Attachment 6

Related Projects

ATTACHMENT 6 - RELATED PROJECTS

1.1 Introduction to Related Projects

A project may produce a significant effect on the environment if any of a number of conditions are met. As defined under CEQA, a significant effect on the environment means a substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project. CEQA requires that, in evaluating a project's potential effects, both direct (primary) effects which are caused by the project and which occur at the same time and place and indirect (secondary) effects which are caused by the project and which are later in time or farther removed in distance but are still reasonably foreseeable be analyzed. An EIR shall also discuss cumulative impacts when the project's incremental effect is "cumulatively considerable." Cumulatively considerable means that the incremental effects of an individual project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects.

The State CEQA Guidelines provides two separate methodologies for the identification of other related projects that, in combination with the proposed projects, could result in significant cumulative environmental effects. As indicated therein, the agency is authorized to use either: (1) list of reasonably anticipated probable future project approach (i.e., list of past, present, and reasonably anticipated probable future projects producing related or cumulative impacts; or (2) summary of projections approach (i.e., summary of projections contained in an adopted general plan or related planning document or in a prior environmental document which has been adopted or certified describing or evaluating regional or areawide conditions contributing to the cumulative impact). Based on the nature of the proposed projects, the Lead Agency has elected to utilize the list of reasonably anticipated probable future projects approach.

The list of probable future projects shall be limited to those "producing related or cumulative impacts" (14 CCR 15130[b][1][A]). In recognition of the specific characteristics of the proposed projects, the list of other probably future projects includes not only identified public and private projects located in reasonably proximity to the projects' various component parts but also: (1) other Commission-licensed hydropower projects; (2) projects that may be directly or indirectly linked to the proposed projects based on eligibility under the State's RPS; (3) energy project ahead of LEAPS in the generation interconnection queue (Application Queue); (4) identified localized or systemwide upgrades that are or may be required to the existing electrical transmission system; (5) other electrical generation and/or transmission projects, facilities, and system-upgrades that might be developed by other entities within the projects' implementation schedule; and (6) other projects affecting or potentially affecting the proposed facility sites.

1.2 Probable Future Projects

1.2.1 Other Commission-Licensed Pumped Storage Hydropower Projects[1]

[1]/ The following discussion focuses only on pumped storage hydroelectric projects and is not offered as being inclusive of all proposed, pending, or approved hydroelectric facilities located throughout the State. The District acknowledges the existence of other run-of-the-river hydropower projects undergoing Commission review (e.g., Mammoth Pool Hydroelectric Power Project, FERC Project No. 2085). Since there are no existing river systems within the southern California area conducive to the development of run-of-the-river facilities, there exists no reasonable probability that those projects could result in cumulative environmental effects.

Other Commission-licensed pumped storage projects now under review by the Commission and located in California are listed in Table 1-1 (Active Federal Energy Regulatory Energy Commission Pumped Storage Projects in California). The following project list may include other federal actions that could relate to the proposed projects should those projects utilize the same natural resources or combine with the proposed projects to produce cumulative environmental effects.[2]

Table 1-1
ACTIVE FEDERAL ENERGY REGULATORY ENERGY COMMISSION PUMPED STORAGE PROJECTS IN CALIFORNIA

Project Name	Description	Company Name	Docket No.	Status	Location
Don Pedro Pumped Storage (440 MW)	The project would be located on the Tuolumne River and Don Pedro Reservoir.	Modesto Irrigation District	P-12745	Notice of Application 11/16/06	Tuolumne County California
Eagle Mountain Pumped Storage (1,000 MW)	Application for preliminary permit to study a proposed hydropower project.	Eagle Crest Energy Company	P-12509	Preliminary Permit 03/07/05	Riverside County California
San Vicente Pumped Storage (1,000 GWh/Yr)	The project would be located on San Vicente Reservoir and San Vicente River.	San Diego County Water Authority	P-12747	Notice of Application 11/07/06	San Diego County California
Sworinger Reservoir Pumped Storage (664.3 GWh)	The project would be located on the Sworinger Reservoir and Lower Reservoir. The penstock and transmission line would occupy federal lands managed by BLM.	NT Hydro	P-12673	Notice of Application 06/06/06	Modoc and Lassen Counties California Washoe County Nevada
West Valley Pumped Storage (264 MW)	The project would use the existing Moon Lake on Cedar Creek and occupy federal lands within Modoc National Forest.	South Fork Irrigation District	P-12575	Preliminary Permit 10/31/05	Modoc and Lassen Counties California

Source: Federal Energy Regulatory Commission (December 2006)

In addition to those pumped storage projects listed above, in November 2000, the Commission received an application from the San Diego County Water Authority (SDCWA) for the proposed Olivenhain/Lake Hodges Pumped-Storage Project (FERC Project No. 11860-000), located on Lake Hodges on the San Dieguito River in San Diego County. In October 2003, the SDCWA submitted an application for exemption as a “small conduit hydroelectric facility” under Title 18 of the Code of Federal Regulations (CFR), Subpart D, Part 4.30(b)(28). An exemption from licensing for a modified 40 MW pumped storage project (FERC Project No. 12473) was issued by the Commission on December 31, 2003. In January 2004, the SDCWA approved a 25-year power purchase and sale agreement with SDG&E for the pumped storage project. The SDCWA

[2]/ Over the past 20 years, the Commission has issued about 45 preliminary permits to enable developers to study the potential for building pumped storage projects in 18 states throughout the country. The pumped storage license applications filed during that period are for the following projects: Dry Fork (Project No. 10725), Summit (Project No. 9423), Blue Diamond (Project No. 10756), Mt. Hope (Project No. 9401), Eagle Mountain (Project No. 11862), River Mountain (Project No. 10455), and Crystal Creek (Project No. 10847). Of these seven projects, Dry Fork, Eagle Mountain, and Crystal Creek did not receive licenses. The rest were licensed but not built, and have had their licenses rescinded. The Eagle Mountain pumped storage project is now being studied again (Project No. 12509) under another preliminary permit.

is currently working with SDG&E on an interconnection agreement to connect the pumped station to the SDG&E power grid via a one-quarter mile electric transmission line.

1.2.2 Renewable Energy Projects

The CEC notes that the "acceleration of renewable development under the RPS has highlighted the role of transmission in renewable energy resource development."[3] Both SDG&E and SCE are currently processing applications through the CPUC for new transmission lines designed, in part, to access those renewable energy resources. SDG&E's Sunrise (Sunpath) Powerlink transmission project and SCE's Tehacapi transmission project have been identified as two possible transmission alternatives that, if constructed, could improve access to renewable energy resources. Both of those transmission projects are identified below and are again described in <u>Chapter 6.0</u> (Alternatives Analysis).

With regards to the eligibility of hydropower facilities to quality for RPS, with the passage of Senate Bill 107[4] (SB107), generation from hydroelectric projects larger than 30 MW cannot be reported by the publicly owned utilities (POUs) as eligible renewable energy.[5]

As specified in the CEC's "Renewable Portfolio Standard Eligibility Guidebook, Second Edition": "Pumped storage hydro may qualify for the RPS to the extent that: (1) the facility meets the eligibility requirements for small hydro, and (2) the electricity used to pump the water qualifies as RPS eligible. The amount of energy that may qualify for the RPS is the amount of electricity dispatched from the system."[6] Subject to CEC determination, in order for the LEAPS project to be certified as RPS eligible, it would: (1) need to be tied to an eligible renewable energy resource; and (2) subject to small hydro eligibility criteria.

Existing or reasonably foreseeable renewable resources located within the southern California area include both wind (San Gorgonio and Tehacaphi) and geothermal (Imperial Valley). As reported by the CAISO,[7] projected renewable energy resources available to or potentially accessed by the LEAPS and TE/VS Interconnect projects are outlined in <u>Table 1-2</u> (Development of New Renewable Resources in the Southern California Area).

1.2.3 Projects Ahead of LEAPS in the Large-Generator Interconnection Queue

An interconnection request, submitted in accordance with the Commission's standard large-generator interconnection procedures (LGIP) and in accordance with the Commission's tariff, constitutes an application to interconnect a new generating facility or to increase the capacity of or make a material modification to the operating characteristics of an existing generating facility that is interconnected with the transmission provider's transmission system. Application Queue position means the order of a valid interconnection request, relative to all other pending valid interconnection requests, that is established based upon the date and time of receipt of the valid interconnection request by the transmission provider. Transmission providers shall assign a queue position based upon the date and time of receipt of the valid interconnection request. The Application Queue position of each interconnection request determines the order of

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[3]/ California Energy Commission, Accelerated Renewable Energy Development, Draft Staff White Paper, 100-04-003D, July 30, 2004, p. 61.

[4]/ Senate Bill 107 (Simitian and Perata), Chapter 464, Statutes of 2006.

[5]/ *Op. Cit*., 2006 Integrated Energy Policy Report Update, Committee Final Report, p. 12.

[6]/ California Energy Commission, Renewable Portfolio Standard Eligibility Guidebook, Second Edition, CEC-300-2007-006-CMF, March 2007, pp. 21-22.

[7]/ Shirmohammadi, Dariush, CAISO South Regional Transmission Plan for 2006, Presentation at CEC Intermittency Analysis Project, Energy Commission Staff Workshop, August 15, 2006, p. 17.

performing the interconnection studies and the cost responsibility for the facilities necessary to accommodate the interconnection request. The higher the queue position, the earlier the request was placed in the queue relative to other later interconnection requests.

Table 1-2
DEVELOPMENT OF NEW RENEWABLE RESOURCES IN THE SOUTHERN CALIFORNIA AREA

Year	Resource Type	Tehachapi	Salton Sea
2010	Wind	4,500 MW	-
	Geothermal	-	445 MW
	Solar	-	300 MW
2015	Wind	4,500 MW	-
	Geothermal	-	1,600 MW
	Solar	-	900 MW
2017	Wind	6,000 MW	-
	Geothermal	-	2,000 MW
	Solar	-	900 MW

Source: California Independent System Operator

The CAISO has assigned Application Queue positions, reflecting the requirements of FERC Order 2003-C for LGIP, applicable to generating facilities that exceed 20 MW. As indicated on the CAISO's Application Queue (dated October 26, 2006), the LEAPS project was listed as Queue Position 72, indicating that there were 71 other projects that submitted valid interconnection requests prior to the CAISO's acceptance of the LEAPS request. SCE and SDG&E projects with higher queue positions are listed in Table 1-3 (SCE and SDG&E Projects with Higher Applicant Queue Position).

Based on the CAISO's Deliverability Phase IIB results, LEAPS project (Application Queue 72) passed the CAISO deliverability test. Under the CAISO's standard modeling assumptions, this means that the energy from the pumped storage project is deliverable to the load centers in southern California without limitation. The ramification of the 100 percent deliverability is that the LEAPS project's full generation capacity can be counted towards resource adequacy capacity requirements of the load-serving entities (LSEs).

1.2.4 Transmission System Upgrades

California Independent System Operator – 2006 Southern Regional Transportation Plan

The "basecase system topology assumptions" for the "CAISO Southern Regional Transmission Plan for 2006" (CSRTP-2006), includes: (1) major transmission projects for the 230 kV and above voltage levels that have been approved by the CAISO board; (2) major 230 kV and above voltage transmission projects that will be included for recommendation in the upcoming board meeting; and (3) other CAISO-approved transmission projects in the starting power flow base case.[8]

[8]/ *Op. Cit.*, CAISO Southern Regional Transmission Plan for 2006, p. 12.

Table 1-3
SCE AND SDG&E PROJECTS WITH HIGHER APPLICANT QUEUE POSITION

Queue	Utility	County	Station or Transmission Line
1	SCE	Riverside	Devers-Gamet 115 kV line
1A	SDG&E	San Diego	Miguel substation/Otay Mesa generation project
3	SCE	Riverside	Devers substation 230 kV bus
4	SDG&E	San Diego	Palomar 230 kV/Palomar Energy
5	SDG&E	San Diego	Encina Power Plant swithchyard
7	SCE	Los Angeles	El Segundo 220 kV bus
8	SDG&E	San Diego	Sycamore Canyon substation
11	SCE	San Bernardino	Mountain Pass
13	SDG&E	San Diego	Escondido
14	SDG&E	San Diego	Miguel-Tijuana (additional MWs)
17	SCE	Riverside	Devers-Palo Verde 500 kV line near Blythe
20	SCE	Kern	Antelope
23	SCE	San Bernardino	San Bernardino (72 additional MW)
25	SDG&E	San Diego	Crestwood
26	SDG&E	San Diego	Crestwood
27	SDG&E	San Diego	Southbay
31	SCE	Kern	Monolith substation
32	SDG&E	San Diego	Boulevard-Crestwood 69 kV transmission line
33	SCE	Curchill	Bishop control sub
34	SCE	Kern	Monolith substation
41	SCE	Kern	Pastoria substation
49	SCE	Riverside	Devers substation
50	SCE	Riverside	SCE Valley substation
58	SCE	Mineral	Dixie-Valley-Oxbow 330
65	SCE	Los Angeles	Long Beach gen station 220 kV switchyard
66	SCE	Los Angeles	Walnut substation
68	SCE	San Bernardino	Pisgah 230 kV substation

Source: California Independent System Operator

As specified therein, “major upcoming approved projects in the south” include: (1) Path 49 Short-Term Upgrade Project (Q3-4, 2006) – sponsored by SCE, SDG&E, and APS, this project was justified based on economic benefits of accessing inexpensive generation from Arizona to serve southern California load and increasing East of River (Path 49) rating by 505 MW to provide additional import capability into CAISO footprint; (2) Rancho Vista 500/230 kV Substation Project (2009) – sponsored by SCE, this project was justified based on reliability needs of San Bernardino and Riverside Counties; (3) Palo Verde-Devers No. 2 500 kV Line Project (2009) – sponsored by SCE, this project was justified based on economic benefits of accessing inexpensive generation in Arizona to serve southern California load and increases Pather 49 rating by 1,200 MW.[9] Basecase system topology assumptions for both the SCE and SDG&E area are listed in <u>Table 3-4</u> (CAISO South Regional Transmission Plan for 2006 – Basecase System Topology Assumptions).[10] Specific “generation retirement assumptions” are also identified by are not listed herein.

[9]/ *Ibid*., pp 114-15.
[10]/ *Ibid*., p. 13.

Table 1-4
CAISO SOUTH REGIONAL TRANSMISSION PLAN FOR 2006 BASCASE SYSTEM TOPOLOGY ASSUMPTIONS

No.	Transmission Project	Operating Dates
SCE Area		
1	South of Pastoria 230 kV T/L Upgrade	2006
2	Path 49 Short-Term Upgrades	2006
3	Two 165 MVAR 500 kV Shunt Capacitors at Valley Sub.	2007
4	Devers-Mirage 115 kV System Split	2008
5	Jurupa 230/66 kV Substation	2008
6	Oak Valley 230/115 kV Substation	2009
7	Rancho Vista 500/230 kV Substation	2009
8	Palo Verde-Devers No. 2 500 kV Line	2009
9	San Joaquin Cross Valley Rector 230 kV Loop Project	2009
10	500 kV VAR Support at Various Locations	2006-2015
11	Mirage 230 kV System Reinforcement	2008-2012
12	Antelope-Bailey System Reinforcement (New A-Bank Station, 66 kV Reconductoring)	2008-2014
SDG&E Area		
1	New 230-KV Shunt Capacitors at Miguel	Dec-2006
2	New 230/138 kV Transformer at Penasquitos	Dec-2006
3	Reconductor TL696, Escondido-Ash	June-2006
4	New 230/138 kV Transformer at Sycamore Canyon	June-2006
5	Path 49 Short-Term Upgrades	June-2006
6	Transmission for Otay Mesa Power Generation	June-2007
7	Reconductor TL6916, Scycamore-Scripps (UG)	June-2007
8	Reconductor TL13836, Talega-Pico	June-2007
9	Lake Hodges Pump Storage Project	Sept-2007
10	500/230 kV Transformer Upgrade at Imperial Valley (1120 MVA)	Dec-2007
11	New 230/69 kV Silvergate Substation	June-2008
12	Reconductor TL606, Division-Naval Station Metering	June-2008
13	Reconductor TL652, Wabash-Main Street	June-2008
14	Loop-In TL23011C, PEN 230 kV Switchyard	June-2008
15	Reconductor TL689, Escondido-Felicity Tap	June 2009
16	Upgrade 138/69 kV Transformer at Escondido	June 2009
17	Relocate South Bay Substation	June-2010
18	Reconductor TL683, Lilac-Rincon	June-2010
19	New 69 kV T/L 6942, Miramar-Sycamore	June-2010
20	Reconductor TL13837, Capistrano-Laguna Niguel	June-2010
21	Reconductor TL13802B, Shadowridge-Calavera Tap	June-2011
22	Reconductor TL678, Los Coches-Alpine and TL6914, Los Coches-Loveland	June-2011

Source: California Independent System Operator

California Independent System Operator – 2007 Transmission Plan

As indicated in the CAISO's "2007 Transmission Plan – 2007 through 2016" (Transmission Plan) "159 transmission project proposals are documented in the plan.[11] These projects were evaluated by the PTOs as part of their planning effort during this past year. Among these projects, 94 transmission project proposals are in PG&E's service territory, 32 projects appear in SCE's service territory, and 33 projects are in SDG&E's service territory."[12] SCE's and SDG&E's expansion plans are separately described below.

- SCE 2007 Expansion Plan. A total of 32 transmission projects on the CAISO-controlled grid appear in SCE's 2007-2016 transmission expansion plan. These include both reliability and economic transmission projects designed to mitigate reliability criteria violations, reduce congestion, locational capacity requirements (LCR) reduction, and economic projects to access low-cost resources.

  Of those projects, twelve projects have been approved. Twelve additional projects, each with capital expenditures of less than $20 million, are needed to mitigate reliability criteria violations and to meet load growth in the SCE service area for the 2008-2012 time frame. An additional eight transmission projects that are needed to be on-line between 2010-2015 to address load growth and mitigated reliability criteria violations. Those projects and their targeted on-line dates include: (1) West of Devers 230 kV rebuild (June 2010); (2) Antelope 4th 230/66 kV transformer (June 2011); (3) Devers-Mirage #3 230 kV line (June 2011); (4) Vincent-Mira Loma 500 kV TL; (5) Alberhill 500/115 kV substation (June 2012); (6) Magunden-Rector 230 kV TL (June 2012); (7) New 230/66 kV substation (June 2014); and (7) Method of Service for San Joaquin 230/66 kV substation (June 2015).[13]

  The CPUC identified the SCE's "Inland Empire Energy Center (IEEC) 500 kV Gen-tie" (A.06.03-028) as the only SCE project with a completed CPCN application.[14]

  Presented in Section 4.0 (Alternative Analysis) is a discussion of SCE's proposed 25-mile 115 kV Ivyglen Subtransmission Project (installation of a second 115 kV line) starting at SCE's exising Valley substation in Romoland and terminating at SCE's existing Ivyglen substation in Glen Ivy.

- SDG&E 2006 Expansion Plan. SDG&E's expansion plan identifies 17 approved projects, including seven transmission projects completed and connected to the CAISO-controlled grid in 2006. SDG&E has also proposed 16 new transmission proposals with targeted on-line dates between 2008-2011. Those projects and their targeted on-line dates include: (1) Sycamore UG cable replacement (June 2008); (2) Reconductor TL 13802B, Shadowridge-Calavera tap (June 2008); (3) Reconductor TL 6913, Poway-Pomerado (June 2008); (4) Lake Hodges Pump Storage project generator interconnect (Sepember 2008); (5) Reconductor TL 689, Escondido-Felicita tap (June 2009); (6) Upgrade 138/69 kV transformer, Escondido (June 2009); (7) New 69 kV line TL 6942, Miramar-Sycamore; (8) Reconductor TL 12837, Capistrano-Laguna Niguel (June 2010);

[11]/ The LEAPS project, SDG&E's Sunrise Powerlink project, and SCE's Tehacaphi transmission project are separately discussed in the Transmission Plan.

[12]/ California Independent System Operator, 2007 Transmission Plan – 2007 through 2016, January 2007, p. 6.

[13]/ *Ibid*., pp. 50-53.

[14]/ California Public Utilities Commission, Transmission Project Tracking, Completed CPCN Applications (http://www.cpuc.ca.gov/static/energy/061206_transmissionprojecttrackingspreadsheetpublicversion.xls).

(9) Reconductor TL 683, Lilac-Rincon (June 2010); (10) Reconductor TL 678, Los Coches-Alpine (June 2011); (11) Loop-in TL 13825 into Shadowridge (June 2008); (12) New Division – Naval Station Metering Line (June 2009); (13) Loop-in TL 651, Wabash-National City; (14) Encina-Penasquitos 230 kV #2 (June 2009); (15) Reconfiguing TL 13821 and TL 13822 (June 2010); and (16) Sunrise Powerlink (June 2010).[15]

California Energy Commission - 2007 Transmission Investment Plan

Section 25301 of the PRC directs the CEC to conduct regular assessments of all aspects of energy demand and supply. These assessments serve as the foundation for analyses and policy recommendations to the Governor, State Legislature, and other agencies. The broad strategic purposes of these policies are to conserve resources, protect the environment, ensure energy reliability, enhance the State's economy, and protect public health and safety. In furtherance of that requirement, pursuant to Section 25303(a)(3) of the PRC, the CEC conducts annual assessments of the "availability, reliability, and efficiency of the electricity and natural gas infrastructure and systems," including the "western regional and California electricity and transmission system capacity and use."

Under Section 25324 of the PRC, the CEC is required every two years to "adopt a strategic plan for the State's electric transmission grid using existing resources." Section 25324 states: "The strategic plan shall identify and recommend actions required to implement investments needed to ensure reliability, relieve congestion, and meet future load growth in load and generation, including, but not limited to, renewable resources, energy efficiency, and other demand reduction measures."

In the development of the strategic transmission plan, Section 25333 of the PRC directs the CEC to "confer with cities and counties, federal agencies, and California Native American tribes to identify appropriate areas within their jurisdictions that may be suitable for a transmission corridor zone. The [California Energy] Commission shall, to the extent feasible, coordinate efforts to identify long-term transmission needs of the state with the land use plans of cities, counties, federal agencies, and California Native American tribes."

The 2005 "Strategic Transmission Investment Plan" (Strategic Plan) limited its recommendations to specific transmission projects that were identified as needed by 2010. In the 2007 Strategic Plan, the CEC has recommended expanded its time horizon to twenty years.

In response to the CEC's solicitation for projects, a number of transmission projects are identified in the CEC's agenda of the "Joint Committee Workshop on In-State and Interstate Transmission and Potential In-State Corridors" for the 2007 Strategic Plan.[16] As indicated therein, in addition to the LEAPS project, the following projects are identified in the southern California area.

- **San Diego Gas and Electric**
  - ◊ Sunrise Powerlink. The Sunrise Powerlink is a new 500 kV transmission line that is currently undergoing review at the CPUC.

[15] / *Ibid*., pp. 54-55.

[16] / California Energy Commission, Joint Committee Workshop on In-State and Interstate Transmission and Potential In-State Corridors, Agenda Attachment: In-State and Interstate Transmission Projects and Corridors for Consideration in the 2007 Strategic Transmission Investment Plan, May 14, 2007, p. 8.

- **Southern California Edison**

  - ◊ West of Devers Rebuild. This project would encompass the four 230 kV lines heading west from the Devers substation and has a planned in-service date of June 2010. These upgrades were part of the recently permitted Devers-Palos Verdes No. 2 500 kV project; however, because of permitting issues, the West of Devers upgrades were replaced with a second Devers-Valley 500 kV line. With the approval of the Devers-Valley 500 kV alternative, the West of Devers Rebuild may no longer be needed.
  - ◊ Devers-Mirage 230 kV Transmission Line. The Devers-Mirage 230 kV line is needed by June 2011 to mitigate reliability criteria violations.
  - ◊ Vincent-Mira Loma 500 kV Transmission Project. The Vincent-Mira Loma 500 kV line is an 80-mile line planned for 2011 and would mitigate South of Lugo transmission congestion.

- **Los Angeles Department of Water and Power** (LADWP)

  - ◊ Intermountain DC Line Upgrade. The existing Intermountain DC line ties the Intermountain Power Plant in Utah to the Adelanto substation in southern California and is rated at 1,920 MW. The planned project would upgrade the converter stations at the substations, increasing the transfer capacity by 480 MW to 2,400 MW. LADWP plans to have this upgrade operating by December 2008.
  - ◊ Green Path North (LADWP/IID). The Green Path North project would be a new connection between the Imperial Irrigation District (IID) and LADWP service areas. This project would consist of 500 kV lines, new substations, and upgrades to both LADWP and IID facilities. The project would be completed by November 2011. The Green Path North facilities include: (1) two new 500 kV substations (Devers No. 2 and Hesperia substations); (2) an 85 mile, new 500 kV line connecting the new Devers No. 2 and the existing Devers substations; (3) a new 5-mile 287 kV tap line from the Hesperia substation to the existing Victorville-Century line; (4) a new 500 kV or 230 kV 30 mile transmission line from a new IID Indian Hills substation to the Devers No. 2 substation; and (5) a new 230 kV line from the new Indian Hills to the existing Coachella Valley substation.
  - ◊ LADWP Tehachapi Transmission Project. The Tehachapi Transmission Project would be designed to connect and deliver new resources, in particular wind resources, in the Tehachapi region. The project would include several new substations and would deliver as much as 1,600 MW to LADWP's Rinaldi and Castaic substations by December 2009. This project would be stages to accommodate new generation resources as they develop and would include five new 230 kV substations (Barren Ridge, Haskell, Pine Tree Wind, Wind No. 2, and Wind No. 3).

United States Department of Energy - National Interest Electric Transmission Corridors

Section 1221(a) of EPAct2005 added Section 216 to the FPA and required the Secretary of Energy to conduct a nationwide study of electric transmission congestion and issue a report on the study "which may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor" (16 U.S.C. 824p[a][2]). The effect of a national corridor designation is to delineate geographic areas within which, under certain circumstances, the

Commission may authorize “the construction or modification of electric transmission facilities” (16 U.S.C. 824p[6]).

Under Section 216(b)(1) of the FPA, the Commission’s jurisdiction is triggered only when either: (1) the state does not have authority to site the project; (2) the state lacks the authority to consider the interstate benefits of the project; (3) the applicant does not quality for a state permit because it does not serve end-use customers in the state; (4) the state has withheld approval for more than one year; or (5) the state has conditioned its approval in such a manner that the project will not significantly reduce congestion or is not economically feasible (16 U.S.C. 824p[b][1]). Under Section 216(b)(2)-(6), the Commission may issue a permit only if all of the following conditions are met: (1) the facilities will be used for the transmission of electric energy in interstate commerce; (2) the project is consistent with the public interest; (3) the project will significantly reduce congestion and protect or benefit consumers; (4) the project is consistent with national energy policy and will enhance energy independence; and (5) the project maximizes, to the extent reasonable and economical, the transmission capabilities of existing towers or structures.

In August 2006, the DOE issuance an initial congestion study.[17] Based on the historical data and modeling results, the study classified the most significant congestion areas in the country. Two “critical congestion areas” (defined as areas where the current and/or projected effects of congestion are especially broad and severe) were identified, including the Atlantic coastal area from metropolitan New York through northern Virginia (Mid-Atlantic Critical Congestion Area) and southern California (Southern California Critical Congestion Area). In May 2007, the DOE provided notice soliciting comments on the draft national corridor designation for the two critical congestion areas, identified as the draft Mid-Atlantic Area National Corridor and draft Southwest Area National Corridor.

The area of the draft Southwest Area National Corridor is illustrated in Figure 1-1 (National Interest Electric Transmission Corridor - Draft Southwest Area National Corridor).[18] As illustrated, in addition to the transmission line associated with the LEAPS and TE/VS Interconnect projects, a number of other transmission lines are represented therein. Although the national corridor designation is “not a siting decision,”[19] the transmission alignments identified in the draft Southwest Area National Corridor may represent related projects that may be permitted under the provisions of Section 216 of the FPA.

1.2.5 Network Upgrades

Based on studies conducted by SCE and SDG&E, a number of network upgrades have been identified which are predicted, either in whole or in part, by the additional power flows attributable to the proposed projects. Because the need for those improvements may or may not predicted by the proposed projects and because their implementation could occur prior to and independent of the proposed projects, each of those network upgrades are or may be part of the proposed projects or may constitute related activities which will be undertaken either by the Applicant or by one or more investor-owned utilities.

[17]/ United States Department of Energy, National Transmission Congestion Study, August 8, 2006.

[18]/ *Op. Cit.*, Notice of Opportunity for Written and Oral Comment, Docket Nos. 2007-OE-01 (Draft Mid-Atlantic Area national Corridor) and 2007-0E-02 (Draft Southwest Area National Corridor), p. 174.

[19]/ *Ibid*., p. 6.

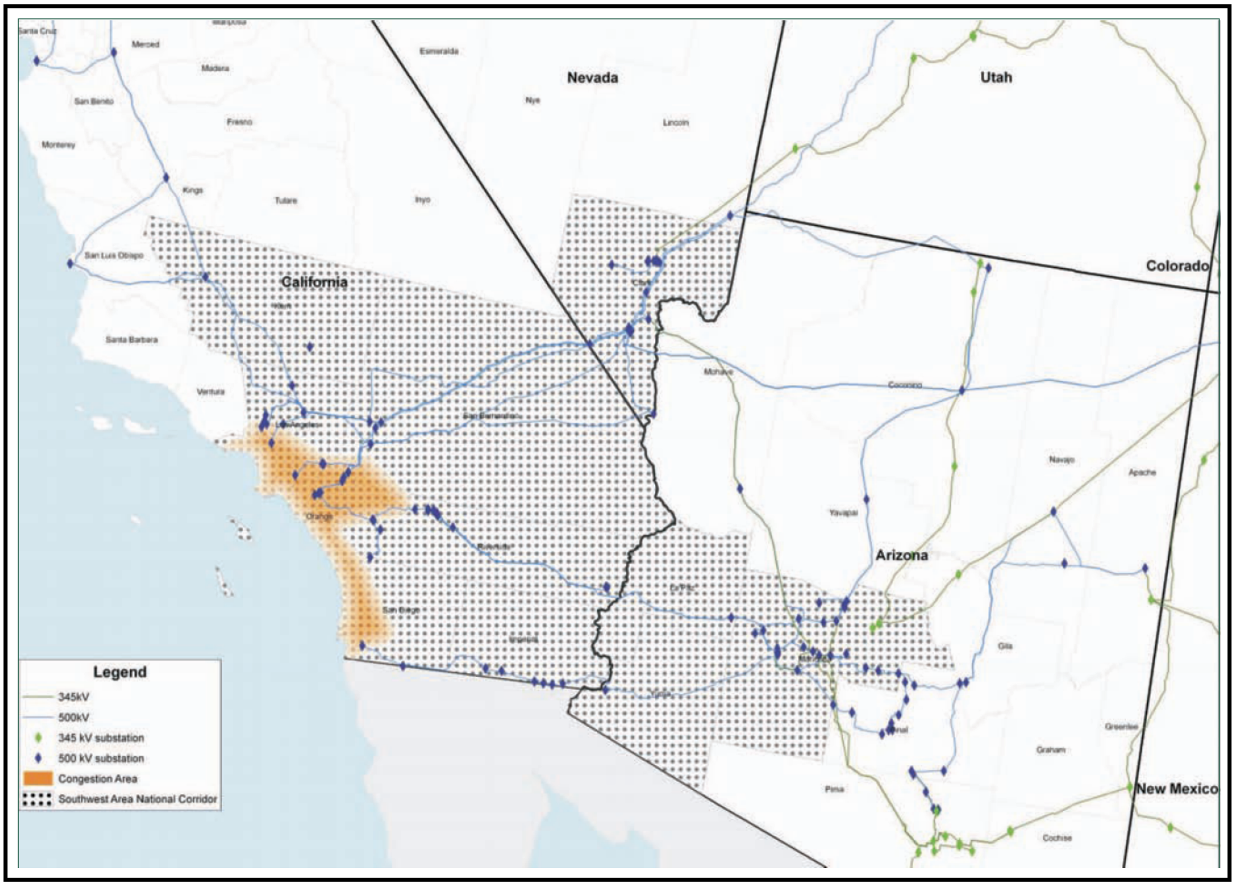

Figure 1-1
NATIONAL INTEREST ELECTRIC TRANSMISSION CORRIDOR
DRAFT SOUTHWEST AREA NATIONAL CORRIDOR
Source: United States Department of Energy

Southern California Edison - Interconnection Facilities Study and Large-Generator Interconnection Agreement[20]

SCE's "Interconnection Facilities Study," dated November 30, 2006, concluded that the present SCE transmission system is not adequate to support the proposed power flows associated with the LEAPS project. Base-case overloads were identified on several SCE transmission lines. The new generation would trigger one single-contingency overload (Etiwanda-Vista 220 kV T/L) and aggregate six pre-existing single-contingency and double-contingencies caused by early

[20]/ To the extent that these upgrades become part of the proposed projects or become the projects' obligations rather than network upgrades conducted by SCE and deemed not to be reimbursable by the Applicant, these upgrades are part of the projects description and not related projects herein. Since these improvements may be undertaken directly by SCE or by others (based on flows produced by earlier projects on the Application Queue) or may constitute responsibilities of the Applicant based on the power flows associated with the proposed projects, these transmission system upgrades have been included in this EIR both as components of the projects description and again as related projects herein.

interconnections placed ahead of the LEAPS project in the present Application Queue.[21] The analysis further identified four 500 kV, 21 220 kV, and 21 115 kV locations where the LEAPS project caused an increase on the three-phase short-circuit duties of 0.1 kA or more and indicated that all circuit breakers at those locations be evaluated. Each of the anticipated overloads, whether predicated by the proposed projects or as a result of those additional facilities placed higher in the Application Queue, and improvements associated with SCE's proposed solutions to those overloads are identified below.[22]

- Etiwanda-San Bernardino 220 kV transmission line. Eliminate the existing line-to-ground clearance restrictions to restore the line conductor rating to N=2480, N-1=2850, and N-2=3350A and replace two 1200A disconnect switches at Etiwanda with 3000A rated to support 60 percent of highest contingency load of 3093A or 1855A.
- San Bernardino-Vista 220 kV transmission line. Upgrade the line by replacing 2-1033KCMIL ACSR conductors with new 2-1590KCMIL ACSR rated N=3230, N-1=3710, and N-2=4360A and replace four 2000A disconnect switches at each San Bernardino and Vista (total of 8) with 3000A rated to support 60 percent of highest contingency load of 3745A or 2250A.
- Etiwanda-Vista 220 kV transmission line. Replace 2000A wave trap at Etiwanda with 3000A rated and N-2 rating of 3210A to support the highest contingency load of 3071A.
- Lugo-Vincent No. 1 500 kV transmission line. Line is adequate (no upgrades required).
- Lugo-Vincent No. 2 500 kV transmission line. Line is adequate (no upgrades required).
- Mira Loma-Vista 220 kV transmission line. Line is adequate (no upgrades required).

As further indicated in the Draft SCE-LGIA, interconnection customer's interconnection facilities shall consist of one interconnection position in the interconnection customer's 500 kV switchrack, using double bus-double breaker configuration, two 500 kV circuit breakers, associated meters, metering equipment, protective relays disconnects, associated 500 kV generation tie-line (Lake-LEAPS 500 kV generation tie-line), and appurtenant facilities.

PTO's interconnection facilities at the Northern (Lake) switchyard shall include the following: (1) install one dead-end structure (108-feet high by 90-feet wide); (2) install three 500 kV CCVT potential devices; (3) install three 500 kV surge arresters; (4) install three 500 kV 4000A wave traps and line tuners; (5) install three line tie-downs with 2-2156KCMIL ACSR conductors; (6) install dual communication channels on separate routes to support the line protection relays on the new Lake-LEAPS 500 kV T/L; one of the communication channels will be provided by installing OPGW on the new 500 kV transmission line; (7) install new light-wave and channel equipment to support Lake-LEAPS 500 kV T/L protection, SCADA and applicable SCE voice and data requirements; (8) construct approximately six miles of new ADSS fiber optic cable to extend existing SCE fiber optic cable from either the Elsinore or Skylark substations to the LEAPS generating facility; the combined (existing + new) fiber optic cable provides the required alternate route between Lake substation and the LEAPS generating facility; (9) install the following relay protection devices for the Lake-LEAPS gen-tie line protection (a) two GE C60 breaker management relays, (b) one SEL-311L line current differential (digital F.O. channel), (c) one GE L90 line current differential (digital F. O. channel), (d) install one GE D60 directional comparison pilot relaying (digital F.O./MW channel), (e) install one RFL 9745 tele-protection channel DTT (digital F.O. channel), (f) install one RFL 9745 tele-protection channel DTT (M/W

[21]/ The analysis determined that the LEAPS project would trigger contingency overloads on the Camp Pendleton 230 kV phase shifter transformer. This transformer is not an SCE facility and was not included in SCE-IFS.

[22]/ The following improvements do not differentiate between those that are required to accommodate the combined LEAPS and TE/VS Interconnect projects versus those that would be required to accommodate only the LEAPS project or only the TE/VS Interconnect project.

channel), (g) install one 32/64 digital fault recorder, (h) install one Ethernet service drop, and (h) install one SEL-2030; (10) install one RTU at Lake substation to monitor the typical bulk power elements such as MW, MVAR, and phase amps at each line and also kV at lines and busses and all circuit breaker status/control, protection relays status and alarms; (11) the RTU will transmit information to the SCE Grid Control Center via the existing Mira Loma Regional Control Center System.

PTO interconnection facilities at the LEAPS generating facility shall consist of the installation of new light wave and channel equipment to support Lake-LEAPS 500 kV generation tie-line protection, SCADA, and applicable SCE voice and data requirements.

PTO's reliability network upgrades at the Northern (Lake) switchyard shall include the following: (1) engineer and construct a new 500 kV interconnection facility to loop the Serrano-Valley 500 kV T/L and provide one 500 kV line position to terminate the Lake-LEAPS 500 kV generation tie-line; (2) install two 500 kV operating buses covering three positions; (3) install three bus dead-end structures (60-feet high by 90-feet wide); (4) install twelve bus dead-end insulator assemblies; (5) install three 500 kV potential devices; (6) install two 270-foot sections of 2-2156 KCMIL ACSR bus conductors (approximately 3,250 feet of conductor); (7) Position 1 (a) install one dead-end structure (108-feet high by 90-feet wide), (b) install three 500 kV - 3000A – 40 kA circuit breakers, (c) install six 500 kV horizontal mounted group operated disconnect switches; two of them equipped with grounding attachments, (d) install six 500 kV bus supports, (e) install three 500 kV CCVT potential devices, (f) install three 500 kV surge arresters, (g) install three 500 kV, 4000A wave traps and line tuners, (h) install three line tie-downs with 2-2156 KCMIL ACSR conductors, (g) install three 660-foot sections 2-2156 KCMIL ACSR bus conductors (approximately 4.000 feet of conductor); (8) Position 2 install one line dead-end structure (108-feet high by 90-feet wide) to terminate the conductors from the Serrano 500 kV T/L at position 2N and cross them over to the structure at position 1S; (9) Position 3 (a) install one dead-end structure (108-feet high by 90-feet wide), (b) install two 500 kV - 3000A – 40 kA circuit breakers, (c) install four 500 kV horizontal mounted group operated disconnect switches; one of them equipped with grounding attachments, (d) install fifteen 500 kV bus supports, (e) install three 500 kV CCVT potential devices, (f) install three 500 kV surge arresters, (g) install three 500 kV, 4000A wave traps and line tuners, (h) install three line tie-downs with 2-2156KCMIL ACSR conductors, (i) install three 660-foot sections 2-2156 KCMIL ACSR bus conductors (approximately 4,000 feet of conductor); (10) Mechanical-Electrical Equipment Room (MEER) install a new 30-foot by 20-foot MEER building to house the following equipment (a) batteries and battery charger, (b) light and power selector switch, (c) light and power panel, (d) A.C. distribution panel, and (e) D.C. distribution panel; (11) Protection Relays (500 kV T/L) install the following relays at each of the two remaining line positions (a) two G.E. C60 breaker management relays, (b) one SEL-311L line current differential (digital F.O. channel), (c) one G.E. L90 line current differential (digital F.O. channel), (d) one G.E. D 60 directional comparison pilot relaying (digital F.O./MW channel), (e) one RFL 9745 tele-protection channel DTT (digital F.O. channel), and (f) one RFL 9745 tele-protection channel DTT (M/W channel); (12) Others (a) install one 32/64 digital fault recorder, (b) install one Ethernet service drop, (c) install one SEL-2030 connected to all three SEL-311L relays; and (13) Other station elements to be Installed (a) install Telecommunications tower and MW dish antenna, (b) install 2,320 linear feet of 8-foot perimeter fence with double barbed wire to cover a 760-foot by 400-foot area, (c) install one 20-foot double door driveway gates, (d) install grounding grid to cover a 766-foot by 406-foot area (3 feet outside the perimeter fence), (e) perform grading and site preparation of a 780-foot by 420-foot area (10 feet outside the perimeter fence), (f) install approximately 2,000 linear feet of 25-foot paved driveway, and (g) install approximately 1,500 linear feet of control cable trench.

PTO's reliability network upgrades at the Serrano substation shall include the following: (1) upgrade the Valley 500 kV line protection as needed to change the line to a new Lake 500 kV T/L; (2) replace the existing LFCB relay with a new SEL-311L line current differential relay and the modification of the existing D60 and L90 relays to change the existing transfer trip schemes from Valley substation to Lake substation, and (3) reconfigure the existing digital channel from Valley substation to Lake substation and the modification of the existing SEL 2030 telecommunications processor with Ethernet to provide connection to the new SEL relay.

PTO's reliability network upgrades at the Valley substation shall include the following: (1) upgrade the Serrano 500 kV line protection as needed to change the line to the new Lake 500 kV T/L; (2) replace the existing LFCB relay with a new SEL-311L line current differential relay and the modification of the existing D60 and L90 relays to change the existing transfer trip schemes from Serrano substation to Lake substation; (3) reconfigure the existing digital channel from Serrano substation to Lake substation and the modification of the existing SEL 2030 telecommunications processor with Ethernet to provide connection to the new SEL relay; and (4) replace six 31.5 kA 115 kV circuit breakers with new 40 kA rated circuit breakes and upgrade six 31.5 kA circuit breakers to 40 kA.

PTO's reliability network upgrades at the Etiwanda generating station shall include the following: (1) replace the 2000A wave trap on the Vista 220 kV line position with 3000A rated wave trap, with N-2 contingency rating of 3210A to support the maximum N-2 line loading of 3071A; (2) replace twenty four 63 kA 220 kV circuit breakers with new 80 kA rated circuit breakers and upgrade the Etiwanda 220 kV switchyard to 80 kA rating; (3) the scope of work for the switchyard upgrade has not been completed at this time; it is, however, expected that, in addition to the work shown above, the following additional upgrades would be required (a) replace 28 220 kV disconnect switches, (b) replace 24 220 kV surge arresters, (c) replace all line and bank vertical risers with tubular conductors, (d) replace all 4/0 CU connectors to the ground grid with new 350 kCMIL ACSR, and (e) install new sections of 350 kCMIL ACSR ground grid and connect to the existing 4/0 CU grid.

PTP telecommunication network upgrades shall include the following: (1) install dual communication channels on separate routes to support the line protection relays on the new Lake-Serrano and Lake-Valley 500 kV T/L; (2) install a new microwave path from Lake substation to the existing Santiago Peak communication site (a) Lake substation install new light wave, microwave (including dish antennas), channel equipment for 500 kV line protection communications tower, fiber optic cable, and DC system, plus new voice and data network infrastructure (operations phones, modem lines, LAN connections to relays, etc.), (b) Serrano substation install new light wave and channel equipment for 500 kV line protection , plus incremental addition of voice and data network infrastructure (rack phones, modem lines, LAN connections to relays, etc.), (c) Valley substation install new light wave and channel equipment for 500 kV line protection, plus incremental addition of voice and data network infrastructure (rack phones, modem lines, LAN connections to relays, etc.), (d) Santiago Peak communications site install new microwave and dish antennas to link Lake substation to Serrano and Valley substations for 500 kV line protection, (e) Mira Loma substation install new light wave equipment to link Lake substation to Serrano substation for 500 kV line protection (i) install dual communication channels on separate routes to support the line protection relays on the new Lake-LEAPS 500 kV generation tie-line (A) install OPGW on the new Lake-LEAPS 500 kV generation tie-line to provide additional communications channel, and (B) Outside plant construction [1] construct approximately six miles of new ADSS fiber optic cable to extend existing SCE fiber optic cable from either the Elsinore or Skylark substations to the LEAPS generating facility; the combined (existing + new) fiber optic cable provides the required alternate route between Lake substation and the LEAPS generating facility, and [2] the communications channels described above will also be used to provide the power management circuits required for the Remote Terminal Units (RTU) to be installed at Lake switchyard and the LEAPS generating facility.

Power system control network upgrades shall include the following: install one RTU at Lake substation to monitor the typical bulk power elements such as MW, MVAR, and phase amps at each line and also kV at lines and busses and all circuit breaker status/control, protection relays status and alarms. The RTU will transmit information to the SCE Grid Control Center via the existing Mira Loma Regional Control Center System.

San Diego Gas and Electric - Interconnection Facilities Study and Large-Generator Interconnection Agreement[23]

SDG&E's "Interconnection Facilities Study," dated December 15, 2006, concluded that the present SDG&E transmission system is not adequate to support the proposed power flows. Each of the anticipated overloads, whether predicated by the proposed projects or as a result of those additional facilities placed higher in the Application Queue, and improvements associated with SDG&E's proposed solutions to those overloads are identified below.[24]

- Gen-tie connection from LEAPS 230 kV transformers into SDG&E's 230 kV swithchyard.
- Installation of a new 230 kV Pendleton swithchyard, including the construction of 4-bays of 230 kV breakers and half-bus design for interconnection with the proposed projects. The switch rack will include 4-line terminals with breakers, 4-tie positions with breakers, 2-bank terminals with breakers, and 2-bank terminals without breakers. The projects also include the installation of a dedicated 230 kV control house with all the required protection, metering, telemetering, Supervisory Control & Data Acquisition System (SCADA) and communication equipment and systems.
- Loop-in of the existing Talega-Escondido 230 kV line.
- Bundle the proposed Pendleton-Talega 230 kV No. 1 line to provide 912 MVA capacity.
- Addition of a second proposed Pendleton-Talega 230 kV line, including the addition of the 230 kV bay positions at the Talega and Escondido substations. The proposed Pendleton-Talega 230 kV portion of this line is to have a capacity of 912 MVA. The proposed Pendleton-Escondido 230 kV No. 2 line is to have a capacity of 456 MVA.
- Upgrade the following breakers from 40 kA to 50 kA: Escondido 50, 684, 688, 6908, 696, and 72 and Penasquitos 665, 666, 667, and 70.

As further indicated in the Draft SDG&E-LGIA, the proposed Southern (Pendleton or Case Springs) 230 kV air-insulated switchyard (AIS) shall include: (1) connection of the LEAPS project's 230 kV phase shifting transformers to SDG&E's 230 kV switch rack; (2) a land right in recordable form that grants perpetual and assignable rights for the switchyard of a size and

[23]/ To the extent that these upgrades become part of the proposed projects or become the projects' obligations rather than network upgrades conducted by SDG&E and deemed not to be reimbursable by the Applicant, these upgrades are part of the projects description and not related projects herein. Since these improvements may be undertaken directly by SDG&E or by others (based on flows produced by earlier projects on the Application Queue) or may constitute responsibilities of the Applicant based on the power flows associated with the proposed projects, these transmission system upgrades have been included in this EIR both as components of the projects description and again as related projects herein.

[24]/ The following improvements do not differentiate between those that are required to accommodate the combined LEAPS and TE/VS Interconnect projects versus those that would be required to accommodate only the LEAPS project or only the TE;VS Interconnect project.

configuration and otherwise meeting SDG&E's specifications and requirements; (3) the switchyard shall be graded to SDG&E's specifications; (4) a wall or fence that encloses switchyard land and provides for adequate access and working room; (5) 4-bays of 230 kV breaker and half bus design for interconnection with the LEAPS project (the switch rack will include 4-line terminals with breakers, 4-tie positions with breakers, 2-bank terminals with breakers and 2-bank terminals without breakers); (6) all structures and foundations, busses and equipment within switchyard fence; (7) switchyard grounding-grid; (8) a dedicated control house, substation below grade conduits and cables, protection systems, supervisory control and telecommunications equipment, batteries and low-voltage circuits (all the required protection, metering, telemetering, SCADA and communication equipment and systems); and (9) a portion of the conductors and dead-end insulators from SDG&E's switchyard to the projects' transformer dead-end.

The connection from the LEAPS project 230 kV phase shifter transformers into the substation will include: (1) 2- transformer dead end structures; (2) 2-sets of tie down assemblies; (3) 2-230 kV circuit breakers; (4) 2-shared 230 kV breakers; (5) 6-230 kV disconnect switches; (6) transformer dead-end strain insulators; (7) transformer lead conductors; (8) lot-bus support structures; (9) equipment and bus jumpers; (10) ground grid interconnection; and (11) control junction box. The 230 kV switchyard facilities will include: (1) eight element air-insulated breaker and half bus design to include 4-line positions, 4-tie positions and 4-bank positions; (2) required bus, line and transformer dead-end structures; (3) lot-bus support structures: (4) 10-230 kV circuit breakers; (5) 22-disconnect switches; (6) 2-potential transformers; (7) 2-station service transformers; (8) 2-metering units; (9) required line synchronizing potential transformers; (10) ground grid; (11) yard wire race ways; (12) yard junction boxes; (13) lighting; and (14) a block control shelter to house the DC-control power, protection relays, communication equipment, supervisory and data acquisition equipment and metering panels.

The SDG&E-LGIA identified the following additional PTO's reliability network upgrades:

- Loop-in of the existing Talega-Escondido 230 kV line. SDG&E's future Southern (Pendleton or Case Springs) substation will be located near the existing Tower No. 163 (Z322651). The scope of work for the loop-in consists of Tower No. 163 removal, installation of two 230 kV anchor bolted dead-end steel poles and hardware and conductor. Replacement of 69 kV over-stressed breakers at the Escondido and Penasquitos substations. The short-circuit analysis also shows there are ten (10) overstressed breakers that need to be upgraded from 40 kA to 50 kA. Short-circuit constraints require the upgrading of the following breakers at the Penasquitos substation: PQ 665, 666, 667, and 70. Short-circuit constraints require the upgrading of the following breakers at the Escondido substation: ES 50, 684, 688, 6908, and 696.

- Interconnection customer's delivery network upgrades. The thermal analysis performed in the IFS indicates there are two SDG&E transmission line overloads caused solely by addition of the LEAPS project that require mitigation: (1) Talega-Southern (Talega-Pendleton or Talega-Case Springs); and (2) Southern-Escondido (Pendleton-Escondido or Case Springs-Escondido) 230 kV lines.

  The following delivery network upgrades are needed to mitigate these overloads: (1) bundle the existing line of the Talega-Southern (Talega-Pendleton or Talega-Case Springs) 230 kV #1 line to provide 912 MVA capacity; and (2) addition of a second Talega-Southern-Escondido (Talega-Pendleton-Escondido or Talega-Case Springs-Escondido) 230 kV line, including the addition of the 230 kV bay positions at the Talega and Escondido 230 kV substations (the Talega-Southern [Talega-Pendleton or Talega-Case Springs] 230 kV portion of this line is to have a capacity of 912 MVA and the Southern-Escondido [Pendleton-Escondido or Case Springs-Escondido) 230 kV #2 line's capacity will be 456 MVA. Looping the second Escondido-Talega tie-line into the Southern (Pendleton or Case Springs) 230 kV switch rack will require the following additional upgrades at Escondido and Talega substations to accommodate the new terminal additions.

- ◊ Escondido substation upgrades: (1) relocation and replace bank 71; (2) modify the north and south buses to make room for a new bay addition; (3) install a new 230kV breaker and half bay to include 1-bank, 1-tie, and 1-line positions; (3) lot-support structures as required; (4) 1-230/69kV transformer; (5) 2-230 kV circuit breakers; (6) 5-230 kV disconnect switches; (7) power and control wiring; (8) tie-line protection; (9) metering; (10) SCADA and communication interface; and (11) re-route the existing 12 kV ducts to make room for bank 71.

- ◊ Talega substation upgrades: (1) install a new 230 kV, breaker and half bay to include 1-line and 1-tie positions; (2) lot-support structures as required; (3) 2-230 kV breakers; (4) 4-230 kV disconnect switches; (5) power and control wiring; (6) tie-line protection; and (7) SCADA and communication interface.

1.2.6 Other Electrical Generation and Transmission Projects

With regards to new generation facilities, the CEC has the statutory responsibility for licensing thermal power plants 50 megawatts and larger and the plants related facilities, such as transmission lines, fuel supply lines, and water pipelines. Recent on-line, approved, current, and expected power plant licensing cases, including both peakers and non-peakers, as reported by the CEC, are illustrated in Figure 1-2 (Recent On-Line, Approved, Current, and Expected Plant Licensing Cases). As is evident, there is a broad array of pending energy projects and energy project technologies in various licensing stages throughout the State.

Presented in Table 1-5 (California Energy Facility Status - Riverside and San Diego Counties) is a list of generation facilities that have either recently become operational (following the CEQA Lead Agency's release of the NOP) or are approved or approved and under construction within Riverside and San Diego Counties. Projects identified by the CEC as "cancelled" or "approval expired" are not included in this inventory. Additionally, those generation and/or transmission projects listed as "projects announced" have not been included.

Although not located in Riverside or San Diego Counties, SCE's proposed "Etiwanda Peaker Unit Project" is located on SCE-owned property in the City of Rancho Cucamanga (San Bernardino County), near the existing Etiwanda Generating Station and Etiwanda substation (8996 Etiwanda Avenue/12206 6th Street, Rancho Cucamanga). SCE is proposing to install a 45-MW peaker consisting of a gas-turbine generator. The new peaker will be connected to the 66 kV bus in the existing substation. A new 500 kV substation is proposed for the SCE-owned property to the south.[25]

[25]/ South Coast Air Quality Management District, Final Mitigated Negative Declaration for: Southern California Edison Etiwanda Peaker Project in Rancho Cucamanga, SCH No. 2006121109, March 2007.

Table 1-5
CALIFORNIA ENERGY FACILITY STATUS
RIVERSIDE AND SAN DIEGO COUNTIES

Under Construction (By On-Line Date)	**Docket Number**	**Status**	**Capacity** (MW)	**Location** (County	**Date Approved**	**Construction Start Date**	**Current On-Line Date**
Inland Empire Combined-Cycle Calpine	01-AFC-17	Const.	800	Riverside	12/17/03	8/29/05	06/08
Not Under Construction (By On-Line Date)	**Docket Number**	**Status**	**Capacity** (MW)	**Location**	**Date Approved**	**Construction Start Date**	**Current On-Line Date**
Otay Mesa Calpine	AFC-5	Const. On hold	590	San Diego	04/18/01	09/10/01 Resumed 6/21/04	Const On hold
Blythe II Combined-Cycle Blythe Energy LLC	02-AFC-1	On Hold	520	Riverside	012/14/05	TBA	TBA
Blythe II Combined-Cycle Blythe Energy LLC	99-AFC-8C	Pre-Const.	230 kV Transmission Line	Riverside	10/11/06	TBA	Unknown
Projects in Review (By Estimated Decision Date)	**Docket Number**	**Process**	**Capacity** (MW)	**Location**	**Date Filed**	**Estimated Decision Date**	**Estimated On-line Date**
Sun Valley Energy Project Simple-Cycle Peaker Edison Mission Energy	05-AFC-3	12-month AFC	500	Riverside	12/01/05	06/07	08/08
South Bay Replacement Combined-Cycle L.S. Power	04-AFC-3	12-month AFC	620	San Diego	06/30/06	09/07	05/10

Source: California Energy Commission (December 2006)

As indicated by SDG&E: "For future in-area resource additions, SDG&E has included only those resources for which there are firm commitments to build the new capacity. The one exception to this is the capacity of the 50 MW Kumeyaay Wind Project, whose construction in eastern San Diego County is now nearing completion. This project is not included because the CAISO has been [sic] not been willing to count wind capacity for purposes of satisfying its G-1/N-1 reliability requirements absent historical evidence that some portion of wind capacity can be relied upon during peak periods. In summary, the major generation resource assumptions are shown below. [1] Palomar provides 541 MW beginning in 2006 and each year thereafter. [2] Otay Mesa provides 561 MW beginning in 2008 and each year thereafter. [3] Miramar provides 46 MW each year."[26]

Under the CAISO's "Generation Assumptions for Grid Planning Studies,"[27] planned new generation falls into one of five stages: Level 1 – Under Construction, Level 2 – Regulatory Approval Received, Level 3 – Application under Review, Level 4 – Starting Application Process, and Level 5 – Press Release Only. In accordance with the CAISO's Planning Standards

26/ San Diego Gas & Electric Company, 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, December 19, 2005, Appendix V, p. V-ix.

27/ California Independent System Operator, Generation Assumptions for Grid Planning Studies, April 16, 2004.

Committee approach toward the consideration of new generation in power flow studies, for generation expected to be in service within one year, only generation that is actually under construction needs to be considered. For generation expected to be in service within five years, only generation that is actually under construction need to be considered. For generation additions planned to be in service 5-10 years in the future, only generation that is under construction or has received regulatory approvals need to be considered.

As illustrated in Figure 1-3 (Southern California Transmission Projects), there are currently a number of additional high-voltage transmission projects that are currently under active regulatory review. Each of those transmission projects are briefly described below.

- Devers-Palos Verde No. 2. In October 2006, a final joint CEQA/NEPA document was released by the CPUC (CPUC Docket No. A.05-04-015) for the 230-mile 500 kV Devers-Palos Verdes No. 2 (D-PV2) project proposed by SCE.[28]

- Sunrise (Sunpath) Powerlink Transmission Project. SDG&E submitted to the CPUC (CPUC Docket No. A.06-08-10) a partial application for this 500 kV transmission project in December 2005 and an amended proponent environmental assessment (PEA) in August 2006. The BLM and the CPUC have commenced preparation of a joint CEQA/NEPA document.[29,30]

- Tehachapi Transmission Project. The Tehachapi transmission project consists of four phases. The first phase, filed by SCE with the CPUC in December 2004, includes two applications consisting of Segment 1 (CPUC Docket No. A.04-12-007) and Segments 2 and 3 (CPUC Docket No. A.04-12-008). A draft joint CEQA/NEPA document for the 25.6-mile Segment 1 (Antelope-Pardee 500 kV line) was released by the CPUC in July 2006.[31] Amended applications for Segment 2 (Antelope-Vincent 500 kV transmission line) and Segment 3 (Antelope-Tehachapi 230 kV transmission line) were filed with the CPUC in September 2005. Filing for later phases of the Tehachapi transmission project are scheduled by SCE in March and June 2007.

- Desert Southwest Project (BN-BS Transmission Line Project). A final CEQA/NEPA document was issued for this 118-mile 500 kV project in October 2005.[32] The BLM issued a "Record of Decision" (ROD) on September 15, 2006.[33]

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[28]/ California Public Utilities Commission and Bureau of Land Management (Aspen Environmental Group, Final Environmental Impact Report/Environmental Impact Statement for the Proposed Devers-Palo Verde No. 2 Transmission Line Project (Application No. A.05-04-015), Vol. I-III, October 24, 2006.

[29]/ United States Department of the Interior, Bureau of Land Management, Notice of Intent to Prepare a Joint Environmental Impact Statement/Report and Proposed Land Use Plan Amendment for the Proposed Sunrise Powerlink Project, San Diego and Imperial Counties, CA, August 31, 2006 (71 FR 51848).

[30]/ California Public Utilities Commission, Notice of Preparation/Notice of Public Scoping Meeting for an Environmental Impact Report/Environmental Impact Statement – SDG&E Sunrise Powerlink Project, September 15, 2006.

[31]/ California Public Utilities Commission and United States Forest Service (Aspen Environmental Group) Antelope-Pardee 500 kV Transmission Project Environmental Impact Report/Environmental Impact Statement, July 2006.

[32]/ United States Department of the Interior , Bureau of Land Management and Imperial Irrigation District (Greystone Environmental Consultants, Inc.), Final Environmental Impact Statement/Environmental Impact Report – Desert Southwest Transmission Line Project, SCH No. 2001041105, October 17, 2006.

[33]/ California Public Utilities Commission, National Electric Transmission Congestion Study – Comments of the Public Utilities Commission of the State of California, October 9, 2006, pp. 7-9.

1.2.7 Elsinore Valley Municipal Water District Projects in Reasonably Proximity

In addition to those projects identified in the District's DSMP and WWMP, the EVMWD is implementing projects and conducting water- and wastewater-related studies in the general projects area. Those projects include:

- Regional Wastewater Treatment Plant Phosphorus Removal Facilities. Phosphorous can be removed from recycled water by the addition of a chemical to form an insoluble precipitate, with the subsequent removal of the precipitate by physical separation processes, such as sedimentation or filtration. The chemicals commonly used are metal salts or lime. The primary metal salts used are aluminum-based salts (most commonly aluminum sulfate or alum) and iron-based salts (ferric chloride, ferric sulfate, ferrous chloride, and ferrous sulfate). Improvements to the Regional Wastewater Treatment Plant will allow the addition of alum to wastewater to meet a total phosphorus (TP) concentration of 0.5 mg/L in effluent.

- Recognfiguration of Back Basin Wetlands for Nutrient Removal Project. The existing Back Basin was constructed in 1991, primarily to provide habitat for migratory waterfowl and as mitigation for the construction of the lake levee. Under agreement with the City of Lake Elsinore, the District is responsible for maintaining the wetlands. The existing wetlands comprise over 200 acres of water, with three islands totaling over 100 acres. The riparian habitat area, also known as the low-flow channel, was established in the existing San Jacinto River bed adjacent to the levee. This portion of the mitigation area was originally envisioned as a flow-through system, whereby 3 cubic feet per second (cfs) of water would make its way through a narrow low-flow channel in the riverbed into the wetlands, thus maintaining the wetland water level. A lake-inlet system was, however, constructed to redirect and convey the normal flows from the last mile of the San Jacinto River directly into the main body of the lake as part of the original Lake Elsinore Management Project. This restricts the availability of normal river water to flow into the wetlands. River water only flows over the weir into the Back Basin during storm events when the lake elevation exceeds 1262 feet AMSL.

  The potential reconfiguration of the Back Basin wetlands into treatment wetlands is under review as a partial offset to input of recycled water into the lake, if additional nutrient offsets are determined to be required. Biological removal via plant uptake can reduce essential plant nutrients, such as nitrate, ammonium, and phosphate. Long-term storage of phosphorus in the soil of a treatment wetland is also possible via phosphate precipitation with iron and aluminum oxides to from mineral compounds (Fe- and Al-phosphates).

  The treatment wetland concept includes conveyance of recycled water to the low-flow channel, lowering and lining the low-flow channel to allow conveyance of recycled water, establishing riparian habitat along the low-flow channel, the development of five shallow wetland cells with plug flow through the entire system, and construction of a visitor center.

- Back Basin Injection Project. The EVMWD is planning a conjunctive use project in the Back Basin to inject imported water for the purpose of augmenting water supply and providing dry-year storage in the Elsinore Groundwater Basin. The project consists of six new injection-extraction wells and associated pipelines and two monitoring wells. Production water during construction of the new wells and water flushed when the wells are turned on each year would be discharged to the existing Back Basin wetlands. Groundwater produced from these wells would supplement EVMWD's water supplies.

- Alberhill Recycled Water Master Plan. The EVMWD has developed a "Final Facilities Planning Report Alberhill Service Area Recycled Master Plan" for the provision of recycled water to the Alberhill area. Within the service area, several source of recycled water have been identified, including the District's existing Horsethief Canyon Water Reclamation Facility and the proposed Alberhill Water Reclamation Facility.[34]

- Deep Aquifer Recharge Project. The EVMWD is evaluating the feasibility of recharging the deep aquifer under Lake Elsinore (Elsinore Basin) using new surface recharge facilities in McVicker and Leach Canyons. The source of water for the recharge would be imported Metropolitan Water District of Southern California (MWD) water and natural runoff.

- Lakeland Village Water System Improvements Project. As part of District's "Distribution System Master Plan,"[35] several improvements to the Lakeland Village water system have been identified including replacement of the water supply pipeline along Adelfa Street from Grand Avenue to the Adelfa Reservoir located along Encina Drive, removal from service of the Cottrell Pump Station and Reservoir, replacement of the Adelfa Pump Station and Reservoir, replacement of the Encina Pump Station, and possible replacement of the Cottrell Reservoir. Operation of the existing water system will be maintained during construction of the proposed facilities.

In addition, with regards to Lake Elsinore, the District is conducting a destratification project involving the placement of axial flow (Garton) pumps into Lake Elsinore. The project seeks to prevent oxygen depletion in lake waters, reduce phosphorus loading in the water column, reduce algal densities, and result in better habitat for zooplankton and fish.

1.2.8 Development Projects in Reasonably Proximity

Substantial private-sector development is proposed on privately owned lands within and surrounding the EVMWD's service area. The following projects have been or are the subject to separate CEQA documentation prepared by the City of Lake Elsinore or County of Riverside.

- Alberhill Ranch Specific Plan. The 1,853-acre specific plan, bordered by Lake Street on the west and the I-15 (Corona) Freeway on the north, allows for the construction of nearly 4,000 dwelling units and other non-residential uses southeast of the proposed Northern (Lake) substation.

- Alberhill Ranch Country Club Specific Plan. A specific plan has been prepared and is being processed by the County for the 1,432-acre Pacific Clay property. If permitted, the project, located southeast of the proposed Northern (Lake) substation, would result in the introduction of approximately 1,200 dwelling units south of the I-15 (Corona) Freeway and east of Horsethief Canyon.

- East Lake Specific Plan. The Back Basin, intended for flood control and storage below elevation 1263.5-feet AMSL, is under the land-use jurisdiction of the City of Lake

[34]/ Elsinore Valley Municipal Water District (Kennedy/Jenks Consultants), Alberhill Recycled Water Master Plan – Mitigated Negative Declaration, October 2006.
[35]/ Elsinore Valley Municipal Water District (MWH), Distribution System Master Plan – Final Report, May 2002.

Elsinore. The Back Basin is shown on the City's land-use and zoning maps as the 3,000 acre "Liberty Founders East Lake Specific Plan" (ELSP), as adopted by the City in 1993 and amended in 1999. As approved, the ELSP would allow for the construction of over 5,000 dwelling units and an array of non-residential uses. Recent approved ELSP Amendment No. 6 (John Laing Homes) and ELSP Amendment No. 8 (LUMOS Communities) will result in the imminent development of new residential and non-residential uses wiithin the Back Basin area.

- La Laguna Estates Specific Plan. The 489 acre specific plan area is located west of the intersection of Grand Avenue and Lincoln Street. The project includes 164 acres of single-family use and 24 acres of multi-family use south of the proposed Northern 500 kV transmission line.

- Sycamore Creek Specific Plan. A segment of the proposed Northern 500 kV transmission line traverses or abuts the "Sycamore Creek Specific Plan" (SP No. 256/EIR No. 325), as amended. That 717 acre planning area is located to the west of the I-15 Freeway, south of Temescal Canyon Road, and north and south of Indian Truck Trail (Sycamore Creek Road). Anticipated development includes 1,764 dwelling units, 165.7-acres of open space, and 14.6 acres of commercial use. Construction within the specific plan area is ongoing.

- Tract Map Nos. 22626. With regards to the proposed Ortega Oaks powerhouse site, on April 20, 2004, the 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 powerhouse site into approximately 100 single-family residential lots. As a result, prior to the Applicant's receipt of all requisite permits and approvals, the Ortega Oaks property could transition from a vacant property to a tract of new single-family detached homes. Construction within this tract map area has not yet commenced.

1.3 Additional Considerations

1.3.1 Southern California Edison Company

On August 15, 2006, the CPUC issued an Assigned Commissioner's Ruling (ACR) addressing electric reliability needs in southern California. As indicated therein: "In light of recent events, I find it is necessary to take additional actions. The heat storm that hit California in July 2006, and the surprising growth of electricity demand throughout the State that had become evident even before the heat storm, have exposed certain vulnerabilities in the electric generation and transmission infrastructure that require immediate attention to assure reliability in 2007, particularly in parts of southern California. Accordingly. . .I direct Southern California Edison Company to expand its Air Conditioning Cycling Program [ACCP]. . .to target an additional 300 megawatts of ACCP program capacity for the summer of 2007 season. In addition, SCE should pursue the development and installation of up to 250 MW of black-start, dispatchable generation capacity within its service territory for summer 2007 operation."[36]

[36]/ *Op. Cit.*, Order Instituting Rulmaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program, Rulemaking 06-02-013, filed February 16, 2006, pp. 1-2.

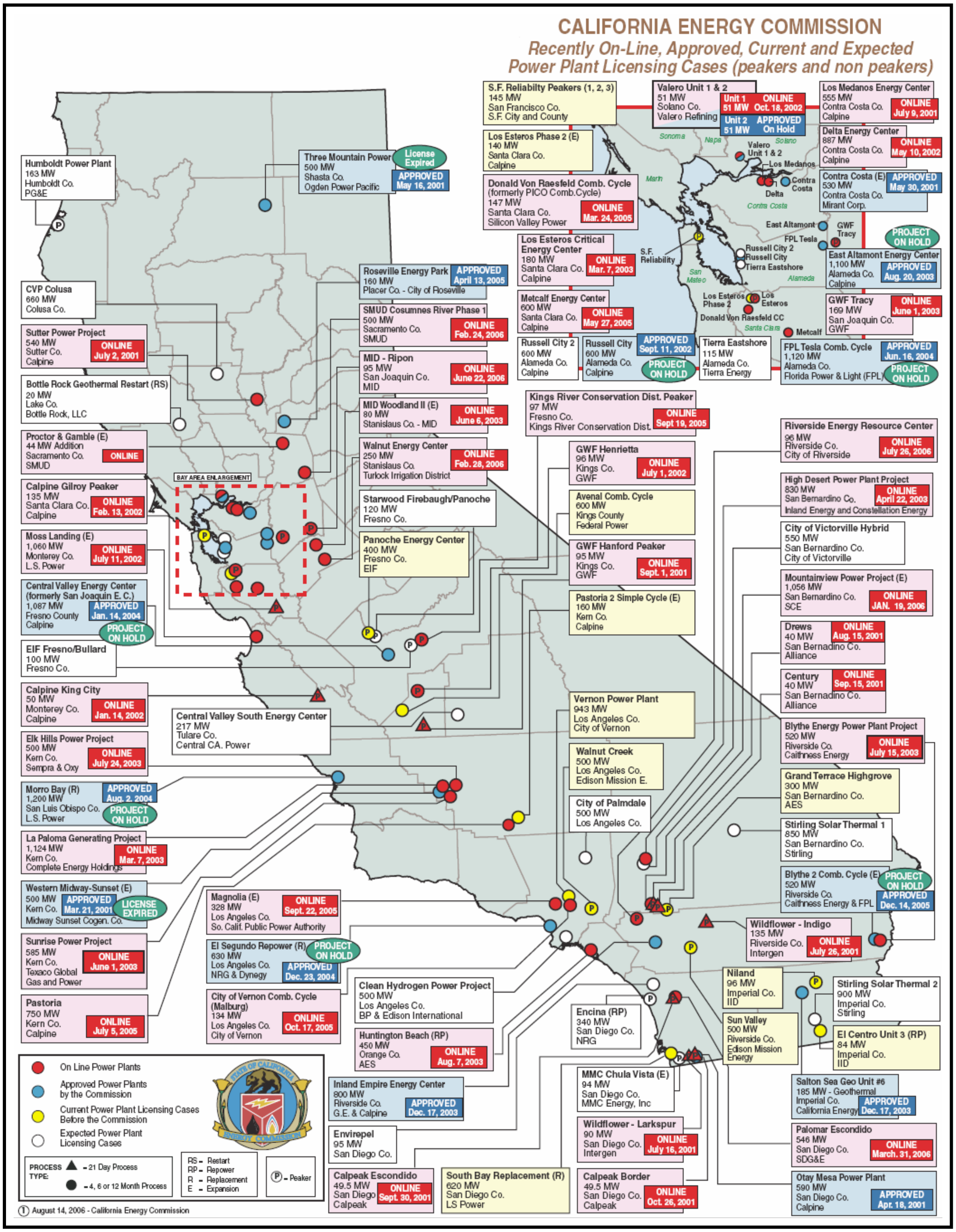


Figure 1-2 (1 of 2)

RECENT ON-LINE, APPROVED, CURRENT, AND EXPECTED PLANT LICENSING CASES (PEAKERS and NON-PEAKERS)

Source: California Energy Commission (August 14, 2006)

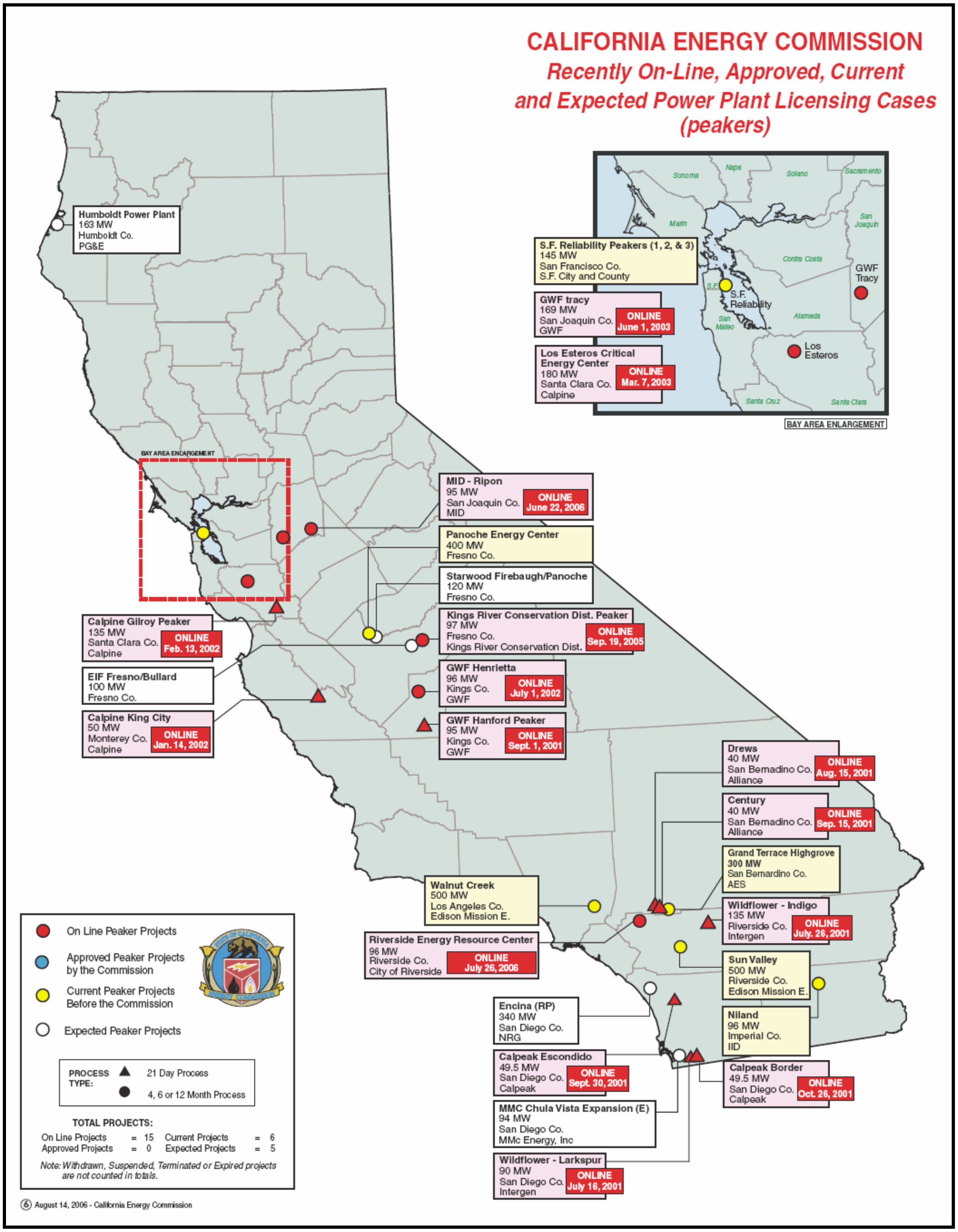


Figure 1-2 (2 of 2)
RECENT ON-LINE, APPROVED, CURRENT, AND EXPECTED PLANT LICENSING CASES (PEAKERS)
Source: California Energy Commission (August 14, 2006)

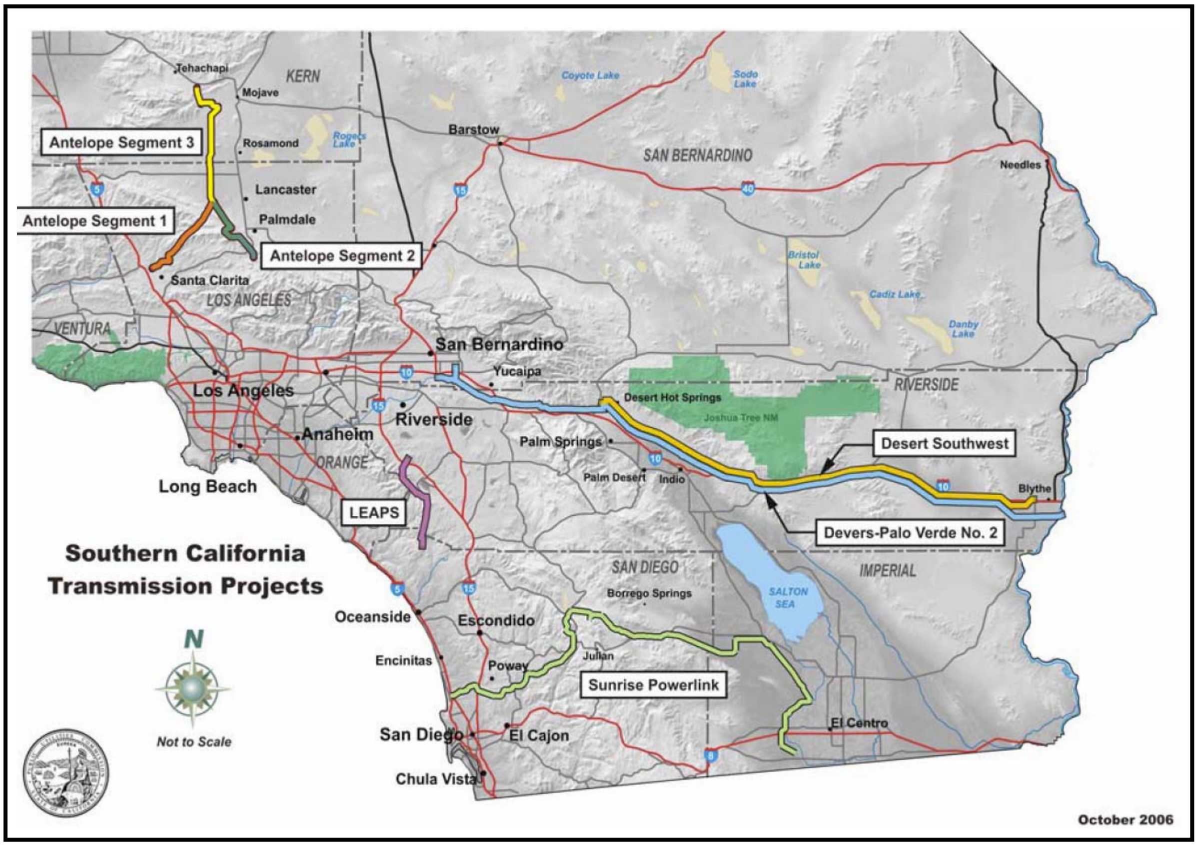
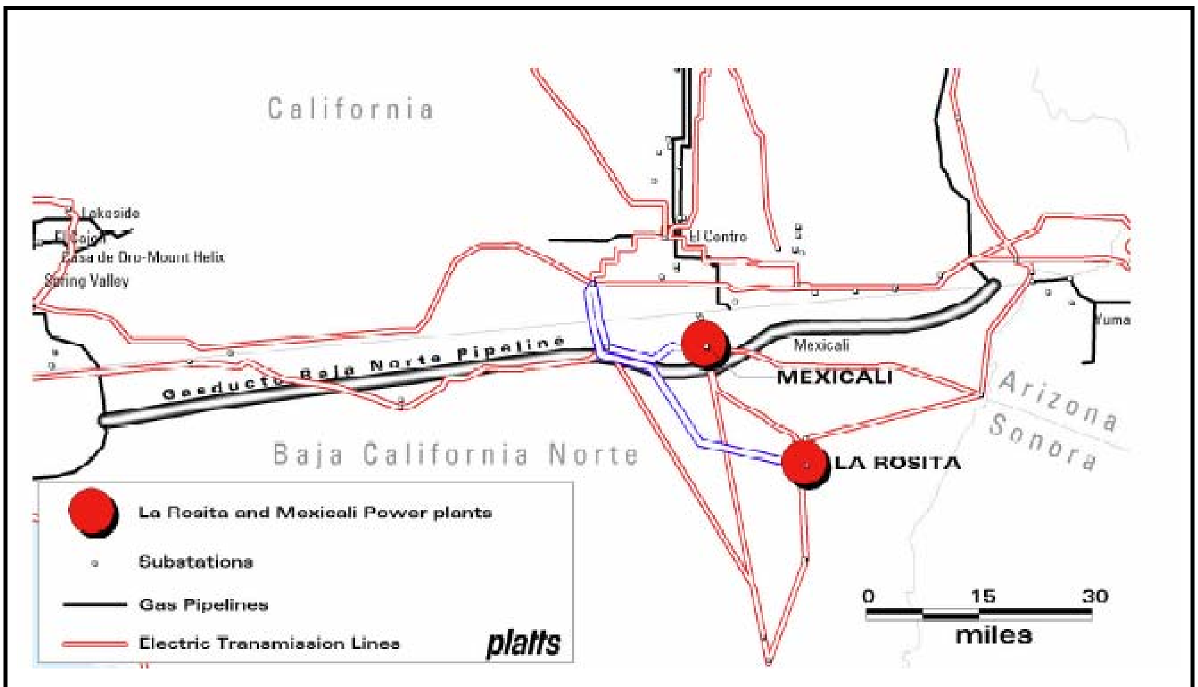


Figure 1-3
SOUTHERN CALIFORNIA TRANSMISSION PROJECTS
Source: California Public Utilities Commission

Figure 1-4
LA ROSITA AND TERMOELÉCTRICA DE MEXICALI POWER PLANTS
Source: Platts Research and Consulting



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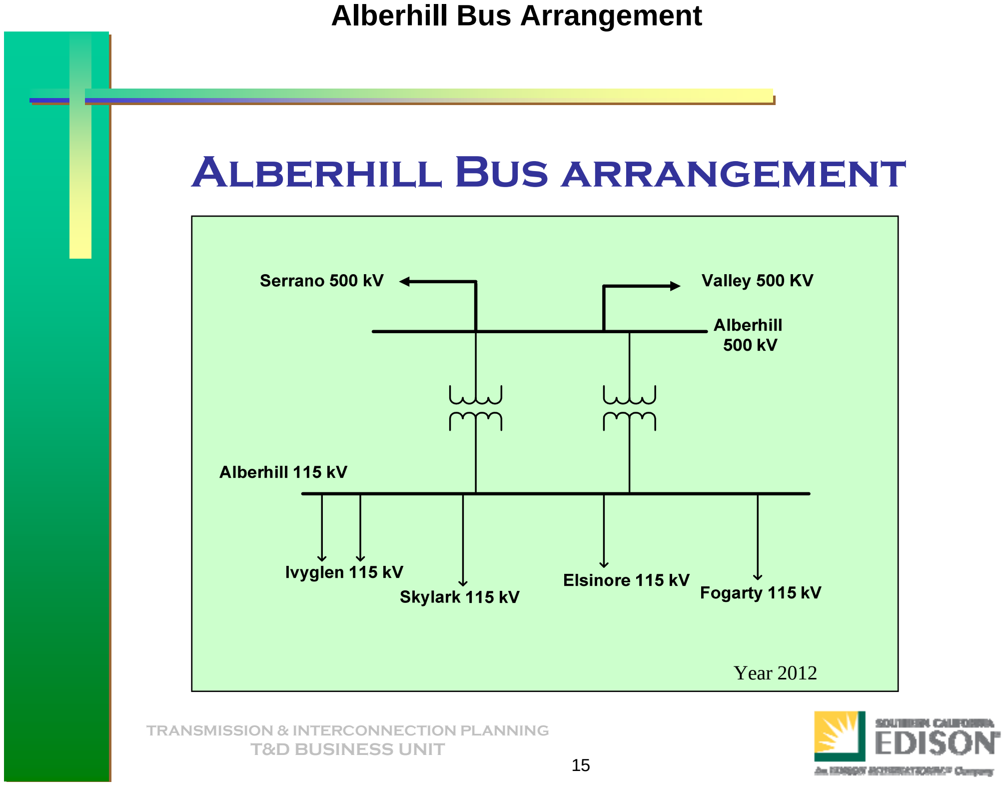
The ACE also indicated that SCE should pursue development of not more than five non-RFO generation units. In addition to the Etiwanda Peaker Project (Rancho Cucamanga), is proposing to construct and operate the following combustion turbine electric generation peaking units, along with an emergency black-start generator: (1) Mira Loma Project (13568B Milliken Avenue, Ontario); (2) Center Project (10639 Firestone Boulevard, Norwalk); and (3) Barre Project (10670 Dale Avenue, Stanton).

Futher, SCE has indicated that it is exploring the development of distribution upgrades in the project area.[37] Objectives of this project include (1) providing added capacity to serve load growth, (2) transfer approximately 300 MW from the Valley substation by 2012, and (3) serve the Lake Elsinore area and western Riverside County. The scope includes constructing a new 500/115 kV substation southwest of the existing Valley substation and looping in the existing Valley – Serrano 500 kV transmission line. The company identified 2012 as the need date for this facility. The proposed bus arrangement appears in Figure 1- 5 (Alberhill Bus Arrangement).

Figure 1-5
Alberhill Bus Arrangement



Source: SCE

The company has indicated that it is exploring the feasibility of sitting this substation at or near the Applicant's proposed alternative Lake Switchyard site. See Chapter 6, Alternative 5 for details.

1.3.2 San Diego Gas & Electric Company

[37]/ SCE, 2008-2017 transmission Expansion Plan Findings and Proposed Solutions, Main Transmission System, 3rd Stakeholders Meeting, July 20, 2007.

Stirling Energy Company (SES) has entered into a contract with SDG&E to provide between 300-900 MW of solar power. SES and SDG&E have agreed to an initial 20-year contract to purchase all the output from a 300 MW solar power plant in Imperial County. SDG&E has options on two future phases that could add an additional 600 MW of additional renewable energy. If all options are developed, the SES facility would consist of approximately 36,000 solar dishes spaced over nine square miles.[38]

As reported by the CPUC: "SDG&E applied on May 11, 2007 for [California Public Utilities] Commission approval of contracts for 131 MW of new Combustion Turbines (CTs) in San Diego with on-line dates in 2008. SDG&E is seeking [California Public Utilities] Commission approval of these contracts in September 2007, that is, before the Commission is scheduled to decide whether to grant a CPCN for Sunrise. SDG&E filed, also on May 11, Advice Letter 1896-E seeking to expand its contract capacity with EnerNOC – an aggregator of demand response and distributed generation resources – to 50 MW effective in 2008."[39]

1.3.3 La Rosita and Termoeléctrica de Mexicali Power Plants

A number of major power plants are either being built or have recently been completed in Baja California (Mexico). As illustrated in Figure 1-4 (La Rosita and Termoeléctrica de Mexicali Power Plants), those generation facilities include: Termoeléctrica de Mexicali's (a subsidiary of Sempra Energy Resources) 600 MW plant in Mexicali (commenced operations in June 2003) and Intergen Aztec Energy's (Intergen) 750 MW La Rosita Power Project (LRPP), and Intergen's 310 MW La Rosita Expansion Project (LRES). Each of these facilities are combined-cycle combustion turbine power plants fueled by natural gas from the Baja North Pipeline, permitted by the Commission and the BLM. Generation in this region is imported into the United States for U.S. markets flows through the Southwest Power Link (SWPL) through SDG&E's Miguel Substation. As indicated by the Border Power Plant Working Group, there are a total of 22 plants slated for the border region.[40]

[38]/ San Diego Gas & Electric Company, Sunrise Powerlink Project - Proponent's Environmental Assessment, August 4, 2006, p. 11-2.

[39]/ *Op. Cit*., A.06-08-010 – Report on the Sunrise Powerlink, San Diego Gas & Electric Company, Phase 1 Direct Testimony, Volume 1 of 5 (Kevin Woodruff), p. ES-2.

[40]/ Barron, Jeffrey, Evolving Impact of Environmental Laws on Cross-Border Power between Mexico and the United States, Platts Research and Consulting, International Association for Energy Economics, October 20, 2003, p. 1.

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