2. General Responses to Major Comments

This section presents detailed responses to comments that were made by many commenters. General Responses address the following topics:

- GR-1 – Project Objectives and Feasibility of the New In-Area All-Source Generation Alternative
- GR-2 – Project Objectives and Feasibility of the New In-Area Renewable Generation Alternative
- GR-3 – Reliability Comparison Between Northern & Southern Transmission Line Routes
- GR-4 – Project Objectives and Feasibility of the LEAPS Project Alternatives
- GR-5 – Status of Development of Renewable Generation in the Imperial Valley, Eastern San Diego County, and Northern Mexico
- GR-6 – Smart Energy 2020 and All-Solar Alternatives
- GR-7 – Sunrise Powerlink Project Connection to Mexican Generation and/or Mexican LNG Import
- GR-8 – Greenhouse Gas (GHG) Impacts of Sunrise Powerlink Project and Non-Wires Alternatives
- GR-9 – Fire Risk and the Comparison of Alternatives.
- GR-10 – Electric and Magnetic Fields (EMF)
- GR-11 – Transmission Line Effects on Property Values
- GR-12 – CEQA, NEPA and the Decision-Making Process
- GR-13 – Biological Resources Applicant Proposed Measures (APMs)
- GR-14 – Biological Resources Impact Calculations/Mitigation Ratios.
- GR-15 – Biological Resources Jurisdictional Delineations
- GR-16 – Adequacy of Biological Surveys
- GR-17 – Consistency with Existing and Draft Regional Conservation Plans
- GR-18 - Identification of Biological Resources Mitigation Lands

General Response GR-1: Project Objectives and Feasibility of the New In-Area All-Source Generation Alternative

Several commenters, including SDG&E, stated that the New In-Area All-Source Generation Alternative would not meet project objectives and it would not be feasible. Specifically, SDG&E has commented that the alternative would substantially impede efforts to develop the renewable power supply in the Imperial Valley. In addition, SDG&E claims that the alternative would rely on several generation facilities that are uncertain or have been completely abandoned by developers and would rely on the unproven ability to greatly expand solar photovoltaic (PV) generating capability. The CPUC's procurement process of generation is also described at the end of this response to respond to comments that questioned what might occur, procedurally, if either the New In-Area All-Source Generation or the New In-Area Renewable Generation Alternative (a.k.a. the "non-wires alternatives") were approved.

Components of the New In-Area All-Source Generation Alternative

The projects considered in the Draft EIR/EIS are representative of reasonable generation scenarios, and are not intended to depend on the progress of contracts for individual utility projects. The New In-Area All-Source Generation Alternative would include a combination of fossil-fuel fired central station and peaking generation, renewable generation, and non-renewable distributed generation (DG). The description and assumptions of this alternative are included in Section 4.10 in Appendix 1, Section C.4.10.2, and Section E.6.1 in the Draft EIR/EIS. Many of the non-wires options were separately identified by SDG&E as alternatives in its Proponent's Environmental Assessment (PEA) Section 3.3.3. The capacity provided by conventional generation projects under this alternative would include at least 620 MW from a central station power plant plus 250 MW from multiple peaking power plants assumed to come online by 2008.

This alternative also includes 203 MW of the solar photovoltaic, wind and biomass/biogas projects that are included in the New In-Area Renewable Generation Alternative discussed in Section E.5 in the Draft EIR/EIS, as well as in General Response GR-2. The conventional generation considered under New In-Area All-Source Generation Alternative includes a range of specific conventional generation projects, listed below.

- **Baseload Generation**. Either the South Bay Replacement Project[1], the San Diego Community Power Project (also known as "ENPEX"), or the Carlsbad Energy Center (repowering project for Encina Power Plant)
- **Peaking Generation**. Four peaking gas turbines from which SDG&E could procure in response to the 2008 Peaker RFO
- **Distributed Generation**. Fossil fuel-fired distributed generation facilities

The New In-Area All-Source Generation Alternative would also involve development of all the renewable resources described under the New In-Area Renewable Generation Alternative in Section E.5 in the Draft EIR/EIS, as well as in General Response GR-2 below and in Section C.4.10.1 and Section 4.10.2 in Appendix 1 of the Draft EIR/EIS, with the exception of Solar Thermal, which would not

[1] The South Bay Replacement Project was under consideration by the California Energy Commission during 2006 and 2007, but was withdrawn by the applicant in October of 2007. Even thought the application is not active, this project is retained as a potential component of the In-Area All Source Alternative as a representative baseload power plant.

occur under the New In-Area All-Source Generation Alternative. The various renewable power projects would involve solar, wind, and biomass/biogas as follows:

- **Solar Photovoltaics**: Individual solar PV systems would be installed on residential and commercial buildings totaling up to a nameplate capacity of 210 MW or 105 MW for reliability accounting by 2010.
- **Wind:** Approximately 200 MW of wind power nameplate capacity or 48 MW for reliability accounting would need to come on line by 2010, with 400 MW of nameplate capacity or 96 MW for reliability accounting by 2016, most likely in the Crestwood wind resource area.
- **Biomass/Biogas:** Approximately 50 MW of new biomass/biogas generation by 2010, with 100 MW of biomass/biogas by 2016, from new landfill gas-to-energy projects or wood waste projects at unspecified locations.

Consistency with Project Objectives

CEQA Guidelines Section 15126.6(a) provides that alternatives should be potentially feasible and should meet "most" of the basic project objectives, while reducing or avoiding one or more the significant effects of the proposed project. Similarly, the Council on Environmental Quality's (CEQ) NEPA Regulations (40 C.F.R. 1502.14) requires analysis of alternatives that are "practical or feasible." Each of the over 100 alternatives evaluated in the Draft EIR/EIS was screened in the Alternatives Screening Report (see Appendix 1 of the Draft EIR/EIS), and only alternatives that meet "most" project objectives, are potentially feasible and would reduce or avoid one or more the significant effects of the proposed project were carried forward for full analysis in the EIR/EIS. Section 3 (Overview of Alternatives Evaluation Process) in Appendix 1 of the Draft EIR/EIS further describes the regulations and alternatives screening methodology. This response clarifies how the New In-Area All-Source Generation Alternative would meet most project objectives and provides additional information on how it would be a practical and potentially feasible alternative.

Section 3.1 of SDG&E's PEA stated eight project objectives of the Sunrise Powerlink Project (see also Section A.2.1 [SDG&E's Project Objectives] in Volume 1 of the Draft EIR/EIS). Having considered the eight objectives set forth by SDG&E, the CPUC and BLM identified the following three basic project objectives in Section A.2.2 of the Draft EIR/EIS:

- Basic Project Objective 1: to maintain reliability in the delivery of power to the San Diego region.
- Basic Project Objective 2: to reduce the cost of energy in the region.
- Basic Project Objective 3: to accommodate the delivery of renewable energy to meet State and federal renewable energy goals from geothermal and solar resources in the Imperial Valley and wind and other sources in San Diego County.

These three basic objectives incorporate all of SDG&E's more specific objectives. Although the New In-Area All-Source Generation Alternative would not, by itself, accommodate the delivery of renewable energy to meet State and federal renewable energy goals from geothermal and solar resources, wind and other sources (Objective 3), as acknowledged in Section 4.10.3 in Appendix 1 of the Draft EIR/EIS, it would nevertheless meet most of the basic project objectives. The CEQA Guidelines explain that the analysis in an EIR should focus on alternatives that can reduce or eliminate significant environmental impacts "even if these alternatives would impede to some degree the attainment of the project objectives…" (CEQA Guidelines § 15126.6(b).) Similarly, under NEPA, lead agencies are prohibited from disregarding alternatives "merely because they do not offer a complete solution to the problem" if they would reduce significant environmental harm associated with the proposed action. (See *Natural Resources Defense Council, Inc. v. Morton* (D.C. Cir. 1972) 458 F.2d 827, 836 ("*Morton*").) In determining whether potential alternatives met "most" of the basic project objectives, alternatives that met at least two of the three basic project objectives were carried forward if they also met the other criteria detailed in Appendix 1 of the Draft EIR/EIS. Therefore, the New In-Area All-Source Generation Alternative was properly evaluated in the EIR/EIS despite the fact that alone it would not accommodate the delivery of renewable energy to meet State and federal renewable energy goals from geothermal and solar resources, wind and other sources. The following paragraphs summarize the New In-Area All-Source Generation Alternative's ability to meet each basic project objective. Although comments were not specifically made regarding compliance with Basic Objectives 1 or 2, a summary is provided below to illustrate how the New In-Area All-Source Generation Alternative would meet these project objectives.

Basic Project Objective 1: Maintain Reliability

Compared to the Proposed Project, in-area generation eliminates the reliability vulnerabilities associated with long-distance transmission. As described in Section 4.10.3 of Appendix 1 and in Section C.10.4.2 in the Draft EIR/EIS, there would be significant reliability benefits with the New In-Area All-Source Generation Alternative. Adding generation in the SDG&E service territory, near the load center, would fully meet SDG&E's reliability objective. Generating power near the load eliminates the vulnerabilities of long-distance transmission.

Commenters stated that the New In-Area All-Source Generation Alternative would not provide an adequate reliability benefit because the components of this alternative could not be operational in 2010. SDG&E's construction schedule, provided in December 2007, shows that summer 2011 would be the in-service date for the Proposed Project (see Section B.4.7). The timing of meeting the reliability objective is yet to be determined in the CPUC General Proceeding (A.06-08-010). As such, there has not been a CPUC determination with respect to the need for the Proposed Project by 2010 (see also General Response GR-12). However, because there are multiple sources of capacity with the New In-Area All-Source Generation Alternative, the generation capacity can be phased in with various components to meet the incremental load growth of the San Diego area over time.

Basic Project Objective 2: Reduce the Cost of Energy

Consistent with the objective of reducing the cost of energy in the region, new in-area generation could provide SDG&E with low-cost power relative to the current generation fleet in the SDG&E service territory. The California Energy Commission's report titled the Comparative Costs of California Central Station Electricity Generation Technology[2] (December 2007) shows the levelized costs for a number of generation technologies, and combined cycle plants are shown as having one of the lowest levelized costs.[3] In addition, the two largest generating plants in the San Diego area (i.e., South Bay and Encina) are both more than 30 years old and do not have highly efficient generation equipment. Thus, the replacement of this generation with new modern generation equipment would reduce the variable costs of in-

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2 Joel Klein and Anitha Rednam, Comparative Costs of California Central Station Electricity Generation Technologies, California Energy Commission, Electricity Supply Analysis Division, CEC-200-2007-011. http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF. December 2007.

3 Levelized cost is defined as the present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

area generation for SDG&E.[4] Expanding the availability of in-area generation would also be likely to reduce the costs of providing local area reliability and payments for meeting local capacity requirements.

Basic Project Objective 3: Accommodate the Delivery of Renewable Energy

One of SDG&E's stated eight project objectives was to "[p]rovide transmission capability for Imperial Valley renewable resources for SDG&E customers to assist in meeting or exceeding California's 20% renewable energy source mandate by 2010 and the Governor's proposed goal of 33% by 2020." This objective is incorporated into the CPUC/BLM's Basic Project Objective 3.

Although commenters have stated that this alternative would conflict with policy decisions of Governor Schwarzenegger and the California Legislature mandating greater use of renewable resources and would not directly accomplish SDG&E's RPS goals, the New In-Area All-Source Generation Alternative provides for development of certain renewable projects in San Diego County, which would facilitate SDG&E's compliance with RPS goals and policies, totaling 203 MW (see Table E.6.1-1 in Section E.6 of the Draft EIR/EIS). Therefore, the New In-Area All-Source Generation Alternative would partially meet the objective of accommodating the delivery of renewable power. In addition, several of the renewable generation components could move forward in the absence of construction of the Sunrise Powerlink Project and would not conflict with California's policy decisions mandating greater use of renewables and less use of fossil fuels. (See General Response GR-2.) The New In-Area All-Source Alternative includes the construction of wind, solar PV, and biogas/biomass renewable generation facilities, and these renewable components would contribute towards the State's RPS goals.

SDG&E could also meet its RPS goals and satisfy the objective of delivering renewable energy by trading Renewable Energy Certificates (RECs) in conjunction with the New In–Area All-Source Generation Alternative for RPS compliance (see Section 4.10.3 of Appendix 1 of the Draft EIR/EIS). As described in Section 4.10.1 (Background on Renewable Energy) under Renewable Energy Certificates in Appendix 1 of the Draft EIR/EIS, RECs are a way of measuring the environmental, non-energy (societal) attributes/benefit of electricity produced by a renewable generator when compared to conventional or fossil-fueled power production. This would allow SDG&E to avoid transmission congestion costs associated with delivery of renewable energy generated outside of San Diego County. Implementing a RECs program as a part of the New In-Area All-Source Generation Alternative could also reduce the cost and environmental impacts of meeting SDG&E's renewable goals, since the delivery of renewable energy into the SDG&E load center would not be necessary. With SDG&E using RECs for RPS compliance, the congestion costs associated with importing renewable power into San Diego County could be greatly reduced or eliminated.

Feasibility

The feasibility of the New In-Area All-Source Generation Alternative has been questioned by several commenters, including SDG&E. Whether or not an alternative is ultimately feasible is a question for the CPUC/BLM decision-makers who will take into account all information in the administrative record to determine whether a particular project is "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social and technological factors." (Public Resources Code § 21061.1 [definition of "feasible"].) While CPUC and BLM acknowledge that they cannot assure the success of the specific projects that make up the New In-Area

[4] Variable costs include the cost of labor, material or overhead that changes according to the change in the volume of production units.

All-Source Generation Alternative in time to meet State and federal renewable energy goals, such assurance is not required for evaluation of the alternative under CEQA or NEPA. The Proposed Project is one potential solution to the reliability, cost and RPS issues SDG&E has identified as the purpose and need for the project. Section 3 (Overview of Alternatives Evaluation Process) in Appendix 1 of the Draft EIR/EIS further describes the regulations and alternatives screening methodology.

The fact that alternative solutions might require specific action from parties outside the control of the CPUC and the BLM does not exclude them from consideration in the EIR/EIS if they would reduce significant environmental impacts of the Proposed Project. "When the proposed action is an integral part of a coordinated plan to deal with a broad problem, the range of alternatives that must be evaluated is broadened" (*Morton*, 458 F.2d at 835.). Further, "[i]n determining the scope of alternatives to be considered, the emphasis is on what is 'reasonable' rather than on whether the proponent or applicant likes or is itself capable of carrying out a particular alternative. Reasonable alternatives include those that are practical or feasible from the technical and economic standpoint and using common sense, rather than simply desirable from the standpoint of the applicant" (CEQ Forty Questions, No. 2a.).

Nevertheless, the specific components of the New In-Area All-Source Generation Alternative were selected because: (a) they are real projects or are representative of reasonably foreseeable projects that have been identified in SDG&E's current or past Request for Offers (RFOs) or in other proceedings/ applications; or (b) they are feasible expansions or modifications of existing operating facilities.

The feasibility of the New In-Area All-Source Generation Alternative depends on the actions and agreements within the control of SDG&E and third-party developers. SDG&E has the authority to enter into contracts with developers of new in-area generation. In CPUC Decision 07-12-052 (December 20, 2007) regarding the Long-Term Procurement Plan (R.06-02-013), the CPUC authorized SDG&E to procure 530 MW of local capacity by 2015, which includes 130 MW of peaking units approved earlier by the CPUC, only if the Sunrise Powerlink application is denied. This means that if the Sunrise Powerlink decision does not allow the transmission line to be developed, then SDG&E would be allowed to procure 400 MW of additional local resources to meet local capacity needs.

The components of the New In-Area All-Source Generation Alternative were developed based on an assessment of existing, potential, and available generation resources in San Diego County. The rationale for consideration of each is described below. Because the projects are representative of a generation scenario, the feasibility of the New In-Area All-Source Alternative does not directly depend on success or status of any individual project. As explained below, many projects exist in addition to those defined as components of the alternative. Thus, the exact generation output of the individual components of the alternative scenario may also vary as it is determined what renewable projects would be built within the project timeframe.

Please refer to General Response GR-2 for a discussion regarding the feasibility of the wind, biogas/ biomass, solar thermal and solar PV generation components of the New In-Area Renewable Generation Alternative. Below, this General Response also discusses the procurement process and subsequent actions required for implementation of non-wires alternatives.

Baseload Generation

South Bay Replacement Project (SBRP). An application for this project was pending with the California Energy Commission (CEC) during 2006 and 2007, but was withdrawn from CEC consideration in October 2007. The impact analysis for the SBRP was completed for the Draft EIR/EIS prior to the withdrawal of the AFC in October 2007, and thus was retained as representative of a typical generation scenario. The SBRP analysis is presented to demonstrate the types of impacts that could result from any coastal power plant in San Diego County. Consistent with this approach, the Draft EIR/EIS (Section E.6, page E.6-1, first paragraph) explains that "[t]he projects considered in this EIR/EIS are representative of reasonable generation scenarios, and are not intended to depend on the progress of contracts for individual utility projects."

It should be noted that South Bay Replacement Project, LLC stated in a letter to the CEC upon cancellation of its Air Pollution Control District application for the Determination of Compliance/Authority to Construct (dated June 13, 2007) that "SBRP continues to work with various local interests to find an alternative site for SBRP. SBRP is also awaiting results of the SDG&E request for offers ("RFO") which may have a bearing on this and/or other projects in the area."[5]

Carlsbad (Encina) Energy Center. As stated in its September 14, 2007 Application for Certification (AFC) with the CEC, the Carlsbad Energy Center could provide a 540.4 MW net (rated at an average annual ambient temperature of 60.97 degrees Fahrenheit [°F] with steam power augmentation and evaporative air cooling) and 558 MW gross combined-cycle generating facility configured using two trains with one natural-gas-fired combustion turbine and one steam turbine per train (or unit). As part of the Carlsbad Project, existing steam boiler Units 1, 2, and 3 at the Encina Power Station will be retired. It is discussed in the EIR/EIS as one of three representative conventional generation options which could provide capacity under this alternative. The CEC's Preliminary Staff Assessment may be published by October 2008 with a possible CEC decision before 2009.[6] With a two-year construction schedule, this project would be operational before the peak summer season in 2011.

ENPEX (San Diego Community Power Project). As discussed in Section E.6.1.4 in Volume 5 of the Draft EIR/EIS, a federal military funding authorization included the approval for the concept of constructing a power plant on MCAS Miramar, which would not be within the City of Santee jurisdiction, and Miramar subsequently conducted a feasibility study to identify a site on the base. This study was used to identify the site that was analyzed in the Draft EIR/EIS. SDCPP has been under development by ENPEX since 2000 and although the development status is unclear, it is identified in the CAISO transmission interconnection queue, and was therefore analyzed in the Draft EIR/EIS as another potential generation option.

While site alternatives are not currently under consideration in the EIR/EIS, other site possibilities would potentially mitigate the City of Santee concerns. In its comment letter on the Draft EIR/EIS (dated June 28, 2008; see Comment Set D0229), the commenter, 7/17/03 Trust "B" (signed by Bob Allan, Trustee), indicates that the Trust owns a potential power plant site that is near and equivalent to the ENPEX site identified in the Draft EIR/EIS. Both the Trust site and the ENPEX sites would be on the USMC boundary about three miles south of Sycamore Canyon Substation. The Trust further states that they are open to the possibility of developing the trust property as a power plant.

In its comment letter on the Draft EIR/EIS (see Comment Set B0026), ENPEX Corporation stated that "[t]he most significant hurdle to the development and implementation of the San Diego Community Power Project is the fact that SDG&E is the only market for power in San Diego and it has not pro-

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5 A copy of the letter from Kevin R. Johnson (Vice President, South Bay Replacement Project, LLC) to Bill Pfanner (Project Manager, California Energy Commission) dated June 13, 2007 can be found on the CEC project website at: http://www.energy.ca.gov/sitingcases/southbay/documents/index.html.

6 The current permitting status of the Carlsbad Energy Center can be found on the CEC project website at: http://www.energy.ca.gov/sitingcases/carlsbad/index.html.

vided a contract to ENPEX for power or the purchase of the generating facility. It is a fact that the San Diego Community Power project provided the lowest cost bid to SDG&E in response to its 2003-2004 request for offers (RFO); and in 2007 ENPEX and its bidding partner Cogentrix (a wholly owned energy subsidiary of Goldman Sachs Group, Inc.) provided to SDG&E an innovative bid that would have provided to SDG&E's ratepayers net energy and capacity at an environmental and economic cost that is significantly less than will be possible from SDG&E's recently acquired El Dorado facility near Las Vegas, NV." These statements support the conclusion that the feasibility of the San Diego Community Power Project is dependent on the actions of SDG&E.

Other Baseload Generation Projects in the San Diego Area. The new Palomar Energy Center, a 546 MW gas-fired power plant owned by Palomar Energy, LLC,[7] is an example of a gas-fired generating station that has come online since 2006. The Application for Certification (AFC) for this project was submitted to CEC on November 28, 2001, and the project was approved on August 6, 2003. The power plant began commercial operation on April 1, 2006, thus, illustrating the feasibility of constructing a gas-fired facility in SDG&E's service territory. Another major generating station (the Otay Mesa Power Plant) is under construction now in the San Diego area. These projects provide examples of the feasibility of gas-fired generation that can be developed in the SDG&E territory.

Peaking Power Plants

Four Peaking Power Plants. This alternative would include various peaking power plant projects that could be developed in order for SDG&E to comply with prior CPUC rulings. The four plants that were analyzed were all identified as peaking power plant sites in SDG&E's 2006 or 2007 RFOs for peaking power. These would be turnkey projects at four existing SDG&E substations. In Application A.07-05-023, filed May 11, 2007, SDG&E selected five proposals for a total of approximately 229 MW. The five proposals are contracts for peakers at Pala and Margarita, "plus a proposal for a fee-for-service development at Borrego Springs, an expected engineering/procurement/construction contract for Miramar II and exercise of an option on distributed generation. The three projects not presented [in this application] will be filed at a later time." Four projects are considered as part of the All-Source Alternative (more detailed descriptions are presented in Section E.6.1.5 and in Section 4.10.3 of Appendix 1 in the Draft EIR/EIS).

- **Pala Substation**. SDG&E's existing Pala Substation is located in northern San Diego County within proximity to the Pala Indian Reservation. The Pala Substation is located on 15 acres of mildly sloping land. Orange Grove Energy, L.P., the applicant for the Orange Grove Project (known as the Pala Peaker in the Draft EIR/EIS), recently withdrew its Small Power Plant Exemption (SPPE) application with the CEC, and on June 19, 2008, Orange Grove filed an Application for Certification (AFC) with the California Energy Commission for the construction and operation of the Orange Grove Power Plant. The change in the application process resulted from the following two substantial project modifications: securing a source of reclaimed water, as suggested by CEC staff; and revising the gas-line route so that it would be located outside of SR76, which in turn triggered new federal permit requirements. The project is moving forward in the permitting process and was declared "data adequate" in July 2008.[8]
- **Margarita Substation**. SDG&E's existing Margarita Substation is located in the community of Ladera Ranch is located east of Interstate 5 between Mission Viejo and State Route 74 in Orange County.

[7] Palomar Energy Project. http://www.energy.ca.gov/sitingcases/palomar/index.html.

[8] The current permitting status of the Orange Grove Energy AFC Power Plant Project can be found on the CEC project website at: http://www.energy.ca.gov/sitingcases/orangegrovepeaker/index.html.

The substation is located on 3.0 acres of undeveloped land, and it could be developed to provide a maximum estimated peaking capacity of 99 MW. On January 2, 2008, Ladera HOPE, a non-profit watchdog organization formed by the residents of Ladera Ranch in southern Orange County, filed suit against Orange County in opposition to the approval of the Margarita Peaker. In the face of strong local opposition and legal challenge, on May 15, 2008, the developer rescinded its application to Orange County to construct the peaking power plant. .

- **Miramar Substation**. SDG&E's existing Miramar Energy Facility presently includes one combustion turbine rated at 47 MW, and a second could be added. The maximum estimated peaking capacity of the site is 49 MW. The utility expects to issue a contract with an unnamed developer to design and build the plant (SDG&E's Application A.07-05-023, May 11, 2007).
- **Borrego Springs Substation**. SDG&E's existing Borrego Springs Substation is located on Borrego Valley Road in Borrego Springs in northeastern San Diego County. The substation site includes 2 acres of graded but undeveloped desert land that could be developed to accommodate 15 MW of peaking power. Because of limited natural gas supplies, the site has been identified by SDG&E as suitable only for biodiesel (e.g., B20 grade or 20 percent biodiesel mixed with 80 percent conventional diesel fuel). The winning bidder in SDG&E's 2008 RFO won the right to help SDG&E develop a generation facility in Borrego Springs (CPUC Data Request 28, dated May 6, 2008), however, in September 2008, SDG&E stated that action on this project has been suspended.

Other Possible Peaking Power Plants. In addition, the New In-Area All-Source Generation Alternative would also include other peaking power plants if the four sites identified in the 2008 Peaker RFO are not fully developed to achieve the 250 MW target of this alternative. For instance, at least two power project owners, NRG Energy Inc. (Encina Peaker Repower, Kearney Mesa Peaker) and MMC Energy Inc. (Escondido Peaker Expansion, Chula Vista Peaker Expansion) have announced plans to repower their existing peaking facilities that are located in the SDG&E area. In fact, on August 10, 2007, MMC Energy, Inc. submitted an Application for Certification (AFC) to the CEC to construct and operate the Chula Vista Energy Upgrade Project (CVEUP), a nominal 100 MW peaking facility, with construction planned to begin in the fall of 2008 and commercial operation planned by the fall of 2009. This site is currently occupied by MMC's Chula Vista Power Plant, a 44.5 MW simple-cycle, natural gas-fired peaking power plant.[9] The Preliminary Staff Assessment was published on April 29, 2008 with a comment period ending on June 6, 2008, and that the schedule for approval is fall 2008. It is possible that these resources may be bid into SDG&E's 2008 Peaker RFO.

Subsequent Actions Required for Implementation of the New In-Area All-Source Generation Alternative or the New In-Area Renewable Generation Alternative (the Non-Wires Alternatives)

The CPUC and BLM have evaluated the various components of the non-wires alternatives in the EIR/EIS to allow for a comparison between transmission and generation alternatives. The following discussion explains what might occur, procedurally, if either of the non-wires alternatives were approved.

If the CPUC and/or BLM select a non-wires alternative after consideration of the Sunrise Powerlink proceeding, it would be within the CPUC's authority to order a CPUC-regulated utility, such as SDG&E, to issue a Requests for Offers (RFO) for the type(s) of generation included in the non-wires scenario. SDG&E would then receive bids from interested parties, and after selecting one, the party selected to construct and operate the generation would initiate permitting and CEQA and/or NEPA compliance for each project.

9 Chula Vista Energy Upgrade Project (CVEUP). http://www.energy.ca.gov/sitingcases/chulavista/index.html.

SDG&E is already required to issue annual solicitations for renewable energy, until it reaches the 20 percent RPS requirement.[10] Utilities may also procure renewable energy through all-source solicitations and bilateral contracts. Utilities, such as SDG&E, can accept renewable energy bids from anywhere within the Western Electricity Coordinating Council (WECC). Bidders located outside the California Independent System Operator's (CAISO) control area are responsible for delivering their energy, which must be firmed, not intermittent, to the CAISO control area.[11] Utilities may adjust bid prices to account for any increased costs (remarketing, swaps, transmission congestion, etc.) that may be associated with generation located outside of the utility's service territory or the CAISO control area.

The following illustrates the CPUC's process for procurement of all generation, including RPS:

1. The utility files a procurement plan and bidding protocol with the CPUC. The CPUC and an independent evaluator review the bidding protocol. The CPUC approves the plan and bidding protocol.

2. The utility issues a request for offers (RFO) for renewable energy which is overseen by the CPUC and the Independent Evaluator (IE).[12]

3. Respondents file notices to bid.

4. Respondents submit their bids to the utility.

5. The utility notifies the CPUC when bidding is closed, and the Independent Evaluator drafts a solicitation report for the CPUC's review.

6. The utility evaluates all of the bids using a "least-cost, best-fit" evaluation process approved by the CPUC, and develops a "short list" of acceptable bids.[13]

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[10] CPUC Procurement Process. Last modified November 13, 2007. http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/faqs/procurement.htm. The RPS program is implemented through CPUC decisions within the RPS rulemakings through two proceedings: (1) Current Proceeding (R.06-02-012, which develops additional methods to implement the California RPS, and R.06-05-027, which continues implementation and administration of the California RPS); and (2) Past Proceeding (R.01-10-024, which established policies and cost recovery mechanisms for generation procurement and renewable resource development, and R.04-04-026, which implemented the California RPS).

[11] "Firmed" energy is energy produced and available on a guaranteed basis (i.e., the generation facility can be immediately switched on and off when needed).

[12] The CPUC requires an Independent Evaluator (IE) for each RPS solicitation. The IE provides third party oversight of the RPS procurement process.

[13] "Least-cost best-fit" criteria were determined by the CPUC in D.04-07-029. Utilities are required to select renewable resources that have the least direct costs of renewable energy generation as well as any indirect costs due integration of the resource and needed transmission investment. In addition, utilities are required to consider renewable resources that "best fit" their system needs.

7. The utility's Procurement Review Group (PRG) reviews the solicitation results and the proposed short list.[14]

8. The utility notifies the CPUC when its initial short list is completed.

9. The CPUC calculates and publicly releases the market price referent once all the utilities have notified their short listed bidders.

10. The utility and bidders negotiate and execute contracts. In Decision 04-06-014 (Rulemaking 04-04-026), the CPUC adopted standard terms and conditions for contracts to be offered to renewable energy generators that successfully bid into a utility's renewable energy solicitation.

11. The utility files with the CPUC an advice letter or application requesting approval of a contract, and the Independent Evaluator submits its final report for the contract.

12. The CPUC reviews the submitted RPS contracts. Contracts priced at or below the market price referent (MPR)[15] may be considered "per se reasonable" by the CPUC. SB 1036 (2007) reformed the process for cost recovery of the above MPR portion of contracts priced above the MPR. Implementation details are currently being considered by the CPUC and CEC.

13. The CPUC approves or rejects the RPS contract by issuing a resolution (if responding to an advice letter) or a decision (if responding to an application).

[14] In D.02-08-071, the CPUC required each utility to establish a "Procurement Review Group" (PRG) whose members, subject to an appropriate non-disclosure agreement, would have the right to consult with the utility and review the details of the utility's: overall procurement strategy; proposed procurement processes including, but not limited to, RFOs; and proposed procurement contracts, before those contracts are submitted to the Commission for review.

[15] The "market price referent" (MPR) is the approximate cost of electricity from new natural gas plants. The MPR is used to judge the cost-effectiveness of renewable energy projects under the current renewable energy mandates.

General Response GR-2: Project Objectives and Feasibility of the New In-Area Renewable Generation Alternative

Several commenters, including SDG&E, stated that the New In-Area Renewable Generation Alternative would not meet project objectives and it would not be feasible. These comments claim that renewable projects, especially the solar thermal and PV components, are hypothetical and technically infeasible and relying on them would put SDG&E's customers' energy reliability at risk. Finally, commenters also wondered what would happen should this non-wires alternative be approved and this is discussed in General Response GR-1 under the section called Subsequent Actions Required for Implementation of the New In-Area All-Source Alternative or the New In-Area Renewables Alternative. This general response briefly describes the components of the New In-Area Renewable Generation Alternative and then discusses how it would meet most project objectives and would be feasible.

Components of the New In-Area Renewable Generation Alternative

The New In-Area Renewable Generation Alternative would involve development of various in-area renewable projects that together could provide sufficient generation capacity to defer the need for the Proposed Project. This alternative would develop nearly 1,000 MW by 2016. No single in-area renewable generation project by itself would be likely to provide the necessary capacity to serve as a viable alternative to the Sunrise Powerlink Project. By considering the availability of in-area renewable resources as a whole, this alternative offers a viable scenario of in-area renewable generation development. The resources involved would be solar (290 MW from solar thermal and 210 MW from solar PV), wind (400 MW), and biomass/biogas (100 MW).

Potential project locations are described in Section E.5.1 in the Draft EIR/EIS. The analysis of each component's environmental effects is based on reasonable assumptions and is meant to be representative of what could be developed.

Consistency with Project Objectives

Each of the over 100 alternatives evaluated in the Draft EIR/EIS was screened in the Alternatives Screening Report (see Appendix 1 of the Draft EIR/EIS), and only alternatives that meet "most" project objectives, are potentially feasible and would reduce or avoid one or more the significant effects of the Proposed Project were carried forward for full analysis in the EIR/EIS. This response clarifies how the New In-Area Renewable Generation Alternative would meet most project objectives and provides additional information on how it would be a practical and potentially feasible alternative. The description and assumptions of this alternative are included in Section 4.10 in Appendix 1, Section C.4.10.1, and Section E.5.1 in the Draft EIR/EIS. Many of the non-wires options were separately identified by SDG&E as alternatives in PEA Section 3.3.3.

Section 3.1 of SDG&E's Proponent's Environmental Assessment (PEA) stated eight project objectives of the Sunrise Powerlink Project (see also Section A.2.1 [SDG&E's Project Objectives] in Volume 1 of the Draft EIR/EIS). Having considered the eight objectives set forth by SDG&E, the CPUC and BLM identified the following three basic project objectives in Section A.2.2 of the Draft EIR/EIS:

- Basic Project Objective 1: to maintain reliability in the delivery of power to the San Diego region.
- Basic Project Objective 2: to reduce the cost of energy in the region.

- Basic Project Objective 3: to accommodate the delivery of renewable energy to meet State and federal renewable energy goals from geothermal and solar resources in the Imperial Valley and wind and other sources in San Diego County.

These three basic objectives incorporate all of SDG&E's more specific objectives and the New In-Area Renewable Generation Alternative would meet most of these basic project objectives. The following paragraphs summarize the New In-Area Renewable Generation Alternative's ability to meet each basic project objective.

Please see General Response GR-1 for a discussion of CEQA and NEPA's requirements for evaluation of a reasonable range of alternatives.

Basic Project Objective 1: Maintain Reliability

Commenters stated that the New In-Area Renewable Generation Alternative would not provide an adequate reliability benefit because the components of this alternative could not be operational in 2010. SDG&E's construction schedule, provided in December 2007, shows that summer 2011 would be the in-service date for the Proposed Project (see Section B.4.7 in the Draft EIR/EIS). The timing of meeting the reliability objective is yet to be determined in the CPUC General Proceeding (A.06-08-010). As such, there has not been a CPUC determination with respect to the need for the Proposed Project in 2010 (see also General Response GR-12).

However, because there are multiple sources of capacity with the New In-Area Renewable Generation Alternative, the generation capacity can be phased in with various components to meet the incremental load growth of the San Diego area over time. The New In-Area Renewable Generation Alternative shown in Table Ap.1-13 in Appendix 1 of the Draft EIR/EIS would provide reliable capacity of 203 MW in 2010 and up to 533 MW in 2016. This level does not allow SDG&E to meet its local reliability requirements through 2020. Solar thermal and wind resources developed under this alternative would help SDG&E meet the reliability objective, although the effective load carrying capability (ELCC) of solar thermal and wind generators (i.e., the capacity of the power plant that can be considered "firm" for reliability calculations) would be less than the nameplate capacity[16]. New solar photovoltaic installations also can help SDG&E to meet the reliability objective (assuming that the generators are geographically dispersed), because it is technically possible for SDG&E to partially depend on PV systems to maintain system reliability. Because there are multiple sources of capacity with the New In-Area Renewable Generation Alternative, the generation capacity can be phased in with various components to meet the incremental load growth of the San Diego area over time. Therefore, the alternative would meet the reliability objective.

Basic Project Objective 2: Reduce the Cost of Energy

Comments stated that the New In-Area Renewable Generation Alternative would not be economical for ratepayers. The various technologies that would be developed under the New In-Area Renewable Generation Alternative might not reduce costs, since the renewable energy projects might require Supplemental

[16] Nameplate capacity is the maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in megawatts (MW) and is usually indicated on a nameplate physically attached to the generator.

Energy Payments[17] to be financially viable and the overall costs would depend on the costs of transmission upgrades necessary to interconnect the projects. However, although individual projects could involve relatively high development costs, under renewable resource procurement rules, SDG&E's ratepayers would be responsible only for costs of renewable power up to the Market Price Referent, which is a proxy for the market price of power and therefore, the alternative would meet the objective to reduce the cost of energy. In addition, expanding the availability of in-area generation would also be likely to reduce the costs of providing local area reliability and payments for meeting local capacity requirements.

Subsequent actions required for implementation of the New In-Area Renewables Alternative are discussed in General Response GR-1.

Basic Project Objective 3: Accommodate the Delivery of Renewable Energy

One of SDG&E's stated eight project objectives was to "[p]rovide transmission capability for Imperial Valley renewable resources for SDG&E customers to assist in meeting or exceeding California's 20% renewable energy source mandate by 2010 and the Governor's proposed goal of 33% by 2020." This objective is incorporated into the CPUC/BLM's Basic Project Objective 3. The New In-Area Renewable Generation Alternative would meet the objective for promoting renewable energy as part of SDG&E's generation portfolio, because it would include the construction of wind, solar PV, solar thermal and biogas/biomass renewable generation facilities, and these renewable components would contribute towards the State's RPS goals.

Feasibility

As a general matter, the Lead Agencies' decision-makers will make the ultimate determination of feasibility of each alternative at the time of project approval. It should be noted that reasonable alternatives under CEQA and NEPA are not limited to ones the lead agency can adopt, and the agency should consider wide-reaching alternatives when the problem at hand is a broad one, such as a large-scale energy supply issue. (See *Natural Resources Defense Council, Inc. v. Morton* (D.C. Cir. 1972) 458 F.2d 827, 836 ("*Morton*").) Further, "[i]n determining the scope of alternatives to be considered, the emphasis is on what is 'reasonable' rather than on whether the proponent or applicant likes or is itself capable of carrying out a particular alternative…" (CEQ Forty Questions, No. 2a.)

This response provides additional information regarding the practicality and potential feasibility of the New In-Area Renewable Generation Alternative. As explained in General Response GR-1, the CPUC and the BLM must consider alternative solutions to the issues SDG&E has identified as the purpose and need for the project if they would reduce significant environmental impacts of the Proposed Project, despite the fact that they might require specific action from parties outside the control of the CPUC and BLM. The fact that the solar thermal, wind, and solar photovoltaic components of the New In-Area Renewable Generation Alternative and the New In-Area All-Source Generation Alternative ("non-wires alternatives") are uncertain does not mean that they are not reasonable or practical. These projects would use existing technology, are based on technical data defining the locations and availability of solar and wind resources within San Diego County, and provide a template for something that could

[17] Under current California law, a utility is not required to pay above a "Market Price Referent" (MPR) for renewable generation procured through CPUC-approved RPS solicitation. Any portion of the contract price that is above the MPR is eligible to be paid by a state subsidy, Supplemental Energy Payment (SEP), which is funded by ratepayer "Public Goods Charges."

reasonably be developed. The exact generation output of the individual components of the alternative scenario may also vary as it is determined what renewable projects would be built within the project timeframe. Please note that the potential feasibility of this alternative does not directly depend on success or status of each individual project discussed below.

Feasibility of Each Renewable Component

Wind Power in Crestwood Wind Area. BLM has a pending application for wind development on its land, specifically within the area identified in the alternative in Section E.5.1 and E.6.1 of the Draft EIR/EIS. Pacific Wind (Iberdrola) was issued a monitoring and testing right-of-way (ROW) encumbering 17,000+ acres in September 2004. In December 2007, Pacific Wind submitted an application for renewal of the monitoring/testing ROW and submitted a Plan of Development (POD) for the 9,000-acre "Tule Wind Project." The project would consist of 1.5 to 3 MW wind turbines, generating up to 200 MW of electricity. In July of 2008, Pacific Wind submitted an application to install additional monitoring/testing towers. When a Record of Decision is issued by the BLM, Pacific Wind would then relinquish the remainder of acreage available for wind development within Eastern San Diego County (ESDC) Resource Management Plan that is currently part of its monitoring/testing ROW. The NEPA process may begin in late 2008. Additional wind projects in the area and their status are discussed under General Response GR-5 below.

As of July 25, 2008, there are four wind projects (for 130 MW, 160 MW, 201 MW, and 300 MW) in San Diego County in the CAISO queue. There are also approximately nine projects in Mexico (Baja California and Mexicali/Ensenada/Tecate), totaling 5,020 MW, in the CAISO queue as well.[18]

In addition, the Campo Band of Kumeyaay Indians has indicated in a letter to Billie Blanchard (CPUC) and Lynda Kastoll (BLM) from Samuel D. Gollis (dated March 23, 2007) its intention to expand the existing wind development on tribal land in eastern San Diego County. The letter states that the Ewiiaapaayp Band of Kumeyaay Indians and the Manzanita Band of Mission Indians are also considering additional wind energy projects in the area. Therefore, consideration of 400 MW of wind generation as part of the New In-Area Renewable Generation Alternative is potentially feasible.

Biomass/Biogas. The Fallbrook Renewable Energy Facility would be a biomass facility located on approximately 80 acres in the Pala Mesa Valley. Envirepel, Inc. would be the facility owner and is preparing an Application for Certification (AFC) to the California Energy Commission for project approval. The facility's three 30 MW steam turbine generators would provide 90 MW of capacity. From these, the facility would be capable of exporting 67 MW of electricity on a continuous basis. Miramar Landfill is a joint public and private facility operated by the City of San Diego on MCAS Miramar. Untapped gas in Miramar Landfill reportedly has the potential to expand electric generation capacity to 13 MW, providing an additional 3 MW to SDG&E (Ray Purtee, San Diego County, 2007). This expansion would occur adjacent to the existing co-generation facility at the landfill. The site is already developed and sits amid existing structures and paved areas. A connection to the grid already exists at the site.

The Miramar Renewable Energy Facility would be a new biomass facility developed by Envirepel, Inc. at the existing Miramar Landfill. The biomass-fueled facility would be separate from the landfill's existing biogas-fueled electric generation facility, and would be either at the landfill or nearby. Biomass materials bound for the landfill would be diverted to the new facility, where they would be processed and combusted. The facility would use a 30 MW steam turbine generator. From the 30 MW capacity installed in the facility, 26 MW would be supplied to the electric grid.

[18] http://www.caiso.com/14e9/14e9ddda1ebf0.pdf

Therefore, 100 MW of biomass and/or biogas generation as part of the New In-Area Renewable Generation Alternative is potentially feasible.

Solar Thermal. There is considerable technical potential for solar thermal generation in the Borrego Springs area of San Diego County. The New In-Area Renewable Generation Alternative would include large-scale solar thermal energy development in the Borrego Springs area. The gross technical potential for solar thermal power that could likely be generated in the unincorporated Borrego Springs area is approximately 6,000 MW.[19] Between 2010 and 2016, up to an overall nameplate potential of 300 MW of new solar thermal generating resources, or approximately 240 MW for reliability accounting purposes, could be added near Borrego Springs. Although no developers have identified sites in Borrego Springs for such a large solar thermal project, this alternative assumes that development would occur near existing transmission infrastructure, namely the existing 69 kV Borrego Springs Substation. However, as of July 25, 2008, a smaller-scale 49.5 MW solar thermal project that would connect into the Borrego Substation is in the CAISO queue and is proposed to be online April 1, 2011.[20]

The existing 69 kV transmission infrastructure would need to be substantially upgraded to deliver the output of this solar development. Although interconnection would be at Borrego Springs, such a large generator in this remote area of the SDG&E grid would require upgrading at least the 69 kV line from Borrego Springs to Narrows and Warner Substations (about 40 miles), and further upgrades between Warner and the Escondido area or Sycamore Canyon could also be needed. The environmentally superior option would be to install a new 138 kV line underground in Highway S3 and SR78, then overhead or underground along Highway S3 in the San Felipe Valley.

BLM is currently reviewing numerous applications for solar thermal generation projects in southern California, as is the California Energy Commission (CEC). The Ivanpah Solar Electric Generating System (SEGS) project in San Bernardino County plans on having its entire 400 MW site online by the end of 2012, with its first 100 MW online by the end of 2010. An application for the Ivanpah SEGS project was filed in August, 2007 with the CEC and deemed complete in October, 2007. The Preliminary Staff Assessment/Draft EIS is scheduled to be completed late 2008. There is also the Carrizo Solar Project in San Luis Obispo County, which is 177 MW and is scheduled to go on the grid by May 2010. An application for the Carrizo project was filed in October, 2007 with the CEC and deemed complete in December, 2007. The Preliminary Staff Assessment/Draft EIS is scheduled to be completed late 2008. The world's largest solar thermal power generation facilities are located in southern California, in the Southern California Edison (SCE) territory. FPL Energy's recently proposed 250 MW plant (Beacon Solar Energy Project) would be situated on 2,012 acres in eastern Kern County within SCE's territory as well.[21] Construction is scheduled to begin in late 2009 and would take about two years to complete (third quarter 2011). Longer term, the company has stated that it aims to add at least 600 MW of new solar by 2015.[22] FPL Energy currently has facilities with a capacity to produce 310 MW of solar power. An application for the Beacon Solar Energy Project was filed in March, 2008 with

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19 SDRRESG (San Diego Regional Renewable Energy Study Group). 2005. "Potential for Renewable Energy in the San Diego Region." http://www.renewablesg.org. August, 2005.

20 http://www.caiso.com/14e9/14e9ddda1ebf0.pdf

21 An Application for Certification (AFC) for the Beacon Solar Energy Project was filed with the CEC on March 14, 2008. http://www.energy.ca.gov/sitingcases/beacon/index.html.

22 Los Angeles Times. 2008. 2 Big Projects Will Amp Up Solar Power In Southland. By Andrea Chang. http://www.latimes.com/business/la-fi-solar27mar27,0,7774595.story. Dated March 27.

the CEC and deemed complete in May, 2008. The Preliminary Staff Assessment/Draft EIS is scheduled to be completed late 2008.[23]

In addition, public comment on the Draft EIR/EIS (Rich Caputo, Comment Set D0078) stated that based on the studies done by San Diego Renewable Energy Society (SDRES) for the Energy Working Group of San Diego Association of Governments (SANDAG), its San Diego Report stated that the solar thermal component of the New In-Area Renewable Generation Alternative could also be located on ranchlands in the eastern part of San Diego County using smaller (5 to 50 MW) dispersed solar power plants and using SDG&E's existing 69 kV transmission lines.[24]

Thus, permitting and construction of a solar thermal facility in Borrego Springs is a potentially feasible component of this alternative. As of July 25, 2008, a 49.5 MW solar thermal project in Borrego Springs (application submitted 4/02/08) is in the CAISO queue and the project is due to be online April 1, 2011. In addition, numerous projects are under development and solar thermal projects could be feasibly developed prior to 2011.

Solar Photovoltaic (PV). Under the alternative scenario approximately 5 percent of the technical potential solar PV resources would be developed by 2010, and 10 percent of the technical potential would be developed by 2016. This is a level of development that would be above its current production. In addition to what PV would be required under the New In-Area Renewable Generation Alternative, there are ambitious plans to increase solar PV development in the state in the coming decade (as discussed in Section 4.10.1 in Appendix 1 of the Draft EIR/EIS). An advantage of commercial and residential PV is the relative lack of siting controversies as compared to other generation and transmission projects because the installations occur on existing buildings. As shown in Table Ap.1-13 in Appendix 1 of the Draft EIR/EIS, the New In-Area Renewable Generation Alternative includes adding 105 MW of reliable solar PV by 2010, or 210 MW nameplate capacity, above what is expected to occur in the absence of implementation of this alternative.

SDG&E correctly quotes Section C (page C-75) and Section 4.10.2 in Appendix 1 of the Draft EIR/EIS that economic, legal, and technical feasibility challenges would need to be overcome in order to develop numerous individual PV installations throughout San Diego County (see Comment E0001-4). SDG&E claims that to obtain 394 MW for reliability accounting by 2010 would require incentives of approximately $1.1 billion (assuming an incentive of $2.80 per installed watt), and these additional funds would be over and above the $2.8 billion currently allocated under the California Solar Initiative (CSI) program. The level of incentives required to implement the 210 MW contemplated under this alternative is not known. The CPUC and the California Energy Commission have jointly implemented the CSI program, and through them, the California Center for Sustainable Energy, not SDG&E, administers the CSI. The utility does not have control of rebate policy or other any other programmatic details.[25]

Regardless, solar PV project are moving forward within the timeframe of the Sunrise Powerlink Project. For example in the CAISO queue, a 58.8 MW solar PV project that would connect into Borrego Substation is scheduled to be online in June 2010 and a 75 MW solar PV project that would also con-

[23] Information regarding the filing status for the proposed solar projects was found on the CEC website *Alphabetical List of Power Plant Projects filed Since 1996, at:* http://www.energy.ca.gov/sitingcases/alphabetical.html. September, 2008.

[24] See http://www.sdres.org and click on San Diego Report.

[25] SDG&E is currently slated to administer the program targeting new residential construction, but this market segment accounts for 15% or less of the overall solar PV program.

nect into the Borrego Substation is proposed to be online by the end of 2010. In addition, as of July 25, 2008, a 50 MW solar PV project that would connect into the Warner Substation and a 58.8 MW solar PV project that would connect into the Cameron Substation are in the CAISO queue and are scheduled to be online by June 30, 2010 and December 15, 2009, respectively.[26] Moreover, the fact that alternatives might require specific action from parties outside the control of the CPUC and the BLM does not exclude them from consideration in the EIR/EIS if they would reduce significant environmental impacts of the Proposed Project. (See *Natural Resources Defense Council, Inc. v. Morton* (D.C. Cir. 1972) 458 F.2d 827, 835; CEQ Forty Questions, No. 2a.)

A core element of San Diego Smart Energy 2020 (see General Response GR-6 for a discussion of the plan) is to add over 2,000 MW of PV locally by 2020.[27] This solar program, the San Diego Solar Initiative, would use an incentive structure similar to that of the California Solar Initiative. Power generated from PV systems, when combined with sufficient solar incentives, current federal tax credits, and current accelerated depreciation, is less expensive than conventional power purchased directly from the utility (E-Tech International, 2007). The report states that the San Diego region is projected to have approximately 4,600 MW of PV technical potential on commercial, buildings, parking structures, and parking lots in 2010, as well as 2,800 MW of technical potential on residential structures (E-Tech International, 2007).

There are two examples of the potential of parking structures and ground-level parking lots to support PV: the 250 kW PV array on the Qualcomm campus parking structure in Sorrento Valley, and the 235 kV Kyocera "solar grove" PV array in Kearny Mesa. Envision Solar, developer of the Kyocera PV array, roughly estimates that the actual PV potential of open parking lots and parking structures in San Diego County is 3,000 MW (E-Tech International, 2007). This estimate assumes that only 25 percent of total estimated parking surface in the county is sufficiently open (i.e., not shaded to a significant degree) so that its full solar potential can be realized.

As stated in the San Diego Smart Energy 2020, there are currently limits on the availability of PV panels, but a rapid expansion of PV manufacturing capacity is underway. Worldwide PV manufacturing capacity expanded 41 percent in 2006. More than a dozen companies in Europe, China, Japan, and the U.S. are expected to bring increased production capacity online in the next two years, reversing manufacturing constraints. The San Diego Smart Energy 2020 report states that the capital cost PV is expected to drop 40 percent by 2010 due to this increase in manufacturing capacity worldwide (E-Tech International, 2007).

Further evidence of the potential feasibility of large-scale PV systems is provided by SCE, which recently announced the largest rooftop solar installation project ever proposed by a utility company. The SCE rooftop project would place PV cells on 65 million square-feet of 125 commercial building roofs in southern California. The cells would generate as much as 250 MW of electricity. The project, subject to approval by the CPUC, will cost an estimated $875 million ($3.85 per watt) and take five years to complete. SCE has stated that it plans to begin installation work immediately on commercial roofs in San Bernardino and Riverside Counties (starting with a 600,000-square-foot distribution center owned by ProLogis in Fontana) and then spread to other locations in southern California at a rate of

[26] http://www.caiso.com/14e9/14e9ddda1ebf0.pdf

[27] E-Tech International. 2007. San Diego Smart Energy 2020: The 21st Century Alternative. Prepared by: E-Tech International, Santa Fe, New Mexico and Bill Powers. October 2007.

one megawatt a week.[28] SCE began installing the solar panels in July 2008 and expects to connect the first panels to the grid in September 2008.[29]

On July 11, 2008, SDG&E unveiled plans to install enough rooftop solar panels to power 50,000 homes. SDG&E said its five-year $250 million plan to install 70 to 80 MW of solar electricity would be the biggest solar power initiative in the county. SDG&E says it is evaluating the solar potential of its own utility-owned rooftops and property throughout the region, as well as retail shopping malls, commercial parking lots and other suitable sites.[30]

For example, as part of the planned expansion of the University Towne Centre, SDG&E plans to install groves of solar "trees" in several of the shopping mall's parking lots. Each tree stands 12 feet high and is equipped with giant solar panels that provide shade for parking spaces below. SDG&E said it also is negotiating agreements with the cities of San Diego, Chula Vista, Santee and Carlsbad to find places to put solar generating facilities. The plan is to use technology that enables photovoltaic panels to track the sun's path throughout the day. The tracking technology enables the cells to produce 65 percent more power than fixed rooftop solar panels during times when the demand for energy is at its peak.[31] Applications for each installation would be filed with the CPUC separately.

Based on the information provide above, it is reasonable to assume that the SDG&E territory could increase the rate of installation of PV beyond the current CSI projections. Overall, the PV component of the New In-Area Renewable Generation Alternative is considered to be potentially feasible, and it was properly evaluated as a reasonable project alternative.

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[28] Los Angeles Times. 2008. 2 Big Projects Will Amp Up Solar Power In Southland. By Andrea Chang. http://www.latimes.com/business/la-fi-solar27mar27,0,7774595.story. Dated March 27.

[29] SCE, 2007. Southern California Edison Begins Construction of World's Largest Solar Panel Installation Project. http://www.edison.com/pressroom/pr.asp?bu=&year=0&id=7083. Dated July 16.

[30] SDG&E. 2008. SDG&E's Solar Energy Project. Online at http://www.sdge.com/environment/solar/sdSolarInitiative.shtml. Accessed on September 16.

[31] Bigelow, Bruce V. 2008. "SDG&E unveils ambitious solar panel project." San Diego Union Tribune. http://www.uniontrib.com/news/metro/20080711-1055-bn11solar.html. Dated July 11.

General Response GR-3: Reliability Comparison Between Northern & Southern Environmentally Superior Routes

Commenters, including SDG&E, stated that the Environmentally Superior Southern Route Alternative identified in the Draft EIR/EIS would need to meet stricter performance reliability criteria than the Proposed Project or any Northern transmission line route, and would be required to have a planned response for the transmission system in case an unexpected event occurs. This response describes the process that was used to reach that reliability conclusion and further describes differences between the northern and southern routes with respect to reliability.

Electric reliability is one of the three project objectives identified in Sections A.2.2 and A.2.3 of the Draft EIR/EIS. The ability of the various southern route alternatives to meet this objective was analyzed in the alternative screening analysis, as discussed in Sections C.2, C.3, and C.4 and detailed in Appendix 1 of the Draft EIR/EIS. The SWPL alternatives would meet this project objective as electric reliability would be improved under both the Proposed Project and the SWPL alternatives.

SDG&E prepared a report containing its recommendation to the Western Electricity Coordinating Council ("WECC") Reliability Performance Evaluation Work Group ("RPEWG").[32] The report was prepared to provide information to WECC that would allow the RPEWG to establish a category rating for the new transmission line, as described below. The rating determines certain operational restrictions placed on SDG&E while the line is in use. The report identifies five categories, detailed below, where SDG&E believes the Southern Alternative Route would have a higher reliability risk than the proposed Northern Route. The table below summarizes SDG&E's conclusions, which the WECC relied upon in making its determination. The WECC RPEWG evaluation of the SDG&E recommendation notes that as a result of the SDG&E data and recommendation, the proposed route should be approved for the category upgrade to Category D, but that along the alternative route the upgrade to Category D should not be approved (and the alternative route would remain at Category C, like most of California's 500 kV lines). A Category C rating is not unusual and does not present extraordinary restrictions on SDG&E's operation of the line.

This transmission system rating refers to the operational limits of a transmission system element under a set of specified conditions. A Category C rating means that a double-line outage is expected to occur at least once in 30 years (but not more frequently than once every 3 years), and that the utility is required to institute planned load dropping. Although undesirable, planned load dropping can minimize the implications of a transmission line outage. The higher Category D rating means that a double-line outage is expected to occur less than once every 30 years, and that no planned load-dropping response is required and cascading is allowed (cascading refers to the uncontrolled successive loss of transmission system elements which can result in widespread service interruption).

SDG&E's reliability recommendation analysis concludes that the southern route would have a higher risk of fire affecting both lines, a higher risk of a conductor from one line being dragged into the second line, a higher risk of lightning affecting both lines, a higher risk of an aircraft flying into both lines, and a higher risk of flashover to vegetation. In general, the CPUC and BLM agree with SDG&E's determinations regarding the reliability risk of the northern route (except for its conclusions about the risk of outage from concurrent fires); however, SDG&E's claims about the reliability risks of the southern route are overstated. SDG&E only evaluated the risk related to the 500 kV sections of the transmis-

[32] The SDG&E report is called "Performance Category Upgrade Request for Imperial Valley – Miguel 500 kV and Imperial Valley – Central 500 kV" (dated December 20, 2007).

sion lines, ignoring the 230 kV segments of both lines that traverse high-risk fuels. In addition, SDG&E evaluated only the risk of a single fire affecting both lines, rather than a more comprehensive evaluation of the risk of a firestorm (consisting of multiple, geographically dispersed large fires) affecting both lines. SDG&E fails to support its conclusions about a conductor from one line being dragged into an adjacent line and the risk of lightning strikes with adequate data. SDG&E's analysis of aircraft collision data fails to consider the reduced risk of collisions through mitigation measures.

Table 1. Summary Comparison of SDG&E Risk Conclusions*

Risk Category		Proposed Route	Southern Route (Alternative)
R1	Fire affecting both lines	Low Risk	High Risk
R2	One tower falling into another line	Low Risk	Low Risk
R3	Conductor from one line being dragged into another Line	Low Risk	Moderate Risk
R4	Lightning strikes tripping both lines	Low Risk	Moderate / High Risk
R5	Aircraft flying into both lines	Low Risk	Moderate Risk
R6	Station-related problems resulting in loss of two lines for a single event	Low Risk	Low Risk
R7	Natural disasters	Low Risk	Low Risk
R8	Loss of two lines due to an overhead crossing	Low Risk	Low Risk
R9	Loss of two lines due to vandalism/malicious acts	Low Risk	Low Risk
R10	Flashover to vegetation	Low Risk	High Risk
R11	Single breaker failure causing loss of two lines	Low Risk	Low Risk

* Highlighted rows show where SDG&E's risk conclusions differed between the two routes.
Source: SDG&E, 2007.

As stated above, SDG&E identified five areas of risk that would be greater for the Southern Alternative Route than for the Proposed Route. These areas of risk are:

R1 – Fire Affecting Both Lines

SDG&E suggests that a single fire event could result in a concurrent outage of two adjacent or nearby transmission lines thereby posing a reliability risk. SDG&E concludes the northern routes would be "Low Risk" because none of the previous 25 fire related incidents along the SWPL route occurred in the 4 miles of shared ROW.[33] The collocated segment is in desert terrain and at a low risk of fire. The Southern Route Alternative is collocated with the SWPL for 36 miles (Segment 1), and SDG&E agrees with the Draft EIR/EIS that collocation in this desert terrain does not create a fire risk.[34] SDG&E's determination of "High Risk" for the southern route alternative is apparently based on the 19 mile center portion of the Southern Route Alternative where the separation between the alternative and the SWPL would be between 4 and 8 miles.

The CPUC and BLM agree that the 4-mile collocation segment is low risk; however because the reliability rating applies only to 500 kV lines, SDG&E did not provide information in the report on the Proposed Project's 230 kV line which passes through the part of San Diego County with a very high overall fire risk. Based on fire history, the 230 kV portion of the Proposed Project is located in a high risk

[33] SDG&E, 2007. "Performance Category Upgrade Request for Imperial Valley – Miguel 500 kV and Imperial Valley – Central 500 kV"

[34] Ibid., Attachment 1A, Appendix 1.

fire section. Also, because SDG&E did not address its 230 kV line segment, it did not discuss the areas where the 230 kV line would likely have been out of service at the same time as the SWPL due to concurrent fires in the central and southern county areas. A complete comparison of alternatives for fire risk can be found in General Response GR-9.

Additionally, on page 63 of the Performance Category Upgrade Request, SDG&E states that the Southern Alternative passes through chaparral, "one of the most fire-prone plant communities in North America."[35] This is true; however SDG&E neglects to state that the Proposed Project, overall, passes through firesheds that consist of over 41 percent chaparral plant communities. The more accurate conclusions for "Fire Risk" would be to state that both the Proposed and Southern routes have High Risk.

SDG&E evaluates fire risk along non-collocated segments for the Southern Route, speculating that a fire starting on the SWPL could spread to cause an outage on the alternative path. As demonstrated by the extent of concurrent fires in October 2007, the very high fire risk for all of San Diego County presents the possibility that any two major transmission lines could have concurrent fire-related outages no matter how far apart they are.

Due to the tendency of southern California to experience multiple large fires during extreme weather conditions, spatial proximity is not the only indicator of a double-line outage due to fire. The fire history record shows that had both lines been present (SWPL was constructed in 1984), there is a very high likelihood that the northern route would have experienced a concurrent outage with SWPL twice since 1970 (in 2003 and 2007). There is also a very high likelihood that the southern route and SWPL would have experienced a double-line outage five times since 1970 (in 1970, 1975, 1995, 2003, and 2007). Please refer to General Response GR-9 for a more complete description of this analysis.

R3 – Conductor From One Line Being Dragged Into Another Line

SDG&E suggests that should a plane snag a conductor or shield wire from one set of towers and drag it so that it touched an adjacent or nearby line, there could be a concurrent outage on both lines therefore posing a reliability risk. SDG&E concludes the Northern Route would present a "Low Risk" based on the lack of previous incidents in the 4 mile segment. SDG&E further concludes that a Southern Route has a "Moderate Risk" in this category because of two previous flight related incidents in the 36 miles segment shared with the SWPL.

SDG&E's conclusion of "Low Risk" along the collocated potion of the Northern Route is valid. SDG&E's statement that a Southern Route has a "Moderate Risk" in this category, however, is unsupported by any recent data. The two flight related incidents mentioned by SDG&E both occurred within 4 years of the SWPL in-service date. After those events, aerial marker balls have been installed on portions of the SWPL where incidents have occurred and no additional incidents have taken place. SDG&E itself notes in its discussion for the Northern Route that since the flight related incidents SDG&E "*has worked to ensure additional incidents do not occur*" [emphasis added.][36] It is illogical to conclude that SDG&E would work to ensure no additional incidents occur along a Northern Route but would not do the same along a Southern Route. Therefore, this risk factor should be reduced to "Low Risk" for a southern route alternative.

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[35] Ibid.

[36] Ibid., pg. 27.

R4 – Lightning Strikes Tripping Both Lines

SDG&E suggests lightning might strike both of the transmission lines causing concurrent outages and posing reliability concerns. SDG&E concludes that the northern route is "Low Risk" because according to SDG&E's data, there have been no known lightning strikes that have taken place within the 4-mile proposed shared SWPL/SRPL ROW. SDG&E concludes that the southern alternative would have "Moderate/High Risk" that a lightning would trip both lines using the same lightning density data for the 4-mile shared SWPL/SRPL ROW plus the 36 miles shared SWPL/southern route ROW. According to SDG&E's data, there has been one SWPL outage caused by a lightning strike in the 36-mile shared segment for the alternative. Other than this outage, there have been no reported lightning strikes that have taken place within the shared right-of-way.

SDG&E's conclusion that the lightning flash density in the 4-mile proposed shared right-of-way is very low is valid; however, the conclusion that a southern route would pose a "Moderate/High Risk" that lightning would trip both lines is invalid. Lightning flash density increases in mountainous terrain that is exposed to dynamic weather influences. The fact that one lightning incident occurred west of Imperial Valley in mountainous terrain in the past 25 years only proves that lightning is more likely to strike a 36-mile corridor in mountainous terrain than a 4-mile corridor located on the valley floor. A similar lightning risk exists for the Northern Route where it traverses east to west over mountainous terrain as it does for a Southern Route traversing east to west over mountainous terrain. Indeed, data provided by SDG&E states that the density of flashes/sq km/unit time is the same for the entire region of southern California[37], so all transmission lines of the same height and material are at the same risk of being hit by lightning.[38] SDG&E presents no data that demonstrates that there is a risk of a single lightning strike affecting two lines that would be located hundreds of feet from one another in a shared ROW. Furthermore, the installation and proper maintenance of shield wires and lightning arresters would insure a minimal risk of outages as a result of lightning. SDG&E uses identical language when explaining the risk of the Northern Route being hit by lightning as it does when explaining the risk of the Southern Route being hit by lightning but concludes that the risk for the former would be low and the risk for the latter would be moderate to high. CPUC and BLM believe that the risk of lightning hitting the Southern Route would be similar to that for the Northern Route.

R5 – Aircraft Flying Into Both Lines

SDG&E suggests that aircraft might fly into collocated transmission lines simultaneously causing concurrent outages and reducing reliability of the line.

SDG&E accurately concludes the Northern Route is at a "Low Risk." There have been no flight-related incidents that have occurred on the 4-mile shared right-of-way. SDG&E concludes a southern route would have a "Moderate Risk" because there have been two flight related incidents that have occurred on the alternative path, making the risk for a double line outage moderate. As stated above for R3, the two flight incidents mentioned by SDG&E occurred soon after SWPL was built over 20 years ago and since that time SDG&E has installed protective measures to ensure additional incidents do not occur (and they have not). Aerial marker balls that have been successfully preventing aircraft collisions along

[37] Ibid., pg. 26.

[38] The fact that all transmission lines have the same chance of being hit by lightning is further supported by SDG&E's own data. On page 24 of the reliability report, SDG&E states that there have been five lightning incidents to the SWPL outside of the 4-mile shared right-of-way. On page 59 of the reliability report, SDG&E states that only one lightning strike occurred within the 36-mile shared right-of-way. One is left to conclude that an additional four lightning incidents occurred to the SWPL outside the 36-mile shared right-of-way and that all transmission lines of the same height and material have a similar risk of being hit by lightning.

the SWPL should be installed on the collocated alternative line to eliminate future risk and the risk of an aircraft flying into both lines for the Southern Route would be similar to that for the Northern Route.

R10 – Flashover To Vegetation

SDG&E suggests contact or proximity of vegetation and overhead ungrounded supply conductors could result in ignition of vegetation, causing fire and potentially outages and therefore would reduce reliability. SDG&E concludes a northern route would have a "Low Risk" for the 4-mile collocation segment. The vegetation in the proposed collocated corridor is sparse, and consists primarily of cacti and creosote bushes, neither of which generally grows above 5 feet in height. Land patrols are performed once every three years and aerial patrols are performed twice a year. This frequency of patrols would aid in the prevention of flashovers that could occur due to vegetation. The lack of vegetation within this corridor makes it extremely unlikely that both lines would trip due to a flashover caused by vegetation. SDG&E concludes a southern route would have a "High Risk." The segment of the Southern route that is collocated with the SWPL is desert terrain and vegetation and would have the same "Low Risk" as for the collocated segment of the northern route. As presented in Attachment 1a of Appendix 1, an extensive risk analysis shows that fuels are sparse along the collocated segment of the southern route and that the ignition and burn history also demonstrate a low risk.

Conclusions

The RPEWG has deemed the Southern Route a Category C, the same rating given to nearly all California 500 kV lines. This rating supports the Draft EIR/EIS position that the Southern Route would not present a significantly different reliability risk compared with the Proposed Project when all components of the two options are considered. If the frequency of an event that would result in an outage of collocated circuits is expected to be between one in three to one in thirty years, the event would be classified as an "N-2"[39]and the transmission line would be rated a Category C. This would also mean that the utility is permitted to institute "planned/controlled"[40] load dropping in order to maintain the transmission system's integrity. A load is the amount of electric power delivered or required at any specified point or points on a system, and the utility would be allowed to interrupt this supply of electricity to its customers under an extreme event. If the event is expected to occur less than once in every thirty years then it would fall under Category D for which no planned response is required." As described in the previous sections, southern San Diego County is an area in which wildfires are the most likely cause of a transmission line outage.

It should be noted that this rating only relates to the 500 kV portion of the SRPL. Fire or reliability issues related to the 230 kV components were not presented by SDG&E and, thus, not evaluated by the RPEWG (see additional details on fire in General Response GR-9). In addition, SDG&E's report provides the technical support that a dual outage, under either routing option, could be controlled without resulting in a cascading[41] event. Service reliability would be improved under both the Proposed Project and SWPL Alternatives.

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[39] At the CPUC Technical Workshop held in San Diego on February 2, 2007, an ISO Lead Regional Transmission Engineer acknowledged that the outage of two transmission elements located in a common corridor would be deemed an "N-2." This means the outage of both lines would not be subject to the ISO's G-1/N-1 requirements.

[40] Footnote "d" from Table I of the NERC/WECC Reliability Criteria: Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

[41] Cascading refers to the uncontrolled successive loss of transmission system elements which can result in widespread service interruption.

General Response GR-4: Project Objectives and Feasibility of the LEAPS Project Alternatives

Several commenters, including SDG&E and CAISO, stated that the LEAPS Transmission-Only Alternative and the LEAPS Generation and Transmission Alternative (collectively, the "LEAPS Project Alternatives") would not meet project objectives and they would not be feasible. This response clarifies how the LEAPS Project Alternatives would meet most project objectives, and provides additional information regarding their practicality and potential feasibility.

History of the LEAPS Project

On February 2, 2004, the Elsinore Valley Municipal Water District (EVMWD) and The Nevada Hydro Company, Inc. (TNHC) filed an application for a hydropower license with the Federal Energy Regulatory Commission (FERC) for the construction and operation of the Lake Elsinore Advanced Pumped Storage Project (LEAPS Project) and associated transmission line (Talega-Escondido/Valley-Serrano 500 kV Interconnect or (TE/VS)) located in Riverside, San Diego, and Orange Counties, California. The 500 MW hydropower project and associated 500 kV transmission line would occupy about 2,412 acres of federal lands, including lands managed by the U.S. Department of Agriculture, Forest Service (USFS), Cleveland National Forest, U.S. Bureau of Land Management (BLM), and the Department of Defense (DoD; Camp Pendleton). On July 3, 2003 EVMWD as applicant, and TNHC as the agent for the applicant, filed an application for a Special Use Permit (SUP) with the USFS for the construction of the TE/VS transmission line. The FERC and the USFS participated as cooperating agencies in the preparation of an environmental impact statement (EIS) for the LEAPS Project, and a Final EIS was issued in March of 2007. At the time of publication of the Sunrise Powerlink Final EIR/EIS, the LEAPS Final EIS has not been certified.

On June 1, 2006, EVMWD published a CEQA Notice of Preparation (NOP) of an Environmental Impact Report, recognizing itself as the appropriate CEQA Lead Agency for the LEAPS and TE/VS Projects. However, no EIR has since been prepared by EVMWD for the LEAPS and TE/VS Projects.

On October 9, 2007 TNHC filed an application with the CPUC for a Certificate of Public Convenience and Necessity (CPCN) and a draft Proponent's Environmental Assessment (PEA) for the TE/VS transmission line. As the CPUC will be the agency with the greatest responsibility for approving the TE/VS Project, CPUC is the appropriate lead agency pursuant to CEQA Guidelines § 15051(b). On February 8, 2008 TNHC submitted a revised PEA to the CPUC. Subsequent to a March 6, 2008 data adequacy review by the CPUC, TNHC submitted a second revised PEA on July 22, 2008. An additional data adequacy review was conducted by the CPUC requesting supplemental information from TNHC on August 18, 2008. It is anticipated that a Notice of Preparation of an Environmental Impact Report for the TE/VS Project will be issued by the CPUC in the fall of 2008.

Two LEAPS Project Alternatives were evaluated as alternatives to the Sunrise Powerlink Project: LEAPS Transmission-Only Alternative (evaluated in Section E.7.1 of the Draft EIR/EIS) and the LEAPS Generation and Transmission Alternative (evaluated in Section E.7.2 of the Draft EIR/EIS). The LEAPS Transmission-Only Alternative is identical to the "staff alternative" transmission alignment as identified in the 2007 Final EIS prepared by FERC for the LEAPS Project. The LEAPS Generation and Transmission Alternative is identical to the "staff alternative" hydropower project and transmission alignment as identified in the 2007 Final EIS for the LEAPS Project. The LEAPS Generation and Transmission Project is proposed by the EVMWD and TNHC, but the LEAPS Transmission-Only Alternative could be built and operated by any entity, including SDG&E. These alternatives were considered because they are potentially feasible, because they would substantially satisfy two of the Proposed Project's major project objectives (to maintain reliability in the delivery of power and to reduce the cost of energy in region), and because they would reduce or avoid certain significant effects of the Proposed Project, as described in detail below. Either the LEAPS Transmission-Only Alternative or the LEAPS Generation and Transmission Alternative could be selected by the CPUC and BLM, and the transmission component authorized by the CPUC through the Sunrise Powerlink Project EIR/EIS process. The CPUC has no authority to make a decision on the hydropower portion of the project, and construction of the generation components would require approval of a hydropower license by FERC.

Other agencies with discretionary authority over the LEAPS Project Alternatives may use the Sunrise Powerlink Project EIR/EIS for CEQA/NEPA compliance in issuing additional permits or certifications required for these alternatives.

Because the LEAPS Project and TE/VS transmission line would occupy lands of the Cleveland National Forest and lands administered by BLM and the DoD, the USFS, DoD, and BLM have authority to impose conditions under Section 4(e) of the Federal Power Act (FPA) for the LEAPS Project Alternatives evaluated in this EIR/EIS. The USFS provided final license conditions for the LEAPS Project March 21, 2007. In addition, as a part of the Sunrise Powerlink Project EIR/EIS process, the CPUC as Lead Agency has the authority to require mitigation measures for the Proposed Project and alternatives, including the LEAPS Project Alternatives that would substantially lessen or avoid significant effects on the environment (CEQA Guidelines § 15041). However, as CPUC has no authority over the hydropower portion of the project, it may only recommend that FERC, as the agency with jurisdiction over that portion, adopt such mitigation measures. Should the FERC choose to issue a hydropower license for the generation component of the LEAPS Generation and Transmission Alternative, it could choose to adopt the additional mitigation measures identified in the Sunrise Powerlink EIR/EIS for the LEAPS Generation and Transmission Alternative.

Either of the LEAPS Project Alternatives would require additional approvals from the United States Fish and Wildlife Service, the State Water Resources Control Board, and other entities.

Consistency with Project Objectives

General Response GR-1 presents a discussion on project objectives related to the alternative selection process. As discussed in Sections 4.9.1 and 4.9.2 in Appendix 1 of the Draft EIR/EIS, the LEAPS Alternatives would provide a new second extra-high voltage (EHV) interconnection into the SDG&E system. This would substantially satisfy two of the major project objectives: to maintain reliability in the delivery of power and to reduce the cost of energy in region.

As discussed in General Response GR-1, the CEQA Guidelines explain that the analysis in an EIR should focus on alternatives that can reduce or eliminate significant environmental impacts "even if these alternatives would impede to some degree the attainment of the project objectives…" (CEQA Guidelines § 15126.6(b).) Similarly, under NEPA, lead agencies are prohibited from disregarding alternatives "merely because they do not offer a complete solution to the problem" if they would reduce significant environmental harm associated with the proposed action (See *Natural Resources Defense Council, Inc. v. Morton* (D.C. Cir. 1972) 458 F.2d 827, 836 ("*Morton*").)

Basic Project Objective 1: Maintain Reliability

Two commenters (CAISO in Comment Set A0029 and Jacqueline Ayer in Comment Set D0017) question whether the LEAPS Alternatives meet the reliability objective because the 500 kV transmission line would be subject to a lower import limit. The Proposed Sunrise Powerlink Project would accommodate delivery of 1,000 MW of power to the San Diego region. There is some uncertainty about the total import capability of the LEAPS Alternatives. Following are import capabilities of the LEAPS Alternatives as stated in various documents:

- The CAISO states that the import limit would be 625 MW (April 11, 2008 comment letter and 2008 Phase 2 testimony).
- FERC's 2007 Final EIS for the LEAPS and TE/VS Projects states that it would be 1,000 MW.
- TNHC's October 9, 2007 CPCN Application to the CPUC for the TE/VS Project states that it would be 1,000 MW.
- TNHC's July 22, 2008 version of PEA for the TE/VS Project states that it would be 1,100 MW

As described in Section 4.9.2 of Appendix 1 in the Draft EIR/EIS (Alternatives Screening Report), there would be significant reliability benefits resulting from the LEAPS Alternatives. Providing a new second EHV interconnection into the SDG&E system would meet SDG&E's reliability objective. While the LEAPS Project Alternatives may not fully match the Sunrise Project's import characteristics, these alternatives would provide an additional EHV connection to the region's transmission grid to enhance regional and system reliability. The extent to which the LEAPS Alternatives match the capabilities of the proposed Sunrise Powerlink Project depends on the design capacity of the line (originally 1,300 to 1,600 MW) and how LEAPS is interconnected to the SCE and SDG&E transmission systems. Ultimately, the need for an alternative to achieve a particular level of import capability must be determined in the General Proceeding, and is beyond the scope of the environmental analysis. However, for purposes of the CEQA/NEPA analysis, the LEAPS Alternatives meet this project objective.

Basic Project Objective 2: Reduce the Cost of Energy

The LEAPS Alternatives would provide a high-voltage transmission line into San Diego that would reduce congestion and increase import capability. TNHC asserts in its Phase 2 Opening Brief (May 30, 2008, page 37-39) the LEAPS Alternatives will reduce the cost of energy by reducing congestion on the grid and enabling access to low-cost energy from Arizona, Nevada, and Southern California. The LEAPS Generation and Transmission Alternative would provide additional benefits by transfering low-cost off-peak power to peak-period availability through pumped-storage technology, which should enable a reduction in payments under reliability must-run (RMR) contracts for inefficient San Diego peakers or a reduction of the San Diego local capacity requirements (LCR). This would reduce costs by reducing the potential for in-basin generation to exercise market power and improving the ability of SDG&E to obtain electricity from diverse fuel sources.

The cost of an alternative and its ability to reduce the cost of energy must be determined in the General Proceeding, and is beyond the scope of the environmental analysis. However, for purposes of the CEQA/NEPA analysis, the LEAPS Alternatives meet this project objective.

Basic Project Objective 3: Accommodate the Delivery of Renewable Energy

SDG&E and the CAISO raised concerns about the ability of the LEAPS Project Alternatives to achieve the objective to access Imperial Valley renewable resources. While providing access to Imperial Valley renewable resources was stated by SDG&E as a project objective, the CPUC and BLM defined this objective more broadly (see Draft EIR/EIS Section A.2.2):

- Basic Project Objective 3: to accommodate the delivery of renewable energy to meet State and federal renewable energy goals from geothermal and solar resources in the Imperial Valley and wind and other sources in San Diego County.

TNHC filed comments on the Sunrise Powerlink Draft EIR/EIS on April 7, 2008 (see Comment Set B0018) stating that the LEAPS Transmission-Only Alternative would provide San Diego with transmission access to the following renewable resources:

- Geothermal energy from the Imperial Valley via IID's proposed Coachella Valley–Devers II Project, a component of the Green Path Coordinated projects that would connect to the SCE system, via interconnection with the SCE system; and
- Wind generation from the Tehachapi Wind Resource Area through SCE's proposed Tehachapi Renewable Transmission Project via interconnection with the SCE system.[42]

TNHC also stated that the LEAPS Generation and Transmission Alternative would provide storage capacity for renewable power generated during off-peak hours that would be dispatched to provide peaking renewable power.

According to Imperial Irrigation District's April 11, 2008 comment letter on the Draft EIR/EIS, IID's Coachella Valley–Devers II Project, which is a 35-mile transmisison line that will connect the IID system in the Coachella Valley area to the LADWP and CAISO areas near Palm Springs, will carry up to 1,600 MW of electricity from Imperial Valley renewables into the SCE system. IID claims that this line, in conjunction with the LEAPS Project Alternatives, will provide SDG&E with direct access to Imperial Valley renewables, and that all three major project objectives are satisfied by the LEAPS Project Alternatives.

The Draft EIR/EIS in Section 4.9.2 of Appendix 1 (under "Objectives, Purpose and Need") states that the LEAPS Transmission-Only Alternative's ability to facilitate import of renewable energy to San Diego depends on whether other proposed transmission system upgrades are actually completed. The Green Path Project and IID's transmission system upgrades have not yet been evaluated under CEQA or NEPA, and permitting would occur after those processes are complete. Because the ability of the LEAPS alternatives to accommodate the delivery of renewables would be dependent on the completion of other projects, the statement in the Draft EIR/EIS that the LEAPS Project Alternatives would only partially meet Basic Project Objective 3 is still considered to be accurate.

Conclusion Regarding Project Objectives

As disucssed above and in Sections 4.9.1 and 4.9.2 in Appendix 1 in the Draft EIR/EIS, while there is uncertainty about the LEAPS Project Alternatives' import capability, access to low-cost power, and access to renewables, there is sufficient evidence that these alternatives would meet most of the Proposed Project's basic project objectives. Therefore, they are viable alternatives based on CEQA and NEPA requirements.

Feasibility

The ultimate determination of feasibility of each alternative is a question for the Lead Agencies' decision-makers at the time of project approval based on substantial evidence in the EIR/EIS and the entire administrative record. However, each alternative carried forward for analysis in the Draft EIR/EIS, including the LEAPS Alternatives, was considered to be potentially feasible and to meet most project objectives in a manner consistent with CEQA and NEPA.

[42] Comments of The Nevada Hydro Company, April 7, 2008.

The LEAPS Transmission-Only Alternative could be built and operated regardless of whether the pumped-storage component is ever constructed. TNHC has applied to the CPUC for a Certificate of Public Convenience and Necessity (CPCN) to construct the Talega-Escondido/Valley-Serrano Interconnect Project or TE/VS (A.07-10-005).[43] The Applicant filed its PEA with the CPUC on February 8, 2008, the project was reviewed several times for data adequacy, and the CPUC anticipates supplemental PEA information to be filed by the Applicant to complete the PEA submittal in the fall 2008. The original PEA states that the TE/VS transmission line is the first phase of a two-phased project, of which the pumped-storage component would be the second phase (February 8, 2008 PEA submittal, page 3-1), and that the online date of the transmisson line would be complete three years prior to the LEAPS pumped-storage online date (February 8, 2008 PEA submittal, page 3-142). In addition, FERC has stated that the transmission line could become operational by 2010, rather than being delayed until completion of the pumped-storage project, and that the transmission line would provide economic and reliability benefits separate from the hydropower project. (May 9 FERC Order Conditionally Accepting Interconnecting Agreement, Docket No. ER08-654-000). The CPUC has jurisdiction to grant a CPCN only for the TE/VS transmission line as a part of the TE/VS CPCN proceeding and EIR process; permitting of the LEAPS pumped storage project rests with FERC and USFS. Similarly, as a part of the Sunrise Powerlink CPCN proceeding and EIR/EIS process, the CPUC could order SDG&E to construct the LEAPS Transmission-Only Alternative and establish the necessary ratesetting. Therefore, the LEAPS Transmission-Only Alternative is viable as a potentially feasible stand-alone alternative.

The Draft EIR/EIS also evaluated the LEAPS Generation and Transmission Alternative (see Section E.7.2 in the Draft EIR/EIS), which includes the LEAPS Transmission-Only Alternative plus the 500 MW pumped-storage facility. The CPUC has a separate review of the application for a CPCN for the TE/VS Project (discussed above), which will analyze the impacts of the transmission line plus the associated pumped-storage facility along with all related upgrades in SCE and SDG&E service territories (April 9, 2008 CPUC Letter to David Kates, Project Manager of TNHC). The CPUC could not, however, establish ratesetting for SDG&E to construct the LEAPS Generation and Transmission Alternative because CPUC lacks jurisdiction over hydropower projects. SDG&E has not sought rate recovery or a hydropower license through the FERC for any aspect of LEAPS Alternatives. These environmental analyses for the Sunrise Powerlink Project and the TE/VS Project ensure that all components of the LEAPS Project Alternatives will be fully evaluated before any LEAPS Alternative is approved by the CPUC.

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[43] The CPUC website for environmental review of the TE/VS Interconnect Project is online at: http://www.cpuc.ca.gov/Environment/info/nevadahydro/talega_escondido_vallyserrano.htm

General Response GR-5: Status of Renewable Generation Projects in the Imperial Valley, Eastern San Diego County, and Northern Mexico

Several comment letters have questioned the viability of renewable energy projects in the Imperial Valley and have asked what renewables the Sunrise Powerlink would be able to import when it is constructed (in order to satisfy SDG&E's project objectives). This response describes the status of solar, geothermal, and wind project development in the Imperial Valley and Eastern San Diego County.

As stated in Section A.4.1 (Power imported to SDG&E Service Territory) in Volume 1 of the Draft EIR/EIS, the existing import capability into the San Diego area is often fully subscribed. As such, the Sunrise Powerlink, built along either the proposed route or one of the southern routes, or other upgraded or new transmission lines, would be required to transmit much of this renewable energy into the San Diego area. The renewable resource generator would need to include in its application a proposal to develop an interconnection transmission line to connect with either the Sunrise Powerlink Transmission Line, or other upgraded or new transmission lines, that would be permitted at the same time as the renewable resource. Additionally, because the CPUC directed the Investor-Owned Utilities to allow bids in their RPS procurements for projects that would deliver energy to any point within the CAISO control area, the renewable energy projects described below do not consider the power purchaser.[44]

Background. SDG&E's third project objective is "Provide transmission capability for Imperial Valley renewable resources for SDG&E customers to assist in meeting or exceeding California's 20 percent renewable energy source mandate by 2010 and the Governor's proposed goal of 33 percent by 2020." In addition, SDG&E states that the transmission line will provide access to available and proposed electricity from environmentally friendly resources such as solar, geothermal and wind power located in the Imperial Valley and eastern San Diego County.[45] While transmission access to renewable generation areas is important to development of these resources, each utility is not required to construct transmission to the sources it proposes to use to meet its RPS target. As stated in the procurement process described in General Response GR-2, utilities can accept renewable energy bids from anywhere within the Western Electricity Coordinating Council (WECC). The electricity needs only to enter the CAISO control area in order to be eligible for RPS credit. Any bidders that are located outside the CAISO control area (but inside the WECC) are responsible for delivering their energy to the CAISO control area.

Renewable project developers provide bids to SDG&E in response to its Request for Offers (RFO) for renewable generation projects. SDG&E or the developer can include in the agreements with developers in Imperial Valley that the generation projects are contingent on SDG&E gaining approval of Sunrise or a similar 500 kV line from Imperial Valley. This ties the viability of Imperial Valley renewable energy projects to SDG&E's success in the Sunrise proceeding and introduces substantial uncertainty for the Imperial Valley renewable projects if the Sunrise Powerlink is denied. According to SDG&E, while development of the Sunrise Powerlink does not guarantee that the renewable project will be successfully developed, approval would encourage and accommodate development of renewable energy projects and assist in meeting California's 20 percent renewable energy source mandate by 2010 and the Governor's proposed goal of 33 percent by 2020, thus furthering CPUC and BLM Basic Project Objective 3. However, IID is also in the process of upgrading its transmission system in the Imperial Valley to allow improved capability to export renewable power.

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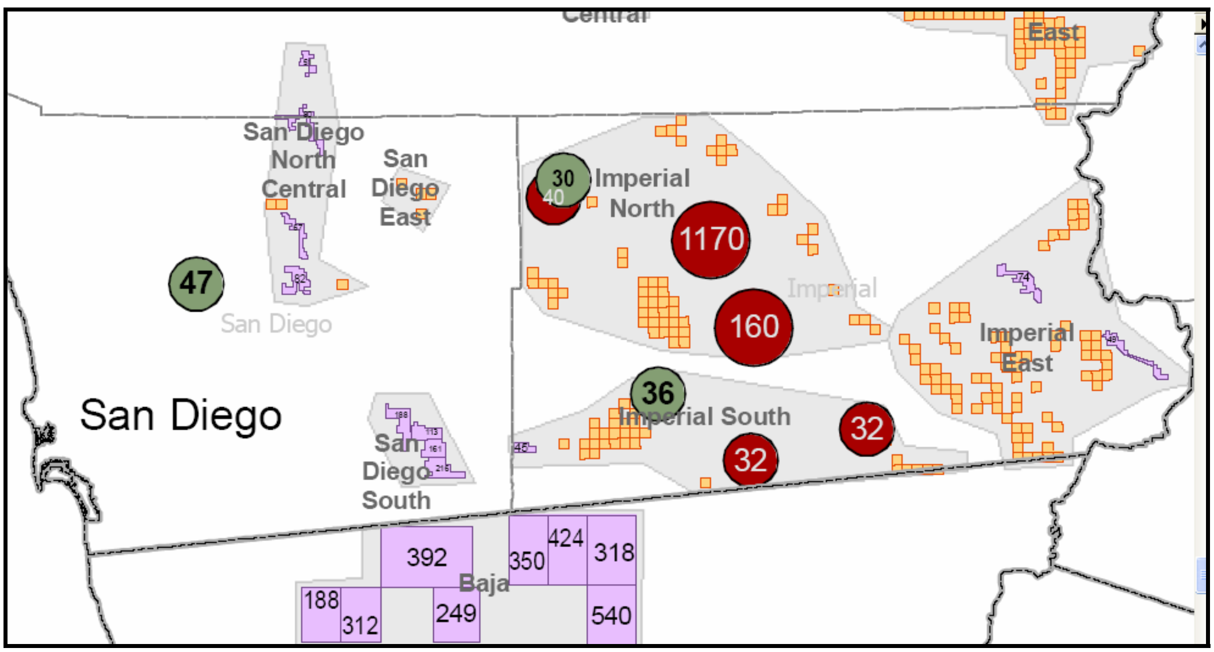
44 CPUC (California Public Utilities Commission). D.05-07-039, July 27, 2005.

45 SDG&E. 2008. Project Benefits. http://www.sdge.com/sunrisepowerlink/benefits/index.htm.

While SDG&E originally included only Imperial Valley renewables as a project objective, during testimony in the CPUC's proceeding, it has referenced renewable generation in northern Mexico and eastern San Diego County as also supporting the need for the Sunrise Powerlink.[46] Therefore, this response includes a summary of renewable proposals in those three geographic areas.

In the following paragraphs, the status of major renewable projects in the Imperial Valley and Eastern San Diego County is described. Three information sources form the basis of this information; however, the lists of renewable energy projects supplies by the sources are changing continuously and the status of each individual project is not always public information. These sources are as follows:

- California Independent System Operator Generation Interconnection Queue[47]
- BLM's maps and tables listing renewable projects with applications to use BLM land
- Draft maps developed for the California Renewable Energy Transmission Initiative (RETI)[48]. RETI's Phase 1B Report (September 2008) shows a total of 1,434 MW of geothermal resources available in Imperial County (red circles in map below), as well as 66 MW of biomass (green circles in map below) and solar resources across the county.



Solar Resources

There are a number of solar project proposals in the Imperial Valley; they are described below. The Stirling Energy Systems (SES) project is described in most detail, because it is specifically tied to the Sunrise Powerlink through the Power Purchase Agreement between SDG&E and SES.

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46 "Since the Sunrise application was filed, more than 6600 MW of renewable generation has applied to the CAISO interconnection queue in the Imperial Valley, eastern San Diego county and adjacent northern Mexico that could be facilitated by Sunrise." Niggli, Michael. Direct Testimony March 12, 2008.

47 CAISO Website: http://www.caiso.com/14e9/14e9ddda1ebf0ex.html

48 The RETI Website presents all project reports and maps: http://www.energy.ca.gov/reti/

- **Stirling Energy Systems** (SES) solar facility is being planned for a several thousand acre area west of El Centro on BLM land. Comment letters have stated that large-scale commercial use of Stirling's solar technology has not been tested at this large scale, which is correct. An Irish green-energy developer, NTR PLC, announced on April 17, 2008 that it has invested $100 million into SES, which would cover all pre-construction costs. An additional investment of several hundred million dollars will be required before construction of the first phase can be completed. NTR will take controlling interest of the company. On June 30, 2008 SES filed an Application for Certification (AFC) for a 750 MW solar generation facility, SES Solar Two, with the CEC. BLM and the CEC expect to initiate preparation of a joint NEPA/CEQA document after the AFC is determined to be complete. Agencies must accept and process an application that is considered to be adequate in all administrative ways, including technical feasibility. Additionally, the BLM has stated that it will require a bond from the applicant so that restoration can be completed even if the company goes out of business, and so the land can be restored at whatever time the project is over. To comply with the SDG&E contract with SES for Phase 1, SES must have 300 MW in operation by December 31, 2010 regardless of the progress of the SRPL.

BLM Data. As of September 2008, 12 applications for solar projects in Imperial County had been submitted to the BLM California Desert District (El Centro Field Office), including the SES Solar Two, LLC (described above). The other projects include the following:

- **BIO Renewable Projects, LLC**: 20 MW, solar PV on 640 acres on western boundary of Chocolate Mountain Gunnery Range. The application was submitted on 7/31/06 and the status of this project is unknown.
- **BCL & Associates**: 500 MW, solar PV on 16,000 acres including 7,500 acres of solar collectors and a 5,740-acre greenbelt located southeast of San Sebastian Marsh, west of SR86, and northeast of the Navy ranges. The application was submitted on 7/18/07.
- **SkyGen Solar LLC:** 50 MW on 1,040 acres of Class L lands between SR86 and the Salton Sea. The application was submitted on 12/10/07.
- **Opti-solar.** 1,500 MW on 2,560 acres using solar photovoltaic technology in southern Imperial County. The application was submitted on 12/03/07.
- **Power Partners Southwest, LLC.** 300 MW, solar thermal project on 240 acres west of Dixieland, south of Old Highway 80, and near Plaster City Open Area. The application was submitted on 01/22/08.
- **Pacific Solar Investments (Iberdrola).** 1,500 MW, solar thermal project using solar trough technology on 25,000 acres. The application was submitted on 09/05/07.
- **Solar Reserve, LLC.** 120 MW, solar thermal project using solar power tower technology on 4,000 acres. The application was submitted on 4/24/08.
- **Bull Frog Green Energy LLC.** 250 MW on 2,600 acres using solar photovoltaic technology. The application was submitted on 2/27/08.
- **Power Partners Southwest LLC c/o enXco.** 300 MW, solar thermal project using solar trough technology on 540 acres located in Imperial County. The application was submitted 4/07/08.
- **Sempra Generation.** 500 MW on 11,000 acres using solar photovoltaic technology. The application was submitted on 7/21/08.
- **LightSource Renewables LLC.** 400 MW, solar thermal project using solar trough technology on 3,020 acres located in Imperial County South of I-8, north of State Highway 98. The application was submitted 8/11/08.

CAISO Queue. As of July 25, 2008, the CAISO queue also identified 13 solar projects in line for transmission connection in San Diego and Imperial Counties. The queue provides minimal information about the projects, but gives a general idea of the types of development that may occur. The projects are:

Imperial County

- 300 MW Solar project (application submitted 8/31/05).
- 600 MW Solar project (application submitted 8/22/06).
- 900 MW Solar thermal project (application submitted 5/29/08).
- 450 MW Solar thermal project (application submitted 5/30/08).
- 280 MW Solar thermal project (application submitted 5/30/08).
- 250 MW Solar thermal project (application submitted 5/30/08).
- 125 MW Solar thermal project (application submitted 5/30/08).
- 84 MW Solar thermal project (application submitted 6/02/08).

San Diego County

- 75 MW Solar PV project in Borrego Springs (application submitted 4/07/08).
- 49.5 MW Solar thermal project in Borrego Springs (application submitted 4/02/08).
- 58.8 MW Solar PV project in Borrego Springs (application submitted 6/02/08).
- 50 MW Solar PV project that would connect into Warner Substation (application submitted 6/02/08).
- 58.8 MW Solar PV project that would connect into Cameron Substation (application submitted 6/02/08).

Note that for both the projects on the BLM application list and those in the CAISO queue, there is no certainty that any or all of these projects will complete the application process, successfully complete CEQA and/or NEPA review, and obtain financing required to construct.

RETI. The RETI Phase 1B Report (August 16, 2008) identifies the potential for nearly 27,000 MWe for Imperial County solar photovoltaic projects. Numerous solar thermal projects were also identified in Imperial County, but their resource potential is not separately totaled.

Geothermal Resources

As described in Draft EIR/EIS Section A.4.3, the Sunrise Powerlink project began as a conceptual transmission line intended to carry geothermal power out of the Salton Sea area. The Imperial Valley Study Group (IVSG), formerly known as the Salton Sea Study Group (SSSG), was a voluntary planning collaborative group for the Imperial Valley area that was created under a policy directive from the CPUC (as a result of D.04-06-010 under Proceeding I.00-11-001). It was also supported by initiatives at the California Energy Commission related to the 2005 Integrated Energy Policy Report proceeding. The IVSG was formed to recommend a phased plan for developing the transmission necessary to export 2,200 MW of renewable geothermal and solar generation from the Imperial Valley to urban coastal load centers. Alternative solutions were created from IID's proposed Green Path initiative and SDG&E's concurrent Transmission Comparison Study for a new 500 kV connection to San Diego. Independent of the IVSG, the Los Angeles Department of Water and Power (LADWP) was also conducting transmission planning activities to access Imperial Valley geothermal resources (known as Green Path North; note that a description of the Green Path Project is provided in Section A.4.4 below), and the IVSG report notes LADWP's plans. The IVSG development plan was released in September 2005, and it aimed to represent the consensus recommendation of the stakeholder participants in the study group, who included the regional transmission owners, CAISO, CPUC, CEC, generation developers, local, state and federal agencies, environmental and consumer groups and other interested parties.

A Final EIS was issued by BLM on February 1, 2008 to analyze the impacts of leasing of geothermal resources exploration, development, and utilization in the Truckhaven Geothermal Leasing Area (Truckhaven) located in western Imperial County, California. Currently, BLM has non-competitive geothermal lease applications pending for portions of this land, including lease applications from Esmeralda Energy, LLC (Esmeralda); however, before any leases can be issued, the NEPA process must be completed. Under the proposed Truckhaven Geothermal Leasing Area action, BLM could approve the pending non-competitive leases and offer competitive leases for all other available lands at Truckhaven, totaling 14,731 acres. Esmeralda has secured a Power Purchase Agreement (PPA) with SDG&E for 20 MW of geothermal power that would likely be developed within Truckhaven. In March 2007, the CPUC approved this renewable contract. The project that would develop the 20 MW of geothermal resources at Truckhaven is referred to as the Esmeralda–San Felipe Geothermal Project. No project application has been submitted for the Esmeralda–San Felipe Geothermal Project.

Potential future geothermal generation projects in the Imperial Valley include the following:

- **Esmeralda Truckhaven Geothermal.** Esmeralda has secured a Power Purchase Agreement (PPA) with SDG&E for 20 MW of geothermal power that would likely be developed within Truckhaven. In March 2007, the CPUC approved this renewable contract. The project that would develop the 20 MW of geothermal resources at Truckhaven is referred to as the Esmeralda–San Felipe Geothermal Project. The BLM released the Final Environmental Impact Statement that analyzed the impacts of leasing of geothermal resources exploration, development, and utilization in the Truckhaven Geothermal Leasing Area (Truckhaven) located in western Imperial County, and the Record of Decision for the Truckhaven Geothermal Leasing Area was released in July, 2008. Additionally, Esmeralda Truckhaven Geothermal won funding from the CEC in May, 2008 for Exploration and Assessment of the San Felipe–Truckhaven Geothermal Area, Imperial County.
- **Salton Sea Geothermal Unit #6, California.** In December 2007, the CEC agreed to extend the deadline for the commencement of construction of the Salton Sea Geothermal Unit #6 by CE Obsidian Energy LLC. The petitioner received an extension of three years, until December 2011. The geothermal power facility would generate approximately 185 MW of energy.
- **IAE Truckhaven I Project, California.** In July 2006 Iceland America Energy (IAE) signed a Power Purchase Agreement with PG&E for the first phase (50 MW) of the Truckhaven project. The Truckhaven area is a low-salinity 365°F area estimated to carry 50-150 MW power generation for a 30-year or longer period. The plan is to aim for three identical units built one after the other as the knowledge base and certainty of the site's size and sustainability grows. The plan is to install three 45 MW units but to account for up-to 5 MW own use of that power for each unit. The power generation system will be of binary type or combined flash and binary type (Geothermal Energy Association, 2008).[49]
- **Ormat Technologies, Inc.** Ormat Technologies has a project at the Truckhaven Known Geothermal Area (KGRA) in the early development stage. The project is planned for 50 MW (Geothermal Energy Association, 2008).

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[49] Geothermal Energy Association. *California – Developing Power Plants – Truckhaven.* http://www.geo-energy.org/information/developing/CA/truckhaven.asp in May 2008.

- **Salton Sea Geothermal Power Plant.** 185 MW geothermal power plant located on 80 acres, six miles northwest of Calipatria in Imperial County. The power plant was approved by the CEC in December 2003 however it has been on hold since that time (CEC, 2008).[50]
- **Geothermal Expandables, LLC.** This company won funding from the CEC in May, 2008 for Research and Development for CFEX Self-Expanding Tubulars in the Salton Sea region (CEC, 2008a).[51]

Wind Resources

The existing transmission system in southeastern San Diego County is limited to a 69 kV line that extends eastward and ends at the Boulevard Substation and the 500 kV SWPL that presently has no interconnection point or substation between the Imperial Valley and Miguel Substations. Transmission upgrades to the 69 kV system, or a new point of interconnection along SWPL (e.g., the potential Jacumba Substation), or a southern route alternative would be required if large wind developments are constructed in this area. Crestwood area and Mexican wind resources could be imported as a result of the Sunrise Powerlink Transmission line as follows: if a northern route is used, it could free up capacity on SWPL; if southern route is constructed, it could itself provide transmission and also could free up capacity on SWPL. Southern route alternatives to the Proposed Project would be more effective than northern route alternatives at alleviating potential interconnection limitations on SWPL by providing the options of either a SWPL interconnection, or directly interconnecting to the southern route, or eventually developing an interconnection between the SWPL and the southern route, which could provide many alternate paths for delivery of Crestwood or Mexican wind resources.

Wind Generation in Crestwood Wind Area. The following wind projects could be developed in the Crestwood area:

- **Pacific Wind (Ibendrola)** was issued a monitoring and testing right-of-way (ROW) permit from BLM, encumbering 17,000+ acres in September 2004, as described in Draft EIR/EIS Section E.5.1 and E.6.1. In December 2007, PPM Wind submitted an application for renewal of the monitoring/testing ROW and submitted a Plan of Development (POD) for the 9,000-acre "Tule Wind Project." The project would consist of 1.5 to 3 MW wind turbines, generating up to 200 MW of electricity. In July of 2008, Pacific Wind submitted an application to install additional monitoring/testing towers. When a Record of Decision is issued by the BLM, PPM Wind would then relinquish the remainder of acreage available for wind development within Eastern San Diego County (ESDC) Resource Management Plan that is currently part of its monitoring/testing ROW. The NEPA process may begin in late 2008.[52]
- **Clipper Wind.** Wind project on 1,318 acres located in southeastern Imperial County adjacent to the Little Picacho Wilderness Area. They are currently testing and monitoring 3 Met towers. The application was submitted in 10/2004 and is pending an Environmental Assessment.

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50 California Energy Commission, Status of all Projects. http://www.energy.ca.gov/sitingcases/all_projects.html in May 2008.

51 California Energy Commission, Notice of Proposed Awards, Geothermal Program Solicitation. http://www.energy.ca.gov/contracts/2008-05-01_GRDA_nopa.html in May 2008.

52 Email correspondence from Lynda Kastoll (BLM, El Centro Field Office) to Hedy Born (Aspen Environmental Group) on March 17, 2008.

- **Wind Hunter.** Wind project on 6,280 acres in Ocotillo, Western Imperial County. The application was submitted in 9/2005 and the installation of met towers is pending SHPO consultation and preparation of a Finding of No Significant Impact (FONSI).
- **RENEWergy.** Wind project on 3,219 acres in Ocotillo, Western Imperial County. The installation of testing and monitoring Met towers is pending an Environmental Assessment. The application was submitted in 4/2006.
- **Superior Renewable.** Wind project on 187 acres in Ocotillo, Western Imperial County. The installation of testing and monitoring Met towers is pending an Environmental Assessment. The application was submitted in 6/2006.
- **Imperial Wind.** Wind power on 1,960 acres in Black Mountain, Eastern Imperial County. Two Met towers have been installed by the previous ROW holder. The new ROW application to Imperial Wind is pending a cultural literature search. The application was submitted in 7/2006.
- **RENEWergy Black Mountain.** Wind power on 11,187 acres in Eastern Imperial County. The BLM authorized a ROW for three Met towers, one of which has been installed. The application was submitted in 12/2005.

As of July 25, 2008, the CAISO queue also identified four wind projects in line for transmission connection in both San Diego County and Imperial County. An additional 9 wind projects in Baja California are in line for transmission connection (see discussion below).

- 201 MW Wind project in San Diego that would connect with the SDG&E Boulevard-Crestwood 69 kV transmission line. The application was submitted 5/12/04.
- 160 MW Wind project in San Diego that would connect with the SDG&E 500 kV Imperial Valley–Miguel transmission line (SWPL). The application was submitted 5/01/06.
- 300 MW Wind project in San Diego that would connect with the SDG&E 500 kV Imperial Valley–Miguel transmission line (SWPL). The application was submitted 6/28/06.
- 130 MW Wind project in San Diego that would connect into the SDG&E Boulevard Substation. The application was submitted on 5/30/08.

Two other projects or project areas are those listed below. No specific applications have been filed for these projects.

- The **Campo Band of Kumeyaay Indians** has indicated in a letter to the CPUC and BLM (dated March 23, 2007) that it may expand the existing wind development on tribal land in the eastern San Diego County area.
- The **Ewiiaapaayp Band of Kumeyaay Indians** and the **Manzanita Band of Mission Indians** are also considering additional wind energy projects in the area.

Wind Generation in Mexico Interconnecting with California Transmission. Several wind projects are listed in the CAISO queue, and the Sempra Rumorosa Wind Energy Projects has submitted an application to the Department of Energy for approval of a transmission connection to a 1,250 MW wind generation area. Specific wind applications or queue requests in Mexico are the following:

- **Sempra.** The "Rumorosa Wind Energy Projects" (RWEP) is located near La Rumorosa, Baja California. On June 30th, 2007, Sempra, the parent company of SDG&E, entered into an agreement with Cannon Power Corporation of San Diego to develop a wind farm east of the town of La Rumorosa in the municipality of Tecate. Sempra filed an Application for a Presidential Permit on December 20, 2007 for a transmission line that would interconnect with up to 1,250 MW of wind power in the La Rumorosa Region. Sempra has indicated that in the Phase 1 of the RWEP only 130 to 190 MW of wind energy would be generated, and that the exact location of subsequent phases of the La Rumorosa projects has yet to be determined. Sempra Generation is currently arranging for additional wind resource properties in the vicinity of La Rumorosa, and Sempra has said it could begin delivering wind from the first phase of the RWEP to Southern California Edison as early as 2010, and the future three phases of additional 250 MW wind generation farms is expected to be completed by 2013 (Presidential App.). Note that this project includes the **Sempra Presidential Permit and Associated Facilities** that was discussed in Section 2 of the RDEIR/SDEIS.

- **Unión Fenosa**, a Spanish company, which purchased 50% of the Mexican company Zemer Energía, with the goal of completing a wind project in the La Rumorosa region with the capacity of between 500 MW and 1,000 MW (BizNews, 2007).[53] Unión Fenosa is considering selling this wind-power to Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) and has also begun the permitting process to gain access to transmission within California (BizNews, 2007). Unión Fenosa already has use permits for the area and for the exportation of energy, according to its president, Pedro López Jiménez. Unión Fenosa is the third largest independent energy producer in Mexico (BizNews, 2007).

The CAISO queue includes the following wind generation projects that are requesting interconnection to the CAISO grid.

- 400 MW Wind project in La Rumorosa, Baja California, that would connect with the SDG&E 500 kV Imperial Valley–Miguel transmission line. The application was submitted 12/06/06.
- 1,000 MW Wind project in La Rumorosa, Baja California, that would connect with the SDG&E Imperial Valley 230 kV switchyard. The application was submitted 01/12/07.
- 1,000 MW Wind project in La Rumorosa, Baja California, that would connect with the SDG&E Imperial Valley Substation. The application was submitted 02/02/07.
- 500 MW Wind project in La Rumorosa, Baja California, that would connect with the SDG&E Miguel Substation. The application was submitted 02/27/07.
- 500 MW Wind project in La Rumorosa, Baja California, that would connect with the SDG&E Imperial Valley Substation. The application was submitted 02/27/07.
- 300 MW Wind project in La Rumorosa, Baja California, that would connect with the SDG&E 500 kV Imperial Valley–Miguel transmission line. The application was submitted 03/05/07.
- 400 MW Wind project in La Rumorosa, Baja California, that would connect with a new SDG&E 230/500 kV substation near the 500 kV Imperial Valley–Miguel transmission line. The application was submitted 05/02/07.
- 420 MW Wind project in La Rumorosa, Baja California, that would connect with the SDG&E Imperial Valley–Miguel 500 kV transmission line. The application was submitted 05/21/07.
- 500 MW Wind project in La Rumorosa, Baja California, that would connect with the SDG&E Imperial Valley–Miguel 500 kV transmission line. The application was submitted 02/27/08.

[53] BizNews North México (BizNews). 2007. Lo construirá Fenosa en La Rumorosa; abastecerá a California. http://www.biznews.com.mx. June 18. Accessed November 5.

General Response GR-6: San Diego Smart Energy 2020 and All-Solar Alternative

Numerous comments suggested that the EIR/EIS should include a full analysis of implementing the San Diego Smart Energy (SDSE) 2020 plan or an All-Solar Alternative as an alternative to SDG&E's proposal to import renewable power from Imperial County.

The All-Solar Alternative was considered and eliminated from detailed analysis in the Draft EIR/EIS (see Section C.5.9.4, in Volume 1 of the EIR/EIS and Section 4.10.7 of Appendix 1 [Alternatives Screening Report] in Volume 6 of the EIR/EIS). The All-Solar Alternative would provide new in-area renewable generation capacity from:

- 406 MW nameplate capacity of rooftop solar PV installations by 2010 with sufficient battery storage to serve as peaking units to achieve at least 203 MW of reliable capacity during peak hours;
- 1,040 MW nameplate capacity of rooftop solar PV installations by 2016 with sufficient battery storage to serve as peaking units to achieve at least 520 MW of reliable capacity during peak hours; and
- 2,040 MW nameplate capacity of rooftop solar PV installations by 2020 with sufficient battery storage to serve as peaking units to achieve at least 1,020 MW of reliable capacity during peak hours.

As stated in Section 4.10.7 of Appendix 1 of the Draft EIR/EIS, the All-Solar Alternative was eliminated because while the increased MW of solar power required by the All-Solar Alternative would help SDG&E meet the local reliability requirements by 2010, the All-Solar Alternative alone would not satisfy the CAISO G-1/N-1 reliability objective of the SRPL transmission line through 2020. Additionally, achieving sufficient capacity of PV installations by 2010 would be economically infeasible. A large initial investment, beyond the existing CSI initiative, through the use of tax credits or outside investment would be necessary to lower the cost of solar PV for the consumer. A fundamental assumption of an All-Solar Alternative is that a large demand for solar PV systems would reduce the cost of these systems to a point where they are cost competitive. The earliest date for this cost competitiveness, however, would be approximately 2017.[54] Building the initial 406 MW contemplated under this alternative would be a much more aggressive deployment (more than double the rate) of solar PV than the CSI program in the early years, and an unknown level of incentives would be required to meet the 2010 and 2016 targets of the All-Solar Alternative.

Under both CEQA and NEPA, lead agencies are required to evaluate a "reasonable range" of alternatives but are not required to evaluate every possible alternative. According to the Council on Environmental Quality (CEQ), "[w]hen there are potentially a very large amount of alternatives, only a reasonable number of examples, covering the full spectrum of alternatives, must be analyzed and compared in the EIS." (CEQ Forty Questions, No. 1b.) Under CEQA, the "range of alternatives required in an EIR is governed by a 'rule of reason' that requires an EIR to set forth only those alternatives necessary to permit a reasoned choice." (CEQA Guidelines § 15126.6(f).) Alternatives involving implementation of the SDSE 2020 plan or a full evaluation of the All-Solar Alternative are within the range of alternatives already evaluated in the EIR/EIS.

Of the 27 alternatives chosen for detailed analysis through the alternative screening process documented in Appendix 1 of the Draft EIR/EIS, the New In-Area All-Source Generation Alternative and the New In-Area Renewable Generation Alternative include components of solar PV generation consistent with the SDSE plan and an All-Solar Alternative. The New In-Area Renewable Generation Alternative

[54] Bill Powers, 2007. San Diego Smart Energy 2020.

analyzed in the Draft EIR/EIS captures the renewable energy benefits of the SDSE plan or an All-Solar Alternative while providing sufficient capacity for reliability purposes and is developable in a competitive timeframe at a reasonable cost. The numerous transmission line route alternatives, the substation alternatives, the system alternatives, the No Action/No Project Alternative, and the non-wires alternatives considered in the EIR/EIS constitute a reasonable range of potentially feasible alternatives designed to reduce the project's environmental impacts. A full and separate environmental analysis of the SDSE 2020 plan or an All-Solar Alternative is not required.

General Response GR-7: Sunrise Powerlink Project Connection to Mexican Generation and/or Mexican LNG Import

The Proposed Project would carry electricity from the Imperial Valley Substation into San Diego County. Two existing natural gas fired power plants are located in Mexicali and connected to the Imperial Valley Substation via a set of existing 230 kV transmission lines. One of the existing Mexican power plants is owned by Sempra Generation an affiliate of Sempra Energy, the SDG&E parent company. In a May 15, 2008 press release, Sempra Energy announced that its Energía Costa Azul liquefied natural gas (LNG) receipt terminal in Baja California, Mexico is ready for commercial operations.

Several commenters suggested that the Proposed Project would result in increased air emissions from the two existing Mexicali power plants or encourage additional power plants to be built in Mexico. These commenters stated that new power plants in Mexico connecting to Imperial Valley Substation could be developed or that the existing power plants would operate more frequently due to the increased transmission capacity out of the Imperial Valley Substation.

The Draft EIR/EIS addresses the air quality impacts of the existing Mexican power plants operating more frequently as part of Section D.11.13.2, Overall Operation Impacts, through an analysis of power plant dispatch prepared by the CAISO. The CAISO forecast concludes that with development of new renewable generation projects in California, the Proposed Project would not lead to increased operation of the existing Mexican power plants (Draft EIR/EIS page D.11-51).

Since the modeling conducted by CAISO forecasts no increased operation of the existing Mexican power plants, there is no evidence to conclude that indirect emission increases would occur from Mexican power plants as a result of the Proposed Project. The conclusion that no increased operation of the existing Mexican power plants would occur is made for the Proposed Project assuming that renewable resources would be developed across California to achieve a Renewable Portfolio Standard (RPS) penetration of 26.5 percent RPS in 2015 (or halfway between the mandated 20 percent target in 2010 and the 33 percent goal that is presently under consideration for 2020). This assumption is identified in the Final EIR/EIS (Section D.11.13.2, Impact AQ-3).

At this time, it is not expected that new power plants would be built to join the existing Mexican power plants. The CAISO Controlled Grid Generation Queue[55] shows no new conventional fossil fuel power plants are proposed for the Imperial Valley Substation or for import from Mexico. Only wind and solar power plants are in the California interconnection approval queue for northern Mexico. For example, the Sempra Generation proposal to develop wind power and the Jacumba Substation are "connected actions" to the Proposed Project, as identified in the RDEIR/SDEIS.

The existing cross-border transmission infrastructure and transmission capability between the Imperial Valley Substation and Mexico would not be expanded by any aspect of the Proposed Project aside from the "connected actions" related to renewables. A recent study sponsored by the CEC noted that although the planned transmission upgrades near the border would reduce congestion on transmission north of the border and offer excellent points of interconnection for Mexican power plants, the Sunrise Powerlink Project would not increase the power export limit from Mexico, which is dictated by the

[55] The CAISO Generator Interconnection Queue available at: http://www.caiso.com/docs/2002/06/11/2002061110300427214.html.

configuration of existing cross-border transmission facilities.[56] No new Mexican fossil fuel power plants are reasonably foreseeable at this time, as there are none in the CAISO interconnection queue, and there is no indication that existing Mexican power plants would operate any more frequently with the Proposed Project in service. Nevertheless, SDG&E and other California utilities can choose to sign contracts for power from the existing Mexican power plants. The existing 230 kV transmission lines between the Imperial Valley Substation and the Mexican power plants have sufficient capacity to accommodate the full-capacity output of the existing power plants, and the fuel supply in Mexico does not constrain the dispatch of the power plants because there appears to be sufficient availability of natural gas including LNG. If SDG&E elects to sign new contracts to procure power from these existing plants in the future, the following institutional measures are in place to protect Imperial Valley air quality:

- The existing Mexican power plants were built with pollution control systems in place, and the plants are required to operate in a manner consistent with the U.S. Department of Energy Environmental Assessment and Environmental Impact Study prepared under NEPA in 2004 (EA-1391). With recent availability of LNG in Mexico, the owners must still meet the emission standards established by the U.S. Department of Energy NEPA process. Information in the Sunrise Powerlink Project Draft EIR/EIS (in Table D.11-5) shows that these plants emit at levels comparable to new plants in California.
- To expand the cross-border capacity of the merchant transmission lines into Mexico, a Presidential Permit would be required and the NEPA process would need to be completed by the U.S. Department of Energy before making any decision on a cross-border transmission expansion. The NEPA process would provide opportunity for the public and the local air districts to review any proposed expansion.
- For greenhouse gases, the CPUC Greenhouse Gas Emissions Performance Standard would apply if SDG&E arranges new contracts for baseload power (Draft EIR/EIS page D.11-16). Information in the Draft EIR/EIS (in Table D.11-5) shows that the La Rosita Power Complex may not be eligible for a baseload contract with SDG&E under this standard.

[56] California Energy Commission. Consultant Report, CEC-600-2008-008. Current Status, Plans, and Constraints Related to Expansion of Natural Gas-Fired Power Plants, Pipelines and Bulk Electric Transmission in the California/Mexico Border Region. Prepared by: KEMA, Inc. August 2008.

General Response GR-8: Greenhouse Gas (GHG) Impacts of Sunrise Powerlink Project and Non-Wires Alternatives

SDG&E, the U.S. Environmental Protection Agency, and others (including Natural Resources Defense Council) raise questions on the impact analysis methodology for global climate change. The framework for the analysis is consistent with CEQA and NEPA requirements. It is based on the characterization of baseline, establishing significance criteria, and comparing the direct and indirect effects caused by project and alternatives with the significance criteria. This general response provides additional information on these topics.

Greenhouse Gas Emissions, Baseline and Level of Significance

The method of analysis in CEQA and NEPA documents is subject to lead agency discretion. For global climate change, the approach will likely evolve as GHG regulations are formed. Pursuant to SB 97, the Governor's Office of Planning and Research (OPR) will develop and the California Resources Agency will adopt amendments to the CEQA Guidelines for GHG analysis by January 1, 2010. The OPR released a Technical Advisory on addressing climate change in CEQA dated June 19, 2008, but specific guidelines for climate change have not yet been adopted. It is always the responsibility of the lead agency to select a level of significance and identify feasible mitigation measures. Determining significance depends on defining what would be a "substantial" level of greenhouse gas emissions (in the Draft EIR/EIS, this is done in Section D.11.4.1). CEQA provides some direction on the use of the term "substantial" but the law leaves the lead agency to decide whether one molecule, one ton, or some other level is significant. Among the various possible definitions of "substantial," the Draft EIR/EIS determined that any level of net GHG increases could be called "substantial." This is a "no net increase" threshold.

The conservative "no net increase" threshold in the Draft EIR/EIS was selected because no guidance is available from any resource agency to support an explicit level of significance, and given CARB's mandate to reduce statewide emissions to 1990 levels by 2020, a project causing any net increase could contribute to CARB missing this goal since it would to contribute to GHG increases. The "no net increase" approach to managing emissions is common for stationary sources of traditional, criteria air pollutants like ozone precursors or particulate matter, where major sources can only be permitted after demonstrating sufficient emission reductions or offsets. Satisfying the GHG significance criteria in the Draft EIR/EIS would ensure that construction and operation of the project causes no net increase compared to the baseline that existed at the time of the Lead Agencies issuing the Notice of Preparation (September 15, 2006). A discussion of the GHG emissions, and data where available, are presented for each alternative in the Draft EIR/EIS (see Sections D.11, E.1.11, E.2.11, etc.). The comparison of project impacts versus impacts of other alternatives that can feasibly respond to the growing demand for electricity is presented in Section H of the Draft EIR/EIS.

Greenhouse Gas Emissions of Proposed Project and Indirect Emissions

U.S. EPA, SDG&E, and others provide comparisons of GHG emissions from construction of the Proposed Project with GHG emissions from operating typical fossil fueled power plants. These comments demonstrate that while construction of the Proposed Project would cause high levels of GHG emissions (up to 109,000 tons of CO_2 over two years), operation of typical fossil fueled power plants would cause substantially more emissions (i.e., millions more tons of CO_2) during every year while generating electricity at a capacity similar to what would be delivered by the transmission line. These comparisons presume that the electricity delivered by the transmission line can be generated without GHG emissions.

This would be possible only if the line is fully subscribed with renewable power, when in fact it would not carry 100 percent renewable power.

SDG&E claims that the Sunrise Powerlink Project facilitates development of renewable power plants in the Imperial Valley and that the project enables GHG reductions by reducing reliance on fossil fuel-fired power plants. However, SDG&E does not and is not able to claim that the line will carry only renewable power. There is no guarantee that the renewable projects now expected to generate power carried by Sunrise will be successfully developed. Since the proposed transmission line would carry power from all types of energy sources (including renewable, nuclear, and fossil fuel), some level of GHG emissions would be attributable to the electricity delivered by the Sunrise Powerlink. The Draft EIR/EIS (in Section D.11.13.2, Impact AQ-3) identifies the difficulties in accurately forecasting the level of GHG reductions because of the uncertain implementation of renewable projects and the inability to precisely predict the ultimate sources of power flowing into the Sunrise Powerlink and other major transmission in the western U.S.

All of the forecasts in the EIR/EIS of the avoided GHG emissions are based on California achieving more than the current mandate of 20% RPS, even though the 33% RPS goal for 2020 has not yet been codified into statute. These indirect emissions estimates include substantial uncertainty because actual renewable development is slow, renewable projects face many risks and barriers, and California utilities, including SDG&E are now not projected to meet the 20% by 2010 target (CPUC RPS Procurement Status Report, July 2008).

The Draft EIR/EIS (in Section D.11.13.2 and Section D.11.13.3, page D.11-55) shows that using existing and future fossil fuel power plants and renewables to generate electricity and delivering electricity via the Proposed Project would cause marginally less GHG emissions than generating electricity and delivering it via the existing transmission grid. In the Draft EIR/EIS, the following data regarding CO_2 were presented:

- Power plants connected to the grid were shown to generate 1,650 tons of CO_2 less in 2015 with the Sunrise Powerlink and new renewable generation in Imperial County compared to the grid without the Sunrise Powerlink but with new renewable generation in Imperial County and elsewhere, so more than 40 years of transmission line operation would be needed to offset the two years of GHG emissions from construction.

This original forecast of avoided power plant emissions included an error in the emission factor for existing fuel oil-fired facilities that has been corrected in the Final EIR/EIS. The Final EIR/EIS shows the new information provided by SDG&E after the close of the Draft EIR/EIS comment period (Data Response 27-6, filed with CPUC on May 6, 2008) and confirmed by CAISO (Submission Pursuant to the June 20, 2008 Assigned Commissioner/ALJ Revised Scoping Memo and Ruling, filed August 4 and August 26, 2008). According to the updated forecast and as stated in the Final EIR/EIS:

- Power plants would emit 8,950 tons of CO_2 less in 2015 with the Sunrise Powerlink and new renewable generation in Imperial County compared to delivering electricity via the existing grid with new renewable generation in Imperial County and elsewhere, so more than 12 years of transmission line operation would be needed to offset the two years of GHG emissions from construction.

The construction phase GHG emission that would certainly occur could eventually be offset by operation of the transmission line providing an indirect net decrease in emissions from power plants. However, the indirect reductions at power plants are uncertain being dependent on actual renewable development. As a result of the conclusions described above, the Draft EIR/EIS and Final EIR/EIS conclude that project activities would cause a net increase of greenhouse gas emissions (Impact AQ-4). This is considered to be a significant and unmitigable (Class I) impact based on the significance criterion, which states that climate change impacts would be considered significant if:

- Activities associated with the Proposed Project would result in greenhouse gas emissions substantially exceeding baseline greenhouse gas emissions. Consistent with the aim of AB32 to provide GHG reductions, overall Proposed Project GHG emissions would "substantially exceed" baseline emissions if the total effect of all project activities causes a net increase of GHG emissions over the baseline.

Greenhouse Gas Emissions Compared to Non-Wires Alternatives

The conclusion that the Proposed Project would cause an overall net increase in GHG emissions and a significant, unmitigable impact should not be surprising considering that the proposed transmission line does not guarantee any new renewable energy facilities. The level of GHG reductions for the Proposed Project depends on the ability of new renewable energy sources to be developed, and the timing of these renewable projects is uncertain. In the comparison of alternatives to the Proposed Project, the Draft EIR/EIS arrives at a logical conclusion that while building transmission causes significant GHG emissions, building and operating a new local fossil-fuel power plant would cause more GHG emissions. The New In-Area All-Source Generation Alternative (Draft EIR/EIS Section E.6.11, page E.6-179) would cause substantially more GHG emissions than the Proposed Project (see Table H-29 in Section H of the Draft EIR/EIS).

The text in Sections H.6.1 and H.6.2 (Comparison of Alternatives) has been modified in several places to show how GHG increases associated with the New In-Area All-Source Generation Alternative compares with the transmission alternatives.

Draft EIR/EIS Section H.6.1, page H-133 has been revised as follows:

- The New In-Area Renewable Generation Alternative would result in an overall net reduction in greenhouse gases ~~**during operation**~~. Direct emissions from the biogas/biomass facilities would be more than offset by avoiding the GHG that would otherwise escape to the atmosphere during decomposition of the fuel feedstock**,** and the**re would be a** beneficial reduction of **fossil fuel-fired power plant** emissions **avoided by generating electricity** from the PV, Solar Thermal, and Wind components. **Emissions from construction of this alternative would eventually be offset by operation of the PV, Solar Thermal, and Wind components.**

Draft EIR/EIS Section H.6.1, page H-134, under the discussion of how the New In-Area All-Source Generation Alternative would increase the impacts compared to transmission has been revised as follows:

- Greatly increases ~~a~~ significant (Class I) air quality impact**s and climate change impacts** from operation air emissions from the power plants, peakers, and biogas/biomass facilities over the lifetime of the project (Impact AQ-3 **and AQ-4**).

Draft EIR/EIS Section H.6.2, page H-136, under the comparison of Non-Wires Alternatives has been revised as follows:

> **The Non-Wires alternatives both provide generation, but the significant climate change impact of the New In-Area All-Source Generation Alternative could be avoided by relying on In-Area Renewable Generation Alternative.** Although the New In-Area Renewable Generation Alternative would not create a significant greenhouse gas impact during operation and the New In-Area All-Source Generation Alternative would increase operational air emissions, [. . .]

Climate Change Policies and the Environmentally Superior Alternative

Comments express concern that the New In-Area All-Source Generation Alternative, which is identified as the Environmentally Superior Alternative, may conflict with AB 32 GHG emission reduction targets and other actions California is taking to manage global climate change. The Draft EIR/EIS shows that the New In-Area All-Source Generation Alternative would cause higher GHG emissions than any transmission-based alternative (for example, see Section H.6.1 and Section H.6.2 including Table H-29, and text modifications presented above), but the selection of Environmentally Superior Alternative is made by considering all environmental values, including climate change and also, for example, preserving park lands and effects on biological and cultural resources.

The GHG emissions forecasts in the Draft EIR/EIS generally show that adding new transmission in the form of the Sunrise Powerlink to California's grid along with anticipated renewable generation would not appreciably reduce GHG from power plants. This finding assumes that statewide renewables policies can be implemented with or without the Proposed Project, which is an assumption consistent with CAISO's testimony in the CPUC's Sunrise proceeding. The CAISO's work incorporates renewable generation projects in the Imperial Valley that are included in the Draft EIR/EIS as "connected actions" (e.g., Stirling Energy Systems project in Draft EIR/EIS Section B.6.1.1). As described in General Response GR-5, renewable generation connecting to any part of the California grid can be counted towards the State RPS goals. As a result, adding the transmission of Sunrise does not show a substantial reduction of GHG beyond what would occur with the new renewables. Although the CPUC proceeding on Sunrise has not yet determined whether this transmission line is needed in order for the State to meet the RPS goals, meeting the RPS goals is an important part of California's actions to reduce GHG emissions.

The New In-Area All-Source Generation Alternative that includes natural gas-fired peaker and baseload generation components would be allowed under any requirements likely to occur under AB 32. This alternative would, however, create a significant and unavoidable GHG impact of greater magnitude than the Proposed Project, as disclosed in the Draft EIR/EIS (e.g., see Section E.6.11, page E.6-179, and Table H-29 page H-154). The generation components of this alternative would replace older, more polluting power plants and would be constructed so that the delivery of baseload power would be produced at levels less than the CPUC Greenhouse Gas Emissions Performance Standard of 0.5 metric tons (1,100 lb) of CO_2 per megawatt-hour, as required under SB 1368. Therefore, these components of the alternative would be consistent with the CPUC's greenhouse gas requirements for new generation. Because there are no established criteria for assessing the climate change impacts of transmission lines, this CPUC standard has been included as part of the significance criteria for climate change impacts in the Draft EIR/EIS (see the discussion of significance criteria in Draft EIR/EIS Section D.11.4.1). Although a significant GHG impact would occur, there are no GHG laws prohibiting development of new natural gas-fired peaker or baseload generation under the New In-Area All-Source Generation Alternative; this alternative would also include in-area renewable generation to assist SDG&E in meeting the RPS goals.

The Draft EIR/EIS (Section D.11.3.3) describes other climate change policies and regulations in place at this time and considers them in the analysis of GHG impacts. The California Climate Action Team guidelines were reviewed prior to preparing the Draft EIR/EIS (see discussion in Draft EIR/EIS, page D.11-15), and only one GHG management action was found to potentially apply to the Proposed Project, related to leaks of sulfur hexafluoride (SF_6) from electrical equipment. Accordingly, the Draft EIR/EIS discloses existing efforts to manage SF_6 and recommends improving such strategies as mitigation. Regarding international policy consistency, the Draft EIR/EIS notes that building new transmission would be consistent with one of the IPCC key strategies for mitigating climate change (Draft EIR/EIS page D.11-55).

While mitigation measures to reduce or offset GHG impacts were considered for the Proposed Project and alternatives, none were available at the time of the Draft EIR/EIS that could fully mitigate the GHG impacts to a less than significant level (i.e., result in no net increase of GHG). The CPUC presently recommends that a cap-and-trade program should eventually be used to cost-effectively reduce GHG emissions from the electricity sector (as found by CPUC in Rulemaking R.06-04-009), but allowances and offset programs for carbon trading in California are still in the developmental phase. Mitigation Measures AQ-4a and AQ-4b would provide offsets for GHG pollutants, but considering current uncertainties in implementing carbon reduction strategies, the Draft EIR/EIS concludes that the impact would remain significant and unavoidable. This Final EIR/EIS includes revisions to these mitigation measures (see Responses A0013-11 and A0028-6).

In a comment on the Draft EIR/EIS, SDG&E identifies GHG emission reductions that can be created through a forestry management program, but subsequently after the close of the comment period, SDG&E does not propose any specific offsets because it contends that GHG emissions will eventually be offset by renewable energy sources that lead to reduced emissions from power plants (Data Response 27-6, filed with CPUC on May 6, 2008). Without a specific mitigation proposal or a program to offset GHG emissions, the indirect emission reductions from conventional power plants remain uncertain and the GHG impact due to this project remains as shown in the Draft EIR/EIS, significant and unavoidable.

The New In-Area All-Source Alternative is feasible and would meet most project objectives; this is why it was retained for full evaluation in the Draft EIR/EIS. While SDG&E's comment letter identifies a concern about meeting AB 32 GHG emission reduction mandates, it should be noted that the objectives stated in SDG&E's PEA do not mention AB 32 [see Section 3.1 of the PEA; Draft EIR/EIS Sections A.2.1 and Section 3.2.1.1 (Consistency with Project Objectives) of Appendix 1 of the Draft EIR/EIS]. Regardless, the New In-Area All-Source Generation Alternative would not prevent SDG&E from meeting the AB 32 GHG emissions reductions. Under the most probable, but yet undefined, future regulations implementing AB 32, the electricity sector (including power plants) could use a cap-and-trade program to reduce GHG emissions (as in the September 12, 2008 CPUC Proposed Decision in R. 06-04-009). Because existing and new power plants alike would be subject to these requirements, the emissions caused by the New In-Area All-Source Generation Alternative would be regulated to ensure reductions across the electricity sector. Renewable resources remain an essential component for reducing GHG emissions and reaching AB 32 goals, but this depends on the state achieving and expanding the current RPS program.

General Response GR-9: Fire Risk and the Comparison of Alternatives

Many commenters raised concerns about fire risk associated with the Proposed Project and alternatives. SDG&E commented that the fire risks from the Proposed Project are generally overstated in the Draft EIR/EIS, and that mitigation measures are too restrictive. This general response discusses how fires can be caused by power lines[57], how the fire and fuels modeling was performed in the Draft EIR/EIS, and how the alternatives were compared to one another with regard to fire risk. The comparison of alternatives presented in this general response provide a technical basis for the conclusions reached in Section H of the Draft EIR/EIS, and it does not change the conclusions in Section H.

Fires Caused by Power Lines

Fires can be started by power lines in the following ways:

- Vegetation contact with conductors
- Exploding hardware such as transformers and capacitors
- Floating or wind-blown debris contact with conductors or insulators
- Conductor-to-conductor contact
- Wood support poles being blown down in high winds
- Dust or dirt on insulators
- Bullet, airplane, and helicopter contact with conductors or support structures
- Other third-party contact, such as Mylar balloons, kites, and wildlife.

SDG&E data for the last four years (2004-2007) demonstrate that, of the power line ignitions in the SDG&E service area, 86 percent (89 ignitions) were distribution system ignitions, and 14 percent (15 ignitions) were transmission system ignitions. Of the transmission system ignitions, 12 were associated with 69 kV and 138 kV lines, 3 were associated with 230 kV lines, and none was associated with a 500 kV line (MGRA, 2008). Distribution system ignitions resulted in a total of 9,818 acres burned, and transmission system ignitions resulted in a total of 198,025.8 acres burned (MGRA Phase 1 Testimony, Appendix B: Power Line Fires, 2008; CAL FIRE Investigation Reports: Rice Fire; Case No. 07-CDF-572; Incident No. 07-CA-MVU-010502 and Witch Fire; Case No. 07-CDF-570; Incident No. 07-CA-MVU-10432, 2008). The large number of acres attributed to transmission system ignitions are due to the influence of the 2007 Witch Fire, which was ignited by a 69 kV SDG&E transmission line. The causes of the 15 transmission system fires include Mylar balloons contacting conductors (4), conductor-to-conductor contact (2), dust on insulators (1), static line failure due to heavy wind and corrosion (3, including two 230 kV fires), kite tail into insulators (1, a 230 kV fire), wire down due to a gun shot (1), wire down due to heavy wind (1), plane crashing into tower (1), and bird flying into conductors (1). Detailed data prior to 2004 are unavailable. (SDG&E Response to MGRA Data Request # 1, January 12, 2007; EIR/EIS Section D.15.1.1)

The energized conductors on distribution and lower-voltage transmission lines are much closer together (as close as 2 feet) compared with higher-voltage transmission lines (17 to 35 feet for 500 kV, depending on structure type; 18 to 21 feet for 230 kV, depending on structure type). Fallen or wind-blown tree limbs and debris can more easily come into contact with and bridge two distribution conductor phases[58], which can cause electrical arcs[59] that can set fire to woody debris. Because higher voltage

[57] The term “power line” is used generally to apply to all voltages.

[58] Multiple conducting wires on a single transmission or distribution line are clustered in groups of three wires that carry currents alternating at different phases.

transmission line conductors are spaced much further apart, this phenomenon is extremely rare on 230 and 500 kV transmission lines. Arcing from a single conductor to ground through vegetation contact can also occur, but conductors are generally much further from the ground than they are from one another, and therefore arcing between conductor phases is more likely than between a conductor and the ground. System component failures and accidents during maintenance activities can cause line faults that result in fires on transmission lines of any voltage, depending on system components. Examples are static line failure due to high winds and corrosion at the point of attachment, insulator flashovers during washing, guy wire failure and subsequent conductor contact, broken crossarms causing conductor-to-conductor contact, and pole or tower collapse. (SDG&E response to CPUC Data Request #24, April 3, 2008; EIR/EIS Section D.15.1.1)

Transmission lines at voltages of 69 kV are subject to conductor-to-conductor contact, also known as "mid-line slap" hazard, which occurs when extremely high winds force two conductors on a single pole to oscillate so much that they contact one another. This can result in sparks that can ignite nearby vegetation. Transmission lines at this voltage are often supported by wood poles, which can typically withstand a lower level of wind loading compared with steel monopoles and lattice steel towers. Wood poles have a higher potential for structural failure during extreme wind events like Santa Ana events. Multiple wood pole failures on a single 69 kV line can result in conductors contacting the ground and igniting nearby vegetation or the wood poles themselves. (EIR/EIS Section D.15.1.1)

While gunshots have also been a cause of power line ignitions, they are more likely to affect distribution and lower voltage transmission lines than higher voltage transmission lines. Support structures for distribution-level and lower voltage transmission lines are shorter (typically 50-80 feet) than high voltage transmission lines (typically 120 feet for 230 kV and 150 feet for 500 kV). Thus, the insulators on the lower poles make easier targets for vandals than those on high-voltage lines. In addition, steel conductors on high voltage lines have much greater structural integrity than lower voltage transmission conductors, making them less susceptible to harm in the event of a gunshot. Typical 230 kV and 500 kV conductors have circumferences at least three times greater than a typical 69 kV conductor (300 kcmil[60] for 69 kV vs. 900 kcmil for 230 kV and 1033.5 kcmil for 500 kV), with a correspondingly greater strength. (EIR/EIS Section D.15.1.1)

Other ignition sources that are associated with power lines of any voltage, including high-voltage transmission lines, may include airborne debris (Mylar balloons, kites) coming into contact with conductors or insulators, dust or dirt on insulators, and accidents related airplanes and helicopters coming into contact with conductors, poles, and towers. (EIR/EIS Section D.15.1.1)

Line Faults

Transmission line protection and control systems are designed to detect faults (such as arcing from debris contacting the line) and rapidly shut off power flow in 1/60 to 3/60 of a second. Distribution systems are designed to be more tolerant to line faults. In an effort to "keep the lights on," distribution line protection and control systems allow faults to last longer and are sometimes set to automatically re-energize a faulted line after a very brief delay (a second or so) in the event that the fault has cleared. If

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59 Electrical arcing is an electric discharge that occurs when electrons are able to jump a gap in a circuit, which often results in a display of sparks.

60 Kcmil (1000 cmils) is a quantity of measure for the size of a conductor; kcmil wire size is the equivalent cross-sectional area in thousands of circular mils. A circular mil (cmil) is the area of a circle with a diameter of one thousandth (0.001) of an inch.

a fault is related to debris tangled in the conductors, immediate re-energizing can cause repeated sparks and ignite nearby vegetation. Because higher voltage lines are designed to be more sensitive to faults, they are typically mounted on very tall structures to provide adequate distance from vegetation. (EIR/EIS Section D.15.1.1)

Distribution lines are mounted with devices, such as transformers and capacitors, that may fail in an explosive manner resulting in an ignition of nearby vegetation. Transmission lines are not mounted with these devices because transmission lines are not used to directly serve customer loads. (EIR/EIS Section D.15.1.1)

On a per-mile basis, annual ignition rates are similar for distribution lines and transmission lines in SDG&E's territory. Table GR.9-1 presents a comparison between SDG&E's distribution and transmission system fault and ignition rates. Although there have been no reported 500 kV related fires in SDG&E's system since 2004, the fault rate for 500 kV lines is about half that of 230 kV lines, meaning 500 kV lines have been approximately half as likely as 230 kV lines to experience physical events that could have resulted in ignitions. None resulted in an actual ignition in the four years for which data are available. (EIR/EIS Section D.15.1.1) In addition, only a single 500 kV-related ignition has been documented as having occurred anywhere in the United States. The fire was not caused by a system component failure but by a large tree falling on the transmission line, an event that could be mitigated through proper vegetation management. (NERC: Vegetation-Related Transmission Outages, Third Quarter 2005, December 21, 2005)

Table GR.9-1. SDG&E System Fault and Ignition Rates

System	Faults/ 100 miles/year[a]	Ignitions/ 100 miles/year[b]
Distribution	Unavailable	0.3
Transmission	1.5	0.2
69/138 kV	1.9	0.3
230 kV	0.7	0.2
500 kV	0.4	0

Source: SDG&E Response to MGRA Data Request # 1, January 12, 2007; MGRA, Appendix 2D: Power Line Fires. Phase 2 Direct Testimony on the Sunrise Powerlink Transmission Line Project. March 12, 2008.

[a] Years 1998-2006.

[b] Years 2004-2007.

SDG&E's data dispute the commonly cited idea that distribution lines are far more likely to cause fires than high-voltage transmission lines, as the ignition rates for the distribution system and the 230 kV transmission system in SDG&E's territory are similar. Nonetheless, there is little evidence that 500 kV transmission lines pose a similar hazard.

Wind as a Cause of Power Line Fires

Both distribution and transmission systems are designed to withstand high winds, and it is extremely rare for higher-voltage transmission structures to blow over. When this rare event does occur, the protection system on a transmission line is designed to shut off power flow in a fraction of a second. However, a fraction of a second can be enough time for an energized conductor to cause sparks and ignite nearby vegetation.

Distribution structure failures are also infrequent, but due to their placement in narrower corridors in close proximity to trees and other tall vegetation, they may be pushed down in storms by wind-blown trees. Assisted by high winds, power line ignitions have caused four of the 20 largest wildfires (measured by acreage burned) in California's history from 1932 to 2007 (CAL FIRE, 2006, 2008). Three of these occurred in SDG&E territory. These fires were the Witch (2007), Laguna (1970), Campbell Complex (1990), and Clampitt (1970) fires. Power lines have been responsible for four of the State's 20 largest wildfires measured by the number of structures destroyed, including the Witch, City of Berkeley (1923), Laguna, and Rice fires. Three of these occurred in SDG&E territory. In the case of the Clampitt Fire, high winds blew down a section of the distribution line, and the Laguna and Campbell Complex Fires were ignited when trees fell across the distribution lines. A detailed investigation report into the cause of the Witch, Guejito, and Rice Fires issued by CAL FIRE July 9, 2008 explains that the cause of the Witch Fire was an SDG&E 69 kV transmission line, the cause of the Guejito Fire (which ultimately merged with the Witch Fire) was a combination of an SDG&E 12 kV distribution line and a Cox Communications cable television line, and the cause of the Rice Fire was an SDG&E 12 kV distribution line in combination with a failure to adequately maintain vegetation around the distribution line in accordance with Public Resources Code 4293. A subsequent investigation report into the cause of the Witch, Guejito, and Rice Fires issued by CPUC's Consumer Protection and Safety Division (CPSD) on September 2, 2008 generally supports CAL FIRE's findings, and further stating that Cox Communications was in violation of GO 95 Rules 31.1 and 31.2 at the time of the Guejito Fire (no violation was cited for SDG&E for this fire), SDG&E was in violation of GO 95 Rules 31.1 and 38 at the time of the Witch Fire, and SDG&E was in violation of GO 95 Rule 31.1 at the time of the Rice Fire.

Wildlife as a Cause of Power Line Fires

Wildfires related to power lines can also be ignited by wildlife contact with conductors and insulators, primarily large birds. Bird-related flashovers[61] are possible on low-voltage distribution and transmission lines where conductors are closely spaced. Birds perched on power poles or flying between poles can simultaneously contact two conductors, causing an electrical flashover. This electrocutes the bird and can cause the feathers to catch fire. The bird may fall to the ground and ignite nearby vegetation. However, bird-caused flashovers are highly unlikely for the Proposed Project and transmission alternatives, which include energized 500 kV conductors at minimum distances of 17.3 vertical feet and 18 horizontal feet apart and 230 kV conductors at minimum distances of 18 vertical feet and 19 horizontal feet apart. These distances are at least 9.3 feet greater than the wingspan of the largest bird species in the project vicinity (see EIR/EIS Section D.2, Impact B-10 for a complete discussion of the risk of bird electrocutions).

Humans as a Cause of Power Line Fires

Ignition threats associated with higher-voltage transmission lines like the 230 kV and 500 kV Proposed Project are both direct, including sparks caused by component failures and wind-blown debris contact, and indirect, including human-caused accidents during construction and maintenance activities and as a result of increased access to wildlands. Construction and maintenance activities that may ignite fires include blasting, the use of equipment such as chainsaws, and the presence of personnel who may inadvertently ignite fires while smoking. The introduction of transmission line access roads can provide increased access to wildlands by members of the public, which may increase ignitions from smoking, campfires, and arson. Failure to trim or remove trees located very close to transmission line conductors can result in wildfire ignitions when trees or branches are blown onto conductors. (EIR/EIS Section D.15.1.1)

Hardware as a Cause of Power Line Fires

New SDG&E data on 230 kV transmission line fires have become available since publication of the Draft EIR/EIS, presenting a more complete picture of the role of inadequate transmission system inspections in the cause of fires[62]. There have been three 230 kV-ignited fires in the last four years (2004-2007), one of which was related to a kite tail becoming entangled in the insulators and arcing

61 A flashover is an unintended electric arc.

62 SDG&E response to CPUC Data Request #24, April 3, 2008.

across conductor phases. Two of the 230 kV system fires were the result of static line (shield wire) failure due to corrosion at the point of attachment in combination with high winds. In both cases, inspections had been performed within nine months of wire failure. Inspections ought to have been sufficient to detect the corrosion problem that twice in four years has resulted in fire, and it has become clear that ground, helicopter, and infrared patrols are insufficient means of detecting fire threats of high-voltage lines. As a result of these new data, a new mitigation measure has been developed to address this threat, and it has been applied to Impact F-2 in all Fire and Fuels Management sections in the Final EIR/EIS, and presented here:

F-2c **Perform climbing inspections.** The Applicant shall perform climbing inspections on 10 percent of project structures annually, such that every project structure has been climbed and inspected at the end of a 10-year period, for the life of the project. In addition, SDG&E shall keep a detailed inspection log of climbing inspections, and any potential structural weaknesses or imminent component failures shall be acted upon immediately. The inspection log shall be submitted to CPUC for review on an annual basis.

This mitigation measure will improve the detection rate of imminent component failures that could result in wildfire ignitions, leading to a reduced rate of wildfire ignitions from the Proposed Project and alternatives compared with high-voltage lines in the rest of SDG&E's system. Although implementation of Mitigation Measure F-2c will substantially reduce the number of project-related ignitions for the life of the project, Impact F-2 remains significant and unavoidable in all firesheds despite implementation of Mitigation Measure F-2c because ignition threats from floating debris and other-third party contact remain.

Fire and Fuels Modeling

Numerous individuals and groups noted that wind-driven wildfires in San Diego County have the tendency to be much larger than the potential burn areas shown in the Fire Behavior Trend Modeling analysis and figures that are presented in Section D.15 of the Draft EIR/EIS. Two 12-hour burn periods were used to simulate biophysical wildfire behavior during Santa Ana winds; beyond two burn periods, fire behavior would be influenced by firefighter suppression response, human features on the landscape, and localized weather patterns that would render the output of the biophysical model less robust. It should be noted, however, that major events often burn longer than two 12-hour burn periods, and therefore, during extreme fire weather, the extent of a wildfire could be greater and the shape of the fire perimeter could be different than simulated. The extent of a wildfire could also be smaller than modeled, due to potential future differences in fuel moisture content, fuel loads, wind speeds, and landscape features than what was assumed in modeling.

In order to evaluate the potential differences in wildfire risk among the environmentally superior routing alternatives based on a longer burn time, the Fire Behavior Trend model was run for four burn periods (twice as long as the model runs presented in the Draft EIR/EIS) for the Final Environmentally Superior Northern Route, the Final Environmentally Superior Southern Route, the LEAPS Project Alternatives, and the Proposed Project (which is nearly identical to the SDG&E "Enhanced" Northern Route Alternative for purposes of fire behavior modeling). A visual presentation of the Fire Behavior Trend model results for these complete routes are presented in Appendix 3E. A discussion of the results of these new models is presented in below under the heading "Comparison of Alternatives from a Fire and Fuels Perspective."

The EIR/EIS relies on fire behavior modeling based on biophysical characteristics of the landscape, including fuel loading. Field-based fuel load inventories were carried out during 2006 and 2007. MGRA (comment B0006-17) claimed that the EIR/EIS fuel inventory performed in the area burned by the 2003 Cedar Fire would bias the fire behavior models because fuel loads were sampled during an atypical year and were uncharacteristically low as a result of the recent Cedar Fire. MGRA suggested that this unfairly penalizes the southern alternatives that had heavier fuel loads at the time of inventory, causing the northern alternatives to appear less hazardous and the southern alternatives to appear more hazardous. MGRA suggested making an "adjustment" to the fuel load input of the fire behavior models to account for this bias. MGRA's claim assumes that older chaparral is associated with higher burn intensity; however, this is not borne out by research. Paysen and Cohen[63] found no relationship between the age class of a chaparral stand and its burn potential (measured as a percent of dead/decadent vegetation), and they noted that other interacting factors including climatic variation, insects, and disease may strongly affect burn potential. Research by Keeley and others[64] also found that large fires are not dependent on old age classes of chaparral fuels. Drought conditions, which have characterized southern California over the last decade, create extremely low fuel moistures that increase burn potential (CAL FIRE, 2008). Therefore, although the models used in the EIR/EIS were based on actual, post-Cedar fuel loads, this approach should not bias the northern alternatives.

Approximately 127,000 acres re-burned in San Diego County during the 2007 firestorm, just four short years after the Cedar Fire. This includes nearly 57,000 acres within the Witch/Poomacha perimeter and nearly 30,000 acres within the Harris perimeter. The fact that so many acres burned twice in four years indicates that chaparral stands burned as recently as four years prior can and do re-burn at high intensities and at great geographical extents. It should not be assumed that the normal state of San Diego chaparral stands is a 20- or 30-year-old climax state, especially with increased human influence throughout southern California wildlands over several decades and the correlated shortening of the interval between large fires.

In many cases, mathematical models of the natural world are our best means of predicting the potential outcome of future events. However, it is difficult for models to predict certain influential factors, such as what a "normal" burn interval might be in the future and certain climatic, insect, or disease conditions that might characterize future chaparral stands in San Diego County. These factors themselves depend on a number of complex influences, including: policy decisions about development in the Wildland-Urban Interface, natural and human-influenced climatic variation and change, and natural and human-influenced prevalence of insects and disease. Thus, a mathematical model's prediction is not a certainty. The fire models presented in the EIR/EIS are based on defensible assumptions and a uniform sampling protocol, and any modifications to the modeling inputs would introduce bias into the results. No change to the model inputs is warranted.

Comparison of Alternatives from a Fire and Fuels Perspective

Several individuals and groups commented that a comparison of the number of significant, unavoidable (Class I) wildfire-related impacts, as presented in Section H of Volume 6 of the Draft EIR/EIS, is not adequate to make a meaningful comparison between the alternative transmission alignments. Some commenters noted that the quantitative nature of the analysis performed throughout the Fire and Fuels Management sections of the Draft EIR/EIS would easily lend itself to a quantitative comparison of alternatives. Others performed a quantitative comparison between routes using several of the metrics presented in the Draft EIR/EIS.

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[63] Paysen, Timothy E and Jack D. Cohen. 1990. Chamise Chaparral Dead Fuel Fraction Is Not Reliably Predicted by Age. West J. Appl. For. 5(4):00-00, October.

[64] Keeley, Jon E., C. J. Fotheringham, Marco Morais. 1999. Reexamining Fire Suppression Impacts on Brushland Fire Regimes. Science 284(5421): 1829-1832, June.

The comparison of alternatives in Section H considered not only wildfire-related impacts, but impacts in every resource area. The EIR/EIS compares the number of Class I impacts among alternatives only to demonstrate high-level conclusions of the EIR/EIS. Preference for one alternative over another was primarily based on the detailed technical analysis in the Fire and Fuels Management sections and other resources sections.

In order to clarify how the conclusions presented with regard to fire risk are reached in Section H, a comparison of the quantitative measures of fire-related impacts, as modeled in the Fire and Fuels Management Sections of the EIR/EIS, is presented in Table GR.9-2, below (2 Burn Periods). In addition, the number of assets at risk based on a longer burn time is also presented, for the reasons discussed above in Table GR.9-3 (4 Burn Periods). For convenience, SDG&E's "Enhanced" Northern route, as presented in the RDEIR/SDEIS, the LEAPS Project Alternatives, and the Final Environmentally Superior Northern and Southern routes are also compared. Because the Final Environmentally Superior Northern and Southern routes are different than the Environmentally Superior Southern route evaluated in Section H of the Draft EIR/EIS, the conclusions presented in Section H in the Final EIR/EIS have also changed.

Table GR.9-2. Fire and Fuels Comparison of Alternatives (2 Burn Periods)

		A	B	C		D		E	F
Route		Overhead through High-Risk Fuels (miles)[a]	High/Very High Burn Probability (miles)	Assets at Risk: Normal Weather		Assets at Risk: Extreme Weather		Firefighting conflict (miles)	Fire reliability (number outages)[b]
				Homes	Acres	Homes	Acres		
Final Environmentally Superior Northern	230 kV	23	17	200	10,000	400	50,000	11.5	2
	500 kV	0	2	0	0	0	0		
Final Environmentally Superior Southern	230 kV	23	10	60	8,000	480	31,000	8	5
	500 kV	62	20	110	27,000	820	137,000		
LEAPS Alternatives	230 kV	8[c]	0	0	0	0	0	2	3
	500 kV	32	12.5	300	19,000	650	99,000		
SDG&E "Enhanced" Northern	230 kV	56	16.5	760	13,000	1,110	70,000	14.5	2
	500 kV	21	2.5	10	6,000	20	44,000		

[a] The number of miles of overhead transmission line through High and Very High Fire Severity Zones as identified by CAL FIRE, 2006.
[b] The number of outages that would have occurred concurrently with SWPL from 1970 to 2007, using MGRA Phase 2 Rebuttal testimony methodology excluding "Type 3" outages.
[c] The calculation for the LEAPS Transmission-Only Alternative doesn't include the 51 miles of Talega-Escondido upgrades, except for the approximately 8 miles of relocated 69 kV circuit, due to the nature of the upgrades that would result in a small increase in project-related ignitions over baseline environmental conditions for the life of the project.

Table GR.9-3. Fire and Fuels Comparison of Alternatives (4 Burn Periods)

		A	B	C		D		E	F
Route		Overhead through High-Risk Fuels (miles)[a]	High/Very High Burn Probability (miles)	Assets at Risk: Normal Weather		Assets at Risk: Extreme Weather		Firefighting conflict (miles)	Fire reliability (number outages)[b]
				Homes	Acres	Homes	Acres		
Final Environmentally Superior Northern	230 kV	23	17	400	20,000	770	72,000	11.5	2
	500 kV	0	2	0	0	0	0		
Final Environmentally Superior Southern	230 kV	23	10	150	16,000	560	37,000	8	5
	500 kV	62	20	180	36,000	820	161,000		
LEAPS Alternatives	230 kV	8[c]	0	0	0	0	0	2	3
	500 kV	32	12.5	430	29,000	720	106,000		
SDG&E "Enhanced" Northern	230 kV	56	16.5	1,200	26,000	1,430	95,000	14.5	2
	500 kV	21	2.5	20	11,000	20	57,000		

[a] The number of miles of overhead transmission line through High and Very High Fire Severity Zones as identified by CAL FIRE, 2006.
[b] The number of outages that would have occurred concurrently with SWPL from 1970 to 2007, using MGRA Phase 2 Rebuttal testimony methodology excluding "Type 3" outages.
[c] The calculation for the LEAPS Transmission-Only Alternative doesn't include the 51 miles of Talega-Escondido upgrades, except for the approximately 8 miles of relocated 69 kV circuit, due to the nature of the upgrades that would result in a small increase in project-related ignitions over baseline environmental conditions for the life of the project.

A. Miles Through High-Risk Fuels. The number of miles of overhead transmission line through high-risk fuels, in accordance with CAL FIRE's Fire Hazard Severity Zone maps, is one measure of the probability of project-related ignitions. SDG&E fault and ignition data (1998-2006 and 2004-2007, respectively) indicates that 230 kV transmission lines in its system have a fault rate that is nearly twice that of 500 kV lines. The 230 kV system has experienced an ignition rate of approximately 0.2 fires per 100 miles per year and the 500 kV system has experienced an ignition rate of zero over four years. In addition, SDG&E's 500 kV system has never been the reported cause of a fire, and only a single 500 kV fire has been documented anywhere in the U.S. Therefore, the length of 230 kV transmission line through high-risk fuels may be weighted more heavily than the length of 500 kV line in a fire risk comparison between alternatives; un-weighted values are presented in the tables above, however values for 500 kV lines are shaded in gray to denote their lesser importance in overall risk.

B. Burn Probability. Another measure of the probability of project-related ignitions is the number of miles of overhead and underground segments located in areas with High and Very High burn probability, as measured by the EIR/EIS Burn Probability Model. Ignitions originating from the transmission line would be more likely to carry a fire and be more difficult to contain in areas of high and very high burn probability.

C and D. Assets at Risk. The number of assets at risk during normal and extreme weather, as measured by the EIR/EIS Fire Behavior Trend Model, represents the number of homes and acres potentially at risk in two burn periods and four burn periods[65]. Similar to the rationale above, assets at risk

[65] The number of assets at risk presented in the table were estimated through the Fire Behavior Trend model described in EIR/EIS Section D.15.4.3. The model uses actual vegetation cover and simulates burn behavior from random ignitions within the border zone (one ignition/50 acres) under both normal and extreme weather conditions and normal and extreme fuel moisture levels. The model was run for two burn periods (each burn period is 2 hours during normal weather and 12 hours during extreme weather) for the Draft EIR/EIS, but

from the 230 kV transmission system may be weighted more heavily than the assets at risk from the 500 kV system based on the ignition history of each system; again, un-weighted values are presented in the tables above, however values for 500 kV lines are shaded in gray to denote their lesser importance in overall risk.

E. Firefighting Conflicts. The number of miles of significant conflicts with fire suppression efforts, as measured by the EIR/EIS Wildfire Containment Conflict Model, is a measure of the long-term interference with firefighting operations presented by each transmission alignment.

F. Reliability. Finally, the fire-reliability number is a measure of the number of times each transmission line would have been out of service concurrently with the Southwest Powerlink (SWPL) due to fire between 1970 and 2007. This is a measure of probable concurrent outages in the past, and is not necessarily a representative prediction of the future. Concurrent outage with SWPL is a continuing concern of SDG&E and the CAISO for a Southern Route Alternative because of the proximity of these routes to one another. However, because of the extreme fire-prone characteristics of San Diego County and other southern California counties, northern routes are also subject to concurrent outages with SWPL even though they are not collocated.

Comparison Conclusion

Based on the reasonable assumption characterized above that 230 kV lines pose a far greater ignition risk than 500 kV lines, the Final Environmentally Superior Northern and Southern Routes are roughly equivalent in terms of assets at risk and miles of overhead transmission line through high-risk fuels based on two burn periods (Table GR-9.2). The LEAPS Alternatives are the least risky in these categories, and the SDG&E "Enhanced" Northern Route is the riskiest. Based on a longer-burning fire (Table GR-9.3), the Final Environmentally Superior Northern Route is somewhat more hazardous than the Southern Route in terms of assets at risk, LEAPS Alternatives are the least risky, and the SDG&E "Enhanced" Northern Route is once again the riskiest. An explanation for the drastically increased risk of the Final Environmentally Superior Northern Route and the SDG&E "Enhanced" Northern Route when a longer burn time is modeled is that the fuels recently burned along the northern alternatives in the 2003 Cedar Fire contain less dead and decaying matter than the fuels along the southern alternatives, and these fuels with a higher living matter content tend to burn cooler and slower than fuels with a greater concentration of dead and decaying matter. Recall that the fuels inventories that are

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Table GR.9-3 represents the outcome of four burn periods in an effort to simulate fires of longer duration like the Cedar Fire of 2003 and the Witch Fire of 2007. The Burn Probability Model therefore predicts how ignitions related to project construction, operation, and maintenance would affect the extent of fire damage by simulating wildfire behavior based on actual biophysical conditions in the vicinity of the transmission line. The model generates an estimate of the number of acres that would burn if multiple simultaneous ignitions occurred along the length of the transmission corridor. Fuel characteristics were inventoried within and slightly beyond the firesheds as defined in the EIR/EIS Section D.15, and therefore the fire behavior simulations do not go much beyond the fireshed boundaries. This is a limitation of the model. In addition, because large fires are often sparked by just one or two ignition sources, the outcome of the Burn Probability Model is unrealistic, as the transmission line would never be the cause of simultaneous ignitions along the entire length of the corridor. However, simulating multiple ignitions along the length of the transmission line was the only means of identifying the varying risk of individual segments of the line, and it provides a useful comparison of the relative risk of various routing alternatives. The number of assets at risk was calculated by identifying the number of residential parcels ¼ acre or less with an improved structure worth $10,000 or more that lay within the Fire Behavior Trend Model fireshed burn area. It was assumed that structures that met these criteria were probably homes. Homes that are located beyond the boundaries of the firesheds as defined in the EIR/EIS Section D.15 were not assessed.

the basis of the Fire Behavior Trend Model were carried out prior to the 2007 firestorm that burned large areas in the vicinity of both the northern and southern alternatives.

The SDG&E "Enhanced" Northern Route presents the greatest conflict with firefighting operations, followed by the Final Environmentally Superior Northern Alternative. The LEAPS Alternatives present the fewest firefighting obstacles, followed by the Final Environmentally Superior Southern Route. In terms of reliability, based on wildfire history, the northern routes are more reliable than the LEAPS Alternatives or the southern route, which is the least reliable from a wildfire history perspective. While past experience suggests that a concurrent outage is more likely to occur with construction of the Environmentally Superior Southern Route, the projected range of such concurrent outages is consistent with WECC reliability criteria and was recognized and found acceptable by the Reliability Work Group[66].

Overall, this analysis reveals that each transmission alignment presents serious fire risks, that the LEAPS Alternatives are the least risky, that the SDG&E "Enhanced" Northern Route is the riskiest, and the Final Environmentally Superior Northern and Southern Routes are roughly equivalent, except with regard to firefighting conflict where the northern route is riskier and reliability where the southern route is riskier.

66 Only three sets of collocated high-voltage transmission lines in California have a higher Category D rating. A Category C line is acceptable to meet reliability standards as it is the standard throughout California. For details on the WECC reliability rating assigned to the northern and southern routes, see SDG&E's December 19, 2007 Performance Category Upgrade Request to the WECC's Reliability Performance Evaluation Work Group (RPEWG) and the RPEWG's January, 2008 recommendation.

General Response GR-10: Electric and Magnetic Fields (EMF)

Many commenters were concerned about the public health effects of EMF from transmission lines as they relate to the Proposed Project and alternatives. The Draft EIR/EIS addresses EMF in Section D.10.20 as it pertains to 230 kV and 500 kV transmission lines. This response includes the following topics:

- Approach to EMF Assessment and Studies about EMF Health Impacts
- Levels of EMF Exposure
- Methods to Reduce Magnetic Fields

Approach to EMF Assessment and Studies about EMF Health Impacts

The CPUC and BLM recognize that there is a great deal of public interest and concern regarding potential health effects from exposure to electric and magnetic fields ("EMF") from power lines. To address public concerns about EMF, the EIR/S provides information regarding EMF associated with electric utility facilities and the potential effects of the Proposed Project and the Alternatives related to public health and safety. Section D.10.21 in Volume 3 of the Draft EIR/EIS summarizes the results of scientific review panels that have considered the body of EMF health effects research. As the EIR/EIS explains, potential health effects from exposure to electric fields from power lines is typically not of concern since electric fields are effectively shielded by materials such as trees, walls, etc. Therefore, the information in Section D.10 of the EIR/EIS related to EMF focuses primarily on exposure to magnetic fields from power lines. However it does not consider magnetic fields in the context of CEQA, NEPA, or the determination of environmental impacts. This is because there is no agreement among scientists whether exposure to EMF creates a potential health risk and because there are no defined or adopted CEQA or NEPA standards for defining health risk from EMF. The correlation between proximity to high voltage power lines and increased leukemia and other cancer rates has been found to be true in some scientific studies and is supported by anecdotal evidence, but has not been found to be true in other studies nor has it been proven in laboratory experiments.[67] As a result, EMF information is presented in response to public interest and concern. Disclosure of such information is consistent with the EIR/S's role as "an informational document." (Pub. Res. Code § 21061; see also 42 U.S.C. § 4321.)

For more than 20 years, questions have been asked regarding the potential effects within the environment of EMFs from power lines. Early studies focused primarily on interactions with the electric fields from power lines. In the late 1970s, the subject of magnetic field interactions began to receive additional public attention and research levels increased. A substantial amount of research into the health impacts of electric and magnetic fields has been conducted over the past several decades; however, much of the body of national and international research regarding EMF and public health risks remains contradictory and inconclusive.

In 1993, the CPUC implemented decision D.93-11-013[68] that requires the utilities use "low-cost or no-cost" mitigation measures[69] for facilities requiring certification under General Order 131-D.[70] This

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[67] Rob Smerling, Harvard Health Publications. *Power lines and your health.* 2008. http://health.msn.com/health-topics/cancer/articlepage.aspx?cp-documentid=100202335&page=2 May, 2008.

[68] http://www.cpuc.ca.gov/Environment/emf/emfopen.htm. Accessed May 2008.

[69] The mitigation measures discussed here are precautionary in nature and are not "mitigation measures" within the context of CEQA or NEPA.

[70] General Order 131-D is entitled "Rules Relating to the Planning and Construction of Electric Generation, Transmission/Power/Distribution Line Facilities and Substations Located in California."

decision is precautionary in nature and was implemented in recognition that "[i]n the absence of a final resolution of the question of such impact…the best response to EMFs is to avoid unnecessary new exposure to EMFs if such avoidance can be achieved at a cost which is reasonable in light of the risk identified." (52 CPUC2d 1, 2.) The decision directed the utilities to use a four percent benchmark on the low-cost mitigation. The decision also implemented a number of EMF measurement, research, and education programs, and provided the direction that led to the preparations of a DHS study described in Section D.10.21.

Most recently the CPUC issued Decision D.06-01-042[71], on January 26, 2006, affirming the low-cost/no-cost policy to mitigate EMF exposure from new utility transmission and substation projects. This decision also adopted rules and policies to improve utility design guidelines for reducing EMF. The CPUC stated "at this time we are unable to determine whether there is a significant scientifically verifiable relationship between EMF exposure and negative health consequences." The CPUC has not adopted any specific limits or regulation on EMF levels related to electric power facilities.

Many comments referenced the BMJ article titled "Childhood cancer in relation to distance from high voltage power lines in England and Wales: a case-control study."[72] The BMJ document states that there is "an association between childhood leukemia and proximity of home address at birth to high voltage power lines." The article further states that while there is an association between childhood leukemia and proximity of house at birth, causality has not been proven and any estimation of the percentage of leukemia caused by high voltage line proximity has considerable statistical uncertainty. The relationship may be due to chance or confounding[73]. The article concludes that there is no satisfactory explanation for the results of the experiments in terms of causation and that the association found in this and other studies has not been supported by laboratory data of an accepted biological mechanism.

As stated in the article "Power Lines and Your Health," encounters with electric and magnetic fields occur on a daily basis and it is still not possible to say with certainty if these impacts are negative, positive or negligible.[74] Reports from major research centers in at least nine countries have come to similar conclusions that there is no compelling evidence of any health hazard from power lines and that if power lines do have any effect on human health, it is small. They do, however, support continued research to look for even small effects on health.

Levels of EMF Exposure

Section D.10.22.1 in Volume 3 of the Draft EIR/EIS presents the estimated EMF levels from SDG&E's Proposed Project. For the proposed overhead 500 kV line configuration, magnetic fields are shown as ranging from 24 to 68 milliGauss (mG) on the left side of the ROW and from 23 to 70 mG on the right side of the ROW. For the proposed overhead 230 kV line configuration, magnetic fields are shows as ranging from 2 to 46 mG on the left side of the ROW and from 2 to 62 mG on the right side of the ROW. Tables D.10-24 and D.10-25 show the estimated magnetic field levels for the proposed 500 kV segments and 230 kV segments respectively.

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[71] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/53181.htm Accessed May 2008.

[72] Draper, Gerald, et al., *Childhood cancer in relation to distance from high voltage power lines in England and Wales: a case-control study*(2005) http://www.bmj.com/cgi/reprint/330/7503/1290. Accessed March 2008.

[73] Ibid., page 2.

[74] Rob Smerling, Harvard Health Publications. *Power lines and your health.* 2008. http://health.msn.com/health-topics/cancer/articlepage.aspx?cp-documentid=100202335&page=2 May, 2008.

The public routinely experiences exposure to EMF in the community from sources other than electric transmission lines and substations. Research on ambient magnetic fields in homes and buildings in several western states found average magnetic field levels within most rooms to be approximately 1 mG, while in a room with appliances present, the measured values ranged from 9 to 20 mG (Severson et al., 1988, and Silva, 1988). Immediately adjacent to appliances (within 12 inches), field values are much higher, as illustrated in Tables D.10-21 and D.10-22 in Volume 3 of the EIR/EIS and can range from 3 to 20,000 mG. These tables indicate typical sources and levels of electric and magnetic field exposure the general public experiences from appliances.

Outside of the home, the public also experiences EMF exposure from the electric distribution system that is located throughout all areas of the community. Estimates of the magnetic field exposures to the public from overhead 12.5 kV distribution lines range from 22mG directly below the lines, to 8 mG at 40 feet from the lines, and 2 mG at 100 feet from the lines. In areas of underground distribution, which typically occurs in residential areas, the 12.5 kV circuits are not buried as deeply as transmission lines, and are not arranged to optimize field cancellation. The estimated fields for underground distribution lines range from 31 mG directly above the line, 4 mG 40 feet from the line, and 1.9 mG 100 feet from the line.[75]

Methods to Reduce Magnetic Fields

As discussed in Section D.10.21 in Volume 3 of the Draft EIR/EIS, magnetic fields can be reduced either by cancellation or by increasing distance from the source. Cancellation is achieved in two ways. A transmission line circuit consists of three "phases": three separate wires (conductors) on a transmission tower. The configuration of these three conductors can reduce magnetic fields. First, when the configuration places the three conductors closer together, the interference, or cancellation, of the fields from each wire is enhanced. This technique has practical limitations because of the potential for short circuits if the wires are placed too close together. There are also worker safety issues to consider if spacing is reduced. Second, in instances where there are two circuits (more than three phase wires), such as in some 230 kV portions of the Proposed Project, cancellation can be accomplished by arranging phase wires from the different circuits near each other. In underground lines, the three phases are typically much closer together than in overhead lines because the cables are insulated (coated), but field cancellation still occurs.

The distance between the source of fields and the public can be increased by either placing the wires higher aboveground, burying underground cables deeper, or by increasing the width of the ROW. For transmission lines, these methods can prove effective in reducing fields because the reduction of the field strength drops rapidly with distance.

SDG&E's Proposed EMF Mitigation

In accordance with CPUC Decisions D.93-11-013 and D.06-01-042, SDG&E evaluated "no-cost" and "low-cost" magnetic field reduction steps for the proposed transmission and substation facilities for facilities requiring certification under General Order 131-D.[76] Appendix 7 (Field Management Plan) presents details of the EMF Plan proposed by SDG&E. The final plan would be prepared and implemented if the CPUC approves a line option in a decision. This decision could include certain specific requirements for the final EMF Plan based on consistency with the adopted SDG&E EMF Guidelines.

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75 Washington State Department of Health. *Electric and Magnetic Field Reduction: Research Needs.* January, 1992.

76 General Order 131-D is entitled "Rules Relating to the Planning and Construction of Electric Generation, Transmission/Power/Distribution Line Facilities and Substations Located in California."

Specific measures to reduce EMF which SDG&E has proposed in its plan for inclusion in the Proposed Project are summarized below:

Central Substation

- Keep electrical equipment as compact as possible, locating high current devices such as transformers, capacitors and reactors away from the fence.
- Orient buses and cables so that parallel runs are as far from property lines as practical.
- Restrict public access to the area around the substation.

500 and 230 kV Transmission Lines

- Locate lines closer to the centerline of the utility corridors.
- Combine existing transmission circuits onto the same structure as the Proposed Project.
- Arrange phases of different circuits to reduce magnetic fields when multiple circuits are located on the same structure or in the same underground ductbank.

General Response GR-11: Transmission Line Effects on Property Values

Several commenters have expressed concern about the effect of the Proposed Project and/or alternatives on property values. A full discussion of operational impacts on property value, including a literature review, can be found in Section D.14.5 (Imperial Valley Link Impacts and Mitigation Measures) under Impact S-5 (Presence of the project would decrease property values). An analysis of property value impacts for every link of the Proposed Project and every alternative is also included under Impact S-5 in the Socioeconomics, Services, and Utilities issue area.

The CPUC has used a literature-review approach in addressing concerns regarding property values in four recent transmission line EIRs. Claims of diminished property value through decreased marketability are based on the reported concern about hazards to human health and safety and increased noise, traffic, and visual impacts associated with living in proximity to unwanted land uses such as power plants, freeways, high voltage transmission lines, landfills, and hazardous waste sites. Studies cited in "A Primer on Proximity Impact Research: Residential Property Values Near High-Voltage Transmission Lines" (Kinnard and Dickey, 1995) show three possible effects have been claimed, singly or in combination:

- **Diminished Price,** which is identified by comparing prices of units that are proximate to power lines with prices of similar and competitive properties more distant from power lines.
- **Increased Marketing Time –** Even when proximate properties sell at or near the same prices as more distant properties, claimants argue that proximate properties take longer to sell. Such increased marketing time can represent a loss to the seller by deferring receipt, availability, and use of sale proceeds.
- **Decreased Sales Volume –** A more subtle indicator of diminished property value if potential buyers decide not to buy in the impact area. A measurable decrease in sales volume in the impact area compared with sales volume in the control area where otherwise similar properties purportedly still are selling can represent evidence of decreased market value from proximity to the high voltage transmission lines (or claimed hazard).

A 2003 Electric Power Research Institute (EPRI) study, "Transmission Lines and Property Values: State of the Science," stated that differences in location and time of data collection, as well as research design, make direct comparisons of results from the various studies very difficult. Although quantitative generalizations from studies cannot be reliably made, the following conclusions from studies seem to be similar across numerous studies (EPRI, 2003):

- There is evidence that transmission lines have the potential to decrease nearby property values, but this decrease is usually small.
- Lots adjacent to the ROW often benefit, because they have open space next to them; lots next to adjacent lots often have value reduction.
- Higher-end properties are more likely to experience a reduction in selling price than lower-end properties.
- The degree of opposition to an upgrade project may affect size and duration of the sales-price effects.
- Setback distance, ROW landscaping, shielding of visual and aural effects, and integration of the ROW into the neighborhood can significantly reduce or eliminate the impact of transmission structures on sales prices.

- Although appreciation of property does not appear to be affected, proximity to a transmission line can sometimes result in increased selling times for adjacent properties.
- Sales-price effects are more complex than they have been portrayed in many studies. Even grouping adjacent properties may obscure results.
- Effects of a transmission line on sales prices of properties diminish over time and all but disappear in five years.
- Opinion surveys of property values and transmission lines may not necessarily overstate negative attitudes, but they understate or ignore positive attitudes.
- The release of findings from the Swedish study on EMF and health effects had no measurable influence on sales prices.

As discussed above, impacts on property values result from visual impacts, or health and safety concerns such as EMF. Implementation of mitigation measures in the Visual Resources section, such as Mitigation Measures V-3a (Reduce visual contrast of towers and conductors) and other visual resources mitigation specific to Key Viewpoints, would reduce the visual impacts of the project. In addition, the CPUC has implemented, and recently re-confirmed, a decision requiring utilities to incorporate “low-cost” or “no-cost” measures for managing EMF from power lines. These measures for mitigation of magnetic fields would be incorporated into the Proposed Project and may help to reduce perceived health effects of transmission lines that would adversely affect property values.

The significance criteria listed in Section D.14.4.1 in Volume 3 of the Draft EIR/EIS state that the impact would be significant if the project would “cause a substantial decrease in property values.” Where Proposed Project impacts in other issue areas that can contribute to reduction in property values are less than significant or have been mitigated to less than significant levels, then they would not cause considerable property value changes. Therefore, any property value impacts associated with those areas would also be less than significant and no mitigation measure is recommended (Class III).

In areas where there would be potentially significant impacts in other issue areas (e.g., visual resources) coupled with other line and/or property characteristics described in the studies that would contribute to property values impacts, the studies discussed in Section D.14.5 conclude that these effects are usually smaller than anticipated and essentially impossible to generally quantify due to the individuality of properties/neighborhoods, differences in personal preferences of individual buyers/sellers, and the weight of other factors that contribute to a person’s decision to purchase a property. Other factors (e.g., neighborhood factors, square footage, size of lot, irrigation potential) are much more likely than overhead transmission lines to be major determinants of the sales price of property (Kroll and Priestley, 1992). In addition, studies have generally concluded that over time, any adverse property value impacts diminish, and within five years the change is negligible. This is most likely due to increased screening as trees and shrubbery grow and/or diminished sensitivity to the line proximity in the absence of adverse publicity. As a result, property values would not substantially decrease and this impact is considered to be less than significant (Class III) throughout the proposed route and alternatives.

CEQA Guidelines § 15131(a) states that economic or social effects of a project shall not be treated as significant effects on the environment, and these effects only need to be considered in a chain of cause and effect if they would result in a physical change to the environment that was caused in turn by the economic or social changes. As concluded above, any decrease in property values would be less than significant, and likewise, there would be no or less than significant resulting physical changes in the environment.

Landowners of any private parcels that would be crossed by the Proposed Project would be compensated by SDG&E for use of its easement across the property based on the fair market value of the property taken.[77] Impacts on revenues on farming land and on tourism in ABDSP are discussed under Impact S-1 (Project construction would cause a substantial change in revenue for businesses) in the Socioeconomics, Services, and Utilities sections of the Draft EIR/EIS. Crop losses to agricultural operations would be compensated under APM LU-3 (see Table D.6-6, Applicant Proposed Measures – Agricultural Resources in the Draft EIR/EIS), and impacts to farmland are discussed under Agricultural Resources throughout the Draft EIR/EIS (e.g., see Section D.6).

Should the CPUC be forced to condemn certain of the land parcels running along the selected transmission line route, the California Eminent Domain Law (contained in California Code of Civil Procedure § 123.010, et seq.) covers, in great detail, the procedural aspects of bringing eminent domain action in court. In an eminent domain action, the only issue tried before a jury is valuation, whereas all other issues (e.g., the right to take the property) are tried by the court. *People v. Volz,* 25 Cal.App.3d 480, 487 (1972).

The measure of compensation for property taken is its fair market value, or the highest price on the date of valuation that would be agreed to by a seller, being willing to sell, but under no particular or urgent necessity for so doing, nor obliged to sell, and a buyer, being ready, willing and able to buy, but under no particular necessity for doing so, each dealing with the other with full knowledge of all the uses and purposes for which the property is reasonably adaptable and available. Cal.Civ.Proc.C. § 1263.320(a); *McMahan's of Santa Monica v. Santa Monica,* 146 Cal.App.3d 683, 700 (1983); Cal.Civ.Proc.C. § 1263.310. The principle which the law seeks to achieve in making this valuation is to place the owner in as good a position monetarily as if the property had not been taken. *San Diego Metropolitan Transit Development Bd. v. Chushman*, 53 Cal.App.4th 918 (1997).

Market value is generally determined by considering the following elements: (a) all uses to which the property is adapted or available; and (b) the highest and most profitable use to which the property might be put in the reasonably near future, to the extent that this probability affects its market value. *People v. Ocean Shore R.*, 32 Cal. 2d 406, 425 (1948); *Ripon v. Sweetin*, 100 Cal.App.4th 887, 899 (2002). And, as may be relevant to the situation at hand, where the property taken is part of a larger parcel, in addition to compensation for the property taken, compensation must be awarded for injury to the remainder. *Cal.Civ.Proc.C. § 1263.410(a)*. The measure of compensation for injury to the remainder is the damage to the remainder, reduced by the benefit to the remainder. *Cal.Civ.Proc.C. § 1263.410(b)*. A separate valuation for loss of good will must be conducted where the condemnation proceeding takes property occupied by a business, or where a business occupies the remainder if the property taken is part of that larger parcel. Cal.Civ.Proc.C. § 1263.510(a).

Another key issue regarding valuation is the date that should be used for valuation of the property. Generally, if the condemner deposits the probable compensation in accordance with the applicable procedures, the date of valuation is the date on which the deposit is made. *Cal.Civ.Proc.C. § 1263.110.*

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77 "Fair market value" is a term defined by California Code of Civil Procedure section 1263.320(a) as "…the highest price on the date of valuation that would be agreed to by a seller, being willing to sell but under no particular or urgent necessity for so doing, nor obliged to sell, and a buyer, being ready, willing, and able to buy but under no particular necessity for so doing, each dealing with the other with full knowledge of all the uses and purposes for which the property is reasonably adaptable and available." In addition, where the property acquired is a part of a larger parcel, the payment of severance damages may be required if the remaining property (remainder), after the portion acquired, has been diminished in market value when compared with the same remainder before the taking.

Absent a deposit, if the issue of compensation is brought to trial within one year after commencement of the proceeding, the date of valuation is the date of commencement of the proceeding. *Cal.Civ.Proc.C. § 1263.120.* But, if the issue of compensation is not brought to trial within one year of commencement of the proceedings, the date of valuation is the date of commencement of the trial, unless the delay was caused by the defendant condemnee, in which case the date of valuation sis the date for commencement of the proceeding. *Cal.Civ.Proc.C. § .130.*

Although no properties are anticipated for taking under the Proposed Project, properties may have to be taken for the LEAPS Transmission Plus Generation Alternative (see Section E.7.2 of the Draft EIR/EIS) and for expansion of the Boulevard Substation (see Section 2 of the RDEIR/SDEIS). If any properties on the eventual path of the project or an alternative do have to be taken via an eminent domain action, then the first issue to be determined by the court would be if the properties could be properly condemned by the state and, second, a trial would be had on the correct fair market valuation for the acquired properties.

Because BLM and CNF lands traversed by the Proposed Project and/or alternatives are public lands, property value impacts would not apply to BLM or CNF lands themselves. Income generated from BLM and Cleveland National Forest ROW grants is discussed under Impact S-4 (Property tax revenues and/or fees from project presence would substantially benefit public agencies) in the Socioeconomics, Services, and Utilities sections of the Draft EIR/EIS.

General Response GR-12: CEQA, NEPA and the Decision-Making Process

Numerous comments included questions regarding the processes for approval or denial of the Proposed Project and alternatives, and questioned what the CPUC and BLM's next steps would be following publication of the Final EIR/EIS. Commenters also stated that they did not think that the Proposed Project is needed. This response discusses the CPUC's CEQA and NEPA environmental review process, the CPUC's general proceeding, which considers project cost and purpose and need, and the CPUC and BLM decision-making processes following completion of this Final EIR/EIS. Section A.6 in Volume 1 of the Draft EIR/EIS addresses the agency use of the document and agency process.

Environmental Evaluation

Once the CPUC as the Lead Agency under CEQA and the BLM as the Lead Agency under NEPA decided that an EIR/EIS would be prepared for the Proposed Project, a series of steps were taken to complete this process:

- The CPUC and BLM held multiple scoping meetings with the issuance of the NOP to help identify the range of actions, alternatives, mitigation measures, and significant effects to be analyzed in depth in the EIR/EIS and to help eliminate from detailed study issues found not to be important.
- After review of the scoping comments, CPUC/BLM conducted a preliminary analysis and screening of all alternatives suggested in the SDG&E Proponent's Environmental Assessment and by the public and other agencies.
- A second scoping period was conducted on the preliminary identification of alternatives with 8 additional public scoping meetings to collect input on alternatives. A notice was mailed regarding the conclusion of alternatives.
- A third comment period was conducted for the New Modified D Alternative proposed by Cleveland National Forest.
- After selecting alternatives for analysis, via the alternatives screening process detailed in Appendix 1 of the Draft EIR/EIS, a Draft EIR/EIS was prepared and published for public review. The Draft EIR/EIS analyzed the environmental impacts that would be caused by the proposed projects and the alternatives that were selected for review through the screening process. The Draft EIR/EIS proposed mitigation measures that would reduce environmental impacts.
- The public was given 90 days to review and comment on the Draft EIR/EIS. Comments on the Draft EIR/EIS were heard at seven public participation hearings in February and May of 2008.
- In light of new information regarding the scope of the La Rumorosa Wind Project, and in order to address modifications to the proposed and alternative transmission line routes, the CPUC recirculated portions of the Draft EIR/EIS on July 11 2008 per NEPA & CEQA requirements.
- The Public Comment period for the RDEIR/SDEIS spanned 45 days from July 11 to August 25, 2008. During that time, the CPUC and BLM held two Informational Workshops in Jacumba, California.
- CPUC/BLM prepared responses to all comments received on the Draft EIR/EIS and on the RDEIR/SDEIS that raised significant environmental issues.
- This Final EIR/EIS contains all revisions made to the Draft EIR/EIS and RDEIR/SDEIS, all comments and recommendations received on the Draft and RDEIR/SDEIS, a list of persons, organizations, and public agencies that commented on the Draft EIR/EIS and RDEIR/SDEIS, and the responses of CPUC/BLM to significant environmental points raised in the public comment process.
- The CPUC and the BLM will consider the Final EIR/EIS in making its final determination on project approval.

In the Draft EIR/EIS, the CPUC identified the Overall Environmentally Superior Alternative in a ranking of alternatives and Proposed Project as required by CEQA Guidelines 15126.6(e)(2). The overall ranking of the alternatives as presented in the Draft EIR/EIS did not change in the RDEIR/SDEIS; however, revisions were made to the transmission routes defined as "Environmentally Superior Northern Route Alternative" and "Environmentally Superior Southern Route Alternative" (see Section 5.1 of the RDEIR/SDEIS). Similarly, the overall ranking of the alternatives (as presented in both the Draft EIR/EIS and the RDEIR/SDEIS) did not change in the Final Draft EIR/EIS; however, further revisions were made to the transmission routes for the "Final Environmentally Superior Northern Route Alternative" and "Final Environmentally Superior Southern Route Alternative".

In accordance with BLM planning regulations, BLM's Agency Preferred Alternative is identified in the Final EIS (BLM Manual 1790-1, Ch. V(B)(4)(c)). The BLM has identified a preferred alternative in the Final EIR/EIS based on analysis of public comments on the Draft EIR/EIS and further internal review of the Draft EIR/EIS and the RDEIR/SDEIS. BLM's "preferred alternative" need not be the same as the CPUC's "Environmentally Superior Alternative." NEPA guidance states that the environmentally preferable alternative is the alternative that causes the least damage to the biological and physical environment, and best protects, preserves, and enhances historic, cultural and natural resources (NEPA's 40 Most Asked Questions, 6a). BLM's Record of Decision (ROD) must specify the environmentally preferable alternative.

As explained in the CPUC's Assigned Commissioner and Administrative Law Judge (ALJ)'s November 1, 2006 Scoping Memo and Ruling (A.06-08-010, A.05-12-014), the "Final EIR/EIS is an informational document. It does not make a recommendation regarding approval or denial of the CPCN [Certificate of Public Convenience and Necessity] application, and it does not establish a route for the project. The purpose of the Final EIR/EIS is to inform both the public and the decision-makers of the environmental impacts of the Proposed Project and alternatives, design a recommended mitigation program to reduce any potentially significant impacts, and identify, from an environmental perspective, a preferred route. In making a final determination on the application, the Commission will consider the information contained in the Final EIR/EIS as well as in the formal evidentiary record."

CPUC General Proceeding

The CPUC's general proceeding is a formal review process in which the CPUC considers how approval of a project might impact the public interest. The General Proceeding includes, as stated in the Public Utilities Code §1002.3, the consideration of cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity. A general proceeding can include pre-hearing conferences, evidentiary hearings, and public participation hearings. The CPUC will seek a decision about the project that strikes a balance among power production, land use, environmental stewardship, and other factors. A CPUC Assigned Commissioner and an Administrative Law Judge (ALJ) are in charge of the general proceeding, which may in part occur while the environmental review is underway.

Phase I and Phase II of the Evidentiary Process

The Phase I and Phase II proceedings offer stakeholders and qualified experts the opportunity to offer their opinions on various aspects of the Proposed Project, including need and cost-benefit of the project. After giving expert testimony, the witnesses are offered for cross-examination by other participants in the proceeding.

The Phase I hearings focused on:

- Computer models and modeling inputs used to determine the net economic and reliability need for the Proposed Project, and the merits of different ways to meet that need;
- Timing issues related to the perceived need for the Proposed Project;
- Assumptions underlying SDG&E and CAISO cost-benefit analyses;
- Additional scenarios and model runs to test assumptions and compare alternatives to the Proposed Project;
- Non-wires alternatives to the Proposed Project, including local generation, enhanced energy efficiency, advanced metering technologies, and demand response;
- Wires-based alternatives that differ fundamentally from the Proposed Project;
- The feasibility and impacts of pursuing the “no project” alternative as defined under CEQA;
- The potential for the likelihood of developing renewable energy resources in the project area;
- The capability of existing and other planned transmission lines to carry non-local renewable generation into the SDG&E load center on a short-term or long-term basis;
- Critical environmental concerns that should inform the CEQA review process;
- Community values;
- Recreational and park areas; and
- Historical and aesthetic values.

After issuance of the Draft EIR/EIS, parties were permitted to submit additional evidence at the Phase II hearings on additional issues, addressing the following:

- A comparison of different modeling efforts, and economic and reliability analyses as informed by the proposed alternatives and mitigation measures in the Draft EIR/EIS;
- Cost-benefit analyses of the Proposed Project and project alternatives as informed by the proposed alternatives and mitigation measures in the Draft EIR/EIS, and by different modeling efforts;
- Material factual inaccuracies or deficiencies in the Draft EIR/EIS
- The effect of project alternatives on system reliability and the ability to deliver renewable energy to SDG&E customers;
- Adequacy of SDG&E’s EMF mitigation plan; and
- Project cost cap.

Need for the Proposed Project

SDG&E states that it developed the Sunrise Powerlink Project for three major reasons: (1) to bring renewable energy resources to San Diego County from Imperial County by providing access to remote areas with the potential for significant development of renewable energy sources; (2) to improve electric reliability within the San Diego area by providing additional transmission during peak loading and for the region’s growing economy; (3) and to reduce congestion and power supply costs of delivering electricity to ratepayers (SDG&E, 2006a). During the CPUC’s Phase I hearings, several parties questioned the need for the Proposed Project.

Purpose and Need for the Proposed Project is discussed in Section A.2 in Volume 1 of the Draft EIR/EIS. The need for this project, however, is not evaluated in the EIR/EIS and is not determined within the context of the environmental review process. The CPUC Administrative Law Judge evaluates project need during the CPUC General Proceeding with information presented by SDG&E, Cal ISO, and other parties. The Commission's General Order (GO) 131-D contains rules relating to the planning and construction of electric facilities. It prescribes that, prior to issuing a CPCN, the Commission must find that the project is necessary to promote the safety, health, comfort, and convenience of the public.

The CPUC maintains a website for the Sunrise Powerlink proceeding (A.06-08-010) at http://docs.cpuc.ca.gov/published/proceedings/A0608010.htm. Most proceeding documents and rulings are available at that site.

Cost of the Proposed Project

The cost of the Proposed Project is not evaluated or decided within the EIR/EIS. NEPA does not require an EIS to perform a monetary cost-benefit analysis. (See 40 CFR 1502.23.) Similarly, CEQA does not require consideration of economic effects unless they would result in physical changes to the environment. (See CEQA Guidelines § 15131.) The CPUC Administrative Law Judge evaluates cost of the project during the CPUC General Proceeding with information presented by SDG&E, Cal ISO, and other parties, as described above. An economic comparison of alternatives was presented by SDG&E in its Phase II testimony which can be found on the CPUC proceeding website listed above. UCAN and the Division of Ratepayer Advocates also addressed the cost/benefit of the Sunrise Powerlink Project in their Phase II testimony. This testimony can also be found on the proceeding website.

CPUC and BLM Decision-Making Processes

CPUC Decision-Making Process

When both the environmental evaluation and general proceeding are complete, the ALJ will prepare a Proposed Decision for consideration by the five CPUC Commissioners. The ALJ will base the Proposed Decision on the general proceeding evidence, the analysis and conclusions made in the Final EIR/EIS, and the public comments received. Each Commissioner may draft an Alternate Decision presenting differing conclusions or opinions. All five Commissioners will then vote on the Proposed Decision and any Alternate Decisions at a meeting of the full Commission. Before approving the project or an alternative, the CPUC will certify that the Final EIR/EIS has been completed in compliance with CEQA, was presented to its decision-making body and the decision-making body reviewed and considered the information contained in the Final EIR/EIS, and that the Final EIR/EIS reflects the independent judgment of the CPUC in compliance with CEQA Guidelines § 15090. Additionally, if the CPUC approves the project or an alternative that will have a significant effect on the environment, the CPUC will make one or more of the findings required by CEQA Guidelines § 15091 for each significant environmental effect identified in the Final EIR/EIS. The CPUC will also adopt a statement of overriding considerations to explain the specific reasons supporting its action based on the Final EIR/EIS and/or other information in the record in compliance with CEQA Guidelines § 15093. If the project or an alternative is approved, the CPUC will adopt a mitigation monitoring and reporting program to require monitoring of adopted mitigation measures and definition of mitigation monitoring procedures.

The CPUC's approval of the project or an alternative may be appealed internally at the CPUC through the following process:

- Within 30 days of the approval of the project, an application for rehearing may be filed with the CPUC. (Pub. Util. Code § 1731 (d).) The purpose of the rehearing application is to alert the CPUC to a legal error so that the CPUC correct it.
- Within 20 days from the filing of the application for rehearing, the CPUC shall issue its decision and order on rehearing (Pub. Util. Code § 1731 (c).)

Pursuant to CEQA Section 21168.6, any judicial action challenging a CPUC CEQA decision must be filed in the Supreme Court of California. Filing and processing of judicial review is governed by §§ 1756 – 1768 of the Public Utilities Code.

BLM Decision-Making Process

The BLM must decide whether or not to grant a Right-of-Way for the proposed project. An amendment to the California Desert Conservation Area (CDCA) Plan (1980) would also be required as the Proposed Project would deviate from BLM designated utility corridors.

Following publication of the Final EIR/EIS, the BLM will have a 30-day period during which individuals and entities may file a protest with the BLM Director regarding the proposed plan amendment. The BLM will also provide a 60 day review period to the Governor of California to ensure consistency with state and local plans, policies, and programs, because the project would require an amendment to the CDCA Plan.

Following the close of these two review periods, and after consultation with the U.S. Fish & Wildlife Service (under Section 7 of the Endangered Species Act) and the State Office of Historic Preservation (under Section 106 of the National Historic Preservation Act of 1966), the BLM will prepare and issue its Record of Decision (ROD) on the Right of Way and CDCA Plan Amendment. The BLM will then serve a notice of decision to participating parties and will publish its decision in the Federal Register.

The BLM's decision may be appealed to the Board of Land Appeals. The Board of Land Appeals' decision may be challenged in court under the federal Administrative Procedure Act.

Other Agencies

Several other State and federal agencies will rely on information in this EIR/EIS to inform them in their decisions regarding issuance of specific permits related to project construction or operation.

California State Parks. The Proposed Project would pass through Anza-Borrego Desert State Park (ABDSP) for an approximate distance of 22 miles. Although SDG&E has an existing ROW for its 69 kV transmission line through the Park, the Proposed Project could not be constructed within the existing BLM easement because of its narrow width. Additional ROW would therefore be required to construct the project as proposed. The existing 69 kV easement is bordered by State designated Wilderness Areas. According to the State Parks Department, expansion of the 69 kV easement into the designated Wilderness Areas or into the area designated Backcountry Zone would require an amendment to the ABDSP General Plan. Current land use policy for ABDSP is detailed in the Final General Plan and Environmental Impact Report (SCH #2002021060), dated February 11, 2005. Sections D.16 and D.17 of the Draft EIR/EIS for the Proposed Project (January 2008) further describe the ABDSP General Plan and potential need for plan amendment if the Proposed Project and/or certain route alternatives are approved.

United States Forest Service. Several route alternatives traverse the Cleveland National Forest and would therefore require a Special Use Authorization from the Forest Service. Some alternatives may also require amendments to the Forest Service's Land Management Plan. The Forest Service is responsible for approval/denial of Land Management Plan amendments and Special Use Authorization. The Proposed Project would also require a 50-year Special Use Permit for construction, maintenance, and use of the 500 kV or 230 kV transmission line, temporary construction permits, and, potentially, a Special Use Easement. Please see Section D.17 of the Draft EIR/EIS for more information regarding which alternatives cross Forest Service land and which alternatives would require Land Management Plan amendments.

The Forest Service must comply with NEPA to issue Special Use Authorization or amend a Land Management Plan. If required, the Forest Service would render a decision on a Special Use Authorization application and, if necessary, a Land Management Plan amendment based, in part, on environmental review under NEPA. The Forest Service would document its decision in a Record of Decision (ROD). The Forest Service's decision is subject to administrative appeal and judicial review.

General Response GR-13: Biological Resources Applicant Proposed Measures (APMs)

Comments on the Draft EIR/EIS were received from a variety of reviewers regarding the Biology Applicant Proposed Measures (APMs). The California Department of Parks and Recreation (Comment A0001-22) commented that State Parks is confused about which of the APMs apply and which do not. The U.S. Fish and Wildlife Service and California Department of Fish and Game (Comments A0024-05, A0024-67) noted that some of the APMs proposed are not adequate to mitigate impacts, and they suggested revisions to the APMs. SDG&E believes (Comments E0002-162 and E0004-129) that the APMs provide adequate mitigation in more cases than the Draft EIR/EIS indicates.

The APMs include environmental measures that are already required by existing regulations and/or requirements, or are SDG&E's standard practices that would minimize or prevent potential impacts. APMs are designed to address temporary and/or permanent impacts, as well as impacts anticipated during operations and maintenance of the completed project. These measures would be implemented regardless of any regulatory oversight by the CPUC and BLM and are not measures added to the project based on the EIR/EIS analysis. Rather, they are proposed by SDG&E to be integrated as part of the project description. CEQA requires that the discussion of mitigation measures in an EIR distinguish between the measures that are proposed by project proponents and other measures proposed by the lead agency. (CEQA Guidelines § 15126.4(a)(1)(A).) The full text of the APMs related to biological resources is included in Table D.2-5 in Section D.2.4.2 of Volume 1 of the EIR/EIS. However, it should be noted that some APMs were based on SDG&E's NCCP, which is not applicable to this project (see discussion in Section D.2.3.3 of Volume 1 of the EIR/EIS). As a result, in some cases, portions of the APMs are not appropriate or are not adequate to provide mitigation for the project's impacts. In these cases, the portions of the APMs which are not appropriate or adequate are shown in struck text in Appendix 8N that has been added to the Final EIR/EIS, and the mitigation measures that are proposed in addition to the applicable portions of the APMs to avoid, minimize, or mitigate the relevant impacts of the project are shown in the second column of Appendix 8N. This new appendix clarifies applicable requirements for the Mitigation Monitoring Reporting Program (Section D.2.27 of Volume 1 of the EIR/EIS). The APMs will be monitored by the lead agencies as part of the Mitigation Monitoring Program for Mitigation Measure B-1c (conduct biological monitoring). All of the BIO APMs are specific to SDG&E and apply to projects for which SDG&E is the applicant. For projects where SDG&E may not be the applicant (e.g. New In-Area Renewable Generation Alternative--solar thermal), applicable SDG&E APMs were applied as mitigation measures for those projects (e.g., Mitigation Measure B-1d [Perform Protocol Surveys], which is the same as BIO APM-1). In Appendix 12 of the Draft EIR/EIS, some of the BIO APMs that were applied as mitigation measures (e.g., Mitigation Measure B-1d) still identified SDG&E as the entity that would implement the mitigation measure; it should have stated, "SDG&E or the applicant…." Appendix 12, Full Text of Mitigation Measures, has been changed for the Final EIR/EIS to clarify this.

General Response GR-14: Biological Resources Impact Calculations/Mitigation Ratios

Comments on the Draft EIR/EIS were received from a variety of reviewers regarding the mitigation ratios used to provide compensatory mitigation for impacts to vegetation communities and in limited cases, for sensitive species. SDG&E commented that the mitigation ratios should be lower. The Center for Biological Diversity (Comment Set B0041) and California Department of Parks and Recreation (Comments A0001-21, A0001-25) suggested higher mitigation ratios for some habitats or for certain areas. The USFWS and CDFG (Comment A0024-10) noted that mitigation should be doubled for areas already in use as mitigation for other projects. The County of San Diego (Comment A0018-13) stated that the edge effects of the introduction of roads and tower platforms in preserves need to be compensated.

The mitigation ratios were developed in consultation with the USFWS, BLM, and State Parks and are based primarily on the requirements established in regional habitat conservation programs (i.e., the MSCP and its various subarea plans), and also on mitigation required for other projects. Much of the western end of the Proposed Project route extends through the MSCP area where mitigation ratios vary depending on the location of the impact and the location of the mitigation. Mitigation ratios were conservatively calculated based on an assumption that all impacts will occur in preserve areas (i.e., areas already preserved or targeted for preservation within the various subarea plans) and that all mitigation will also occur in such preserve areas. The assumption that all impacts will occur in preserve areas is conservative since not all impacts would occur there, but the higher ratios (i.e., higher than those that would be used for impacts outside of preserve areas) would be used to help offset the impacts to the preserves that regional conservation plans rely upon. In other words, the Sunrise Powerlink is a large-scale project that would have impacts in preserves not anticipated by the regional habitat conservation plans. Also, mitigation ratios for regional conservation plans are based, in part, on commitments to preservation of habitat made by the permittee (e.g., County of San Diego) and project proponents in order for the Wildlife Agencies to agree to the mitigation ratios in the plans (i.e., ratios lower than would be applied to a non-participant in the regional planning process, or a party such as SDG&E whose NCCP Plan does not cover activities outside of its Plan Area). Because the project extends well outside of SDG&E's NCCP Plan Area, the USFWS (Chris Otahal, USFWS, pers. comm., May 14, 2007) has stated that the project will not be evaluated by the standards set forth in the SDG&E NCCP and that the higher ratios, described above, shall be applied. Based on a USFWS/CDFG comment (Comment A0024-11), which stated that potential impacts to mitigation land should be doubled, Mitigation Measure B-1a in Section D.2.5 (page D.2-88) of Volume 1 of the Draft EIR/EIS has been revised to include the following statement. Also see Response to Comment A0024-11.

> <u>In cases where the impacts to sensitive vegetation communities occur on lands already in use as mitigation for other projects, the mitigation ratios shall be doubled, as is standard practice in San Diego County.</u>

General Response GR-15: Biological Resources - Jurisdictional Delineations

Comments on the Draft EIR/EIS were received from a variety of reviewers regarding the lack of jurisdictional delineations for the Proposed Project and alternatives. Some reviewers suggested that jurisdictional delineations should have been performed for the Draft EIR/EIS. Some reviewers suggested that delineations should have been conducted, and that consultation with wetland permitting agencies should have occurred as part of the Draft EIR/EIS.

The Draft EIR/EIS documents the presence of potential jurisdictional areas. For the Proposed Project and alternatives, wetland vegetation was mapped (which is anticipated to be at least partly jurisdictional), and the National Wetland Inventory (http://www.fws.gov/nwi/) and hydrologic study for the Proposed Project and alternatives were used to identify potential jurisdictional drainages including desert washes (Section D.12 of Volume 3 of the Draft EIR/EIS). The Draft EIR/EIS does include impact data for anticipated impacts to sensitive wetland habitats, and the number of drainages that would be crossed is provided. It is not practical or reasonably feasible to conduct a jurisdictional delineation and define precise impacts to jurisdictional areas for each of the various alternatives analyzed in the EIR/EIS prior to a final decision on project approval and until a final route is selected that includes project-specific features and final engineering. At that time, a formal delineation would be conducted by an experienced delineator to determine those impacts so that SDG&E can apply for permits from the U.S. Army Corps of Engineers, Regional Water Quality Control Board, and CDFG. "CEQA does not require a lead agency to conduct every test or perform all research, study and experimentation recommended or demanded by commenters." (CEQA Guidelines § 15204(a)). Further, "the sufficiency of an EIR is to be reviewed in light of what is reasonably feasible." (CEQA Guidelines § 15151). It would not be reasonably feasible to conduct a formal delineation on each of the various alternative routes analyzed in the EIR/EIS. The analysis provides sufficient detail as required by NEPA and CEQA to identify impacts, and to allow for a reasonable comparison of the alternatives in terms of their potential impacts to "waters of the U.S." and "waters of the state" and with a sufficient degree of analysis to provide decision-makers with information which enables them to make a decision which intelligently takes account of environmental consequences. There is no evidence that the project will cause net loss of jurisdictional habitats, and adequate measures (such as biological monitoring to ensure impacts stay within designated limits, habitat restoration, and habitat creation) are available and can be used to avoid, minimize, or mitigate these impacts. Federal and state agency permits will be required, and the mitigation imposed by those permits, as well as that included in the Draft EIR/EIS, will be adequate to compensate the impacts.

General Response GR-16: Adequacy of Biology Surveys

Comments on the Draft EIR/EIS were received from a variety of reviewers regarding the adequacy of the biology surveys used to evaluate impacts of the Proposed Project and alternatives. Some reviewers felt that the lack of access to certain parcels makes it difficult to fully analyze impacts. Some reviewers noted that the dry weather conditions during the survey year, which limited or prevented detection of some rare plants (particularly in the desert), left unanswered the potential impact of the Proposed Project and/or alternatives. SDG&E disagreed with conclusions of the Draft EIR/EIS regarding the detectability of rare plants in certain areas and felt that the Draft EIR/EIS should have concluded that more of the Proposed Project did have adequate surveys. The Center for Biological Diversity (Comment B0041-10, B0041-11, B0041-12) alleged that the survey limitations affect the adequacy of the Draft EIR/EIS, and that years of surveys in advance of the Draft EIR/EIS would have allowed for a better evaluation of potential impacts from the Proposed Project and alternatives.

The Proposed Project and alternatives traverse both public and private lands. In some areas, the routes would follow existing SDG&E ROW easements, while in other areas new ROW easements would be required. Landowner right-of-entry (ROE) permits are required for conducting biological field surveys on public and private lands. Some permission to enter was granted in time to complete surveys prior to release of the Draft EIR/EIS, but some permission was denied, and some was not granted in time to meet the timing requirements of survey protocol. In areas where landowners denied access or permission to access was not granted in time, data for those portions of the routes were collected remotely from public access points or interpreted from aerial photographs and were not verified in the field. In many cases, the presence of a threatened or endangered species was assumed based on the presence of potential habitat and the lack of access permission to conduct surveys.

The accuracy of the various surveys being conducted for this project was limited by the following factors:

- Both the CPUC/BLM and SDG&E had difficulty gaining permission to access private properties along the 300 miles of alternative routes and for approximately five miles of the Proposed Project route (in the Central Link).
- Exceptionally dry weather conditions in 2007 made the results of some 2007 surveys conducted for the EIR/EIS (i.e., Quino checkerspot butterfly and special status plant species) either inconclusive or questionable. It should be noted that protocol surveys for listed or highly sensitive species are required prior to construction. These surveys would likely be completed during the year prior to construction. Surveys for the Quino checkerspot butterfly, Hermes copper butterfly, and special status plant species were completed in 2008 by SDG&E for the Proposed Project and alternatives because 2008 was a better rainfall year than 2007, and SDG&E was concerned that if unfavorable weather/rainfall conditions occurred in future years (2009, 2010, etc.), it might have missed a survey window opportunity. A summary of the 2008 survey results are included in new Appendix 8R in the Final EIR/EIS.
- Exceptionally dry weather conditions in 2007 prevented arroyo toad surveys conducted in 2007 for the EIR/EIS analysis from being conducted in several areas that contained suitable habitat; the species was assumed to be present in these cases and is still assumed present in the Final EIR/EIS, because SDG&E did not conduct surveys for this species in these areas in 2008.
- Survey areas did not always include all of the proposed impact areas (e.g., access roads and staging areas that occur outside of the 200-foot PSA) because, in most cases, these areas were not known at the time of the surveys.

- Some of the protocol surveys had to be started too late in the season to meet the full protocol, either because of the time-intensive process of developing alternative routes or because access was not granted until too late in the season to begin the surveys on time.

In recognition of these limitations, the CPUC, BLM, and the Wildlife Agencies decided on the following course of action in a meeting at the USFWS office in Carlsbad on February 8, 2007 during which an approach to biological resources surveys was discussed: (1) surveys would be performed on public lands and private lands where permission to access was obtained (surveys were conducted for all properties for which ROE permission was granted up until publication of the Draft EIR/EIS); (2) the CPUC/BLM and SDG&E would continue to aggressively pursue rights to enter private properties (via letters and follow-up court action), and as many surveys as possible would be performed once access is obtained; (3) efforts concerning the pursuit of access would be documented; and (4) where access is not possible, other information such as regional habitat assessment models and air photos would be used to identify suitable habitat for each species, species would be assumed to be present (where appropriate), and mitigation would be developed based on that assumption (i.e., the worst case scenario). Where species are assumed to be present and impacted, pre-construction surveys that meet USFWS protocol would be required that would determine the presence or absence of species, and the mitigation required may be reduced or eliminated based on the results of these surveys.

In recognition of these survey limitations, the EIR/EIS specifically defined affected acreage and presented mitigation based on anticipated project effects for areas in which protocol surveys were completed. For the Proposed Project and all alternatives, all structure pads, roads and other impact features were plotted on vegetation maps and maps of sensitive species in order to calculate anticipated impacts. Features such as towers and permanent access roads were considered permanent impacts. Features such as pulling sites and staging areas were considered temporary impacts.

As disclosed in the EIR/EIS, the survey limitations noted above affected the impact analysis in the following ways:

1. For areas in which protocol surveys have been completed, the EIR/EIS specifically defines affected acreage and presents specific mitigation based on anticipated project effects.

2. For areas in which protocol surveys could not be done — either because access was not granted, or because 2007 was not an acceptable survey season, the analysis of biological impacts identifies suitable habitat areas in which the special status species are likely to be present. Because the special status species are likely to be present in the identified habitat, the analysis assumed the presence of species in all potential habitats, and identified appropriate mitigation.

3. For surveys that did not meet the full protocol due to a late start, the impact assessment states whether or not this has an effect on the validity of the surveys for determining presence or absence.

4. Where the EIR/EIS identified habitat in which special status species are likely to be present, mitigation measures were set forth to minimize this potential impact to species assumed to be present. Avoidance of sensitive plant and wildlife species is the primary means of mitigating these impacts. For example, Mitigation Measure B-7l (Conduct coastal California gnatcatcher surveys, and implement appropriate avoidance/minimization/compensation strategies) requires SDG&E to conduct all brush removal and grading outside the gnatcatcher breeding season to avoid impacts to nearby nesting gnatcatchers and to conduct a survey for the gnatcatcher prior to other project construction activity if it is to occur during the species' breeding season. If the gnatcatcher is present and

nesting, a 300-foot no construction buffer is to be established around the nest site. This mitigation measure explicitly prioritizes avoidance and minimization of impacts to nesting gnatcatchers as the primary means to address impacts. Only if avoidance and minimization are not feasible would compensation measures (in the form of acquisition and preservation of gnatcatcher-occupied habitat) be taken.

Further, survey reports will be prepared in accordance with USFWS protocol for use by the BLM and USFWS as part of the Section 7 consultation. A Section 7 consultation is a process during which the lead federal agency, in consultation with the Secretary of the Interior/Secretary of Commerce, ensures that any action it authorizes, funds, or carries out is not likely to jeopardize the continued existence of a listed species or result in the destruction of, or adverse modification of, designated critical habitat. The lead federal agency for the Sunrise Powerlink Project is the BLM. The BLM will likely initiate the Section 7 consultation after selection of the preferred project route. Appendix 8B provided a table with a summary of all the protocol surveys conducted. Maps showing critical habitat, historical occurrences, observations during surveys conducted for this project, survey locations, and the location of the Proposed Project and each alternative were provided as Appendix 8C.

TRC Companies, Inc., contracted by SDG&E, conducted focused surveys for the Quino checkerspot butterfly (QCB), Hermes copper butterfly, and special status plant species for the Proposed Project and alternatives in the spring of 2008 after release of the Draft EIR/EIS. TRC Companies, Inc. did not conduct surveys for the non-wires alternatives, LEAPS, or the reroutes discussed in the RDEIR/SDEIS. The surveys were conducted because spring 2008 was a better rainfall year than 2007 (i.e., better data could be gathered), and the survey results would be useful data for the USFWS in issuing its Biological Opinion on the project following the Section 7 consultation. These survey results are presented in Appendix 8R 2008 Survey Results Summary of the Final EIR/EIS to provide complete disclosure of all special status species data that were collected by the date of publication of the Final EIR/EIS. These surveys were not done as part of the EIR/EIS, and they were not overseen (nor were their results verified) by the BLM, CPUC, and their consultants. Also, it should be noted that additional surveys may be required prior to construction which could yield different results. Therefore, the results of these surveys do not change the Class I (i.e., significant and not mitigable to less than significant levels) conclusions made in the Draft EIR/EIS for the QCB (Impact B-7J), Hermes copper butterfly (covered under Impact B-7), and special status plant species (Impact B-5).

The EIR/EIS included best efforts to investigate and disclose environmental information (see CEQA Guidelines § 15144) and used all available resources to determine where additional surveys may be required once project-specific features are sited and access is obtained. The mitigation measures identified in the EIR/EIS commit the CPUC, BLM and SDG&E to specific standards of performance to avoid and minimize impacts. (See *Defend the Bay v. City of Irvine* (2004) 119 Cal.App.4th 1261, 1275-1276 [agency may defer defining the specifics of mitigation measures if the agency commits to the mitigation, the EIR specifies mitigation criteria, and the agency "lists the alternatives to be considered, analyzed, and possibly incorporated in the mitigation plan."].) In this way, the EIR/EIS used a conservative approach to fully disclose the full range of potential impacts to sensitive plant and wildlife species.

General Response GR-17: Consistency With Existing and Draft Regional Conservation Plans

Comments on the Draft EIR/EIS were received from a variety of reviewers with concerns regarding the consistency of the Proposed Project and alternatives with existing and draft regional conservation plans. The USFWS/CDFG letter (Comments A0024-41, 42) requests a more thorough analysis of impacts to preserve areas located within regional conservation program areas, including the Multi-Habitat Planning Area (MHPA) and Pre-Approved Mitigation Area. The County of San Diego (Comment A0018-12) noted that the Draft EIR/EIS should examine impacts to areas designated as high biological value areas or Pre-Approved Mitigation Area with the existing and proposed MSCP plans. The County wants assurances that impacts from the project do not result in impacts to covered species to such a magnitude that the project would preclude the County's take authorization for these species under these plans.

In response to these comments, a new appendix, Appendix 8O, is included in the Final EIR/EIS that graphically shows the relationship of the Proposed Project, Environmentally Superior Northern and Southern Route Alternatives (including reroutes that were analyzed in the RDEIR/SDEIS), and SDG&E's "Enhanced" Northern Route Alternative (included in the Draft EIR/Supplemental Draft EIS) with the boundaries of the various regional habitat conservation program areas and the designated or proposed preserve areas within each program area. A table is provided in Appendix 8O with the acreages of temporary and permanent impacts to each preserve/program area. The information in this appendix is designed to clarify the information provided in the Draft EIR/EIS and RDEIR/SDEIS.

One of the potential concerns noted in comments on the Draft EIR/EIS is that location of the transmission line could impact a preserve and be in conflict with the goals and objectives of a regional conservation plan, primarily through impacts to linkages or wildlife movement corridors. As discussed in the analysis of impacts to wildlife corridors for the Proposed Project on Pages D.2-142, 143 and other locations of the Draft EIR/EIS for the alternatives, construction and operation/maintenance of transmission lines are not expected to result in significant impacts to wildlife movement since wildlife can move under and around the towers, (although it is noted that significant impacts to Peninsular bighorn sheep movement may occur; page D.2-114 of Volume 1 of the Draft EIR/EIS).

Another concern voiced by the County of San Diego is that impacts to species covered under the adopted and draft MSCP plans must be adequately analyzed. The County is concerned that the project may impact species covered under the adopted and draft MSCP plans and may jeopardize the County's take authorization for these species. The take authority comes from County compliance with the policies in the Subarea Plans. The project's consistency with the Subarea Plans has been analyzed in Appendix 8O Consistency with Existing and Draft Regional Conservation Plans in the Final EIR/EIS to ensure that significant issues do not arise from the project that would jeopardize the County's commitment to preserve sensitive resources to the level needed to maintain their take authority. Impacts to listed and sensitive species are analyzed in Impact B-7 and subsections of Impact B-7 (e.g., B-7a) of the Draft EIR/EIS The level of impacts to individual species and designated preserves within the subarea plans resulting after mitigation is applied do not reach the level that the County's take authorization would be jeopardized (see Appendix 8O of the Final EIR/EIS).

General Response GR-18: Identification of Biological Resources Mitigation Lands

Multiple comments on the Draft EIR/EIS addressed the timing of identification of mitigation lands relative to the Draft EIR/EIS. The USFWS and CDFG stated that they do not think it is reasonable to postpone identification of commensurate mitigation lands until the time of project approval. The County of San Diego voiced similar concerns. The USFWS and CDFG also noted that the location of the mitigation lands should focus on identified core preserve and linkage areas identified in regional resource management plans.

The comment that the Final EIR/EIS should identify the specific locations for mitigation lands is acknowledged. The Draft EIR/EIS does not identify the specific locations for mitigation land because it is not practical or reasonably feasible to identify available mitigation land for each of the various alternatives analyzed in the EIR/EIS prior to a final decision on project approval because the extent of impacts to different habitat types varies among the alternatives. Identification of appropriate mitigation lands will be based on the ultimate decisions of the CPUC and BLM. However, Mitigation Measure B-1a on Page D.2-90 of the Draft EIR/EIS states that SDG&E shall find adequate mitigation lands acceptable to the various wildlife and regulatory agencies. The mitigation land must compensate for the loss of sensitive vegetation [Mitigation Measure B-1a]; it also must compensate for the loss of occupied habitat with the acquisition and preservation of occupied habitat [Mitigation Measures B-7d, B-7e, B-7i, B-7j, jB-7k, and B-7l]; for the loss of critical habitat with the acquisition and preservation of critical habitat [Mitigation Measures B-7c, B-7e, B-7i, and B-7l]; for the loss of FTHL MA with the acquisition and preservation of FTHL MA [Mitigation Measure B-7b]; have enough trees to mitigate for the loss of trees [Mitigation Measure B-1a]; has to be appropriate to add to ABDSP, BLM, etc.; and has to be acceptable to CPUC, BLM, Wildlife Agencies, State Parks (for impacts to ABSDP), and USDA Forest Service (for alternatives on National Forest lands) [Mitigation Measure B-1a].

Since adequate mitigation land that meets the required criteria has not been identified, and because it will be difficult to mitigate for each species or habitat in an in-kind (like for like) manner, the EIR/EIS did not assume that establishing mitigation ratios without identifying mitigation land could reduce impacts to less than significant levels. However, SDG&E must provide adequate mitigation lands at least in a "landscape sense" that meet the various criteria outlined in the Draft EIR/EIS. In other words, the mitigation land may not specifically addresses impacts to each species individually, but the overall mitigation "package" must be acceptable to the CPUC, BLM, Wildlife Agencies, State Parks (for impacts to ABDSP), and USFS (for impacts to National Forest lands). As discussed above, until final approval of a project route, it is not practical or reasonably feasible to identify mitigation lands to address the wide variety of mitigation requirement possibilities for all the alternatives identified in the Draft EIR/EIS

SDG&E is currently conducting preliminary work on mitigation concepts for the Sunrise Powerlink based on the analysis in the Draft EIR/EIS. It has obtained maps from the USFWS that identify desired mitigation lands. It has begun to link potential vegetation impacts associated with Sunrise to specific mitigation parcels within USFWS-identified mitigation land target areas. The locations of potential mitigation lands are currently confidential to avoid artificial inflation of property values in response to the prospect that SDG&E might purchase specific, identified parcels.

SDG&E is aware that the quantity and definition of specific mitigation parcels will be determined only after the issuance of the Final EIR/EIS, and after the U.S. Fish & Wildlife Service issues its Biological Opinion. Mitigation Measure B-1a, as revised in this Final EIR/EIS, requires that mitigation parcels be purchased prior to the new transmission line being energized, but a Habitat Acquisition Plan must be prepared and submitted for approval before any ground disturbance occurs.