Comment Set B0012
Powers Engineering

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April 3, 2008

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Ms. Billie Blanchard
California Public Utilities Commission
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Subject: Powers Engineering Comments on A.06-08-010 Sunrise Powerlink DEIR B0012-1

Dear Ms. Lee and Ms. Blanchard:

Please find attached Powers Engineering comments on the Sunrise Powerlink DEIR. These comments are in the form of Powers Engineering's March 12, 2008 Phase II testimony in the Sunrise Powerlink proceeding.

The Powers Engineering comments address two general topic areas: 1) inaccuracies or deficiencies as they relate to the two in-area generation alternatives evaluated in the DEIR, the New In-Area Renewable Generation Alternative and the New In-Area All-Source Generation Alternative, and 2) the failure of the DEIR to perform an environmental impact analysis of the route of the reasonably foreseeable 500 kV interconnection along Highway 76 between the Central substation on SDG&E's preferred Sunrise Powerlink route and the Pendleton substation on the proposed 500 kV LEAPS transmission line. SDG&E asserts in its application that it intends to link the Sunrise Powerlink and LEAPS to form the Full Loop 500 kV transmission project. SDG&E also asserts in its March 12, 2008 Phase II testimony that the preferred Sunrise Powerlink route must be followed to afford the "expandability" necessary to construct the Full Loop transmission project.

Please feel free to call me at (619) 295-2072 or e-mail at bpowers@powersengineering.com if you have any questions about the comments in this letter.

Regards,

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Comment Set B0012, cont.
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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U 902-E) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project	Application 06-08-010 (Filed August 4, 2006)

B0012-1 cont.

PHASE II DIRECT TESTIMONY
OF POWERS ENGINEERING
ON BEHALF OF BILL POWERS, P.E.

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Dated: March 12, 2008

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1. Introduction

My name is Bill Powers, P.E. My resume is provided as Attachment A. I am a professional engineer with 25 years of experience in the energy and environmental fields, a member of San Diego Area Governments (SANDAG) Energy Working Group tasked with charting strategic energy development in the San Diego region, the former U.S. co-chair of the bi-national Border 2012 Air Work Group sponsored by the U.S. Environmental Protection Agency to reduce air pollution in the San Diego/Tijuana, Baja California region, and chair of the Border Power Plant Working Group, a bi-national, nonprofit organization founded in 2001 to promote a sustainable energy infrastructure in the border region. I was also a participant in the Imperial Valley Study Group, a California Energy Commission (CEC)-funded group formed to examine transmission options for maximizing the development of geothermal resources in the Imperial Valley. I participated in the SANDAG strategic energy planning process in 2002-2003 that led to the development of the "San Diego Regional Energy Strategy 2030," which was approved by the SANDAG Board of Directors in July 2003. I authored the report "*San Diego Smart Energy 2020 – The 21st Century Alternative*," prepared with grant funding from the San Diego Foundation, in October 2007. *San Diego Smart Energy 2020* serves as the primary reference for my testimony and is included as Attachment B. *San Diego Smart Energy 2020* in its entirety describes an in-area generation alternate that is directly germane to the two in-area generation alternatives evaluated in detail in the DEIR. B0012-1 cont.

I offer the following testimony on: 1) material factual inaccuracies or deficiencies in the DEIR, and 2) the effect of project alternatives on system reliability and the ability to deliver renewable energy to SDG&E customers, as they relate to the two in-area generation alternatives evaluated in the DEIR. These two alternatives are the New In-Area Renewable Generation and New In-Area All-Source Generation alternatives. I also offer testimony on the failure of the DEIR to perform an environmental impact analysis of the route of the reasonably foreseeable 500 kV interconnection along Highway 76 between the Central substation on SDG&E's preferred Sunrise Powerlink route and the proposed Pendleton substation on the proposed 500 kV Lake Elsinore Advanced Pump Storage (LEAPS) transmission line.

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2. Comments On The New In-Area Renewable Generation Alternative

B0012-2

A. Solar thermal plant will likely consume over 700 million gallons of water per year, not 300,000 gallons per year

The Commission should be concerned that the solar thermal plants may not be viable because of excessive water use. For example, a concentrating solar trough plant is proposed for Borrego Springs in the In-Area Renewable alternative. The nameplate output of this project is stated as 290 MW. The firm on-peak capacity is identified as 232 MW (DEIR, p. E.5-1). The statement is made that "approximately 80 gallons of water is required per MWh of electricity produced, 60 gallons per MWh to produce steam and 20 gallons per MWh to wash mirrors (DEIR, p. E.5-219)." The 60 gallons per MWh to produce steam refers to the boiler feedwater make-up demand of a solar trough power plant. The DEIR assumes that the solar trough will be completely air-cooled, although this is not stated in the text. The water consumption of a completely air-cooled solar trough plant is 80 gallons per MWh. The water consumption of a water-cooled solar trough plant is 1,000 gallons per MWh. The existing California solar trough plants ("SEGS") are water-cooled.[1] A two-cell cooling tower is visible as part of the SEGS III solar trough power plant shown in Figure E.5.1-1b (upper right-hand portion of photograph, DEIR, p. E.5-7).

The output of an air-cooled of a relatively low steam pressure plant can drop dramatically at high ambient temperature. For example, the output of a low steam pressure geothermal plant can drop by more than 50 percent at peak summer temperatures.[2] Comparable performance may be expected unless a very large and expensive air-cooled condenser is included in the design of the solar trough plant. The negative impact on peak day performance of using air cooling alone with the solar trough plant may require a switch to water cooling to justify the project.

[1] U.S. DOE – Energy Efficiency and Renewable Energy, *Cooling for Parabolic Trough Power Plants - Overview*, 2006 Parabolic Trough Technology Workshop, February 14, 2006, Incline Village, NV. Online at: http://www.nrel.gov/csp/troughnet/pdfs/40025.pdf

[2] C. Kutscher et al – NREL, *Hybrid Wet/Dry Cooling for Power Plants*, 2006 Parabolic Trough Technology Workshop, February 14, 2006, Incline Village, NV. Online at: http://www.nrel.gov/csp/troughnet/pdfs/40026.pdf

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The annual capacity factor of a solar trough plant is approximately 0.29.[3] At this capacity factor, the 290 MW solar plant in Borrego Springs would produce 736,716 MWh per year of output.[4] The water consumption of this plant if it is air cooled would be 80 gallons per MWh x 736,716 MWh per year = 58,937,280 gallons per year. The annual water consumption stated for the 290 MW solar trough plant in the DEIR is 300,000 gallons per year (DEIR, p. E.5-224). This is an incorrect figure, low by a factor of 200. B0012-2 cont.

It is improbable that the 290 MW solar trough plant will be exclusively air cooled, given this would add major additional expense to the capital cost of the plant and result in a major performance reduction on peak days. If the plant is water cooled, as existing California solar trough plants are, the annual water consumption of the plant will be 1,000 gallons per MWh x 736,716 MWh per year = 736,716,000 gallons per year. This is equivalent to 2,246 acre-feet per year of consumptive water use.[5]

Borrego Water District draws its water from the Borrego Valley Aquifer and has a water usage is 22,300 acre-feet per year (DEIR, p. E.5-219). If water cooled, the most likely scenario, the 290 MW solar trough power plant would increase the aquifer withdrawal rate by approximately 10 percent.[6] The Borrego Valley Aquifer is currently in overdraft and could be completely depleted in as little as 52 years (DEIR, p. E.5-219). An additional consumptive water use of over 700 million gallons per year is prohibitive in this context and leads the reasonable observer to conclude that the project is not likely to be viable or, if so, would be increasingly expensive.

B. Concentrating PV would have similar performance as solar trough without the high water consumption B0012-3

As described in Attachment B to this testimony, concentrating photovoltaic (PV) systems are beginning to enter commercial service. This promising technology involves concentrations of 400 to 1,000 suns used in concentrating PV systems. Cell efficiencies of 28 to 40 percent are

[3] U.S. DOE – Energy Efficiency and Renewable Energy, *Cooling for Parabolic Trough Power Plants - Overview*, 2006 Parabolic Trough Technology Workshop, February 14, 2006, Incline Village, NV. Online at: http://www.nrel.gov/csp/troughnet/pdfs/40025.pdf

[4] 290 MW × 0.29 × 8,760 hours/year = 736,716 MWh per year

[5] 736,716,000 gallons per year ÷ 328,000 gallons per acre-foot = 2,246 acre-feet per year

[6] 2,246 acre-feet per year ÷ 22,300 acre-feet per year = 0.101 (10.1 percent)

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achieved, with electric efficiencies of 18 to 25 percent.[7] A prototype 1 MW plant was built by Amonix for Arizona Public Service and has been operating for several years. Concentrating PV has performed well at the 1 MW pilot stage and appears ready for commercial scale-up to a 5 to 10 MW size. PG&E has announced a contract for a 2 MW concentrating PV peaking power plant on 8 acres in Tracy, California.[8] B0012-3 cont.

The only water use associated with concentrating PV systems is panel cleaning. Assuming the mirror cleaning water consumption of 20 gallons per MWh for solar trough plants cited in the DEIR is also representative for the panel cleaning water demand of concentrating PV systems, the annual water consumption of a 290 MW concentrating PV array in Borrego Springs would be about 15 million gallons per year, or approximately 45 acre-feet per year. This is less than 1/50th the water consumption of a conventional wet-cooled 290 MW solar trough power plant. Thus, it is more likely that concentrating PV, not solar troughs, will be deployed in arid desert areas.

C. Tracking and fixed PV systems have low water consumption and are being built at utility scale

Large tracking PV and fixed PV systems are in commercial use, as described in Attachment B. Tracking PV systems have been built as large as 11 MW. Large flat-plate fixed PV is fully commercial. A 14 MW PV project came online at Nellis Air Force Base (Nevada) in December 2007.[9] PG&E has announced an agreement for 5 MW of fixed PV on 40 acres near PG&E's Mendota substation in Fresno County. A 40 MW thin-film PV array is under construction in Germany at an estimated installed cost of approximately $5 per watt.[10] Both tracking PV and fixed PV offer fully commercial low water consumption alternatives to solar trough technology.

[7] B. Powers, *San Diego Smart Energy 2020*, October 2007, p. F1.
[8] Ibid, p. 53.
[9] U.S. Department of Energy, Western Area Power Administration press release, February 2008: http://www.wapa.gov/ES/pubs/esb/2008/feb/feb081.htm
[10] February 2007 press release, JUWI Group, *World's largest solar power plant being built in eastern Germany – 40 megawatt project near Leipzig a milestone on the road toward a 100% renewable energy supply*. Installed cost of the 40 MW PV project is €3.25/watt, or $4.85/watt. The euro (€) to dollar exchange rate as of February 26, 2008 is 0.67 euro to 1 dollar. The JUWI Group press release is online at: http://www.juwi.de/international/information/press/PR_Solar_Power_Plant_Brandis_2007_02_eng.pdf

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B0012-4

D. Concentrating PV, tracking PV, and fixed PV plants can be sited at or near the existing SDG&E 69 kV grid

"Renewable energy parks," discussed in detail in Attachment B, are a viable alternative to best match the topography and land use of more rural areas of San Diego County with appropriate solar options.[11] This concept was outlined in the testimony of Michael Shames on behalf of UCAN in the first phase of this proceeding and is also described in detail in Attachment B. Mr. Shames' proposal was casually dismissed by SDG&E as "unrealistic", yet it is very realistic and should have played a larger role in the DEIR. The "energy park" concept I offer for consideration entails the deployment of many smaller concentrating PV or tracking PV arrays in the 1 to 10 MW size on commercially available land near existing or future SDG&E transmission lines and substations. SDG&E owns a network of 69 kV transmission lines that serve the rural areas of the county. Power from these renewable energy parks would be delivered over the 69 kV grid to developed areas of the county.[12] This is similar in concept to the transmission scheme that will be used with the Fallbrook Renewable Energy Facility (biomass) described in the In-Area Renewable Generation alternative. The facility will deliver power to an existing 69 kV circuit approximately one mile from the site (DEIR, p. E.5-14).

This more dispersed approach to large-scale solar trough generation would eliminate the 138 kV overhead (or underground) transmission line from the 290 MW solar trough plant in Borrego Springs through Anza Borrego State Park to the Warner Springs substation. The wildfire risk associated with the overhead 138 kV line would also be eliminated (DEIR, p. E.5-269).

Substituting the solar trough component of the In-Area Renewable Generation alternative with urban or suburban PV installations would also eliminate the 138 kV transmission line.

E. Solar trough and wind turbine siting impacts can be mitigated by substituting these renewable resources with urban/suburban PV systems

The impacts described by the DEIR for the solar trough and wind energy components of the In-Area Renewable Generation alternative can be avoided altogether by limiting the scope of the renewable energy elements of this alternative to: 1) PV installations developed in urban and suburban locations of San Diego County, and 2) the 100 MW of proposed biomass/biogas

[11] Ibid, p. 53-55.
[12] Ibid, p. 54.

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projects already proposed in the In-Area Renewable Generation alternative. As described in Attachment B, 920 MW of PV, primarily at commercial scale, with sufficient storage to match PV system output to the afternoon peak demand load profile, can be installed in San Diego County with an incentive budget equal to that portion of the Sunrise Powerlink levelized cost ($700 million in 2010 levelized dollars) that will be borne by SDG&E ratepayers.[13] B0012-4 cont.

The estimated peak output technical potential of residential and commercial PV in San Diego County in 2010 is 4,400 MW, of which 1,800 MW is commercial PV and 2,600 is residential PV, as explained in Attachment B.[14] This does not include the potential of open ground-level parking lots or parking structures. A rough estimate of the actual PV potential of open parking lots and parking structures in San Diego County is 3,000 MW. There is ample PV potential in San Diego County in developed urban and suburban areas to substitute for both the solar trough and wind energy components of the In-Area Renewable Generation alternative.

As explained in greater depth in Attachment B, urban/suburban PV can be substituted for the wind component of the In-Area Renewable Generation alternative to avoid numerous impacts associated with the wind component. As noted in the DEIR, "Presence of the wind towers/turbines and associated facilities would change the character of a recreation area, diminishing its recreational value" (DEIR, p. E.5-135). Wind energy siting in the In-Area Renewable Generation alternative will affect up to 4,988 acres on Indian lands near the existing 46 MW Kumeyaay wind project, and up to 2,275 acres of nearby Bureau of Land Management land (DEIR, pp. E.5-24 and E.5-25). A new aboveground 230 kV transmission line approximately 10 miles long would connect to the existing 500 kV Southwest Powerlink. A new substation for the transmission line interconnection would also be constructed on 20 to 25 acres (DEIR, pp. E.5-31 and E.5-32). These wind energy development impacts would be eliminated if PV installations in the urban and suburban core of San Diego County are substituted for this wind energy.

Little or no firm on-peak capacity can be assigned to the San Diego County wind resource, as detailed in Attachment B.[15] In contrast, the solar resource consistently produces power on hot sunny days. The output of a PV system controlled to match the peak demand load profile if equipped with limited battery storage.

[13] Ibid, p. 49.
[14] Ibid, pp. 30-31.
[15] Ibid, p. 57.

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Modifying the In-Area Renewable Generation alternative to consist of 920 MW of PV with battery storage, as explained in greater detail in Attachment B, along with the 100 MW of biomass/biogas described in In-Area Renewable Generation alternative, would provide up to 1,020 MW of firm on-peak renewable power by 2016. As noted in the DEIR, distributed PV generation will occur at sites already connected to the distribution grid, so there would be no need for additional transmission facilities (DEIR, p. E.5-12). B0012-4 cont.

The addition of limited storage to each PV system ensures that the PV nameplate capacity is firm on-peak capacity. As explained in Attachment B, the CEC is funding a demonstration in Southern California Edison service territory of sophisticated energy management/battery systems integrated with residential PV to serve as peaking units to meet the late afternoon summertime peak. The energy management/battery systems are fully controllable by the utility as peaking units. The addition of energy management and battery storage allows the PV system to supply the utility grid with its peak output through the late afternoon summertime demand peak. The energy management/battery system adds approximately 10 percent to the cost of the PV system.[16]

F. High percentage of residential PV will result in higher costs and slower PV capacity additions B0012-5

The DEIR errs in assuming that the PV component of the In-Area Renewable Generation alternative will consist overwhelmingly of residential PV installations. According to the DEIR, the PV component will consist of 60,000 3.3 kW residential installations and 255 65.4 kW commercial installations by 2010 (p. E.5-12). The nameplate residential PV capacity is 198 MW. The nameplate commercial PV capacity is 16.7 MW. The nameplate output of this PV capacity is stated as 210 MW in the (DEIR, p. E.5-12). The firm on-peak capacity is identified as 105 MW.

By basing the In-Area Renewable Generation alternative upon these assumptions, the DEIR has presented an overly expensive and unlikely scenario to the Commission. The DEIR errs in assuming that approximately 10 percent of the installed PV capacity is commercial-scale, while approximately 90 percent is residential PV. The overwhelming emphasis on residential PV adds unnecessarily to the cost of the PV component of the In-Area Renewable Generation

[16] Ibid, pp. 47-48.

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alternative. The DEIR notes that most residential PV systems take less than one week to install, while also noting that large-scale commercial systems may take as little as one week to install depending on siting requirements (DEIR, p. E.5-13). It is reasonable to assume that large commercial installations will have lower installation costs on a "kW installed" basis than residential systems due to the economies of scale. B0012-5 cont.

The PV system size trend in the California Solar Initiative (CSI) program reflects the economic benefits of commercial PV systems over residential systems. Commercial PV systems account for a large majority of the PV capacity being installed under the CSI program. More than 80 percent of the CSI PV capacity currently reserved is commercial-scale PV.[17]

As explained in Attachment B, Large commercial PV developers purchase PV system components in wholesale quantities and as result tend to receive greater discounts on PV hardware than small-scale PV system installers. The current installed cost of residential rooftop PV systems is approximately $8 per watt prior to incentive payments and tax credits. The cost is 10 to 15 percent lower for large wholesale buyers of PV panels and associated hardware.[18]

3. Comments On The New In-Area All-Source Generation Alternative B0012-6

A. Load reduction implications of new CPUC aggressive energy efficiency strategies are not considered

CPUC decision D.07-10-032 dated October 18, 2007 requires the California electric utilities to achieve unprecedented levels of energy efficiency.[19] The decision also requires the utilities conduct joint energy efficiency planning facilitate achieving the aggressive energy efficiency targets. The utilities jointly developed a draft "*California Energy Efficiency Strategic Plan*" on February 8, 2008. The first workshop on the Plan was held at SDG&E on February 21, 2008. The target of the plan is to incorporate 100 percent of cost-effective energy efficiency measures by 2020.[20] Achievement of this energy efficiency target would mean an average

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[17] Telephone conversation between B. Powers and J. Supp, California Solar Initiative (CSI) program manager, California, Center for Sustainable Energy, February 25, 2008. Currently 225 MW of commercial PV capacity and 40 MW of residential PV capacity are reserved under CSI.
[18] B. Powers, *San Diego Smart Energy 2020*, October 2007, p. 46.
[19] PG&E, SCE, SDG&E, California Energy Efficiency Strategic Plan – Draft, Rulemaking 06-04-010, February 8, 2008, pp. ix-x. Online at: www.californiaenergyefficiency.com
[20] Ibid

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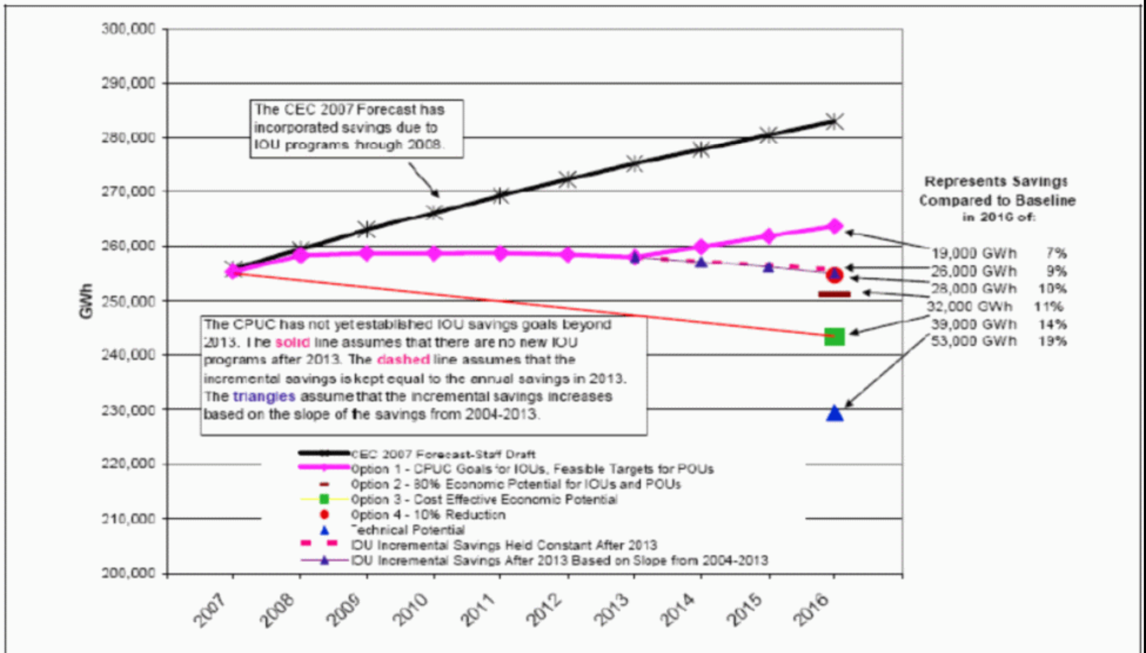
demand decline of approximately 0.5 percent per year over the next decade in SDG&E service territory (See Figure 1 below). B0012-6 cont.

This decline in peak demand would reverse the 482 MW increase in demand by 2016 projected by SDG&E as the reliability justification for the Sunrise Powerlink and convert it into a 280 MW demand decline over the same period. Energy efficiency is the highest priority on the Energy Action Plan loading order. As explained in Attachment B, dozens of cost-effective energy efficiency projects have been carried-out by the City of San Diego with an average absolute reduction of energy use of 20 percent.[21] The DEIR errs by not including 600+ MW of firm on-peak capacity in the form of energy efficiency. This firm on-peak energy effiency capacity should also be included in the In-Area Renewable Generation alternative.

Figure 1. California Energy Commission Projection of Impact of Varying Levels of Energy Efficiency (EE) on Electric Energy Consumption by California Utilities – Red Line Represents Achievement of 100% of Cost-Effective EE Measures



Source: California Energy Commission. From *Statewide Energy Efficiency Potential Estimates and Targets for California Utilities*, pp. 60-60 CEC-200-2007-019-SD, August 2007.

Source: This is Figure 3-5 of the CEC's 2007 Integrated Energy Policy Report, November 2007. Red line between 2007 starting point and 2016 green square, representing achievement of 100% of cost-effective energy efficiency measures, was added by B. Powers.

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[21] B. Powers, *San Diego Smart Energy 2020*, October 2007, p. 32.

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B. Simple, cost-effective demand response programs are readily available should not be identified as optional B0012-7

Also discussed at the February 21, 2008 workshop were very simple and low-cost demand response procedures for shedding large amounts of MWs on peak demand days. SDG&E, with 1.4 million total customer meters,[22] has a modest air conditioning cycling program. SDG&E reported demand reduction due primarily to the air conditioning cycling program in the range of 18 MW during the summer of 2006 heat wave.[23] SDG&E has understated the potential for the demand reduction. PG&E just received authorization from the CPUC to enroll 400,000 customers in an air conditioning cycling program that PG&E estimates will reduce demand by 345 MW at peak.[24] In reference to the PG&E air conditioning cycling program, PUC President Peevey stated, "*It's an extremely cost-effective demand response program, it avoids system emergencies.*"[25] Controllers will be installed that allow the utility to shut off air conditioning units for brief periods as needed. An air conditioner cycling program in SDG&E territory of similar magnitude to PG&E's program would eliminate much of the 482 MW reliability justification for the Sunrise Powerlink. By failing to consider the potential of air conditioner cycling, the DEIR has understated the role that demand response plays as an environmentally preferable alternative.

Air conditioning load is responsible for approximately one-third of total demand on hot summer days.[26] Yet SDG&E has no efficiency rebates for central air conditioning units.[27] The 2006 federal standard for new central air conditioning units is Summer Energy Efficiency Rating (SEER) 13. However, as explained in Attachment B, SEER 21 central air conditioning units are commercially available, nearly 40 percent more efficient than SEER 13 units, and only incrementally more expensive.[28]

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[22] B. Powers, *San Diego Smart Energy 2020*, October 2007, p. 13.
[23] CPUC Decision D.06-11-049, Order Adopting Changes to 2007 Utility Demand Response Programs. Online at: http://docs.cpuc.ca.gov/published/FINAL_DECISION/62281-02.htm#P170_11760. Summary of SDG&E demand response program performance in July 2006: "*SDG&E reports reasonably good participation by demand response customers during several July 2006 events. Its day-of subscribers reduced load by an hourly average of 18 MW, most of which came from its AC Cycling program and smaller amounts from several other programs.*"
[24] California Energy Circuit, *PG&E allowed AC turn off power*, February 15, 2008.
[25] Ibid
[26] Ibid, p. 35.
[27] Ibid, p. I-1.
[28] Ibid, p. 38.

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The difference in the installed cost prior to rebates of a reference case Carrier Corporation 3-ton SEER 13 residential central air and heating unit, which costs approximately \$9,000, and a state-of-the-art Infinity® 21 unit (SEER 21) is around \$2,000. Carrier offers a rebate on high efficiency units that reduces the cost difference between the SEER 13 and SEER 21 alternatives. As explained in Attachment B, the SEER 21 unit would save approximately 1,200 kWh relative to the SEER 13 unit over 1,000 hours. Summer peak savings would be \$300 per year, assuming a peak demand rate of \$0.25/kWh and smart meters to measure real-time consumption. The simple payback for the \$2,000 additional cost of the Infinity® 21 would be 6 to 7 years.[29] B0012-7 cont.

Focusing SDG&E efficiency rebate dollars on central air conditioning units to assure that only units with state-of-the-art SEER ratings are installed in hotter areas of San Diego County is one cost-effective way to assure the 249 MW demand reduction described in In-Area All-Source alternative as "optional" is achieved in practice. The DEIR erred in classifying the 249 MW of demand reduction as optional. This additional level of demand response is readily achievable with simple procedures that can operate seamlessly with the advanced digital meters that all SDG&E customers will have by 2011.[30] The firm addition of 249 MW of on-peak demand reduction is an assumption that the DEIR should have, but failed to, incorporate into the resource mix in the In-Area All-Source Generation alternative and the In-Area Renewable Generation alternative.

C. Non-renewable distributed generation is higher in Energy Action Plan "loading order" than combined-cycle plants B0012-8

Non-renewable distributed generation (DG) should substitute for the 620 MW combined-cycle plant in the In-Area All-Source alternative, as explained in detail in Attachment B. The CPUC/CEC Energy Action Plan, first approved in 2003, establishes a "loading order" that prioritizes non-renewable DG over utility-scale natural gas-fired power plants.[31] One reason that non-renewable DG, also known as "combined heat and power" (CHP), is higher in the loading order than combined cycle generation is that it has the lowest CO_2 emissions of any fossil fuel

[29] Ibid, pp. 38-39.
[30] Ibid, p. 13.
[31] CPUC/CEC, Energy Action Plan II – Implementation Roadmap for Energy Policies, September 21, 2005, p. 2.

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power generation system at 639 lb CO_2 per MWh. This compares to 819 lb CO_2 per MWh for combined cycle plants.[32]

The DEIR acknowledges that there was 105 MW of non-renewable DG capacity in SDG&E territory at 61 sites as of mid-2006 (DEIR, p. E.6-27). Non-renewable DG is a proven component in the energy generation mix in SDG&E territory. Ample untapped potential is available at existing commercial, industrial, and institutional facilities in San Diego County to generate 620 MW from new non-renewable DG systems.

The In-Area All-Source alternative includes either 0 MW of non-renewable DG (DEIR, p. E.6-2, Table E.6.1-1) or 70 MW of nameplate new non-renewable DG (DEIR, p. E.6-26). This discrepancy needs to be addressed in the final EIR document.

Non-renewable DG is also assigned the same firm on-peak to nameplate relationship, 50 percent, that is assigned to PV systems without battery storage. It would be reasonable to assume that firm on-peak non-renewable DG would equal 80 to 90 percent of nameplate capacity. This is especially true if a simple system of two-way communication between the DG operators and SDG&E is established to ensure that non-renewable DG scheduled outages are minimized during periods of peak demand. The DEIR erred by assuming a low firm on-peak DG capacity.

The March 2007 *Distributed Generation and Cogeneration Policy Roadmap for California* report prepared by CEC staff calls for ten more years of subsidies for DG technologies. These include incentive payments for CHP under the CEC's self-generation program. Making such policy changes, according to the report, could turn DG from a nascent technology that makes 2.5 percent of peak power to a significant provider that meets 25 percent of the state's peak power needs by 2020. Among the changes envisioned by the CEC to generate a quarter of the state's power from off-grid DG are transparent dynamic rates for electricity. The report also recommends removing institutional barriers. For instance, DG has been hampered by a lack of uniform rules and standards that could speed installation of equipment.[33] The DEIR

As explained in Attachment B, there are approximately 240 candidate sites for conventional combined heat and power facilities in San Diego County. These include large private employers, large city and county government centers, military bases, large hospitals, large hotel complexes, large shopping complexes, and large universities and colleges. Some of

[32] Ibid, p. 60.
[33] Ibid, p. 61.

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B0012-8 cont.

these sites already operate CHP plants, such as the University of California San Diego, San Diego State University, Children's Hospital, and Qualcomm.[34] Commercial CHP systems are now available in increments down to 240 kW. The availability of such small CHP packages greatly expands the potential number of candidate CHP facilities in San Diego County.[35] The development of 620 MW of CHP, by reducing CO_2 emissions relieving congesting on the urban transmission and distribution system, would be a superior substitute for the 620 MW combined cycle plant in the In-Area All-Source alternative. The DEIR errs by prioritizing combined cycle over CHP for the provision of baseload natural gas fired power.

B0012-9

D. Firm PV capacity can substitute for 250 MW of peaker turbines

Renewable energy is higher in the loading order than conventional utility-scale power plants. As explained in Attachment B, urban/suburban PV with limited battery storage provides firm on-peak capacity at or near the nameplate capacity of the PV system(s). The CO_2 emission rate of peaking turbines is 1,170 lb CO_2 per MWh.[36] This compares to 0 lb CO_2 per MWh for PV. The distributed nature and relatively small size of individual PV systems compared to peaking turbines assures that a forced outage of a single PV system has no impact on grid reliability at peak demand. In contrast, the forced outage of one or two 50 MW peaking turbines at peak demand might have a material effect on grid stability due to the significance of the lost output. The DEIR errs by presuming that peaking turbines must provide the bulk of the peaking power envisioned in the In-Area All-Source alternative when PV with limited battery storage is available, provides firm on-peak capacity at or near nameplate rating, and is much higher in the loading order.

B0012-10

4. Failure Of DEIR To Include Detailed Environmental Impact Analysis Of Reasonably Foreseeable 500 Kv Interconnection Along Highway 76 Between Sunrise Powerlink And LEAPS Transmission Lines

A. Recirculation of DEIR necessary to include detailed environmental analysis of 500 kV corridor along Highway 76 between Sunrise Powerlink and LEAPS

[34] Ibid, p. 61.
[35] Ibid, p. 62.
[36] Ibid, p. 60.

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SDG&E's ultimate objective is a 500 kV Full Loop to SCE territory.[37] SDG&E has cited in its presentations to policymakers the desire of the company to support the California Independent System Operator (CAISO) long-term concept to add a 500 kV Full Loop through Southern California, stating:[38] B0012-10 cont.

"*Needs for a New 500 kV Transmission Line - To improve reliability for San Diego and CAISO by enhancing California's 500 kV electric grid, consistent with the CAISO's long-term concept of adding a 500 kV loop through Southern California.*"

The SDG&E Aug. 4, 2006 application to the California Public Utilities Commission (PUC) describes the route that will be used to complete the 500 kV Full Loop, stating (p. VI-13):

"*Of the Full Loop alternatives originating at Imperial Valley, the best-performing Full Loop alternative went from Imperial Valley to a new "Central" Substation to a new substation in SCE's territory between the Serrano and Valley Substations. This alternative also had the advantage of combining the Sunrise Powerlink (Imperial Valley – Central 500 kV) with the LEAPS transmission.*"

A combination of 500 kV Sunrise Powerlink and the 500 kV LEAPS transmission line is presented by SDG&E as the Full Loop option in the application, not one of several options.

However, the Full Loop described by SDG&E is missing one piece, an interconnection between the Sunrise Powerlink's Central substation near Lake Henshaw and the LEAPS 500 kV substation on Camp Pendleton's northern boundary. The Talega-Escondido 230 kV line is a component of the LEAPS transmission project. This existing 230 kV corridor is only about 30 miles from the proposed Central substation of the Sunrise Powerlink. The interconnecting 500 kV line between the Central substation and the LEAPS 500 kV substation will follow the route of the existing Warners-Rincon 69 kV transmission line along Highway 76, then the existing Rincon-Lilac 69 kV transmission line to the Lilac substation north of Escondido. The 500 kV line would then parallel the existing Talega-Escondido 230 kV line about 30 miles to the proposed Pendleton substation on the 500 kV LEAPS transmission line. The portion of the 500 kV interconnection route passing through or by Indian lands along Highway 76 is shown below in Figure 2 (map extracted from Figure B-12b, DEIR, p. B-30, tags added by B. Powers).[39]

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[37] SDG&E Aug. 4, 2006 application, p. VI-4: "The Full Loop would complete the 500 kV loop through Southern California, connecting SCE's 500 kV Palo Verde-Devers-Valley-Serrano system to SWPL."
[38] David Geier - SDG&E, *Transmission Constraints to Geothermal Resource Development*, presented at CEC IEPR Committee Workshop, April 11, 2005. Online at: http://www.energy.ca.gov/2005_energypolicy/documents/2005-04-11_workshop/Geier_David_SDGE.PDF
[39] The complete Full Loop route map is shown in Figure B-12b of the DEIR/EIS at: http://www.cpuc.ca.gov/Environment/info/aspen/sunrise/deir/figs/Figure%20B-12b_Future%20Expansion_500kV_CE_Riverside.pdf

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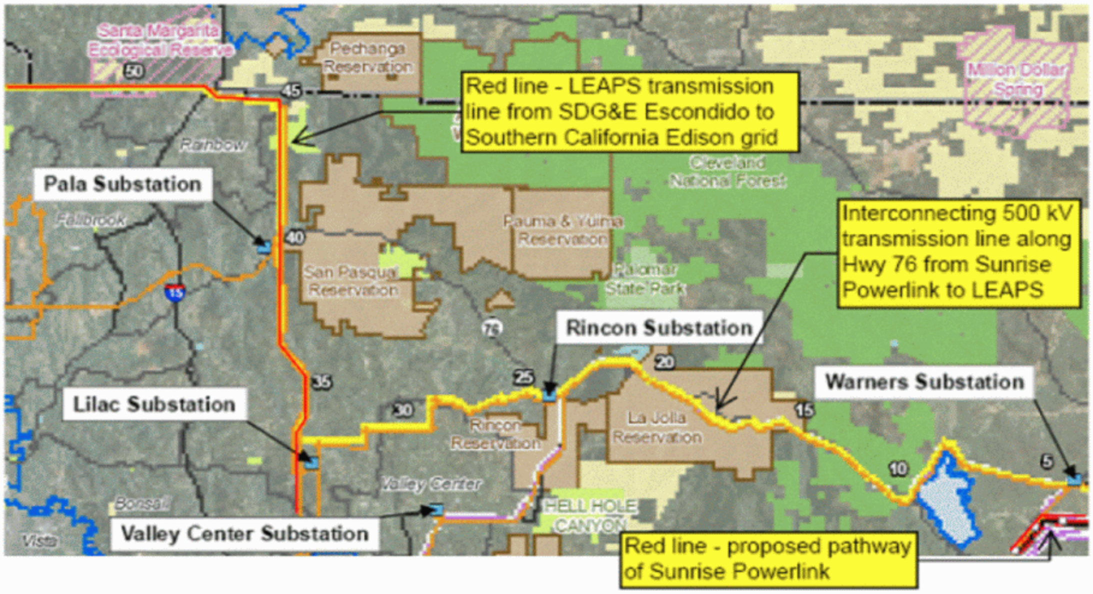
B0012-10 cont.

Figure 2. 500 kV Interconnection between Sunrise Powerlink and LEAPS lines



The failure of the DEIR to include an environmental analysis of this 500 kV interconnection between the Sunrise Powerlink Central substation and the proposed Pendleton substation on the 500 kV LEAPS transmission line is a critical omission.

B. It is reasonable to assume construction of SDG&E's Full Loop route is foreseeable and imminent

The SDG&E Aug. 4, 2006 application was explicit in representing that SDG&E considers the highest ranking transmission alternative to be the "Full Loop" interconnection with the SCE grid, stating (application, VI-3, VI-4):

> *"This assessment determined the two highest ranking alternatives to be the Imperial Valley – Central – Serrano/Valley 500 kV alternative (or the "Full Loop" 2) and the Imperial Valley – Central 500 kV alternative (the "Sunrise Powerlink"). These two alternatives were found to be the best performing thermally and economically, and provide the best access to renewable energy resources.*

SDG&E goes on to state (application, VI-15):

> *"Although performing adequately—technically and economically—the Full Loop was not selected as the preferred alternative. The main reasons were its higher cost, the low probability of operation by 2010 and the need for a Full Loop could not be justified today,*

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under the ISO's grid reliability criteria or for economic reasons. The July 28th CAISO report concurred with SDG&E's findings, but noted it is in the process of further evaluating the Full Loop proposal. If upon further evaluation a Full Loop option is justified in the future, SDG&E would seek appropriate approvals for transmission facilities for the Full Loop and conduct any requisite environmental review of such facilities at that time." B0012-10 cont.

This Full Loop route was rejected for analysis in the DEIR for the stated reason that it had more negative impacts than the proposed project while achieving the same objectives (DEIR, p. C-125, p. C-132). However, a 500 kV interconnection with the SCE grid is not one of SDG&E's stated objectives for the Sunrise Powerlink. Yet SDG&E is clear in its application that the Sunrise Powerlink is a critical component of the Full Loop project that SDG&E considers to be the highest ranking transmission alternative, and that a favorable opinion from CAISO on the energy and economic merits of the Full Loop via the CAISO's in-process evaluation would initiate a formal application process by SDG&E to complete the Full Loop.

The CAISO can not reasonably be considered a neutral party in the Sunrise Powerlink proceeding. The CAISO technical analysis that supports the need for the Sunrise Powerlink was finished days before SDG&E filed its Aug. 4, 2006 application. SDG&E inserted the entire July 28, 2006 CAISO report as an attachment to the executive summary of its application as supporting technical justification for the Sunrise Powerlink. Regarding the Full Loop alternative, CAISO states (July 28, 2006 report, p. 47): "*The CAISO is in the process of evaluating the energy benefits of this project to determine if the Full-Loop proposal would provide economic value for further consideration.*" As noted, SDG&E has cited in its presentations to policymakers the desire of the company to support CAISO's long-term concept to add a 500 kV Full Loop through Southern California.[40] SDG&E also lists CAISO as a supporter of the Sunrise Powerlink on its Sunrise Powerlink "supporters" webpage.[41] Given SDG&E points to CAISO as a primary reason for pursuing the construction of the Full Loop, the DEIR errs by presuming there is uncertainty that CAISO will be anything less than an enthusiastic partner in providing SDG&E with the necessary technical and policy support to complete the Full Loop once approval for Sunrise Powerlink is granted.

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[40] David Geier - SDG&E, *Transmission Constraints to Geothermal Resource Development*, presented at CEC IEPR Committee Workshop, April 11, 2005. Online at: http://www.energy.ca.gov/2005_energypolicy/documents/2005-04-11_workshop/Geier_David_SDGE.PDF
[41] http://www.sdge.com/sunrisepowerlink/supporters.html

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