 100-MW plant with a lower heat rate at full output if the latter requires several hours and combusts large amounts of fuel to start up, must be kept on overnight or for several hours in order to be available later the same day or the next day, and/or cannot operate at 30

[16] **Exhibit 7007**: TN 215396, Applicant's Responses to Information Requested by VCAPCD re Application for Authority to Construct/ Determination of Compliance, May 15, 2015, Attachment 3 Section 5, Alternatives – Puente Power Project Application for Certification, p. 5-5.
[17] FSA, p. 5.3-5.
[18] **Exhibit 7007**: TN 215396, Applicant's Responses to Information Requested by VCAPCD re Application for Authority to Construct/ Determination of Compliance, May 15, 2015, Attachment 3 Section 5, Alternatives – Puente Power Project Application for Certification, p. 5-5.
[19] FSA, pp. 4.1-149 & 4.1-150.

MW without a marked degradation in thermal efficiency (and thus increases in GHG emissions).

- At levels of renewable energy penetration in excess of 33 percent, relatively efficient fast-start, fast-ramping resources such as Puente further contribute to GHG emission reductions by increasing the amount of renewable energy that can be integrated into the electricity system.

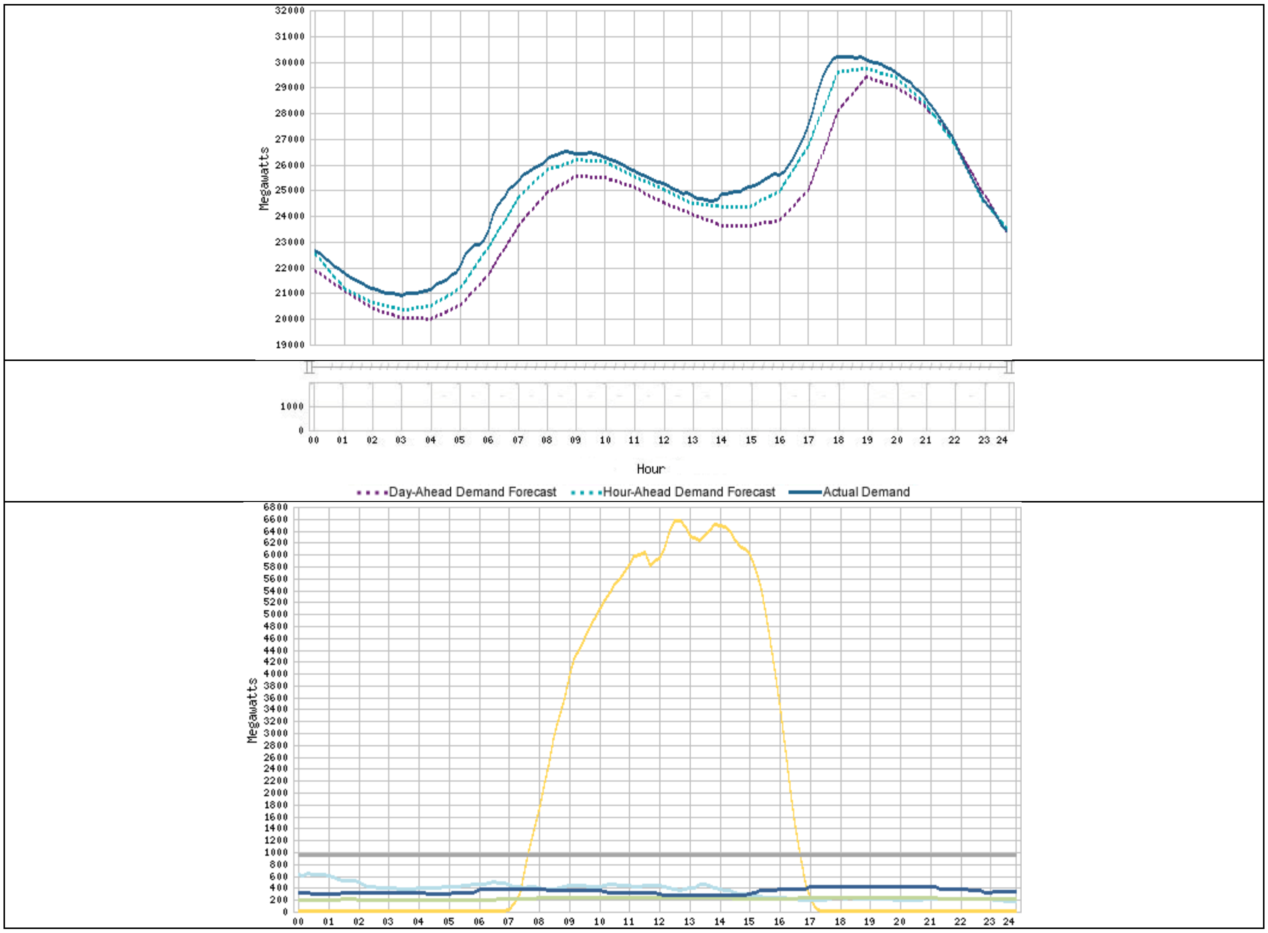
The only hypothetical reason given in the FSA for operating a lower efficiency simple cycle unit before a more efficient gas-fired unit is that the more efficient unit, presumably a combined cycle unit, is slow starting and inflexible in output. However, no evidence is provided to support this contention. On the contrary, NRG owns and operates the El Segundo combined cycle power plant and lauds its fast start capabilities and its flexibility.[20]

The FSA provides no evidence to support the implication that fast ramping to track the very predictable afternoon decline of solar resources in the CAISO control area is a unique characteristic of a simple cycle gas turbine like Puente. CAISO demand forecasts are generally accurate within about +/- 10 percent twenty-four hours in advance, and accurate to within 1 to 2 percent an hour in advance.

Figure 1 is a sample of the CAISO “24-hour ahead” and “1-hour ahead” forecasts with the actual demand for January 16, 2017. There is no need for dispatching units like Puente from cold start to full load in 10 minutes when the ramping demand is accurately predictable in advance and more efficient gas-fired resources can be scheduled to meet the ramping demand. If they are already online, they can simply adjust their output when they are already online to meet this demand.

[20] **Exhibit 7008**: Gas Turbine World, *550 MW El Segundo combined cycle provides 300 MW in 10 minutes*, September-October 2013.

Figure 1. Comparison of CAISO forecast to actual demand, January 16, 2017[21]



a. Generic assertions in FSA about need for gas-fired generation do not necessarily apply to the specific case of Puente

Commission staff make global comments in the FSA about the role of gas-fired generation and imply these are specific reasons why Puente must be constructed:[22]:

> A large share of midday generation must also be flexible, dispatchable natural gas as: (a) a threshold amount of thermal capacity needs to be idling (or at least readily available, not unlike a hybrid car) at mid-day at minimum output to protect against sudden component failures (major power plants and transmission lines), or drops in solar output; and, (b) a large amount of gas-fired generation will be needed 4 to 8 hours later when solar energy is unavailable, and thus must be on line and generating at minimum output at mid-day.

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[21] **Exhibit 7009**: CAISO homepage, January 17, 2017: http://www.caiso.com/Pages/Today's-Outlook-Details.aspx
[22] FSA p. 4.1-151.

The gas-fired generation role being described is applicable to the CAISO control area as a whole and is not specific to the Big Creek/Ventura LCA. A gas-fired generator located anywhere in Southern California, and potentially anywhere in California, could serve this ramping/load following need. High efficiency combined cycle power plants are the logical candidates to fill this role, given their high efficiency and flexibility.

However, California is now in the awkward position of allowing high efficiency combined cycle power plants to be mothballed while building lower efficiency simple cycle gas turbines to fill the same role. For example, CAISO advised in 2016 that the 965 MW La Paloma Generating Station, a combined cycle power plant located in Kern County, should be mothballed due to lack of demand for the plant's output. CAISO indicated that the company could seek approval from the CPUC for a "cold lay-up" of its units as a response to insufficient revenue from power sales or contracts to maintain profitability.[23] CAISO went on to state that Calpine Corporation was seeking such relief for the 500 MW Sutter Energy Center for at least the balance of 2016. The Sutter combined cycle plant is of a similar vintage to the La Paloma facility, and its owners have claimed economic issues similar to those claimed by La Paloma.

Existing combined cycle plants like La Paloma and Sutter are completely adequate to fill the ramping function described in the FSA for Puente.

D. Puente Will Not Reduce GHG Emissions from Power Generation at the Mandalay Facility

Commission staff concluded that Puente would replace less efficient power plant generation in the Big Creek/Ventura LCA, reducing the GHG emissions associated with and facilitating the retirement of units at the Mandalay Generating Station and Ormond Beach Generating Station.[24] Mandalay Units 1 & 2 averaged a 5 percent capacity factor over 2013-2014.[25]

The heat rate of Mandalay Unit 2 is 11,572 Btu/kWh.[26] The heat rate of Puente is 9,819 Btu/kWh.[27]

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[23] **Exhibit 7010**: CAISO, *Answer of the California Independent System Operator Corporation to (FERC) Compliant*, Docket No.EL16-88-000, July 7, 2016, pp. 7-8.
[24] FSA, p. 4.1-90.
[25] FSA p. 4.1-49, AQ Table 29.
[26] FSA p. 4.1-153, GHG Table 4, Mandalay Unit 2 heat rate = 11,572 Btu/kWh.
[27] Puente = 2,572,000,000 Btu/hr (FSA, p. 3-10) ÷ 262,000 kW (net) = 9,819 Btu/kWh (net).

The fuel efficiency of Puente is about 18 percent better than that of Mandalay Unit 2, 9,819 Btu/kWh vs 11,572 Btu/kWh. However, Puente is permitted to operate six times more frequently, 30 percent capacity factor, than the actual average operating rate of Mandalay 2 or Mandalay 1 (5 percent capacity factor). As a result, far more GHGs will be emitted from Puente than from existing operation of Mandalay Units 1 & 2 if Puente operates at or near its assumed capacity factor.

Also, as Puente is dispatched ahead of more efficient combined-cycle capacity, the GHG "cost" of this out-of-merit-order dispatch is significant. Puente will produce 306 lb CO_2/MWh more GHG emissions than a combined cycle unit performing the same ramping function.[28] As noted, that this out-of-merit-order dispatch is happening with greater frequency is reflected in: 1) the higher average heat rate of gas-fired generation in California and the WECC from 2010 to 2014, and 2) in the declining capacity factors of combined-cycle units in California, and the rising capacity factors of simple-cycle units, since 2010.

E. Thermal Efficiency of the Proposed GE Frame 7HA.01 Gas Turbine Is Poorer Than "Standard" LMS100 Simple Cycle Option

Puente will consist of a single General Electric (GE) Frame 7HA.01 single-fuel combustion turbine generator (CTG) and associated auxiliaries.[29] The GE Frame 7HA.01 has a thermal efficiency of 41 percent.[30] A simple cycle gas turbine alternative in common use in California is the 100 MW GE LMS100. The LMS100 has a thermal efficiency of 44 percent, significantly greater than the thermal efficiency of the GE Frame 7HA.01 turbine.[31] The reason given in the FSA for not selecting the LMS100 based on its superior fuel efficiency is that "*Three of them would be needed, since two of them would result in only approximately 200 MW net. The project site's available footprint is not large enough to accommodate three LMS100s*."[32] First, as explained in this testimony, not all of the 262 MW is needed and rejecting any consideration of this alternative turbine type solely on the basis of the area that would be needed

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[28] 9,819 Btu/kWh - 7,201 Btu/kWh = 2,618 Btu/kWh. This is equivalent to 2.618 MMBtu/MWh. The CO_2 emission factor per MMBtu = 117 lb CO_2/MMBtu. Therefore, every additional MWh of electricity production by Puente, that could have been produced by a more efficient combined cycle unit, will add 117 lb CO2/MMBtu x 2.618 MMBtu/MWh = 306 lb CO2/MWh that otherwise would not have been produced.

[29] FSA, p. 3-1.

[30] FSA, p. 5.3-5.

[31] Ibid.

[32] Ibid.

for three units is not supported. No evidence is provided in the FSA to support this contention of lack of space. The FSA cover photo of the proposed project shows a large amount of available unused space on the property.[33] It is also inconsistent with the fact that Applicant submitted a bid to SCE to construct LMS100s at the site.[34] It is not credible that NRG would have submitted a bid to SCE for an LMS100 project that could not fit on the site.

V. ALL POTENTIAL AIR EMISSION INCREASES MUST BE OFFSET WITH VALID EMISSION REDUCTIONS

A. Commission Staff Offset Calculations Based on 11 Percent Capacity Factor Are Valid Only if 11 Percent Capacity Factor Is Enforceable Cap

The FSA cites to three different assumed capacity factors for Puente: 30 percent,[35] 24 percent,[36] and 11 percent. Air emissions and GHG emissions would be proportional to the capacity factor. If Puente operates at a capacity factor of 30 percent instead of 11 percent, both air emissions and GHG emissions will be nearly three times greater.

Commission staff acknowledge that the modeled project emissions are significant and should be offset:[37]

> The results shown in Revised Air Quality Table 23 and Revised Air Quality Table 24 indicate that the project's normal operational impacts . . . could further exacerbate currently-occurring exceedances of the PM10 standards. In light of the existing state PM10 non-attainment status for the project site area, staff considers the modeled impacts to be significant and, therefore, staff is recommending appropriate mitigation. Additionally, the NOx and VOC emissions from operation, when considering their potential secondary ozone formation added to the existing ozone "background", have the potential to contribute to existing exceedances of the ozone standard and are therefore potentially significant. Therefore, staff is recommending appropriate mitigation.

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[33] FSA, cover page.
[34] **Exhibit 7007**: TN 215396, Applicant's Responses to Information Requested by VCAPCD re Application for Authority to Construct/ Determination of Compliance, May 15, 2015, Attachment 3
Section 5, Alternatives – Puente Power Project Application for Certification, p. 5-5.
[35] FSA, p. 3-10. Total annual fuel consumption would be 6,790,000 MMBtu (HHV), based on a 30 percent dispatch.
[36] FSA, 4.1-26. The facility would be capable of operating seven days a week, 24 hours per day, and is being permitted for a maximum of 2,150 hours per year at full load operation of the combustion turbine. This is equivalent to an annual full load capacity factor of approximately 24 percent.
[37] FSA, p. 4.1-41.

However, apparently to ease the financial burden on the Applicant of procuring offset credits, Commission staff recommend offsetting air emissions based on an assumed capacity factor of 11 percent.[38] If Commission staff conservatively conclude that Puente will not operate with a capacity factor of more than 11 percent, and impose enforceable mitigation requirements on the basis of this conclusion, then Puente must be subject to an enforceable annual fuel consumption limit that is equivalent to an 11 percent capacity factor.

B. Emission Offsets Proposed by Commission Staff for CEQA Mitigation Are Not Valid

The net potential increase in air emissions at the Mandalay site as a result of the Puente project are shown in Table 3:[39] These net increases in air emissions assume a capacity factor for Puente of 24 percent.[40] The "estimated reasonable worst case annual emissions" to be mitigated under CEQA, based on a capacity factor of 11 percent as determined by Commission staff,[41] are also shown in Table 3.

Table 3. Air emission offsets necessary at Puente capacity factors of 24 percent and 11 percent

Air pollutant	Air emissions increase to be offset (tons per year)	
	24 percent capacity factor (Ventura County APCD air permit)	11 percent capacity factor (proposed CEQA mitigation)
NO_x	29.8	15.7
CO	28.55	14.5
VOC	9.94	5.9
PM_{10}	9.06	3.1
SO_x	7.48	0.48

The proposed CEQA mitigation, for the emission increases based on an 11 percent capacity factor, includes offsets and emission reductions under the Carl Moyer Fund or similar

[38] FSA, p. 4.1-49, p. 4.1-50. Energy Commission staff analyzed the QFER data and found that the Puente/MGS Units 1 and 2 equivalent would have operated a maximum capacity factor in 2009 of around 13.3 percent and around 11 percent in 2015. The Puente/MGS Units 1 and 2 equivalent would have had an average over the past 5 year period of around 7.86 percent, and any two years average over the past 5 years still averaged below 11 percent. . . For CEQA purposes, staff is recommending a 11 percent capacity factor as a mitigation basis.
[39] FSA, Air Quality Table 21, pdf 100, p. 4.1-30.
[40] FSA, 4.1-26.
[41] FSA, Air Quality Table 29a, pdf 120, p. 4.1-50.

mechanisms. Nitrogen oxides (NO_x) and volatile organic compound (VOC) emissions, which are ozone precursors, would be mitigated using the Applicant's currently owned facility Emission Reduction Credits (ERCs).[42]

The CO emission increases would not be mitigated because CO is an attainment pollutant and would not impact CO attainment status. The increase in emissions of PM_{10}/$PM_{2.5}$ and SO_x would be mitigated using ERCs or by funding emission reductions through the Carl Moyer Fund or similar mechanism. These are not valid mitigations under CEQA, as explained below.

1. CEQA mitigation must be local and contemporaneous

Condition of Certification (COC) AQ-SC9 requires the Applicant to mitigate 3.1 ton/yr of PM_{10}/$PM_{2.5}$ and 0.48 ton/yr of SO_x using "any combination" of ERCs within census tract areas identified in the FSA Environmental Justice Figure 1[43] (or demonstrate a good faith effort to do so before using ERCs outside of this area) and emission reduction projects selected and funded by VCAPCD with funds provided by the Applicant under the Carl Moyer or similar program. As worded, this COC would allow 100 percent of the mitigation to occur in the past, before the Project is built and/or at great distances from the source of the emissions.

a. *Emission Reduction Credits*

The use of ERCs, which could provide 100 percent of the mitigation under COC AQ-SC9, does not assure mitigation is local and contemporaneous. Emission reductions associated with ERCs typically do not occur contemporaneously with project emissions, but rather decades before the project and thus are part of the project baseline. Further, under COC AQ-SC9, they may occur anywhere within the VCAPCD air basin. Therefore, the ERCs may not provide any actual reductions in local air pollution affecting the communities near the Project. Further, the FSA does not require that the Applicant identify the PM_{10}/$PM_{2.5}$ and SO_x ERCs it would rely on prior to Project approval so location and timing can be evaluated by affected parties.

On a common sense level, it is not logical to assume that the retirement of historic ERCs, which requires nothing but shuffling paper (or electronic files), would do anything to counteract present-day emission increases due to the Project. While ERCs are legal instruments under the federal Clean Air Act for long-term air quality planning, no demonstration of actual present-day

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[42] FSA, p. 4.1-48/52.
[43] FSA, p. 4.5-21.

net air quality benefits can be produced as the associated emission reductions have occurred in the past and are therefore part of the baseline of existing air quality. Instead, the City and affected local communities will experience real-time, present-day emissions increases which will increase the exposure of residents to elevated concentrations of PM_{10}/$PM_{2.5}$ and SO_x and will jeopardize the County's future compliance and progress towards attainment of the state PM_{10} ambient air quality standard.

As the retirement of ERCs provides no beneficial effect whatsoever on post-Project air quality, ERCs should not be considered valid CEQA mitigation, especially not for a nonattainment pollutant such as PM_{10}. The use of ERCs should be expressly prohibited from mitigation measures and replaced by post-baseline, quantifiable emission reductions that benefit the surrounding communities.

b. Carl Moyer reductions

The Carl Moyer Program provides funding for emission reductions that are not required by any federal, State, or local regulation, memorandum of agreement/understanding with a regulatory agency, settlement agreement, mitigation requirement, or other legal mandate.[44] Condition of Certification AQ-SC9, as worded, would allow 100 percent of the PM_{10}/$PM_{2.5}$ and SO_x emission reductions to be supplied under the Carl Moyer Program. This program typically retrofits or replaces sources such as off-road and on-road heavy duty vehicles and fleets, emergency vehicles, portable and stationary agricultural sources, locomotives, and marine vessels.[45]

The FSA does not require any demonstration that suitable retrofit sources are locally available and would remain in the impacted community. Rather, COC AQ-SC9 only requires that the Applicant provide funding to the VCAPCD to mitigate increases in PM_{10} and SO_x emissions. The VCAPCD has the discretion to select any project from among those that meet Carl Moyer guidelines. There is no requirement that retrofit sources be local and contemporaneous. The use of Carl Moyer or other similar funding should be contingent on projects that would benefit the affected community.

[44] **Exhibit 7011**: CARB, Carl Moyer Program Guidelines, Chapter 1, Program Overview, p. 1-4; https://www.arb.ca.gov/msprog/moyer/guidelines/2011gl/2011cmp_chp1_4_28_11.pdf.
[45] **Exhibit 7012**: CARB, Carl Moyer Program Source Categories; https://www.arb.ca.gov/msprog/moyer/source_categories/moyer_schome2.htm.

c. CEQA mitigation must be for the life of the project

Emission reduction projects under the Carl Moyer Program must have a minimum life of only three years. The emissions that must be mitigated will occur for the life of the Project, which is 30 years or more. Therefore, COC AQ-SC9 must be modified to clearly require emission offset projects that cover the entire lifetime of the Project.

d. NO_x and VOC mitigation

NO_x and VOCs are converted into ozone in the atmosphere. The proposed mitigation for these pollutants mitigates them as ozone impacts. However, these pollutants have other, non-ozone impacts as NO_x and VOCs are a collection of chemicals, which individually have impacts. The air dispersion modeling performed by the Sierra Club, for example, indicates that NO_2 emissions exceed ambient air quality standards for NO_2.[46] The proposed ERCs would not mitigate these impacts because ERCs are emission reductions that occurred in the past and thus do not reduce future increases in NO_2 emissions.

VI. ALTERNATIVES ARE FEASIBLE

In addition to the No Project Alternative, there are other feasible and cost-effective alternatives to the Puente project. The FSA defines the roles that natural gas-fired power plants fill in an evolving high-renewables, low-GHG grid as:[47]

1. Provide variable generation and grid operations support.
2. Meet extreme load and system emergency requirements.
3. Meet local capacity requirements.
4. Provide general energy support.

Both battery storage and demand response can effectively fill these same roles in the high renewables, low GHG California grid, as described in the following paragraphs.

a. Battery Storage

SCE is required to have 580 MW of energy storage under contract by 2020 by Public Utilities Code Section §2836(a)(2) and D.13-10-040.[48] The CPUC authorized contracts for 264

[46] **Exhibit 7013**: L. Sears, *Air Quality Review and Comments: Puente Power Project*, prepared for Sierra Club, July 29, 2016., p. 3.
[47] FSA, p. 4.1-142.

MW of energy storage capacity in SCE's LA Basin LCR in the same Long-Term Procurement Proceeding (LTPP) procurement cycle where the CPUC authorized 0.5 MW of energy storage in the Big Creek/Ventura LCR.[49,50]

The 2009 California Electricity Demand forecast that the Puente authorization is based on a projected 1-in-10 year 2020 peak demand in the Big Creek/Ventura LCR of 5,186 MW.[51] This same forecast projected a 1-in-10 year 2020 peak demand in the LA Basin LCR of 20,529 MW.[52] The demand in the Big Creek/Ventura LCR represents about 20 percent of the combined demand of the LA Basin and Big Creek/Ventura LCRs.[53]

However, all of the SCE energy storage procurement is concentrated in the LA Basin and essentially none is allocated to Big Creek/Ventura. If a proportionate allocation of the 580 MW of energy storage that SCE must have under contract by 2020 was realized, 116 MW of energy storage would be located in Big Creek/Ventura.[54] To fulfill its energy storage mandate, SCE must still contract for an additional 316 MW of energy storage by 2020.[55]

Battery storage was identified by SCE in its November 2014 application for LA Basin grid reliability resources as a superior least-cost best-fit source over simple cycle combustion turbine capacity to meet peak demand need.[56] Battery storage technology responds more quickly

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[48] Section §2836(a)(2). "The commission shall adopt the (energy storage) procurement targets, if determined to be appropriate pursuant to paragraph (1), by October 1, 2013." The CPUC established an energy storage procurement target for SCE of 580 MW under contract by 2020 in D.13-10-040 (October 17, 2013, pp. 15-16).

[49] **Exhibit 7014**: CPUC, *D.15-11-041: Decision Approving, In Part, Results of Southern California Edison Company Local Capacity Requirements Request for Offers for the Western LA Basin Pursuant to Decisions 13-02-015 AND 14-03-004*, November 19, 2015, Finding of Fact 17, p. 35.

[50] **Exhibit 7015**: CPUC, *D.16-05-050: Decision Approving, In Part, Results of Southern California Edison Company Local Capacity Requirements Request for Offers for Moorpark Sub-Area Pursuant to Decision 13-02-015*, May 26, 2016, p. 5.

[51] **Exhibit 7003**: California Energy Demand 2010-2020 Staff Revised Forecast, Statewide Form 1.5d, 1-in-10 Net Electricity Peak Demand by Agency and Balancing Authority, December 2009.

[52] Ibid.

[53] [5,186 MW ÷ (5,186 MW + 20,529 MW)] = 0.202 (20.2 percent)

[54] 0.20 x 580 MW = 116 MW.

[55] 580 MW – 264 MW = 316 MW.

[56] **Exhibit 7016**: Southern California Edison, Application A.14-11-012, *Testimony of Southern California Edison Company on the Results of Its 2013 Local Capacity Requirements Request For Offers (LCR RFO) for the Western Los Angeles Basin*, November 21, 2014, pp. 57-58. "All (least-cost best-fit model) draws contained significant amounts of in-front-of-meter energy storage (Draw 1 had over 400 MW and Draw 25 had over 900 MW). . . SCE (then) limited the amount of in-front-of-meter energy storage that could be selected to 100 MW . . . Initially, in conjunction with the (100 MW) in-front-of-meter energy storage constraint, the optimization selected a higher amount of gas-fired generation. This was largely due to the (100 MW) limitation on in-front-of-meter energy storage, and gas-fired generation being the next economic resource in terms of net present value (NPV)."

than a gas turbine and can store and release intermittent renewable energy. This capability is acknowledged in the FSA:[57,58]

> Energy storage can replace generation capacity by being charged during non-peak hours and discharged on peak, in lieu of dispatching natural gas-fired generation. If located in a transmission-constrained area, storage can replace generation capacity needed for local reliability in the Moorpark sub-area.
> In recent years, energy storage has achieved preferred resource status due to its ability to: (a) absorb over-generation that may occur at high levels of solar penetration, and (b) obviate the need for natural gas-fired generation and associated capacity to meet ramping needs during evening hours when solar resource output declines to zero.

The FSA acknowledges that storage is the ultimate solution for the application which Puente will fill, while stating that storage is not available in sufficient quantities currently:[59,60,61]

> A long-term solution for over-generation is expected to be the development of cost-effective, multi-hour storage, allowing the surplus to be stored until it can be used in evening hours. In the interim, however, over-generation can be dealt with by curtailing renewable generation or reducing the amount of gas-fired generation that is needed during midday and early afternoon hours. The latter is facilitated by developing gas-fired resources such as the Frame 7HA that can cycle on and off at least twice a day.
>
> In the long-run, zero- and low-carbon resources, including demand-side management and storage resources may provide a majority, if not all of the balancing services needed to integrate variable renewable resources. However, the technologies that are needed to do so are not expected to be available in sufficient quantities by the early- to mid-2020s to obviate the need for dispatchable, flexible, natural gas-fired electricity generation.
>
> While demand-side resources and multi-hour battery storage may ultimately provide large quantities of ramping services in a cost-effective fashion, only pumped hydro and compressed air storage facilities are currently capable of doing so on the necessary scale.

The approach taken in the FSA is to ignore that SCE has: 1) already contracted for more energy storage capacity in the LA Basin, 264 MW, than the 262 MW capacity of Puente, and 2) determined through its own least cost-best fit modeling that energy storage is more cost-effective

[57] FSA, p. 4.2-14.
[58] FSA, p. 4.2-11.
[59] FSA, p. 4.1-151.
[60] FSA, p. 4.1-141.
[61] FSA, p. 4.1-143.

than simple cycle gas turbines. Instead the FSA repeats multiple times with no evidence that energy storage is "*not expected to be available in sufficient quantities by the early- to mid-2020s to obviate the need*" for Puente.

An example of how quickly large amounts of battery storage can be deployed in Southern California is the emergency energy storage procurement process at the CPUC initiated in the wake of the Aliso Canyon natural gas storage facility blowout.[62] SCE received approval for two battery storage projects totaling 27 MW in mid-September 2016.[63] SDG&E received approval for three battery storage projects totaling 37.5 MW in mid-August 2016.[64] These projects are expected to be online by the end of January 2017.[65,66] A total of 64.5 MW of battery storage capacity will come online within eight months of the time the CPUC issues a resolution that SCE and SDG&E should pursue such storage projects. Fast deployment of large amounts of battery storage capacity has already been demonstrated in Southern California.

The Commission staff perspective on the feasibility of battery storage to serve as an alternative to Puente is inaccurate, unsupported, and should be given no weight. As of 2017, energy storage is available at scale, is more cost-effective than simple cycle gas turbine technology, and is far more appropriate for the role of maximizing renewable energy development and minimizing GHG emissions in California.

b. Demand Response

Demand response (DR) is a zero emission resource that can meet all of the performance objectives described for the Puente project in the FSA:[67]

> DR has attributes that can partially meet some of the project objectives by: (1) contributing to or reducing the need for capacity-related reliability services, including an array of ancillary services (regulation and spinning reserves), and (2)

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[62] **Exhibit 7017**: CPUC, *Resolution E-4791 Authorizing expedited procurement of storage resources to ensure electric reliability in the Los Angeles Basin due to limited operations of Aliso Canyon Gas Storage Facility*, May 26, 2016.

[63] **Exhibit 7018**: *CPUC, Resolution E-4804. Southern California Edison Company (SCE) requests approval of three resource adequacy only contracts with Western Grid Development, LLC, AltaGas Pomona Energy Storage Inc., and Grand Johanna LLC*, September 15, 2016.

[64] **Exhibit 7019**: SDG&E press release, *California regulators approve SDG&E energy storage projects*, August 18, 2016.

[65] **Exhibit 7020**: Utility Dive, *Inside construction of the world's largest lithium ion battery storage facility*, December 6, 2016.

[66] **Exhibit 7021**: Utility Dive, *SCE taps Tesla for 80 MWh storage project to deal with Aliso Canyon gas shortage*, September 16, 2016.

[67] FSA, p. 4.2-12.

> reducing the need for flexible generation if called upon during hours in which ramping needs are highest. When such programs reduce loads in the Moorpark sub-area, they reduce local capacity requirements. DR programs can facilitate the integration of renewable resources by meeting incremental needs for regulation and reserves and reducing ramping needs. Unlike natural gas-fired generation, since DR directly affects end use, it can effectively absorb load during periods of renewable over-generation (e.g., when there is surplus solar generation at midday).

There is no evidence provided in the FSA to substantiate the statement that demand side management (demand response) will not be available in sufficient quantities before the mid-2020s in the Big Creek/Ventura LCA to serve the role that Puente will fill.[68] Therefore there is no way of assessing the legitimacy of this claim.

VII. CONCLUSIONS

- The project objectives listed in the FSA need to be modified to assure a neutral certification process.
- The decline in the demand forecast for the Big Creek/Ventura area has eliminated the justification for the project, making the No Project Alternative feasible and preferred.
- Puente will contribute to increasing GHG emissions from gas-fired generation in California, as less efficient simple cycle gas turbines are operated more frequently.
- The 11 percent capacity factor assumed by Commission staff for CEQA mitigation air emission offsets must be an enforceable cap.
- Emission offsets must be post-baseline, quantifiable emission reductions that benefit the surrounding communities.
- Battery storage is a feasible and cost-effective alternative to Puente that meets all the performance objectives of the proposed project.
- Demand response is a feasible and cost-effective alternative to Puente that meets all the performance objectives of the proposed project.

[68] FSA, p. 4.1-141.

Declaration of Bill Powers P.E.

Re: Opening Testimony for Proposed Puente Power Project

Docket 15-AFC-01

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 are incorporated herein by reference.

3) I prepared the opening testimony attached hereto and incorporated herein by reference after reviewing the FSA and other relevant documents in the docket.

4) I prepared the testimony attached hereto and incorporated herein by reference relating to the proposed Puente Power Project, 15-AFC-01, in Oxnard, California.

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.

Dated: January 18, 2017 Signed: Bill Powers, P.E.

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.

LNG Liquefaction Plant Experience

Corpus Christie LNG Air Permit Review. Conducted review of BACT determinations for the proposed Corpus Christie LNG liquefaction facility in Corpus Christie, TX. Issues addressed included: electric compressor drive systems as alternative to gas turbine compressor drive, technical feasibility and cost-effectiveness of SCR to reduce compressor drive gas turbine NOx emissions, and comparative benefits of ground flares over elevated flares to assure consistent flare performance.

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 ^{o}F) 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.

PUBLICATIONS

Bill Powers, "*More Distributed Solar Means Fewer New Combustion Turbines*," Natural Gas & Electricity Journal, Vol. 29, Number 2, September 2012, pp. 17-20.

Bill Powers, "*Bay Area Smart Energy 2020,*" March 2012. See: http://pacificenvironment.org/-1-87

Bill Powers, "*Federal Government Betting on Wrong Solar Horse*," Natural Gas & Electricity Journal, Vol. 27, Number 5, December 2010,

Bill Powers, "*Today's California Renewable Energy Strategy—Maximize Complexity and Expense*," Natural Gas & Electricity Journal, Vol. 27, Number 2, September 2010, pp. 19-26.

Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

Bill Powers, "*PV Pulling Ahead, but Why Pay Transmission Costs?*" Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

Bill Powers, "*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues*," Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

Bill Powers, "*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective*," Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

W.E. Powers, *"Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler,"* presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

W.E. Powers, R. Wydrum, P. Morris, *"Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant,"* presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

W. E. Powers, et. al., *"Retrofit Control Options for Particulate Emissions from Magnesium Sulfite Recovery Boilers,"* presented at 1992 TAPPI Envr. Conference, April 1992. Published in *TAPPI Journal*, July 1992.

S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094