Document 0016

Sempra Energy Resources

Octávio M. C. Simões
Vice President
Planning & Analysis

101 Ash St.
San Diego, CA 92101-3017

Tel: 619.696.2267
Fax: 619.696.2911
Cellular: 619.540.6345
osimoes@sempra-res.com

Via E-Mail, Facsimile and Overnight Delivery

Ms. Ellen Russell
U.S. Department of Energy
Office of Fossil Energy, FE-27
1000 Independence Avenue, S.W.
Washington, DC 20485

July 30, 2004

Re: Comments on Draft Environmental Impact Statement for the Imperial-Mexicali 230-kV Transmission Lines (May 2004) (DOE/EIS-0365)

Dear Ms. Russell:

Sempra Energy Resources ("Sempra"), on behalf of Termoelectrica-US, LLC ("T-US"), the permittee for the existing transmission line from the Termoelectrica de Mexicali ("TDM") power plant in Mexico to the Imperial Valley substation, has reviewed the Draft Environmental Impact Statement ("DEIS") for the Imperial-Mexicali 230-kV transmission lines project and submits following additional information and comment on the DEIS to assist the decision maker in its consideration of the proposed action and its potential impacts.[1]

SER generally concurs with the analysis and findings contained in the DEIS and supports implementation of the proposed action and preferred alternative -- granting the Department of Energy ("DOE") Presidential Permit and Bureau of Land Management ("BLM") right-of-way to T-US. The DEIS complies with the requirements of the National Environmental Protection Act ("NEPA") and demonstrates that the environmental impacts in the United States associated with construction of the transmission line is *de minimus*. 0016-1 The DEIS also comprehensively evaluates the indirect and cumulative impacts on the United States[2] associated with TDM and InterGen La 0016-2

[1] As you know, T-US is a wholly owned subsidiary of Sempra Energy Resources ("SER") who was the original applicant for the proposed Presidential Permit and right-of-way grant. T-US subsequently became the owner of the SER transmission line through an internal corporate reorganization of Sempra Energy, the corporate parent, and is now the permittee and applicant for the proposed action.

[2] The DEIS properly omits evaluation of impacts in Mexico. These impacts have already been evaluated by the permitting authorities in Mexico. Due to Mexican involvement in the environmental analysis and permitting of the power plants in Mexico consistent with

Rosita Power Complex operations in Mexico, and demonstrates that these impacts are likewise relatively minimal. 0016-2 (cont.)

Permanent Removal of TDS

The DEIS includes a description of the proposed action including, among other things, an assessment of the amount of total dissolved solids ("TDS") removed by the TDM wastewater treatment plant, which is described and discussed in the DEIS at 2-33 to 2-34 and 4-19 to 4-20.[3] Additional detail regarding the TDS removal process is attached as Exhibit A to these comments. As shown in Exhibit A and in the DEIS, water balance calculations performed on the water treatment process demonstrate the removal of 3.7 million pounds per year of TDS when based on a 100% operations scenario. The DEIS assumes a 100% operations scenario because this generally results in a very conservative, worst case disclosure of potential impacts (in particular, with respect to air quality emissions and water flow reductions).[4]

However, with respect to TDS removal, it is also important to understand the expected TDS removal when analyzed based on an expected operations scenario. As explained in Exhibit A, with expected operations at TDM, 2.7 million pounds per year of TDS will be removed. Testing during actual operating experience verifies the removal of TDS and, in fact, demonstrates that actual removals are somewhat greater than what was conservatively calculated under the expected operations scenario in Exhibit A. Although the number of pounds of TDS actually removed by the water treatment plant will vary depending on the level of power plant operations, it is a substantial amount of TDS removal in any case. Along with the significant amount of dissolved organics, ammonia, phosphorous, and agricultural and industrial chemicals removed, operation of the wastewater treatment plant at the TDM project will have an overall beneficial impact on water quality in the New River and in the Salton Sea. 0016-3

Double Circuit Transmission Line

The DEIS (pages S-6, 1-6, and 2-15) also indicates that the transmission line for TDM is a double circuit, each with the capacity to carry the total output of the plant. The rationale for the double circuit is simply good engineering practices --- to enhance reliability of operation. Having two circuits capable of carrying the full output of the plant is typical of power plants that only have one link to the delivery point over long distances, nine miles in this case. This allows for maintenance of each circuit (insulators, conductors, etc.) without interruption in deliveries of electricity. In addition, each circuit terminates at different points at both the plant switchyard and the Imperial Valley substation. This allows for maintenance of yard equipment such as circuit breakers and switches, again without interruption of service to the grid. This feature is a 0016-4

Mexican law, neither NEPA nor Executive Order 12114 requires a duplicative assessment of environmental impacts within Mexico in the EIS for the proposed action.

[3] On Page 4-19, Section 4.2.4.1.2, there appears to be an error in the conversion of pounds to kilograms ("29 million and 14 million pounds" are incorrectly converted to "36 and 43 million kg", when the text should read "13 and 6.5 million kg"). 0016-5

[4] Of course, no power plant can ever operate 100% of the time 365 days a year in actual operations due to down time needed for scheduled maintenance, forced outages, and varying electricity demands.

benefit that can be achieved at very low cost as the cost of the added circuit is a very small component of the total cost of the transmission line. As explained in SER's letter to the Department of Energy dated April 7, 2004, SER is not currently developing a second power plant in the vicinity of the existing TDM facility. 0016-4 (cont.)

Alternatives and Mitigation Measures

The DEIS also evaluates a range of alternatives to the proposed action including an alternative that would grant the Presidential Permit only if the transmission lines were connected to a power plant that employed alternative cooling technologies such as dry cooling or wet-dry cooling.[5] The reason for using an alternative technology would be to reduce the amount of water necessary for cooling. For numerous reasons, however, these cooling alternatives would neither be feasible at TDM nor achieve a sufficient amount of water use reduction to justify the high cost and inefficiencies involved in retrofitting the plant to utilize such technology. In addition, the economic impacts to Mexico from loss revenue associated with water sales would also be significant.

First, dry cooling or wet-dry cooling technology is normally only used when sufficient water is not available for wet cooling and the economics of the project can withstand the increased cost and loss of performance caused by use of the dry cooling technologies. The use of dry-cooling alone or in parallel with wet-cooling for any portion of the operation at TDM means less electricity will be produced with the steam produced and thus more fuel per unit of electricity produced will be consumed, as explained in technical detail in Exhibit B hereto. How much less electricity will be produced depends on the ratio of dry cooling to wet cooling selected for the plant design. 0016-6 (cont.)

The detrimental performance effects of dry cooling would be especially pronounced at TDM because the daily mean maximum temperature exceeds 90°F for seven months of the year and 80°F for nine months of the year. These time periods coincide with the months of high electricity demand when the plant would be expected to operate the most hours and at its highest output level. Because of these harsh climate conditions, wet cooling is necessary for a majority of the year in order to maintain output and minimize impact on plant efficiency. In the current wet-cooled-only configuration, it is estimated that TDM uses approximately 70% of its annual amount of water during the warmer months.[6] This means that most of this water would still be

5 The DEIS also evaluates equipping the power plants with selective catalytic reduction ("SCR") technology and use of oxidizing catalysts on all gas turbines. The TDM plant was designed and built, and is operating with both SCR and oxidizing catalytic controls for NOx (2.5 ppm) and CO (4 ppm). The plant's Mexican environmental permits reflect this condition.

6 The owners of TDM also own and operate a fully dry cooled power plant in Nevada, the El Dorado generating station. El Dorado is a smaller power plant because it does not have the amount of peak load duct firing (i.e. increased steam production and steam condensing cooling load) that TDM has. The annual consumption of water at El Dorado from cycle demands (no steam condensing) is 215 acre-feet. Using the same proportion, TDM cycle demands are estimated at 300 acre-feet alone. The estimated water

consumed in a wet-dry system and the reductions in water consumption from a wet-dry retrofit would be small and come at a very large cost, as discussed in more detail below.

Second, because the TDM plant is already completed, it would be extremely costly to retrofit the plant with wet-dry cooling technology. A description of the components of a retrofit similar to that designed for another SER facility under development in an arid region of the United States ('Project Alpha'), which would be capable of providing dry cooling for temperatures up to the 75°F to 80°F range, and preliminary estimate of its cost is included in Exhibit B. The extensive nature of the modifications and amount of new equipment would cost over $75 million. In addition, there would be significant costs associated with shutting down the facility for the 4-5 months necessary to complete the construction related to the retrofit.

If the wet-dry cooling system were required to provide dry-cooling up to ambient temperatures of 90°F (which could not be accomplished by the Project Alpha design), and wet cooling for temperatures above that, the size of the air-cooled condenser, according to equipment manufacturer information, would occupy an area of 6.5 acres, utilize 144 fans, consume 20 MW of power, and it would cost $80 million plus $40 million to install. *See* Exhibit B. These costs do not include the cost of the other extensive required modifications, which would likely add at least another $50 million based on the Project Alpha design estimate, or lost opportunity costs. There would also be significant air quality and noise issues associated with such an operation. 0016-6 (cont.)

Clearly, the capital costs for implementing any type of wet-dry cooling retrofit at TDM would be cost-prohibitive, in particular when there is sufficient water available to allow use of a much more efficient wet cooling system. In addition, water use impacts are minimal as documented in the DEIS.

Third, use of dry or wet-dry cooling at TDM would be inconsistent with the operation of the biological treatment component of the wastewater treatment plant, which must be operated at constant levels of flow to keep the microorganisms performing at optimal levels. Additional capital cost was incurred for the water treatment plant at TDM, however plant performance is not sacrificed. Operating this water treatment plant for long stretches of time while not using the water for cooling adds to the economic infeasibility of retrofitting TDM with dry or wet-dry cooling technology.

In any event, because the TDM power plant is located in Mexico, not in the United States, neither DOE nor BLM has any regulatory jurisdiction over the TDM power plant. The TDM plant is being operated in compliance with its Mexican-issued operating permit.[7] Adoption of any measure that purports to require alteration of the facilities and/or operations of a legally

consumption of TDM with a wet cooled system under normal operation is 2,500 acre-feet per year, which means that 2,200 acre-feet are used in wet cooling for steam condensing.

7 Although physically located in Mexico, the TDM plant is within the California Independent System Operator ("ISO") control area. This fact, however, does not make TDM any less of a Mexican facility and certainly does not turn it into a California facility. For example, other power plants located in Nevada are likewise included within the California ISO control area, however, those plants continue to be regulated under the laws of the jurisdiction (Nevada) in which the plant is physically located.

permitted power plant in another country would constitute improper and undue interference with the affairs of another country and should be rejected.[8] Thus, DOE and BLM should not include any additional conditions to the already existing permits. 0016-6 (cont.)

Air Quality and Health Impacts

With respect to the air quality analysis included in the DEIS, SER agrees with the approach used in the conformity analysis on DEIS pages 4-38 to 4-39. In particular, given the Supreme Court's recent decision in *U.S. Dept. of Transportation v. Public Citizen*, 124 S.Ct. 2204 (2004) and the lack of DOE or BLM regulatory authority over the power plants in Mexico, only emissions caused by construction and operation of the transmission lines should be considered in the conformity analysis. Moreover, even if the Imperial Valley were reclassified as a "serious" non-attainment area for PM10[9] resulting in an applicable exemption level of 70 tons/year, the proposed action with a maximum total of less than 12 tons of PM10 emissions per year would still be exempt from any additional conformity review.

The DEIS uses EPA-established significance levels ("SLs") as thresholds or yardsticks to assist the decision maker in judging the significance of potential adverse impacts of power plant emissions. We understand from the DEIS that the SLs are not being applied to emissions from the power plants as part of any direct application of the Clean Air Act ("CAA") Prevention of Significant Deterioration or EPA regulatory requirements to the plants. Because the power plants are located in Mexico and permitted under Mexican law, the United States has no authority to apply the CAA to the power plants or to designate areas in Mexico as "attainment" or "non-attainment;" such designations simply do not apply to areas outside the United States. Accordingly, it would not be appropriate for the DOE to directly apply CAA requirements (such as the requirement for offsets under CAA section 173(c)) to the power plants or attempt to regulate the power plants under the CAA through the conditioning of the transmission line permits. However, SER agrees that the EPA SLs can serve as a useful gauge of the significance of particular emissions and agrees with the DEIS' conclusions that comparing the emissions in the United States caused by the power plants with the SLs demonstrates that such impacts would 0016-7

[8] The TDM plant was designed and built with state-of-the-art emissions controls equivalent to those required in California and it is the cleanest gas-fired power plant in Mexico. While the DEIS properly discusses mitigation measures to assist in disclosing and understanding the potential environmental impacts of the proposed action, there is no legal requirement under NEPA to mitigate potential environmental impacts.

[9] The Ninth Circuit Court of Appeals' order rejecting the claim that Imperial County's PM10 non-attainment was caused by emissions coming from Mexico into the United States and ordering that the Imperial Valley be reclassified as a "serious" non-attainment area for PM10 has evidently not yet occurred. *See Sierra Club v. U.S. Environmental Protection Agency*, 346 F.3d 955 (2003), *cert. denied* 124 S.Ct. 2873 (June 21, 2004); http://www.epa.gov/airprogm/oar/oaqps/greenbk/pnca.html#3471. Interestingly, the Court's finding with respect to the impacts of Mexican emissions on the Imperial Valley is consistent with the DEIS' finding (pages 4-52 to 4-54) that for much of the year (exceptions being June-August), the winds that transport air pollutants mainly blow from the United States into Mexico.

be minimal. This approach is also consistent with that utilized in the original Environmental Assessment prepared for the proposed action, which was upheld by the District Court. *See* DEIS Appendix A at A-25 to A-27, A-43 to A-44. 0016-7 (cont.)

We also concur with the DEIS analysis with respect to secondary PM10 formation from the power plant emissions. The DEIS correctly recognizes that an increase in the ammonia emission rate would not have a linear effect on the secondary ammonium nitrate concentration. The equilibrium relationship between ammonium nitrate formation and ammonia and nitric acid concentrations, illustrated on page 4-42 of the DEIS, is non-linear. In an ammonia-rich environment, increases in ammonium nitrate concentrations are less than proportional to increases in ammonia concentrations. In addition, as explained on pages 4-45 and 4-46, the analysis is extremely conservative because it assumes that the production of secondary ammonium nitrate from NOx emissions in the Imperial Valley is as efficient as in the cooler, more humid San Joaquin Valley, which is obviously not the case. 0016-8

Finally, SER agrees with the DEIS conclusion that the proposed action's O_3 and PM10 contributions would cause, at most, only a very minor increase in the asthma problem in Imperial Valley. Indeed, a quantitative analysis of the potential for increases in PM10 to cause increased asthma problems confirms this conclusion in the DEIS. *See* Exhibit C. As shown by the quantitative, conservative over-estimation of the impact, less than a single additional case of asthma hospitalization would be caused by power plant emissions assuming the power plants operated at 100% capacity 365 days a year. 0016-9

Thank you for the opportunity to comment on the DEIS.

Sincerely,

Enclosures

EXHIBIT A

TDM Water Treatment Plant ('WTP') Operation

The Water Treatment Plant at Termoelectrica De Mexicali consists of the following main components:

1. Biological Treatment Reactor and Secondary Clarifiers
2. DENSADEG™ reactor
3. Demineralizer Plant
4. Press and Filter House
5. Waste Sump

The activity of each component can be summarized as follows:

1. *Biological Treatment Reactor and Secondary Clarifiers.* Water from the Zaragoza lagoons is introduced in this two-stage process block (aerobic and anaerobic environments) that uses biological treatment to oxidize organic matter and ammonia and to remove nitrates (formed as a result of oxidation of ammonia). Significant amounts of dissolved organics, ammonia and phosphorous compounds are removed in this Reactor, as well as agricultural and industrial chemicals. The Secondary Clarifiers separate the activated sludge from the water and recirculate the sludge to the biological reactor. A portion of the activated sludge is sent to the Press and Filter House (described below). Water balance calculations performed on this component of the treatment process show that for an incoming stream with a TDS concentration of 1,200 mg/l, the effluent displays a TDS concentration of 1,180 mg/l.

2. *DENSADEG™ reactor.* This is a commercially available proprietary physical-chemical process, incorporating lime softening - clarification, that is accomplished in two tanks. The majority of the TDS removal accounted for in the DEIS occurs here (other reductions include those resulting from moisture in the sludge removed and cooling tower drift). In this stage, lime is added causing the precipitation of calcium and magnesium, thus removing much of the hardness, as well as substantial amounts of alkalinity, heavy metals and phosphate. The precipitated sludge is flocculated and separated from the water by sedimentation in the clarification process and sent to the Press and Filter House. The effluent flow, which is lower than the flow from the lagoons due to carryover in the sludge leaving this process, has concentrations calculated between 900 and 1,000 mg/l. After leaving the DENSADEG™, sulfuric acid and chlorine are added for pH control and disinfection, and the water is stored in the main service tank to be used in the fire protection system, the cooling tower, and the service water system.

3. *Demineralizer Plant.* To be used in the steam cycle, a very small portion of the water needs further purification. This is accomplished by filtering the water through sand and cartridge filters, a Reverse Osmosis System and an Electro-de-ionization System. As this plant operates in a closed cycle, the waste streams from these systems contain most of the dissolved solids that are removed. All of these waste streams are accounted for in the final balance.

4. *Press and Filter House.* All of the sludge streams (biological as well as lime softening sludge) are treated for water removal and converted into a nonhazardous solid waste that is disposed according to applicable Mexican laws. These materials are not reintroduced into the New River. Land disposal of these solids results in TDS reductions that benefit the New River.

5. *Waste Sump.* Waste streams are collected here for return to the drainage channels. Three streams collect here: (1) Cooling Tower basin, (2) Demineralizer Plant waste streams, and (3) Steam Cycle Blowdown. Assuming an 80% evaporation rate at the cooling tower, the TDS concentrations for each waste stream are: 4,504 mg/l for the Cooling Tower Basin (95%), 3,777 mg/l for the Demineralizer Plant (4%), and 5 mg/l for the Steam Cycle (1%). The combined effluent has a concentration of 4,430 mg/l.

As with any power plant, maintenance, forced outages such as those caused by equipment failure and market conditions, do not allow TDM to operate 100% of the time; however, the biological reactor should remain in operation to keep the microorganisms performing at optimum levels. As a result, when the plant is not producing electricity, the WTP operates in bypass mode and all the water obtained from the Zaragoza lagoons is treated in the Biological Reactor and Secondary Clarifiers and then returned to the drainage channels.

To calculate the amount of TDS removed, the difference in salt loading between the stream entering the plant and the stream being discharged into the drainage channels is calculated. Two modes of operation are considered:

1. '*Maximum Operation*' - TDM operates 100% of the time at full load.

2. '*Expected Operation*' - TDM operates 75% of the time. During this time, the plant operates at the average maximum load (600 MW) 40% of the time and at base load (500 MW) 60% of the time. When TDM is not in operation, the WTP is in bypass mode (25% of the time).

The following calculations were made to estimate the amount of TDS removed annually. The balances were run for each month of the year using typical weather data to determine the amount of water required. Evaporation at the cooling tower was fixed at 80%:

1. *Maximum Operation.*
   Total amount of water received by TDM is 4,372 acre-feet per year (@ 1,200 mg/l).
   Total amount evaporated is 3,497 acre-feet.
   Total amount discharged is 874 acre-feet (@ 4,430 mg/l).
   Total amount of TDS received is 6.5 million kg
   Total amount of TDS discharged is 4.8 million kg.
   Total amount removed is 1.7 million kg per year (3.7 million pounds).

2. *Expected Operation.*
   Total amount of water received by TDM is 3,794 acre-feet per year (@ 1,200 mg/l).
   Total amount evaporated is 2,503 acre-feet.
   Total amount discharged when producing electricity is 626 acre-feet (@ 4,430 mg/l).
   Total amount discharged when in bypass mode is 665 acre-feet (@1,180 mg/l).
   Total amount of TDS received is 5.6 million kg.
   Total amount of TDS discharged is 4.4 million kg (3.4 when producing electricity and 1.0 during bypass mode).
   Total amount removed is 1.2 million kg (1.18 when producing electricity and 0.02 during bypass mode) per year (2.7 million pounds).

It should be noted that when TDM is in bypass mode, in addition to the TDS removal benefits, all other benefits associated with running the Biological Reactor and Secondary Clarifiers are still being realized.

These calculations are based on water balance results for reductions of dissolved solids and were performed using an average raw water TDS of 1,200 mg/l. Estimated TDS concentrations in the treated water streams from the biological treatment system and the lime-softening process that were utilized were 1,180 mg/l and 1,000 mg/l, respectively.

Actual operating data has shown these numbers to be conservative. The TDM turnkey water treatment system contractor (Degremont de Mexico) took numerous conductivity readings for the raw water, biological treatment system effluent and lime softener effluent for a five-month period during startup. Conductivity (specific conductance) is an easy analytical method of measuring the conductive dissolved solids content (TDS) of water. Average conductivity readings for the three sample points were 1960 microS/cm, 1830 microS/cm, and 1600 microS/cm, respectively. Assuming that a conductivity value of 1960 microS/cm is equivalent to a TDS concentration of 1,200 mg/l, resultant TDS concentrations in the biological system and lime softener effluent streams would be 1,116 mg/l and 976 mg/l, respectively[1]. These are both below the calculated dissolved solids concentrations at these points of the process. Thus, not only does actual operating experience verify the removal of TDS, it also demonstrates that actual removals will be somewhat greater than what is conservatively calculated above for the Maximum and Expected Operation scenarios.

---

[1] 1960 microS/cm to 1,200 mg/l yields a reasonable TDS:conductivity ratio of 0.61, which falls comfortably in the range of industry-accepted values.

EXHIBIT B

Discussion of Wet-Dry Cooling and Retrofit to TDM

Background of Wet-Dry Cooling

In a combined cycle power plant like TDM, electricity is generated by two combustion turbines and by one steam turbine. In relatively simple terms, the process starts when burning natural gas in the combustion turbines that are attached to generators produces electricity. The exhaust of these turbines is very hot and is then used in a boiler to heat up water and produce steam. At TDM, additional heat can also be added by burning additional fuel in the boiler to produce more steam (duct firing). This steam, which is very hot and at very high pressures, is then sent to the steam turbine where more electricity is produced by the generator attached to the turbine. What drives the steam through the steam turbine is the difference in pressure between the inlet of the turbine and its exhaust. The greater the difference in pressure, the greater the amount of electricity produced. Therefore, since the inlet pressure is fixed, it is extremely important to have the lowest backpressure available at the exhaust of the steam turbine.

Cooling creates the backpressure of the steam turbine. When steam condenses vacuum is created (vapor takes up less room than water) and the pressure is actually lower than the atmospheric pressure. The lower the pressure, the greater the amount of electricity produced. In other words, good cooling is required to allow the maximum extraction of energy from the steam produced in the cycle.

In a wet cooled power plant, water is circulated through a shell and tube (water in the tubes and vapor in the shell) heat exchanger to condense the steam (i.e. wet-cooled) and then is cooled by an evaporative process in a cooling tower,. An alternative method for steam condensing is a direct air cooled condenser (i.e. dry-cooled) wherein the steam is condensed in tubes with air blown across them.

Lower backpressure, and thus higher steam turbine output, is always achieved with wet cooling at high ambient temperatures because the backpressure is determined by the cooling water temperature which, in turn, is determined by approach to the wet bulb air temperature. Conversely, the backpressure in the air cooled condenser is determined by approach to the dry bulb air temperature. Since wet bulb temperature is always lower than the dry bulb temperature, lower backpressures are always achieved with wet cooling for a given set of conditions than with dry cooling. Air-cooled condensing costs more and generally achieves less electrical production for a given amount of steam. If a power plant has large amounts of duct firing with resulting large amounts of steam produced, and is located in an area that experiences high temperatures year round, when dry cooling is used to maintain the same backpressure achieved by wet cooling, reductions in efficiency occur in the 10-15% range due to the power needed to run the air cooled condenser fans. . Because of this, air cooled condensing is only used when water is not available or site location conditions prevent evaporative cooling (generally due to cooling tower plume considerations).

The use of wet-dry cooling, usually designated as Parallel Condensing System (PCS), wherein an air-cooled condenser and a wet-cooled condenser are installed and operated in parallel, has only recently evolved as a primary design alternative to either wet cooling or dry cooling. The first units were developed as a result of necessity. For example, the Tucuman project in Argentina was converted during design of the facility when a determination was made in the middle of the project that not enough water was available. The Streeter station in Cedar Falls, Iowa is another example of a conversion to parallel condensing. However, this is an old, small plant, under 50 MW, which needed to be retrofitted to avoid winter icing of the highway from cooling tower drift. This highway was being constructed adjacent to the unit, and the Department of Transportation paid for the retrofit.

TDM's owners are considering wet-dry cooling technology for Project Alpha (still in the design phase) where only enough water can be obtained to maintain steam turbine performance during periods of peak demand and high ambient temperature.

Performance

The performance of an air cooled condenser (ACC) is dependent on the incoming steam temperature (measured at the exhaust of the steam turbine), steam flow and the ambient dry bulb temperature (the temperature indicated by a typical thermometer). The smaller the difference between the two temperatures (Inlet Temperature Difference, ITD) the bigger the air-cooled condenser must be for the same steam flow. The relationship between the ITD and the size of the ACC is logarithmic so that as the ITD becomes smaller (at high ambient conditions) the size of the ACC grows asymptotically to maintain performance.

The performance of a cooling tower and surface condenser or "wet cooling" is dependent on the incoming steam temperature and the wet bulb ambient temperature (wet bulb is a harder concept to explain, but in a very simplified way, one could say that it takes into account the cooling value of evaporation available). The primary reason cooling towers are always more effective than air-cooled condensers is that the ambient wet bulb is always lower than the ambient dry bulb, and therefore the ITD is always higher for a wet cooling system.

A parallel cooling system (PCS) improves the steam turbine output in comparison to dry cooling alone by adding a wet cooling component for periods of high dry bulb temperature.

Cooling is extremely important in a power plant because the better the cooling the lower the backpressure that the steam turbine works against. With low backpressure values, more energy can be extracted from the steam turbine to produce electricity in the generator. A steam turbine can lose up to 8 MW for every inch (HgA) of increased backpressure.

In addressing the feasibility of a wet-dry system for TDM, a preliminary check was made of requirements to maintain a 2"HgA backpressure up to a temperature of 90°F dry bulb ambient temperature at base load conditions at TDM. Wet cooling would be activated above this ambient temperature. According to Marley Cooling Technologies, Inc., a well-respected manufacturer of

cooling systems for power plants, the plant would require an air-cooled condenser consisting of 144 modules or fans in a 24x6 arrangement. The structure would be 1,035 ft wide, 273 ft long and 230 ft high (an area of approximately 6.5 acres). The power required to run the fans would be 20,100 kW and the unit alone would cost roughly $80 million plus the cost to erect the unit, which could be as high as $40 million. These costs do not include other retrofit costs required to integrate this air cooled condenser into the TDM facility. In addition, noise and particulate emissions from operation of the air cooled condenser fans would be significant. Clearly a dry cooling system to match the performance of the wet cooling system at base load and 90°F is not practical. In other words, a wet-dry cooling system that would work 100% on dry cooling up to 90°F and on wet cooling for temperatures above that is not feasible for TDM.

Although a PCS can improve steam turbine output at high dry bulb temperatures when compared with dry cooling alone, the output is still less than a wet cooling plant for high ambient conditions. The auxiliary load from the parallel system is also higher than for a wet cooled plant. The performance limits of a PCS is between the performance of a dry cooled plant and a wet cooled plant, and depends on the percentage of wet cooling that is selected.

Retrofit Issues

Given the impracticality of using an air cooled condenser to provide 100% dry cooling up to 90°F at TDM, a preliminary estimate was also made for retrofitting TDM with a more reasonably sized PCS similar to what is being considered for Project Alpha and the cost was estimated to be more than $75 million. It is expected that such a retrofit would allow TDM to operate in dry cooling mode in temperatures up to the 75-80°F range. A description of the necessary modifications and an estimate of cost and schedule are set forth below under the heading 'RETROFIT OF TDM TO "PROJECT ALPHA" DESIGN'.

One additional concern is that the application of a PCS presents a particular operations problem for the TDM plant due to the nature of the raw water pretreatment system on site. This process treats water intercepted at the discharge of Mexicali's sewage treatment lagoons. There are significant operational limitations regarding the ability of the pretreatment plant to change process load quickly or to start up and shut down. The continuous flow for make up water for a cooling tower is manageable but the wet cooling portion of a PCS is expected to be cycled on and off seasonally and daily which is not consistent with the operation of TDM's water treatment plant. Turndown is slow and difficult and if shut down, startup and re-establishment of the biological treatment process takes several weeks.

Water Consumption

Even full dry cooling plants consume water. The annual consumption of water at El Dorado Energy, a fully dry cooled plant in Nevada is 70 million gallons of water (215 acre-feet) for steam cycle makeup and gas turbine air inlet evaporative cooling. There is no water used for cooling/condensing steam from the turbine at El Dorado. El Dorado is a smaller plant than TDM as it has a much smaller amount of duct fired steam production for peaking operation. If TDM were to be 100% dry cooled, TDM's water use would be higher than El Dorado due to the higher

level of duct firing. It is estimated that for cycle demands alone, TDM would use approximately 300 acre-ft annually.

The amount of water consumed by a cooling tower in a PCS is dependent on the level of wet cooling used. The dry bulb temperature at the TDM site exceeds 100°F Fahrenheit for more than 100 days per year. For 7 months of the year, the daily mean maximum temperature exceeds 90°F. For 9 months of the year, the daily mean maximum temperature exceeds 80°F. These months also coincide with the peak demand periods for electricity when TDM is expected to be operated more hours and at higher output. It is clear from the basic climate at TDM that a significant amount of water cooling is required for a large portion of the year to maintain performance at TDM.

Conclusions

It is not practical to retrofit the TDM project to use a PCS because of the following factors:

1. High capital cost (over $75 million).
2. Lost opportunity cost from the outage required for the retrofit (5 months of no production).
3. Increased operating costs from running auxiliary equipment and lower efficiency of cooling system.
4. Minimal water savings to maintain performance as close to the performance with a wet-cooled system due to climate conditions at the TDM site.
5. Operational difficulties in regard to the water treatment plant.

RETROFIT OF TDM TO "PROJECT ALPHA" DESIGN

Project Scope
An engineering study would need to be performed to review the interfaces with the existing infrastructure at TDM. Many systems throughout the plant would be affected and the following work is anticipated to be required with regard to the following systems:

Circulating Water
The condenser for the PCS would be smaller in capacity than the current one and sited at a new location further from the cooling tower than the existing unit. New circulating water piping would have to be installed to the new condenser and interfaced with the existing piping. The new circulating water system needs to be characterized so that the system pumping curve can be compared with the pump curves for the existing circulating water pumps to determine the impact. Any reduction in flow due to a higher pumping head from the PCS will most likely be acceptable due to the reduced load on the cooling tower.

Condensate
The condensate for the PCS would have to be collected at a location far removed from the existing location. This requires a new condensate system to be designed and constructed so that

the system characteristics at the interface with the existing condensate pump discharge piping are equivalent. This will require a new set of pumps controls, piping, instrumentation and DCS according modifications. A new make up water line will also be required.

Dearation
The TDM project currently employs a dearating condenser for the removal of dissolved oxygen. The PCS requires the use of an integral dearator on the HRSG low pressure steam drums or a remote dearator. Incorporation of integral dearators on the existing boilers is not expected to be practical so a remote dearator would have to be installed. Sources and interfaces with continuous and pegging dearating steam would be required and the additional modifications required achieving this.

Chemical Feed
A new chemical feed program would need to be developed for the PCS to accommodate the impacts of the air cooled condenser on the condensate chemistry and the specific characteristics of the PCS. The condensate chemical feed system would be located adjacent to the condensate tank and PCS condenser hotwell. Additional modifications would need to be made to the existing sampling panel system for condensate.

Closed Cycle Cooling Water
The heat rejection for the closed cycle cooling water system would still be accomplished by the cooling tower but by using the auxiliary cooling pump during dry cooled operations. The auxiliary cooling water pump was originally intended for use only during times when the plant was shut down but cooling was still required for this system. An entire spare pump would need to be purchased to provide a level of availability consistent with the existing use.

Air Removal System
The existing air removal system at TDM is a set of liquid ring vacuum pumps. The large internal volume of air-cooled condensers requires a steam jet air ejection system for hogging and continuous air removal during operations. The existing steam system would have to be modified to support the steam jet air ejection system.

Controls
A significant modification to the distributed control system would need to be engineered and implemented including new graphics, logic programming, digital and analog data points and potentially system cards. A new cabinet would probably be installed within an MCC building associated with the PCS with a fiber connection to the control room.

Electrical
The PCS and other plant modifications would impact the plant electrical system significantly. It is likely that the entire auxiliary electrical system including the plant 4160V bus and the auxiliary transformers would require significant modifications. The transformers would most likely need to be replaced, as they are not sized for the increased auxiliary load for running the PCS as well as other increases in auxiliary load from the CCCW and condensate systems. The modifications to the 4160 V switchgear are expected to be extensive.

Additionally, new 4160/480 V transformers and 480V MCCs would be required to support the PCS with associated duct bank and electrical trays.

Engineering, Procurement & Construction

A design/construction contract would be required to complete the retrofit based on the following expected scope.

- PCS
  - Air-Cooled Condenser
  - Steam Duct
  - Steam Turbine Expansion Joint
  - Surface Condenser
  - Condensate Tank
  - Air Removal System
- All New Electrical Systems, Duct Bank & Cable Tray
- New Circulating Water Pipe
- New Condensate System Including Chemical Feed
- Spare Auxiliary Cooling Water Pump
- All Mechanical Retrofits As Required For PCS Integration
- Remote Dearator Installation & Retrofit
- All DCS Retrofits Required
- New Access Roads
- Disposal Of All Discarded Equipment

Schedule

The engineering study would take approximately five months to complete at which time a request for proposals could be developed. Another four months would be required to assemble a contract and detailed specifications for the work to be completed, bid and select a contractor. Another two months would be required to issue a full notice to proceed to the contractor for detailed engineering to begin.

Major equipment deliveries are expected to require up to 21 months.

Even though a good portion of the construction work can be performed while the plant is running a significant outage would be required for the following work:

- Removal Of Old Condenser and Steam Duct Connection
- Mechanical Integration Of Condensate & CCCW Systems
- Electrical Modifications
- Circulating Water Piping Modifications
- DCS Modifications
- HRSG Modifications
- Steam System Modifications (Air Removal & Dearation)
- Start Up & Commissioning

The estimated duration of the outage is 120-150 days depending on the results of the detailed engineering study. This assumes two shifts working six days per week.

It is anticipated that a retrofit of the TDM project would require approximately three years.

Cost

A budgetary estimate has been generated for retrofitting TDM with a PCS approximately the size of Project Alpha:

	Thousand $
Initial Engineering Study	$500
PCS Equipment	$30,000
Electrical Retrofit	$7,000
Circulating Water Retrofit	$1,300
Condensate System Retrofit	$1,100
Mechanical Retrofit	$1,800
Dearator Retrofit	$1,500
Controls Retrofit	$1,500
Civil Works	$1,000
Detailed Engineering & Procurement	$3,000
Construction Management, Labor & Equipment $25,000	
Contingency	$2,500
Other Costs (Consulting/SER Internal/Legal) $500	
TOTAL	**$76,700**

In addition, there would be lost opportunity costs from the loss of electricity production during the outage that would be required to install the system. This additional cost needs to be estimated and added to the total cost of retrofitting TDM with a PCS.

ENSR INTERNATIONAL

EXHIBIT C

Memorandum

To:	Alberto Abreu/Octavio Simoes Sempra Energy Resources	**Date:**	July 27, 2004
From:	Steven Heisler	**File:**	06205-042-100
RE:	DEIS for the Imperial-Mexicali 230-kV Transmission Line project	**CC:**	Sara Head

At your request, we have reviewed the Draft Environmental Impact Statement (DEIS) prepared by the U.S. Department of Energy and U.S. Department of the Interior dated May 2004 for the Imperial-Mexicali 230-kV Transmission Line project with respect to health impacts and provide the following comments.

PM10 Impacts on Asthma Hospitalizations

Page 4-98 of the DEIS states that "The high incidence of asthma is a particular concern in Imperial County. O_3 and PM in the region are likely to be contributing factors. However, the operation of the TDM plant and the EBC and EAX export units at the LRPC plant would contribute only very minor increases to the O_3 and PM levels in the region, and thus would contribute at most a very small increase in the asthma problem ..." We agree with this statement. However, the DEIS does not provide a quantitative estimate of the potential impacts of PM10 emissions from the power plants on the asthma problem.

We have developed the following conservative estimate of the potential increase in asthma hospitalizations in Calexico that might be caused by PM10 emissions from the power plants. Dr. Paul English[1] stated that Pope and Dockery[2] reported that analyses of epidemiological data found that a 10 $\mu g/m^3$ increase in PM10 concentrations is associated with a three percent increase upper respiratory symptoms and asthma. Assuming, as Dr. English did, that the increase in asthma is proportional to the increase in PM10 concentrations, the 2.45 $\mu g/m^3$ maximum modeled increase in 24-hour average

[1] June 16, 2003 Supplemental Declaration of Paul Brian English, Ph.D., in Support of Plaintiff's Request for Permanent Relief, Case No. 02-CV-513-IEG (POR)

[2] Pope, CD, and Dockery, DW, 1999. Epidemiology of Particle Effects. In: Air Pollution and Health. Holgate, S; Samet, J; Koren, J; and Maynard, RL, eds. Academic Press, London.

ENSR INTERNATIONAL

PM10 concentrations from emissions from the TDM and LRPC export turbines could cause a 0.74 percent increase in asthma hospitalizations, and an increase as large as the 5 $\mu g/m^3$ significance level could cause a 1.5 percent increase in asthma hospitalizations.

The California Department of Health Services (DHS) reported that the age-adjusted annual asthma hospitalization rate in Imperial County from 1998 through 2000 was 19.56 per 10,000 population for all ages and was 52.43 per 10,000 for children ages 0-14.[3] The population of Calexico during 2000 was 27,109, and population between ages 0 and 14 was 7,727.[4] Thus, the annual number of asthma hospitalizations between 1998 and 2000 is estimated to be 53 for the entire population (19.56 per 10,000 x 27,109 / 10,000) and about 41 for children aged 0-14.

If the power plant emissions caused an increase of 0.74 percent in the asthma hospitalization rate, which corresponds to the maximum modeled 24-hour average PM10 impact, the total annual number of asthma hospitalizations for all ages would increase by 0.4 (0.74 percent increase x 53 / 100), and the annual number for children ages 0-14 would increase by 0.3 (0.74 percent increase x 41 / 100). Thus, there would be less than one additional asthma hospitalization per year caused by emissions from the power plants. This is a conservatively high estimate because it assumes that the maximum modeled 24-hour average PM10 impact would occur every day throughout the entire City of Calexico when, in fact, it would only occur at a single location (the point of maximum modeled impact) on a single day.

Additionally, If the power plant emissions caused an increase of 1.5 percent in the asthma hospitalization rate, which corresponds to the 5 $\mu g/m^3$ 24-hour average PM10 significance level, the total annual number of asthma hospitalizations for all ages would increase by 0.8 (1.5 percent increase x 53 / 100), and the annual number for children ages 0-14 would increase by 0.6 (1.5 percent x 41 / 100). Thus, there would be less than one additional asthma hospitalization in Calexico per year, even if impacts caused by emissions from the power plants were as high as the significance level. Again, this is a conservatively high estimate because it assumes that the impacts would be equal to the significance level every day throughout the entire City of Calexico when, in fact, it would only occur at a single location on a single day.

These conservative estimates of potential increases in asthma hospitalizations in Calexico demonstrate that, as concluded in the DEIS, emissions from the power plants would contribute at most a very small increase in the asthma problem.

[3] Stockman JK, Shaikh N, Von Behren J, Bembom O, Kreutzer R. California County Asthma Hospitalization Chart Book: Data from 1998-2000. Oakland, CA: California Department of Health Services, Environmental Health Investigations Branch, September 2003.

[4] http://calexico.areaconnect.com/statistics.htm