8.0 ALTERNATIVES TO THE PROPOSED ACTION

8.1 Introduction to the Alternatives Analysis

As indicated in the CPUC's "Information and Criteria List," the PEA shall describe all reasonable alternatives to the project(s) or to the location of the project(s) which could feasibly attain the basic objectives of the project(s) and state why they are rejected in favor of the ultimate choice. The specific alternative of "no project" must also be evaluated, along with the impact. The discussion of alternatives shall include alternatives capable of substantially reducing or eliminating any significant environmental effects, even if these alternatives substantially impede the attainment of the project(s) objectives and are more costly.

As authorized therein, in addition to the information and analysis presented in this PEA, the Applicant hereby incorporates by reference the alternatives analysis presented in the "Draft Environmental Impact Report/Environmental Impact Statement and Proposed Land Use Amendment – San Diego Gas & Electric Company Application for the Sunrise Powerlink Project, SCH No. 2006091071, DOI Control No. DES-07-58" (CPUC/BLM, January 2008), as applicable to the proposed projects.

8.2 Alternatives Considered but Rejected by the Applicant

8.2.1 Non-Wires Alternatives

On January 17, 2001, then Governor Grey Davis declared a "state of emergency" in response to California's then "existing energy shortage." As indicated in that executive order, "California's energy shortage has resulted in unanticipated power outages for California residents and for critical services in the State, including but not limited to, schools, transportation facilities, businesses, and agriculture" and "these power outages threaten the health and safety of California residents, critical services in the State, and vital segments of California's economy."[1]

The DOE acknowledges that "most of California is currently a generation-short load pocket." Because it is frequently difficult to site and build efficient new generation or to build additional transmission within urban areas, the resulting load pocket will often experience congestion, meaning that "it cannot import as much low-cost energy as it would like, and the city's electricity provider(s) must operate one or more existing power plants inside the city more intensively to ensure that all customer needs are met, although at higher cost. If electricity demand inside the load pocket grows quickly without being checked by energy efficiency and demand response, the load pocket may be facing a looming reliability problem, with too little supply (local generation plus transmission-enabled imports) relative to demand – whether in actual terms or according to accepted rules for safe grid operation. In such cases, it is necessary for the transmission owner(s) serving the load pocket to resolve the reliability problem as quickly as possible. In the case of a load pocket, there are three primary ways to deal with a long-term congestion problem: (1) Build new central-station generation within the load pocket; (2) Build new or upgrade transmission capacity to enable distant generators to serve a portion of the area's load; or (3) Reduce electricity demand within the load pocket, through some combination of energy efficiency, demand response and distributed generation."[2]

[1]/ Governor Grey Davis, Executive Order D-20-01, Executive Department January 17, 2001.
[2]/ United States Department of Energy, National Electric Transmission Congestion Study, August 2006, p. 4.

The Applicant's proposed projects involve two (i.e., new generation and transmission facilities) of the three DOE-identified strategies that can be implemented to address long-term congestion problems. The third strategy (i.e., reduce electricity demand) is, therefore, a possible alternative to the proposed projects.

As indicated by the CEC: "When an inadequacy is identified in the power transmission gird, the problem can often be solved in a variety of different ways. The installation of a new transmission line to move electricity from one place to another is one way of solving that problem. However, at various points in the transmission planning process, alternative means of solving the problem are considered. These options generally include the following: [1] Different transmission line routes, different tower designs, and installation of lines either overhead or underground. All of these options are still transmission lines, but with varying types and extents of environmental impacts and widely varying cost. [2] Generation can reduce or eliminate the need for transmission lines. Generation includes gas, coal, or nuclear-powered power plants, as well as renewable energy technologies (solar, wind, geothermal, biomass, hydro, and tidal power). [3] Electricity storage could reduce the need to import power to an area of load. [4] Conservation (demand-side management) can reduce demand for power, thus reducing or eliminating the need for new transmission lines."[3]

As indicated by the CEC: "According to the State Energy Action Plan jointly written by the Energy Commission, CPUC, and California Power Authority (CPA), the State currently uses 265,000 GWh of electricity per year. Consumption is growing two percent annually. Peak demand is growing at about 2.4 percent per year, roughly equivalent of three new 500 megawatt power plants per year. This demand will need to be met by increased generation, but generation cannot always be located in areas of greatest demand so transmission of power is required. Major transmission lines are increasingly difficult to site, so consideration of other alternatives is critical. Non-transmission alternatives (also called 'non-wires' alternatives) are those that do not involve major transmission lines and are one way to respond to this load growth. Renewable energy and fossil fuel generation, if they can be produced near the location where they would be used, are potential non-wires alternatives. In addition, DSM [demand-side management] or conservation, electricity storage, and distributed generation (DG) can reduce the need for a transmission project and thus are also considered as non-wires alternatives."[4]

As indicated in EAP II with regards to the State's "priority sequence for actions," the "loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications."[5]

As part of this evaluation, since the Applicant considered whether one or more non-wires options could be undertaken as a potentially feasible option to the construction of new generation and/or transmission facilities. Possible non-wires alternatives included distributed generation (DG), energy-efficiency (EE) measures, and demand-response (DR) strategies. Presented below is a brief summary of those non-wires alternatives and the rationale for the Applicant's election not to conduct a detailed assessment of one or more of those non-construction options.

[3]/ *Op. Cit*., Comparative Study of Transmission Alternatives: Background Report, pp. 2-3.
[4]/ *Ibid*., p. 5.
[5]/ *Op. Cit*., Energy Action Plan II – Implementation Roadmap for Energy Policies, p. 2.

- Distributed generation. As defined by the CEC: "DG refers to stationary applications of electric generating technologies which are smaller than 50 MW of net generating capacity, the Energy Commission's power plant siting jurisdiction threshold. They may be owned by electric or gas utilities, by industrial, commercial, institutional or residential energy consumers, or by independent energy producers. They include generating technologies such as diesel engines, fuel cells, small and micro gas turbines, solar PV [photovoltaics], and wind turbines, and may be combined with electric storage technologies such as batteries and flywheels."[6]

  DG generally refers to "electric power generation within the distribution network or on the customer side of the meter."[7] DG technologies are considered to be "behind the meter" if residential, commercial, or industrial customers implement them to reduce the amount of electricity they purchase from the distributing utility. If a technology is "behind the meter," its energy output reduces the amount of electricity purchased from the distribution utility. DG can substitute for other investment in transmission circuits and large generation if a sufficient amount of distributed generation is operating during peak-load periods. The challenge for DG is to reliably provide sufficient capacity at the right time to mitigate overloads.[8] DG applications include emergency and stand-by generators and battery systems to supply back-up electric power for critical loads in the event of a power outage, co-generation and renewable energy systems (e.g., solar,[9] wind, small hydroelectric and biomass facilities) installed to augment utility power supplies and, if grid connected, to sell power, remote or off-grid electric loads.[10]

  Distributed generation can serve to reduce loading and use on transmission lines.[11] DG can improve reliability by adding generation capacity at the customer site for continuous power and backup supply, adding system generation capacity, freeing up addition system generation, transmission, and distribution capacity, relieving transmission and distribution system bottlenecks, and supporting power system maintenance or restoration operations with generation of temporary backup power.[12]

  The CPUC has adopted favorable rate policies for DG, including exemptions from stand-by and departing load charges, and expanded net metering. As of 2005, State incentive programs[13] have paid rebates leading to 116 MW of renewable DG from the CPUC's

[6]/ California Energy Commission, Distributed Generation: CEQA Review and Permit Streamlining, P700-00-019, December 2000, p. 10.

[7]/ Ackermann, T., Anderson, G., and Soder, L., Distributed Generation: A Definition, Electric Power Systems Research, Vol. 57, pp. 195-204.

[8]/ Energy and Environmental Economics, Inc. and Bonneville Power Administration, Olympic Peninsular Study of Non-Wires Solutions to the 500 KV Transmission Line from Olympia to Shelton and a Transformer Addition at Shelton, Draft, January 12, 2004, pp. 11 and 13.

[9]/ On January 12, 2006, the CPUC approved the California Solar Initiative, an 11-year $3.2 billion incentive program which aims to install 3,000 MW of new solar systems on-site at customers of the State's IOUs. The CPUC portion of this program will cost $2.8 billion and target 2,600 MW of solar technology. The CEC portion will focus on the CEC's responsibility for Statewide energy building codes. The CEC will seek to include solar systems in new home construction, calling upon a budget of $350 million with target of 400 MW of new solar installation (Source: California Public Utilities Commission, California Solar Initiative – Design and Administration 2007-2016, Rulemaking 06-03-004 (Filed March 2, 2006), April 24, 2006, p. 3).

[10]/ *Op. Cit*., Distributed Generation: CEQA Review and Permit Streamlining, pp. 1 and 15.

[11]/ Office of Ratepayer Advocates, Tipping Point Analysis and Attribute Assessment for DPV2, Testimony of Lon W. House, California Public Utilities Commission, November 22, 2005, p. 34.

[12]/ Arthur A. Little, Reliability and Distributed Generation, 2000, p. 16.

[13]/ Assembly Bill 970 (AB970), signed by the Governor on September 6, 2000, required the CPUC to initiate certain load control and distributed generation activities. In March 2001, the CPUC ordered (Decision 01-03-073) the State's IOUs to work with the CPUC, the CEC, and the San Diego Regional Energy Office (SDREO) to develop and

Self-Generation Incentives Program and 53 MW of primarily solar from the CEC's Emerging Renewables Program. The CPUC and the CEC have streamlined interconnection rules, resulting in 487 MW of interconnected DG since January 2001.[14]

Notwithstanding these potential benefits and achievements, a potential DG alternative was rejected based on the following legal and social factors: (1) effectuation would be subject to the actions of another agency; and (2) this option failed to substantially fulfill the identified objectives for the proposed projects.

The SWRCB has the ability to reject this alternative because it does not relate, either directly or indirectly, to the activities of the SWRCB and to the permit applications now before that agency. Since DG, EE measures, and DR strategies alone are not sufficient to address the State's energy needs, the CPUC has the ability to reject this alternative since it cannot be demonstrated that implementation of this option would facilitate the expansion of the State's backbone transmission and generation systems.

- Energy-efficiency measures. As indicated in the CEC's and CPUC's most recent energy action plan, "cost effective energy efficiency is the resource of first choice for meeting California's energy needs. Energy efficiency is the least cost, most reliable, and most environmentally-sensitive resource, and minimizes our contribution to climate change."[15] Certain conservation (load reduction) measures, such as heating efficiency, weatherization, and energy efficient lighting, can reduce loads and have an impact on peak-demand reductions.[16] The challenge with the EE measures approach is to achieve a sufficient on-peak load reduction to substantively contribute to the deferral of the need for new generation or transmission facilities.

  The CEC states that "[p]olicy makers have searched for ways to reduce expected increases in annual Statewide electricity use of roughly 43,000 GWh[17] over the next decade by either increasing spending for energy efficiency programs or increasing the rate of development of renewable generation."[18] In order to achieve an annual reduction of 0.5 percent per capita by 2013 (32,428 GWh), the CEC estimated that annual program expenditures would need to be $1.60 billion in 2013 and, in order to achieve a

implement a self-generation equipment incentive program (SGIP). Assembly Bill 1685 (AB1685), signed by the Governor on October 12 ,2003, extended the SGIP through 2007. In January 2006, the CPUC (Decision 06-01-047) established the California Solar Initiative. Self-generating technologies eligible for the SGIP are grouped into the following three incentive levels: Level 1 – Solar (photovoltaics); Level 2 – Renewable Non-Solar (fuel cells operating on renewable fuel; wind turbines; micro-turbines, internal combustion engines and gas turbines operating on renewable fuel); and Level 2 – Non-Renewable Non-Solar (fuel cells operating on non-renewable fuel and utilizing sufficient waste heat recovery; micro-turbines, internal combustion engines, and gas turbines operating on non-renewable fuel or waste gas fuel, utilizing sufficient waste heat recovery, meeting reliability and emissions criteria, as applicable) (Source: California Energy Commission, California Public Utilities Commission, San Diego Regional Energy Office, Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison, Southern California Gas Company, Self-Generation Incentive Program, July 1, 2006 – Rev. 1).

[14]/ *Op. Cit*., Energy Action Plan II – Implementation Roadmap for Energy Policies, Appendix A, pp. 6-7.

[15]/ California Energy Commission and California Public Utilities Commission, Energy Action Plan II, Implementation Roadmap for Energy Policies, October 2005, p. 3.

[16]/ *Op. Cit.*, Olympic Peninsular Study of Non-Wires Solutions to the 500 KV Transmission Line from Olympia to Shelton and a Transformer Addition at Shelton, Draft, p. 14.

[17]/ Average MW = number of GWh savings per number of hours. For the purpose of analysis, the CEC assumed that the baseload period included a total of 8,760 hours/year and the peak-load period was 560 hours. Based on a baseload period, 43,000 GWh represents 4,909 MW (43,000 GWh/8,760 hours = 4,909 MW).

[18]/ California Energy Commission, Proposed Energy Savings Goals for Energy Efficiency Programs in California, Prepared in Support of the 2003 Integrated Energy Policy Report Proceedings (02-IEP-01), 100-02-021, October 27, 2003, p. 1.

1.0 percent per capita decline in electricity use (42,502 GWh), annual expenditures would need to exceed $4.25 billion by 2013 (representing an 18-fold increase in funding over then existing levels).[19]

The CEC has formulated a set of short-term and long-term goals for Statewide energy-efficiency programs. Short-term goals seek to achieve a 7,000 GWh savings per year (over a 2004 base year) by 2006 and a 30,000 GWh savings by 2013. Achieving recommended long-term goals "would be equivalent to reducing per capita electricity use by 0.3 percent per year over the next decade from 7,145 kWh per capita in 2003 to 6930 kWh per capita in 2013. This is also equivalent to meeting roughly 50 percent of the projected increase in electricity usage over the next decade."[20] The CEC concluded that "[a]chieving the additional savings necessary to achieve a sustained reduction of 0.3 percent per capita per year would be unprecedented in the 'history of energy policy.'"[21]

A potential EE alternative was rejected based on the following legal and social factors: (1) effectuation would be subject to the actions of another agency; and (2) this option failed to substantially fulfill the identified objectives for the proposed projects. In addition, the SWRCB has the ability to reject this alternative because it does not relate, either directly or indirectly, to the activities of the SWRCB and to the permit applications now before that agency. Since DG, EE measures, and DR strategies alone are not sufficient to address the State's energy needs, the CPUC has the ability to reject this alternative since it cannot be demonstrated that implementation of this option would facilitate the expansion of the State's backbone transmission and generation systems.

- Demand-response strategies. As indicated by the CEC: "By reducing system loads during critical-peak times, demand response can help reduce the threat of brownouts and blackouts. DR is also widely regarded as having an important role in lowering power costs – and customer bills, by making organized wholesale power spot markets more competitive and efficient and less subject to the abuse of market power. Consequently, there is common agreement among California's energy policy makers, utilities, independent system operators and other interested parties that DR should be a key resource option. The California 'Energy Action Plan II' places DR at the top of the resource procurement loading order with energy efficiency. It species that five percent of system peak demand be met by DR in 2007. However, despite significant past and continuing efforts by all of the parties, this goal is unlikely to be achieved."[22]

  Reducing electric demand can defer the need for transmission lines for varying time periods. Demand can be reduced through broad strategies that encourage energy efficient appliances and public awareness, to highly technical Internet-based technologies that manage peak load. Load shifting is a fundamental demand-side management objective. It is the practice of altering the pattern of energy use so that on-peak energy use is shifted to off-peak periods. Incentives can include programs such as receiving lower prices of energy through "time-of-day" rates offered by the electric utilities. [23]

[19]/ *Ibid*., pp. 22 and 23.
[20]/ *Ibid*., p. 20.
[21]/ *Ibid*., p. 32.
[22]/ Faruqui, Ahmad and Hledik, Ryan (The Brattle Group), Draft Consultant Report – The State of Demand Response in California, CEC-200-2007-003-D, California Energy Commission, April 2007, p. 5.
[23]/ *Op. Cit.*, Comparative Study of Transmission Alternatives: Background Report, pp. 15-16.

As indicated by SDG&E: "Demand response offers an alternative to maintaining system reliability through capacity additions by providing customers opportunities to participate in demand-side management while seeking to limit the impact of their operation."[24] Most broadly, demand response defined applies rate design, incentives, and technology to enhance the ability of customers to change demand in response to prices and/or system conditions. DR strategies use real-time meters to track power usage constantly instead of once a month. Real-time meters would not alter how customers are charged but would give customers information about what they were being charged at any given time. Since power costs more during peak than during off-peak period, consumers could set-up an automatic system to regulate how much energy they use and when they use it so that they can be most cost effective.

The CPUC (D.01-05-056) has identified two general types of demand-response programs that have been used to reduce demand when energy prices are high or when supplies are tight, "'price-responsive' programs (in which customers choose how much load reduction they can provide based on either the electricity price or a per-kilowatt (kW) or kilowatt-hour (kWh) load reduction incentive) and 'reliability-triggered' programs (in which customers agree to reduce their load to some contractually-determined level in exchange for an incentive, often a commodity price discount)."[25] The CPUC (D.06-03-024) approved the majority of the IOUs' programs for the period 2006-2008. The decision stated that both price-response and load-response programs were approved because "[b]oth types of programs motivate customers to reduce their loads in exchange for some type of benefit such as reduced energy rates, bill credits, or exemptions from rotating outages."[26]

As indicated by the CAISO, one of the barriers to DR programs "is the availability of hourly meters for residential customers. . .unless the CPUC adopts a default retail tariff for all customers that passes through the hourly wholesale price in the hourly retail rate that customers face, it is unlikely that active demand-side participation in the wholesale market will materialize."[27]

A potential DR alternative was rejected based on the following legal and social factors: (1) effectuation would be subject to the actions of another agency; and (2) this option failed to substantially fulfill the identified objectives for the proposed projects. In addition, the SWRCB has the ability to reject this alternative because it does not relate, either directly or indirectly, to the activities of the SWRCB and to the permit applications now before that agency. Since DG, EE measures, and DR strategies alone are not sufficient to address the State's energy needs, the CPUC has the ability to reject this alternative since it cannot be demonstrated that implementation of this option would facilitate the expansion of the State's backbone transmission and generation systems.

Since transmission systems can potentially increase capacity with technology improvements, the capacity of the existing transmission system could potentially be increased without the siting

[24]/ *Op. Cit*., Supplement to Application of San Diego Gas & Electric Company (U 902-E) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink, A.05-12-014, Appendix V, p. V-v.

[25]/ Quantum Consulting, Inc. and Summit Blue Consulting, LLC, Evaluation of 2005 Statewide Large Nonresidential Day-Ahead and Reliability Demand Response Programs, Final Report, April 28, 2006, p. 2-3.

[26]/ California Public Utilities Commission (Summit Blue Consulting, LLC and Quantum Consulting, Inc.), Protocols for Estimating the Load Impacts from DR Programs, Draft Version 1, April 3, 2006, pp. 3 and 4.

[27]/ Wolak, Frank A., Memorandum: Summary of the Market Surveillance Committee Meeting of August 8, 2006, California Independent System Operator, August 31, 2006, pp. 7-8.

of new transmission lines. The New York Independent System Operator (NYISO) concluded that equipment upgrades could significantly increase line ratings and reduce congestion. The study of the New York transmission system indicated that a substantial number of transmission lines operate below their thermal limits due to equipment limitations at substations. Technological improvements to increase transmission capacity and allow transmission systems to operate more efficiently include upgrading transformers, retrofitting electro-mechanical devices with digital devices to allow operation of the system closer to thermal limits, and restringing existing towers with aluminum conductor composite core cable.[28]

As indicated by the NERC: "Building new transmission lines is not the only way to alleviate transmission constraints and to increase the capacity of the transmission systems. With continued public resistance to the siting and construction of new transmission facilities, other methods for increasing transmission capacity must be found. Better utilization of the existing transmission facilities is one way to accomplish this. Some of these methods to increase transmission system capacity include (1) re-conductoring existing lines with a larger wire size, if tower design permits; (2) utilizing empty tower position on multiple circuit tower lines; (3) providing voltage support by adding capacitor banks or static var compensators in existing substations; (4) utilizing new flexible AC transmission (FACTS) devices; (5) replacing transmission transformers with larger capacity ones or by adding additional transformers at existing locations; and (6) upgrading limiting circuit components within substations. All of these methods can result in additional transmission capacity but require no additional right-of-way acquisition that may drastically delay or even derail a new transmission line project."[29]

Since the installation of technological improvements designed to increase transmission capacity would not serve to fulfill the projects' stated objectives, this alternative was not further examined. In addition, the SWRCB has the ability to reject this alternative because it does not relate, either directly or indirectly, to the activities of the SWRCB and to the permit applications now before that agency. Since technological improvements, undertaken in combination with DG, EE measures, and DR strategies, are not sufficient to address the State's energy needs, the CPUC has the ability to reject this alternative since it cannot be demonstrated that implementation of this option would facilitate the expansion of the State's backbone transmission and generation systems.

8.2.2 Alternative Transmission Routing Alternatives[30]

As indicated on March 23, 2001 by the CAISO: "The Valley-Rainbow Project is necessary to reliably serve the growing electric demands in the San Diego area. In addition, the project is an important component of a comprehensive strategy to enhance access by consumers in San Diego and other parts of California to reasonably priced, efficient and environmentally superior generation. . .the Valley-Rainbow Project should now be evaluated by the Board as part of a broad strategy by the State of California to put into place a robust transmission system to support reliable service to customers. In this regard, the Valley-Rainbow Project provides benefits to consumers in San Diego and the rest of California. . .Unlike the route proposed by

[28]/ Congressional Research Service, Electric Reliability: Options for Electric Transmission Infrastructure Improvements, CRS Report to Congress, RL32075, September 20, 2006, p. CRS-7.

[29]/ *Op. Cit*., Reliability Assessment: 2002-2011, The Reliabiilty of Bulk Electric System in North America, Final Draft for BOT Approval, p. 29.

[30]/ The consideration of "alternative transmission routing" differs from the subsequent assessment of "alternative transmission alignments." Under the former option, routes other than those described in the FLA, DEIS, and FEIS were considered. Under the latter, some of the alignment variations presented in the FLA, DEIS, and FEIS are examined.

SDG&E, the route associated with the Lake Elsinore project will have minimal impacts on residential communities. SDG&E can and should be encouraged to explore the Forest Service land alternative and other alternatives that would minimize impacts on affected communities."[31]

On March 30, 2001, without selecting a preferred near-term alternative and without regards for routing, the CAISO Board of Governors adopted a resolution finding that a new 500-kV project(s), such as the Valley-Rainbow Interconnect Project, is needed to address the identified reliability concerns of San Diego and the southern Orange County portion of the ISO grid beginning in 2004. As noted by the CEC: "Although not proposed for this function, EVMWD's LEAPS can also be viewed as an alternative to the SDG&E Valley-Rainbow 500 kV Interconnect Project."[32]

The CAISO Board of Governors' formal needs determination neither specifically identified a precise transmission for a new 500-kV transmission line or route serving San Diego nor contained any expiration terms or conditions. As such, the CAISO's actions serve as a relevant and applicable needs determination applicable to the proposed projects.

In 2002, the CAISO established the "Southwest Transmission Expansion Plan" (STEP) as a collaborative ad-hoc study group whose goal was "[t]o provide a forum where all interested parties are encouraged to participate in the planning, coordination, and implementation of a robust transmission system between Arizona, Nevada, Mexico, and southern California areas."[33] Studies conducted by the CAISO (Kyei Report) concluded that a new high-voltage electric transmission line between Riverside and San Diego Counties was critically needed to serve future load growth. "Studies conducted by the Southwest Transmission Expansion Plan in 2003 indicated that a new 500 kV line into San Diego will be needed to serve future load growth. . .STEP examined several options for routing a new line to San Diego." Figure 8-1 (SDG&E's 230/500-kV System with the LEAPS Project) is extracted from the Kyei Report.[34]

As further indicated in the Kyei Report: "Several alternative transmission lines were considered from the Imperial Valley into San Diego as well as the new 500 kV line associated with the Lake Elsinore Advanced Pumped Storage Project."[35] Options examined included: (1) Imperial Valley-Ramona 500-kV line (Imperial Valley-San Diego Expansion Plan [ISEP]); (2) Talega-Escondido/Valley-Serrano 500-kV line (without the 500-MW LEAPS project); (3) Talega-Escondido/Valley-Serrano 500-kV line (with the 500-MW LEAPS project); and; (4) both the ISEP and Talega-Escondido/Valley-Serrano 500-kV line (without the 500-MW LEAPS project) combined and connected to the same substation in San Diego. The Kyei Report concluded that "both projects would provide a significant increase in San Diego import capacity (from 2850 MW to 3600 MW with all lines in service). . .A combination of ISEP and LEAPS project provides additional benefits such as a 3800 MW import capability."[36] The ISEP project has become

[31]/ Memorandum from James Detmers, Acting Vice President of Operations, Armando J. Perez, Director of Grid Planning, and Steve Greenleaf, Director of Regulatory Policy, California Independent System Operator to the CAISO Board of Governors, Re: Valley-Rainbow Transmission Project, March 23, 2001, p. 1 (http://www.caiso.com/docs/09003a6080/0c/af/09003a60800cafd1.pdf).

[32]/ *Op. Cit*., Comparative Study of Transmission Alternatives: Background Report, p. 62.

[33]/ California Independent System Operator, Southwest Transmission Expansion Plan, January 17, 2003, p. 1.

[34]/ Kyei, John, Comparative Reliability Evaluation for Alternative New 500 kV Transmission Lines into San Diego, Grid Planning Department, California Independent System Operator, April 17, 2004, Figure 7, p. 16.

[35]/ *Ibid*., p. 2.

[36]/ *Ibid*., p. 34.

SDG&E's SRPL project and its potential to serve as an alternative to the proposed projects is addressed below.

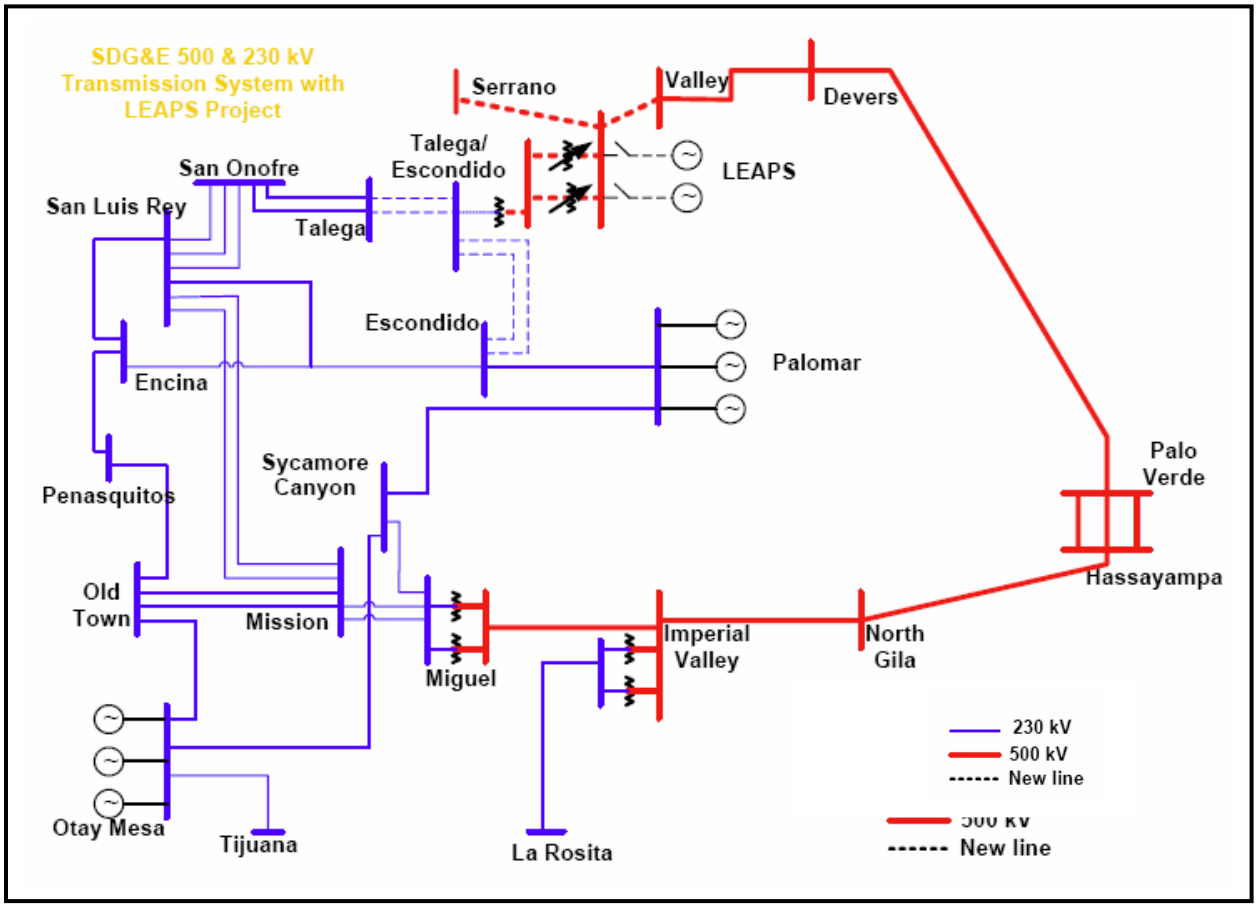


Figure 8-1
SDG&E'S 230/500-KV SYSTEM WITH THE LEAPS PROJECT
Source: California Independent System Operator

In 2004, the CAISO initiated the "CAISO South Regional Transmission Plan" (CSRTP) for the purpose of assessing the following three major transmission projects in the southern California region: (1) Tehachapi project (transmission infrastructure to accommodate wind generation in the Tehachapi area); (2) Sun Path project (combination of SDG&E's SRPL and Citizens Energy's and Imperial Irrigation District's [IID] Phase 2 Green Path projects connecting Imperial Valley to the San Diego area); and (3) LEAPS project (Lake Elsinore pumped storage plant and associated transmission line). The CAISO recognized "[e]ach of these projects offers unique reliability and economic benefits."[37] Those three projects, as generally represented in Figure 8-2 (CSRTP Projects), constitute possible alternatives to the proposed projects.

Most transmission projects in California are sponsored by one of the three IOUs: SCE, SDG&E, and PG&E. The activities of each IOU are governed by the CPUC. Under Section 1001 of the

[37]/ *Op. Cit.*, CAISO South Regional Transmission Plan for 2006, Presentation at CEC Intermittency Analysis Project, Energy Commission Staff Workshop, p. 4.

Public Utilities Code, a utility is required to file a certificate of public convenience and necessity (CPCN) with the CPUC, who must find that the present or future public convenience and necessity requires or will require such construction. The needs determination may be based on: (1) reliability; (2) cost-effectiveness (project costs recovered over time through consumer savings); (3) State renewable goals; or (4) any combination of the above factors.[38]

Those transmission projects that have filed CPCN applications, including both SDG&E's proposed Sunrise (Sunpath) Powerlink (SRPL) and SCE's partially permitted Tehachapi transmission projects, in addition to SDG&E's previous Valley-Rainbow Interconnect project (Valley-Rainbow), constitute potential alternatives to the proposed projects and are separately discussed below.

- Valley-Rainbow Interconnect Project (SDG&E Proposed Alignment). As indicated by SDG&E: "Can the TE/VS-LEAPS project be configured to provide the same benefits as the Valley-Rainbow Interconnection (VRI)?" The answer is "'yes,' provided that the necessary associated projects and upgrades are identified and built. . .the TE/VS-LEAPS can be configured to provide the same benefits as VRI."[39]

  As indicated by the CEC, the LEAPS project "is a potential source for importing more power into San Diego. Associated with the proposed project is a 30-mile, merchant-owned 500 kV transmission line that would connect Southern California Edison's Valley-Serrano 500 kV line to a new substation within SDG&E's service territory. This transmission line would be similar electrically to the Valley-Rainbow line that was denied by the CPUC in December 2003. The Lake Elsinore Advanced Pump Storage Project would increase the transmission capacity form Southern California Edison into SDG&E by approximately 750 MW. The Lake Elsinore Advanced Pump Storage Project is not subject to State regulation, but under the jurisdiction of the Federal Energy Regulatory Commission, where an application is currently in review."[40]

  On March 23, 2001, SDG&E submitted an application (CPUC Docket No. A.01-03-036), seeking authorization from the CPUC for the Valley-Rainbow interconnect project. As illustrated in Figure 8-3 (Previously Proposed Valley-Rainbow Interconnect Project), the 31-mile Valley-Rainbow project was proposed as an interconnection between SDG&E's existing 230-kV transmission system (at the proposed Rainbow substation to be located in the unincorporated community of Rainbow in San Diego County) and SCE's existing 500-kV transmission system (at the existing Valley substation located in the unincorporated community of Romoland in Riverside County).

  As part of the alternatives analysis for the Valley-Rainbow project, the CAISO considered a non-wires alternative. As noted by the CAISO: "Pitting generation against transmission challenged the notion of facilitating a competitive market. Staff felt that 'While there certainly may be a place for 'competition' between generation and transmission projects at a local level. . .any tangible short-term benefit resulting from a generation project deferring or displacing a larger regional transmission project is likely

[38]/ California Public Utilities Commission, Developments in Transmission Siting at the PUC, November 9, 2006.

[39]/ San Diego Gas & Electric Company, Attachment ALT-36, Response ALT-36, Sunrise Powerlink Project (A.06-08-010), SDG&E Response to Data Request No. 1, November 17, 2006.

[40]/ California Energy Commission, Environmental Issues and Opportunities in the California-Mexico Border Region, Staff Paper, CEC-600-2005-022, May 2005, p. 44.

to be outweighed by the less tangible costs of reduced access and therefore less competition. Moreover, reliance on 'market' generation to displace the need for critical regional transmission facilities will inevitably give rise to market power problems and the need to 'negotiate' a deal with such generation on a long-term basis.'"[41]

As indicated by the CAISO: "The Valley-Rainbow Project is necessary to reliably serve the growing electric demand in the San Diego area. In addition, the project is an important component of a comprehensive strategy to enhance access by consumers in San Diego and other parts of California to reasonably priced, efficient and environmentally superior generation. . .Since October 2000, additional information has emerged regarding a potential alternative route for the Valley-Rainbow Project, in association with a pumped storage project at Lake Elsinore. The project includes a transmission line that can be extended to connect Valley substation to the proposed Rainbow substation and would thus be functionally equivalent to the project proposed by SDG&E. . .The Valley-Rainbow Project supports the State's goal of ensuring reliable, cost-effective service to all California users by strengthening transfer capability between the San Diego area and regions to the north, as well as access by San Diego to power from Arizona and access by northern California to generation in San Diego and Mexico."[42] As reported by SDG&E, less new generation would be built if the Valley-Rainbow project were not to be build because economic incentives for new generation would be limited "due to congestion constraints going north from SDG&E."[43]

As proposed by SDG&E, the Valley-Rainbow interconnect project included a new single-circuit 500-kV electric transmission line approximately 31 miles in length connecting a proposed new SDG&E 500-kV/230-kV bulk power transmission substation near the community of Rainbow (San Diego County) to SCE's Valley substation near Romoland (Riverside County). The proposed 500-kV transmission line would have been built on steel poles and lattice towers within a new transmission right-of-way. A second 230-kV circuit would have been added to the existing Talega-Escondido 230-kV transmission line. The proposed second 230-kV circuit would have been placed on existing steel supported structures. A 7.7-mile section of an existing 69-kV transmission circuit, currently installed on one side of the Talega-Escondido 230-kV transmission line structures, would have been rebuilt on new structures within the existing right-of-way between SDG&E's Pala and Lilac substations (San Diego County). Voltage support upgrades to SDG&E's existing Mission, Miguel, and Sycamore Canyon substations were also included in the Valley-Rainbow interconnect project.

SDG&E set forth a number of project objectives, including: (1) maintain reliable power delivery; (2) increase the region's import capability; (3) meet continuing growth and SDG&E customer load; (4) increase the region's export capability; (5) provide a link to the California transmission grid 500-kV infrastructure; and (6) utilize generation resources in the San Diego region. Since these objectives are similar to many of the Applicant's objectives for the TE/VS Interconnect project, the Applicant initially

[41]/ County of San Diego, San Diego Regional Energy Office, City of San Diego, Utility Consumers Action Network, San Diego County Water Authority, San Diego Association of Governments, and Ports of San Diego (Science Applications International Corp.), San Diego Energy Infrastructure Study, December 30, 2002, p. 4-16.

[42]/ Memorandum from James Detmers (Acting Vice President of Operations), Armando J. Perez (Director of Grid Operations), and Steve Geenleaf (Director of Regulatory Policy) to CAISO Board of Governors, Re: Valley-Rainbow Transmission Project, March 23, 2001, pp. 1 and 4.

[43]/ *Op. Cit*., San Diego Energy Infrastructure Study, p. 4-16.

considered the Valley-Rainbow project a possible alternative to the proposed transmission project.

On October 23, 2002, the assigned Administrative Law Judge (ALJ) issued a decision denying, without prejudice, SDG&E's application to construct the Valley-Rainbow project. The ALJ found that SDG&E would continue to meet established reliability criteria for the region until 2008. Utilizing a five-year planning horizon (2001-2006), the ALJ concluded that the Valley-Rainbow project was not then needed for reliability purposes. The ALJ also concluded that the project could not be justified on economic grounds. An "Alternate Proposed Decision," which was not adopted, concludes that SDG&E has a reliability need in 2006, which fell within the required five-year planning horizon.

As reported by the CEC, "the CAISO had determined that it [Valley-Rainbow] was needed. Had the project been allowed to go into service in 2004 as requested, SDG&E stated that it would have saved its customers about $191 million in its first two years, because RMR [Reliable-Must-Run[44]] costs from the MLCC [Minimum Load-Cost Compensation] side as well as the fixed option payment."[45]

On December 19, 2002, the CPUC rejected SDG&E's application (D.02-12-066, rehearing denied in D.03-05-038) based on need and cost-benefit analysis. As reported by the CEC, the CPUC "denied the CPCN despite the fact that the California CAISO had approved the project and directed SDG&E to construct the line in order to satisfy a need it had identified. CAISO provide a witness to testify to that effect in the hearing. Nonetheless the CPUC disagreed and found that need had not been demonstrated."[46]

The CPUC issued a subsequent decision stating that "SDG&E will have a capacity deficiency in 2008 under N-1/G-1 conditions."[47] A "reasonably foreseeable forecast" deficiency of 301 MW was documented by 2010 and a 571 MW deficiency was documented by 2012 with the SDG&E service area.[48] The CPUC's decision directed the preparation of "a document that provides a preliminary alternatives feasibility analysis based on the environmental information developed to date"[49] as part of the Valley-Rainbow proceedings.

The CEC concluded: "Although not proposed for this function, EVMWD's LEAPS can also be viewed as an alternative to SDG&E's Valley-Rainbow 500 kV Interconnect Project."[50] As excerpted from the CPUC/BLM proceedings, the geographic relationship between the proposed projects and the SDG&E's Valley-Rainbow alignment is shown in Figure 8-4 (Relationship between the Proposed Projects and the Valley-Rainbow 500-kV Interconnect Project Alignments).

[44]/ Reliability-Must-Run (RMR) contracts are contracts the CAISO enters into to assure that units required for local reliability are available.

[45]/ *Op. Cit*., Addendum to Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond, Staff Report Addendum, p. 9.

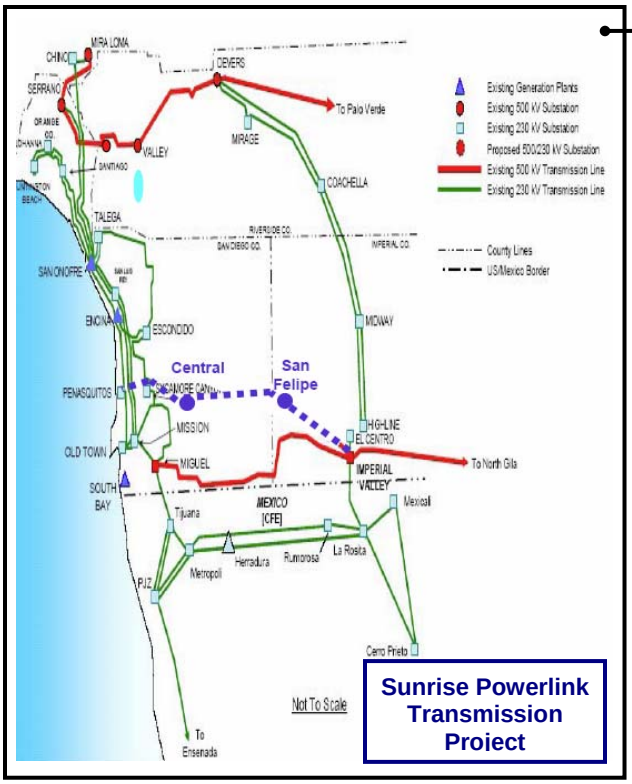
[46]/ *Op. Cit*., Comparative Study of Transmission Alternatives: Background Report, p. 38.

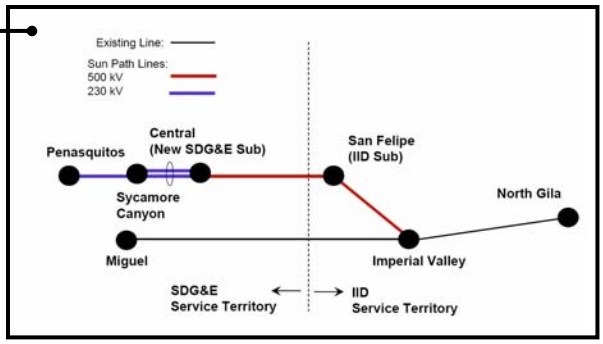
[47]/ "N-1" refers to the outage of the most critical transmission network element. "G-1" refers to the outage of the most significant in-basin generator.

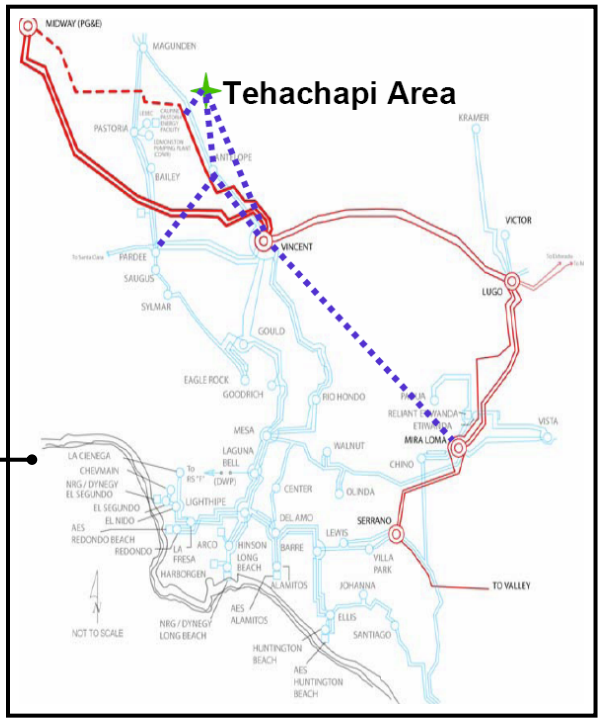
[48]/ California Public Utilities Commission, Opinion on the Need for Additional Transmission Capacity to Serve the San Diego Gas & Electric Company Service Territory, Decision 02-12-066, December 19, 2002, p. 52.

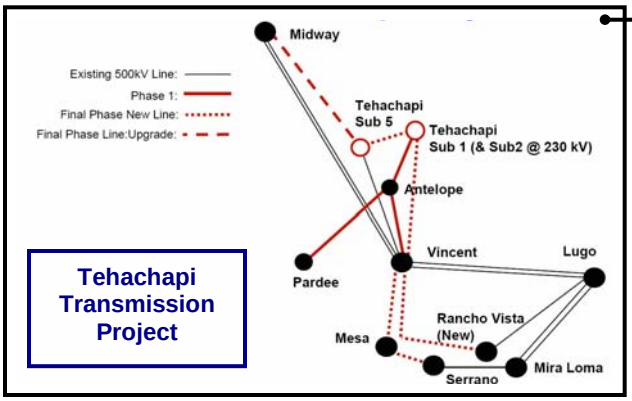
[49]/ *Ibid*., p. 71.

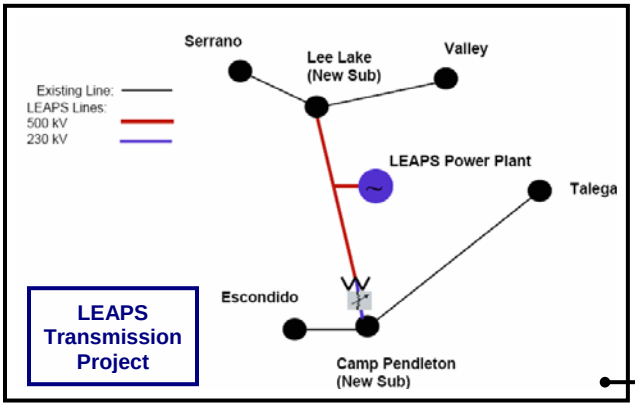
[50]/ *Op. Cit*., Comparative Study of Transmission Alternatives: Background Report, p. 62.











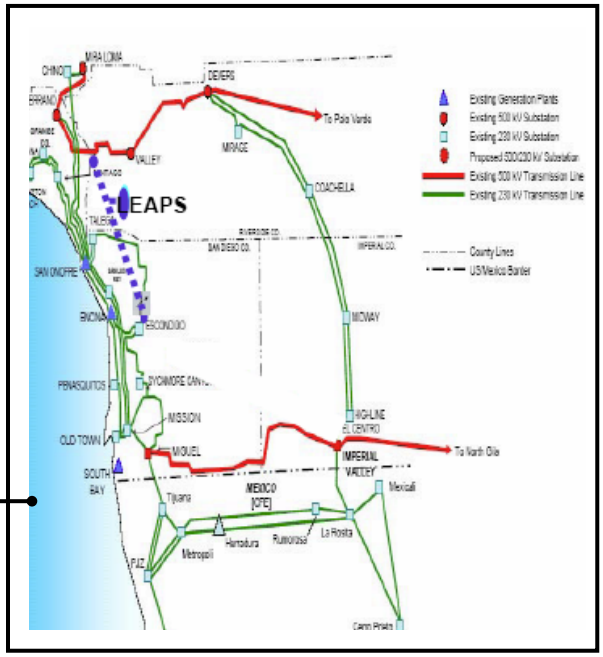


Figure 8-2
CSRTP PROJECTS
Source: California Independent System Operator

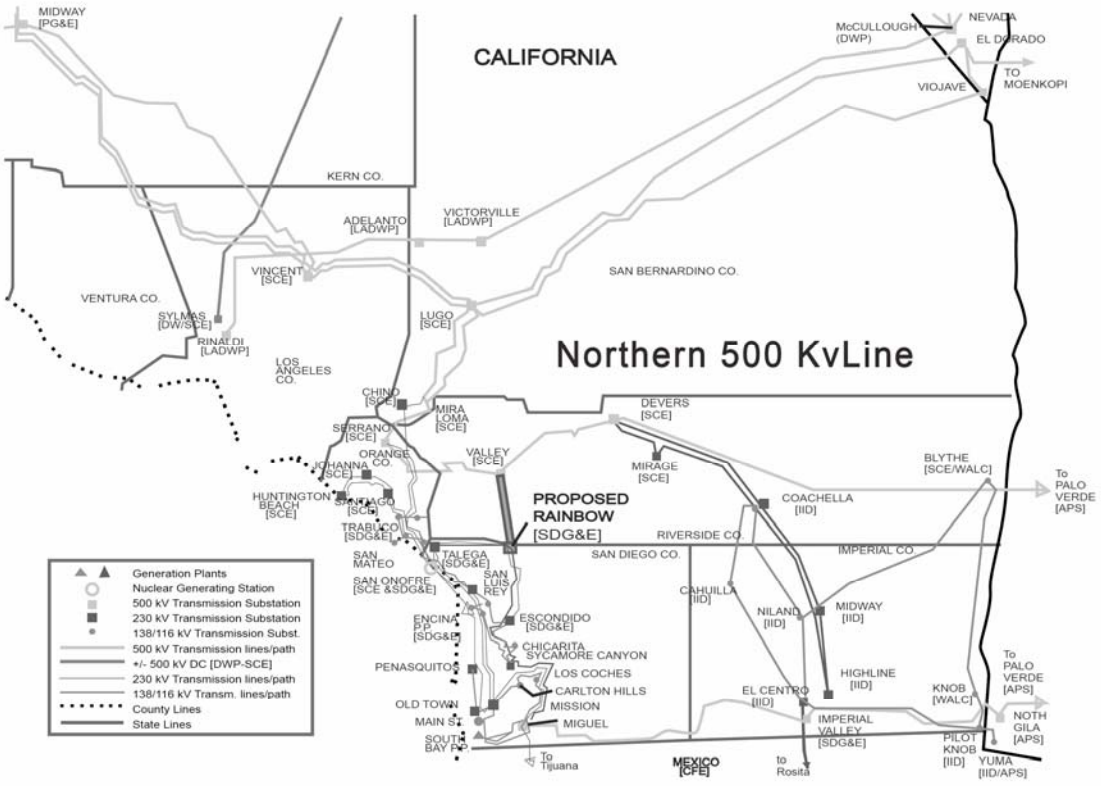


Figure 8-3
PREVIOUSLY PROPOSED
VALLEY-RAINBOW INTERCONNECT PROJECT
Source: Southwest Consortium for Environmental Research and Policy

As illustrated, the Valley-Rainbow alignment generally parallels and is located to the east of the transmission alignments associated with the proposed project. This figure is presented for illustrative purposes only since the Applicant's proposed alignments have been modified from the date of this graphic's preparation.

Although providing a linkage to SCE's Tehachapi wind resources, absent a pumped storage component, the Valley-Rainbow project would not as effectively promote the use of renewable energy resources within the San Diego area.

Unlike the public routing of the proposed projects, the primarily private routing of the Valley-Rainbow project would not reduce potential impacts to private-property owners. The Valley-Rainbow alternative was, therefore, rejected as non-responsive to the projects' primary objectives.

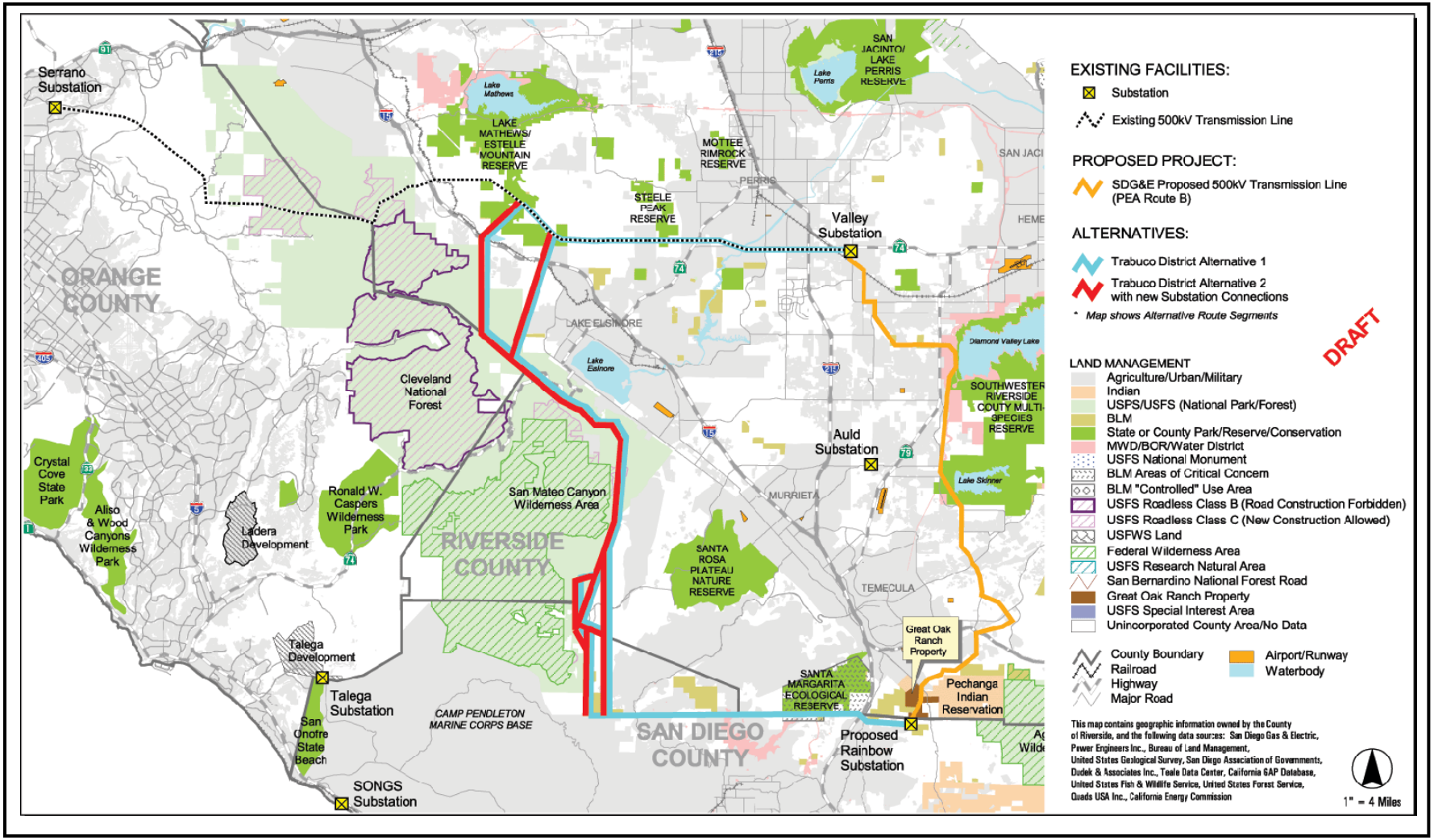


Figure 8-4
RELATIONSHIP BETWEEN THE PROPOSED PROJECTS AND THE VALLEY-RAINBOW ALIGNMENTS
Source: California Public Utilities Commission/Bureau of Land Management

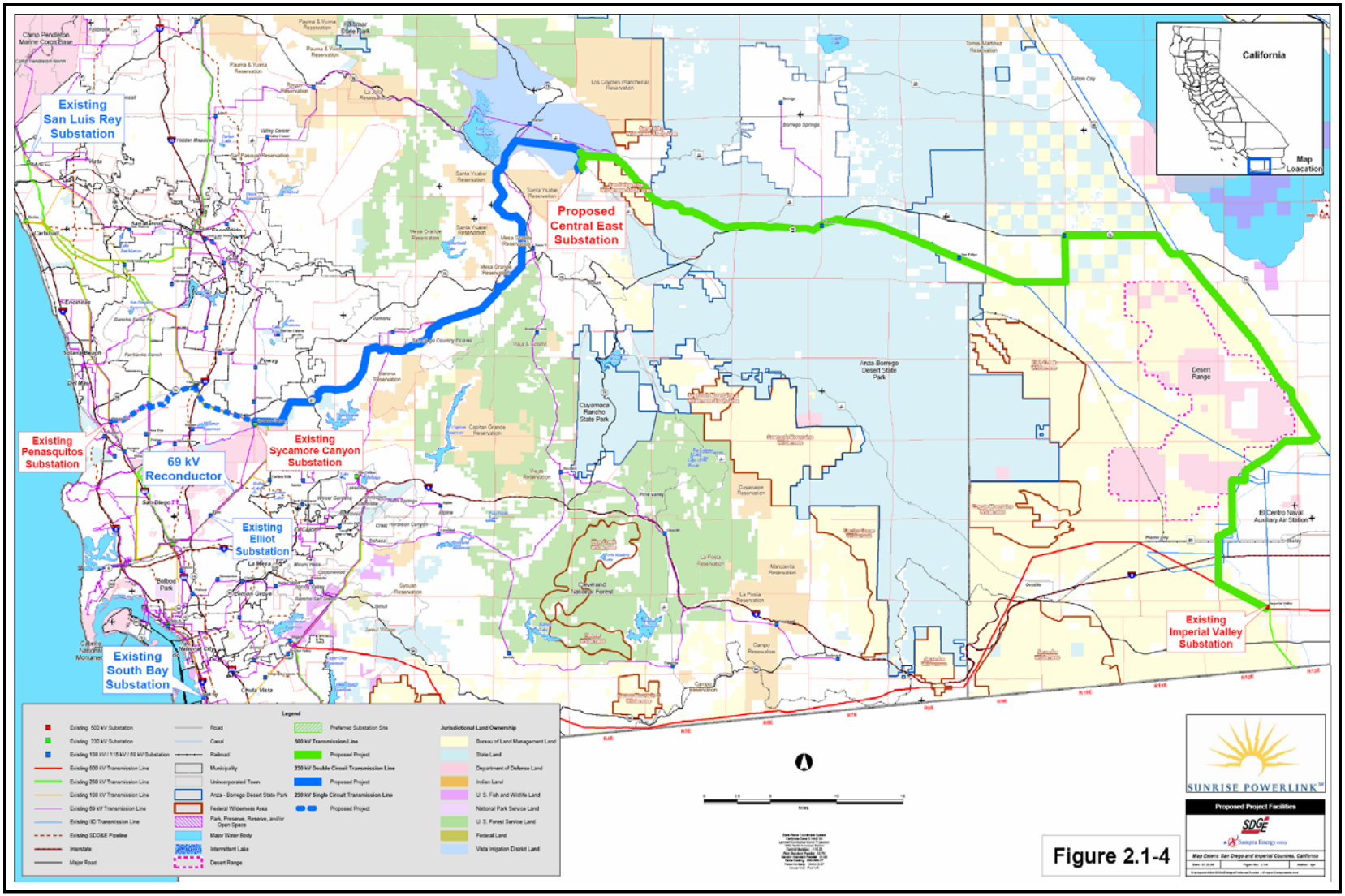


Figure 8-5
SUNRISE (SUNPATH) POWERLINK TRANSMISSION PROJECT
Source: San Diego Gas & Electric Company

As part of their independent deliberations concerning the SRPL project, on March 16, 2007, the CPUC and the BLM published a "Final Notice – CPUC/BLM Notice Regarding Conclusions on EIR/EIS Alternatives to the Proposed Sunrise Powerlink Project – Results of the Second Scoping Process." With regards to the Valley-Rainbow project, the CPUC and BLM note: "these alternatives would either build a new single-circuit 500 kV line from SCE's Valley substation to a new 500/230 kV Rainbow substation in northern San Diego County or implement a Valley-Rainbow alternative that was evaluated in the November 2002 Interim Preliminary Report on Alternatives Screening for the SDG&E Valley-Rainbow 500 kV Interconnect Project (the V-R Alternatives Report). Valley-Rainbow as the subject of SDG&E's filing for a CPCN and a PEA on March 23, 2001, and the CVPUC denied the CPCN in December 2002 with the view that a reliability need had not been demonstrated. In the vicinity of Temecula, the Great Oak Ranch property, and the Pechanga Indian Reservation, a feasible corridor for Valley-Rainbow does not exist. Other Valley-Rainbow 500 kV alternatives recommended for elimination include: Devers-Pala, Devers-Ramona, Coachella-Ramona-Miguel, Devers-Miguel via Northern San Diego County, and Devers-Miguel via Imperial County. Due to potential land use impacts to national monuments, Roadless Areas on National Forest lands, Indian reservations, the Beauty Mountain Wilderness Study Area, and ABDSP, no corridors are available that would reduce impacts in comparison to those of the proposed [Sunrise Powerlink] project."[51]

The Applicant has considered the analysis presented by the CPUC and BLM in the "Final Notice – CPUC/BLM Notice Regarding Conclusions on EIR/EIS Alternatives to the Proposed Sunrise Powerlink Project – Results of the Second Scoping Process" and concurs that the "Valley-Rainbow" alternatives do not have the potential to substantially reduce the proposed projects' potential environmental effects.

- Valley-Rainbow Interconnect Project (CPUC/BLM Alternative Alignments). An alternative analysis for the Valley-Rainbow project was prepared in response to the ALJ's October 21, 2002 and December 19, 2002 rulings, directing the CPUC to prepare a document providing a preliminary alternatives feasibility analysis for that project. The alternatives screening process culminated in the identification and screening of about 45 alternatives, including the transmission lines associated with the proposed projects. As indicated in the CPUC/BLM analysis, those alignments "would follow transmission paths across the Trabuco [Ranger] District and would result in a project that is electrically the same or similar to the proposed [Valley-Rainbow] project. Alternative 1 would be essentially the same as the proposed project, since the 500 kV line would still connect between the existing Valley and proposed Rainbow substations. Alternative 2 would entail construction of a new 500 kV switching station on or near the Valley-Serrano 500 kV right-of-way, located about 15 miles west of the existing Valley substation, and the relocation of the Rainbow substation site somewhere to the west of Rainbow, along the existing Talega-Escondido right-of-way. The 230 kV system changes would remain as described in the proposed project. Since this alternative is electrically the same as the proposed project, it would meet all project objective criteria."[52]

[51]/ California Public Utilities Commission and United States Department of the Interior - Bureau of Land Management, Final Notice – CPUC/BLM Notice Regarding Conclusions on EIR/EIS Alternatives to the Proposed Sunrise Powerlink Project – Results of the Second Scoping Process, March 16, 2007, p. 26.

[52]/ California Public Utilities Commission and United States Department of the Interior – Bureau of Land Management, Interim Preliminary Report on Alternatives Screening for: San Diego Gas & Electric Company Valley - Rainbow 500kV Interconnect Project CPCN Application No. 01-03-036 U.S. BLM Case No. CACA-43368, November 2002, p. ES-29.

Other alternatives identified by the CPUC/BLM related primarily to possible routing options for the Valley-Rainbow project (i.e., alternative transmission routes between the Valley and Rainbow substations). Those routing options not eliminated by the CPUC/BLM based on their failure to meet preliminary feasibility criteria included: (1) Eastern Riverside County – Route North of Vail Lake (45 miles); and (2) Eastern Riverside County – Route South of Vail Lake (47 miles).[53]

In addition, the following additional potential transmission routes, traversing the Palomar Ranger District (PRD) of the CNF, were not eliminated by the CPUC/BLM based on the preliminary screening criteria: (1) Alternative 1 (SDG&E Southeast Route) (57-61 miles)[54]; and (2) Alternative 3 (46 miles).[55]

As noted in correspondence from the CAISO: "While the ISO is not responsible for the specific siting of transmission lines, we are responsible for identifying transmission system technical needs and recommended transmission system additions. Currently, there is only one major transmission interconnection between the San Diego area and the rest of the State of California. This line has limited capacity to import or export power and creates a bottleneck that, absent transmission system additions, will seriously impact the reliability of electric service to the San Diego area in the future. In March 2001, the ISO recommended that a new 500 kV transmission line be constructed linking the San Diego area with the rest of the State's electrical grid by the year 2004. Based on this recommendation, the San Diego Gas and Electric Company filed an application for a Certificate of Public Convenience and Necessity for such a line (Valley-Rainbow 500 kV Transmission Project) with the California Public Utilities Commission. The CPUC application identified several potential routes for such a line, however, during the permitting process, essentially all of the routes being considered for this line were deemed to be infeasible. A transmission line through the Cleveland National Forest, as suggested in the potential legislation, would be the functional equivalent of the Valley-Rainbow 500 kV Transmission Project. Such a line would provide a major benefit to the San Diego area well into the future by helping to ensure system reliability, by reducing

[53]/ As described, the Eastern Riverside County alternative would diverge from the proposed Valley-Rainbow project alignment between Diamond Valley Lake and Lake Skinner. The transmission line would generally follow Rawson Road in a west to east direction across the Southwestern Riverside County Multi-Species Reserve. The alternative would continue in an easterly direction for about 4 miles, to east of County Route 3, before turning south. The alternative would travel in a southerly direction for about 5 miles, before turning southwesterly towards Vail Lake. One route would pass north of Vail Lake and the other to the south. Both routes would re-connect to the proposed Valley-Rainbow alignment east of Highway 79. These two variations to the Valley-Rainbow alignment are not further addressed since they share much of the same alignment as the Valley-Rainbow line and, from the perspective of the LEAPS and TE/VS Interconnect projects, do not represent distinct variations thereof.

[54]/ As indicated in the CPUC/BLM Valley-Rainbow analysis, PDR Alternative 1 would traverse designated roadless areas, the Southwest Riverside County Multi-Species Reserve, and had the potential to adversely impact both the Palomar Observatory and Palomar Mountain State Park. Since the Eastern Riverside County alternative would introduce additional impacts beyond those associated with the LEAPS and TE/VS Interconnect projects, that alternative was eliminated since it would not likely result in the avoidance or minimization of the projects' significant environmental effects.

[55]/ The PRD Alternative 3 would traverse the Agua Tibia Wilderness Area and the Pala Indian Reservation. Presidential authorization would be required in order to encroach into an established wilderness area. In addition, approval of the transmission right-of-way across tribal lands would be required from the Pala Band of Mission Indians. Because of the sovereign nature of tribal lands and the Applicant's own understanding of the complexity and likelihood of obtain a Presidential waiver to encroach onto designated wilderness, the Applicant has concluded that this alternative is not feasible.

power costs and by helping connect a proposed new pumped hydro project in the area, the Lake Elsinore Advanced Pumped Storage facility."[56]

The CAISO concluded that the Valley-Rainbow alternative alignments were "deemed to be infeasible." The CAISO did, however, identified the Applicant's proposed transmission alignment as being "functional equivalent" and of "major benefit to the San Diego area." Based on that determination and the benefits to the grid resulting from the development of that interconnection, the Applicant filed a separate SUP application with the USFS for the stand-alone TE/VS Interconnect project. Subsequent environmental and engineering analyses undertaken by the Applicant has been based on the assumption that the proposed transmission lines would function as a regional interconnection.

The Applicant has considered the analysis presented by the CPUC and BLM in the "Final Notice – CPUC/BLM Notice Regarding Conclusions on EIR/EIS Alternatives to the Proposed Sunrise Powerlink Project – Results of the Second Scoping Process" and, relative to the proposed projects, concurs that the Valley-Rainbow alternatives do not have the potential to substantially reduce the proposed projects' potential environmental effects.

- Sunrise (Sunpath) Powerlink Project (SDG&E Proposed Alignment).[57] As indicated by the CEC, "California must urgently encourage major investment in new transmission infrastructure needed to access remotely located renewable resources in the Tehacaphi and Imperial Valley areas. Without this investment it will be difficult for California to meet its Statewide Renewable Portfolio Standards. . .Transmission upgrades in the Tehacapi wind and the Imperial Valley geothermal resource areas[58] are needed to reap the benefits of some of California's most promising renewable resources."[59]

  As indicated in the CPUC's 2006 report to the Legislature regarding the progress of the State's three IOUs to achieve California's RPS, mandated under Senate Bill 1078 (SB1078),[60] the CPUC noted that "[i]n addition to the Tehachapi and Sunrise Powerlink

[56]/ Letter from Terry M. Winter, President and Chief Executive Officer to Honorable Spencer Abraham, Secretary of Energy, and Honorable Gale A. Norton, Secretary of Interior, Subject: HR 1230, April 16, 2003, p. 2.

[57]/ On December 14, 2005, SDG&E filed with the CPUC an application to construct and operate the Sunrise Powerlink project, a 500-kV interconnection between the San Diego and the Imperial Valley substations. On March 16, 2006, SDG&E, the Imperial Irrigation District (IID), and Citizens Energy Corporation executed a memorandum of agreement allowing for the consolidating two separate projects under a single CPUC application. Under the MOA, the SDG&E-owned portion, identified as the "Sunrise Powerlink," would consist of the 500-kV line from the Narrows Substation to the new proposed Central Substation and all of the related facilities west of the Central Substation. The IID-owned portion, identified as "Greenpath Southwest," would consist of the 500-kV line from the Imperial Valley Substation to the Narrows Substation. The CAISO's "South Regional Transmission Plan for 2006 – Findings and Recommendations on the Sun Path Project" (CAISO, July 28, 2006) called the combined project "Sun Path." On August 4, 2006, SDG&E submitted an amended application to the CPUC for the consolidated transmission project.

[58]/ The Imperial Valley has a "layer-cake" arrangement of formations, similar to sedimentary oil and gas fields, where geothermal fluids are produced in the boundaries of an area that has subsided due to the actions of the San Andreas fault. The Salton Sea reservoir is in the Imperial Valley, about 25 miles from El Centro. A number of productive wells have been drilled and are producing in that area, including Vonderahe I which is the most productive well in the continental United States. Approximately 300 MW are now being generated from the Salton Sea reservoir (Source: Massachusetts Institute of Technology, The Future of Geothermal Energy – Impact of Enhanced Geothermal Systems on the United States in the 21st Century, An Assessment by an MIT-Led Interdisciplinary Panel, 2006, Section 6.2.1).

[59]/ *Op. Cit*., Integrated Energy Policy Report, CEC-100-2005-007CMF, pp. 8 and 99.

[60]/ SB1078 allows publicly-owned electric utilities the flexibility to define their own RPS programs. A number of publicly-owned utilities are planning to define large hydroelectric generation as an eligible renewable technology (Source: CEC, Renewable Resources Development Program, p. 78).

transmission projects, the [CA]ISO and FERC are independently reviewing a third RPS-related transmission project in southern California. The proposed Lake Elsinore Advanced Pumped Storage (LEAPS) project would add a 500 MW pumped storage project, and interconnect a 500 kV transmission line to SCE and SDG&E transmission lines, which could increase SDG&E's ability to import additional energy from the SCE area."[61] Since the transmission lines associated with the proposed projects are often discussed in relation to the Tehachapi and Sunrise (Sunpath) Powerlink projects, the Applicant examined whether one or both of those projects would constitute a potentially feasible alternative.

On August 4, 2006, SDG&E filed an amended application (A.06-08-010), including a proponent's environmental assessment (PEA), with the CPUC for authority to construct the SRPL. As described in SDG&E's amended application, the "Sunrise Powerlink is a proposed 500 kilovolt alternating current transmission line that would be placed in service by the year 2010. The project will connect the existing Imperial Valley substation near El Centro, California to a new 'Central' substation located east of Warner Springs, California. SDG&E will construct two new 230 kV lines connecting the Central substation to the existing Sycamore Canyon substation and one new 230 kV line between the Sycamore Canyon substation and the Peñasquitos substation."[62] The Sycamore Canyon substation is located about 13 miles southwest of the City of Ramona and the Peñasquitos substation is located about 13 miles north of downtown San Diego. The transmission project presented in that application is shown in Figure 8-5 (Sunrise [Sunpath] Powerlink Transmission Project) and in Figure 8-6 (Sunrise [Sunpath] Powerlink Alternatives –System Alternatives).

On September 11, 2006, the CPUC and the BLM issued a NOP (SRPL-NOP) for the SRPL project, a proposed 150-mile long transmission line between the El Centro area in Imperial County and northwestern San Diego County, including both a 91-mile 500-kV line in Imperial County and eastern San Diego County and a 59-mile 230-kV line in central and western San Diego County.

As indicated in the SRPL NOP, "SDG&E's stated purpose for the project is to bring renewable resources into San Diego County from Imperial County, and to improve electric reliability for the San Diego area."[63] Although none of the eight objectives listed in the SRPL-NOP specifically referenced hydropower, among those objectives was the provision of transmission capacity for the region's (Imperial Valley) renewable resources.[64]

[61]/ California Public Utilities Commission, Progress of The California Renewable Portfolio Standard as Required by the Supplemental Report of the 2006 Budget Act, Report to the Legislature, October 2006, p. 12.

[62]/ *Op. Cit*., In the Matter of the Application of San Diego Gas & Electric Company for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, Application No. 05-12-014, Amended Application of San Diego Gas & Electric Company (U 902-E), Volume I, p. 12.

[63]/ California Public Utilities Commission and Bureau of Land Management, SDG&E Sunrise Powerlink Project, Notice of Preparation/Notice of Scoping Meeting for an Environmental Impact Report/Environmental Impact Statement, September 11, 2006, p. 1.

[64]/ *Ibid*., p. 3.

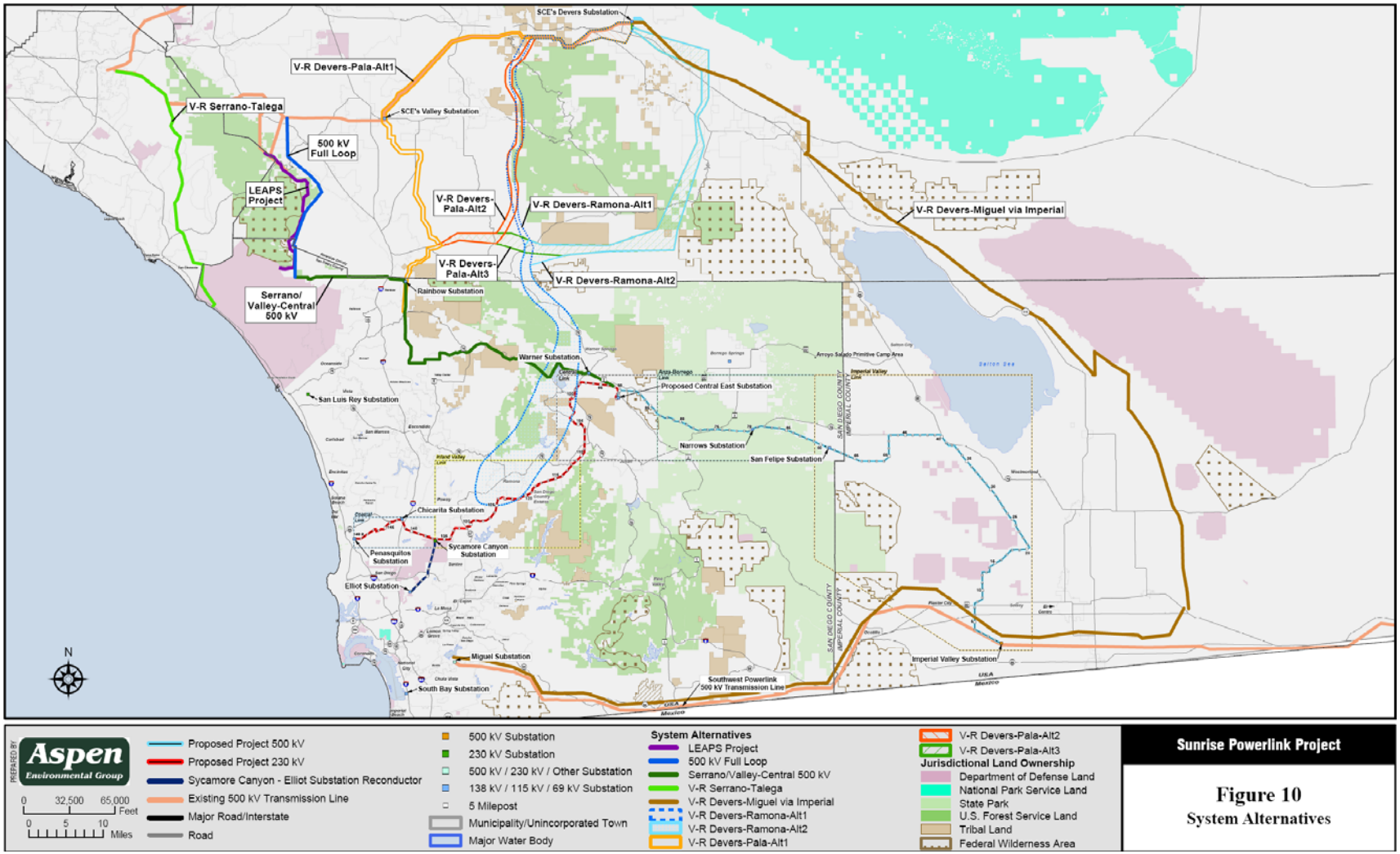


Figure 8-6
SUNRISE (SUNPATH) POWER LINK ALTERNATIVES
SYSTEM ALTERNATIVES
Source: Bureau of Land Management and California Public Utilities Commission

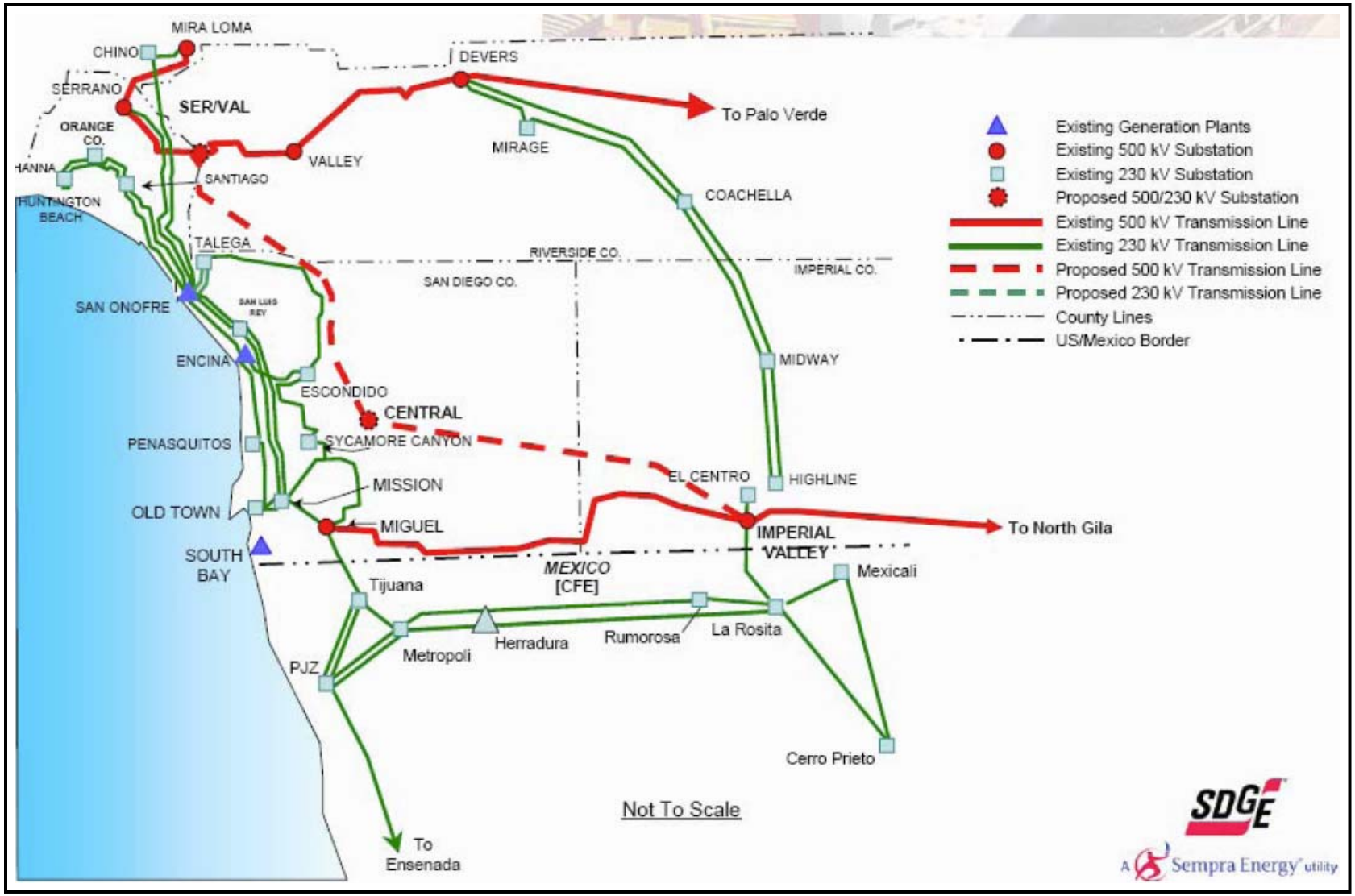


Figure 8-7
FULL LOOP ALTERNATIVE
Source: San Diego Gas & Electric Company

As indicated by the Imperial Valley Study Group (IVSG), "California's Imperial Valley contains 1,950 MW of geothermal power reserve and one-quarter of the State's entire solar generation potential."[65] The IVSG makes no reference to any hydropower potential in the Imperial Valley. As a result, any transmission route that identifies the Imperial Valley as either a starting or end point would not serve to increase capacity to or facilitate the transmission of hydroelectric energy. The SRPL project alternative has, therefore, been rejected since that alternative fails to meet the projects' objectives.

- Sunrise (Sunpath) Powerlink Project (Imperial Valley-Central-Serrano/Valley). As indicated in the SRPL NOP, a number of routing alternatives were "identified by SDG&E" and "SDG&E considered and eliminated several sets of alternatives." Eliminated alternatives included "[a] combination of new SDG&E/SCE transmission lines in the Talega-Escondido and Valley-Serrano corridors [that] could be combined with the Lake Elsinore Advanced Pumped Storage Project to allow hydroelectric power generated at LEAPS to be transmitted to the San Diego area. Eliminated because LEAPS is not approved and faces regulatory hurdles."[66] Although permitting uncertainty remains, the rationale for SDG&E's rejection of the LEAPS project as part of its own analysis is not supported by evidence of FERC's release of the FEIS.

  In 2005, SDG&E conducted a "transmission comparison screening study" in order "to evaluate various transmission alternatives and to select the best alternative(s) to: increase import capability into the SDG&E service area to meet a grid reliability deficiency in 2010, reduce congestion and reliability must run (RMR) costs for California ratepayers, [and] access, at an acceptable cost, renewable resources in support of goals set by the State of California and the CPUC. SDG&E reported that "the highest ranking alternative" was the "Full Loop alternative." The "Full Loop Options are so named because they complete the 500 kV loop from Palo Verde [Arizona] to SDG&E to SCE and then back to Palo Verde [Arizona] by adding the portion from SDG&E's 500 kV to SCE's 500 kV system."[67]

  SDG&E stated: "To the extent the transmission associated with the LEAPS project follows the same corridor as the Central-Serrano/Valley portion of the Full Loop, Imperial-Central Serrano/Valley 500 kV alternative, the transmission associated with the LEAPS project can be considered to constitute the bulk of the northern segment of the Imperial Valley-Central – Serrano/Valley 500-kV alternative."[68]

  As illustrated in Figure 8-7 (Full Loop Alternative), a variation of one of the alternatives discussed in SDG&E's December 2005 application was the "Imperial Valley-Central-Serrano/Valley" (Full Loop) alternative. This alternative would connect SDG&E's 500-kV system to SCE's 500-kV system through a proposed new 500/230-kV Central substation, feeding into SDG&E's existing 230-kV system near the center of SDG&E's system, and then connects to SCE's 500-kV system"[69]

[65]/ Imperial Valley Study Group, Development Plan for the Phased Expansion of Transmission to Access Renewable Resources in the Imperial Valley, California Energy Commission, September 30, 2005, p. 1.

[66]/ *Op. Cit*., SDG&E Sunrise Powerlink Project, Notice of Preparation/Notice of Scoping Meeting for an Environmental Impact Report/Environmental Impact Statement, pp. 10, 11, and 12.

[67]/ San Diego Gas and Electric, Report for SDG&E's Transmission Comparison Study, October 5, 2005, pp. 1-2 and 29.

[68]/ *Ibid*., p. 2.

[69]/ San Diego Gas & Electric Company, Sunrise Powerlink Transmission Project – Purpose and Need, Volume 2, December 14, 2005, p. VI-ii.

The Full Loop alternative "would complete the 500 kV loop through southern California, connecting SCE's 500 kV Palo Verde-Devers-Valley-Serrano system to SDG&E's 500 kV Southwest Powerlink."[70] As indicated by SDG&E: "The Technical Working Group determined that the Full Loop option and the Sunrise Powerlink were the best performing transmission alternatives with respect to grid reliability and technical performance, accessing areas of high renewable resource potential, and providing economic benefits."[71] Under this alternative, SDG&E's proposed 500-kV transmission line extending from the Imperial Valley substation to the proposed new Central substation would be further extended northward, connecting SDG&E's proposed new 500-kV system to the Serrano/Valley segment of SCE's 500-kV system. SDG&E's initial application noted that this alternative would "free up some amount of capacity on the existing Imperial Valley-Miguel 500 kV transmission line (the Southwest Powerlink or 'SWPL') and thereby allow renewable energy resources to economically connect to this existing 500 kV line. This could encourage renewable energy development that might otherwise not be feasible."[72]

"SDG&E has performed several sensitivities involving the Sunrise Powerlink. The first sensitivity assumes that in addition to the Sunrise Powerlink, the Lake Elsinore Advanced Pump Storage project is constructed and that the southern terminus of the associated 500 kV transmission is located at a new 500/230 kV substation on SDG&E's existing SONGS-Talega 230 kV line. The second sensitivity assumes that in addition to the Sunrise Powerlink, the LEAPS project is built and the southern terminus of the associated 500 kV transmission is located at Central substation. Both sensitivities include two 250 MW pump/generator sets interconnected with the CAISO grid via a 500 kV line connecting to the SDG&E system and a 500 kV line connecting to the SCE system on SCE's existing Serrano-Valley 500 kV line. The first sensitivity represents SDG&E's understanding of the LEAPS project sponsors' current proposal for integrating the LEAPS project into the CAISO grid. The second sensitivity represents a logical modification of the LEAPS project sponsors' current proposal because it eliminates the need for a 500/230 kV substation and has the advantage of completing a 500 kV loop through the Southern California load centers. The second sensitivity does require additional 500 kV transmission to reach Central substation. For analytic purposes, SDG&E has assumed that the cost of the 500/230 kV substation on the existing SONGS-Talega 230 kV line and the cost of the additional 500 kV transmission necessary to reach Central substation are approximately equal."[73]

"A variation of the Full Loop is to incorporate the 500 kV transmission system associated with the planned LEAPS project which, as currently envisioned, would have a southern terminus at a new 500/230 kV substation somewhere along SDG&E's Talega-Escondido 230 kV line in northern San Diego County. It would have a northern terminus at a 500 kV switchyard somewhere along SCE's Serrano-Valley 500 kV line. A logical 'full loop' grid configuration would be to substitute the 500 kV transmission associated with the LEAPS project for most or all of the Central – Serrano/Valley portion of the Full Loop alternative. This configuration would eliminate the need for the LEAPS project's planned 500/230 kV substation on SDG&E's Talega-Escondido 230 kV line."[74]

[70]/ *Ibid*., p. VI-5.
[71]/ *Ibid.*, p. II-3.
[72]/ *Ibid*., p. VI-iv.
[73]/ *Ibid*., p. V-28.
[74]/ *Ibid*., p. VI-8.

Because the Full Loop alternative "is consistent with the transmission additions that have been proposed in association with the Lake Ellsinore [sic] Advanced Pumped Storage project"[75] and could, therefore, accommodate the LEAPS project and facilitate the transmission of hydroelectricity, that option represents a possible alternative to the TE/VS Interconnect project.

To accommodate this alternative, the Applicant's proposed transmission alignment would need to be substantially modified. In lieu of the approximately 16.5-mile segment extending between the Applicant's proposed new LEAPS and Pendleton substations, the 500-kV transmission line would need to be rerouted from the Applicant's proposed LEAPS substation to SDG&E's proposed new Central substation, located southeast of Lake Henshaw. From the new Central substation, the new 500-kV transmission line would continue to extend southward to SDG&E' existing Imperial Valley substation near El Centro (San Diego County). Assuming that the proposed new Central substation was constructed, the Applicant's proposed new Pendleton substation could be eliminated.

This alternative cannot exist in the absence of both the rerouting of the Applicant's transmission alignment and the implementation, either by the Applicant or by SDG&E, of the SRPL project. Since FERC and the Applicant have both concluded that a non-National Forest alignment cannot be feasibly constructed, it is not feasible to construct the required modifications to the Applicant's transmission plan without introducing substantial additional environmental effects.

As indicated by the Cities of Temecula, Hemet, and Murrieta, those cities "oppose the Full Loop alternative because it would almost certainly result in significant environmental and other impacts to their communities and residents. Because SDG&E's submittal lacks critical route information, it is impossible to discern the nature and extent of those impacts. It does appear, however, that the northern portion of the Full Loop Alternative would cross through Southwest Riverside County. A similar transmission line was previously proposed and rejected in the Valley-Rainbow proceedings (A.01-03-036, filed March 23, 2001) after strong opposition from local residents. Because Riverside County is now even more populated and developed than it was during the Valley-Rainbow proceedings, construction of a transmission line through the area would be even less appropriate and feasible now."[76]

As indicated in the CPUC's and BLM's "Final Notice – CPUC/BLM Notice Regarding Conclusions on EIR/EIS Alternatives to the Proposed Sunrise Powerlink Project – Results of the Second Scoping Process": "Full Loop Alternatives would build a new 500 kV transmission line from the existing imperial Valley substation to either the proposed [Sunrise Powerlink] project's new Central East substation or to another new substation in northern San Diego County (e.g., Rainbow substation), then continue the new 500 kV line to a new substation in SCE's territory between the existing Serrano and Valley substations. Other partial implementation of the Full Loop alternatives recommended for elimination include: Imperial Valley-Ramona 500 kV; Imperial Valley-Rainbow 500 kV; and Imperial Valley-East of Escondido 500 kV. These alternatives do not pose an option to, but rather an expansion of the proposed [Sunrise Powerlink] project. By expanding the Sunrise Powerlink project to include a 500 kV link to Ramona, or further west, or an

[75]/ *Ibid*., p. VI-iii.

[76]/ Cities of Temecula, Hemet, and Murrieta (Shute, Mihaly & Weinberger), In the Matter of the Application of San Diego Gas & Electric Company for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, Protest of the Cities of Temecula, Hemet and Murrieta, January 17, 2006, p. 3.

interconnection with the SCE system, these alternatives would enhance the proposed [Sunrise Powerlink] project's ability to meet reliability and import capability objectives. However, these alternatives would add to the impacts of the proposed [Sunrise Powerlink] project due to the additional construction and ROW required."[77]

The Applicant has considered the analysis presented by the CPUC and BLM in the "Final Notice – CPUC/BLM Notice Regarding Conclusions on EIR/EIS Alternatives to the Proposed Sunrise Powerlink Project – Results of the Second Scoping Process" and, relative to the proposed projects, concurs with those agencies' findings. The Full Loop would neither avoid nor substantially lessen the significant environmental effects attributable to the proposed projects. In addition, as a result of the need to traverse a substantially greater number of privately owned properties, the Full Loop alternative would introduce new impacts and further exacerbate the projects' significant impacts. As a result, the Applicant has eliminated this alternative from further consideration.

- Tehachapi Transmission Project.[78] As indicated by the CPUC, the "Tehachapi wind resource area" (Tehachapi WRA) lies at the southern end of the San Joaquin Valley in the mountainous region between Bakersfield and Mohave. Transmission connections between the Tehachapi WRA and the existing grid can be made to the east at the Midway Substation near Buttonwillow and the south at the Vincent substation near Lancaster. Three existing transmission lines connect the Midway and Vincent Substations, collectively referred to as Path 26. Permit applications have been filed for the first transmission component, connecting Tehachapi to the Vincent substation with one 500-kV line. Two more 500-kV lines are expected to be needed to export the projected 4,500 MW of wind power from the Tehachapi WRA to the existing grid.[79]

  On December 9, 2004, SCE filed an application requesting a CPCN to construct a new 500-kV transmission line connecting SCE's existing Antelope substation located in Lancaster (Los Angeles County) to SCE's existing Pardee substation located in Santa Clarita (Los Angeles County). As indicated in that project's documentation, "[t]he purpose for making application for the Antelope Transmission Project is derived from Ordering Paragraph No. 8 of Decision 04-06-010, which requires SCE to 'file an application seeking a certificate authorizing construction of the first phase of Tehachapi transmission upgrades [the Antelope Transmission Project] consistent with its 2003 conceptual study and the study group's recommendation within six months of the effective date of this order.' This order was premised on Finding of Fact No. 18, which described that the 'magnitude and concentration' of renewable resources identified in the California Energy Commission's Renewable Resource [Development] Report justified a 'first phase of Tehachapi transmission upgrades' to facilitating achievement of the

[77]/ *Op. Cit*., Final Notice – CPUC/BLM Notice Regarding Conclusions on EIR/EIS Alternatives to the Proposed Sunrise Powerlink Project – Results of the Second Scoping Process, p. 27.

[78]/ When completed in 2013, the provide will provide the following benefits: (1) provide the least-cost solution to connect 4,350 MW of generation in the Tehachapi area; (2) serves new load growth and ease transmission constraints in the Antelope Valley; (3) help the State's utilities comply with RPS; and (4) make it possible to expand the transfer capability of Path 26, a major north-south transmission corridor, in the future (Source: California Independent System Operator Corporation, News Release: California ISO Board Approves Tehachapi Transmission Project, January 24, 2007).

[79]/ Tehachapi Collaborative Study Group, Electric Power Transmission Facilities in the Tehachapi Wind Resource Area, Second Report, April 19, 2006, p. 8.

Renewable Portfolio Standard goals."[80] The Antelope-Pardee 500-kV Transmission Project represents the first phase of a multiple segment project designed to access the wind energy potential that now exists within the Tehacapi area of Kern County.

The three segments of SCE's Tehachapi transmission project are generally illustrated in Figure 8-8 (Tehachapi Transmission Project). Once the connection to SCE's Vincent substation has been established, generated power can then flow through SCE's Vincent-Lugo, Lugo-Mira Loma, Mira Loma-Serrano, and Serrano-Valley transmission lines, allowing for a connection between Tehacpahi and the LEAPS project. All three phases of the Tehacaphi transmission project were considered by the Applicant as a possible projects' alternative.[81] Also considered where the other alternatives examined in the CPUC/USFS' "Antelope-Pardee 500-kV Transmission Project Environmental Impact Report/Environmental Impact Statement" (Appendix 1 - Alternative Screening Report), inclusive of each of the design variation, alternative corridor, and other transmission alternatives and combination of alternatives considered therein.[82]

Any transmission route that identifies the Imperial Valley as either a starting or end point would not serve to increase capacity to or facilitate the generation or transmission of hydroelectric energy. Since the SRPL project fails to meet the Applicant's objectives, the Tehachapi transmission project is not a feasible alternative.

On January 24, 2007, the CAISO Board of Governors approved SCE's Tehachapi Transmission Project, consisting of a series of 17 new facilities or upgrades that will come on line over a period of five years, beginning in late 2008. As a result, the Tehachapi Transmission project constitutes a "related project," potentially producing cumulative impacts, rather than an "alternative project."

- Valley-Serrano Transmission Corridor. As required under Section 1221(b) of the EPAct 2005, the Secretaries of Agriculture, Energy, and Interior and the Chairman of the Council on Environmental Quality were directed to prepare a report identifying: (1) all existing designated transmission and distribution corridors on federal land; (2) the status of work related to proposed transmission and distribution corridor designations under Title V of the Federal Land Policy and Management Act of 1976 (FLPMA) and any impediments to completing the work; (3) the number of pending applications to locate transmission facilities on federal land; and (4) the number of existing transmission and distribution rights-of-way on federal land that will come up for renewal within the next 5-year, 10-year, and 15-year periods and how those renewals will be managed.

  In compliance with that mandate, the USDA, United States Department of the Interior, DOE, and the Council on Environmental Quality prepared a "Report to Congress: Corridors and Rights-of-Way on Federal Lands." As reported by the Forest Service, in the general projects' area, only SDG&E's 500-kV "Valley-Serrano" (identified as an

[80]/ California Public Utilities Commission and United States Forest Service, Draft Environmental Impact Report/Environmental Impact Statement – Antelope-Pardee 500 kV Transmission Project, July 2006, p. A-15.

[81]/ On January 24, 2007, the CAISO Board of Governors approved SCE's Tehachapi transmission project, including 17 new facilities and upgrades that will come on line beginning in late 2008.

[82]/ California Public Utilities Commission and United States Forest Service (Aspen Environmental Group), Antelope-Pardee 500-kV Transmission Project Environmental Impact Report/Environmental Impact Statement, Appendix 1, Alternative Screening Report, May 2006, pp. Ap. 1-3 through Ap. 1-6.

"Existing Designated Transmission and Distribution Corridor"[83]) and the Applicant's 500-kV "Elsinore Valley Municipal Water District" (identifies as a "Pending Transmission Facility Application") were identified.[84]

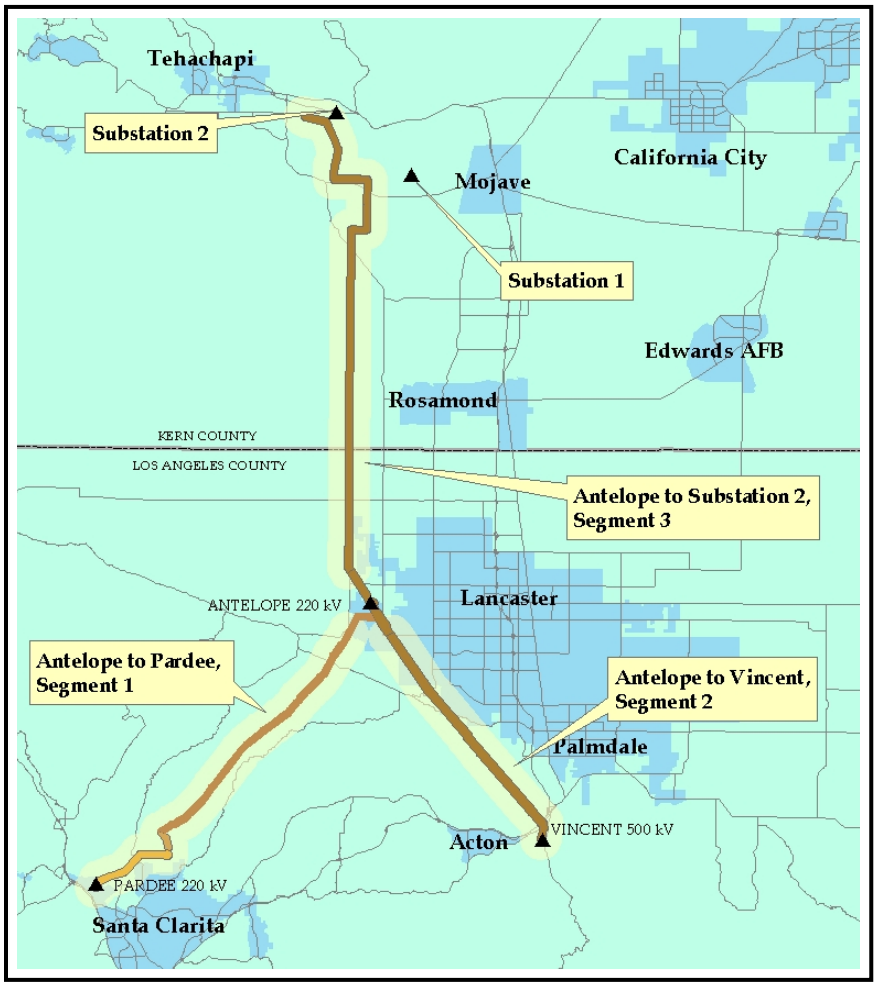


Figure 8-8
TEHACHAPI TRANSMISSION PROJECT
Source: Southern California Edison Company

SCE's existing "Valley-Serrano" transmission line traverses the TRD west of Lake Elsinore and connects SCE's Valley substation (Romoland, Riverside County) and Serrano substations (Orange, Orange County). The Valley-Serrano 500-kV transmission line represents that segment of SCE's existing transmission system into which the northern leg of the proposed projects will connect. As such, this existing transmission line does not constitute a distinct alternative but an element of the existing projects. Different points of junction may exist with the Valley-Serrano line.

The CPUC and BLM considered a "Serrano/Valley-Central 500 kV alternative" in the "Final Notice – CPUC/BLM Notice Regarding Conclusions on EIR/EIS Alternatives to the Proposed Sunrise Powerlink Project – Results of the Second Scoping Process." The CPUC and BLM concluded that this alternative "would have environmental impacts as

[83]/ Defined as "[a]ll electric transmission line ROW corridors that have been formally designated by law, Secretarial order, land use planning process, or other management decision."

[84]/ United States Department of Agriculture, United States Department of the Interior, United States Department of Energy, and the Council on Environmental Quality, Report to Congress: Corridors and Rights-of-Way on Federal Lands, November 7, 2005, pp. 18 and 37.

severe as those of the proposed [Sunrise Powerlink] project."[85] The Applicant has considered the analysis presented by the CPUC and BLM and, relative to the proposed projects, concurs that those agencies' findings.

- Other Transmission Line Upgrades. As indicated by the CEC, "it is generally easier to upgrade an existing transmission line or build a new line within an existing transmission line right-of-way than to create an entirely new right-of-way because no land must be converted from its current use."[86] Transmission lines in the general projects' area include SCE's 500-kV Valley-Serrano and SDG&E's 230-kV Talega-Escondido transmission lines. Upgrades to SDG&E's existing line, as well as upgrades of the local distribution system, are already part of the proposed projects.

  As illustrated in Figure 8-9 (Southern California Edison - Ivyglen Subtransmission Project), other transmission line upgrades presently being planned in the Lake Elsinore area include the 25-mile 115-kV Ivyglen Subtransmission Project (installation of a second 115-kV line) starting at SCE's exising Valley substation in Romoland and ending at SCE's existing Ivyglen substation in Glen Ivy. As proposed, that transmission upgrade would serve existing and projected demand for electricity in the southwestern area of Riverside County.[87] Approximately 16 miles of the proposed line would be constructed along SCE's existing ROW or along public streets. The proposed line would be constructed on steel poles that are typically 65 feet in height. While enhancing the reliability of the local distribution system, the Ivyglen Subtransmission Project does not provide either additional capacity for or access to hydroelectric energy resources.

  The PTOs have identified those upgrades that can be feasibly implemented and are already proceeding with those improvements. These upgrades do not constitute reasonable alternatives but represent "related projects" which, in combination with the proposed projects, have the potential to produce cumulative impacts.

- Non-National Forest Route. The Applicant submitted and the USFS accepted for processing separate SUP applications for the proposed projects.[88] In accordance with FSH 2709.11, the Applicant was required to explain the selection of the location of the proposed uses, state why the use of NFS lands was necessary, and demonstrate why lands under non-federal ownership could not be feasibly utilized.[89] As indicated in the FEIS: "Given the numerous constraints on locating transmission line corridors in the Lake Elsinore area, the USFS concluded during the application screening that National Forest System lands are necessary for the proposed interconnect. It is also evident that alternative locations are not reasonably available to the co-applicants."[90]

[85]/ *Op. Cit*., Final Notice – CPUC/BLM Notice Regarding Conclusions on EIR/EIS Alternatives to the Proposed Sunrise Powerlink Project – Results of the Second Scoping Process, p. 26

[86]/ *Op. Cit*., Environmental Issues and Opportunities in the California-Mexico Border Region, p. 55.

[87]/ Southern California Edison Company, Ivyglen Subtransmission Project, Update, October 2006.

[88]/ Activities for which SUPs are authorized include: (1) systems and related facilities for generation, transmission, and distribution of electric energy (36 CFR 251.53[l][4]); and (2) such other necessary transportation or other systems or facilities which are in the public interest and which require rights-of-way over, upon, under, or through NFS lands (36 CFR 251.53[l][7]). The requested hydropower license can only be issued if the Commission determines that the proposed project is in or consistent with the public interest (16. U.S.C. 797[e]).

[89]/ As stipulated in FSM 2703.3(3), the Forest Service may deny proposals located on NFS land if the proposal "can reasonably be accommodated on non-National Forest System lands."

[90]/ *Op. Cit*., Final Environmental Impact Statement for Hydropower License – Lake Elsinore Advanced Pumped Storage Project, FERC Project No. 11858, FERC/EIS-0191F, p. A-1.

As evidenced, in part, by the inability of SDG&E to successfully advance the Valley-Rainbow project and the findings of the CPUC/BLM alternatives analysis for that project, it can be reasonably concluded that no feasible non-NFS routes exist to interconnecting SCE's Valley-Serrano and SDG&E's Talega-Escondido transmission lines. The Applicant concurs with FERC's and the USFS' independent conclusion that the proposed projects cannot be reasonably accommodated on non-NFS lands and that a non-NFS route is, therefore, not reasonably feasible.

A freeway right-of-way alternative was also considered. However, as indicated by the California Department of Transportation (Caltrans or Department): "Placement of longitudinal utility encroachments within freeway and expressway right-of-way is prohibited under Department policy."[91] The Federal Highway Administration (FHWA) has "delegated authority to Caltrans to approve public (utility companies regulated by the CPUC) utility longitudinal installations."[92] A freeway ROW alternative does not address either the specific transmission-related needs or the statutorily constrained objectives of the proposed projects. Based on the Caltrans-imposed prohibition, the ability of the Applicant to obtain FHWA and/or Caltrans authorization is considered speculative and is, therefore, deemed infeasible (14 CCR 15145).

The Applicant considered each of the wires and non-wires alternatives identified in the "Final Notice - CPUC/BLM Notice Regarding Conclusions on EIR/EIS Alternatives to the Proposed Sunrise Powerlink Project – Results of the Second Scoping Process" and independently considered information presented in support of the CPUC's and the BLM's election to include or exclude those alternative.[93] The Applicant concurs with the rationale posited by the CPUC and BLM for the rejection of those alternatives.

The alternatives presented therein would not result in the attainment of the basic objectives of the proposed projects and/or would result in the creation of additional or comparable environmental impacts. In addition, a number of the alternatives identified therein relate only to the consideration of relatively short alternative line segments associated with SDG&E's proposed SRPL project and do not represent a distinct alternative therefrom. As such, those alternatives are rejected since they do not foster meaningful pubic participation and informed decisionmaking relative to the proposed projects (14 CCR 15126.6[e][3][C]).

8.2.3 Alternative Transmission Technologies

As indicated by the DOE: "The significance of electricity to the U.S. economy is enormous. The total value of electric generation and distribution assets in America is estimated to exceed $800 billion. America's annual 'electric bill' exceeds $240 billion. Electricity's significance includes the protection of the economy, environment, public health and safety, and national security. Blackouts serve as powerful reminders of the critical role electricity plays in people's everyday lives. Billions of dollars were lost during the August 13, 2003 blackout. Public health and safety were jeopardized. America cannot afford to let its electric system degrade and potentially fall short of meeting the economy's growing needs for electric power."[94]

[91]/ California Department of Transportation, Encroachment Permits – Manual for Encroachment Permits on California State Highways, Seventh Edition, revised January 2002, p. 6-11.

[92]/ *Ibid.*, p. 6-12.

[93]/ *Op. Cit.*, Final Notice, CPUC/BLM Notice Regarding Conclusions on EIR/EIS Alternatives to the Proposed Sunrise Powerlink Project – Results of the Second Scoping Process, pp. 1-28.

[94]/ United States Department of Energy, National Electric Delivery Technologies Roadmap, January 2004, p. 1.

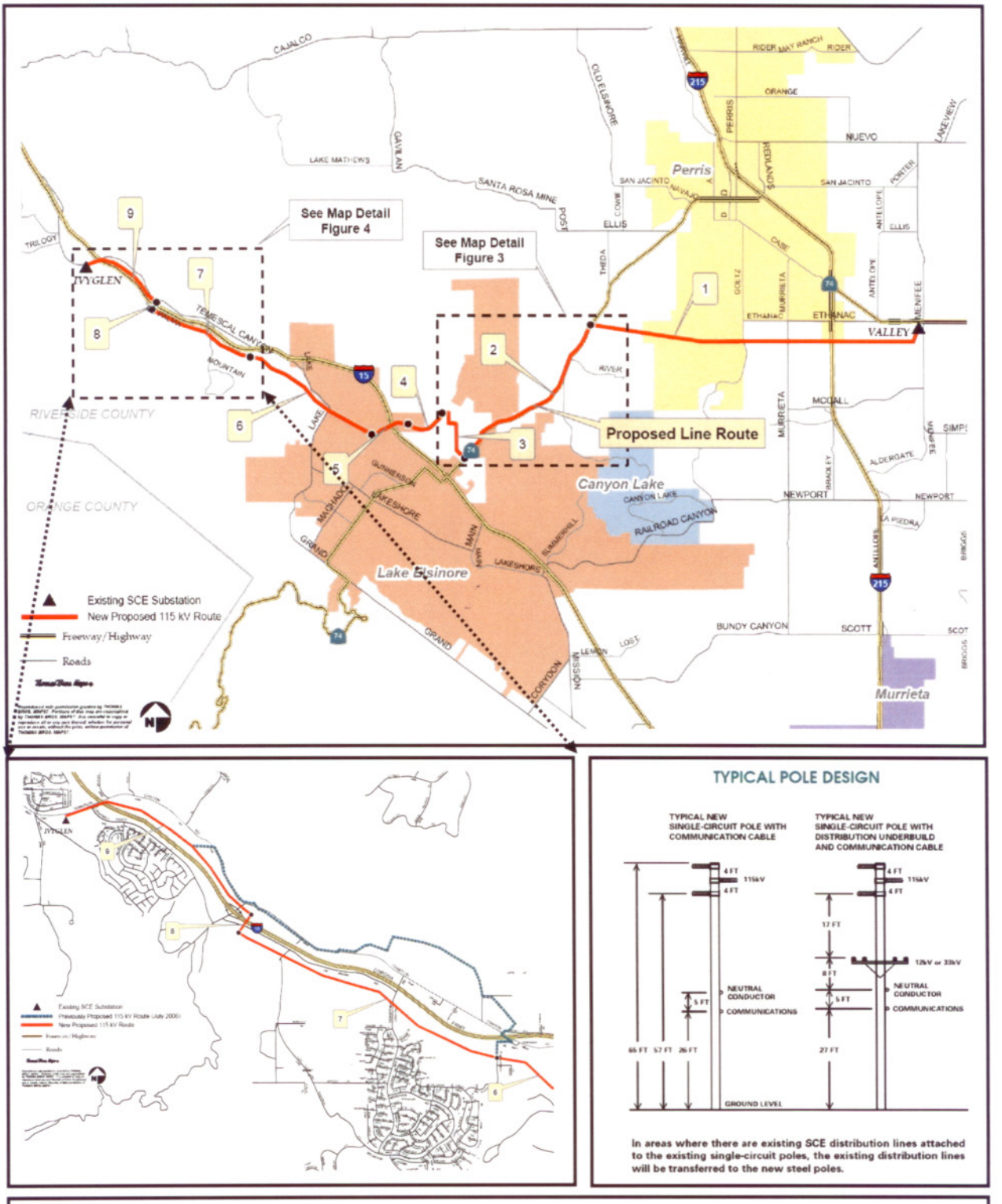


Figure 8-9
SOUTHERN CALIFORNIA EDISON - IVYGLEN SUBTRANSMISSION PROJECT
Source: Southern California Edison Company

"One of the keys to achieving the Administrations goals of reducing greenhouse gas emissions and reducing the nation's dependence on foreign fuel sources is to modernize our current energy delivery system and reduce inefficiencies so that we can get more usable power from our existing generation facilities. Another priority to improving the efficiency of the grid is to reduce the duration and frequency of power outages. Fortunately, there are technologies available today as well as those being developed that can help to reduce the likelihood of future outages."[95]

The "Report of the Energy Policy Development Group" contains 13 recommendations for strengthening the electric delivery system. The "National Transmission Grid Study" contains 51 recommendations. The "Transmission Grid Solutions Report" provides further suggestions for improving the physical and financial state of the nation's electric infrastructure. The President's Council of Advisors on Science and Technology's "Report on Energy Efficiency" call for the "the Nation to proceed with the development of the 21st Century electricity grid."[96]

Not addressed as a separate alternative herein are the application of "smart-grid technologies" designed to improve the efficiency and operation of the transmission grid. The Applicant lacks the ability to implement those technologies on transmission facilities operated by other entities.

8.2.4 Alternative Hydropower Sites

The CalEPA notes that "[a] finite water supply and lack of suitable dam sites that do not already have hydroelectric facilities severely limits the potential for expansion."[97] As further indicated in Table 8-1 (Planned Nameplate Capacity Additions from New Generation by Energy Source [2006-2010]), only minimal conventional hydroelectric generation and no pumped storage hydroelectric generation is nationally forecast between 2006 and 2010. The DOE predicts that "[a]lmost no new hydropower capacity is predicted through 2020."[98] Only 560 MW of conventional hydropower capacity is expected to be added to the nation's energy supplies by 2025.[99] The CEC notes: "Opportunities for construction of new hydroelectric plants and pumped storage projects are extremely limited in California."[100] This is particularly evident in southern California where only 20 MW of installed hydroelectric capacity now exists.[101]

As indicated in the 1990 Tudor Engineering Company study, which initially identified the general projects' area as a candidate for a pumped storage facility and served as a foundation for the initial federal hydropower licensing efforts: "Pumped storage units are used by various utilities to mitigate the effects of daily peaking problems. The southwest region of California, however, has few sites that can be utilized for pumped storage projects, either because of insufficient or

[95]/ *Ibid*., p. 15.
[96]/ *Ibid*., pp. 1-2.
[97]/ *Op. Cit*., California Response to the Federal Energy Regulatory Commission Staff Report on Hydroelectric Licensing Policies, Procedures, and Regulations – Comprehensive Review and Recommendations Pursuant to Section 603 of the Energy Act of 2000 – May 2001, p. viii.
[98]/ Sale, M.J., *et al*., DOE Hydropower Program Annual Report for FY 2002, DOE/ID-1107, United States Department of Energy July 2003, p. 1; Sale, M.J., et al., DOE Hydropower Program Biennial Report for FY 2005-2006, ORNL/TM-2006/97, United States Department of Energy, July 2006, p. 1.
[99]/ Cada, Glen F., *et al*., DOE Hydropower Program Annual Report for 2003, DOE/NE-ID-11136, United States Department of Energy, February 2004, p. 1.
[100]/ *Op. Cit*., Integrated Energy Policy Report, CEC-100-2-5-007CMF, p. 141.
[101]/ *Op. Cit*., California Hydro-Electricity Outlook for 2002, Staff Report, p. 5.

varying water supplies or an unacceptable elevation between the upper and lower reservoirs."[102]

Table 8-1
PLANNED NAMEPLATE CAPACITY ADDITIONS FROM NEW GENERATION BY ENERGY SOURCE (MEGAWATTS)

Energy Source	2006	2007	2008	2009	2010
Coal[1]	602	1,589	1,056	15,287	9,350
Petroleum[2]	269	78	168	817	300
Natural Gas	10,657	16,892	15,050	8,511	5,815
Other Gases[3]	-	391	1,160	-	-
Nuclear	-	-	-	-	-
Hydroelectric Convention	8	3	4	-	1
Other Renewables[4]	3,027	2,454	695	236	-
Pumped Storage	-	-	-	-	-
Other[5]	10	-	-	-	-
Total	14,573	21,407	18,133	24,850	15,466

Notes:
1. Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
2. Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum), and waste oil.
3. Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
4. Wood, black liquor, and other wood waste, municipal solid waste, landfill gas, sludge waste, tire, agricultural byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
5. Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

Source: United States Department of Energy, Energy Information Administration, Form EIA-860, Annual Electric Generator Report (http://www.eia.doe.gov/cneaf/electricity/epa/epat2 p4.html)

As illustrated in Figure 8-10 (Southern California Renewable Energy Resources[103]), within the southern California area, additional renewable energy will be predominately from wind and geothermal sources. As indicated by the CPUC, "San Diego County is located in the southwest corner of the State, adjoining Riverside and San Bernardino Counties in the east and Mexico on the south. Power is imported from Arizona to San Diego by a 500kV transmission line, which runs just north of the border with Mexico. Merchant electricity plants in Mexico also transmit their output to San Diego over this line. . .The renewable resources identified by the CEC in the area consist of wind and biomass in eastern San Diego County."[104]

Early in the 20th Century, abundant hydrological resources were the main sources of electricity. Hydroelectric development continued in all decades throughout the century, peaking in the 1960's. Substantial hydroelectric pumped storage capacity was added from the late 1960's to the early 1980's. Most of the cost-effective, environmentally appropriate sites for hydropower projects have already been developed.[105] Opportunities for new hydropower dam and storage projects are extremely limited in California due to a lack of sites, lack of availability of unallocated water rights, environmental protection measures, and strong political opposition.

[102]/ Tudor Engineering Company, Report on Reconnaissance Level Investigation of Lake Elsinore Pumped Storage Project, June 1990, p. 1-2.

[103]/ California Public Utilities Commission, Report to the Legislature – SB 1038/Public Utilities Code Section 383.6: Electric Transmission Plan for Renewable Resources in California, December 1, 2003, Map 5.

[104]/ *Ibid*., p. 78.

[105]/ California Energy Commission, California Hydropower System: Energy and Environment, Append D – 2003 Environmental Performance Report, 100-03-018, October 2003, p. D-6.

New development requires an approximate 10-year timeframe in order to plan and understand the potential environmental effects and prepare appropriate environmental safeguards.[106] The lack of additional suitable sites inhibits the further application of this technology.[107]

Based on a Statewide resource assessment conducted by the DOE, a total of 3,390 MW of undeveloped hydropower potential exists in California. Of that, 51 percent is contained within three major river basins: American, Feather, and Stanislaus River basins. As illustrated in Figure 8-11 (Megawatts of Undeveloped Hydropower Potential in the California River Basins), the DOE has not identified any megawatts of undeveloped hydropower potential in the southern California coastal region.[108] Because of the limited potential for additional pumped storage and other hydropower facilities, it is unlikely that any substantial new regional capacity could be created. Based on the limited inventory of hydropower sites, the Applicant has determined that there exists no hydropower generation alternatives not involving the use of waters within Lake Elsinore. As a result, the Applicant has concluded that this alternative is not feasible.

8.2.5 Alternative Electricity Storage Technologies

In 2004, the nation's total electricity generation increased by two percent (to 3,953 billion kilowatt hours [kWh]). In contrast, renewable electricity generation decreased one percent (to 359 billion kWh). Total renewable energy consumption (for electricity generation) increased by three percent (to 4.3 quadrillion British thermal units [Btu]), despite a decline in conventional hydroelectric power. Overall, renewable electricity was nine percent of the total United States net generation. Excluding hydropower, that share was only two percent.[109]

Increasing the use of renewable resources, is one of the prime goals of the nation's energy policy. The FERC acknowledges that "[t]he development of renewable sources of energy, including wind resources, brings benefits to energy customers by providing environmental benefits and supports increased reliability by increasing the diversity of energy supplies. Wind energy can satisfy certain federal and state-mandated programs for the development of renewable energy."[110]

The transmission grid is often considered analogous to a "highway" linking generation to load. Transmission networks are the "principal media for achieving reliable electric supply." Those transmission networks provide flexibility so that the highway functions can be maintained over a wide range of generation, load and transmission conditions, reduce the amount of installed generating capacity needed for reliability by connecting different electrical systems, permit economic exchange of energy among systems, and connect new generators to the grid.[111] As indicated in the "National Transmission Grid Study," electricity is not a commodity that can be easily stored.[112] In drawing an analogy, the study states: "Image an interstate highway system

[106]/ *Op. Cit*., Comparative Study of Transmission Alternatives: Background Report, 700-04-006, p. 13.
[107]/ Price, Anthony, Thijssen, Gerald, and Symons, Phil, Electricity Storage, A Solution in Network Operations?, October 12, 2000.
[108]/ Conner, Alison M. and Francfort, James E., U.S. Hydropower Resource Assessment for California, Idaho National Engineering and Environmental Laboratory, U.S. Department of Energy, October 1998, pp. 2 and 5.
[109]/ United States Department of Energy, Renewable Energy Trends 2004, Highlights, Energy Information Administration, August 2005, pp. 1, 4, and 5.
[110]/ Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, Docket No. RM05-10-000, April 14, 2005, p. 53.
[111]/ Hirst, Eric and Kirby, Brendan, Transmission Planning for a Restructuring U.S. Electricity Industry, Edison Electric Institute, June 2001, p. 1.
[112]/ "Since electricity is not economically storable in large quantities, it must be generated when demanded and is consumed nearly instantaneously. Consumers or others acting on their behalf, cannot simply put a large

without storage depots or warehouses, where traffic congestion would mean not just a loss of time in delivering a commodity, but a loss of the commodity itself."[113]

As indicated by the Electric Power Research Institute: "Electricity is unique among energy commodities because of the difficulty of storing it in bulk. Instant-response storage units such as batteries, for example, have a very limited capacity, while pumped hydro storage is large but involves a long response time. . .Until large-scale storage of electricity becomes practical, electricity must be generated to closely follow the swings of demand in real time."[114] "Some power sources are intermittent and uncontrollable in that they do not provide continuous electrical power. This intermittent nature is characteristic of certain renewable energy technologies such as solar and wind power. They require backup sources of power and/or storage devices to store power for later use."[115,116]

As indicated by the United States Government Accountability Office (GAO), "wind and solar energy are intermittent energy sources because wind speed and sunlight vary, depending, for example, on the time of day and the weather – on average, wind turbines operate the equivalent of less than 40 percent of the hours in a year due to the intermittency of wind. Alternatively, the electricity generated must be immediately used or transmitted to the power transmission gird because no cost-effective means exists for storing electricity."[117]

The traditional function of energy storage devices is to save production costs by holding cheaply generated off-peak energy that can be then be dispatched during peak-consumption periods. Stored energy produced by base generation units during off-peak periods can avoid the need to use highly polluting supplemental/peak generation units during periods of peak demand. In addition, energy storage can be used to provide effective power system control. Different dispatch modes can be superimposed on the daily cycle of energy storage and additional capacity can be reserved for the express purpose of providing these control functions. As a

amount of power in storage when the price is low for use later or resell it when the price is higher. If storage were available, it could be used to moderate the price and dampen any supplier market power. Also, because of transmission constraints and other physical limits on sending power over long geographic distances, power may not be available to send to higher prices areas to moderate the price" (Rose, Kenneth, 2005 Performance Review of Electric Power Markets – Update and Perspective, Virginia State Corporation Commission August 23, 2005).

[113]/ United States Department of Energy, National Transmission Grid Study, May 2002, p. ii.

[114]/ Electric Power Research Institute, The Western States Power Crisis: Imperatives and Opportunities, An EPRI White Paper, June 24, 2001, pp. 18 and 45.

[115]/ International Atomic Energy Agency, Health and Environmental Impacts of Electricity Generation Systems: Procedures for Comparative Assessment, Technical Report Series No. 394, 1999, p. 47.

[116]/ As indicated by the President's Committee of Advisors on Science and Technology Panel on Energy Research and Development: "The extent to which intermittent renewable energy technologies (iRETs), wind and solar, can penetrate utility grids without storage depends on what other generating capacity is on the system. An electric system optimized to accommodate iRETs would have less baseload and more load-following or peaking capacity. However, if iRETs are to make very large contributions to electricity supplies in the longer term, technologies are needed that would make it possible to store energy for many hours at attractive costs. . .Storage will take on added importance in the future to ensure reliable, high-quality service. It will provide for increased renewable use and system stabilization with distributed generation. Areas of importance include pumped hydro, compressed air, battery, inertial, and SMES [superconducting magnetic energy storage] technologies covering a wide capacity range" (Source: President's Committee of Advisors on Science and Technology Panel on Energy Research and Development, Report to the President on Federal Energy Research and Development for the Challenges of the Twenty-First Century, November 1997, pp. 6-3, 6-4, and 6-25).

[117]/ United States Government Accountability Office, Department of Energy – Key Challenges Remain for Developing and Deploying Advanced Energy Technologies to Meet Future Needs, GAO-07-106, December 2006, p. 31.

distributed resource, energy storage devices can enhance power quality and reliability.[118] When used in combination with renewable resources, storage devices can make supply coincident with periods of peak consumer demand and can facilitate large-scale integration of intermittent renewable resources onto the electric grid.[119] Figure 8-12 (Wind Generation and System Load Have Different Daily Patterns) presents a curve that plots energy demand and wind turbine generation on an hourly basis in California.[120] As noted, wind turbine generation is not coincident with demand.[121] In order to optimize the use of wind energy and facilitate the balancing of generation and load, storage devices would permit off-peak and non-firm wind turbine energy to be stored and provided to consumers as firm and on-peak energy. As indicated by the American Solar Energy Society, "even greater wind and solar contributions might be possible through greater use of storage and high-efficiency transmission lines."[122]

Alternating current electricity is not directly stored but is converted and stored by mechanical, chemical, or electrical potential energy methods. Each of these methods has its own particular operational range and capabilities. Electricity storage technologies include pumped hydroelectric storage, compressed air energy storage (CAES), flow batteries, sodium sulfur batteries, lead-acid batteries, nickel-cadmium batteries, flywheels, electro-chemical capacitors, superconducting magnetic energy storage, and thermal storage.[123] Pumped storage is the "most popular large storage technology in the world with 19 gigawatts in the United States (2.7 percent of total generation).[124] Of those technologies, only CAES has the ability to proximate the storage capacity of pumped hydroelectric storage.

Since this alternative addresses only storage and not transmission, it would not result in the attainment of the basic objectives of the proposed projects.

8.2.6 Generation-Interconnection Alternatives

With regards to the point of juncture for the LEAPS project, a number of options were identified, including: (1) a single point of connection via a transmission line extending northward from the LEAPS powerhouse to a new substation located along the SCE's 500-kV Valley-Serrano transmission line; (2) a single point of connection via a transmission line extending southward from the LEAPS powerhouse to a new substation located along the SDG&E's 230-kV Talega-Escondido transmission line; or (3) two points of connection, one extending northward to a new substation located along the SCE's Valley-Serrano transmission line and one extending southward to a new substation located along the SDG&E's Talega-Escondido transmission line.

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[118]/ California Energy Commission, California's Electricity System in the Future – Scenario Analysis in Support of Public-Interest Transmission System R& D Planning, P500-03-010F, Public Interest Energy Research Program Energy Systems Integration Team, April 2003, p. 41.

[119]/ University of Missouri-Rolla, Energy Storage, Overview of Energy Storage Technologies, undated, p. A-1 (http://www.ece.umr.edu/links/power/Energy_Course/energy/Renewables/DOE_Charac/append_overview.pdf).

[120]/ Hawkins, David, Wind Generation and Grid Operations: Experience and Perspective, California Independent System Operator, March 23, 2005.

[121]/ On the day of the State's peak demand (August 24, 2006), wind power produced at 254.6 MW at the time of peak demand. 254.6 MW represents only 10.2 percent of wind's rated capacity of 2,500 MW. Over the preceding seven days (August 17-23, 2006), wind produced at 89.4 to 113.0 MW, averaging only 99.1 MW at the time of peak demand or just 4 percent of rated capacity (Source: Dixon, David, Wind Generation's Performance durint the July 2006 California Heat Storm, Energy Central Network, August 8, 2006).

[122]/ American Solar Energy Society, Tackling Climate Change in the U.S., - Potential Carbon Emission Reductions from Energy Efficiency and Renewable Energy by 2030, January 2007, p. 4.

[123]/ Baxter, Richard, Energy Storage - A Nontechnical Guide, 2006, pp. 55-164.

[124]/ United States Department of Energy (Energetics, Incorporated), Technology Briefs – Overview of Advanced Electric Delivery Technologies, Office of Electric Transmission and Distribution, August 2004, p. 40.

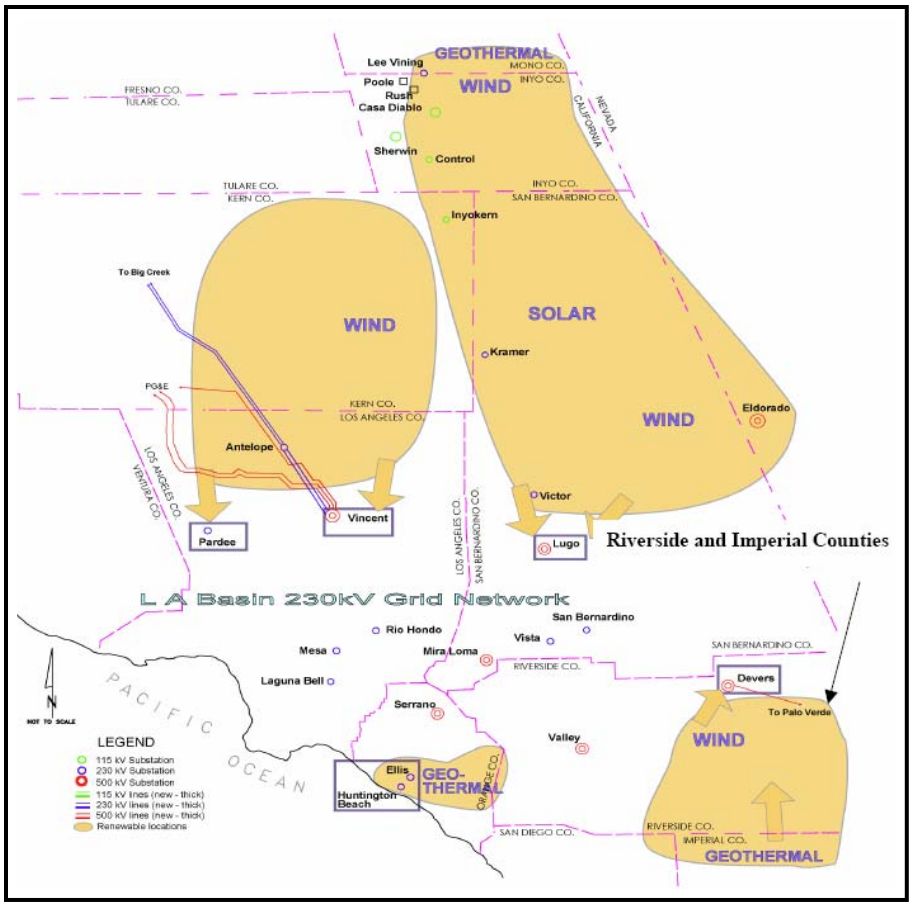

Figure 8-10
SOUTHERN CALIFORNIA RENEWABLE ENERGY RESOURCES
Source: California Public Utilities Commission

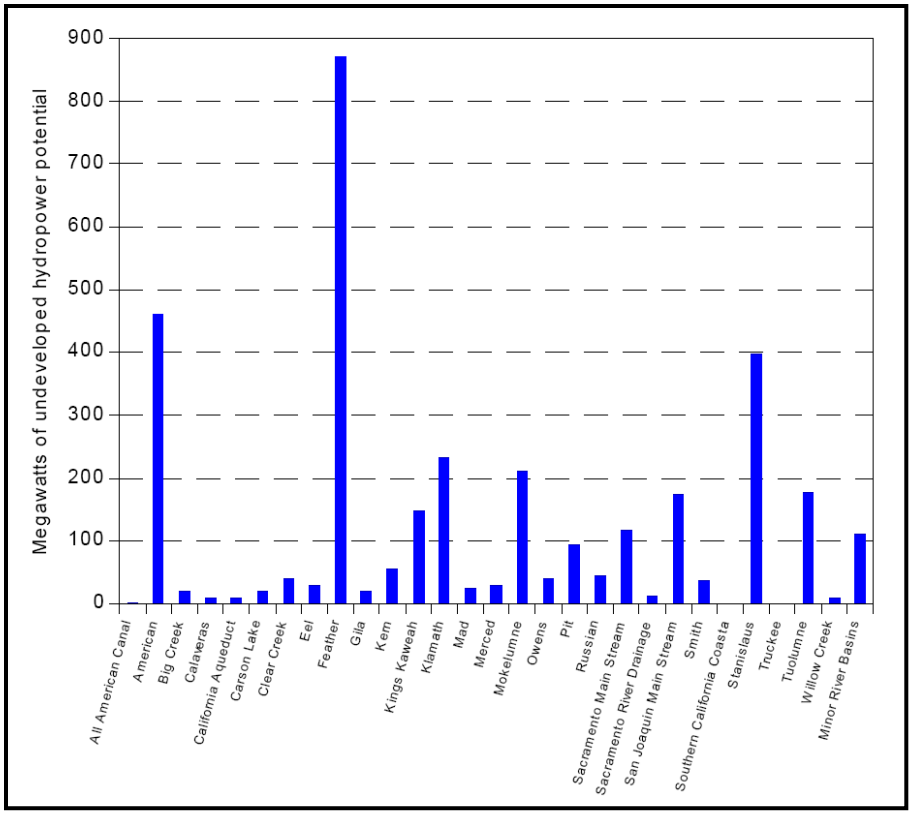

Figure 8-11
MEGAWATTS OF UNDEVELOPED HYDROPOWER POTENTIAL IN THE CALIFORNIA RIVER BASINS
Source: United States Department of Energy

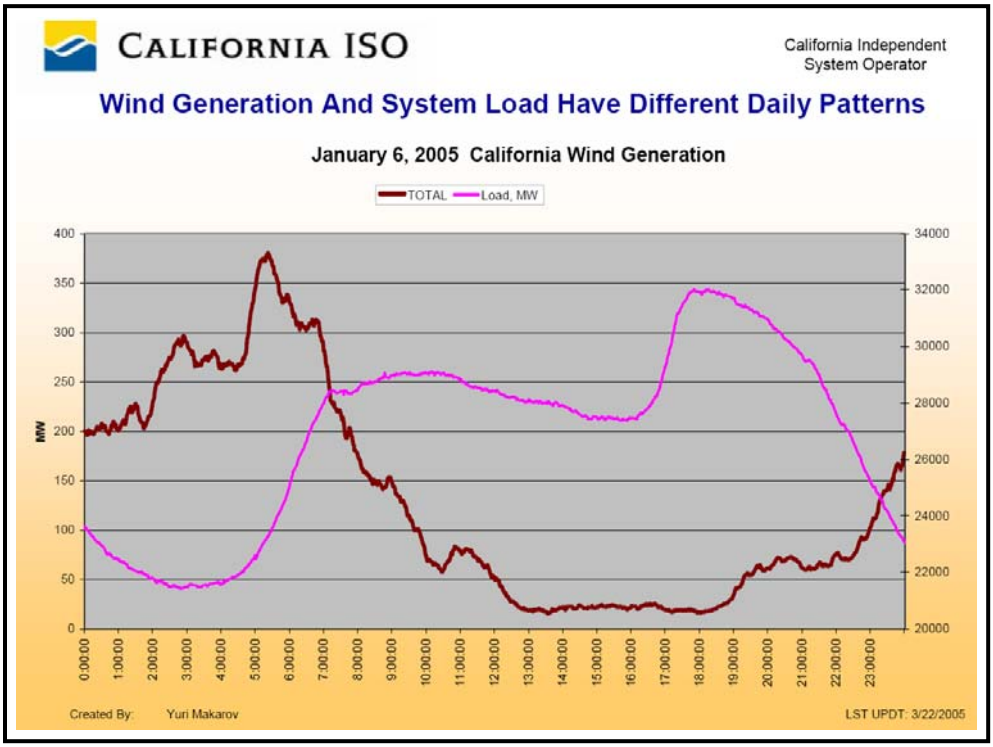

Figure 8-12
WIND GENERATION AND SYSTEM LOAD HAVE DIFFERENT DAILY PATTERNS
Source: California Independent System Operator

The possible integration of the northern and the southern segments of the proposed 500-kV transmission line into a single, consolidated project was identified in the ISCD (e.g., "If constructed concurrently, the two high-voltage transmission lines would appear as a single, integrated 500-kV conduit linking SCE's Valley-Serrano line in Riverside County to SDG&E's Talega-Escondido line in San Diego County. The combined high-voltage transmission line could possibly serve as an alternative to and functional equivalent of SDG&E's Valley-Rainbow Interconnect Project"[125]) and was separately identified by the CPUC/BLM as part of its alternative analysis for the Valley-Rainbow interconnect project.

The "San Diego Energy Infrastructure Study," as prepared by the San Diego Association of Governments (SANDAG) and others, concludes that "[t]ransmission capacity and import capability become important over the 2004-2010 time period. To avoid near-term imbalances the region needs 1 to 2 new generation plants, additional transmission, and increased energy efficiency. If these resources are not available, higher prices and load curtailments may occur. Unless the [San Diego] region pursues a strategy of diversifying its electric supply portfolio, including energy efficiency, demand response, distributed generation, renewables and additional transmission, the ability of the region to meet its needs in the longer-term will become increasingly difficult, particularly in the outer years."[126] SANDAG states that without a project like Valley-Rainbow, "the generation development in these areas may for all practical purposes be limited to about 1,000 to 1,400 MWs due to congestion constraints going north from SDG&E. An outage of the single connection to SONGS can leave SDG&E with a serious power shortage, such as that which occurred on February 27, 2002. If the Valley Rainbow interconnect project

[125]/ Elsinore Valley Municipal Water District and The Nevada Hydro Company, Inc., Initial Stage Consultation Document – Lake Elsinore Advanced Pumped Storage Project, FERC Project No. 11858, April 2001, p. 66.

[126]/ *Op. Cit*, San Diego Energy Infrastructure Study, p. 4-1.

had been in operation at the time of this event, it would have prevented the need for firm load shedding of some 211,000 customers (approximately 300 MW) in SDG&E's service area."[127,128]

With regards to either a single northern point of juncture or a single southern point of juncture between the proposed pumped storage project and the CAISO-controlled grid, as indicated by FERC: "SDGE needs additional in-area generation resources. Therefore, the southern route is the indicated choice. However, the maximum benefit to both the CAISO and SDGE would be derived from completing the total connection between the TE [Talega-Escondido] and VS [Valley-Serrano] transmission lines. The second connection would also add" other benefits, including reliability, reduced congestion, improved access.[129]

As proposed, assuming the construction of both the northern (Lake-LEAPS) and the southern (LEAPS-Pendleton) segments, the TE/VS Interconnect project would provide substantial reliability benefits to the San Diego area, contribute to providing the "full loop" most benefiting the region, provide additional import capacity into the San Diego area, and provide a path for the importation of Techapi wind renewable energy. If only one-half of the integrated transmission project were to be construct, the TE/VS Interconnect project would not serve its primary intent. Similarly, by eliminating the Applicant's southern line (LEAPS-Pendleton) segment, the LEAPS project would not benefit the San Diego area. By eliminating the northern segment (Lake-LEAPS), pending the concurrent development of the SRPL project, the LEAPS project would not serve to provide a regional renewable resource benefit. As such, the Applicant has concluded that this alternative would not substantially meet the projects' basic objectives.

8.2.7 Other Hydropower Alternatives

The Applicant considered the following additional hydroelectric facility alternatives.

- Small-hydro alternative. "Small hydro" (<30 MW) is considered a renewable energy resource. FERC treats, as a single generating facility, the aggregated generation at a site for which an interconnection customer seeks a single point of interconnection. As such, if the total aggregated generation exceeds 20 MW, the combined projects would not qualify as small-generator status. The Applicant would need to undertake multiple small-hydro projects to approach the generation capacity associated with the LEAPS project. Multiple small-generator projects would likely increase the impacts associated with a single, albeit, larger project. A small hydro project was considered and rejected because the LEAPS project's basic objective is for large generation, there are not sufficient water resources in southern California to allow for the development of multiple small-scale hydropower projects, and, if opportunities could be located, multiple small-generator projects would not substantively reduce or result in the avoidance of the projects' significant environmental effects.

[127]/ *Ibid*., p. 4-17.

[128]/ On February 27, 2002, a power outage occurred in the San Diego area when the electrical system suffered a loss of 1,100 megawatts of generation when SONG's Unit No. 3 tripped off-line due to problems at the substation. The CAISO ordered 300-megawtts of load shedding to prevent a potential uncontrollable blackout in the San Diego area (Source: California Independent System Operator, News Release – Transmission Event at San Onofre Necessitates Brief Power Outage in San Diego Area, February 27, 2002).

[129]/ *Op. Cit*., Final Environmental Impact Statement Final Environmental Impact Statement for Hydropower License – Lake Elsinore Advanced Pumped Storage Project, FERC Project No. 11858, FERC/EIS-0191F, p. B-21.

- Relicense, retrofit, upgrade existing hydroelectric facilities alternative. Retrofit of and upgrades to existing hydropower projects, including increasing the efficiency of turbines and generators and increasing the flow or head, could increase the capacity of those facilities and reduce the need for new hydropower alternatives. Based on an analysis conducted by the Oak Ridge National Laboratory for the DOE, no existing hydropower facilities located in the southern California area were identified which were "likely to benefit from upgrades." Projects deemed to be "likely to benefit from upgrades" included those that were constructed prior to 1940 and those that were constructed between 1940 and 1970.[130]

  Only about five percent of the 67,000 existing dams in the United States have potential hydropower capacity and many of these dams are unsuitable for hydropower development because of size, isolation, or safety consideration. The Applicant has not identify any existing hydropower projects, located in the southern California area, that would be apparent candidates for potential relicensing, retrofitting, and/or upgrading that were not presently proposed for or presently undergoing relicensing. Even if one or more projects could be identified, substantive contractual constraints would likely exist which would need to be resolved allowing for the Applicant's joint participation. In recognition of the speculative nature of any contractual agreements, the Applicant concluded that this alternative was not feasible.

- 300/330-MW advanced pumped storage alternative. As indicated in the District's 1994 preliminary permit (FERC Project No. 11504), a 300-MW advanced pumped storage project was previously proposed by the District. As indicated in the District's 2000 preliminary permit application, the project that has now evolved into the current projects was initially identified as comprising "three pump/turbines [which] would be of the vertical, reversible Francis type, rated to produce 110 to 167 MW at the minimum operating head."[131] Those separate actions suggest the potential feasibility of a 300 to 330-MW pumped storage project.

  On October 21, 2000, Voith Siemens Hydro, Inc. (VSH) completed an in-depth study of three alternatives plant sizes for the LEAPS project. The intent of those studies was to optimize the turbine generator selections, current utility rates, cost equipment utilization, and interconnect voltages. Of the options examined by VSH, a 500-MW facility was found to be the best selection for a 230/500-kV primary interconnection to the existing SDG&E and SCE system.

  Construction of a 300/330-MW pumped storage facility would incorporate the same general features as associated with the LEAPS project, including a new upper reservoir, powerhouse, transmission lines, and substations. Other than the size and the efficiency of the reversible turbines, the construction-related and the operational impacts would be virtually identical to those associated with the proposed hydropower project, including the need for similar mitigation measures. The electrical and ancillary benefits of the LEAPS project would, however, be reduced if the generation capacity were itself to be reduced, as would the LEAPS project's ability to both serve electricity needs of the San

[130]/ Railsback, S.F., *et al*., Environmental Impacts of Increased Hydroelectric Development of Existing Dams, Publication No. 3585, United States Department of Energy, Oak Ridge National Laboratory, April 1991, pp. 2-3.

[131]/ Elsinore Valley Municipal Water District, Application for Preliminary Permit – Lake Elsinore Advanced Pumped Storage Project, September 15, 2000, p. 1-3.

Diego area and facilitate the attainment of the State's RPS goals. Since a 300/330-MW hydropower project would not reasonably be expected to substantively reduce or avoid any of the projects' significant environmental effects, the Applicant concluded that the further consideration of this option would not foster informed decisionmaking.

- 1,000-MW advanced pumped storage hydropower alternative. As now proposed, the LEAPS project involves a single approximately 100-acre upper reservoir (Decker Canyon) and the use of two 250-MW Francis-type reversible turbines. Although no power flow studies have been performed, none of the studies conducted by or for the Applicant and none of the documents reviewed in the preparation of this PEA have demonstrated the lack of feasibility of constructing two upper reservoirs (Decker Canyon and Morrell Canyon) and installing four 250-MW turbines in an enlarged powerhouse.

  The State CEQA Guidelines limits the investigation of reasonable alternatives to those that could feasibly accomplish most of the basic objectives of the project and avoid or substantially lessen one or more of the significant impacts (14 CCR 15126.6[c]). It can be reasonably concluded that, based on the larger development footprint and the additional construction impacts associated with developing a larger project, this alternative's impacts would be greater than those associated with a 500-MW hydropower project. Since the impacts of a larger hydropower project would not likely be less that those associated with the proposed projects, the Applicant has eliminated this alternative not because of its inability to satisfy the projects' basic objectives but because it does not satisfy the intent of the State CEQA Guidelines.

- Other hydropower alternatives. A run-of-the river (ROR) hydropower project alternative was eliminated because, in the general projects' area, there does not exist a river or other waterbody of sufficient size or containing year-round flows conducive to the development of this type of facility.

  In March 2007, the United States Department of the Interior, Minerals Management Service, released a "Draft Programmatic Environmental Impact Statement for Alternative Energy Development and Production and Alternative Use of Facilities on the Outer Continental Shelf, OES EIS/EA MMS 2007-010" which examined a number of off-shore energy-generation alternatives, including a number of alternatives that could be categorized as hydroelectric (e.g., point absorbers, attenuators, overtopping devices, terminators, ocean currents).[132]

  Each of those alternatives were considered but eliminated based on limited application of those technologies,[133] the absence of suitable lands or waters, the speculative nature of the Applicant's ability to obtain permits from the California Coastal Commission and

[132]/ *Op. Cit.*, Draft Programmatic Environmental Impact Statement for Alternative Energy Development and Production and Alternative Use of Facilities on the Outer Continental Shelf, OES EIS/EA MMS 2007-010.

[133]/ Ocean waves represent a form of renewable energy created by wind currents passing over open water. Capturing the energy of ocean waves in offshore locations has been demonstrated as technologically feasible. Basic research to develop improved designs for wave energy conversions (WEC) devices is being conducted in regions, such as near the Oregon coast, with high energy resources (Source: Minerals Management Service, Technology White Paper on Wave Energy Potential on the U.S. Outer Continental Shelf, United States Department of the Interior, May 2006, p. 2).

the Federal Marine Fisheries Service, and the absence of current environmental information upon which an alternative analysis could be based.[134]

8.2.8 Other Generation Alternatives

The Applicant considered other energy generation alternatives and other generation technologies, including solar energy.

As an example of a solar energy project, Inland Energy is currently pursuing the development of a 50-MW solar-thermal technology project in the City of Victorville (High Desert Power Project). As proposed, that project would use a 250-acre array of parabolic mirrors to capture the sun's radiant energy and use that energy to boil water, producing steam to power a turbine. Based on that ratio, a 2,500-acre site (generally comparable to the size of Lake Elsinore) would likely be required to generate 500-MW of energy. Use of solar technologies was eliminated by the Applicant as infeasible since solar, as well as other non-hydroelectric technologies, would not meet the projects' basic objectives.

As indicated in the FEIS, FERC identified "a natural gas-fired simple cycle combustion turbine as the likely alternative to the LEAPS project because the LEAPS project would operate at a 35.6 percent plant factor and would be dispatched in a somewhat similar manner to meet peak demand."[135] The Applicant considered and eliminated from further consideration other types of peakers, such as natural-gas fired combustion-turbine generators. The construction and operation of non-hydropower peaking facilities would not meet the projects' basic objectives.

8.2.9 Design Variation Alternatives

The results of detailed design and engineering studies were presented in the Applicant's FLA. In addition to those alternative upper reservoir, powerhouse, transmission alignment, and substation alternatives identified therein, numerous design variations were identified for the projects' component parts. Those design options included: (1) dam and dike design variations (e.g., zoned earthfill dam with a central impervious core or inclined upstream impervious zone, concrete-faced earthfill dam, earthfill dam with an asphaltic-concrete upstream face, and gravity dam constructed of roller compacted concrete); (2) reservoir liner system variations (e.g., clay, asphaltic concrete, geo-membrane, and combination liner systems); (3) penstock alignments and configuration variations; (4) transmission tower design variations (e.g., guyed, V-shaped structure, guyed, delta structure, four-legged, self-supporting structure, and H-Frame, tubular-steel structure); and (5) alternative aeration system variations (e.g., turbine aeration, surface-water pumps, oxygen injection systems, aerating weirs, and air compressors and blowers). With regards to proposed transmission facilities, all substantially different routes and alignments, including the Valley-Rainbow interconnect project, SRPL project, Tehachapi transmission project, Valley-Serrano corridor, and Non-NFS routes, have been eliminated from further consideration for the reasons described herein.

[134]/ The Minerals Management Service (MMS), a bureau of the United States Department of the Interior, has conducted initial scoping meetings in advance of the preparation of a "Outer Continental Shelf Renewable Energy and Alternative Use Programmatic Environmental Impact Statement." The programmatic EIS will evaluate the issues associated with renewable energy development in federal waters of the Outer Continental Shelf (OCS).

[135]/ *Op. Cit*., Final Environmental Impact Statement for Hydropower License – Lake Elsinore Advanced Pumped Storage Project, FERC Project No. 11858, FERC/EIS-0191F, p. 2-2.

The Applicant's proposed transmission alignment will extend from the general area of Alberhill (Riverside County) on the north end to the general area of Camp Pendleton (San Diego County) on the south end. Between those points of connection to the CAISO-controlled grid, a number of transmission segment variations have been identified. For the most part, those alignments constitute slight variations of the proposed projects' transmission system rather than substantially different alignments.

With regards to possible upper reservoir sites, based on topographic considerations and the proximity of the San Mateo Canyon Wilderness, only two candidate reservoir sites where identified in the Elsinore Mountains (Decker Canyon [south fork] and Morrell Canyon). Based on environmental consideration, Decker Canyon was identified both by FERC and by the Forest Service as the preferred location and is included under the description of the proposed LEAPS project herein. Two different configurations for the Decker Canyon reservoir were identified in the FLA (Alternatives B-1 and B-2). Because Decker Canyon - "Alternative B-1" retained a natural shoreline, the Applicant concluded that the reservoir could not feasibly be lined with a geo-membrane liner system. Based on water quality concerns, "Decker Canyon - Alternative B-1" was subsequently eliminated by the Applicant from further consideration. To further increase the surface area of the Decker Canyon reservoir, a variation to "Decker Canyon - Alternative B-2" was identified in the FLA (i.e., realignment of an approximately 700-foot-long section of Main Divide Truck Trail) and is identified as the proposed upper reservoir herein.

Alternatives considered under CEQA relate to the project as a whole. As such, the CEQA lead agency is not required to analyze specific alternatives to those separate parts that do not foster meaningful decisionmaking (Big Rock Mesas Property Owners Association v. Board of Supervisors). In formulating a reasonable range of alternatives herein, the Applicant has not elected to examine other alternatives involving only relatively minor design variations to the projects' individual components.

8.2.10 Concurrent vs. Sequential Construction Alternative

The projects' schedule assumes that the proposed network upgrade, including both the interconnection between SCE's existing 500-kV Valley-Serrano transmission line and SDG&E's existing 230-kV Talega-Escondido transmission line and the proposed upgrades to SDG&E's 230-kV transmission line, would be constructed prior to the construction of the hydroelectric facility's upper reservoir, powerhouse, high-head and low-head conductors, and LEAPS substation.

The sequential construction of the LEAPS and TE/VS Interconnect projects is the result of a number of factors, including: (1) increased engineering complexity associated with the generation facility as compared to the transmission facility; (2) the benefits to the regional transmission grid that early energization of the interconnection will provide the State and the region; (3) the ability of permitting agencies to bifurcate the two projects from a permitting perspective; (4) the ability to finance and physically construct one project component in advance of the other; and (5) the different electrical purposes that the two energy projects serve.

The Applicant, however, retains the option to construct the generation and transmission facilities either concurrently or sequentially, subject to receipt of appropriate permits and approvals. The Applicant has rejected, as distinct alternatives, any options wherein various development and staging sequences are examined as separate alternatives.

8.2.11 Additional Considerations

On January 23, 2007, the BLM and the CPUC issued a "Notice of Second Round of Scoping Meetings on Alternatives to the Proposed Sunrise Powerlink Project" (SRPL NOP^2) for SDG&E's proposed Sunrise Powerlink Project. As indicated therein, BLM and the CPUC "completed preliminary assessment of nearly 100 alternatives, including 24 identified by SDG&E in its proponent's environmental assessment. The rest of the alternatives were suggested by the public and public agencies during scoping, or were developed by the EIR/EIS team in order to reduce or avoid impacts of the Sunrise Powerlink Project as proposed."[136]

The Applicant considered each of the alternatives identified in SRPL NOP^2. Those alternatives that constitute segmental variations of the proposed SRPL project, including variations of the Southwest Powerlink (SWPL), were eliminated since they those alternatives could not be implemented separate from the remaining components of the SRPL project.

The SRPL NOP^2 also identified a number of "system alternatives," defined as different transmission line upgrades and interconnections. The following three system alternatives are being carried forward as part of the SRPL project: (1) "LEAPS project or Serrano/Valley-North 500-kV alternative"; (2) "Mexico Light 230-kV alternative"; and (3) "Path 44 upgrade alternative." The "LEAPS project or Serrano-Valley-North 500-kV alternative" generally constitutes the proposed projects and are, therefore, not identified as separate alternatives herein.

The "Mexico Light 230-kV alternative" includes building a new "short 230 kV transmission line in Mexico between circuits that are normally disconnected, to provide an optional path for export-designated generators through the Comisión Federal de Electricidad (CFE) grid rather than through the existing SWPL (Imperial Valley-Miguel 500 kV line). This also involves upgrading the two 230 kV lines connecting La Rosita generators to CFE's La Rosita 230 kV substation."[137] Based on its international nature, the Applicant asserts that this alternative is highly speculative and is, therefore, not subject to further review.

Path 44 consists of the five 230-kV lines from SONGS to SDG&E. The combined flow on those five lines is Path 44 flow. The "Path 44 upgrade alternative" includes an "upgraded transmission corridor in SCE territory to increase the import rating of Path 44 (South of SONGS) into SDG&E territory by approximately 300 MW."[138] The proposed TE/VS Interconnect project includes a proposed upgrade (second circuit) to the Talega-Escondido transmission line, using primarily the existing towers. Since any other "Path 44 upgrade" would be presumed to generate greater environmental impacts, the Applicant has eliminated this alternative as non-response to CEQA criteria for alternative selection.

8.3 Alternatives under Consideration

With the exception of the "no project" (no build) alternative, each of the following development (build) alternatives appear to satisfy the basic objectives of the Applicant for the proposed projects. The comparative environmental impacts associated with each of the following alternatives is examined in the FEIS.

[136]/ Bureau of Land Management and California Public Utilities Commission, Notice of Second Round of Scoping Meetings on Alternatives to the Proposed Sunrise Powerlink Project, January 23, 2006, p. 1.
[137]/ *Ibid*., p. 23.
[138]/ *Ibid*.

8.3.1 "LEAPS Project Only" Alternative

The identification of the LEAPS project as an "alternative" herein is presented for informational purposes only. The LEAPS project is not specifically an alternative to the proposed projects but is one of the two principal components of the projects addressed herein.

In the derivation of these projects, in addition to a broad range of other issues, a number of possible scenarios were considered. Under the first scenario, the TE/VS Interconnect project and the LEAPS project are combined to create a single, fully integrated and entitled FERC-licensed project that includes both a new 500-MW generation facility and a new transmission facility allowing for 1,000 MW of additional import capacity into the San Diego region. The transmission line provides a network connection between SCE's 500-kV Valley-Serrano transmission line and SDG&E's 230-kV Talega-Escondido transmission line and links those network upgrade to the hydroelectric facility via a new short-tap gen-tie (extending from the Midpoint [LEAPS] substation to the point of interconnection with the new Northern-Southern [Lake-Pendleton] transmission line). Because they constitute an "advanced transmission technology," subject to FERC's determination, the 500-kV Northern (Lake-LEAPS) and Southern (LEAPS-Pendleton) and the 230-kV Western (Talega-Pendleton) and Eastern (Pendleton-Escondido) transmission line segments both serve as network upgrades.

Under the second scenario, the LEAPS project's facilities are constructed but the associated transmission facilities are sized only to serve as primary lines and are not sized to accommodate the additional power flows beyond those minimally necessary to get all of the hydropower to market. Under this scenario, the primary differences between this alternative and the combined project relates to FERC's designation, the sizing and capacity of the LEAPS-only transmission lines (including minor design variations relative to conductors and insulators on the transmission towers), the placement and sizing of individual substation components, and design variations within the proposed substations themselves.

Subject to FERC determination, the transmission line's 230-kV Western (Talega-Pendleton) and Eastern (Pendleton-Escondido) segments continue to serve as network upgrades but the transmission line's 500-kV Northern (Lake-LEAPS) and Southern (LEAPS-Pendleton) segments become interconnection facilities.

From an environmental perspective, these differences are not substantial. As a result, the impacts attributable to a "LEAPS project only" alternative would not be expected to be substantially different from those associated with the proposed projects. The potential environmental impacts of this alternative are, therefore, similar to those outlined in Section 5.0 (Environmental Impact Assessment Summary) and Section 6.0 (Detailed Discussion of Environmental Impacts) herein.

8.3.2 "TE/VS Interconnect Project Only" Alternative

The identification of the TE/VS Interconnect project as an "alternative" herein is presented for informational purposes only. The TE/VS Interconnect project is not specifically an alternative to the proposed projects but is one of the two principal components of those projects addressed herein.

In the derivation of these projects, in addition to a broad range of other issues, the following three possible scenarios were considered: (1) the 500-MW pumped storage project is not licensed by FERC and/or permitted by the USFS and is, therefore, not constructed; and (2)

notwithstanding the Applicant's receipt of a federal hydropower license and requisite SUP, the 500-MW pumped storage project (including the proposed powerhouse, upper reservoir, LEAPS substation, penstocks, and intake/outlet structures and such other related improvements and facilities as may be associated therewith) is not constructed based on the Applicant's inability to secure necessary financing or other factors preventing its implementation; and (3) the federal license expires based on the Applicant's inactivity or inability to proceed with the timely construction of the hydroelectric facilities. Although the LEAPS project is not construction, under those scenarios, those facilities associated with the transmission lines interconnecting SCE's 500-kV Valley-Serrano and SDG&E's 230-kV Talega-Escondido systems (including the new 500-kV transmission lines, 230-kV second circuit upgrades (Talega-Escondido No. 2), and new Northern [Lake] and Southern [Pendleton] substations), including all appurtenant facilities, are constructed and energized.

With regards to those transmission lines, two possible design variations were considered under this alternative: (1) assuming that the TE/VS Interconnect project is a precursor to the LEAPS project, the transmission lines and related facilities are sized to accommodate both the power flows associated with the SCE/SDG&E interconnect and the additional electricity required for the 600-MW of pumping or the 500-MW of generation associated with the hydropower project (1,000-MW path rating); or (2) assuming that the TE/VS Interconnect project is not a precursor to the LEAPS project or can be constructed in such a fashion as to phase the installation of such additional improvements as may be required to accommodate the additional power flows associated with the hydroelectric facility, the transmission lines and related facilities would only be initially sized to accommodate the power flows attributable to the SCE/SDG&E interconnect and not the additional capacity required for the pumping and generation associated with the hydropower project (<1,000-MW rating). The primary differences between these variations relate to the size and capacity of the transmission lines, including any resulting design variations relative to conductors and insulators on the transmission towers and design variations within the Northern (Lake) and Southern (Pendleton) substations.

If the construction of the transmission lines were phased such as to include two distinct construction phases, construction impacts would occur at two distinct occasions rather than just once. Although they would occur over a longer duration, the impacts that would likely manifest during the second construction sequence would not be expected to exceed those likely to exist during the initial construction. From an impact perspective, two construction phases would extend the overall construction time period but may not substantively increase the significance of the impacts predicted to occur during those construction activities.

Because CEQA is to "be interpreted in such a manner as to afford the fullest possible protection to the environment" (14 CCR 15003[f]), for the purpose of this PEA analysis, it is assumed that the transmission line is designed, sized, and constructed to accommodate both interconnection and generation functions. Under this variation, for the purpose of this CEQA analysis, the transmission lines would have a 1,000-MW path rating. The resulting new 500-kV transmission line (Lake-Pendleton) and the 230-kV second circuit upgrade (Talega-Escondido No. 2), including all appurtenant facilities, constitute network upgrades. This scenario allows for the consideration of a "transmission only" alternative.[139]

[139]/ Since the 500-MW rated scenario is merely a permitting variation of the proposed projects, that alternative is not separately addressed but is, nonetheless, retained as an option herein.

The potential environmental impacts of this "TE/VS Interconnect project only" alternative are outlined in Section 5.0 (Environmental Impact Assessment Summary) and Section 6.0 (Detailed Discussion of Environmental Impacts) herein.

8.3.3 "LEAPS Facilities Siting" Alternatives

For consistency, except where otherwise modified, the Applicant's proposed projects, as examined in this PEA, constitutes FERC's and the USFS' "staff alternative," as described in the FEIS. As the projects have progressed from that described in the Applicant's PP and FLA, in FERC's and the USFS' DEIS and FEIS, the Applicant's proposed projects have evolved or been modified over time. For a number of facility components, one or more locational alternatives have been identified. The following siting alternatives constitute options that have been retained and examined as possible alternatives to those components that constitute the Applicant's proposed projects.

"Ortega Oaks Powerhouse" Alternative

As indicated in the Applicant's FLA, three possible LEAPS powerhouse sites were identified. The names used for the purpose of identifying these powerhouse sites (Ortega Oaks, Santa Rosa, Evergreen) related to proximal streets or other local landmarks. The Santa Rosa powerhouse site was identified in the FLA as the Applicant's "preferred project" based, in part, on its relationship to the Applicant's preferred Morrell Canyon reservoir site. The FEIS identified the Santa Rosa powerhouse and the Decker Canyon upper reservoir sites as FERC's and the Forest Service's "staff alterative."

Of the two alternative powerhouse sites (Ortega Oaks and Evergreen), only the Ortega Oaks site has been retained as an alternative and examined herein. Because the distance between the Decker Canyon upper reservoir site and the previously identified Evergreen powerhouse site would substantially increase tunneling costs, the Applicant has elected not to examine the Evergreen powerhouse site herein. The decision not to carry forward the discussion of the Evergreen powerhouse site is based a preliminary economic analysis conducted by TNHC and is not itself indicative of the presence of environmental constraints that would preclude the possible development of that property.

Elevations range from a maximum of 1480-feet AMSL at the extreme southerly point of the site to a minimum of approximately 1340-feet AMSL along the northerly site boundary. Topographically, the alternative power plant site comprises a portion of a relatively broad alluvial fan that is transected by small erosion gullies. Drainage is to the north towards Lake Elsinore. On-site vegetation comprises a mix of Riversidian sage scrub and non-native grasses. The majority of the site has been cleared of all scrub at some point in the past. Some of the more readily identifiable trees and plants included a single live oak, numerous olive and pepper trees, buckwheat, chamise, white sage, sumac, wild tobacco, coyote gourd, and foxtails.

Presented in Table 8-2 (Comparative Grading Quantities - Powerhouse) is a comparison of the estimated grading quantities, in cubic yards of excavation, for the Santa Rosa and Ortega Oaks powerhouse sites. As illustrated in Figure 8-13 (Alternative Ortega Oaks Powerhouse Site), the alternative Ortega Oaks powerhouse site[140] would be located near the southeastern corner of

[140]/ Tentatively identified as County Assessor's Parcel Map Nos. 386120028, 386120029, and 387110021 (pre-2004).

SR-74 (Ortega Highway) and Grand Avenue, in the unincorporated Lakeland Village area of Riverside County.

Table 8-2
COMPARATIVE GRADING QUANTITIES – POWERHOUSE

Powerhouse Site	Estimated Depth of Excavation (ft)	Estimated Quantity of Excavation (CY)
Santa Rosa	340	450,000
Ortega Oaks	320	430,400

Source: The Nevada Hydro Company, Inc.

The alternative Ortega Oaks powerhouse site is privately owned[141] and, although located within the Congressional boundaries of the CNF, is not administered by the Forest Service. The powerhouse site is about 60-acre in size and is bordered on the north and east by the City of Lake Elsinore. The site is presently vacant but is used by the Elsinore Hang Gliding Association (EHGA), launching from the TRD (under a USFS-issued SUP[142]), as a landing site.[143] If constructed on the Ortega Oaks powerhouse site, the powerhouse would be located about 340-feet underground at 1,050 feet AMSL, approximately 1,950 feet from Lake Elsinore. The powerhouse design would generally be as described for the proposed Santa Rosa powerhouse.

The following analysis compares the potential environmental effects of this alternative against the potential impacts associated with the proposed projects.

- **Aesthetics**. The visual resource impacts of this alternative would be generally comparable to those associated with the Santa Rosa powerhouse site. Because the Ortega Oaks powerhouse site has greater visibility and abuts Ortega Highway, construction-term impacts would be more pronounced. Once operation, the greater visibility would result in beneficial aesthetic impacts based on the limited nature of above ground improvements, the proposed landscaping, and the incorporation of a neighborhood park abutting that State Highway.

- **Agricultural Resources**. Since neither the Ortega Oaks nor the Santa Rosa powerhouse sites are presently used for any agricultural or farm-related use, the impacts on agricultural resources would be generally comparable.

- **Air Quality**. The quantity of construction-term and operational criteria emission would not be expected to differ substantially between the two alternative powerhouse sites. However, because the Ortega Oaks powerhouse site is located in closer proximity to a larger number of residential receptors, construction-related air quality impacts on those

[141]/ On April 20, 2004, the Riverside County Board of Supervisors approved final Tract Map Nos. 22626 and 22626-1 (Board of Supervisors Agenda Item Nos. 2.15 and 2.16), subdividing the proposed Ortega Oaks powerhouse site into approximately 133 single-family residential lots. In the event that residential development were to occur on that site, it is likely that powerhouse development of that property would be deemed infeasible and an alternative powerhouse site (Santa Rosa or Evergreen) selected.

[142]/ Authorization ID: TRD05805; Contact ID: TRD0303.

[143]/ The use of the proposed Ortega Oaks powerhouse site by the Elsinore Hang Gliding Association is the subject of two ongoing lawsuits before the Riverside County Superior Court (Elsinore Hang Gliding Association v. Western International Development, LLC, Kang Shen Chen, CKS Concordia Development, L.L.C. [Case RIC411343] and Western International Development, LLC, Kang Shen Chen, CKS Concordia Development, L.L.C. v. Elsinore Hang Gliding Association [Case RIC455494]).

residences, both in terms of fugitive dust and toxic air contaminants, would be expected to be greater.

- **Biological Resources**. Although possessing remnants of Riversidean sage scrub, the Ortega Oaks powerhouse site has been predominately cleared of most native vegetation and is routinely maintained for weed abatement purposes. Conversely, the Santa Rosa powerhouse site is generally undisturbed, containing a predominant Riversidean sage scrub plant community. As a result, selection of the Ortega Oaks powerhouse site would result in an incremental reduction in the acreage of disturbance to that plant community. Riversidean sage scrub is not, however, categorized as a plant community that is "known or believed to be of high priority for inventory in CNDDB [California Natural Diversity Database]."[144] As such, this habitat type is not categorized as a "rare natural community."[145]

- **Cultural Resources**. Two archaeological sites have been identified in the area of the Santa Rosa powerhouse site, including one prehistoric site (RIV-5878[146]) and two historic site (RIV-5877H[147] and RIV-7658H[148]). Field reconnaissance surveys of the Ortega Oaks powerhouse site have been negative and no prehistoric or historic resources have been encountered on that property. Ground-borne vibration from construction could potentially affect a number of historic-period buildings (33-7177 and 33-7221) adjacent to the Santa Rosa powerhouse site.

- **Geology and Soils**.[149] Both the Santa Rosa and Ortega Oaks powerhouse sites are feasible from a geotechnical perspective. Based on the geophysical survey results and geologic mapping, competent bedrock will be encountered at the required depths at both the Santa Rosa and Ortega Oaks powerhouse sites. The depth to bedrock at the Ortega Oaks powerhouse site is estimated to range from 110-160 feet below ground surface. Depth to bedrock at the Santa Rosa site is estimated to range form 70-145 feet below ground surface.

[144]/ California Department of Fish and Game, The Vegetation Classification and Mapping Program List of California Terrestrial Natural Communities Recognized by The California Natural Diversity Database, September 2003 Edition.

[145]/ California Department of Fish and Game, Guidelines for Assessing the Effects of Proposed Projects on Rare, Threatened, and Endangered Plants and Natural Communities, December 9, 1984, Revised May 8, 2000.

[146]/ RIV-5878 comprises a bedrock milling station situated adjacent to a small building pad located midway along the eastern margin of the site. The building pad comprises the only vestiges of a dwelling that was demolished in the mid 1960's in connection with the Cox Mine eviction. The single, elongated granitic boulder bears one milling slick and one starter mortar. No obvious signs of a subsurface deposit were observed at this location.

[147]/ RIV-5877H consists of the ruins of a dwelling, most likely that of a cabin or small house located adjacent to a dirt road approximately 700 feet northwest of RIV-5878. The only visible remains of the structure itself comprise a small concrete cellar. It is rectangular in plan and measures 8 feet by 11 feet with a depth of approximately 6 feet. A four-step staircase leads into the cellar from the northern elevation. The age of the ruin is unknown although it may have been contemporaneous with the dwelling demolished in conjunction with the Cox Mine eviction. The location of the ruin is illustrated on the 1942 Lake Elsinore 15-Minute United States Army War Department map (Corps of Engineers, U. S. Army Grid Zone G).

[148]/ RIV-7658H is described as consisting of the wall and foundation remnants of a historic and semi-subterranean building located along an ephemeral drainage on the north-facing slope north of the Elsinore Mountains and south of Lake Elsinore.

[149]/ A comparative analysis of the two powerhouse sites is included in "Comparative Review of Geotechnical Conditions at Three Candidate Powerhouse Sites: Ortega Oaks, Santa Rosa and Evergreen, Lake Elsinore Advanced Pumped Storage Project, FERC Project No. 11858" (GENTERRA Consultants, Inc., March 24, 2006), submitted to the Commission in response to the Commission's release of the "Draft Environmental Impact Statement – Lake Elsinore Advanced Pumped Storage Project, California, FERC Project No. 11858," incorporated by reference herein.

For the Ortega Oaks site construction access to the powerhouse may require significant excavation in the overburden soils. At the Ortega Oaks site, a shaft-type of powerhouse may be the most feasible method of construction since the overburden soils will require a shoring system, which could be incorporated into the permanent support system for the shaft powerhouse. For the Santa Rosa site, an underground cavern-type or shaft-type of powerhouse could be considered because of the proximity of bedrock to the ground surface.

- **Hazards and Hazardous Materials**. The quantity of hazardous materials that may be on the projects' sites during the facility's construction would be minimal and, with the possible exception of explosive material, would not be expended to differ substantially between the two sites. Based on preliminary geotechnical information, grading activities at the Santa Rosa site may require a greater quantity of blasting for the excavation of the powerhouse. Potential hazards would be incrementally less at the Santa Rosa site based on the smaller number of near-site receptors and the greater separate distances between the powerhouse and existing residences.

  Once operation, the same quantity of hazardous materials would be expected on the two powerhouse sites. The potential for exposure to those materials by any off-site sensitive receptors located near either property would be minimal.

  Development plans for the Ortega Oaks property include provisions of the incorporation of a hang glider landing area either at the upslope or downslope portion of the powerhouse site. Because hang gliding is an identified hazardous recreational activity, subject to the skill level of the pilot and changing meteorological conditions, a number of additional hazards would be associated with the Ortega Oaks powerhouse site.

- **Hydrology and Water Quality**. Since the quantity of impervious surfaces would generally be similar and since compliance with applicable water quality permits constitutes a pre-existing obligation, no appreciable difference in hydrologic or water quality impacts would result from the selection between the proposed Santa Rosa and the alternative Ortega Oaks powerhouse sites.

- **Land Use and Planning**. Only limited residential development currently exists in close proximity to the Santa Rosa powerhouse site. In comparison, residential uses directly abut the Ortega Oaks powerhouse site to the east of the site and west of Ortega Highway. Mountainside Ministries (30515 Ortega Highway, Lake Elsinore) is located to the north of Ortega Highway. In addition, while the Santa Rosa powerhouse site is not presently subject to any authorized land use, the Ortega Oaks site is used as a landing zone for hang gliders launching from within the CNF.

  With regards to the Ortega Oaks powerhouse site, on April 20, 2004, the County Board of Supervisors approved Tract Map Nos. 22626 and 22626-1,[150,151] subdividing the alternative powerhouse site into approximately 100 single-family residential lots. As a result of that action, prior to the Applicant's receipt of all requisite permits and approvals,

[150]/ County of Riverside, Board of Supervisors Agenda Items Nos. 2.15 and 2.16, Tract Map Nos. 22626 and 22626-1, April 20, 2004.

[151]/ Tract 22626 was recorded in Book 354, Pages 91-95 of Miscellaneous Maps in the Recorders Office for the County of Riverside and Tract 22626-1 was recorded in Book 354, Pages 41-46 of Miscellaneous Maps in the Recorders Office for the County of Riverside, Assessors Parcel Numbers 386-120-028-6 and 386-120-029-7.

the Ortega Oaks property may transition from a vacant property to a tract of new single-family homes. If so developed and occupied, the development of the Ortega Oaks property for a powerhouse may not be economically or politically feasible.

- **Mineral Resources**. Neither powerhouse site contains recoverable mineral resources.

- **Noise**. The Ortega Oaks property is located in close proximity to single-family residential and a religious use and the Santa Rosa site is located in close proximity to multi-family residential uses and an existing school facility. Construction on either the Ortega Oaks or the Santa Rosa powerhouse sites would, therefore, expose near-site sensitive receptors to short-term increases in ambient noise levels above levels existing without the construction of the LEAPS project.

- **Population and Housing**. Should the Santa Rosa powerhouse site be selected, the Applicant has indicated an intent to purchase the 12-unit Santa Rosa Mountain Villas (33071-33091 Santa Rosa, Lake Elsinore) and, if required, provide relocation assistance to any displaced residences. Upon completion of the facility's construction, those units could be returned to the regional housing inventory, producing not net loss of any housing units. In addition, one or more lakeshore properties may need to be acquired to accommodate the construction of the proposed intake/outlet structure. In the event of any inverse condemnation, if inverse condemnation is asserted and upheld through judicial action, additional properties may be impacted should acquisition be specified for those properties located within the inundation hazard areas associated with the proposed upper reservoir.

  Should the Ortega Oaks site be selected, presently no residential units have been identified for purchase by the Applicant. With the exception of short-term cessation of residential use for the Santa Rosa Mountain Villas property and any other occupied units so acquired, the impacts on population and housing would be incrementally less under the Ortega Oaks option. Based on the size of the regional housing inventory, the incremental differences between the two sites would not be significant.

  It is, however, noted that on April 20, 2004, the Riverside County Board of Supervisors approved Tract Map Nos. 22626 and 22626-1 (Board of Supervisors Agenda Item Nos. 2.15 and 2.16), subdividing the Ortega Oaks powerhouse site into approximately 100 single-family residential lots. Should those units be developed prior to the commencement of construction operations, should the Ortega Oaks property be selected, any of the housing units then constructed and occupied would need to be acquired and the occupants displaced. If the Ortega Oaks site was substantially built out and the homes purchased and occupied, the impact of the demolition of approximately 100 new homes and the displacement of 100 households would be deemed significant.

- **Public Services**. The two alternative powerhouse sites would have a generally comparable impact upon fire protection and vector control services.

- **Recreation**. The Elsinore Hang Gliding Association and others have asserted a right to utilize the Ortega Oaks powerhouse site, or a portion thereof, as a landing site for recreational hang gliding originating from within the CNF. Although the Applicant has indicated an intent to develop a hang glider landing site upon the Ortega Oaks powerhouse site should that site be selected, the use of that property for any

recreational purposes would need to be suspended during the facility's construction. As a result, there would be a short-term and less-than-significant impact upon recreation.

As proposed, new recreational facilities will be provided by the Applicant under the federal hydropower license. Different but generally comparable facilities will be provided at either the Santa Rosa or Ortega Oaks powerhouse site. Additionally, construction of the intake/outlet structure extending from the powerhouse into Lake Elsinore would result in the closure of a portion of the lake to recreational use. The impacts on lake-related recreation from either powerhouse site would be similar.

- **Transportation and Traffic**. Because the Ortega Oaks powerhouse site abuts Ortega Highway and since vehicular access to that site would be limited to the use of that roadway, construction-related traffic would impose a greater impact on traffic along that State highway.

  Prior to the commencement of construction operations, the Applicant would prepare a traffic management plan consistent with the SCCAPWA's "Work Area Traffic Control Handbook" and Caltrans' "Manual of Traffic Controls for Construction and Maintenance Work Zones." Flag persons would be positioned to facilitate ingress and egress to and from the site by construction vehicles, result in short-term disruptions to traffic flow. As documented in Caltrans' "State Route 74 Safety Improvement Project from San Juan Canyon Bridge to Orange/Riverside County Line," implementation of a traffic management plan which contemplates short-term street closures would significant impact traffic and would reduce construction-term impacts to a less than significant level.

  Construction activities conducted on the Santa Rosa powerhouse site would place construction traffic in close proximity to Butterfield Elementary Visual and Performing Arts Magnet School and the Ortega Trails Youth Center (16275 Grand Avenue, Lake Elsinore). Grand Avenue is the primary travel path used by children going to and coming from the elementary school and by adult caregivers dropping off an picking up children from those sites. Similarly, construction traffic would utilize Grand Avenue in order to access the powerhouse site. Heavy trucks entering and exiting the site may, therefore, cross the path of children going to or coming from school. No sidewalks now exist along Grand Avenue along the Santa Rosa powerhouse site's frontage. In order to address potential safety hazards, a traffic management plan would be developed in consultation with the Lake Elsinore Unified School District.

- **Utilities and Service Systems**. The two alternative powerhouse sites would have a generally comparable impact upon potable and non-potable water services and supplies.

- **Energy Resources**. The two alternative powerhouse sites would have a generally comparable impact upon energy resources.

"Morrell Canyon Reservoir" Alternative[152]

The Alternative Morrell Canyon reservoir site (Sections 22, 23, and 27, T6S, R5W, SBBM, Lake Elsinore, Alberhill, and Sitton Peak USGS 7.5-Minute Topographic Quadrangles) is bounded by

[152]/ Morrell Canyon was identified by the Applicant as the preferred upper reservoir site in the FLA. Additional information concerning Morrell Canyon, its existing environmental setting, and the potential impacts associated with the development and operation of a new reservoir at that location is presented in the FLA., incorporated herein by reference.

the San Mateo Canyon Wilderness Area to the south, South Main Divide Truck Trail (Forest Route 6S07) to the north, and Morgan Trail (Forest Route 7-s-12) to the west. The site, at elevation 2700 to 2900-feet AMSL, encompasses the area identified as Lion Springs. While Lion Spring is shown as a discrete point on published maps, the spring is actually a linear feature along the valley floor subjected to artesian groundwater pressure. Flows from Lion Spring, including upstream flows from upper tributary areas, would be maintained by constructing a subdrain collection system under the reservoir to collect and safely discharge flows downstream of the facility.

The Morrell Canyon site is about 3.1 miles (16,300 feet) upstream of where it flow under Ortega Highway. In comparison, the Decker Canyon site is about 2.1 miles (11,200 feet) upstream of its Ortega Highway crossing. The confluence of these two creeks is approximately 0.25 miles below the Morrell Canyon undercrossing of Ortega Highway. Below this confluence, the combined streamflow from Morrell and Decker Canyons flow into the San Juan Creek channel.

Of the three different configurations for the Morrell Canyon reservoir considered and described in the FLA, "Morrell Canyon - Alternative A-3" was identified by the Applicant as the optimal configuration ("preferred project") in the FLA. Some general features of "Alternative A.3" include: (1) 180-foot-high main dam located on the southwest side of the reservoir; (2) perimeter dike ranging up to 60-feet-high located along the northeast side of the reservoir; (3) normal reservoir water surface at elevation 2,880 feet AMSL; (4) inlet at elevation 2,760 feet AMSL for the intake structure; (5) reservoir surface area of approximately 76 acres; and (6) reservoir sideslopes would allow lining of the reservoir. The required fill volume of the dam and dike is approximately 2.5 million cubic yards. "Morrell Canyon - Alterative A-3" has been retained as an alternative to the proposed Decker Canyon reservoir. That alternative site and upper reservoir configuration are illustrated in Figure 8-14 (Alternative Morrell Canyon Upper Reservoir Site).

Table 8-3 (Comparative Design Characteristics - Decker Canyon and Morrell Canyon Upper Reservoirs) and Table 8-4 (Lengths of Shafts and Tunnels for High-Head Conductor - Decker Canyon and Morrell Canyon Upper Reservoirs) presents a summary comparing the two upper reservoir sites.

Table 8-3
COMPARATIVE DESIGN CHARACTERISTICS
DECKER CANYON AND MORRELL CANYON UPPER RESERVOIRS[1]

Upper] Reservoir Site	Reservoir Capacity (AF)[1]	Surface Area (acres)	Max. Elevation (ft)	Min. Elevation (ft)	Main Dam Height (ft)	Dike Max. Height (ft)	Earthwork Volume (10^6 CY)	Total Footprint (acres)
Decker	5,500	80	2,830	2,720	240	50	2.0	120
Morrell	5,500	76	2,880	2,760	180	60	2.5	130

Note:
1. Information and design assumptions subject to change and refinement based on final engineering and both FERC and DSOD review and approval.

Source: The Nevada Hydro Company, Inc.

The following analysis compares the potential environmental effects of this alternative against the potential impacts associated with the proposed projects.

- **Aesthetics**. Construction activities would result in the introduction of construction equipment, including security lighting, into a relatively undisturbed landscape, involve the

removal of existing vegetation, and the grading of the reservoir site. These activities, which would be visible along South Main Divide Truck Trail, would be viewed as disharmonious with the natural environment.

Table 8-4
LENGTHS OF SHAFTS AND TUNNELS FOR HIGH-HEAD CONDUCTOR DECKER CANYON AND MORRELL CANYON UPPER RESERVOIRS

Upper Reservoir (Powerhouse)	Configuration	Vertical Shaft Length (LF)	Concrete-Lined Horiz. Tunnel (LF)	Concrete-Lined Inclined Tunnel (LF)	Steel-Lined Tunnel (LF)
Decker Canyon (Santa Rosa)	H-1	1,390	6,400	N/A	2,500
	H-2	50	3,450	3,250	2,500
	H-3	N/A	3,270	3,420	2,500
Morrell Canyon (Santa Rosa)	H-1	1,400	5,100	N/A	2,500
	H-2	50	2,150	3,250	2,500
	H-3	N/A	1,970	3,420	2,500
Decker Canyon (Ortega Oaks)	H-1	1,390	4,520	N/A	2,180
	H-2	50	1,720	3,100	2,180
	H-3	N/A	1,020	3,400	2,180
Morrell Canyon (Ortega Oaks)	H-1	1,400	6,710	N/A	2,180
	H-2	50	3,910	3,100	2,180
	H-3	N/A	3,210	3,400	2,180

Source: The Nevada Hydro Company, Inc.

The two alternative reservoirs sites exist along South Main Divide Truck Trail. A similar number of motorists and other observers pass by the two sites. Based on existing topography, Morrell Canyon may be partially screened from the roadway and could be further screened through the installation of additional road adjacent landscaping, thus reducing its potential impact. The Morrell Canyon reservoir site is located adjacent to Morgan Trail, a Forest Service maintained hiking trail extending south from South Main Divide Truck Trail. Individuals traveling along that trail would likely have an unimpeded view of the reservoir. Judgments as to the aesthetic value of a water element verse a terrestrial landscape would be subject to the individual perceptions of each viewer.

- **Agricultural Resources**. Since neither the Decker Canyon nor the Morrell Canyon upper reservoir sites are presently used for any agricultural or farm-related use, the impacts on agricultural resources would be generally comparable.

- **Air Quality**. The quantity of construction-term and operational criteria emission would not be expected to differ substantially between the two alternative upper reservoir sites. No sensitive receptors exist in close proximity to either area.

- **Biological Resources**. No protected wildlife species has been observed or are expected to occur in the area of the Morrell Canyon and Decker Canyon reservoir sites. However, based on the available of a seasonal source of water (Lion Springs), the Morrell Canyon site would appear more conducive to species occurrence. Coast live oak riparian woodland primarily occur in Morrell Canyon with a smaller stand present in Decker Canyon.

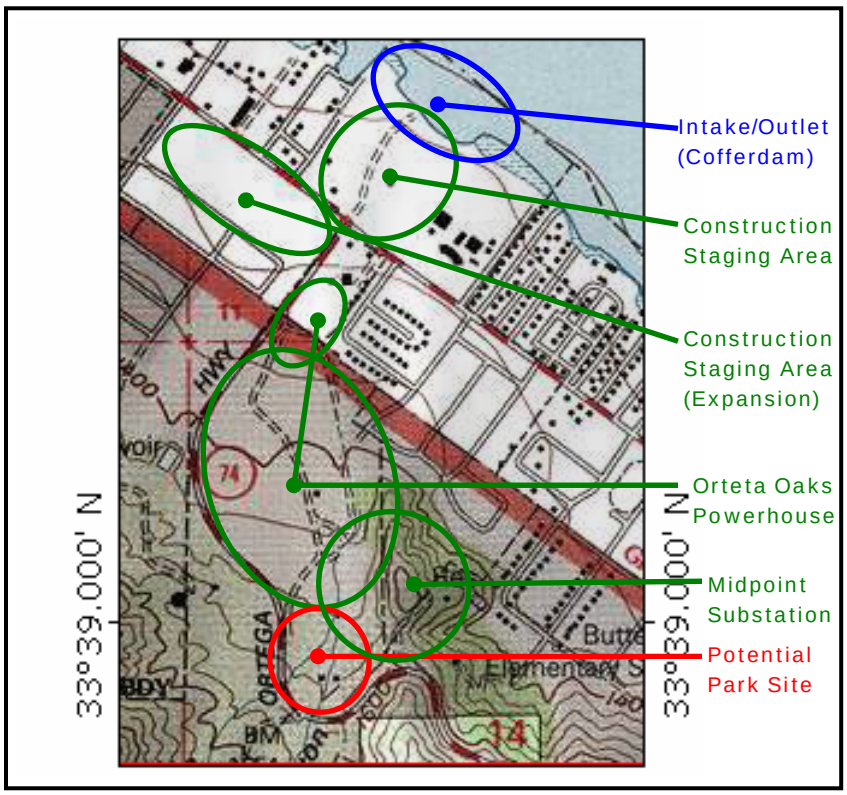

Figure 8-13
ALTERNATIVE ORTEGA OAKS POWERHOUSE SITE
Source: The Nevada Hydro Company, Inc.

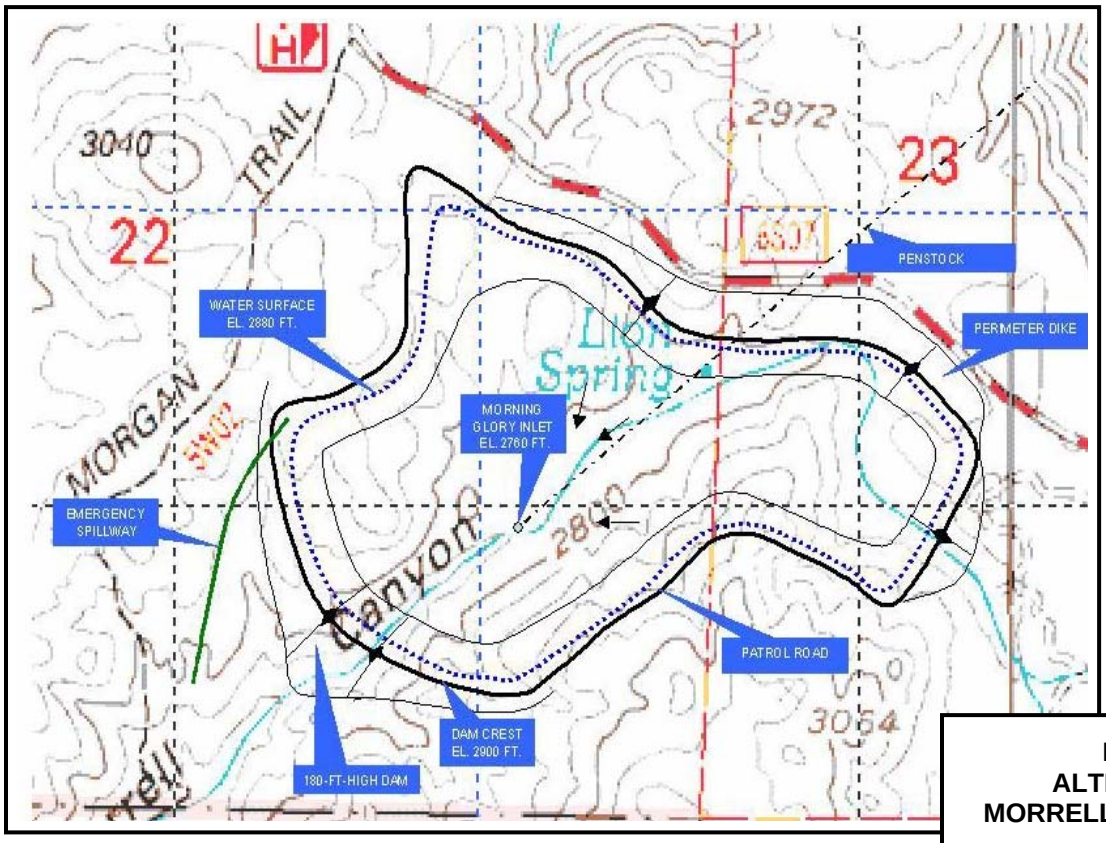

Figure 8-14
ALTERNATIVE MORRELL CANYON UPPER RESERVOIR SITE
Source: The Nevada Hydro Company, Inc.

The provision of compensatory resources is required under Section 21083.4(b) of the PRC. The Forest Service has specified a replacement ratio of 2:1 (Condition No. 38: Habitat Mitigation Plan). Compliance with those obligations will reduce impacts on this sensitive plant species to a less-than-significant level.

- **Cultural Resources**. Sensitive cultural resources have been identified in the general area of Morrell Canyon (RIV-1082, RIV-2205, RIV-3836). No sensitive resources have been identified in the area of the proposed Decker Canyon reservoir. Grading activities within the Morrell Canyon area would likely result in the destruction of those resources. No comparable impact would occur in the vicinity of the Decker Canyon reservoir.

- **Geology and Soils**. The two alternative upper reservoir sites would have a generally comparable impact upon geology and soils.

- **Hazards and Hazardous Materials**. Since no hazardous materials are known to exist for either Morrell Canyon or for Decker Canyon and since construction would result in the introduction of a comparable quantity of such materials, from a hazardous materials perspective, no substantive difference exists between the two sites.

  As indicated by the United States Department of the Interior - Bureau of Reclamation: "The 1964 failure of the Baldwin Hills Dam, near Los Angeles, California, and the near failure of Lower Van Norman (San Fernando) Dam in 1971 prompted the State of California to enact statutes requiring dam owners to prepare dam failure inundation maps" and "[t]he Federal Guidelines for Dam Safety, dated June 25, 1979, stated that inundation maps be prepared."[153]

  In accordance therewith, preliminary inundation maps have been prepared for both the proposed Decker Canyon and the alternative Morrell Canyon upper reservoir sites. Inundation zones, as illustrated in Figure 8-15 (Dam Breach Analysis), in proximity to the two reservoir sites differ based on the separate distances between those reservoirs and the local topography.[154] A catastrophic breach of either the Decker Canyon or the Morrell Canyon reservoirs would cause inundation of downstream recreational areas, Ortega Highway road crossings, and some low-lying buildings, as well as scouring along San Juan Creek from the dam to area of the I-5 Freeway undercrossing. Based on the analysis of the flow (discharge) through a hypothetical breach of either dam, the peak outflow would be less than 91,000 cubic feet per second (ft^3/s) for the Morrell Canyon scenario and approximately 115,000 ft^3/s for the Decker Canyon scenario.

  The time to peak flow at the Morrell Canyon dam would be approximately 0.33 hours (20 minutes); the time to peak flow at the Decker Canyon dam would be approximately 0.28 hours (17 minutes). Downstream of the confluence of Morrell Canyon and Decker Canyon, the depths shown on the inundation map correspond to the Decker Canyon

[153]/ United States Bureau of Reclamation, Prediction of Embankment Dam Breach Parameters – A Literature Review and Needs Assessment, DSO-98-004, July 1998, pp. 4-5.

[154]/ Detailed information concurring the development of the inundation maps for the LEAPS project, the methodologies and assumptions used in the derivation of those maps, and a description of the affected properties is presented in "Conceptual-Level Inundation Study – Lake Elsinore Advanced Pumped Storage Project, FERC Project No. 11858, Riverside County, California" (GENTERRA Consultants, Inc., August 28, 2003) and in "Supplemental Report Conceptual-Level Inundation Study – Lake Elsinore Advanced Pumped Storage Project, FERC Project No. 11858, Riverside County, California" (GENTERRA Consultants, Inc., December 12, 2003), included as part of the FLA.

scenario since they are generally higher than the depths corresponding to the Morrell Canyon scenario.

Water flowing in the upstream portion of the channel below either dam would attain depths of about 30 feet for the Morrell Canyon scenario and about 33.5 feet for the Decker Canyon scenario. For the Morrell Canyon scenario, it is estimated that the peak discharge would reach the first stream crossing of Ortega Highway in approximately 0.45 hours (27 minutes), with a maximum depth of about 20 feet. Some inundation of the roadway would expected at this street crossing because the existing culvert under Ortega Highway doe not have sufficient capacity to convey all of the flow.

The first stream crossing of Ortega Highway in the Decker Canyon scenario would have a peak depth of about 28 feet and would arrive in approximately 0.38 hours (23 minutes). Some inundation of the roadway would expected at this street crossing because the existing culvert under Ortega Highway doe not have sufficient capacity to convey all of the flow. The flooding would inundate low-lying areas of the campground that is located just downstream of the Ortega Highway crossing.

Farther downstream, two other areas along the San Juan Creek channel would experience relatively deeper flows during the period of peak discharge. The model simulation shows the greatest flow depths in the vicinity of the Riverside County – Orange County line, where the maximum depth of flow would reach approximately 37 feet for the Morrell Canyon scenario and 39 feet for the Decker Canyon scenario. The other areas of relatively deeper flows is located approximately one-mile east (upstream) of San Juan Hot Springs in Orange County. San Juan Canyon has relatively steep sides through this reach. Through this area, the depth of flow would attain a maximum of about 36.4 feet for the Morrell Canyon scenario and about 35.9 feet for the Decker Canyon scenario.

San Juan Creek passes near the southern boundary of Ronald W. Caspers WIldnerness Park at its confluence with Bell Canyon Creek. As the flood wave moves past the park, the entrance road, visitor's center, and several campgrounds located a short distance upstream along the banks of Bell Canyon Creek are likely to be impacted by the flood inundation.

Below Ronald W. Caspers WIldnerness Park, San Juan Creek traverses the Rancho Mission Viejo Company's (RMVC) "The Ranch" development (General Plan Amendment/Zone Change [PA01-114]). The LEAPS project's inundation maps were submitted to the County of Orange and to the RMVC as part of the separate CEQA process conducted for that development.

The distance from the proposed Morrell Canyon reservoir to the Pacific Ocean, the last downstream crossing of San Juan Creek, is approximately 27 miles. For the Decker Canyon site, the approximate distance is about 26 miles. By the time the flood wave reaches the confluence of Trabuco Creek, it would have attenuated to well below 50,000 ft^3/s, which is less than the peak flow of the 100-year storm event (58,600 ft^3/s).

A catastrophic failure of either reservoir could result in an overtopping of the ridgeline separating Morrell and Decker Canyons from Lake Elsinore. In that event or in the event of an overtopping of the dike crest and/or internal erosion through the dike embankment

material, waters could discharge toward Lake Elsinore. In order to assess potential inundation hazards, it was assumed that the direction of outflow from the breach was oriented perpendicularly toward nearby low points along the South Main Divide Truck Trail roadway and that the momentum of escaping water was sufficient to force the water over the ridgeline and down the slope toward Lake Elsinore to the northeast, ignoring the quantity of water that would be retained south of the roadway.

The estimated extend of flood inundation for the Morrell Canyon scenario is based on a peak outflow (discharge) of approximately 60,300 ft^3/s through the breach. For the Decker Canyon scenario, the corresponding peak outflow would be approximately 6,130 ft^3/s. The time to peak flow at the dike due to the breach of the Morrell Canyon reservoir would be approximately 0.30 hours (18 minutes). At the last modeled cross section, near Lake Elsinore (1.76 miles downstream), the maximum depth at the deepest point would be approximately 10.2 feet. For the Decker Canyon reservoir, the time to peak flow would be approximately 0.28 hours (17 minutes). At the last modeled cross section, near Lake Elsinore (1.76 miles downstream), the maximum depth at the deepest point would be approximately 4.2 feet.

Comparison of the flows produced for the two dike breach scenarios revealed that the peak outflow for the Decker Canyon simulation is an order of magnitude lower that the peak outflow for the Morrell Canyon simulation. This outcome is due to the lower maximum water level elevation (2830-feet AMSL) for the Decker Canyon reservoir design compared to the water level (2880-feet AMSL) for the Morrell Canyon reservoir design.

For the Morrell Canyon reservoir scenario, there are no stream crossings of Ortega Highway. In comparison, there are two stream crossings of Ortega Highway for the Decker Canyon scenario. The transitory flow of water over the roadway at these crossings has the potential to temporarily block traffic, wash away any vehicles traveling along that State highway, and to cause erosion of the roadway embankment. Similarly, flood waters from both reservoir sites would cross Grand Avenue, temporarily block traffic, and place vehicles and their occupants at risk.

For the Morrell Canyon scenario, the inundation analysis indicated that Butterfield Elementary Visual and Performing Arts Magnet School (16275 Grand Avenue, Lake Elsinore) and Lakeland Children Center (17159 Grand Avenue, Lake Elsinore) are outside the flow pathways. A number of single-family homes, located between Santa Rosa Drive and Magnolia Street are, however, located with the resulting flood zone.

For the Decker Canyon scenario, a number of single-family residences located along Ortega Highway and in proximity to Grand Avenue are located within the flood inundation zone. Residential areas located in the Decker Canyon flood zone include residents located along Lighthouse, Shoreline, Bonnie Lae, Pepper, Cedar, and Oleander Drives, and Leeward and Anchor Ways. Additionally, Mountainside Ministries (30515 Ortega Highway, Lake Elsinore) appears to be located within the flow path for the Decker Canyon reservoir.

A downstream hazard is defined as “the potential loss of life or property damage downstream of a dam from floodwaters released at the dam or waters released by partial

or complete failure of the dam."[155] Downstream hazard classification does not correspond to the condition of the dam or appurtenant works nor the anticipated performance or operation of the dam. It is a description of the setting in areas downstream of the dam and an index of relative magnitude of the potential consequences to human life and property should the dam fail. Hazard classification is based on the size of the dam and an estimation of potential structural damage and risk to human life in case of a dam failure. Large-size dams may be defined as those that are 100 feet or higher or have a reservoir volume of a least 1,000 acre-feet. Since the LEAPS' upper reservoir will be approximately 5,500 acre-foot in size and since the dam is expected to be greater than 100 feet in height, that facility would be classified as being a "large-size" dam.

As defined by the United States Bureau of Reclamation, a "significant hazard dam" is "[a] dam which places 1-6 lives at risk or would cause appreciable economic loss (rural area with notable agriculture, industry, work sites, or outstanding natural resources)" while a "high hazard dam" is defined as "[a] dam which places more than 6 lives at risk or would cause excessive economic loss (urban area including extensive community, industry, agriculture, or outstanding natural resources)."[156]

As defined by FERC: "Dams in the high hazard potential category are those located where failure may cause serious damage to homes, agricultural, industrial and commercial facilities, important public utilities, main highways, or railroads, and there would be danger to human life. . .Included in the high hazard potential category are dams where failure could result in loss of life of people gathered for an unorganized recreational activity where concentrated use of a confined area below the dam is a common annual occurrence during certain times of year."[157] As defined by the Interagency Committee on Dam Safety: "Dams assigned the high hazard potential classification are those where failure or mis-operation will probably cause loss of human life. The hazard potential classification assigned to a dam should be based on the worst-case failure condition, i.e., the classification is based on failure consequences resulting from the failure condition that will result in the greatest potential for loss of life and property damage."[158]

A dam constructed to form the proposed Decker Canyon or the alternative Morrell Canyon reservoir would have a "high-hazard" classification, based on the classification system outlined by the United States Army Corps of Engineers,[159] indicating the potential for loss of six or more lives should a catastrophic failure occur. Based on existing development near Lake Elsinore, the potential for loss of life would appear incrementally greater from the Decker Canyon upper reservoir site.

[155]/ Ad Hoc Committee of Dam Safety of the Federal Coordinating Council for Science, Engineering and Technology, Federal Guidelines for Dam Safety, Washington DC, June 1979.

[156]/ United States Bureau of Reclamation, Reclamation Manual FAC 06-01, Reclamation Dam Safety Program, January 8, 2002, p. 2.

[157]/ *Op. Cit*., Engineering Guidelines for the Evaluation of Hydropower Projects, p. 1-2.

[158]/ Federal Emergency Management Agency, Federal Guidelines for Dam Safety: Emergency Action Planning for Dam Owners, FEMA 333, Interagency Committee on Dam Safety, October 1998, Section III(B)(3).

[159]/ United States Army Corps of Engineers, Engineering and Design – Earthquake Design and Evaluation for Civil Works Projects, ER 1110-2-1806, July 31, 1995, Appendix B.

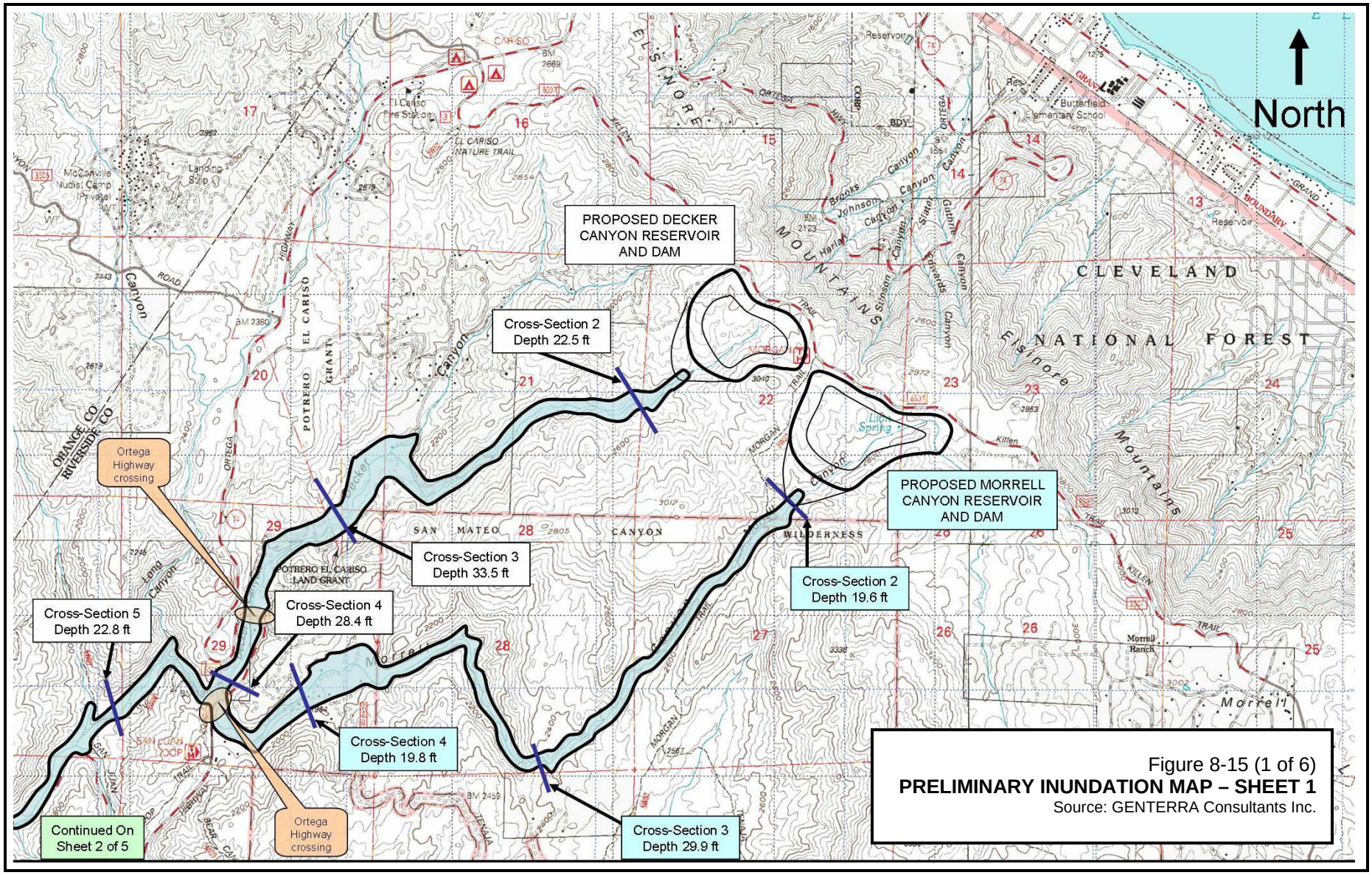

Figure 8-15 (1 of 6)
PRELIMINARY INUNDATION MAP – SHEET 1
Source: GENTERRA Consultants Inc.

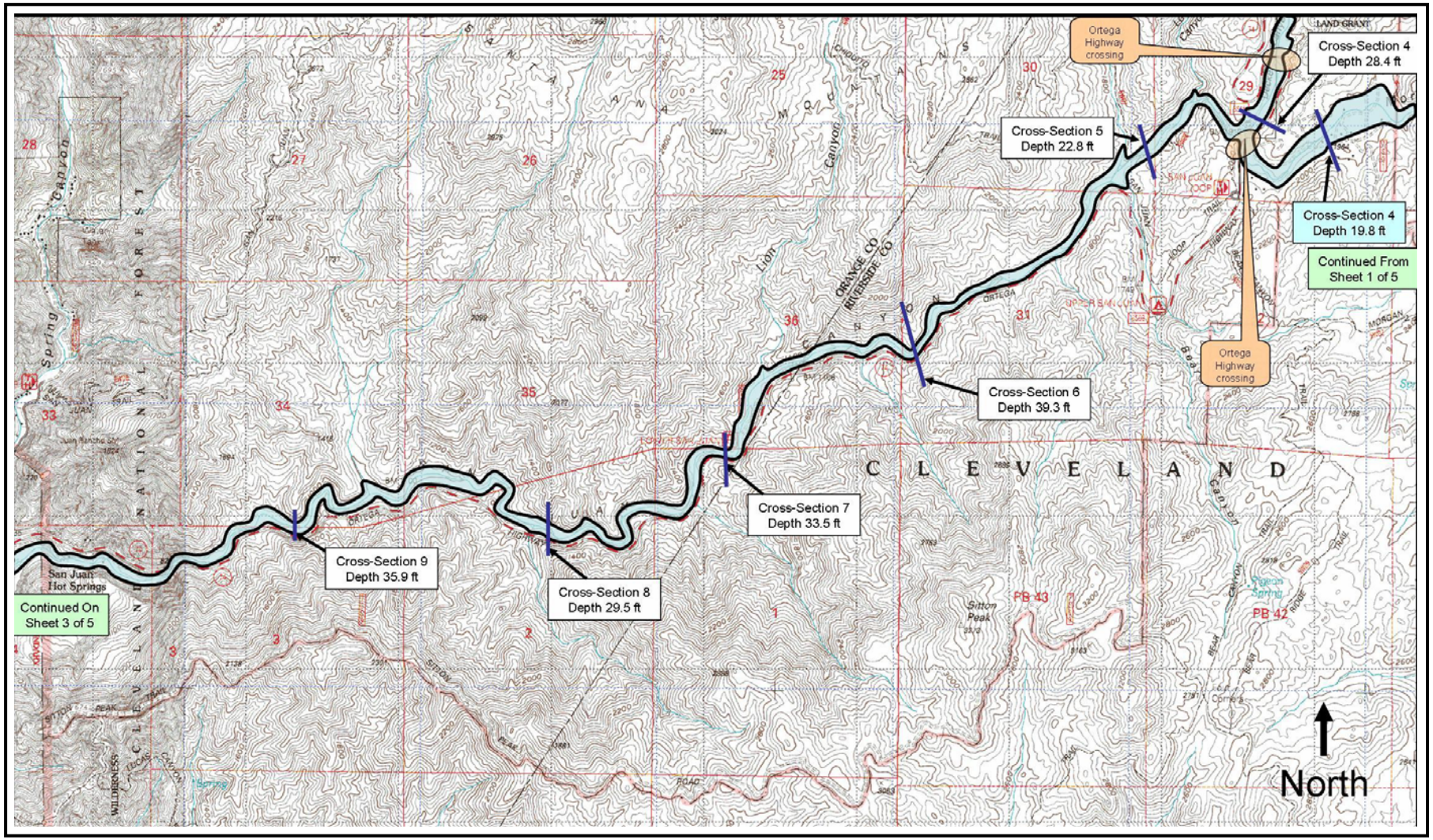

Figure 8-15 (2 of 6)
PRELIMINARY INUNDATION MAP – SHEET 2
Source: GENTERRA Consultants Inc.

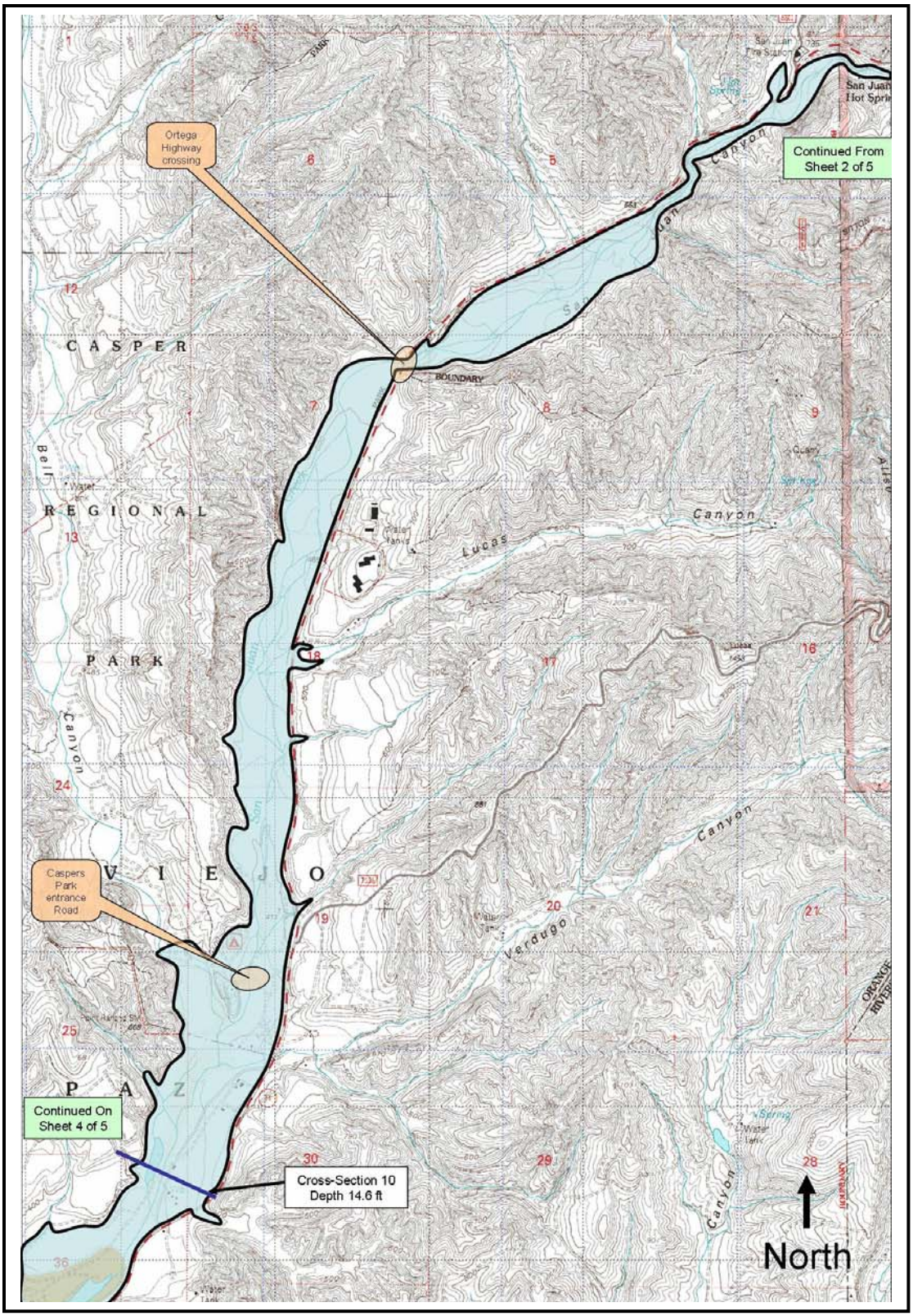

Figure 8-15 (3 of 6)
PRELIMINARY INUNDATION MAP – SHEET 3
Source: GENTERRA Consultants Inc.

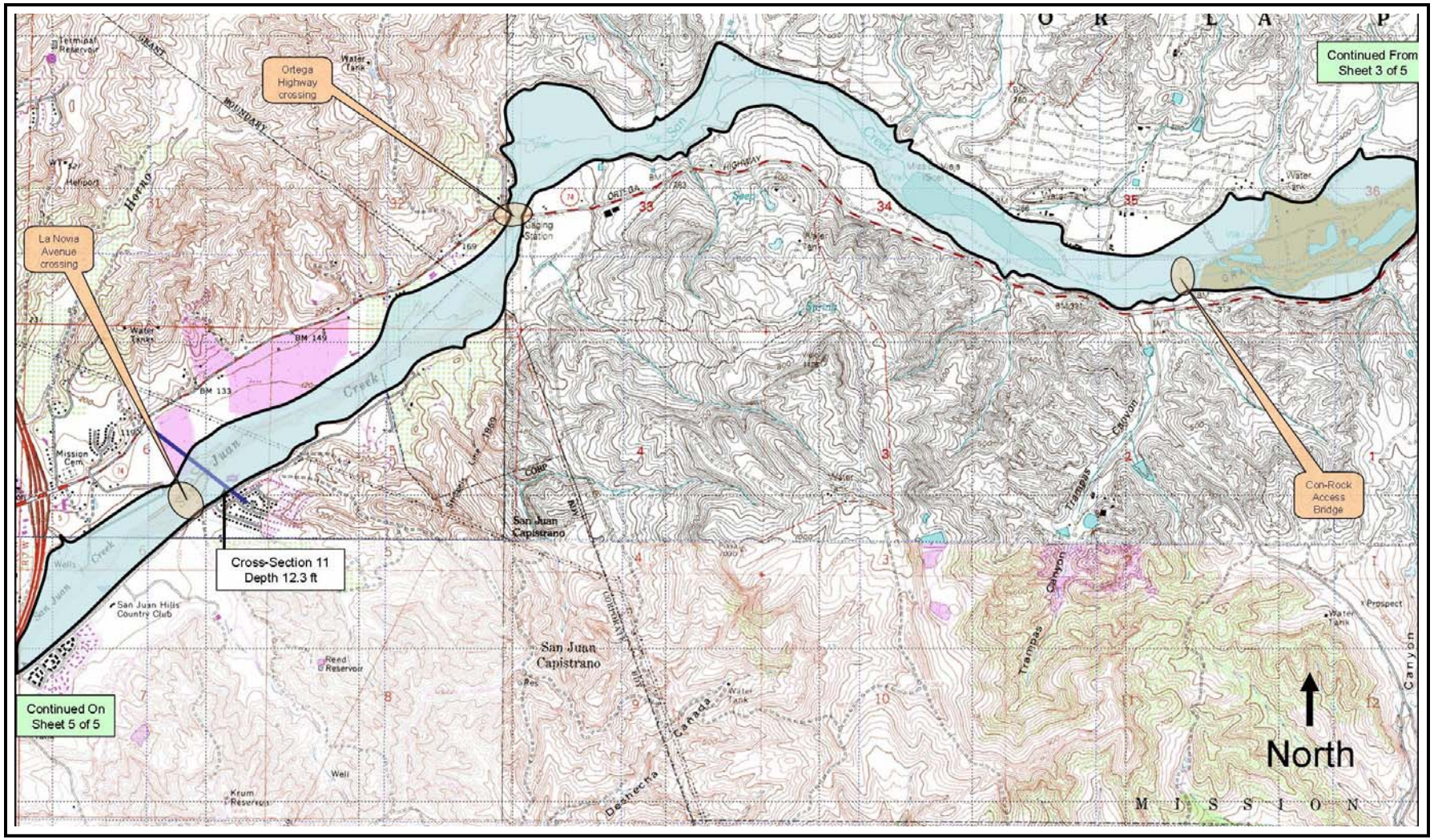

Figure 9-15 (4 of 6)
PRELIMINARY INUNDATION MAP – SHEET 4
Source: GENTERRA Consultants Inc.

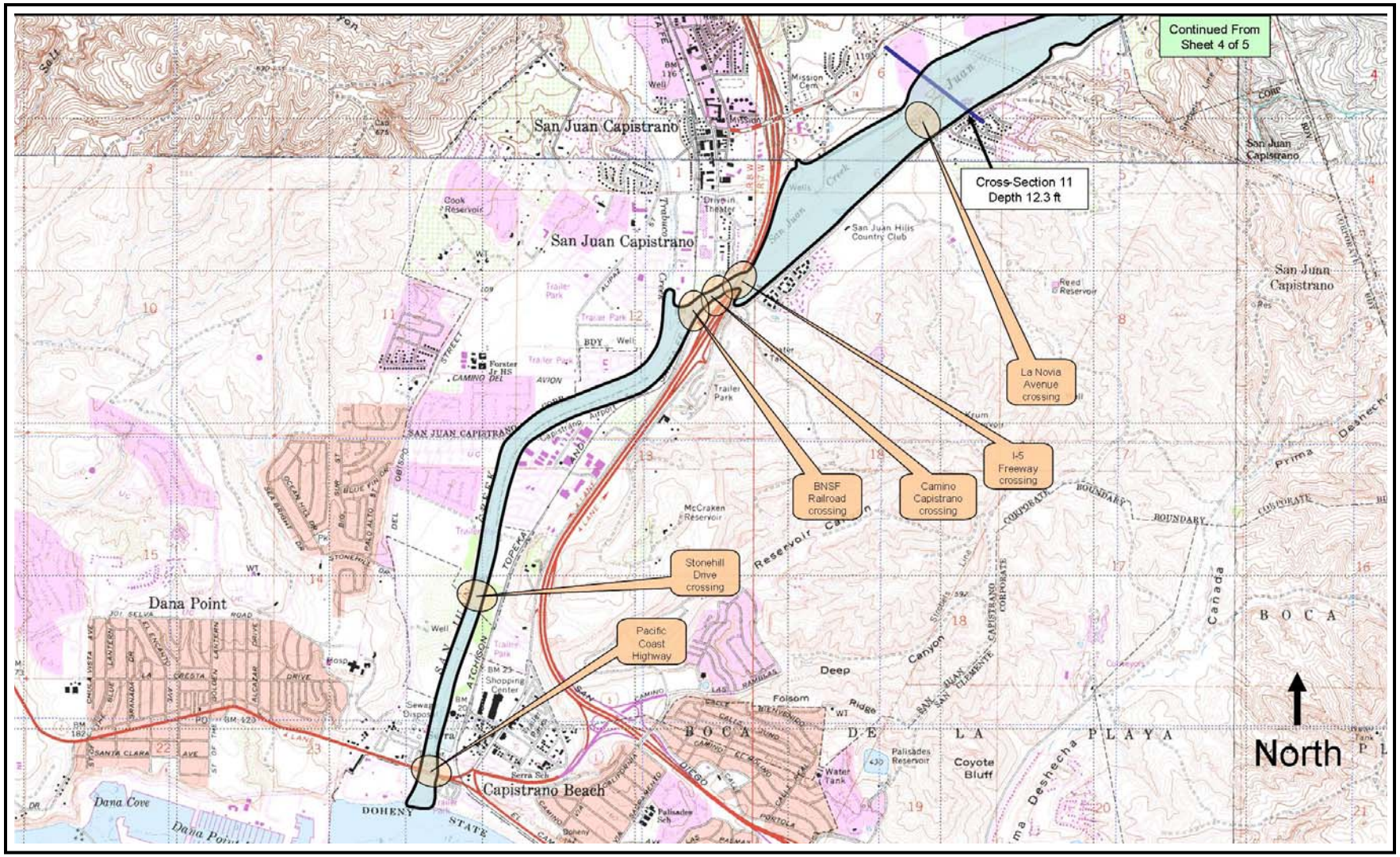

Figure 9-15 (5 of 6)
PRELIMINARY INUNDATION MAP – SHEET 5
Source: GENTERRA Consultants Inc.

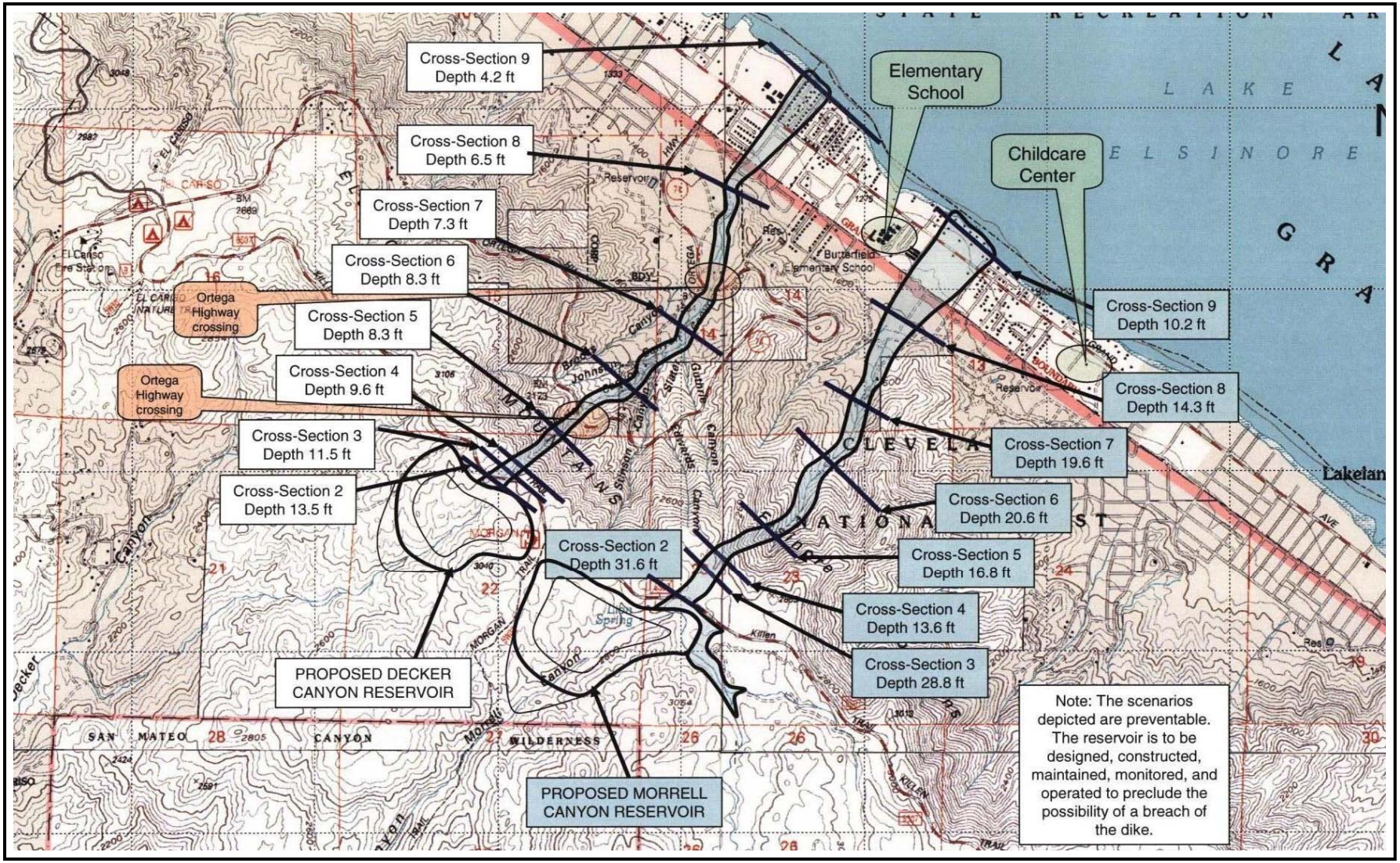

Figure 9-18 (6 of 6)
PRELIMINARY INUNDATION MAP – SHEET 5
Source: GENTERRA Consultants Inc.

As indicated by the United States Department of the Interior: "As potential targets for acts of terrorism, hydroelectric dams present unquantifiable costs in terms of diminished national security. The damage resulting from failure of a conventional hydroelectric facility could be severe in terms of lives lost and electricity supply disruption. As the same time. . .a real but not readily quantifiable benefit of conventional hydropower is its contribution to U.S. energy independence."[160]

Compliance with applicable federal and State dam construction and safety requirements, including implementation of a dam safety surveillance monitoring plan, will reduce potential hazards to the maximum extent feasible.

- **Hydrology and Water Quality**. Decker Canyon is located at the headwaters of the watercourse and has not contributing upstream drainage. Conversely, the drainage area upstream of the Morrell Canyon site is approximately 560 acres (0.9 square miles). The runoff generated from a 100-year rainfall event would produce a peak flow of approximately 2,200 ft^3/s. Based on the presence of Lion Springs, as evidenced by the coast live oak riparian forest that exists within Morrell Canyon, additional stream flows exist at that site. A significant impact would likely exist if the construction of the Morrell Canyon reservoir were to reduce or eliminate flows from Lion Springs and/or impede the conveyance of storm waters from upstream to downstream areas. Engineering studies, however, demonstrate that both upstream flows and Lion Springs flows can be safely and effectively conveyed to a point of discharge downstream from the dam area.

- **Land Use and Planning**. Existing Forest Plan plans and policies allows for the construction and subsequent operation of the proposed and/or the alternative reservoir sites for the propose use. As such, the two upper reservoir sites would have a generally comparable land use and planning impact.

- **Mineral Resources**. Neither reservoir site contains recoverable mineral resources.

- **Noise**. The two alternative upper reservoir sites would have a generally comparable noise impacts.

- **Population and Housing**. The two alternative upper reservoir sites would have a generally comparable impact upon population and housing.

- **Public Services**. The two alternative upper reservoir sites would have a generally comparable impact upon fire protection and vector control services.

- **Recreation**. Because of its proximity to Morgan Trail, accessibility from South Main Divide Truck Trail, oak woodland, and presence of Lion Springs, Morrell Canyon receives frequent recreational use. Conversely, although more visible from South Main Divide Truck Trail, there exist no trails to facilitate public access into Decker Canyon. Construction and construction staging activities conducted at either reservoir site would not directly impact the Elsinore Hang Gliding Association's existing launch sites. In accordance with the provisions of the federal hydropower license and the Forest Services 4(e) conditions, subject to Forest Service specifications, new recreational facilities will be provided independent of which upper reservoir site is selected.

[160]/ Weiss, John C., Boehlert, Brent B., and Unsworth, Robert E., Assessing the Costs and Benefits of Electricity Generation Using Alternative Energy Resources on the Outer Continental Shelf – Final Report, MMS 2007013, United States Department of the Interior, Minerals Management Service, March 2007, p. 39.

- **Transportation and Traffic**. The two alternative upper reservoir sites would have a generally comparable impact upon transportation and traffic.

- **Utilities and Service Systems**. The two alternative reservoir sites would have a generally comparable impact upon potable and non-potable water services and supplies.

- **Energy Resources**. The two alternative reservoir sites would have a generally comparable impact upon energy resources.

8.3.4 "500-kV Transmission Alignment" Alternatives

Both during the projects' planning and engineering process and in response to specific environmental factors identified by FERC and/or the USFS, a number of alternative transmission line segments were identified.[161] Many of those alternative segments have been subsequently eliminated because they were found either not to result in the avoidance or substantial reduction of identified environmental effects or had the potential to introduce additional or exacerbate other potential impacts. In addition to the 500-kV transmission alignment described in Section 3.0 (Project Description) and illustrated in Figure 8-16 (Alternative Transmission Alignments), the following alternative alignments have been identified.

- **"FLA Transmission Alignment" Alternative**. Under this alternative, the Northern 500-kV transmission line would extend generally from the area of the upper reservoir, below and on the north side of the ridgeline dividing the Santa Ana River and San Juan Creek watersheds, in a northwesterly direction to an area near the Orange/Riverside County line. From there, the line would extend in a northeasterly direction to connect with the existing 500-kV Valley-Serrano line located north of Interstate 15 (I-15) Freeway in the unincorporated area of Alberhill (Riverside County).

  The Southern 500-kV transmission line would extend from the upper reservoir in a southeasterly direction past Rancho Capistrano (Morrell Potrero) and below and on the northern side of the ridgeline, generally at an elevation of about 2,600 feet AMSL. From there, the line would extend southward, east of Elsinore Peak, to intersection with the National Forest boundaries near Los Alamos Canyon. The line would then generally follow the National Forest boundaries southward past the Tenaja Ranger Station, jogging southeasterly before extending southward to Camp Pendleton. All segments of this alignment would be installed on above-ground lattice towers.

  This alternative was identified as the Applicant's proposed projects in the "Draft Application for License of Major Unconstructed Project, Lake Elsinore Advanced Pumped Storage Project, Federal Energy Regulatory Commission, Project Number 11858." The comparative impacts of this alternative are as described therein.

- **"Mid-Slope Transmission Alignment" Alternative**. This alignment, as independently developed by FERC and the Forest Service, is as described in the DEIS. As described therein, the "northern segment of the mid-slope transmission alignment would be about 10.4 miles long. From the Ortega Oaks powerhouse substation, the alignment would run

[161]/ Since, with the exception of new transition towers and the directly adjoining towers located adjacent to the proposed Southern (Pendleton) substation and new 69-kV poles, existing in-place 230-kV SDG&E towers would be utilized, no alternatives to the proposed 230-kV transmission line (Talega-Escondido) upgrade have been identified. Possible alternatives involving new transmission towers would likely result in additional site disturbance and produce a greater impact that associated with the retention and utilization of the existing transmission towers.

uphill in a westerly direction. From north of Ortega Highway, the transmission alignment would run parallel to the northern segment of the co-applicant's proposed transmission alignment, but at a distance of 0.2 to 0.4 mile east (and downslope) of the co-applicant's proposed alignment. At this point, the alignment would generally parallel the Cleveland National Forest boundary, extending north over its northern boundary and then generally heading in a northeasterly direction to connect with the existing 500-kV Valley-Serrano line located north of the I-15 Freeway in the unincorporated Alberhill area of Riverside County. The southern portion of the mid-slope transmission alignment would be about 20.3 miles long with almost its entire length located within the Trabuco Ranger District of the Cleveland National Forest or on other federal lands. From the northern segment described above, the mid-slope transmission alignment would continue westward until just crossing the South Main Divide Trunk Trail. Here it would turn south and run parallel with South Main Divide Road for approximately 1.45 miles. Once beyond the primary hang gliding launch site, it would turn eastward back downhill and would then generally run parallel to the co-applicants' proposed southern alignment for about 3 miles at a distance of 0.2 to 0.4 mile east (downslope) of the co-applicants' proposed alignment. Then it would depart from the co-applicants' proposed alignment and continue in a southeasterly direction until it intersects with the Cleveland National Forest boundary. The mid-slope alignment would then extend southward following along inside the Cleveland National Forest boundary southward past the Tenaja Ranger Station, swerving southward out and around the wilderness boundary east of Miller Mountain. Then it would turn in a southeasterly direction and match the co-applicants' proposed alignment. From here, the southern portion of the alternative mid-slope transmission alignment would meander south, avoiding designated wilderness areas until it reached the Cleveland National Forest's southern boundary. From there, it would turn and follow the boundary west and connect with SDG&E's 230-kV system at the intersection of the Cleveland National Forest boundary and Camp Pendleton."[162] All segments of this alternative alignment would be installed on above-ground lattice towers.

The "Midslope transmission alignment" alternative was identified by FERC and the USFS as the preferred staff alternative in the "Draft Application for License of Major Unconstructed Project, Lake Elsinore Advanced Pumped Storage Project, Federal Energy Regulatory Commission, Project Number 11858." The comparative impacts of this transmission alternative are as described therein.

8.3.5 "No Project" Alternative

A "no project" alternative is expressly required by the State CEQA Guidelines (14 CCR 15126.6[e]) and has, therefore, been included herein. The "no project" (no build) alternative serves as a baseline against which all other development options are compared. The "no project" alternative generally reflects the conditions and associated environmental impacts that would predictably occur should the proposed projects be denied by regulators or should the projects' regulators fail to take affirmative action on the proposed development plans, resulting in, the retention of the projects' sites in their existing conditions.

Should the proposed projects or an identified alternative not be approved, the regional need for new generation and transmission facilities would continue to exist. The failure by the State, the IOUs, or another party to address those needs and/or the failure of conservation, distributed

[162]/ *Op. Cit.*, Final Environmental Impact Statement for Hydropower License – Lake Elsinore Advanced Pumped Storage Project, FERC Project No. 11858, FERC/EIS-0191D, pp. 2-23 and 2-24.

generation, or other efforts to increase supply or reduce demand would have regional environmental and economic consequences (e.g., increased potential for black-outs and brown-outs).[163] Those regional consequences are not addressed herein; rather, the "no project" alternative focuses on the localized implications with regards to the individual projects' sites.

Since it cannot be presumed that new energy development and/or conservations will occur elsewhere within the region, any election not to evaluate the continuing disparity between anticipated supply and expected demand underestimates the potential adverse impacts that would likely occur should the proposed projects not be implemented. Regional energy shortfalls can be anticipated beginning in 2010 but are not direct consequences of the "no project" alternative. The "no project" alternative does not include the two scenarios whereby the LEAPS project would be constructed but the TE/VS Interconnect project is denied or not constructed, or vise verse.

The following analysis compares the potential environmental effects of this alternative against the potential impacts associated with the proposed projects. Although each of the projects' sites are assumed to be retained in their current conditions, additional areawide development is assumed in a manner consistent with agency projections and other related projects, as located within the generalized geographic scope of cumulative impacts, would continue to occur. Related projects are assumed to include the development of the Ortega Oaks powerhouse site for residential use (Tract Map Nos. 22626 and 22626-1). In addition, under the "no project" alternative, any positive impacts associated with the proposed projects would be forfeited.

Aesthetics. Under the no project alternative, no physical change would occur to any of the sites upon which the projects' facilities have been identified. As a result, the significant aesthetic impacts of the proposed projects would be avoided. Localized and other areawide development would continue to occur and contribute to the furtherance of urbanization throughout the southern California area.

- **Agricultural Resources**. Independent of the development of the proposed projects or the retention of those sites in their current conditions, because areawide development will continue to result in the conversion of farmlands to non-agricultural uses, impacts on agricultural resources will remain cumulatively significant.

[163]/ As indicated by SDG&E, speaking with regards to their proposed Sunrise (Sunpath) Powerlink project: "In the unfortunate event that the proposed project cannot be in place by the summer of 2010, at least 247 MW of in-basin generation or increased import capability would be needed to satisfy the identified reliability deficiency. This deficiency grows over time (reaching 835 MW by year 2020). In response to this growing deficiency, SDG&E must implement alternative schemes to meet the San Diego area reliability requirement. Certain new in-area generation options may be feasible. It might be possible to install enough new gas turbines to meet the San Diego area local reliability requirement for a few years. SDG&E, on behalf of its bundled customers, has issued a Request for Offer to see if additional peaking capacity can be economically added to the service territory by the summer of 2008. Assuming no other local plants retire, this additional peaking capacity would meet part of the identified need beginning in year 2010. SDG&E has also identified in its resource plan filed in R.06-02-013, a resource need starting in 2010 for additional capacity to meet bundled customer needs. A portion of this capacity may need to be in the form of new in-area generation if the Sunrise Powerlink is delayed. However, over the longer term it is impractical and inefficient to build enough gas turbines to satisfy the San Diego area reliability requirement, even without considering the obvious consequences for air quality. Even the most efficient gas turbines emit significant amounts of particulate matter (PM), sulfur dioxide (SO2), nitrogen oxides (NOx), carbon monoxide (CO) and volatile organic compounds (VOC). Case 200, SDG&E's gas-turbine reference case, requires 18 gas turbines each sized 46.6 MW to meet local reliability requirements in year 2020" (Source: San Diego Gas & Electric, Chapter VII – Supplemental Testimony, A.06-08-010, January 26, 2007, pp. 55-56).

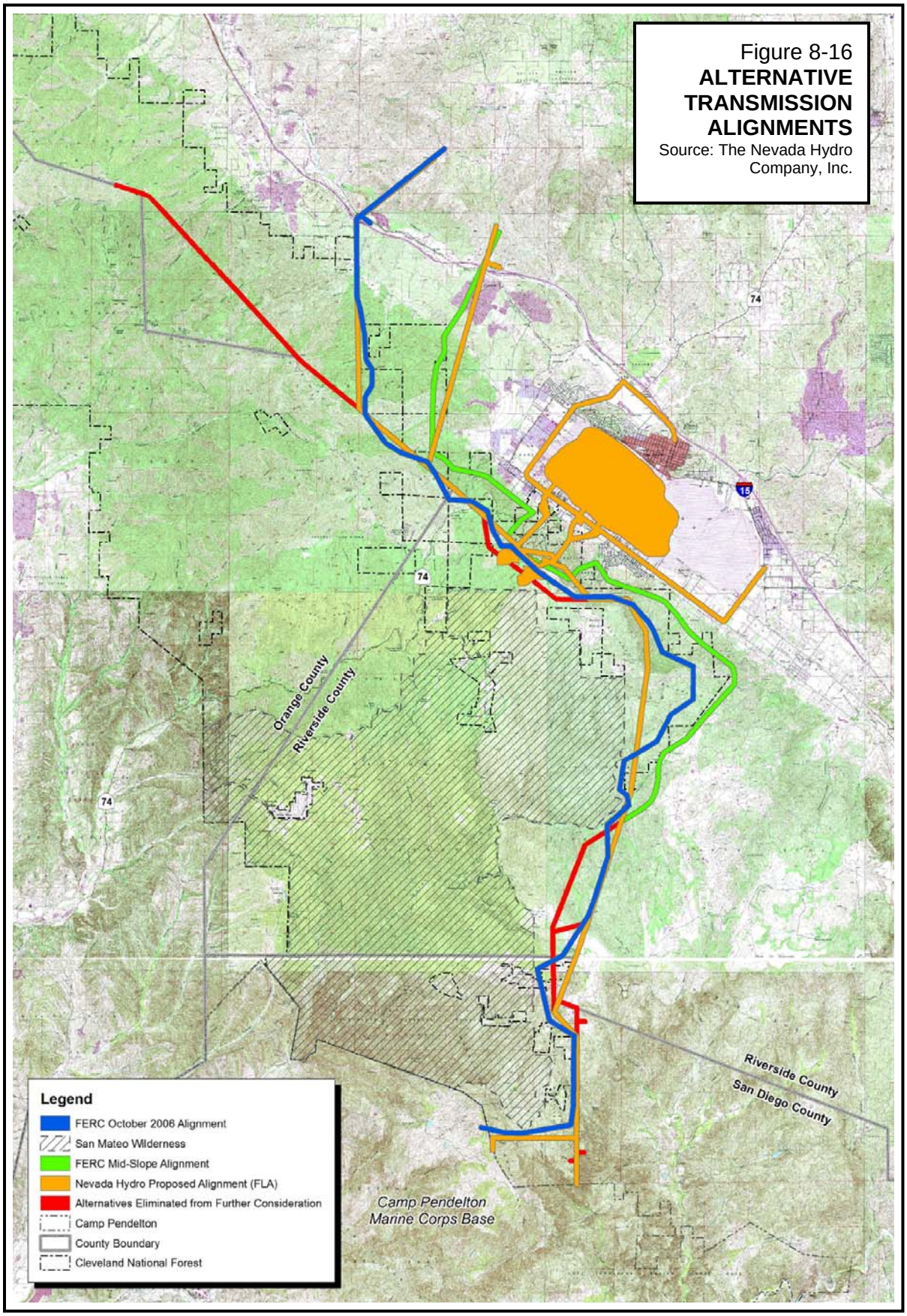
Figure 8-16
ALTERNATIVE TRANSMISSION ALIGNMENTS
Source: The Nevada Hydro Company, Inc.
Legend
FERC October 2006 Alignment
San Mateo Wilderness
FERC Mid-Slope Alignment
Nevada Hydro Proposed Alignment (FLA)
Alternatives Eliminated from Further Consideration
Camp Pendelton
County Boundary
Cleveland National Forest
Orange County
Riverside County
Riverside County
San Diego County
Camp Pendelton
Marine Corps Base
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74
74
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- **Air Quality**. The SDAB and SCAB continued to be classified as non-attainment for a number of criteria pollutants, including ozone and inhalable particulate mater. As a result, since areawide development will continue to occur under this alternative, air quality impacts will remain cumulatively significant.

- **Biological Resources**. Predicted areawide development will contributes to the progressive fragmentation of habitat areas and decline in species diversity throughout southern California. Independent of the development of the proposed projects or the retention of those sites in their current conditions, the long-term, areawide loss of biological resources attributable to future development will produce a significant cumulative impact on biological resources.

- **Cultural Resources**. Under this alternative, impacts upon both on-site and near-site cultural resources (prehistoric, historic, and paleontological) attributable to the proposed projects would be avoided.

- **Geology and Soils**. Since none of the sites are developed for any project-related use, no grading activities would be initiated by the Applicant. As a result, no significant geologic or soils impacts would occur.

- **Hazards and Hazardous Materials**. Since none of the sites are developed for any project-related use, no significant hazards or hazardous materials impacts would occur.

- **Hydrology and Water Quality**. Since none of the sites are developed for any project-related use, no significant hydrology or water quality impacts would occur.

- **Land Use and Planning**. Since none of the sites are developed for any project-related use, no significant land use and planning impacts would occur.

- **Mineral Resources**. Since none of the sites are developed for any project-related use, no significant mineral resource impacts would occur.

- **Noise**. Under the “no project” alternative, none of the projects’ sites would be developed for the proposed uses. Proximal properties would, therefore, not be subjected to either construction-term or operational noise attributable to the proposed projects.

- **Population and Housing**. Under this alternative, no homes or other real property would be purchased, no residents would be displaced, and no inundation hazard zone would be created.

- **Public Services**. Since none of the sites are developed for any project-related use, no significant impacts to fire protection or vector control services would occur.

- **Recreation**. Since none of the sites are developed for any project-related use, no significant recreational impacts would occur.

- **Transportation and Traffic**. Since none of the sites are developed for any project-related use, no significant transportation and traffic impacts would occur.

- **Utilities and Service Systems**. Since none of the sites are developed for any project-related use, no significant impacts to potable or non-potable water services or systems would occur.

- **Energy Resources**. Since none of the sites are developed for any project-related use, no significant energy resource impacts would occur.