BORDER POWER PLANT WORKING GROUP

GRUPO DE TRABAJO DE TERMOELECTRICAS FRONTERIZAS

December 1, 2003

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Subject: Border Power Plant Working Group (BPPWG) Comments Related to Preparation of Draft Environmental Impact Statement for Baja California Power (BCP) and Sempra Energy Resources (SER) Transmission Lines

Dear Ellen:

Thank you for this opportunity to comment on the scope of the draft Environmental Impact Statement (EIS) for the BCP and SER transmission lines. A number of the following comments were presented by me verbally at the EIS scoping workshop on November 20, 2003 in Calexico, California. This letter also includes additional comments that I did not present at the November 20th scoping workshop.

BPPWG continues to favor an alternative that requires mitigation for all of the cumulative impacts to air, water, and human health created by the permitting of the SER and BCP transmission lines. This alternative, and variations of it, was presented to DOE during the original comment period on the Environmental Assessment (EA) and during the course of litigation challenging the EA. We strongly urge you to consider such alternatives and require of these companies what we require of companies building transmission lines and power plants in the desert border region of California.

Comment 1: PSD Increment Analysis Significance Levels Not Applicable

Prevention of Significant Deterioration (PSD) increment analysis is not applicable to new sources located in a non-attainment area (Mexicali) that are impacting an adjacent non-attainment area (Imperial County). DOE assumed that Mexicali is a hypothetical attainment area in the original EA air quality analysis. This is an incorrect assumption. It is not in dispute that Mexicali is non-attainment for PM_{10}, ozone, and carbon monoxide (CO). The November 2003 Environmental Defense study "*Pollution Without Borders*"[1] includes a summary of Mexico's ambient air quality standards and the attainment status of Mexicali. The Environmental Defense document is available at http://www.environmentaldefense.org/go/borderenergy. A California Air Resources Board CD containing 1996-2001 ambient air quality data for the six Mexicali air

[1] Environmental Defense, *Pollution Without Borders – How Power Plants in U.S.-Mexico Border States Threaten Human Health and the Environment*, November 2003.

monitoring stations was also provided to the DOE team by me at the November 20, 2003 scoping workshop in Calexico.

The on-the-ground reality is that air emissions from the BCP and SER power plants are exacerbating air quality problems in both the source and receptor non-attainment areas. The public health implications of this effect are explained succinctly in the supplementary declaration prepared by Dr. Paul English on behalf of plaintiffs for the June 16, 2003 federal hearing in this case. The supplemental declaration of Dr. English is provided as Attachment A to this comment letter.

Comment 2: Ammonia Slip Limit of 3.5 ppm Must be Condition in Presidential Permit (PP)

Leaving aside for the moment the issue of PSD increment analysis applicability, the 24-hour ambient PM_{10} increase significance level is 5.0 μg/m^3 under PSD regulation. This is correctly noted in the original EA. Above 5.0 μg/m^3 action must be taken to mitigate the impact. Mitigation would be either more restrictive emission limits or emission offsets. The court determined in its July 3, 2003 Order that the modeled 24-hour PM_{10} increment was 4.8 μg/m^3, just below the 5.0 μg/m^3 trigger level for mitigation. As noted in the Order, 3.0 μg/m^3 of this total is primary PM_{10}, and 1.8 μg/m^3 is secondary PM_{10} in the form of ammonium nitrate emissions (p. 24). The Order also notes that the 4.8 μg/m^3 24-hour increment is not necessarily a conservative estimate, stating *"Indeed, the contribution to particulate formation from ammonia may even be higher since it appears from Heisler's declaration that he has used estimates of actual ammonia emissions, rather than the more conservative "potential to emit" estimates normally required when reviewing new emissions sources. (See Supp. Stockwell Decl. at ¶ 3)."*

The NO_x control technology proposed by both BCP and SER to minimize NO_x emissions is selective catalytic reduction (SCR). Ammonia is the reagent used in the catalytic reaction to reduce NO_x to molecular nitrogen (N_2) and water (H_2O). The catalytic activity of the SCR is high initially and slowly degrades over the operational life of the catalyst. Relatively little ammonia "slips" through the catalyst during the initial phase of operation if ammonia injection is precisely controlled and the SCR is maintained in optimum condition. The SCR ammonia slip level is apparently guaranteed at 10 ppm for the BCP turbines, and is guaranteed at 10 ppm for the SER turbines. Dr. Heisler assumed an ammonia slip level of 3.5 ppm from the BCP and SER turbines, based on the SCR manufacturer's expected performance at two years of operational life, in calculating the 1.8 μg/m^3 increment in secondary 24-hour PM_{10} ammonium nitrate emissions. It is critically important that the ammonia slip emissions remain at or below 3.5 ppm at all times if BCP and SER are not required to offset PM_{10} emissions, given: 1) the 1.8 μg/m^3 increment in secondary 24-hour PM_{10} puts the 24-hour PM_{10} emissions increment nearly at the 5.0 μg/m^3 significance level, and 2) the Order acknowledges the 1.8 μg/m^3 increment is probably not conservative. If DOE continues to rely on the PSD increment analysis to determine the "significance" of impacts, a permit condition must be included that requires: 1) continuous monitoring of ammonia concentration at the turbine stacks, and 2) suspension of export of power along the BCP or SER transmissions lines at any time the ammonia concentration exceeds 3.5 ppm. The appropriate ammonia concentration averaging time is one hour, consistent with the monitoring period specified in New Source Performance Standard GG, "Standards of Performance for Stationary Gas Turbines."

However, as discussed in Comment 1, DOE should not use PSD increment analysis under the Clean Air Act to measure the significance of air impacts in these two nonattainment areas.

Comment 3: DOE Must Include Impacts from Power Plants Supplying the Second Circuits on the BCP and the SER Transmission Lines

The modeled air and water quality impacts in the EA assumed only one plant per transmission line. However, both the BCP and SER transmission lines are double-circuit designs capable of carrying the full power output from two 600 MW plants each. The export component of the BCP plant has a capacity of 560 MW, while the SER plant has a capacity of 600 MW. Each circuit of the double circuit transmission lines has a capacity of approximately 600 to 700 MW. The total capacity of each double circuit transmission line is 1,200 to 1,400 MW, as stated by BCP and SER in their respective applications for Presidential Permits (Permits). The EA analyzed the environmental impact of 1,160 MW of power generation capacity while the Permits authorize BCP and SER a total of up to 2,800 MW of power transmission capacity. The cumulative impacts analysis must address a level of power plant environmental impact that is representative of the transmission capacity the DOE is authorizing under the permits. At a minimum the DOE must assume two identical power plants on each transmission line when assessing environmental impacts. Alternatively, if DOE opts to assess impacts from a single power plant on each transmission line, then it should only authorize the construction and operation of one line per applicant or the Permits must include an explicit condition that the second circuit can only receive power from plant(s) that have no environmental impact. In concrete terms this condition must define the characteristics of the power plant(s) supplying the second circuit as: 1) net zero air emissions (catalytic controls and emission offsets), 2) dry cooling, and 3) zero liquid discharge. These criteria describe what could be defined as the "Nevada Model," given virtually all new power plants built in Nevada incorporate these characteristics.

The Council on Environmental Quality is explicit that a National Environmental Policy Act (NEPA) cumulative impacts analysis must include cumulative effects caused by reasonably foreseeable future actions.[2] It is reasonably foreseeable that BCP and SER, having requested and received authorization to build double circuit transmission lines capable of transmitting 1,200 MW to 1,400 MW each, will at some point utilize most or all of the authorized transmission line capacity. The Comisión Federal de Electricidad (CFE), the Mexican national utility monopoly, shows a second 600 MW SER export power plant coming on-line in Mexicali in June 2005. The March 2003 CFE PowerPoint presentation containing this information is available on the California Independent System Operator webpage titled "Southwest Transmission Expansion Plan – STEP" at http://www1.caiso.com/docs/2002/11/04/2002110417450022131.html. Scroll down to "March 13, 2003 STEP Meeting." The CFE presentation is also provided as Attachment B to this letter.

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[2] Council on Environmental Quality, Executive Office of the President, *Considering Cumulative Effects Under the National Environmental Policy Act*, January 1997, p. 8.

Comment 4: DOE Must Condition the Permits on a Requirement that the BCP and SER Turbines Be Equipped with SCR Technology

The following announcement appeared in the November 2003 edition of Diesel and Gas Turbine Worldwide[3] magazine:

> **Retrofit SCR Systems for Power Plants in Mexico**
> *Peerless Mfg. Co., Dallas, Texas, U.S.A., announced that it has received an order in excess of $3 million for selective catalytic reduction systems (SCRs) to reduce nitrogen oxides from multiple power plant units in Mexico. The first unit of the multi-plant order is scheduled to ship in the first quarter of 2004 with the remaining units presently scheduled for completion in 2005 and 2006.*

The two SER turbines are already equipped with SCR. The only other plant in Mexico that is obligated to use SCR is Intergen's La Rosita plant, of which BCP is a part. La Rosita consists of four turbines, two export units (BCP) and two Mexico domestic units. It is understood that the units scheduled to receive SCR in 2005 and 2006 are the two Mexico domestic turbines. This is consistent with public statements made by Intergen regarding the SCR installation schedule for the two Mexico domestic turbines. The statement that the first SCR unit will ship in the first quarter 2004 has major and serious implications. It implies that the BCP turbines are not currently equipped with SCR. The EA air quality impact analysis and all declarations by BCP representatives during the court proceedings made explicit that the BCP turbine NO_x emissions would be controlled to 4 ppm or less using SCR at the time commercial operation was initiated in June 2003. A primary reason Judge Gonzalez chose not to enjoin operation of BCP during the EIS preparation phase was precisely because BCP was controlling BCP NO_x emissions to "less than significant" levels using SCR.

The BPPWG requests that: 1) DOE provide immediate confirmation regarding whether or not the BCP turbines are currently equipped with functional SCR systems, and 2) make the use of SCR a condition of any permits issued.

Comment 5: DOE Must Employ Realistic Retrofit Costs When Assessing the Cost to Install a Wet-Dry Cooling System

Intergen has publicly stated that the cost of adding SCR to the four turbines at the La Rosita plant is $20 million[4]. Intergen's SCR subcontractor states in Diesel & Gas Turbine Worldwide that the cost of what appears to be all four turbines at Intergen's La Rosita plant is somewhat over $3 million. The rule-of-thumb among manufacturer's of SCRs for the utility power industry is that installation accounts for approximately 25 percent of the total capital cost. Assuming the $3 million stated by the SCR vendor is an "equipment only" cost, the installed capital cost would be

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[3] Diesel & Gas Turbine Worldwide, Vol. 35, No. 9, November 2003, pg. 23.
[4] San Diego Union Tribune, *Intergen Plans Top Pollution Controls on All 4 Units of New Mexicali Plant*, January 29, 2003.

somewhat over $4 million. The actual cost of adding SCR to the four La Rosita turbines appears to be in the range of one-fifth the cost publicly stated by Intergen.

It is incumbent upon the DOE to use accurate costs when assessing the cost feasibility of retrofit mitigation options for BCP and SER. For example, SER has estimated spectacularly high costs for a dry cooling retrofit, in the range of $200 million for a plant that cost less than $400 million to build. In reality the wet-dry alternative recommended by the BPPWG would cost $30 million or less. The vendor equipment cost for a single air-cooled condenser (ACC) cell with a standard fan is approximately $500,000. Use of an ultra-low noise fan and a fan motor noise attenuation housing would increase this cost to approximately $600,000 per cell. The installation cost for ACC in Mexico is well known in the industry due to the high number of ACC installations on Mexican combined-cycle power plants, a total of eight to date. Installation in Mexico adds approximately 20 percent to the basic equipment cost. Adding a 30-cell ACC to either BCP or SER would reduce annual cooling system water consumption by as much as 90 percent. The greenfield installed cost of a 30-cell ACC in Mexico should be less than $20 million. Assuming a 30 percent premium for retrofit challenges, a typical retrofit premium for major power plant pollution control retrofits such as flue gas desulfurization, the total installed cost of a 30-cell ACC retrofit would be considerably less than $30 million.

A number of parallel wet-dry cooling systems are in operation around the world on a variety of combustion systems, including combined-cycle power plants. The one conversion of a wet cooling system to a wet-dry system, at the 37 MW Streeter No. 7 pulverized coal-fired unit in Cedar Falls, Iowa in 1995, incurred minimal additional retrofit costs and has been operating successfully for nearly a decade. An excellent 2003 paper on wet-dry cooling systems is provided as Attachment C.

Comment 6: Non-Permanent, Non-Verifiable, Historic Emission Reductions in the Mexicali Area Can Not Serve as Ex Post Facto Emission Reduction Credits for Air Emissions Associated with BCP or SER Transmission Lines

SER constructed a natural gas pipeline to Mexicali in 1997 to serve industrial installations in the city. Many sources converted to natural gas following the arrival of the pipeline. However, natural gas prices soared in Mexicali during the California energy “crisis” of 2000-2001. Most industrial gas customers in Mexicali reverted to either distillate or heavy oil firing in response to the high natural gas prices, and continued to fire oil long after the natural gas price had returned to competitive levels. Industries in Mexicali retain the ability to switch to oil whenever firing oil is more cost effective than burning natural gas.

SER has stated on numerous occasions that it is entitled to ex post facto emission reduction credits as a result of providing natural gas to industrial customers in Mexicali. Any reductions achieved by introducing natural gas to Mexicali are neither verifiable nor permanent. At any moment SER natural gas customers in Mexicali can switch to liquid fuel. The 1997 gas pipeline project had no connection whatsoever to the 600 MW SER export project. SER’s claim that it should be awarded ex post facto emission reduction credits for the 1997 Mexicali pipeline project would be rejected out-of-hand by U.S. air quality regulators.

A verifiable and permanent source of emission reduction credits for the BCP and SER projects is road paving. The cost of PM_{10} and NO_x emission offsets, assuming both PM_{10} and NO_x emissions are offset at a one-to-one ratio as PM_{10} reductions via road paving, would be approximately $17 million for BCP and $10 million for SER. These PM_{10} offset costs are derived from the documentation included in the air quality improvement road paving loan package recently approved by the North American Development Bank (NADBank) for Mexicali, Tecate, and Tijuana/Rosarito. BCP and SER can meet their offset obligations by paying that portion of the Mexicali loan amount that offsets their PM_{10} and NO_x emissions. DOE should evaluate this form of mitigation in the EIS.

The NADBank loan package text provides detailed calculations of cost and PM_{10} emission reductions achieved through road paving. The NADBank PM_{10} offset expenditure is far less on a unit basis than the combined PM_{10} and NO_x offset expenditure of approximately $30 million projected for the 510 MW Otay Mesa Project. Otay Mesa is located approximately 2 miles north of the U.S.-Mexico border about 15 miles southeast of San Diego. Otay Mesa will pay $30 million to offset PM_{10} and NO_x emission levels that are significantly lower than the projected PM_{10} and NO_x emission levels from either BCP or SER. Otay Mesa is a merchant power plant, like BCP and SER, and will compete with BCP and SER in the California power market.

Comment 7: The EIS Must Provide Detailed and Verifiable Information on the Extent of TDS Reduction Achieved by BCP and SER Wastewaster Treatment (WWT) Systems and Condition the Permits on Such Reductions

Experts for BCP and SER, as well as the SER project manager, claimed in their respective declarations that up to 8.8 million pounds per year (lb/yr) of TDS would be removed due to BCP and SER WWT operations.[5] According to these BCP and SER expert declarations, approximately 26 percent of the TDS entering the WWTs is removed during plant operations[6]. The purported reduction in TDS, along with projected reductions in pathogens, nutrients, and total suspended solids, was a principal reason the court chose not to enjoin operation of BCP and SER during the EIS preparation phase. The plaintiff's water treatment expert pointed-out that none of the processes identified by BCP or SER as TDS removal processes are typically considered to be TDS removal processes.[7]

The same BCP and SER expert declarations that assert a major reduction in TDS across the WWTs also directly contradict this assertion. Both BCP and SER wastewater treatment experts identify the incoming wastewater TDS concentration as 1,200 mg/l.[8] The SER expert also makes clear that this wastewater will continue to be treated and discharged to the New River even when the power plant is offline, stating, "*Expected maximum operations have the plant running at full*

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[5] Hromadka Decl. ¶ 32, Simoes Supplemental Decl. ¶ 5.

[6] Hromadka Decl. ¶ 29-31. SER treated water demand is 4,371 acre-ft/yr (AFY) at maximum potential operating schedule. 1 AFY = 325,000 gallons. There are 3.785 liters per gallon. Incoming water TDS concentration is 1,200 mg/liter. 1 mg equals 2.2×10^{-6} lb. Therefore total lb/yr of TDS entering SER WWT at maximum potential operation = 14.2 million lb/yr. TDS removed across SER WWT at maximum potential operation = 3.7 million lb/yr. Therefore TDS removal across SER WWT is 3.7 million lb/yr ÷ yr 14.2 million lb/yr = 0.26, or 26 percent.

[7] Angel Decl. ¶¶ 13-18

[8] Hromadka Decl. ¶ 29, Kasper Decl. ¶ 6.

capacity 75 percent of the time and operating in bypass mode the remaining 25 percent of the time on an annual basis. During bypass mode of operation, because the water is treated but not used to cool the plant, . . . the treated water is simply discharged into the drainage channels without the effects of evaporation."[9] Yet the SER project manager identifies the treated water TDS concentration as "approximately 1,180 mg/l," essentially no different than the incoming untreated water TDS concentration of 1,200 mg/l. Specifically the SER project manager states, "*During bypass operation (approximately 25% of the time), when the plant is not producing power, the discharge has an approximate TDS concentration of 1,180 mg/l*."[10]

There is apparently no reduction in TDS across the BCP or SER WWTs, according to the influent and effluent TDS concentration data provided by the BCP and SER wastewater treatment experts. This reality corroborates the claim by BPPWG's wastewater treatment expert that "*essentially no TDS are removed*"[11] in the BCP and SER WWTs. This reality also has major and serious implications, given BCP and SER were allowed to continue operation during the EIS preparation phase in part because of the stated TDS removal that would be achieved by operating the BCP and SER WWTs. The claim of TDS removal across the BCP and SER WWTs appears to be baseless.

Comment 8: The EIS Must Define the Minimum BCP and SER WWT Throughput Rates that Are Consistent with Stated Levels of WWT Pollutant Removal

The original EA and subsequent BCP and SER expert declarations identify precise quantities of dissolved oxygen demand, chemical oxygen demand, total suspended solids, and TDS that will be removed in the BCP and SER WWTs.[12] The minimum removal levels stated in the EA and expert declarations are based on the assumption that the power plants will be operational 75 percent of the time and offline the remaining 25 percent of the time. BCP and SER expert declarations are also explicit in stating that the WWTs must operate around-the-clock (24 hours per day, 7 days a week) to avoid disrupting the biological treatment processes at the WWTs. The annual WWT throughput rates that correspond to the "75 percent online, 25 percent offline" operating scenario must ultimately be established as the minimum WWT throughput rates in the Permits, given the pollutant removal rates associated with this scenario were cited by DOE to demonstrate the water quality improvement benefits of allowing the plants to operate during the EIS preparation phase. The Permits must also include a condition specifying the WWTs will operate on a continuous basis, as well as appropriate means to monitor that the condition is being meet. Failure to operate the WWTs on a continuous basis, or failure to treat at least the quantity of wastewater that corresponds to the expected annual water demand rates described in the EA and repeated in the BCP and SER expert declarations, should result in suspension of use of the transmission line(s) until the situation is rectified.

However, BPPWG maintains that conversion to dry or wet-dry cooling as a means to maintain pre-project quantities of water in the New River and the Salton Sea is an environmentally

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[9] Hromadka Decl. ¶ 29.
[10] Simoes Supplemental Decl. ¶ 9.
[11] Angel Decl. ¶ 21.
[12] Hromadka Decl. ¶ 23.

superior alternative that should be required as mitigation for the water consumption and wastewater discharge issues associated with the wet-cooled BCP and SER power plants.

Thank you again for this opportunity to comment on the scope of the EIS for the BCP and SER transmission lines. Please contact me at (619) 295-2072 if you have any questions about this comment letter.

Sincerely,

Bill Powers, P.E.
Chair, Border Power Plant Working Group

cc: U.S. Senator Diane Feinstein
U.S. Senator Barbara Boxer
Congressman Bob Filner
State Senator Denise Ducheny
State Assemblyman Juan Vargas
Imperial County Supervisor Joe Maruca
Imperial County APCD Director Steve Birdsall
California Air Resources Board
California Environmental Protection Agency
Regional Water Quality Control Board 7
Salton Sea Authority
New River Wetlands Project
Environmental Defense
Sierra Club
American Lung Association
Border Ecology Project
Sky Island Alliance
Marshall Magruder

Attachment A: *June 2003 Dr. Paul English Supplemental Declaration*
Attachment B: *CFE Generation and Transmission Expansion Plan - Baja California System, 2003-2007*
Attachment C: *2003 Cooling Technologies Institute paper on wet-dry cooling systems*