CALIFORNIA
ENERGY
COMMISSION

Preliminary Electricity and Natural Gas Infrastructure Assumptions

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Table of Contents

Executive Summary

The *Preliminary Electricity and Natural Gas Infrastructure Assessment* report is intended to itemize the electricity generation, electricity transmission and natural gas infrastructure changes in California and neighboring regions during the past three years, assess the current electricity market conditions, and present a preliminary ten year "resource plan." This is the first in a series of draft reports that the Energy Commission staff are preparing, under the direction of the Ad Hoc Integrated Energy Policy Report Committee, to support the development of the *Integrated Energy Policy Report* (IEPR). Chapter 568 of the Statutes of 2002 (formerly SB 1389) mandates that the Energy Commission present the IEPR to the California Legislature in Fall 2003.

The Ad Hoc Integrated Energy Policy Report Committee will conduct a workshop on February 25-26, 2003, to receive public comments on this and several other staff draft reports. The staff draft reports and an agenda for the workshop were published on February 11, 2003. Public comments will be instrumental in improving the Energy Commission staff analysis for evaluating California's energy reliability concerns.

Highlights

Over the coming decade, new power plants will be needed in California, the western states, and Mexico. The number and location of these new power plants will impact how the remainder of our energy infrastructure is developed, specifically the need for new/upgraded transmission lines and new/upgraded natural gas pipelines, storage facilities and potential LNG import terminals. Each of these areas of our energy infrastructure (electricity generation, electricity transmission, and natural gas) cannot be analyzed in isolation – rather, they must be considered in an integrated fashion. Hence, this report includes all aspects of California's energy infrastructure, and subsequent analysis will consider how changes in one area affect the other areas.

Electricity Generation Infrastructure

The Energy Commission staff concludes that sufficient electricity generation capacity has been added in the west to assure reliable, competitively priced electricity through 2005, based on analysis of electricity generation additions in the Western Electricity Coordinating Council area from 2000 to 2003. Regulatory and economic uncertainies, however, will likely delay the construction of some generation capacity previously anticipated in the 2004 to 2006 timeframe. While the Energy Commission staff believe that there will be a net increase in capacity during this period, the increase may not be keep up with the increase in electricity demand, causing reserve margins to fall. Finally, the period of 2007 though 2013 presents considerable uncertainties regarding which power plants may be added or retired. Therefore, the Energy Commission staff has assembled a working "resource plan" for 2007 through 2013 to serve as a baseline assumption for the electricity generation that will be added during this time. Because such a "resource plan" is highly speculative, the Energy Commission staff will develop alternative resource assumptions and development scenarios and analyze the impacts of each of these on the state's energy markets. The Energy Commission staff invites comment on the appropriate assumptions and scenarios that it should consider in future modeling efforts.

Electricity Transmission Infrastructure

California's investor-owned utilities plan, develop, and complete electricity transmission projects to address local reliability needs within their respective service territories. These actions are documented in each utility's annually updated, five-year planning process. In this report, the Energy Commission staff includes 137 investor-owned utility projects, taken from these plans, in various stages of development in California – the vast majority of which address local reliability needs. By contrast, bulk transmission system additions, those that would allow large amounts of power to move from one region to another, have not kept pace with recent electricity generation resource additions. Currently, only two such projects are before the California Public Utilities Commission for permitting consideration, and another project is soon expected to file an application for a Certificate of Public Convenience and Necessity. Additionally, on December 19, 2002, the proposed Valley-Rainbow project was denied a Certificate of Public Convenience and Necessity by the California Public Utilities Commission; however, San Diego Gas and Electric Company filed an appeal to that decision on January 23, 2003. The lack of sufficient bulk electricity transmission capacity makes it difficult for grid operators to fully capitalize on the system-wide economic benefits of recent resource additions in and around California.

Natural Gas Infrastructure

Since the 2000-2001 energy crisis, numerous natural gas pipeline and storage projects have come on stream to meet California's, and its neighbors', growing demand for natural gas. These facilities have added more than two billion cubic feet of additional transfer capacity from throughout the western states and within California. Moreover, two other pipeline projects are scheduled to begin operation during the next two years, adding 1.6 billion cubic feet of additional capacity. The Energy Commission staff's analysis indicates that the key determinant for natural gas demand growth, and the resultant need and location of additional natural gas infrastructure, is growth in electricity demand, as natural gas is the fuel of choice for most new power plant projects. This report does not offer any conclusions regarding the need for additional natural gas infrastructure because the type, size and location will be determined, in large part, by the location of new power plants. In the coming months, the Energy Commission staff will conduct sensitivity analyses, coordinated with the analysis described in the electricity generation section.

Chapter 1 Introduction

The purpose of this draft report is to itemize the electricity generation changes in California and neighboring regions during the past three years, assess current electricity market conditions, and present a preliminary ten-year "resource plan." The preliminary resource plan is a set of assumed generation capacity additions, retirements and transmission upgrades in the West from 2004 to 2013. Energy Commission staff do not offer this as a "most likely" set of changes to the region's electricity infrastructure, but merely as one plausible and well-reasoned set of assumptions.

This preliminary resource plan is proposed as a benchmark for evaluating the adequacy of the state's generation and transmission systems, and implications to the natural gas infrastructure needs. The Energy Commission staff also intends to evaluate the system sensitivity to changes in both the resources added (and retired) during the next decade and other significant variables (e.g., demand growth, hydro conditions). This is the first of the building blocks necessary for evaluating the uncertainty that will affect actual infrastructure developments in the next several years and to assess the risks associated with long-term resource adequacy concerns.

The Energy Commission staff uses MARKETSYM™ as its principal assessment tool for the electricity market. The MARKETSYMTM™ software application, licensed by Henwood Energy Services, Inc., simulates the operation of the Western Electricity Coordinating Council (WECC) electricity market on an hourly basis, using information on the operating characteristics of individual power plants and the transmission grid, fuel prices, and the bidding behavior of power plant operators. MARKETSYM™ produces hourly estimates of plant output, fuel use, and emissions, as well as transmission line usage, congestion costs and wholesale prices.

For the natural gas analysis, the North American Regional Gas (NARG) model is the primary modeling tool used by the Energy Commission staff. The projections included in this report are drawn from the Energy Commission staff's *Natural Gas Supply and Infrastructure Assessment* (Publication No. 700-02-006F), which was published in December 2002. The key assumptions in that assessment included how much new electricity generation would be constructed in the Western United States between 2002 and 2012, and where those facilities would connect to natural gas pipelines.

This report is organized into the following chapters:

- Chapter 1 – Introduction
- Chapter 2 – Electricity Generation Infrastructure
- Chapter 3 – Electricity Transmission Infrastructure
- Chapter 4 – Natural Gas Infrastructure

The flow of the report is based on the assumption that electricity demand is the driving force behind future electricity generation, electricity transmission, and natural gas improvements and additions. The need for additional electricity supplies determines when, and where, new electricity generation infrastructure will be built. The location of the new electricity generation infrastructure then dictates whether new transmission projects must be undertaken to support it, or if the new power plant relieves current electricity transmission constraints. Finally, the amount and location of electricity generation will determine how much natural gas infrastructure must be added to support it, as natural gas has become the marginal fuel source for new power plants in the United States.

The second chapter, Electricity Generation Infrastructure, begins with an assessment of the changes in generation resource adequacy in California and the remainder of the area supported by the WECC from 2000 to 2003. The focus then shifts to the magnitude and likely impact of recent delays and cancellations of permitted electricity generation projects, and how this might affect reserve margins for the timeframe of 2004 to 2006. Uncertainties related to changes in resource assumptions during 2007 to 2013 are discussed in detail.

Chapter 3, Electricity Transmission Infrastructure, presents the status of major projects likely to go into service in the next ten years, the local reliability projects for the three investor-owned utilities in California, as well as some municipal utility projects in the state. Also covered are other economic projects, projects to support renewable electricity facilities, and relevant out-of-state projects.

The final chapter, Natural Gas Infrastructure, provides details about the interstate and intrastate natural gas pipeline projects, as well as the in-state natural gas storage projects, completed since 2001. This chapter goes on further to discuss projects either under construction or in the permitting process.

Chapter 2
Electricity Generation Infrastructure

The past three years have witnessed a substantial increase in electrical generation capacity in California and the remainder of the West. We have moved from a condition of shortage – with price spikes, voluntary load curtailments, and rotating outages – to one of sufficiency if not, for the moment, surplus. The purpose of this chapter is to itemize the recent changes in capacity in California and neighboring regions during the past three years, assess current electricity market conditions, and present a ten-year benchmark "resource plan," a set of capacity additions, retirements and transmission upgrades in the West during 2004 – 2013. After public review, the amended plan will be used in computer simulations of the electricity market in the West for the period 2003 – 2013; the results of these simulations will be used as inputs in analysis done by Energy Commission staff during the coming months for the ***Integrated Energy Policy Report.***

This report begins with an assessment of the changes in generation resource adequacy in California and the remainder of the area supported by the Western Electricity Coordinating Council (WECC) during 2000 – 2003. Since the adequacy of the generation infrastructure is influenced by changes in the demand for electricity, changes in both generating capacity and electricity consumption are discussed. Current conditions in the West's wholesale electricity markets are then assessed. A summary of wholesale spot market prices during the past eighteen months contributes to the conclusion that enough capacity has been added in the west to assure reliability and competitively-priced electricity during 2003 – 2005. We also evaluate the magnitude and likely impact of recent delays and cancellations of permitted projects. A discussion of likely changes in generation capacity and electricity demand in the West during 2004 – 2006 then indicates that reserve margins are apt to fall during this period.

Uncertainties surrounding changes in resource adequacy during 2007 – 2013 are then discussed in detail. These relate not only to the addition and retirement of generation capacity, but also to transmission system upgrades that will or may be necessary to deliver energy from generation facilities to load centers. We then present a "baseline" set of power plant additions, retirements and transmission upgrades for discussion and comment. Finally, we offer a set of scenarios for analysis in the IEPR. These scenarios are chosen to assess resource adequacy (including electric transmission and natural gas pipelines) under a set of adverse conditions, and test the sensitivity of our baseline results to such variables as the amounts of capacity added or retired, and economic and hydro conditions.

Changes in Supply and Demand, 2000-2003

California

The energy crisis of 2000 – 2001 led to a reduction in the amount of electricity consumed in California. As prices increased and threats to the reliability of the system led to calls for conservation, Californians responded with unprecedented reductions in electricity consumption. While some conservation will ebb as the crisis recedes into the past, a share of it will persist, a result of the adoption of energy-efficient appliances and demand reduction measures. Changes in the demand for electricity in California during 2000 – 2003 are discussed in detail in staff draft report *California Energy Demand 2003-2013 Forecast.*

The high prices of 2000 – 2001 also encouraged the construction of new power plants and the maintenance of older, existing facilities (see **Table 2-1**). Almost 6,000 MW of new capacity have come on line in the past two and one-half years; an additional 3,300 MW are anticipated prior to summer 2003 (for a detailed list of additions, see **Appendix A, Table A-1**).

Table 2-1
Capacity Additions and Retirements
California, 2000 – 2003 (MW)

Calendar Year	Additions	Retirements
2000	59	285
2001	2,329	396
2002	2,970	423
2003*	4,038	964
Total	9,396	2,068
Net Additions	7,328	

*Includes all plants expected to be on-line or retired by July, 2003

While these additions have been somewhat offset by the retirement of several aging power plants, and others that do not plan to install the emission controls that are required by law to continue operation, the net effect of changes in supply and demand in California during 1999 – 2003 has been a substantial increase in the state's reserve margin (see **Table 2-2**). This has occurred despite the cancellation or delay of numerous additional projects which have sought or received permits (see **page 6**).

Table 2-2
Net Capacity Additions *vs.* Peak Load Growth
California, 1999 – 2003 (MW)

	1999	2000	2001	2002	2003
Peak Load	52,016	52,699	48,640	50,773	51,956
Net Additions (Cumulative)*		-24	104	2,714	7,328
Total Change in Reserves					7,388

* As of July 1st of each year

Remainder of WECC

The California electricity grid is part of an interconnected system that encompasses eleven western states, British Columbia and Alberta, and Baja California. During the 1990s, California met nearly 20 percent of its electricity needs with imports. Excess capacity in the Southwest (primarily coal-fired) and, during the spring and summer, surplus hydroelectric energy in the Northwest, has been relied upon to reduce the need for capacity in California.

One of the proximate causes of the energy crisis of 2000 – 2001 was a gradual deterioration of the supply – demand conditions during the 1990s in both the Northwest and Southwest. Despite substantial growth in the demand for electricity during the decade (2.1 percent annually in the Northwest, 3.8 percent in the Southwest[1]), little new generation capacity was added; both areas relied on existing surpluses. By 2000, the export potential of these regions was well below what California needed to offset its own declining reserve margin.

Reserve margins have increased substantially in the Northwest and Southwest since 2000, as **Table 2-3** indicates. Almost 8,700 MW of capacity have been added beyond peak load growth in the last four years. These values do not include additional capacity in Baja California, where 748 MW came on line in 2000 – 2002. An additional 1,500 MW is anticipated during the first half of 2003 (for a complete list of the new capacity assumed to come on line in these regions during January – July 2003, see **Appendix A, Table A-2**).

While a substantial amount of new capacity has been built in the Northwest, the increase in its reserve margin has largely been a result of a reduction in demand. The coincident, weather-adjusted peak load for the Northwest Power Pool in December, 2002 was 51,600 MW, 2,100 MW below what had been forecasted a year earlier and 7,400 MW below the all-time peak in 1998.[2] Electricity demand in the Northwest is at mid-1990's levels.

The economic slowdown of the past two years is a contributing factor to reduced demand in the Northwest, as are the higher retail prices necessitated by the costs incurred during the energy crisis. Of key importance was the effect of these price increases on the competitiveness of the Northwest's aluminum industry, which, prior to 2000, constituted six percent of the region's peak demand for electricity. At the height of the crisis, the Bonneville Power Administration (BPA) repurchased the electricity entitlements of aluminum smelters at prices below those that BPA would have had to pay on the spot market to meet this demand. Subsequent increases in BPA's rates (forty-six percent), in conjunction with depressed prices in the world aluminum market, have led to the closure of all but three of the smelters in the Northwest (only one of which is operating at full capacity), and a 2,400 MW reduction in demand.

Table 2-3
Net Capacity Additions *vs.* Peak Load Growth
Northwest and Southwest, 1999 – 2003 (MW)

	1999	2000	2001	2002	2003*
Peak Load					
Southwest	19,954	21,724	23,360	24,528	25,754
Northwest**	47,527	49,686	42,782	48,425	49,394
Increase 1999-2003					7,667
Net Additions (cumulative)* **					
Southwest		456	1,723	2,816	8,741
Northwest		188	2,662	5,343	7,624
Increase 1999-2003					16,365
Total Change in Reserves					**8,698**

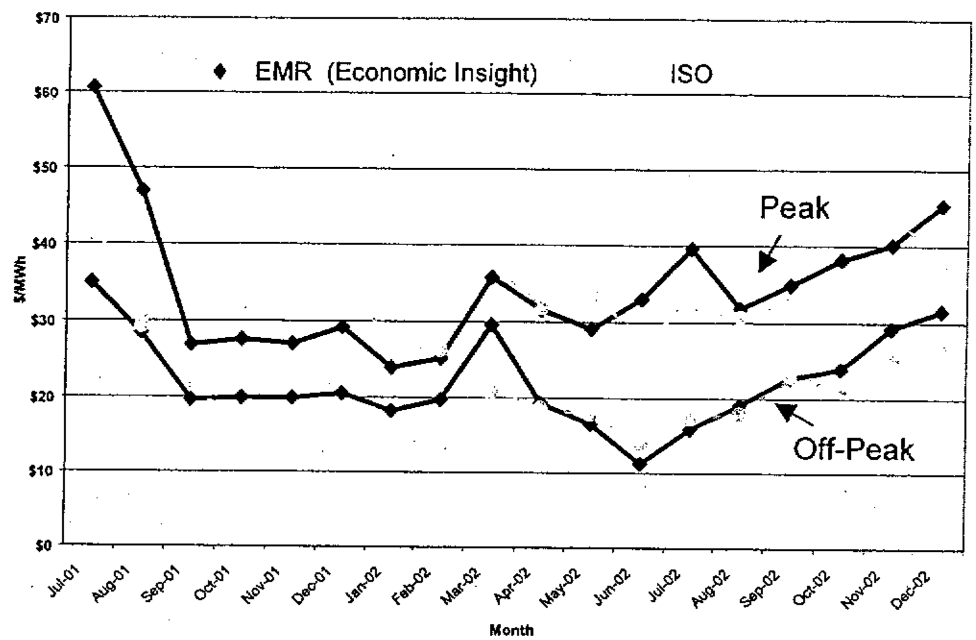
* Forecasted
** Summer peak
*** For twelve months preceding July 1st of each year

Demand growth in the Southwest has probably slowed somewhat during the past two years, but the region's reserve margins have largely increased due to the construction of several large power plants.

Current Conditions

Improvements in the supply-demand balance in California and throughout the West have contributed to a substantial reduction in spot market and forward prices for electricity (see **Figure 2-1**). Increases in these prices during the past three months are not due to shortages in electricity generation capacity and/or the concomitant ability of generators to manipulate wholesale markets, but higher prices for natural gas. The causes of the recent run-up in natural gas prices are discussed in Chapter 4 of this report.

Figure 2-1
Monthly Average Prices, ISO Imbalance Market and Economic Insight Spot Market Survey, July 2001 – December 2002



The financial consequences of "price spikes" in wholesale spot markets that might occur are far less today than two years ago. **Table 2-4** illustrates that a significant share of the energy needed during peak hours by the investor-owned utilities (IOU) has already been procured.

Table 2-4
Residual Net Short Position of IOUs during Peak Hour 2003 and 2004 (MW)

	2003	2004
URG Thermal	5,291	5,291
IOU Hydro (derated)	5,000	5,000
QF (derated)	5,573	5,573
Must-take DWR Contracts	7,066	7,696
Other Contracts*	1,075	1,075
Total Firm Capacity	**24,005**	**24,635**
DWR Dispatchable	5,934	5,133
Total Capacity	**29,939**	**29,768**
Coincident Peak Load	34,050	34,731
Residual Net Short	**4,111**	**4,963**

*Does not include contracts signed as part of interim procurement proceedings
Source: Energy Commission Staff

These figures do not include additional contracts that have been or may be entered into as part of California Public Utilities Commission (CPUC) procurement proceedings, which will reduce spot market exposure below the levels indicated. They also represent the peak hour of the year; IOU spot market exposure can be expected to be less than 2000 MW during all but a handful of hours during the next two years.

California ratepayers will also have far less exposure to spikes in the spot markets for natural gas. Only a small share of the must-take Department of Water Resources (DWR) contracts are tolling agreements, the IOUs have the right to buy (and hedge) the natural gas needed for most of the latter. They also have the option to buy the natural gas for many of the dispatchable DWR contracts.

Construction Delays, Cancellations, and Debt

The past eighteen months have seen the delay or cancellation of dozens of proposed power plants in California and the western United States (see **Table 2-5**). These constitute tens of thousands of megawatts of capacity and have given rise to concerns that supply will be insufficient to meet demand by as early as mid-decade. In California alone, more than 4,000 MW of permitted capacity has been cancelled or delayed:

Table 2-5
Delayed and Cancelled Plants (MW)

Projects Delayed or Cancelled that were:	California	Southwest	Northwest	Rocky Mountains	Baja California	WECC Total
Under Construction	2,321	2,350	1,145	0	0	**5,816**
Permitted	1,944	2,041	5,178	880	0	**10,043**
Under Review	4,335	8,781	6,108	66	500	**19,790**
Announced	7,929	3,860	2,004	275	640	**14,708**
Total	**16,529**	**17,032**	**14,435**	**1,221**	**1,140**	**50,357**

The large number of cancellations has been attributed in part to the deterioration of the balance sheets of the major power plant developers. While their stock prices have plummeted during the past year, they have accumulated a large amount of debt, much of it short-term (due in 2003 and early 2004). Debt service has been rendered difficult by the collapse of electricity prices since early 2001, all the more so as the unrealistically high revenue streams projected from newly built plants were often leveraged: used to debt-finance additional projects which have yet to be completed. This has restricted developers' access to both the additional equity capital and debt needed to complete construction.

Given the improvement in the supply-demand balance in both California and the remainder of the West, these delays and cancellations do not pose an immediate threat to the reliable delivery of electricity in the West. Current supplies, and those conservatively anticipated to come on line by the summer of 2003, are sufficient, even under 1-in-10 year peak summer temperatures, to meet demand during 2003 and 2004. Supply adequacy also means that Californians are less likely to face high wholesale prices during periods of peak demand.

While Energy Commission staff recognizes the role that credit issues can play in delaying projects under development and securing the capital needed to finance additional construction, staff believes that low forward prices and regulatory uncertainty are the primary impediments to the completion of unfinished projects. Staff does not believe that the debt overhang poses a threat to the development of new generation as it is needed during the next three to five years. There is no reason to believe that the capacity market will not 'shake out,' with new sources of capital stepping forward to reliquify the market when it is profitable to do so. This will take the form of financially healthy players, perhaps new to investment in the power generation sector, buying up existing projects at 'fire sale' prices or financing new ones. This is slowly beginning to happen already. An acceleration of this process will take place when expected revenue streams from new projects are both high enough and stable enough to attract financing.

Projections, 2004 – 2006

While Energy Commission staff have carefully monitored the progress of development projects in California and the remainder of the West, projections of infrastructure development during 2004 – 2006 must acknowledge a great deal of uncertainty. Decisions regarding capacity additions, retirements and transmission upgrades are, more often than not, being delayed pending developments in both the electricity and natural gas markets and various regulatory arenas.

Futures prices for 2004 do not appear to be sufficient to encourage the rapid completion of projects under construction. As of this writing, forward prices for 2004 delivery yield sparkspreads[3] in the $12 - $15 range, albeit in a very illiquid market. At the high end, this is enough to allow for debt service and an adequate return to equity in a stable setting, but several factors mitigate against new capacity coming on-line quickly.

First, as noted above, a substantial share of the energy needed to meet loads has already been procured. During shoulder and off-peak hours, the IOUs are frequently long, indicating that new baseload capacity may have a limited market in California for its output in the near-term. The requirements of the renewable portfolio standard (RPS), as well as contracts entered into under CPUC procurement proceedings during 2002 and 2003, will further reduce the market for non-renewable baseload generation in the state. These facts, combined with the presence of excess capacity, indicate that, in the absence of a contract for its output, a new combined cycle will be hard pressed to operate at the capacity factor necessary to make current prices attractive.

Second, regulatory uncertainty continues to unsettle both developers and the financial markets to which they turn for capital. Questions related to market price caps, resource adequacy requirements, transmission interconnection and pricing, possible State assumption of partial responsibility for new generation, CPUC activity with respect to procurement and reasonableness determination, *etc*, remain unanswered. In the absence of very high spot market prices, these uncertainties must be resolved before a substantial amount of new capacity is brought to the market.

California

Electricity Demand

The Energy Commission's Demand Analysis Office has recently completed a forecast of electricity demand in California for 2003 – 2013. This forecast is discussed in detail in a companion staff report.

Additions and Retirements

Staff feels that new construction in California may be limited to a handful of plants during 2004 – 2006. **Table 2-6** lists the plants that are to be added or retired in the staff's simulations of the WECC, yielding a net increase in thermal capacity of 1126 MW. This is roughly 40 percent of the load growth anticipated during this period.

The Calpine facilities are two of three for which the state has "step in" rights, which allow it to complete construction of the facilities and bring them on line if the developer fails to meet construction milestones. Staff does not assume the state's agreement with Calpine assures their completion. Both plants are situated in Local Reliability Areas (LRAs) and may thus generate a larger revenue stream than similar plants located elsewhere in the state. They may be completed by Calpine, the state, or appear in the guise of other plants in these areas that have been proposed for development (Palomar, East Altamont). The San Francisco plants are assumed to be completed as they are a first step toward facilitating the shutdown of the aging Hunters Point facility.

The remaining gas-fired plants assumed to be completed are projects for which applications have been submitted to the Energy Commission by municipal utilities. Many of these utilities are "short on peak" or are replacing facilities that are being retired. Each of these utilities is building primarily to meet load-serving obligations rather than to sell the power on the spot market. As such, completion risk is low, with uncertainties about capitalization and revenue being minimized.

The baseline assumes the retirement of the coal-fired Mohave units in Laughlin, Nevada. In order for the facility to remain in operation, it will be necessary to install emission controls and resolve issues related to water source and fuel delivery. As estimates of the financial cost of the necessary upgrades exceed $1 billion; prudence dictates that we assume the plant ceases operation at the end of 2005.

Table 2-6
Additions and Retirements
California, 2004 – 2006*

Unit Name	Max Rating (MW)	Installation Date	Owner
Additions			
Valley CC	520	Oct-03	LADWP
Salton Sea #6	300	Dec-03	Cal Energy
Vernon GT	135	Apr-04	Vernon
Walnut CC	250	Dec-04	TID
Kings River Peaker	50	Dec-04	KRWA
San Francisco Peakers	150	Jan-05	SF
Magnolia CC	250	Mar-05	Burbank
Cosumnes	547	Mar-05	SMUD
Pico	147	May-05	Santa Clara
Metcalf	602	Jun-05	Calpine
MID Cogen	80	Dec-05	MID
Otay Mesa	580	Dec-05	Calpine
Total MW	3,611		
Retirements			
Grayson GT	18	Jul-03	Glendale
Haynes 4	222	Nov-03	LADWP
Alamitos GT	147	Dec-03	AES
Etiwanda 5	141	Dec-03	Reliant
Olive 3 & 4	56	Jan-04	Burbank
Magnolia GT	22	Jan-04	Burbank
Valley 1- 4	513	Apr-04	LADWP
Haynes 3	222	Sep-04	LADWP
Mohave	915	Dec-05	SCE/LADWP
Hunters Point 1 & 4	219	Jan-06	Mirant
Total MW	2,475		

* During 12 months prior to July 1st of each year

Salton Sea #6 is a geothermal facility located in the Imperial Irrigation District (IID) service area. The owners have signed a twenty-year contract with IID to deliver 170 MW.

Several facilities are retired pursuant to the South Coast Air Quality Management District's (AQMD) Rule 2009. In compliance with Air District regulation, these plants, having failed to install required emission controls, are expected to shut down. While the possibility remains that some will install controls prior to their shutdown dates, or do so at a later date and resume operation, a conservative estimate dictates that we assume the capacity is unavailable. The remaining retirements assumed during this period include four units in the San Diego area that have lost their lease.

Energy Commission staff acknowledge that much of California's generation capacity consists of aging and increasingly inefficient plants, and that a share of these will certainly be retired by the end of the decade. This issue is discussed in greater detail in a subsequent section of this chapter.

RPS Additions

The baseline simulations assume that the new renewable capacity needed to meet the RPS targets through 2013 is brought on line in a timely fashion. Energy Commission staff proposes adding capacity during 2003 – 2006 (see **Table 2-7**). Actual build-outs will depend on the results of ongoing proceedings and solicitations.

Table 2-7
Renewable Capacity Added to Meet RPS Targets
2003-2006

Technology	Total MW 2003 – 2006	Capacity Factor
Biofuels	129	87%
Geothermal	115	87%
Wind	767	33% - 38%

Additions during 2003 – 2006 are limited somewhat as existing renewable capacity is assumed to satisfy a share the purchase requirements that follow from the RPS. A majority of the geothermal capacity is assumed to be located in the Imperial Irrigation District (IID) service area. A majority of the wind capacity is assumed to be located south of Path 15, and has a higher capacity factor than wind located north of Path 15.

Transmission Upgrades

The simulation model used by Energy Commission staff to assess market conditions divides California into nine transmission areas (see **Appendix A, Figure A-1**). Four upgrades that affect the transfer capability between these areas are assumed to occur during 2004 – 2006. The transfer capability from SCE to ZP26 is increased by 400 MW in October 2003. Path 15 (connecting NP15 and ZP26) is upgraded in January 2005 (an additional 1500 MW from south to north, 1135 MW from north to south) as of January 2005. Upgrade of the Jefferson-Martin line increases the ability to import energy into San Francisco from 700 to 1100 MW as of January 2006. Finally, a Miguel – Mission upgrade increases the transfer capability from Miguel into San Diego by 560 MW in January 2005.

Remainder of WECC

Electricity Demand

Staff uses forecasts of out-of-state demand provided by Henwood Energy Services, Inc. The values in **Table 2-8** reflect the vendor's 2002 forecast of peak demand growth for the other regions of the WECC.[4]

Table 2-8
Annual Peak Demand Growth
(Summer), 2003 – 2006

	2003-4	2004-5	2005-6	2003-6
Southwest	2.8%	2.8%	2.7%	2.7%
Baja California	6.0%	6.0%	5.1%	5.6%
Northwest	4.5%	1.9%	1.7%	2.6%
Rocky Mountains	3.1%	3.6%	2.7%	3.1%

The Energy Commission staff do not anticipate a resurgence of demand in the Northwest by 2006. The primary reason is that aluminum industry loads are unlikely to return to anywhere near pre-crisis levels. Two of the ten smelters in the region have been permanently shut down and will be dismantled. Aluminum prices, which have stagnated below $1450/ton since mid-2001, may rise as the global economy recovers, but structural changes in the aluminum industry do not bode well for the Northwest. These include the addition of a substantial amount of new capacity in China, and the increasing obsolescence of the smelting technologies used in the Northwest. Finally, the rates charged by BPA are apt to remain at current levels or higher through 2006, at which time BPA is likely to reduce the industry's entitlement to 600 MW, further exposing the industry to the spot market. These all point to the demise of the industry and a permanent reduction in the region's demand for electricity. Recent hints of an additional 15 percent increase in BPA rates indicate a possible dampening of demand in other sectors in other sectors as well during the next one to three years. Accordingly, Energy Commission staff will probably revise the above forecast downward prior to beginning analyses for the IEPR.

Capacity Additions and Retirements

Table 2-9 summarizes the assumptions regarding additions and retirements in the remainder of the WECC during 2004 – 2006.

While this might seem an optimistic assessment of new capacity in light of the number of delays and cancellations that have occurred during the past eighteen months, it is arguably conservative. More than 3,100 MW of the 4,000 MW expected prior to summer 2004 are near completion and are expected on-line by next January. The Southwest addition in 2005, for which ground has already been broken, is a single plant that is being built to alleviate local reliability concerns in the Phoenix area. The 472 MW being retired in the Southwest is the share of Mohave that is not owned by California entities. For a detailed list of plants to be added see **Appendix A, Table A-3.**

Table 2-9
Additions and Retirements
Remainder of WECC, 2004 - 2006 (MW)

	Additions			Retirements	Increase
	2004*	2005	2006	2004-2006	2004-2006
Southwest	2417	825	0	472	2770
Northwest	387	450	0	261	576
Rockies	601	0	0	0	601
Baja California	600	0	0	0	600
Total	4005	1275	0	733	4547

* Plants coming on during 12-month period preceding July 1st

A slowdown in development in the both the Northwest and Southwest during 2004 – 2006 can be expected for several reasons. Foremost among these are the capacity surpluses that have arisen during the past 24 months due to decreases in demand (in the Northwest) and substantial new construction (primarily in the Southwest). The Northwest also faces uncertainty regarding the role that BPA will play in meeting incremental load growth when current contracts expire in 2006. In the Southwest, numerous transmission issues must be resolved; most notably the constraints in exporting power from Palo Verde must be alleviated if capacity is to be added there at the levels contemplated.

Transmission Upgrades

Two major upgrades are assumed to take place outside California during 2004 – 2006. The first is a series of projects that will increase the transfer capability between Palo Verde and the remainder of Arizona from 5,000 MW to 6,200 by June 2003 and to 7,700 by June 2004.

The second increases the limits between Northern Nevada and Utah by 155 – 220 MW in May 2005.

Projections, 2007 – 2013

Whatever uncertainty exists surrounding changes in the energy infrastructure during 2004 – 2006 are multiplied ten-fold for the years that follow. While we have survived the calamity of 2000 – 2001, we have yet to erect a new market structure that will provide reliable energy at reasonable and stable prices. There is general agreement that those entities with load-serving obligations should be responsible for resource adequacy, but there is substantial disagreement regarding what steps they should or must take to meet this responsibility, and who will ensure that they take them.

Government intervention in the market, if successful, will likely dampen the investment cycle, eliminating periods during which there is insufficient capacity to reliably meet loads at a reasonable price.

The baseline "resource plan" for 2007- 2013 discussed below does not require assumptions about the precise role that the state will play in the energy markets during the coming decade. It only assumes that there will be sufficient capacity to reliably meet load at a reasonable price, however that is to be achieved. The resource plan is only a forecast to the extent that it assumes that whatever regulatory policies are adopted; they ensure timely construction of an adequate amount of capacity. Realizing that success in this regard is by no means certain, simulating and assessing a less optimistic future is suggested in the form of a separate scenario.

Electricity Demand

The Energy Commission's Demand Analysis Office has recently completed a forecast of electricity demand in California for 2003 – 2013. This forecast is discussed in detail in the staff draft report *California Energy Demand 2003-2013 Forecast.*

Thermal Additions

Any of several approaches may be taken in estimating the amount of new capacity that will be brought on line in 2007 – 2013. The most sophisticated involves estimating the revenue stream that both potential new and existing plants will yield, and applying decision criteria for both construction and retirement. In practice, however, investment (and retirement) decisions are far more complex, yielding periods of capacity surplus and shortage. Estimating the likely magnitude and periodicity of these cycles borders on guesswork, especially so in light of uncertainties regarding the future roles of the state and federal government in ensuring resource adequacy.

Energy Commission staff propose adding new capacity for simulation purposes during 2007 – 2013 to maintain reserve margins at those levels observed in 1998 – 1999 (see **Table 2-10**). This period is chosen as it arguably reflects reserve margins that are high enough to ensure reliability and allow for competitive wholesale spot markets, but low enough to yield prices that, along with other available sources of revenue (*e.g.*, ancillary services, capacity payments), provide an adequate return to investment. This reserve margin is plausible across various assumptions regarding the extent to which the state and the federal government intervene in the capacity and energy markets.

Table 2-10
Thermal Capacity Additions, California, 2007 – 2013* (MW)

	NP15	SCE	ZP26	San Diego	San Francisco	IID	Total
2007		150					150
2008		500					500
2009	250	150	500	415**	250		1,565
2010	150	250					400
2011	150	250	250				650
2012	400	150					550
2013	0	250					250
Total	950	1,700	750	415	250		4,065

* During twelve months prior to July 1st
** Net of South Bay retirement (695 MW)

Approximately 25 percent of the 4,065 MW is assumed to be peaking capacity. Preliminary analysis yielded capacity factors for new combined cycles around 80 percent when one-fourth of the additions were peaking units.

Renewable Additions

By 2007, Energy Commission staff believes that all incremental energy contracted for in order to meet RPS requirements will come from new renewable capacity. Assumptions regarding this capacity appear in **Table 2-11**.

Table 2-11
New Renewable Capacity, 2007 – 2011 (MW)

Technology	Average Annual Additions 2007-13	Total 2003-13	Percent NP15
Biofuels	74	645	48%*
Geothermal	104	843	12%**
Wind	214	2,263	37%

* Small percentage in San Diego, remainder in SCE
** Remainder in IID

Retirements

Given the above assumptions regarding additions and retirements in 2004 - 2006, 2007 will arrive with reserve margins in the WECC well above those of 2000 – 2001. It is possible, of course, that some of the capacity assumed to come on-line in 2004 – 2006 will not do so, and all but certain that some existing, older plants, will retire in 2007 - 2013. Recent prices, and those that have recently been forecasted for 2003 – 2005 are not high enough alone to sustain existing steam turbines with heat rates in the 9,500 – 11,000 Btu/kWh range. Caps on wholesale prices call into question the profitability of peaking units that lack capacity contracts. Should these types of plants retire *en masse*, reserve margins would fall, spot market prices would rise, and, in a worst-case scenario, both the competitiveness of the market and system reliability would be compromised.

The "retirement decision" is a complex one, requiring consideration of numerous variables. These include qualitative estimates (e.g., regulatory policy), proprietary data (alternative uses of the land or investment opportunities for the owner), and knowledge of the decision-maker's expectations regarding future conditions. It is further complicated by the possibility of keeping the plant in one of several states of "stand-by." While a large share of the state's capacity is aged and much of that will become increasingly non-competitive, it should be noted that a not-insignificant portion of that capacity does not rely on the market alone for revenue. Many of these units have RMR contracts and will not be retired unless and until new generation (or transmission) replaces these facilities. Several have long-term contracts with an IOU.

Accordingly, Energy Commission staff, in designing a baseline "resource plan," hesitate to assume the retirement of specific facilities. In fact, the figures in **Table 2-10** assume that the San Diego area's South Bay facility will be the only major retirement in California during 2007 – 2013.

From a simulation modeling perspective, when the system is characterized by surplus capacity the decision to retire existing facilities, short of doing so to the point of threatening reliability, is arguably not a crucial matter. Previous simulations have indicated that existing steam turbines, which have traditionally met baseload demand, will become marginalized, increasingly used only in the summer during periods of high demand. This function is shared with newer "peaking" units, plants that are as efficient as the steam turbines (or more so) and can be brought up to full load more quickly. Effectively, the "supply curve," even on weekdays during the summer, becomes very flat over a broad range, with the least efficient peakers (13,000 Btu/kWh) being seldom if ever called upon. Under these circumstances, estimates of prices, fuel use, emissions, *etc.* are insensitive to assumptions about the retirement of (a moderate amount of) older capacity, save for during a handful of hours of the year.

We do not mean to minimize the significance of the system's ability to meet loads during these hours, nor of the potentially high prices that might prevail. Energy Commission staff will run a "low addition, high retirement" scenario to determine the impact of a lower reserve margin on system conditions during hours of very high demand, but tentatively propose not to retire existing facilities in California (other than South Bay) during 2007 – 2013 in the baseline study. Comments on this proposal are actively solicited.

Transmission Upgrades

Two upgrades are assumed for California during 2007 – 2013. One increases the transfer capability between San Diego and SCE by 750 MW; the other increases the transfer capability between IID and SCE from 600 to 1,600 MW. Both are assumed to occur in January 2009. The latter is assumed to be necessary to accommodate the movement of RPS-driven renewable energy from new facilities in the IID service area.

Remainder of WECC

Electricity Demand

Henwood Energy Services, Inc. has provided a forecast of out-of-state demand. The values in **Table 2-12** reflect the vendor's forecast of peak demand growth for the other regions of the WECC.

Table 2-12
Annual Peak Demand Growth (Summer),
Remainder of WECC,
2007 – 2013

Southwest	2.7%
Baja California	5.6%
Northwest	2.6%
Rocky Mountains	3.1%

Capacity Additions

The additions in **Table 2-13** are based on the assumption that reserve margins will decline in 2007 – 2008 to levels observed in 1998 – 1999.

Retirements

For the purpose of simulation, Energy Commission staff assumes the retirement of 1350 MW of capacity during 2007 – 2013. All but 75 MW of this capacity is in the Northwest.

Transmission Upgrades

Energy Commission staff does not assume transmission upgrades outside California that will affect the transfer capability between the transmission areas in the topology used for simulation.

Table 2-13
Capacity Additions, Remainder of WECC, 2007 – 2013 (MW)

	Southwest	Baja California	Northwest	Rockies	Total
2007*			620		620
2008			1,090		1,090
2009	150		1,120		1,270
2010	150	250	1,450		1,850
2011	150		920	150	1,220
2012	150	250	920	400	1,720
2013	680		1,710	150	2,540
Total	1,280	500	7,830	700	10,310

* During twelve months prior to July 1st

Proposed Scenarios

Because of the numerous uncertainties that temper any projection of future conditions in California's energy markets, Energy Commission staff propose several scenarios, in which the sensitivity of the "baseline results" to explicit or underlying assumptions is assessed. Staff welcomes comments on the following proposed list, as well as suggestions for additional inquiry.

- As the baseline assumes minimal retirements in California in 2004 – 2006, it would be prudent to consider a scenario with some combination of fewer additions, more retirements, and a booming economy (higher loads). A suggested year for analysis is 2006 or 2007.

- As natural gas prices are primary drivers of wholesale electricity prices, "high" and "low gas price" scenarios will be run for 2003 – 2013.
- The simulations proposed here will be used to assess the adequacy of the natural gas delivery system. Accordingly, we propose a scenario with adverse hydro conditions in both California and the Northwest, as well as a booming economy. Proposed years for analysis are 2006, 2009, and 2012.
- The impact of the RPS can be assessed by comparing the baseline against a scenario in which the RPS targets are not achieved. Total renewable capacity would be reduced by 50 percent compared to the baseline and a share of this would be replaced with new gas-fired generation.
- The impact of a substantial increase in funding for efficiency programs and/or increased reliance on distributed generation can be measured by comparing the baseline against a scenario which assumes slower load growth and a concomitant reduction in new generation or increased number of retirements.

Chapter 3
Electricity Transmission Infrastructure

Staff's update on the status of transmission projects needed for both reliability and economic reasons is presented in this chapter. First, staff presents the major projects (primarily inter-utility projects) that will likely be in service in the next 10 years. Staff then presents the local reliability projects which the three investor-owned utilities (IOUs) Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE) need to meet reliability criteria during the next five years. This information is based on each utility's annual five-year transmission plan. Some longer-term reliability projects are also included in each utility's plan; these projects are also included in staff's tables. Staff then discusses some non-IOU projects. Next, staff discusses major economic projects, followed by a discussion of transmission projects to support renewable energy projects. The chapter ends with a discussion of relevant out of state transmission projects.

Major Transmission Projects Modeled in the Next Ten Years

Staff has taken a conservative approach to selecting the transmission projects that will be used in the MARKETSYM™ model, the tool the Energy Commission staff currently uses to analyze the transmission system. While there are many transmission projects built and planned every year in California, very few of these projects affect the way the transmission system is described in the MARKETSYM™ model. The MARKETSYM™ includes only inter-utility transmission paths and a few intra-utility paths. Staff has included both reliability and economic projects that are appropriate for transmission modeling assumptions. **Table 3-1** describes the transmission additions used in the MARKETSYM™ modeling. Each of the projects in **Table 3-1** is described in more detail below.

Path 15 Upgrade: This project includes a new 500 kV line between the Los Banos and Gates Substations as well as other system reinforcements. It is currently on schedule for operation in the fall of 2004. Studies are underway to change the Western Electricity Coordinating Council (WECC) South to North path rating and to establish a North to South rating. In the MARKETSYM™ dataset, the South to North rating of this path is increased from 3,900 MW to 5,400 MW and the North to South from 2,130 to 3,265 MW both in January of 2005, as a result of this upgrade.

Path 26 Upgrade: This project is primarily an operating procedure change, although some equipment is required. The Path 26 upgrade was originally scheduled for completion in June of 2003 but PG&E has recently stated that it may be delayed until October of 2003. In the MARKETSYM™ dataset, this path is increased in both directions from 3,000 MW to 3,400 MW in October of 2003, as a result of this upgrade.

Table 3-1
Transmission Additions Used in MARKETSYM™ Modeling

Project Name & Path Number	Project Proponent(s)	Purpose(s)	On-line Date	Modeling Impact
Path 15 Upgrade: Los Banos-Gates	WAPA, PG&E, and TransElect	Reduce Path 15 bottleneck	Jan/2005	N-S:+1,135 MW S-N:+1,500 MW
Path 26 Upgrade Midway-Vincent	SCE	Increase Path Rating	Oct/2003	SCE-PG&E:+400 MW PG&E-SCE:+400 MW
Path 45[5]	SDG&E	Increase Path Rating	Jan/2003	CFE-SDG&E:+400 MW SDG&E-CFE:+400 MW
Miguel-Mission and Imperial Valley Substation	SDG&E	Increase imports into San Diego	Jan/2005	To San Diego: +560 MW
Path 46 Upgrade (West of River)	Unknown	Accommodate Geothermal Development in the Salton Sea	Jan/2009	IID-SCE:+1,000 MW SCE-IID:+1000 MW
Jefferson-Martin	PG&E	Improve SF reliability	Jan/2006	PG&E-SF:+400 MW PG&E-SF:+400 MW
Valley-Rainbow	SDG&E	Improve reliability	Jan/2009	SCE-SDG&E:+750 MW SDG&E-SCE:+750 MW

Path 45 Upgrade: One part of Path 45 is a 230 kV line from La Rosita in Mexico to the Imperial Valley Substation in SDG&E territory. This line was reconductored in November 2001 to add a second circuit. While this upgrade has the potential to increase the physical rating of the entire Path 45 from about 400 MW to 800 MW, the WECC has not yet approved the increased south to north transfer capability for the summer months. However, WECC approval is expected soon. In the MARKETSYM™ dataset this path is rated at 800 MW in both directions starting in January 2003.

Miguel-Mission and Imperial Valley Substation: These two projects include the upgrade of an existing 138/69 kV line to a 230 kV line between the Miguel and Mission substations and the upgrade and addition of transformers at the Imperial Valley substation. The upgrade of the existing Imperial Valley Substation bank is expected in June 2003, while the addition of a second bank is expected in December 2003. The tentative on-line date for the Miguel-Mission line upgrade was June of 2004; however, that date assumed that a Certificate of Public Convenience and Necessity (CPCN) was not needed. The January 14, 2003 Interim Opinion for Proceeding #00-11-001 states that a CPCN will be required for the Miguel-

Mission line. Thus a revised, reasonable on-line date for this project is January 1, 2005. These projects will increase the transfer capability between the Miguel and San Diego areas in the MARKETSYM™ model from 1690 MW to 2250 MW in January of 2005.

Path 46 Upgrade: This is an increase in the West-of-River WECC path. The studies required to create a potential Path 46 Upgrade have not been completed; hence, any upgrade is a long way off. However, there is a need for renewable electric generation in California as encouraged by the new Renewable Portfolio Standard, and geothermal power from the Salton Sea region is a likely source for that power in this area. Electricity from geothermal generators near the Salton Sea will not reach California loads without new transmission lines, so the Path 46 Upgrade is included in the MARKETSYM™ dataset. In MARKETSYM™ the path rating from Imperial Irrigation District (IID) to SCE is increased from 600 MW to 1,600 MW in both directions starting in January of 2009.

Jefferson-Martin: This project consists of a new 230 kV line from the Jefferson to the Martin Substation as well as other system reinforcements in the PG&E service area. This project has California Independent System Operator (CAISO) approval and is under review at the CPUC. In the MARKETSYM™ model, the transfer capability from PG&E North of Path 15 into San Francisco in increased from 700 MW to 1,100 MW in January of 2006, as result of this project.

Valley-Rainbow: This project consists of a new substation and a new 500 kV line from the Valley substation in the SCE area to the (new) Rainbow substation in SDG&E, plus other system reinforcements. In December of 2002, the CPUC denied SDG&E a CPCN for this project. SDG&E subsequently filed an appeal of this decision. Part of the CPUC's denial was based on the finding that the project would not be needed for reliability until 2008 at the earliest. This project has been included in the MARKETSYM™ dataset starting in January of 2009 and increases the transfer capability from SCE to SDG&E from 2,200 MW to 2,950 MW. The transfer capability from SDG&E to SCE is increased from 700 MW to 1,450 MW in 2009.

Most of the projects included in the MARKETSYM™ dataset have either been completed or are in the midst of permitting. Three projects, Path 46 Upgrade, the Valley-Rainbow project, and the Jefferson-Martin project are more uncertain. However, it is reasonable to expect that the actual project will be developed at some point in the case of the Jefferson-Martin and Valley-Rainbow projects, and something similar to a 1,000 MW increase in the Path 46 rating. Many projects recently proposed in CPUC and CAISO proceedings could have been included in a 10-year forecast, but until further studies are completed any more projects than staff has already included would be too speculative.

Local Reliability Projects

The following discussion includes transmission projects which the utilities have determined are needed for reliability purposes within their five-year planning horizons, plus an outlook of longer-term projects. The plans for these projects were prepared in accordance with

Section 3.2.2.1 of the CAISO Tariff, which requires each of the three investor-owned utilities to submit on an annual basis a transmission expansion plan that covers a minimum five-year planning horizon. Conformance with the CAISO Planning Standards was used as the criterion by which to judge the adequacy of each utility's system. These planning standards include the North American Electric Reliability Council (NERC) and WECC Planning Standards, specific nuclear unit standards for San Onofre and Diablo Canyon, the San Francisco Greater Bay Area Generation Outage Standard, and the Additional Line and Generation Outage Standard (which states that a single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC Planning Standards for Category B contingencies.) Category A contingencies refer to normal conditions, Category B contingencies refer to single element outages, and Category C contingencies refer to overlapping outages.

Each of the three investor-owned utilities is near the end of its 2002 annual five-year expansion plan process, with final expansion plans having been completed in the last two months. These plans re-evaluate projects approved by the CAISO in previous annual review cycles, since conditions affecting the need for transmission, such as load growth, new/retired generation, and the economy, can affect the timing and/or need for new transmission facilities.

In addition to the likely projects discussed below for PG&E, SDG&E, and SCE, staff has identified likely transmission projects by the Western Area Power Administration (WAPA), IID, and the City of Santa Clara/Silicon Valley Power.

PG&E Service Area

PG&E's transmission system includes the 60, 70, 115, 230, and 500 kV system. PG&E's ***2002 Electric Transmission Grid Expansion Plan (Final) Report*** includes the following projects:

- 10 transmission projects seeking CAISO approval. These include four new projects seeking CAISO approval for the first time (Bay Area Reactive Support (Potrero SVC), Cottonwood 230/60 kV Transformer, Ignacio Substation 60 kV Reinforcement Project, and Reedley Second 115/70 kV Transformer); three projects that were previously submitted to the CAISO but were not approved (Lockeford 230/60 kV Transformer, Atlantic 230/60 kV Transformer, and Gold Hill-Placer 115 kV Reinforcement); one customer-sponsored project (City of Santa Clara/Silicon Valley Power 230 kV Interconnection); and two previously-approved projects with scope modifications (Humboldt-Arcata Jct. 60 kV Line and Lakeville 230/115 kV Transformer.)
- 78 transmission projects that had received CAISO approval in previous years. As noted above, an update is included for each of these projects since conditions affecting the reliability need for these projects can change.

- Long-term planning studies and projects in planning development stages. There are eight long-term studies, eight projects in planning development, and two projects in the 2001 Expansion Plan that are not needed in the next five years.

For a comprehensive discussion of each of these projects, please see the PG&E report, Sections 1 through 3.

Staff used Sections 1 through 3 of the PG&E report, along with the latest (February 3, 2003) monthly filing that PG&E made to the CPUC in response to AB 970 requirements, to prepare a list of the transmission projects that are likely to be built. Staff also included transmission projects that came on line in 2002. **Appendix B, Tables B-1 through B-7** show the status of the projects in each of the seven PG&E planning areas (Humboldt Area, North Coast and North Bay Areas, Central Coast and Los Padres Areas, North Valley Area, Central Valley Area, Greater Fresno and Kern Areas, and Greater Bay Area, respectively.) The information about each project includes its designation number assigned by the Participating Transmission Owner (PTO), name, purpose, current projected or actual on-line date, status of CAISO approval, status of PTO funding approval, whether or not a CPCN is required from the CPUC, project status, and description/comments.

Certain areas within PG&E's system present the most pressing reliability problems (both in the near term as well as expected in the longer term.) These include the following: City of San Francisco, East Bay, San Jose, and Humboldt. A brief description of the problems and proposed mitigation measures is included here.

The City of San Francisco is a transmission-constrained area which has its own planning standard called the San Francisco Bay Area Generation Planning Standard. This standard requires the local system to be analyzed with multiple generation units assumed to be off line. A key finding of the October 2000 ***San Francisco Peninsula Long Term Electric Transmission Planning Technical Study*** was that new 230 kV facilities would be needed by the summer of 2006 unless new local generation sources are built. The study group selected the Jefferson-Martin 230 kV Transmission Project (T082 in **Appendix B, Table B-7**) as the preferred alternative. PG&E filed its CPCN application at the CPUC on September 30, 2002. Assuming the project is approved by the CPUC, the expected in-service date is September 2005.

PG&E is completing a long-term study on the Oakland transmission system which investigated the failure of underground 115 kV cables, the availability of in-area generation to serve peak load, and future growth. PG&E's analysis showed that the system is adequate for at least the next 10 years under normal and emergency conditions, assuming all generation in the Oakland area is available. Thus, no other transmission reinforcements are recommended at this time, subject to reevaluation if local generating facilities become unavailable.

PG&E recently completed a long-term study on the San Jose area which evaluated the impact of the current economic slowdown on the timing of transmission projects. The study showed that three of the Metcalf reconductoring projects (T694, T854, and T692 in **Appendix B,**

Table B-7) are needed in the near term order to keep pace with demand growth as the economy recovers. Additional transmission capacity projects will be needed in the longer term, though no specific preferred alternative has yet been identified.

The primary long-term concern in the Humboldt area is having adequate power transfer capability. Although load growth is small, there are uncertainties associated with the continued operation of existing local generation. PG&E's long-term analysis shows that with the two CAISO-approved projects shown in Table B-1, there will be no criteria violations expected until the year 2012. Thus, no other transmission reinforcements are recommended at this time, subject to reevaluation if local generating facilities become unavailable.

SDG&E Service Area

SDG&E's transmission system consists of 69 kV and greater facilities. The January 30, 2003 ***SDG&E 2002 Grid Assessment Study & Transmission Expansion Plan Final Report*** includes the following projects:

- Ten capital projects proposed to be in service between the beginning of 2003 and the end of 2004. Three of these projects are distribution projects associated with the building of new distribution substations to meet local area load. A fourth project is transmission interconnection facilities for the Calpine Otay Mesa project.

- Fourteen capital projects needed with in service dates between 2005 and 2007. Four of these projects are distribution projects associated with building new distribution substations to meet local load.

- Three capital projects which are economic projects. Two of these projects, the Imperial Valley 500/230 kV transformer upgrades and the second Miguel-Mission 230 kV line, are major projects that mitigate congestion. They were described earlier in the section entitled "Major Transmission Projects Modeled in the Next Ten Years." The third project is the reconductoring of the 69 kV line between Border Tap and Otay Lake Tap.

- The Valley-Rainbow 500 kV transmission project. Studies performed assumed an in service date of June 2005. However, the recent (December 2002) CPUC decision found that the project is not needed until 2008. SDG&E filed an appeal in January 2003. At this time, the timing of this project is uncertain. For modeling purposes staff has assumed an in service date of January 2009, as discussed above in the section entitled "Major Transmission Projects Modeled in the Next Ten Years."

For a comprehensive discussion of these projects, please see the SDG&E report, pp. 2-20.

Staff used the SDG&E report, along with the latest (February 3, 2003) monthly AB 970 filing, to prepare a list of transmission projects that are likely to be built. Staff also included transmission projects that came on line in 2002. **Appendix B, Table B-8** shows the status of these projects.

SCE Service Area

SCE's transmission system consists primarily of 500 and 230 kV systems, with most of the load in the Los Angeles basin. Most of the imported power flows through SCE's four main 500/230 kV bulk power substations at Devers, Mira Loma, Serrano, and Vincent. Staff used SCE's December 5, 2002 ***CAISO Controlled SCE Transmission Expansion Plan 2003-2007 – Rev. 2***, along with their latest (February 3, 2003) monthly AB 970 filing, to prepare a list of transmission projects that are likely to be built. Staff also included transmission projects that came on line in 2002. **Appendix B, Table B-9** shows these projects.

Two of these projects, both involving the Midway-Vincent 230 kV line (Path 26), are considered to be economic projects. The short-term Path 26 upgrade includes a new remedial action scheme (RAS) which will increase the bi-directional path flow from 3,000 to 3,400 MW (see **Appendix B, Table B-9** and the section entitled "Major Transmission Projects Modeled in the Next Ten Years" for more information). SCE is also considering a long-term solution to relieve transmission congestion on this line. See the section entitled "Major Economic Projects" for more information.

Imperial Irrigation District

The Imperial Irrigation District (IID) is considering three major transmission expansion projects to access generation to serve IID load and to provide expanded outlet capacity for the Blythe I and II generation projects. One option, a 230 kV double circuit, would cover approximately 80 miles from the Buck Blvd. Substation near the Energy Commission-approved Blythe I project to IID's Midway X Substation. Two other options under review by IID and the Bureau of Land Management (BLM) originate at the Buck Blvd. Substation and terminate at SCE's Devers Substation approximately 120 miles away. One of these options is a 230 kV double circuit while the other is a 500 kV single circuit design. All three options have received some environmental review by IID, BLM, and the Energy Commission. The likelihood of any of these options going forward is uncertain at this time.

Western Area Power Administration (Sacramento Area)

As noted in the Western Area Power Administration's (WAPA's) ***Sacramento Area Voltage Support Draft Environmental Impact Statement (EIS)***, population growth and development in the Sacramento area have steadily increased load demand, which has reduced the security and reliability of the interconnected transmission system. Power system studies conducted by the Sacramento Area Transmission Planning Group (SATPG) and the River City Transmission Group (RCTG) concluded that transmission additions are necessary to alleviate voltage sag and ensure system reliability. WAPA's draft EIS proposed action to address these concerns consists of reconductoring a double-circuit 230 kV transmission line from the Elverta Substation to the Tracy Substation; constructing a new double-circuit 230 kV transmission line from the O'Banion Substation to the Elverta Substation; and realigning the transmission line near Pleasant Grove Cemetery between the O'Banion and Elverta Substations and a portion of the Cottonwood-Roseville single-circuit 230 kV transmission line.

The comment period for the draft EIS ended on December 30, 2002. The Final EIS is scheduled for May 2003.

City of Santa Clara/Silicon Valley Power

Silicon Valley Power (SVP) has recently received approval from the Santa Clara City Council to move forward on a four-mile 230 kV transmission project that will significantly increase the transmission capacity in the area. SVP's forecast showed that the current transmission capability to bring power into the Santa Clara area to meet load would be exceeded within three to five years. Following final budget approval and completion of an environmental impact report on the project, which involves both overhead and underground lines, construction could begin by summer 2003 and the project could be in service by the end of 2004.

The project would provide additional transmission capacity between SVP's Northern Receiving Station and PG&E's Los Esteros Substation which is currently under construction. The Los Esteros Substation project is part of PG&E's Northeast San Jose Reinforcement Project (see project T011 in **Appendix B, Table B-7**). The proposed SVP project is also included in **Appendix B, Table B-7** (see project T747) for informational purposes only, since it is not a PG&E project.

Major Economic Projects

As noted in the section above entitled "Major Projects Expected Within the Next Ten Years," there are several major projects which are largely economic projects. These projects are not needed strictly for reliability purposes (i.e., to avoid planning criteria violations), but provide economic benefits in the form of reduced congestion costs and access to lower-cost generation. These include the Path 15 Los Banos-Gates upgrade, the second Miguel-Mission 230 kV line, Imperial Valley 500/230 kV Substation transformer upgrades, and the 400 MW Path 26 Midway-Vincent upgrades.

In addition to the short-term increase in the Path 26 rating, the CAISO has proposed a longer-term solution that would increase the path rating by another 600 MW, to a total bi-directional transfer capability of 4,000 MW. Path 26 limits the north-to-south imports occurring when there has been average or above average rainfall and lower cost energy is available, and hydroelectric power is available from Northern California and the Pacific Northwest. London

Economics Incorporated, under contract with the CAISO, has issued a preliminary study of the Path 26 upgrade and found that there are significant benefits to increasing the Path 26 rating to 4,000 MW. The in-service date for this longer-term project is uncertain.

Transmission Projects to Support Renewables

Senate Bill (SB) 1038 and 1078 require the Energy Commission, the CPUC, the CAISO, and the utilities to work together to determine the transmission facilities needed to interconnect new renewable energy projects to the existing California electricity grid. Through the CPUC Investigation #00-11-001, a "hand-off" process has been established. This process will analyze the transmission needs of renewable energy resources needed to meet the Renewable Portfolio Strategy established by SB 1078.

As currently proposed, the "hand-off" process has three major steps. First, by July 1, 2003 the Energy Commission will provide a draft forecast of renewable energy development and potential to the CPUC and CAISO. This forecast will then be used by the CAISO and utilities (PG&E, SCE and SDG&E) to determine the transmission facilities needed for the potential renewable energy projects. The CPUC will then create a renewable transmission plan from the analysis. There will be workshops held at each stage of this process to ensure that interested parties, stakeholders and the public will have several opportunities to comment on the transmission plan. The exact steps, workshops, hearings, and timing have not been formally established in the CPUC Investigation #00-11-001.

Two renewable resource developers, Coral Power and Vulcan Power have requested an examination of specific transmission projects through the CPUC Investigation #00-11-001. In the January 29, 2003 ruling the utilities were ordered to investigate the projects described by Coral Power and Vulcan Power. These projects include a 500 kV line from the Imperial Valley substation to the Devers substation, the Bishop/Control Upgrade, the Weed Upgrade, the Surprise Upgrade, the Pacific DC Intertie Green Intertie, the California Oregon Border Green Power Priority Use Order, and the Southwest Clean Power Link. The analysis of these projects will be folded in to the CPUC's final transmission plan.

Out-of-State Transmission Projects

The Western Electricity Coordinating Council's 10-Year Plan Summary for 2002-2011 identified only one proposed out-of-state transmission project that could be of significance to California. The proposed Navajo Transmission Project would consist of a single 500 kV transmission line from the Four Corners area of New Mexico to southern Nevada (Las Vegas area). The tentative on-line date for this project is 2005 and financial commitments to proceed with the project are now in place. System studies are currently in progress to determine the potential effects of this project on adjacent systems and to establish an acceptable rating for this project. An additional out-of-state project not noted in the recent WECC plan summary, but proposed for the timeframe from 2011 and beyond, is the Southwest Intertie Project. This project consists of a single 500 kV transmission line from southern Idaho to southern Nevada (Las Vegas area). This project has been studied by system planners for more than 10 years, however commitments by interested parties to finance and construct this project have yet to materialize.

In the absence of an appropriate forum to facilitate the planning of transmission projects in the west that support a competitive and efficient wholesale electricity market, the CAISO initiated the Southwest Transmission Expansion Plan (STEP). This collaborative ad-hoc study group provides a forum where interested parties are encouraged to participate in the planning, coordination, and implementation of a robust transmission system between Arizona, Nevada, Mexico, and southern California. Specific interstate transmission projects that may be evaluated in STEP include:

- A second Palo Verde (Arizona) to Devers (southern California) line.
- A second line added to the Southwest Power Link (Arizona to southern California).
- Upgrading the Mead-Phoenix-Adelanto Project (Arizona to Nevada to southern California) to direct current.
- A new line from El Dorado Valley (Nevada) to southern California.
- Upgrading the series compensation in the existing 500 kV lines between Arizona and southern California.

As a logical follow-on to the STEP process, the CAISO is currently considering the initiation of a similar process for the Pacific Northwest.

Chapter 4
Natural Gas Infrastructure

Since the 2000-2001 energy crisis, a number of infrastructure projects have come on stream to meet California's, and its neighbors', growing demand for natural gas. Moreover, several other projects are scheduled to begin operation during the next two years. As the analysis below indicates, the determinant for natural gas demand growth, and the resultant need and location of additional natural gas infrastructure, is growth in electricity demand because natural gas fuels most new power plants. The following section will examine the recent expansions, enhancements, and additions to the interstate gas infrastructure serving California, as well as projects that are either under construction or in the permitting process. This will be followed by a similar analysis of California's intra- and in-state infrastructure.

This spring, the Energy Commission staff will issue its *2003 Natural Gas Market Outlook*, a more detailed analysis of the natural gas market during 2003 to 2013. This report will update the recently released *Natural Gas Supply and Infrastructure Report* (Publication No. 700-02-006F, December 2002) and will include staff's assessment of natural gas demand, prices, supply, and infrastructure. The *2003 Natural Gas Outlook* will provide the basis for additional sensitivity analysis of natural gas demand/supply issues – analysis that will be coordinated with similar analysis in the electricity demand/generation areas and included as part of the Energy Commission's *Integrated Energy Policy Report.*

Interstate Pipelines Serving California

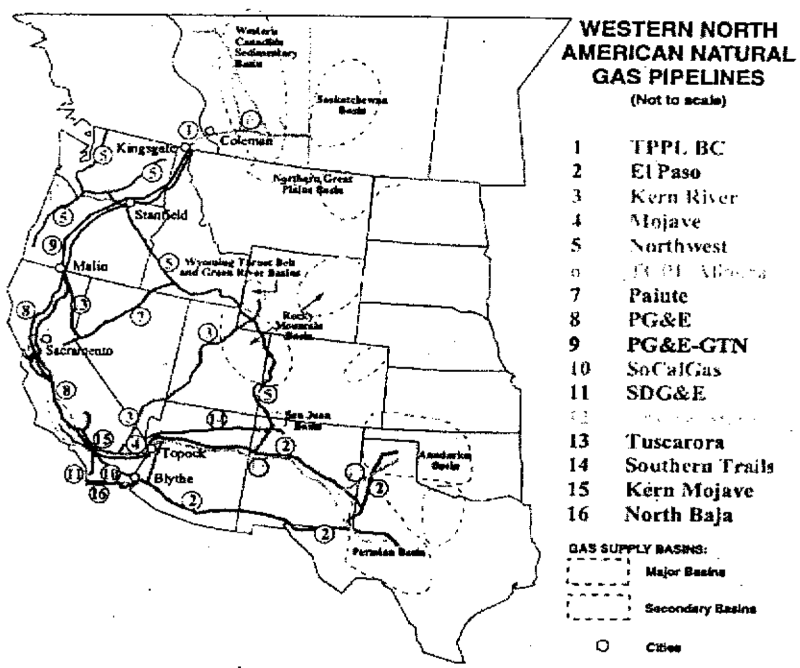
Natural gas production in California accounts for only about 15 percent of the gas consumed in the state.[6] The balance of California's natural gas supply is transported to the state via interstate pipelines from the Southwest, Rocky Mountains, and Canada. The map in **Figure 4-1** depicts the natural gas supply regions and major pipelines serving the western states, including California. The map also shows that California is at the end of the interstate pipeline system, and that the majority of the natural gas consumed in California must travel great distances to reach the state.

To keep pace with the growing demand for natural gas in California, surrounding states, and Mexico, several companies have either recently completed infrastructure improvement projects or have undertaken them. **Appendix C, Table C-1** provides a list of natural gas infrastructure projects completed since 2001. **Appendix C, Table C-2** details pending projects that are either under construction or in the permitting process.[7]

Southwest Pipeline Corridor

California receives its southwest supply principally from the San Juan basin, although the Permian and Anadarko basins also supply California with limited quantities of natural gas. Three pipeline companies bring southwest supplies to California: El Paso Natural Gas Company, Transwestern Pipeline Company, and Questar Pipeline Company. Furthermore, the El Paso Company's pipelines serving California are split into a northern system (EPN), which transports mainly San Juan gas, and a southern system (EPS), which primarily moves Permian gas.

Figure 4-1
Western North American Natural Gas Pipelines



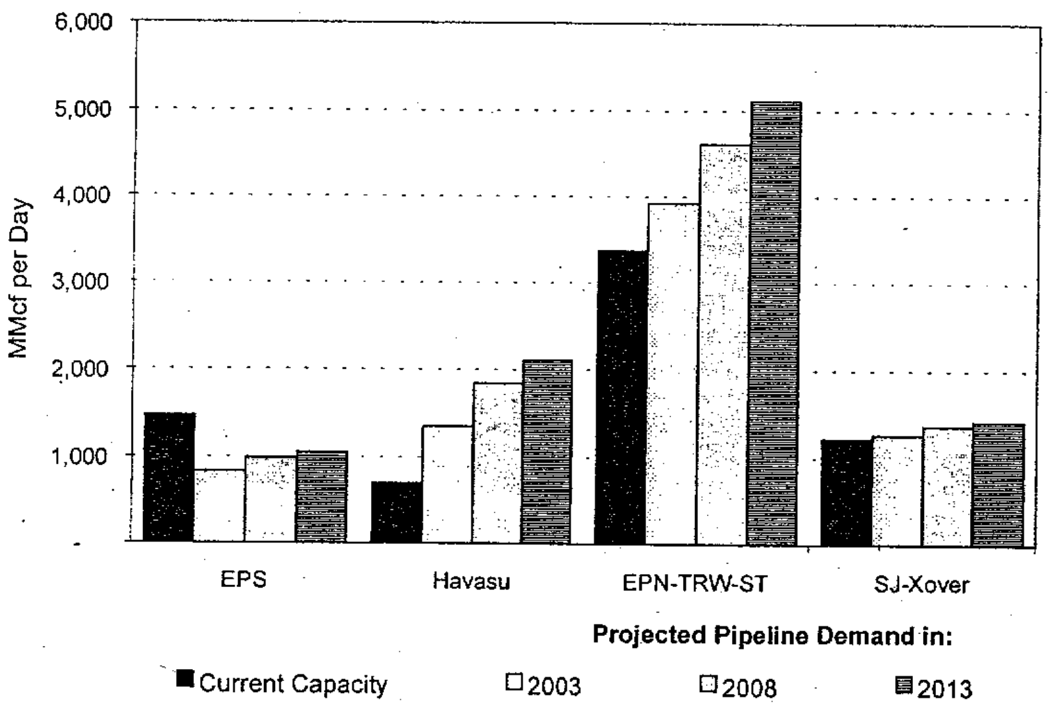
Source: California Energy Commission

Over the past year, all three of these companies have completed projects to increase the capacity to deliver natural gas to California. In June 2002, Transwestern began operation of its 120 million cubic feet (MMcf) per day Red Rock expansion project, which increased delivery capacity on its existing pipeline by adding compression at three stations in Arizona. The following month, Questar completed the eastern portion of the Southern Trails Pipeline. The converted 16-inch-diameter oil pipeline, formerly owned by Arco, has the capacity to bring 80 MMcf per day of gas from the San Juan basin to the California border. Similarly, El Paso completed the first phase of its conversion of the All American oil pipeline around the end of 2002, adding 230 MMcf per day of capacity to its southern system.

Additionally, Pacific Gas & Electric (PG&E) National Energy Group and Sempra Energy International recently completed the 500 MMcf per day North Baja Pipeline (also referred to as Baja Norte), which delivers gas from EPS to Rosarito, Baja California, Mexico. While presently, the pipeline does not deliver gas to California, it provides an immediate benefit to the San Diego area by serving the natural gas demand in northern Baja California, Mexico. That area had previously received its gas from the San Diego Gas & Electric (SDG&E) system via deliveries to the Transportadora de Gas Natural (TGN) pipeline near Tijuana, Mexico. Regulators in California and Mexico are currently considering proposals to allow gas to flow from North Baja to San Diego on the TGN pipeline, which is now connected to the North Baja pipeline. Additionally, the North Baja pipeline could potentially provide gas to Calpine's 510-megawatt Otay Mesa power plant, located in California, east of San Diego.

In **Figure 4-2**, the current capacity of the pipelines delivering gas from the southwest supply regions to California is contrasted with the projected demand for gas flows on those pipelines during 2003, 2008, and 2013. This provides an estimate of how much additional capacity will be needed along interstate pipeline corridors in the Southwest to ensure that there is sufficient capacity to deliver natural gas to California, as well as customers east of California. In the figure, the EPN, Transwestern and Southern Trails pipelines have been combined to depict total capacity and demand along the northern portion of the southwest corridor. The Havasu and San Juan crossovers are included because those two pipelines allow El Paso to move gas produced in the San Juan basin from its northern system to the southern system.

Figure 4-2
Projected Pipeline Capacity Demand
Along the Southwest Pipeline Corridor



Source: California Energy Commission

In the next two years, El Paso plans to complete the California Lateral, which is the second phase of its conversion of the All American oil pipeline. This 700 MMcf per day capacity pipeline will allow El Paso to move gas from its southern system to both PG&E's intrastate pipelines, and the Kern/Mojave interstate pipeline. Currently, only Southern California Gas Company (SoCalGas) and the North Baja Pipeline are connected to EPS at the California border. Questar is considering whether to continue with the western portion of the Southern Trails Pipeline, which extends from the California border to Long Beach, California. Should Questar proceed with its conversion project, it would add 120 MMcf per day of takeaway capacity from the California border. Several other companies have recently began soliciting interest in additional projects through the southwest corridor, but to date, no new applications have been filed with the Federal Energy Regulatory Commission (FERC), which governs interstate pipeline projects.

Pacific Gas and Electric - Gas Transmission North Corridor

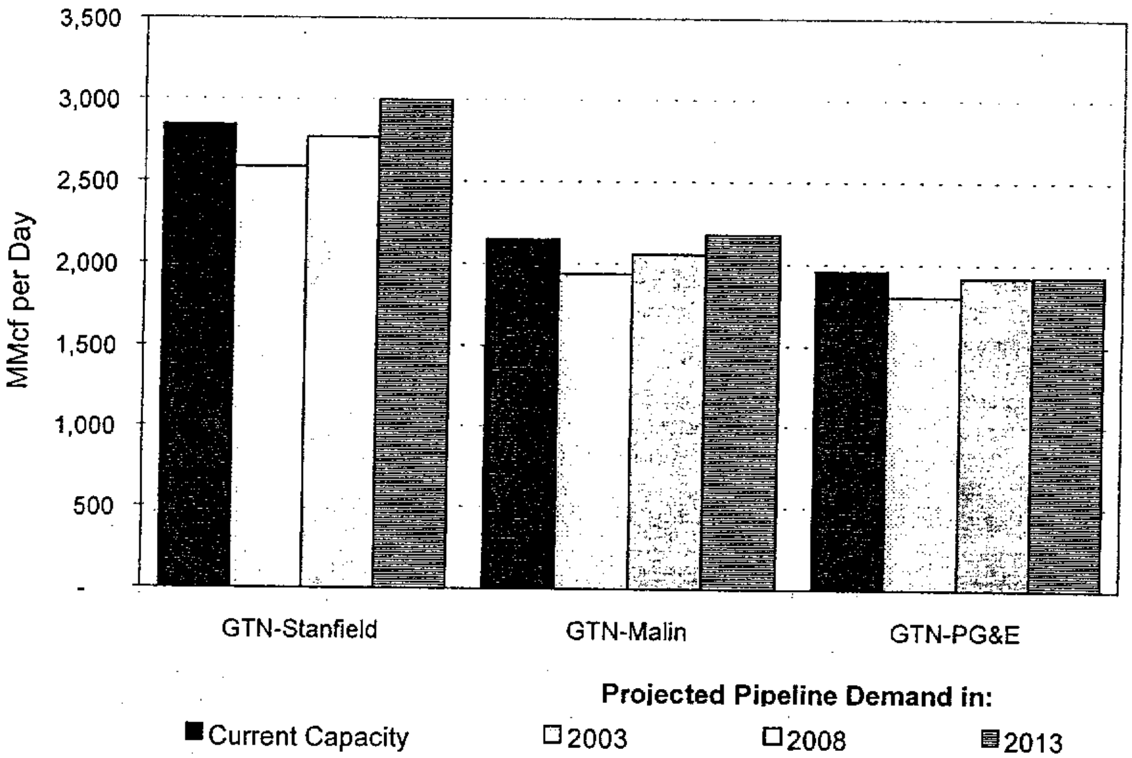
The PG&E-Gas Transmission North (GTN) pipeline is California's source for Canadian-produced gas, as well as small amounts of gas produced in the Rocky Mountain region. The pipeline traverses 612 miles through Washington and Oregon until it reaches its terminus at the Northern California border near Malin, Oregon.

Over the past two years, PG&E-GTN has added about 210 MMcf per day of capacity to the northern end of its system, mainly to serve new electricity generation facilities in Washington. The upgrade also helped ensure that the additional demand in Washington would not disrupt flows to California.

In January 2003, Sierra Pacific Resources completed the Tuscarora Pipeline expansion. The pipeline receives natural gas at Malin, Oregon before crossing northeastern California to serve the Susanville, Lake Tahoe and Reno areas. This expansion increased deliverability by 65 MMcf per day to satisfy gas demand in Reno. From 1989 to 1999, gas sales served by Tuscarora and another pipeline in the Reno area grew more than 150 percent. Total capacity on Tuscarora now stands at 190 MMcf per day.

As was done in the previous section, **Figure 4-3** relates the current capacity on the PG&E-GTN pipeline to the projected demand for capacity at various points along the pipeline.

Figure 4-3
Projected Pipeline Capacity Demand
Along the PG&E-GTN Pipeline Corridor



Source: California Energy Commission

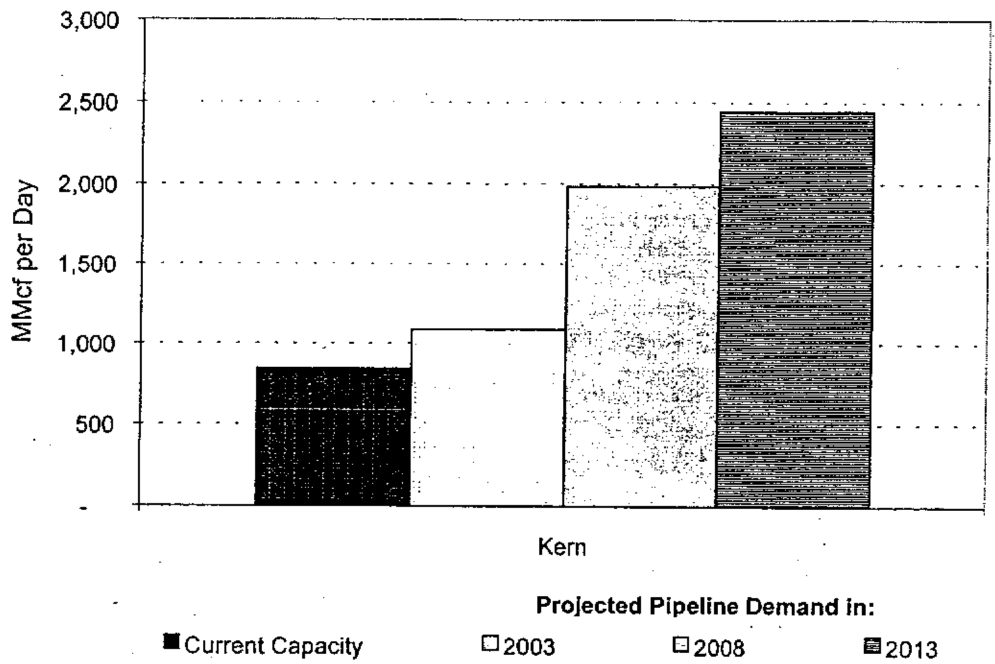
Kern River Corridor

The majority of the Rocky Mountain production delivered to California is transported via the Kern River Pipeline. Prior to 2001, this pipeline was capable of delivering 700 MMcf day of natural gas to points in Southern California. During the summer of 2001, Kern River Gas Transmission Company added 135 MMcf per day of capacity to its pipeline with a temporary compression upgrade, which had been permitted by the FERC on an expedited, emergency basis. The following year, Kern River replaced the temporary expansion with a permanent, 146 MMcf per day compressor upgrade, bringing the Kern River Pipeline to its present capacity of about 845 MMcf per day. During the summer of 2002, Kern River also completed the 282 MMcf per day High Desert Lateral project, which delivers gas to the 830 MW High Desert Power Plant near Victorville, California. This project is not intended to increase delivery capacity to the California border.

Figure 4-4 illustrates the staff assessment of the how much additional capacity will be needed to accommodate projected capacity demand by 2013. Analysis indicates that the Kern

River pipeline could nearly triple its capacity by 2013 to meet California's growing demand for gas produced in the Rocky Mountain region. Much of this additional capacity is already under construction and expected to be operational in May 2003 when Kern River completes it 906 MMcf per day upgrade, bringing capacity to around 1,750 MMcf per day.

Figure 4-4
Projected Pipeline Capacity Demand
Along the Kern River Pipeline Corridor



Source: California Energy Commission

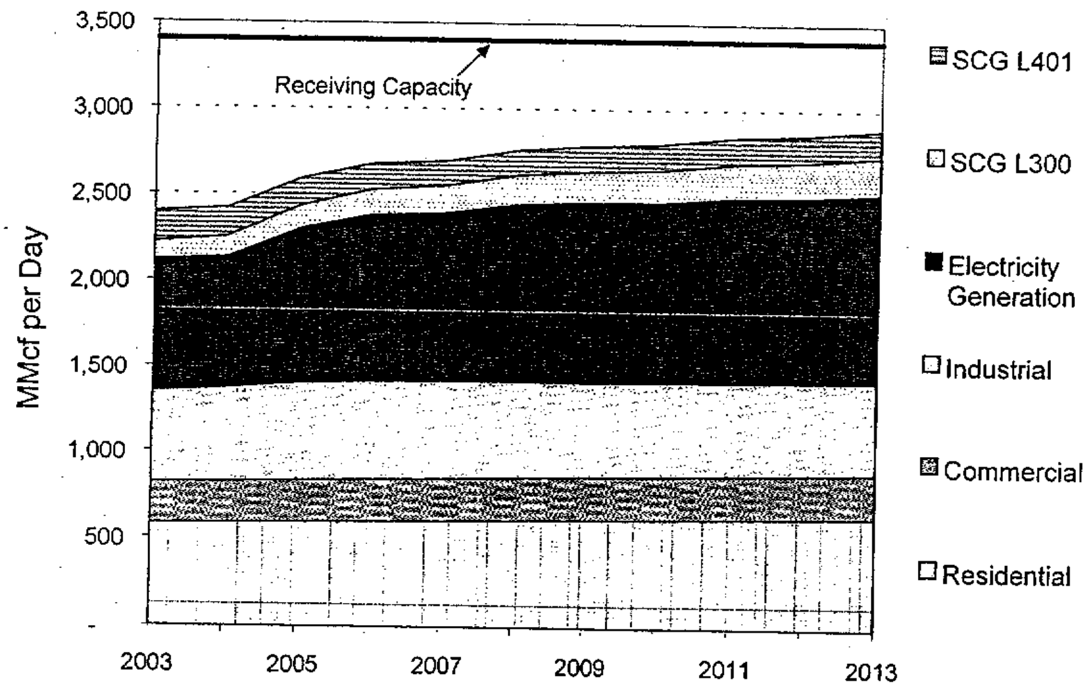
California's Intrastate Pipeline Infrastructure

In 1990, the California Public Utilities Commission (CPUC) adopted a policy requiring the state's investor-owned utilities to maintain excess receiving capacity on their natural gas pipeline systems to provide the flexibility to meet seasonal changes in demand and adverse system conditions. The CPUC determined that it is prudent for the utilities to maintain receiving capacity[8] up to 20 percent above the average annual daily demand in a year with average hydroelectricity and temperature conditions.[9] Many refer to this extra capacity as slack capacity. Analysis by the Energy Commission staff indicates that the largest increase in natural gas demand over the next decade will come from the use of natural gas to fuel electricity generation. Therefore, electricity generation demand will likely determine when and where upgrades to California's intrastate pipeline infrastructure will be most appropriate to maintain sufficient slack capacity within the state.

PG&E Receiving Capacity

Figure 4-5 presents the Energy Commission staff's assessment of the average daily natural gas demand, by sector, in the PG&E service area from 2003-2013. The demand assessment includes natural gas delivered to SoCalGas from PG&E via the Wheeler Ridge inter-tie and assumes average weather and hydroelectricity conditions. To meet this demand, the PG&E system has a total receiving capacity of about 3,400 MMcf per day, represented in the figure by a horizontal line. This capacity includes the 180 MMcf per day Redwood Path (Line 400/401) expansion that PG&E completed in the summer of 2002.

Figure 4-5
Projected Natural Gas Demand
by End-Use Sector Compared to PG&E's Supply Receiving Capacity



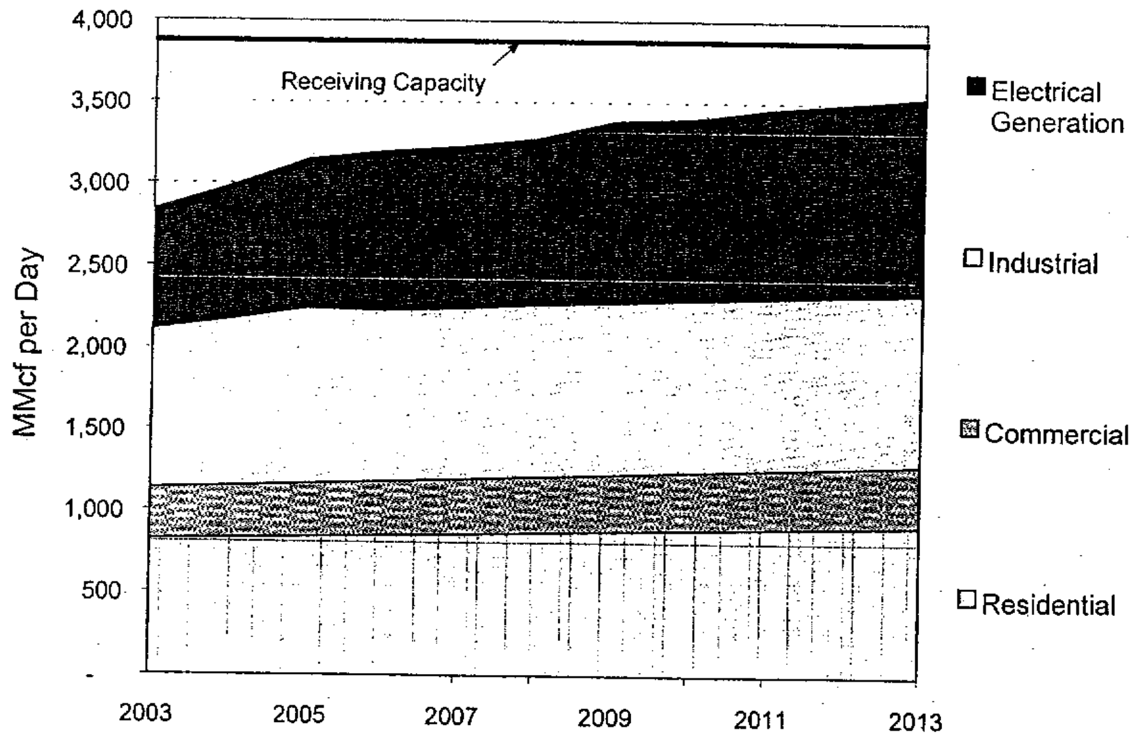
Source: California Energy Commission

Up until 2007, PG&E will have at least 21 percent slack receiving capacity on its system; however, by 2013, the slack receiving capacity drops to 15 percent. Accordingly, PG&E will need to increase its pipeline infrastructure to maintain sufficient slack receiving capacity on its system.

Southern California Gas Company Receiving Capacity

Similar to the previous dicussion, **Figure 4-6** provides the Energy Commission staff's projections of average daily natural gas demand, by sector, for the SoCalGas service area, assuming average weather and hydroelectricity conditions. As in the PG&E service area, electricity generation is the major driver behind rising natural gas demand in Southern California.

Figure 4-6
Projected Natural Gas Demand by End-Use Sector Compared to SoCalGas's Supply Receiving Capacity



Source: California Energy Commission

Since the 2000-2001 energy crisis, SoCalGas has aggresively sought to increase its natural gas receiving capacity. In doing so, SoCalGas has increased its firm receiving capacity from 3,500 MMcf per day to around 3,875 MMcf per day by completing the following projects:

- 85 MMcf per day Wheeler Ridge compressor station expansion
- 50 MMcf per day North Needles compressor station expansion
- 40 MMcf per day Line 85 (Sylmar Compressor Station) compressor station expansion (increasing receipts from in-state production)
- 200 MMcf per day Kramer Junction interconnect pipeline addition

The heavy dark line at the top of the figure reflects the new total receiving capacity, which also includes deliveries of California production into the utility pipeline system. SoCalGas's slack capacity has been greatly enhanced, relative to the annual average daily natural gas demand projected for the next ten years. Slack receiving capacity will range from 37 percent in 2003 to 10 percent in 2013. Without the additions, SoCalGas would not have had any slack receiving capacity on its system by 2013.

San Diego Gas and Electric Service Area

The San Diego Gas and Electric (SDG&E) service territory does not have direct interstate pipeline receiving capability. While this could change if gas from the North Baja Pipeline is eventually allowed to flow from south to north on the TGN pipeline, SDG&E is presently dependent on deliveries from the SoCalGas system to meet all of its natural gas demand. In mid-2001, SoCalGas expanded Line 6900 by 70 MMcf per day, enhancing its delivery capability to SDG&E.

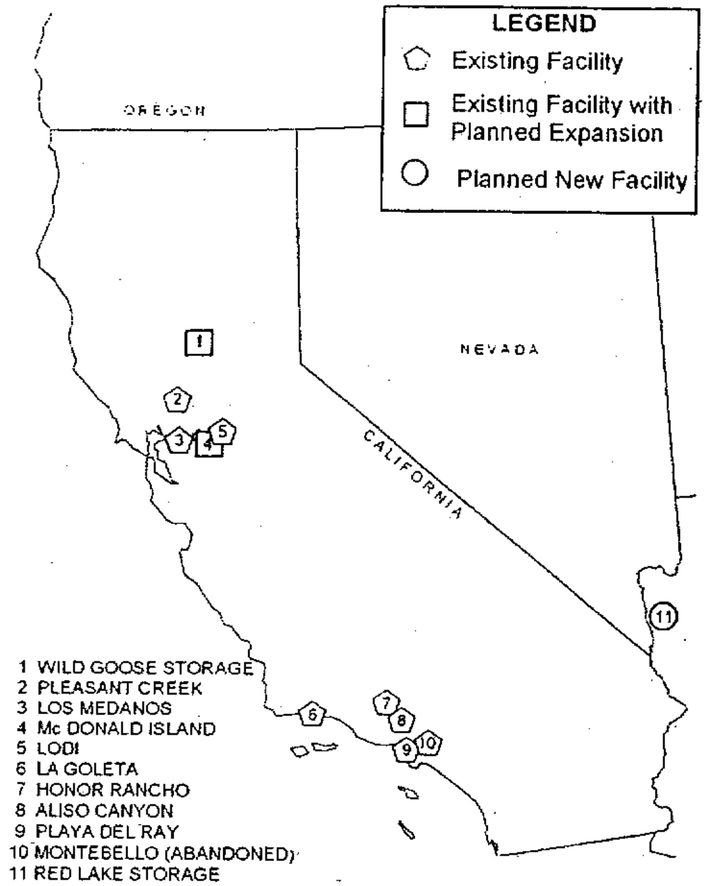
Natural Gas Storage Facilities

Enhancing the inter- and intrastate pipelines are not the only ways to improve California's ability to meet growing natural gas demand; another option is to expand and augment in-state natural gas storage facilities. To this end, a number of projects have been completed since 2001 in both Northern and Southern California. Moreover, by the end of 2004, three more projects in, and around, California are scheduled to go on stream. **Figure 4-7** illustrates the location of existing natural gas storage facilities in California, as well as a recently permitted project in Arizona.

At the end of 2001, Aquila's Lodi Gas Storage Facility began operation, adding 12 billion cubic feet (Bcf) of new storage capacity in Northern California. Future expansions are planned at two other Northern California storage facilities, both with scheduled completion dates around the spring of 2004. PG&E will add 6.5 Bcf of storage capactity to its McDonald Island facility, increasing available storage at that facility from 28.1 Bcf to 34.6 Bcf. EnCana plans to more than double the capacity at the Wild Goose storage facility by adding 15 Bcf to the existing 14 Bcf capacity. EnCana also plans to vastly improve the gas injection and withdrawal rates at Wild Goose.

In Southern California, SoCalGas's ability to meet peak day requirements has been augmented by increasing its storage capacity at the Aliso Canyon and La Goleta storage facilities.

Figure 4-7
Natural Gas Storage Facilities
In and Around California



Source: California Energy Commission

One new facility recently gained the FERC's approval and will begin partial operation at the end of 2003. Aquila's planned 12 Bcf Red Lake storage facility, located near Kingman, Arizona, will serve customers in Arizona, California and Nevada. Aquila expects half of the facility's storage capacity will be available by the end of 2003 with the remainder of the facility operating by the end of 2004.

LNG Import Capability – a Possibility

A natural gas supply option that currently does not exist in, or near, California – but could in the next ten years – is the ability to import liquefied natural gas (LNG) via transoceanic freighter (LNG tanker). As yet, no company has filed an application for a permit to build an LNG terminal in California, but several companies have announced plans to explore that option. Other developers have focused on Baja California, Mexico. These companies include

Marathon Oil, Sempra, and ChevronTexaco, all of whom have filed applications with the Mexican government. Potential developers of these projects seek to provide natural gas for use at local power plants, as well as demand in California and east of California.

In the upcoming *2003 Natural Gas Market Outlook* report, the Energy Commission staff intends to investigate the impact of LNG imports in or near California on the need for future natural gas infrastructure improvements, among other issues.

Endnotes

1. WSCC, *2001 Information Summary*
2. Northwest Power Pool, *Monthly Report, December 2002*. Figures include control areas in Canada.
3. The 'sparkspread' measures the difference between the fuel costs of generation and the wholesale price of electricity. As of February 5, 2003, 12-month strips for 6x16 delivery during 2004 were approximately $54.00 and $57.50 for NP15 and SP15, respectively. Off-peak prices are assumed to average 60 percent-65 percent of peak prices. The forward prices for natural gas for the same period were $4.50 - $4.75/mmBTu.
4. Henwood Energy Services revised their forecast of load growth for the quadrants of the WECC on February 6, 2003. Energy Commission staff has yet to review the new forecast, but plans to do so, and consider its use for the IEPR-related analyses.
5. Currently the rating for Path 45 is 408 MW in the summer and 800 MW in the winter. The physical additions have been completed but the path rating increase has not received WECC approval.
6. California Gas Utilities, 2002 California Gas Report, "Table: Statewide Total Supply Sources and Requirements", July 2002.
7. The Energy Commission staff is aware of additional projects under consideration by developers; however, the staff has chosen to report on only those projects in operation, under construction, or in the permitting process. The staff regularly updates its list of projects as each potential project changes its status.
8. Receiving capacity refers to each utility's ability to take deliveries of gas from the interstate pipelines or in-state production.
9. California Public Utilities Commission, Decision 90-02-016, Order Instituting Investigation on the Commission's own motion into the interstate natural gas pipeline supply and capacity available to California, February 7, 1990.

Appendix A

Table A-1
Additions, California, 2000-2003*

Operational				
Facility	**Output (MW)**	**Online Date**	**Owner**	**N/S Path 15**
CalEnergy Units	59	Jun-00	CalEnergy	S
SMUD GT Projects	66	May-01	SMUD	N
Sunrise Power Phase I	320	Jun-01	Edison Int	S
Sutter Power	540	Jul-01	Calpine	N
Los Medanos	555	Jul-01	Calpine	N
Red Bluff & Chowchilla	96	Aug-01	NEO	N
Hanford Peaker	95	Sep-01	GWF Power	S
Wildflower LLP Peakers	225	Sep-01	Wildflower LLP	S
Alliance Colton Peakers	80	Sep-01	Alliance Colton	S
LADWP CT Projects	235	Nov-01	LADWP	S
Wellhead Peakers	117	Dec-01	Wellhead	S
Gilroy & king City	185	Feb-02	Calpine	N
Delta Energy Center	887	May-02	Calpine	N
Redding	68	Jun-02	City of Ridding	N
Lake One	47	Jul-02	City of Burbank	S
Lemoore (Henrietta)	96	Jul-02	GWF	S
Moss Landing	1060	Jul-02	Duke Energy	N
CalPeak Peakers 1	248	Jul-02	Calpeak	N
Huntington Beach	225	Jul-02	AES	S
Whitewater & Cabazon	103	Sep-02	Cannon Power	S
Valero Cogeneration I	51	Oct-02	Valero Oil	N
La Paloma 1 & 3	562	Jan-03	PG&E NEG	S
Misc Small Units	102	thru Jul-03	Various	
Total Operational	**6022**			
Under Construction				
Facility	**Output (MW)**	**Estimated Online Date**	**Owner**	**N/S Path 15**
La Paloma 2 & 4	562	Feb-03	PG&E NEG	S
Blythe	520	Mar-03	Summit Energy	S
Tracy	169	Apr-03	GWF	N
Woodland	80	May-03	MID	N
Calpine Peakers 2	405	May-03	Calpine	N
Elk Hills CC	500	Jun-03	Sempra/OXY	S
Colton Peaker	43	Jul-03	Colton PUD	S
Sunrise Power Phase II	265	Jul-03	Edison Int	S
High Desert	830	Jul-03	Constellation	S
Total Under Construction	**3374**			

* Through July 2003

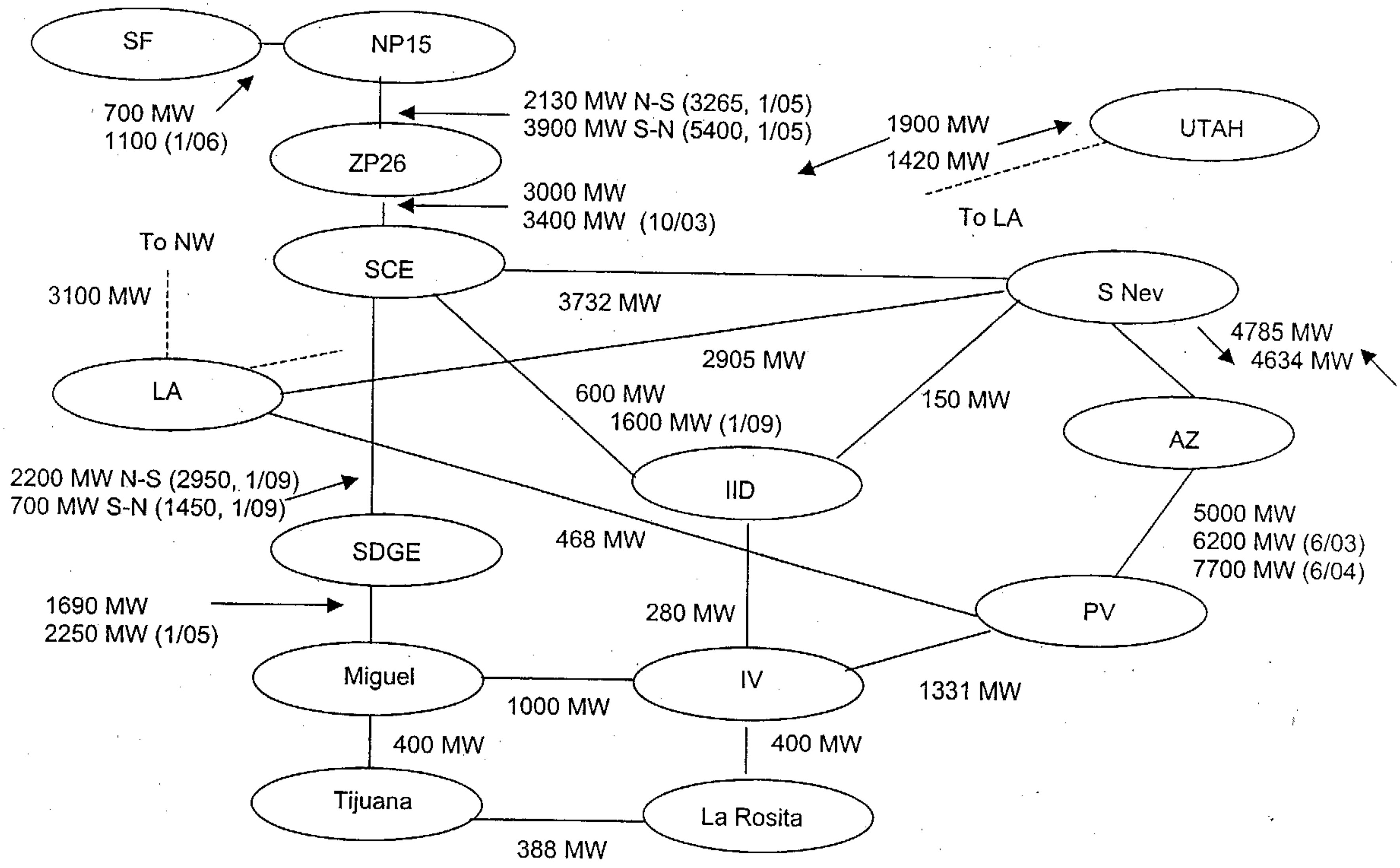
Table A-2
Additions, Northwest and Southwest and Mexico,
January - July 2003 (MW)

Facility	Location	Output (MW)	Est. Online Date	Company
Northwest				
Tesoro Phase I	Washington	19	Jan-03	Tesoro
Nine Canyon	Washington	48	Jan-03	Energy Northwest
Cold Lake	Can. - Alberta	160	Feb-03	Imperial Oil
Fort Macleod	Can. - Alberta	70	Mar-03	Altec Power
Scotford	Can. - Alberta	160	Mar-03	ATCO
Pingston	Canada - BC	30	Mar-03	Canadian Hydro
Muskeg River	Can. - Alberta	170	Mar-03	ATCO
Rye Patch	Nevada	12	Mar-03	Mt Wheeler power
Bear Creek Cogeneration	Can. - Alberta	80	Mar-03	TransCanada
Calgary Energy Centre	Can. - Alberta	300	Apr-03	Calpine
Rocky Reach Rehabilitation	Washington	27	Apr-03	Chelan PUD
Intermountain Unit 1 Ph 1	Utah	25	May-03	IPA
Goldendale	Washington	248	Jul-03	Calpine
Total		**1349**		
Southwest				
Lordsburg (Pyramid)	New Mexico	160	Apr-03	Tri-State
Apex Industrial I	Nevada	550	Apr-03	Mirant
West Phoenix (Phase 2)	Arizona	530	Jun-03	APS
Gila River	Arizona	1060	Jul-03	Panda Energy/TECO
Mesquite Power I	Arizona	630	Jul-03	Sempra Energy
Total		**2930**		
Mexico				
Energia de Baja Phase 2	Mexico - Baja California	150	Apr-03	Intergen
La Rosita(Energia Azteca)	Mexico - Baja California	750	Apr-03	Intergen
Thermoelectrica de Mexicali	Mexico - Baja California	600	Jun-03	Sempra
Total		**1500**		

Table A-3
Additions, Remainder of WECC, 2004-2006 (MW)

Northwest		
Edmonton Cogen	Sep-03	30
Pincher Creek	Oct-03	37
Bonanza Upgrade	Jan-04	80
First Megawatts CC	May-04	240
Genesee	Dec-04	450
Total		**837**
Southwest		
Gila River	Aug-03	1060
Reliant Bighorn	Oct-03	580
Pyramid Power Plant	Oct-03	152
Mesquite CC	Jan-04	625
Santan CC	Jun-05	825
Total		**3242**
Mexico		
TDM CC	Aug-03	600
Rockies		
Rocky Mountain EC	May-04	601

Figure A-1
Transmission Topology



Appendix B

PG&E, SDG&E, and SCE Transmission Projects

Table B-1
PG&E Transmission Projects – Humboldt Area

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T376	Humboldt 60 kV protection upgrade	Reliability: Resolve transient instability in the Humboldt area	9/1/03	Yes	Yes	No	Planning	Upgrade to High Speed Protection Schemes.
T658	Humboldt-Arcata Third Line	Reliability: Increase 60kV supply at Arcata Substation	10/1/04	Yes (Scope Mod.)	Pending Cost Estimate	No (NOC)	Planning	Construct 3rd 60kV transmission line between Humboldt and Arcata Substations.

Table B-2
PG&E Transmission Projects – North Coast and North Bay Areas

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T572	Fulton - St. Helena Jct. 60 kV Line SCADA	Low voltages, emergency overload	3/31/02	Yes	Yes	No	In service	Install Supervisory Control and Data Acquisition (SCADA) for remote load transfer operation.
T643	Tulucay - Napa #1 & #2 60 kV Line Reconductoring	Reliability: Resolve thermal overload	9/1/02	Yes	Yes	No (NOC effective)	In service	Reconductor a 60 kV line.
T777	Fulton-Santa Rosa 115 kV Line Reconductoring	Reliability: category B	5/1/03	Yes	Pending Cost Estimate	No (NOC)	Planning	Reconductor lines.
T254	Sonoma/Mendocino Coast Voltage Support	Reliability: Provide voltage support	5/1/04	Yes	Pending Cost Estimate	No	Planning	Install distribution capacitors at Big River Substation.
T245	Lakeville 230/115 kV Transformer	Reliability: Resolve Emergency low voltage and thermal overloads	5/1/04	No (scope change from 2001)	Pending Cost Estimate	No	Planning	Replace Transformers Nos. 1 and 1A with one large (420 MVA) transformer.
T199	Ignacio 115/60 kV Transformer	Reliability: Increase 60 kV supply	5/1/06	No	No	No	Planning	Add a new 115/60 kV transformer.
T253	Sonoma - Napa Electric Transmission Capacity Project	Reliability: Increase capacity of power interchange	5/1/06	No	No	TBD	Planning	Construct one or two 115 kV transmission circuits from Lakeville Substation to Sonoma and Pueblo Substations. May involve 230 kV facilities.
T654	Eagle Rock-Mendocino System Upgrade	Reliability: increase transmission capacity	TBD				Planning	In early planning stage, may involve construction of 230kV transmission facilities.

Table B-3
PG&E Transmission Projects – Central Coast and Los Padres Areas

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date.	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T833	Diablo Canyon Power Plant Special Protection System	Reliability: Increase grid reliability	2/1/04	Yes	No	No	Planning	SPS to trip generation. Change in schedule to coordinate with re-fueling.
T698	Salinas 115/60 kV Transformer Capacity Increase	Reliability: Increase 60 kV supply	5/1/04	Yes	Pending Cost Estimate	No	Planning	Install a third 115/60 kV transformer bank at Salinas Substation.
T049	Moss Landing-Green Valley 115 kV Line Reconductoring	Reliability: category B	12/1/04	Yes	No	No (NOC)	Planning	Reconductor both lines.

Table B-4
PG&E Transmission Projects – North Valley Area

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T228	Paradise Area Reinforcement Project	Resolve normal & emergency overload, low voltage	3/1/02	Yes	Yes	No (PTC effective)	In service	Reliability: increase capacity of Paradise Substation.
T230	Cottonwood 60 kV Line Reconfiguration	Reliability: category A	7/31/02	Yes	Yes	No	In service	Modify 60 kV switches.
N/A	Round Mountain 500/230 kV Transformer Bank Upgrade	Reliability	12/31/03	N/A	Yes	No	Construction	Replace existing 3-280 MVA single pahse bank with 4-374 MVA single phase banks.
T901	Cottonwood 230/60 kV Transformer	Reliability: Increase 60 kV supply at Cottonwood	5/1/05	Not yet (New Project)	Not yet	No	Planning	Add a new 230/60 kV transformer at Cottonwood
T759	Atlantic 230/60 kV transformer at Atlantaic Substation	Reliability: Increase 60 kV supply at Atlantic Substation	5/1/05	Not yet	Pending Cost Estimate	No	Planning	Install second 230/60 kV transformer at Atlantic Substation.

Table B-5
PG&E Transmission Projects – Central Valley Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T673 / T675	Cortina-Colusa 60 kV Transmission	Normal and Emergency overloads, Low Voltages	2/1/02	Yes	Yes	No (NOC effective)	In service	Reconductor portion of the Cortina-Colusa 60 kV Transmission Line #3.
T691	Rerate Rio Oso-Atlantic and Rio Oso-Gold Hill 230 kV Lines	Resolve normal and emergency 115 kV line overloads	9/1/02	Yes	No	No	In service	Rerate 230 kV lines.
T881	Path 26 Contingency RAS South-to-North	Reliability: Increase capacity of power interchange between PG&E and SCE	12/1/02	Yes	Yes	No	In service	Install substation equipment at Midway Substation and modify computer software at the San Francisco RAS Controller.
T891	Vaca Dixon 230 kV Breaker	Reliability: Increase transmission of 115 kV power and reduce Reliability Must Run contract cost	5/1/03	Yes	Yes	No	Construction	Install a new 230kV circuit breaker at Vaca Dixon Substation dedicated to the 115/230 kV Transformer No. 4.
T242	Goldhill 230/115 kV Transformer Bank	Reliability: Resolve thermal overload	6/1/03	Yes	Yes	No	Construction	Increase transformer capacity.
T346	Cortina Substation Capacity Increase	Reliability: Resolve thermal overload	5/1/04	Yes	Pending Cost Estimate	No	Planning	Install a new 230/115 kV transformer.
T758	Brighton Second 230/115 kV Transformer Bank	Reliability: Increase 115 kV supply	5/1/04	Yes	Pending Cost Estimate	No (NOC TBD)	Planning	Install second transformer.
T177	West Sacramento - Davis	Reliability: Serve increased loads	5/1/04	Yes	Pending Cost Estimate	No (NOC/PTC TBD)	Planning	Convert 60 kV facilities to 115 kV.

Table B-5 – Continued
PG&E Transmission Projects – Central Valley Area

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T101	Atlantic-Del Mar New 60kV line	Reliability: Resolve normal overload and low voltage	5/1/04	Yes	Yes	No (PTC under CPUC review)	Permitting	CPUC A.01-07-004. Currently in the CPUC permitting process.
T243	Colgate-Smartville 60 kV Line Reconductoring	Reliability: category B	5/1/04	Yes	Pending Cost Estimate	No (NOC)	Planning	Reconductor Colgate-Smartville Nos. 1 and 2 lines. 01/27/03 PG&E Draft Yuba and Sutter Counties Long-Term Transmission Plan lists expected on-line date as 11/03.
T786	Lockeford 230/60 kV Capacity Increase	Reliability: resolve overload	5/1/04	No (scope change from 2000)	Pending Cost Estimate	No	Planning	Replace existing 134 MVA transformer with two 200 MVA transformers.
T845	Tesla 230/115 kV Transformer Bank	Reliability: Increase 115 kV supply	5/1/04	Yes	Yes	No	Planning	Replace Transformer Bank No. 1.
T678	Lockeford 230 kV Voltage Support	Reliability: Provide voltage support to area around Lockeford Substation	5/1/04	Yes	Pending Cost Estimate	TBD	Planning	Loop the Brighton-Bellota 230 kV transmission line into Lockeford Substation; other alternatives are being investigated.
N/A	Path 15 Upgrade; new 500 kV line (MOU project)	Increase transfer capability of Path 15 from 3,900 MW to 5,400 MW (south to north)	1/1/05	Yes (6/25/02)	N/A	N/A	Letter Agreement accepted by FERC on 6/12/02	May 2002 - MOU between Trans-Elect, PG&E, and WAPA has been initiated with the following ownership percentages: Trans-Elect at 72%, PG&E at 18%, and WAPA at 10%. PG&E would be responsible for substation modifications at Los Banos and Gates. WAPA would act as project manager. Letter Agreement filed with FERC on April 30, 2002, and accepted by FERC on 6/12/02. Approved by ISO Board on 6/25/02. Participants are working on more detailed agreements necessary to complete the project. No release date has been identified. 12/30/02 MOU (Construction and Coordination Agreement) signed between WAPA, TransElect, PG&E.

Table B-5 - Continued
PG&E Transmission Projects – Central Valley Area

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T783	Vaca Dixon 230kV Transformer Replacement	Reliability: Increase 115 kV supply	5/1/05	Yes	Pending Cost Estimate	No	Planning	Transformer replacement. The addition of a 230 kV circuit breaker has changed the timing of this project.
T314	Colgate 230/60 kV Capacity Increase	Reliability: Increase power to 60 kV grid	5/1/05	Yes	Pending Cost Estimate	No	Planning	Installation of second transformer is an infeasible alternative. Other options are being assessed to determine recommended alternative.
T815	Marysville-Pease 60 kV Line	Reliability: Increase 60 kV capacity to Marysville Substation	5/1/07	No	No	No	Planning	PG&E is not requesting ISO approval at this time. Additional analysis will be performed as part of the 2003 Expansion Plan to determine a preferred plan.
T686	Palermo-Rio Oso 115 kV Line	Reliability: resolve overloads	5/1/07	No	No	No	Planning	PG&E is not requesting ISO approval at this time. Additional analysis will be performed as part of the 2003 Expansion Plan to determine a preferred plan.
T444	Gold Hill-Placer 115 kV Lines	Reliability: category B	5/1/07	No (scope change from 2001)	Pending Cost Estimate	No (NOC)	Planning	Reconductor the limiting sections of the No. 2 line.

Table B-6
PG&E Transmission Projects – Greater Fresno and Kern Areas

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T362	Oakhurst Area Reinforcement - Kerckhoff 1-Kerckhoff 2 Lines and Breakers	Reliability: Emergency overload, Low voltages	3/1/02	Yes	Yes	No	In service	Breaker work completed in 3/02. See T756 for Phase 2 reconductoring work.
T646	Panoche - Panoche Jct. 115 kV Line Reconductoring	Reliability: Resolve thermal overload	8/21/02	Yes	Yes	No (NOC effective)	In service	Reconductor 115 kV lines between Panoche-Oro Loma and Panoche-Mendota.
T765	Midway Third 500/230 kV Transformer	Reliability: Resolve normal and emergency overloads	11/1/02	Yes	Yes	No	In service	Install third transformer to accommodate new Kern County generation.
T848	Madera Power-Newhall Reconductoring	Reliability: category B	11/13/02	Yes	Yes	No	In service	Reconductor line.
T756	Oakhurst Area Line Reconductoring	Reliability: Increase capacity	1/18/03	Yes	Yes	No (NOC effective)	In service	Reconductor Lines. See T362 for circuit breaker work.
T855	Wilson-Le Grand 115 kV Reconductoring	Reliability: category B	5/1/03	Yes	Yes	No	Planning	Reconductor lines.
T717	Reedley 115/70 kV Special Protection System	Reliability: Increase grid reliability	5/1/03	Yes	Yes	No	Planning	Install Special Protection Scheme at Reedley Substation.
T706b	Wilson 115 kV Bus Reconfiguration	Reliability: Increase 115 kV power and reduce Reliability Must Run contract cost	5/1/03	Yes	Yes	No	Construction	Reconfigure the Wilson 115 kV bus to balance thermal loading between transformers Nos. 1 and 2.
T726	Midway-McCall 115 kV Line	Reliability: Increase capacity of power interchange between substations	5/1/03	Yes	Pending Cost Estimate	No	Planning	Rerate lines and add SCADA.
T857	Arco 230/70 kV Special Protection System	Reliability: Resolve low voltage	5/1/03	Yes	Yes	No	Planning	Expand the existing Special Protection System to guard against low voltage.

Table B-6 - Continued
PG&E Transmission Projects – Greater Fresno and Kern Areas

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T708	Wilson 230/115 kV Transformer Upgrade	Reliability	5/1/04	Yes	Pending Cost Estimate	No	Planning	Transformer replacement.
T710	Los Banos Second 230/70 kV Bank	Reliability: Increase 70 kV supply	5/1/04	Yes	Pending Cost Estimate	No	Planning	Install second transformer bank.
T496	Westpark-Magunden 115 kV Reconductoring	Reliability: Increase capacity of power interchange	5/1/04	Yes	Pending Cost Estimate	No (NOC)	Planning	Reconductor 115 kV lines.
T717A	Reedley 115/70 kV Transformer	Reliability: Increase 70 kV supply at Reedley	5/1/05	Not yet	Not yet	No	Planning	Add a new 115/70 kV transformer at Reedley
T706a	Wilson 230 kV Loop		5/1/05	Yes	?	?	Detailed Scoping	Loop Warnerville-Borden 230 kV line into Wilson.
T725	Midway 230/115 kV Transformer Bank Replacement	Reliability: Increase 115 kV supply	5/1/05	Yes	Pending Cost Estimate	No	Planning	ReplaceTransformer Bank No. 1 with a larger (420 MVA) bank.
T773	Kern 230/115 kV Transformer Bank Replacement	Reliability: Increase 115 kV supply	5/1/05	Yes	Pending Cost Estimate	No	Planning	Replace Transformer Bank No. 4 with a larger (420 MVA) bank.
T316	Borden 230/70 kV Second Transformer	Reliability: Increase 70 kV supply	5/1/06	Yes	Pending Cost Estimate	No	Planning	Install second transformer.

Table B-7
PG&E Transmission Projects – Greater Bay Area

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T339	BART SFO Extension - Shaw Road Sub	Interconnect BART's Shaw Substation to the transmission grid	1/1/02	Yes	Yes	No	In service	Customer funded. Reliability: serve new loads.
T665	Pittsburg-Tassajara 230 kV Line Reconductoring - Phase 2	Normal and emergency line overloads	4/1/02	Yes	Yes	No (NOC effective)	In service	Reconductor remainder (12 miles) of Pittsburg-Tassajara transmission line. 1/27/03: ISO lists in-service date as 4/1/02.
T768	Pittsburg 230 kV Line Reactors	Normal and emergency overloads	4/1/02	Yes	Yes	No	In service	For accommodating Los Medanos generation.
T764a	Metcalf-Moss Landing 230 kV Line Rerate	Reliability: Increase capacity of power interchange between substations	4/1/02	Yes	Yes	No	In service	
T635	San Mateo-Martin 115 kV line capacity increase	Increase import capability to San Francisco, Daly City and the Peninsula Corridor	4/30/02	Yes	Yes	No (NOC effective)	In service	Increase rating by re-conductoring the underground 115 kV "dips" near the S.F. International Airport and rerating the overhead 115 kV lines. 1/31/03: CAISO revised on-line date from 5/02 to 4/02.
T558 Phase I	Tesla Third 500/230 kV Transformer Bank - Phase I	Resolve normal and emergency overloads	6/15/02	Yes	Yes	No	In service	Install new transformer bank. See also T558 Phase II.
T745	Bay Area Reactive: Potrero 115 kV Shunt Capacitor	Reliability: Provide voltage support	6/17/02	Yes	Yes	No	In service	Install 150 MVar of 115 kV shunt capacitors at Potrero.
T081	San Mateo South 115kV Transmission Reinforcements	Emergency 115 kV line overload	7/31/02	Yes	Yes	No (NOC effective)	In service	Build 2nd Ravenswood-Bair line using existing structures.

Table B-7 Continued
PG&E Transmission Projects – Greater Bay Area

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T181	North Receiving Station - Santa Clara	New customer substation	7/31/02	Yes	Yes	No	In service	Connect Silicon Valley Power's (Santa Clara) Northern Receiving Substation to both existing Newark-Scott 115kV lines.
T088	BART SFO Extension - Santa Paula Sub	New customer substation	12/8/02	Yes	Yes	No	In service	Customer funded.
T787	Ravenswood-San Mateo 230 kV Line Reconductoring	Reliability: G-4, L-1	12/31/02	Yes	Yes	No (NOC effective)	In service	Install bundled conductors on #2 circuit.
T784	Pittsburg-Martinez 115 kV Line Reconductoring	Reliability: category B	5/1/03	Yes	Yes	No (NOC effective)	Construction	Reconductor two 115 kV lines.
T769	San Jose B-FMC Junction 115 kV Line	Reliability: category B	5/1/03	Yes	Yes	No	Planning	Reconductor one span.
T771	Monta Vista 230/115 kV Transformer Replacement	Resolve emergency overload. Reliability: category B	5/1/03	Yes	Yes	No	Construction	Replace Transformer No. 3 with a 420 MVA bank.
T792	Pittsburg 230/115 kV Bank Capacity Increase	Congestion and RMR issues	5/1/03	Yes	Yes	No	Construction	Replace a smaller-size transformer with a 420 MVA transformer.
T846	Newark/Dumbarton 115 kV Line	Reliability: category B	5/1/03	Yes	Yes	No	Planning	Install protection equipment to guard against an equipment overloading problem.
T157	Tri-Valley Long Term Transmission Project	Resolve insufficient 60 kV normal capacity	5/1/03	Yes	Yes	Yes; filed and completed on 10/10/01	Construction	CPUC A.99-11-025. Construct two 230/21 kV distribution substations and sections of 230 kV overhead and underground transmission lines.
T197	Ignacio 230/115 kV Capacity Increase	Resolve emergency overload	5/1/03	Yes	Yes	No	Construction	Install a new 230/115 kV transformer.
T655a	Jefferson Bank Capacity - Protection Work	Emergency overload, Low voltages	5/1/03	Yes	Yes	No	Construction	Modify 60 kV line projection in 2002, and install second Jefferson transformer in 2005 (see T655b).
T010	Nortech (Kifer-Trimble) 115 kV Loop	Reliability: Increase reliability of supply to Nortech Substation	5/1/03	Yes	Yes	No (PTC Effective)	Construction	CPUC A.98-06-001. New 115 kV substation and new 115 kV lines. Has encountered local permitting delays.

Table B-7 Continued
PG&E Transmission Projects – Greater Bay Area

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T011	Northeast San Jose Reinforcement Project	Reliability: Resolve normal and emerg. line and transformer overloads	5/1/03	Yes	Yes	Yes; filed and completed in March 2002	Construction	CPUC A.98-07-007. Construct new 230/115 kV Los Esteros Substation, two new 230 kV Los Esteros-Newark circuits, new 115 kV Los Esteros-Montague circuit, and reroute 115 kV line from Newark to Milpitas.
T340	Metcalf 230/115 kV fourth transformer bank	Reliability: Resolve emergency transformers' overload	5/1/03	Yes	Yes	No	Construction	Install a fourth transformer.
T590	Metcalf 500/230 kV Third Transformer Bank	Reliability: Resolve emergency transformers' overload	6/1/03	Yes	Yes	No	Construction	Install a fourth transformer.
T558 Phase II	Tesla 500/230 kV Third Transformer Bank - Phase II	Resolve normal and emergency overloads	6/1/03	Yes	Yes	No	Construction	Install third transformer.
T767	Metcalf 500 kV Special Protection Scheme	Reliability: category C	12/1/03	Yes	Pending Cost Estimate	No	Planning	Construct permanent connection facilities for the third 500/230 kV transformer. See also T558 phase I.
T902	East Shore 230 kV Circuit Breaker	Reliability: Increase reliability of supply	5/1/04	Yes	No	No	Planning	Install a special protection scheme to drop load after an overlapping outage of two 500 kV lines.
T847	Newark-Fremont 115 kV Line	Reliability: Increase capacity of power interchange between substations	5/1/04	Yes	Pending Cost Estimate	NOC	Planning	Install a 230 kV circuit breaker at East Shore.
T656	Ravenswood 230/115kV Capacity Increase	Reliability: Increase 115kV at Substation	5/1/04	Yes	Pending Cost Estimate	No	Planning	Reconductor the Newark-Fremont 115kV transmission line.
T744	Hunters Point-Potrero 115 kV Circuit	Reliability: Increase reliability of supply in San Francisco	5/1/04	Yes	Pending Cost Estimate	PTC/NOC TBD	Planning	Install 2nd 230/115kV transformer at Ravenswood Substation.
T521	FMC 115 kV Loop	Increase service reliability	5/1/04	Yes	Yes	No (PTC effective)	Planning	Install a 115 kV underground cable between Potrero and Hunters Point Power Plant Switchyards.

Table B-7 Continued
PG&E Transmission Projects – Greater Bay Area

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T694	Metcalf - El Patio 115 kV Reconductoring	Reliability: Increase 115 kV supply	5/1/04	Yes	Pending Cost Estimate	No (NOC)	Planning	Second 115 kV line to FMC Distribution Substation.
T747	City of Santa Clara/Silicon Valley Power - PG&E 230 kV Interconnection	Tariff Compliance	5/1/04	No	Customer Funded	No	Planning	Interconnect Silicon Valley's proposed 230 kV line from its Northern Receiving Station to Los Esteros Substation.
T790	Bay Area Reactive: Potrero SVC	Reliability: voltage support	9/1/04	No (New Project)	No	No	Planning	Install a +240/-100 Static Var Compensator at either Potrero Switchyard or Hunters Point Switchyard.
T746	San Mateo-Martin 60kV conversion to 115kV and Line Reconductoring.	Reliability: increase power supply to SF and No. San Mateo County	12/1/04	Yes	Pending Cost Estimate	Application pending; NOC/PTC/ TBD	Planning	A. Upgrade 60kV TL between San Mateo and Martin Substation to 115kV and reconductor. B. Install 115/60kV transformer at Millbrae Substation. C Upgrade Burlingame Substation from 60kV to 115kV.
T772	Contra Costa-Las Positas 230 kV Line	Reliability: category B	5/1/05	Yes	Pending Cost Estimate	No (NOC)	Planning	Mirant has announced a two-year delay in its Contra Costa 8 powerplant project. On line date changed from 5/1/03 to 5/1/05.
T655b	Jefferson Bank Capacity - Transformer Work	Emergency overload, low voltages	5/1/05	Yes	Pending Cost Estimate	No	Planning	Install a second transformer bank. See also T655a (modify 60 kV line protection.)
T854	Metcalf - Evergreen 115 kV Reconductoring	Reliability: Increase 115 kV supply	5/1/05	Yes	Pending Cost Estimate	No (NOC)	Planning	Reconductor 115 kV lines between Metcalf and Evergreen Substations.
T692	Metcalf-Piercy and Newark Dixon Landing 115 kV Reconductoring	Reliability: Increase capacity of power interchange between substations	5/1/05	Yes	Pending Cost Estimate	No	Planning	Reconductor the lines.

Table B-7 Continued
PG&E Transmission Projects – Greater Bay Area

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
T082	Jefferson-Martin (San Francisco Peninsula) New 230 kV line	Transmission deficiency under contingency condition	9/1/05	Yes	Yes	Yes (Pending)	Planning	CPUC A.02-09-043. ISO Board approved the beginning of permitting process. See S.F. Peninsula Long-Term Planning Study. 9/1/02 - PG&E still preparing Proponent's Environmental Assessment. PG&E filed CPCN application 9/30/02. 1/10/03 - Pre-Hearing Conf. at CPUC.
T776	Monta Vista 60 kV Upgrade	Reliability: Increase 60 kV supply	5/1/06	Yes	Pending Cost Estimate	No	Planning	Replace the existing Monta Vista 115/60 kV transformer with a larger unit.
T073	Bay Area 500 kV Transmission Long Term Plan	Increased electric demand in the Bay Area	TBD	No	No	Yes (TBD)	Planning	Final alternative is not selected. In the conceptual planning stage. Phase 2 economic studies underway with input from the CAISO, San Francisco, and Palo Alto.

Table B-8
SDG&E Transmission Projects

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
BP98195	Sycamore Canyon Substation: New 230/69 kV transformer	Reliability: Handle load growth	6/1/02	Yes	Yes	No	In service	Install new 230/69 kV (224 MVA) transformer bank.
BP99125A	Install reactive power support (Talega Substation capacitors and STATCOM)	Reliability: Provide reactive power support and support increase to import capability	12/1/02	Yes	Yes	No	In service	Install 207 MVAR, 230 kV capacitor bank and 100 MVAR, 230 kV STATCOM at Talega Substation.
BP98191	Reconductor TL 622: Chollas-Spring Valley 69 kV Line	Reliability: Resolve Chollas-Spring Valley 2.5% overload	12/1/02	Yes	Yes	No	In service	Supports load growth in the Lemon Grove and Spring Valley areas.
BP99120	Expand 230 kV capability at San Luis Rey Substation	Reliability: Support increase in import capability and load growth	4/1/03	Yes	Yes	No	Construction	Loop three 230 kV lines into San Luis Rey Substation and upgrade one 138 kV line to 230 kV.
BP01148A	Imperial Valley 500/230 kV Transformer Upgrades Phase A - replace existing bank	Economic: mitigate congestion	6/1/03	Yes	Yes	No	Design/ Construction	Phase A involves replacing the existing bank. Mitigates transmission system congestion due to new generation injection from the La Rosita Expansion Projects, SER's Thermoelectrica de Mexicali Project, and high exports from CFE.
BP01143	Reconductor TL649F: Border Tap - Otay Lake Tap 69 kV	Economic: remove Congestion	12/1/03	Yes	Yes	No	Design	Reconductor 5.7 miles of 69 kV line from Border Tap to Otay Lake Tap.
BP01148B	Imperial Valley 500/230 kV Transformer Upgrades Phase B - add a second bank	Economic: mitigate congestion	12/1/03	Yes	Yes	No	Design/ Construction	Phase B involves installing a new second 500/230 kV transformer bank. Mitigates transmission system congestion due to new generation injection from the La Rosita Expansion Projects, SER's Thermoelectrica de Mexicali Project, and high exports from CFE.
BP01146	Reconductor Portion of TL636 and TL638 at Santee Substation and Loop-in TL13821	Reliability: load growth	12/1/03	Yes	Yes	No	Design	This project is associated with the Santee 138kV Conversion Project proposed by Distribution Planning. Reconductor 3.8 miles of two 69 kV lines near Santee Substation.
BP01147	San Diego-Coronado 69 kV Line: Relocate Portion of the Line Under the San Diego Bay	Mandated/ Reliability	2/1/04	Yes	Yes	No	Design	Project conflicts with the proposed channel dredging of the San Diego Bay by the US Army Corps of Engineers.

Table B-8 continued
SDG&E Transmission Projects

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
BP95144	Torrey Pines-UCM Substation 69 kV Line	Reliability: Handle load growth	6/1/04	Pending	Yes	PTC expected	Planning	Construct approximately 2.5 miles of new underground 69 kV line between UCM and Torrey Pines Substations.
BP02162	TL 13813 and TL 13814 Capacity Increase	Reliability: Handle load growth	6/1/04	Not yet	Yes	No	Planning	Increase capacity of TL 13813 and TL 13814, South Bay-Main street line reconductoring.
BP02160	Transmission Capacitors	Reliability: Support load growth	6/1/04	Not yet	Yes	No	Planning	Install transmission capacitors at Telegraph Canyon, Sycamore Canyon, and San Luis Rey.
BP00150	Reinforce TL23030 Transmission Between Escondido and Orange County	Reliablity	12/1/04	Yes	Yes	Part of Valley-Rainbow CPCN	On hold	Reinforce TL23030 Transmission Between Escondido and Orange County
BP02161	Upgrade Scripps Sycamore Canyon and Miramar to Scripps	Reliability: Handle load growth	6/1/05	Not yet	Yes	No	Planning	Build new 69 kV line between Sycamore Canyon and Miramar Substations.
BP00146	Escondido-Lilac: Reconductor TL688	Reliability: Mitigate thermal overload	6/1/05	Yes	Yes	No	Design	Reconductor 9 miles of the Escondido-Lilac 69 kV transmission line.
BP01144	Miguel-Mission Second 230 kV line	Economic: Remove congestion; accommodate new generation south of Miguel Substation	6/1/05	Yes	Yes	Yes	Permitting/ Design	CPUC Proceeding I.00-11-001. A. Construct a new 230 kV double-circuit line from Miguel Substation to Fanita Junction, using the existing 138 kV steel tower line. B. Extend the new 230 kV line from Fanita Junction to Mission Substation. 6/25/02 - ISO approval obtained. 7/12/02 - Application for CPCN filed (A.02-07-022). 8/12/02 - SDG&E received deficiency letter for their CPCN application. 9/6/02 - Pre-hearing conference was held on CPCN application. 1/27/03 - the CPCN application was deemed adequate.
BP98192	Escondido-Ash: Reconductor TL 696	Reliability: Escondido-Ash 1% overload & increases transmission capacity to Ash	6/1/05	Yes	Yes	No	Design	Reconductor 3.5 miles of 69 kV line between Escondido and Ash Substations.
BP00152A	Static and Dynamic Reactive Power Support	Reliability	6/1/05	Subject to re-evaluation	Yes	Part of Valley-Rainbow CPCN	On hold	Install 69 MVAR, 230 kV capacitor bank at Miguel Substation; install 200 MVAR STATCOM at Mission Substation.

Table B-8 continued
SDG&E Transmission Projects

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
BP00154	Shadowridge-Calavera Tap: Reconductor TL 13802B	Reliability: Load growth	6/1/06	Yes	Yes	No	Design	Reconductor 3.5 miles of the 138 kV Shadow Ridge-Calavera Tap transmission line.
BP01141	Reconductor 138 kV Talega-Pico Transmission Line	Reliability: Handle load growth	6/1/07	Under study	Yes	No	Planning	Reconductor 0.68 miles of 138 kV line between Talega and Pico Substations.
BP01142	Rincon-Lilac 69 kV: Reconductor TL683	Reliability: Load growth	6/1/07	Yes	Yes	No	Design	Reconductor 12.2 miles of the 69 kV line Rincon-Lilac transmission line. New project due to casino load.
BP00153	Reconductor 138 kV Capistrano-Laguna Niguel Transmission Line	Reliability: Handle load growth	6/1/09	Yes	Yes	No	Planning	Reconductor 2.9 miles of 138 kV line from Capistrano Substation to Laguna Niguel Substation.
BP99123	Valley-Rainbow Interconnection Project, 500 kV	Reliability: Support increase to import capability and load growth	Unknown (previously was 6/1/05)	Yes	Yes	Yes; filed 3/23/01. Docket closed & CPCN denied 12/19/02.	On hold because of CPUC denial on 12/19/02	Appeal filed with CPUC 1/23/03.

Table B-9
SCE Transmission Projects

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
N/A	North of Lugo RAS Modifications - Alta RAS	System Stability	3/1/02	Yes	Yes	No	In service	
04701	Mesa/Pardee/Sylmar 230 kV Transmission Lines	Reliability plus elimination of higher-cost RMR contract	6/1/02	Yes	Yes	No	In service	Replace wave traps on the Mesa/Pardee/Sylmar 230 kV line terminals at Eagle Rock Substation.
04917	Hinson-Lighthipe 230 kV Transmission Line	Reliability	6/1/02	Yes	Yes	No	In service	Replace existing wave traps with 3000A wave traps on the Hinson-Lighthipe 230 kV line terminal at Lighthipe Substation.
04701	Serrano-Villa Park #1 and #2 230 kV Transmission Lines	Reliability plus elimination of higher-cost RMR contract	6/1/02	Yes	Yes	No	In service	Re-rating of the line risers at Serrano Substation on the Serrano-Villa Park #1 and #2 230 kV lines.
04701	Barre-Lewis, Barre Villa Park 230 kV Reconductoring, and misc terminal equipment	Reliability plus elimination of higher-cost RMR contract	6/1/02	Yes	Yes	No	In service	Reconductor Barre-Lewis/Villa Park 230 kV lines.
N/A	North of Lugo RAS Modifications - Mc Gen RAS	Reliability: eliminate risk of N-1 overload	12/31/02	Yes	Yes	No	In service	
04833	Path 26 Upgrade Project (Short-term solution) - - RAS to Drop SCE Load	Economic: increase transfer capability and relieve transmisison congestion	6/1/03	Yes	Yes	No	Construction	Upgrade the existing Path 26 transmission system by installing a new remedial action scheme (RAS) to drop new generation in the Midway area, to increase the path rating from 3000 to 3400 MW north to south (short-term solution.) See also the Path 26 Upgrade Project Long-term solution.
04701	2001 RMR Elimination Project Capacitor Banks	Reliability plus elimination of higher-cost RMR contract	6/1/03	Yes	Yes	No	Construction	Install 79 MVAr, 230 kV capacitor banks at Mesa, La Fresa, and Laguna Bell Substations.
04936	Vincent 500/230 kV Transformer bank	Reliability	7/1/03	No	Yes	No	Construction	Install fourth transformer bank to avoid overload during outage of any of the three transformers at Vincent.
04825	Antelope-Bailey 66 kV System Upgrades (Phase II)	Reliability: minimize voltage problems	1/1/04	Yes	Yes	No	Planning	On-going studies aimed at resolving constraints placed upon wind developers. See also the Tehachapi Transmission Line project below (project ID#04928).

Table B-9 continued
SCE Transmission Projects

PTO ID #	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for funding	CPCN Required	Project Status	Description / Comments
04902	Zack Tap 55 kV Reliability Project (aka Silver Peak Circuit Breaker; aka Control - Zack Switch)	Reliability: reduction of circuit Interruption	6/1/04	Yes	Yes	No	Planning	Install a switch at the tap for the Silver Peak leg on the Control-Zack-White Mountain-Deep Springs 55 kV transmission lines.
03773	Valley Substation 500/115 kV Transformer - Phase 1	Reliability: relieve substation overload	6/1/04	Yes	Yes	No	Construction	Install 500/115 kV Transformer #3 (560 MVA) at Valley Substation.
04521	Mira Loma 500/230 kV Fourth Transformer Bank	Reliability: resolve emergency overloads	6/1/04	No	Yes	No	Planning	Install 500/230 kV Transformer #3 (1120 MVA) at Mira Loma Substation.
04889	Upgrade the three 500 kV Transmission Lines between Lugo, Serrano, and Mira Loma Substations	Reliability: avoid overload during outage of two of the three lines	6/1/04	Yes	Yes	No	Planning	For each of the three lines, this upgrade will do the following: (a) increase separation of line conductors from ground at several locations; (b) replace all wave traps (18 total); and (c) upgrade the 500 kV GIS line riser at Serrano Substation on the Lug
03773	Valley 560 MVA, Fourth 500/115 kV transformer	Reliability: relieve substation overload	2004	Yes	Yes	No	Construction	Install 500/115 kV Transformer #4 at Valley Substation.
03603	Viejo 230/66 kV Substation	Reliability	6/1/05	Yes	Yes	No (PTC expected)	Permitting	Connect to 230 kV system by looping San Onofre-Chino 230 kV line into it.
04928	Tehachapi Transmission Line	Reliability: minimize voltage problems and connect wind generation	12/1/06	No	Yes	No (CPCN expected)	Planning	SCE completed and issued the Phase 2 Tehachapi Transmission Conceptual Study on January 15, 2003. Includes both 230 and 69 kV facilities.
None	Path 26 Upgrade Project (Long-term solution)	Economic: increase transfer capability and relieve transmisison congestion	TBD	No	No	No	Planning	Upgrade the existing Path 26 transmission system by making facility upgrades at the Midway and Vincent Substations, and reconductoring a 500 kV line segment, in order to increase thé bi-directional path rating from 3,400 MW (following a short-term upgrade

Appendix C

Table C-1
Natural Gas Infrastructure Projects Completed Since 2001

Pipeline Owner	Pipeline/Location Name	Nature of Project	Capacity (MMfc/d) *	Completion Date
	Interstate Pipeline Projects (FERC Jurisdiction)			
Kern River Gas Transmission Co.	Kern River Pipeline	Temporary compression upgrade	135	July 2001
PG&E National Energy Group (NEG)	Gas Transmission Northwest (GTN)	Expansion	42	November 2001
Kern River Gas Transmission Co.	Kern River Pipeline	Permanent compression upgrade	146	May 2002
Kern River Gas Transmission Co.	Kern River Pipeline	Removal of temporary upgrade	(135)	May 2002
Transwestern Pipeline Co.	Transwestern Pipeline	Red Rock compression upgrade	120	June 2002
Questar Pipeline Company	Southern Trails Pipelin	Conversion of oil pipeline	80	June 2002
PG&E-NEG/Sempra International	North Baja Pipeline	New pipeline	500	September 2002
Kern River Gas Transmission Co.	High Desert Lateral	New pipeline	282	September 2002
PG&E National Energy Group (NEG)	Gas Transmission Northwest (GTN)	Expansion	169	November 2002
El Paso Natural Gas Company	All-American Pipeline	Conversion of oil pipeline	230	November 2002
Sierra Pacific Resources	Tuscarora Pipeline	Expansion	65	January 2003
Total interstate pipeline capacity additions since 2001			**1,634**	**MMcf/d**
	Intrastate Pipeline Projects (CPUC Jurisdiction)			
SoCalGas	Line 6900	Expansion	70	June 2001
SoCalGas	Wheeler Ridge	Compression upgrade	85	December 2001
SoCalGas	North Needles	Compression upgrade	50	February 2002
SoCalGas	Kramer Junction	New pipeline	200	April 2002
PG&E	Line 400	Redwood Path expansion	179	September 2002
Total intrastate pipeline capacity additions since 2001			**584**	**MMcf/d**
	Intrastate Storage Projects (CPUC Jurisdiction)			
SoCalGas	Aliso Canyon/La Goleta Facility	Conversion of cushion gas	14 Bcf	August 2001
Aquila	Lodi Gas Storage Facility	New facility	12 Bcf	December 2001
Total in-state storage capacity additions since 2001			**26**	**Bcf**

* Storage projects are measured in Bcf

Table C-2
Pending Natural Gas Infrastructure Projects

Pipeline Owner	Pipeline/Location Name	Nature of Project	Capacity (MMfc/d) *	Completion Date
Interstate Pipeline Projects (FERC jurisdiction)				
Kern River Gas Transmission Co.	Kern River Pipeline	Expansion	906	May 2003
El Paso Natural Gas Company	All-American Pipeline	Conversion of oil pipeline	700	June 2004
Total pending interstate pipeline capacity additions			**1,606**	**MMcf/d**
Out-of-state Storage Projects (FERC jurisdiction)				
Aquila	Red Lake Storage Facility (Arizona)	Phase 1 of new facility	6 Bcf	November 2003
Aquila	Red Lake Storage Facility (Arizona)	Phase 2 of new facility	6 Bcf	December 2003
Total pending out-of-state storage capacity additions			**12**	**Bcf**
In-state Storage Projects (CPUC jurisdiction)				
PG&E	McDonald Island Storage Facility	Expansion	6.5 Bcf	April 2004
EnCana	Wild Goose Storage Facility	Expansion	15 Bcf	April 2004
Total pending in-state storage capacity additions			**21.5**	**Bcf**
Out-of-state LNG Import Facilities (various jurisdictions)				
Marathon Oil Company	Tijuana, Baja California, Mexico	New Facility	750	2005
Sempra International	Ensenada, Baja California, Mexico	New Facility	800	2006
ChevronTexaco	Tijuana, Baja California, Mexico	New Facility	750	2006

* Storage projects are measured in Bcf