CALIFORNIA
ENERGY
COMMISSION

# Electricity Infrastructure Assessment

Prepared in Support of the *Electricity and Natural Gas Report* under the Integrated Energy Policy Report Proceeding, Docket # 02-IEP-01

STAFF REPORT

MAY 2003
100-03-007F

Gray Davis, *Governor*

# CALIFORNIA ENERGY COMMISSION

Judy Grau
Karen Griffin
Don Kondeleon
Jim McCluskey
Bob Strand
David Vidaver
***Principal Authors***

Al Alvarado
***Electricity & Natural Gas Report Project Manager***

David Ashuckian
***Manager***
**Electricity Analysis Office**

Terry O'Brien
***Deputy Director***
**Systems Assessment and Facilities Siting Division**

Bob Therkelsen
***Executive Director***

# Table of Contents

# Introduction

The purpose of the IEPR staff studies is to evaluate the implications of important uncertainties on the integrated electricity and natural gas infrastructure. The primary goal is to identify key factors that may stress the energy infrastructure and to determine if there may be a need for additional development to mitigate potential supply shortfalls in the next decade. Considering that electricity generation's use of natural gas has the largest effect on future natural gas demand, the energy infrastructure study is focused on the potential stresses to the natural gas system. Staff developed a number of electricity consumption scenarios and generation resource development plans to evaluate the potential implications on natural gas demand.

The report is divided into two sections. After an overview of the state's electric generation and transmission infrastructure, the report focuses primarily on market conditions:

- An assessment of current conditions in the electricity market
- Projected 2004 – 2006 conditions
- 2004 – 2006 electricity system simulation results
- An assessment of the state's increased dependence on natural gas as a generation fuel
- DSM/renewable scenario impacts
- 2007 – 2013 simulation results

The report then turns to a discussion of transmission resources:

- The role of transmission resources in ensuring supply adequacy and stable prices in California
- Major transmission constraints and local reliability areas
- Obstacles to the development of transmission resources
- Current efforts to facilitate transmission development
- Coordinating transmission and generation development
- Overview of transmission planning in 2004

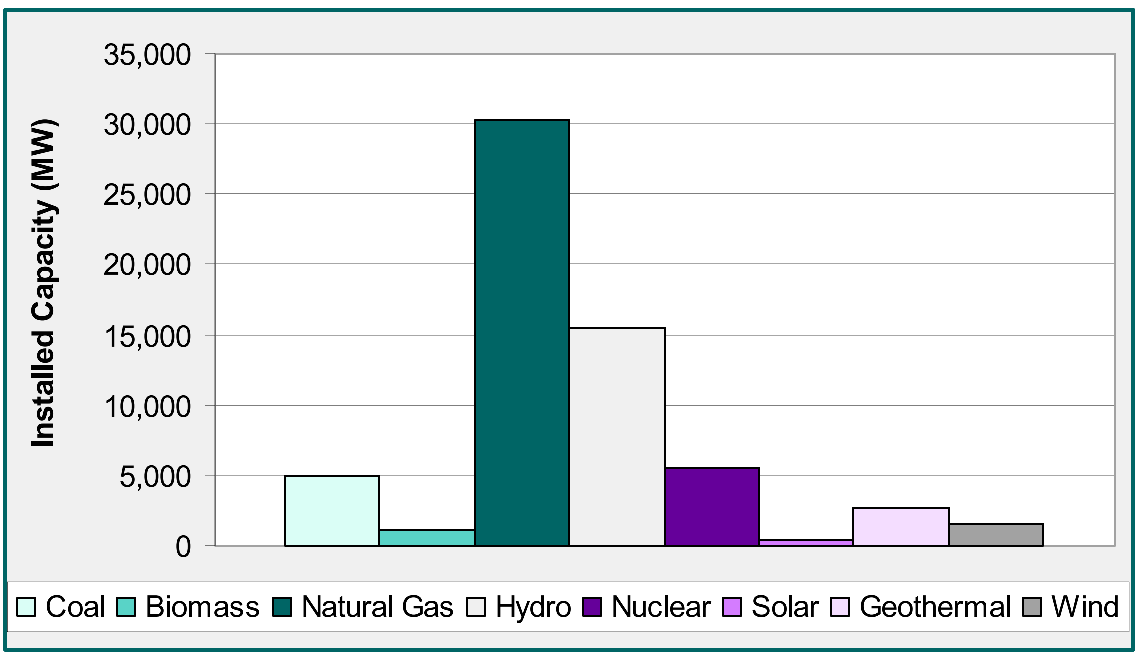
These analyses build on the input assumptions contained in five draft reports which were the subject of a Committee workshop on February 25 and 26, 2003.[1] As a result of the technical feedback received at the workshop, numerous assumptions were revised. The input assumptions included energy demand trends, comparative costs of central station generation facilities, retail rates projections given current tariffs, and the progress of new electricity generation, transmission, gas pipelines and storage projects throughout the west. Potential scenarios for use in this study were also discussed. The revised material is reflected in the technical appendices.

# California’s Electricity Infrastructure

## Generation Resources

California’s demand for electricity[2] is served by a mix of in-state and out-of-state resources. In addition to the 55,800 MW in-state, California utilities own more than 6,200 MW of capacity in Arizona, Nevada, Utah and New Mexico. **Figure 1** illustrates the diverse fuel sources of California’s generation resources. Natural gas plants became the capacity of choice in California, as they are more efficient, more flexible to site and operate, cheaper and cleaner than other central station options.

**Figure 1**
**Capacity by Fuel/Technology Type**




Only 42 percent of capacity in **Figure 1** is owned by California utilities. **Figure 2** illustrates the composition of ownership of California’s generation resources.

**Figure 3** shows the growth of gas-fired generation from its 25 percent share twenty years ago. Today, 35 - 40 percent of the electricity consumed in California is generated using natural gas. The figure also illustrates the variability of hydro generation in both California and in the Northwest, the latter reflected in the amount of energy imported.

**Figure 2**
**Capacity by Owner Type**

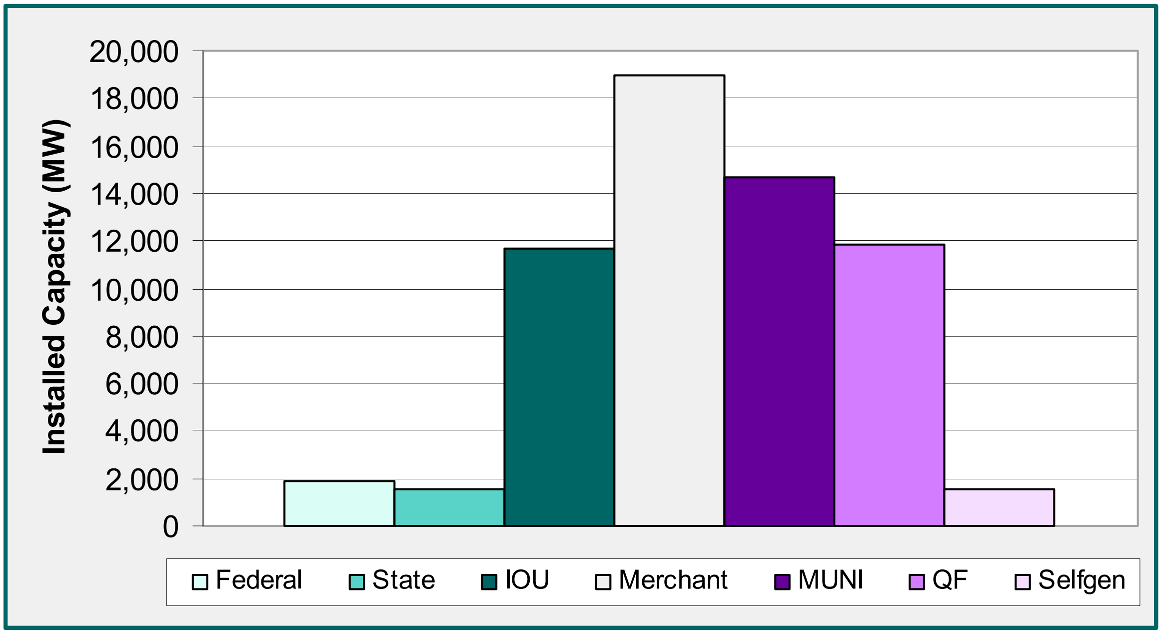
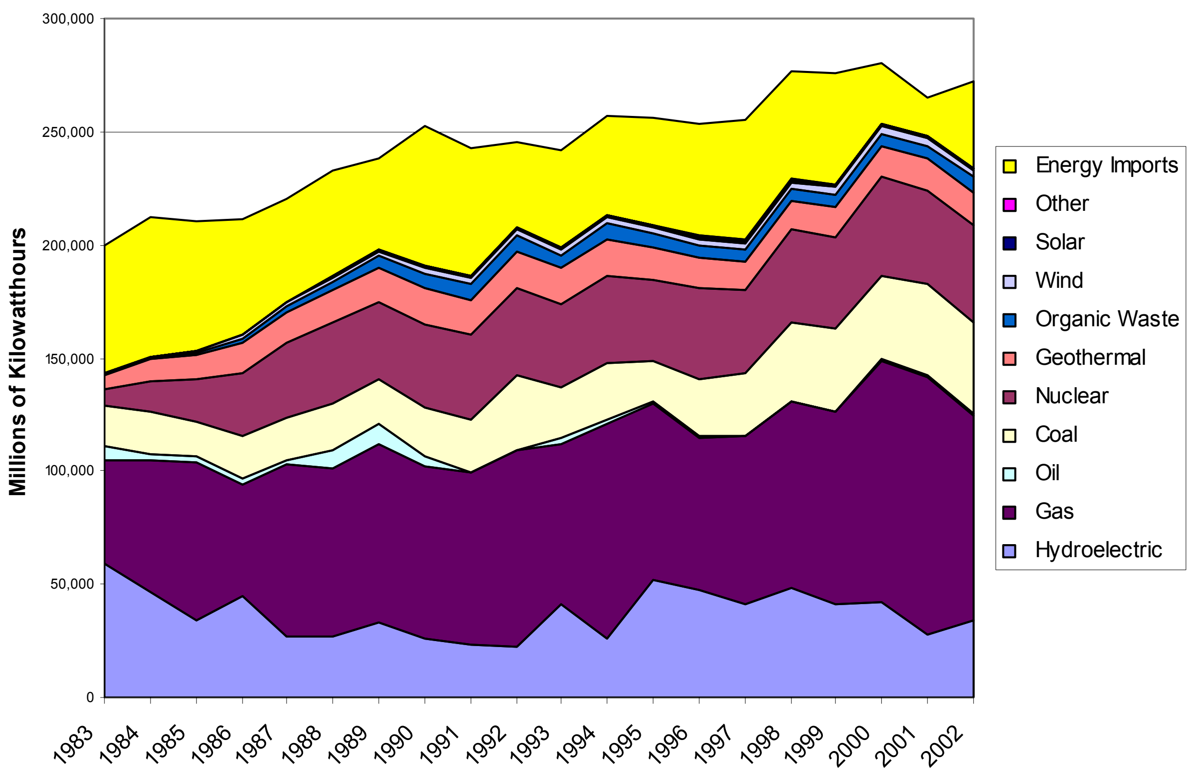



**Figure 3**
**Sources of California Electrical Energy Consumption**
**1983 - 2002**



# Transmission Resources

## Import Capability

The summer maximum transfer capabilities for the three major regions across which power flows into California include the following:

- At the border to the north: the California-Oregon Intertie is rated at 4,800 MW North-to-South
- At the border to the south: Path 45 from Mexico is currently rated at 408 MW South-to-North, but is expected to increase to 800 MW South-to-North in summer 2003.
- Into Southern California: the Southern California Import Transmission (SCIT) nomogram has a maximum simultaneous import capability of 14,500 MW.

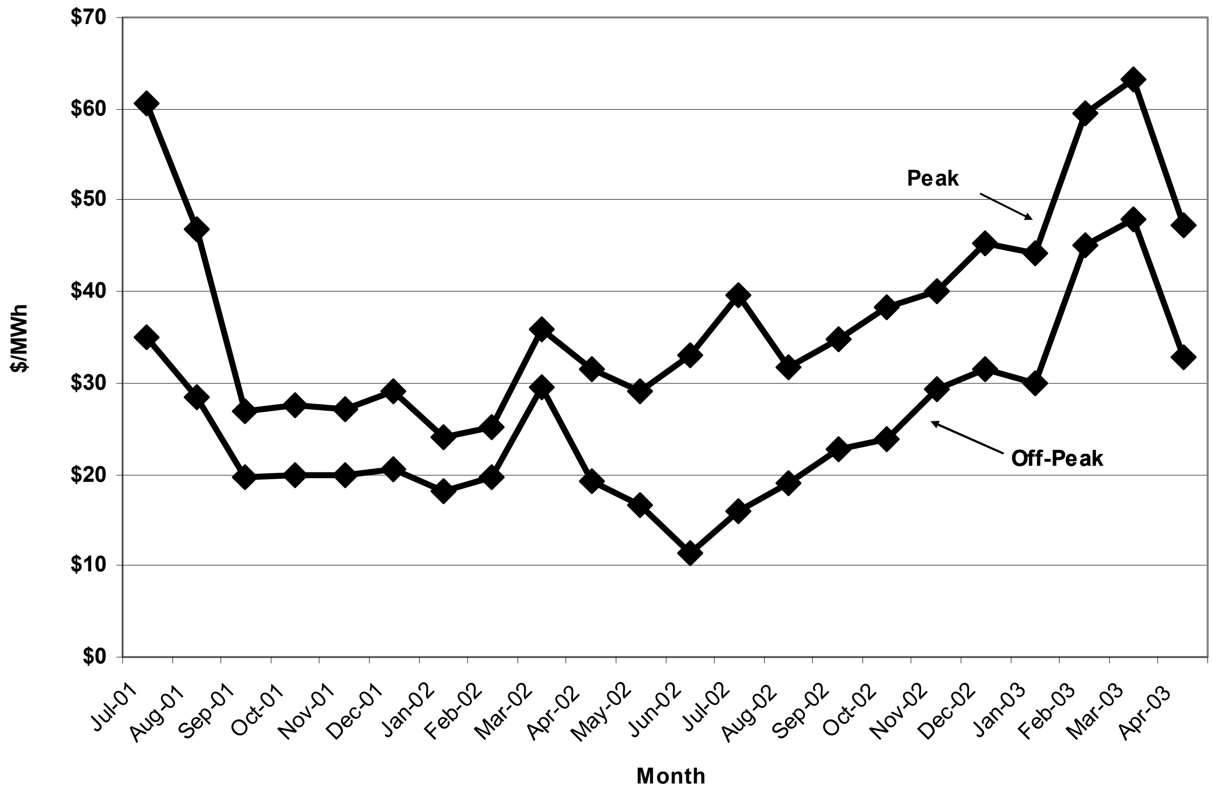
Transfer capabilities are established on a seasonal basis through a process administered by the Western Electric Coordinating Council (WECC) Operating Transfer Capability Policy Committee.

For information on constrained paths, see the section entitled "Constrained Transmission Paths and Local Reliability Areas." For a list of the transmission upgrades assumed in the market simulations discussed in this report, see **Appendix A.**

# Current Conditions in the California Electricity Market

The trend in spot market prices is a key indicator of both supply-adequacy and market conditions. Wholesale spot market prices in California have been competitive since July, 2001, as evidenced by **Figure 4** and in the ISO's monthly market analysis. Spring 2003 saw prices rise due to run-ups in the natural gas price in California and nationwide. These gas prices have been caused by low storage levels and fears that insufficient amounts of natural gas will be available to meet heating needs this winter; this is discussed in detail in staff's *2003 Preliminary Natural Gas Market Assessment*. Unlike the price run-ups of 2000, recent increases do not appear to be due to shortages of generation capacity or dysfunction in either the electricity or natural gas markets. It appears that national natural gas prices may not return to previous levels; these higher but stable prices will ripple through the electricity sector.

**Figure 4**
**Monthly Average Prices, SP15 Delivery**
**July 2001 – April 2003**




Source: Economic Insight, Inc. market surveys, published in *Energy Market Report*

The stabilization of the spot market for electricity in California has been largely the result of three factors:

- Conservation on the part of California consumers and their adoption of energy efficiency measures, accompanied by a slowdown in the economy. (See the California Energy Commission's website for monthly peak and total consumption values for 2000 – 2002; www.energy.ca.gov). 2003 forecasted peak loads are at 1999 levels.

- The addition of more than 7,100 MW of new capacity in the state between 2000 and 2003, as illustrated in **Table 1**. For a complete list of individual additions during 2003, see **Appendix B**. The combined effect of the capacity additions and reduced demand is an increase in the state's dependable reserve capacity of 6,800 MW, based on 2003 normal weather or 3,400 MW if we have an unusually hot peak (1-in-10).

**Table 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* | 4,042 | 1,234 |
| Total | 9,400 | 2,338 |
| Net Additions | 7,162 | |

* Includes all plants expected to be on-line or retired by August 1, 2003

- A dramatic reduction in the amount of energy purchased in the spot market by load-serving entities in California. As documented in ISO monthly reports, the spot market has shrunk dramatically. Most of the energy needs of the investor-owned utilities (IOUs) in the state are being met by utility-owned resources, contracts with QFs and other utilities, and long-term contracts signed by the State's Department of Water Resources (DWR) in 2001. Additional energy needs are being met by contracts being entered into as part of the interim procurement proceedings being conducted by the California Public Utilities Commission (PUC). It is anticipated that the spot market needs of the IOUs during the summers of 2004 – 2005 will be more than 1000 – 2000 MW in only a handful of hours. Municipal utilities continue to rely upon their own plants and long-term contracts to meet a majority of their needs. Direct access consumers appear to be served by a mix of mid-term contracts and the spot market.

As noted in the CAISO's *2003 Summer Assessment* dated April 11, 2003:

> "The ISO anticipates that the transmission system is sufficient to meet WECC and NERC reliability criteria during peak demand periods under forecasted operating conditions. However, there are numerous transmission constraints that the ISO must mitigate during various operating conditions using the ISO's congestion management procedures or Reliability Must Run (RMR) generation. Major transmission path constraints that often require flow mitigation actions during the summer peak demand periods include the Southwest Power Link (SWPL), Path 26 [Midway to Vincent], South of Lugo, total Southern California Import Transfers (SCIT), and the California-Oregon Intertie (COI)." (p. 3)

## Projected 2004 – 2006 Conditions

Staff believes that loads will be reliably served (largely through owned-generation and long-term contracts) and that spot market prices should remain at competitive levels through 2004 - 2006. This is based on an assessment of new additions, retirements, and a decreasing reliance on the spot market for energy. For a complete list of the additions and retirements in California assumed by staff in the capacity-balance tables and baseline simulation presented in this report, see **Appendices C** and **G** (the latter contains assumptions regarding renewable capacity added in response to the Renewable Portfolio Standard.

### Generation Additions

- While net additions during 2004 – 2006 are not expected to keep pace with load growth, staff believes that load-serving entities with projects currently before the Commission fully intend to bring new capacity on line if permitted. Several of these projects replace existing facilities that have been or will be retired; others will cover short positions during peak hours year –round. This capacity totals 1,934 MW (1,694 dependable MW). In addition, staff assumes that two major repowerings (98 MW net) will be completed by LADWP.

- The state has step-in rights on two facilities that have been permitted (Otay Mesa and Metcalf, totaling 1,051 MW). While staff does not offer a projection regarding the exercise of these rights, their completion is a policy option, one that is more likely to be exercised if the coming eighteen months demonstrate their being needed for reliability purposes or to meet resource adequacy requirements imposed or agreed to by the PUC. It is also possible that another project in the San Diego area (Palomar, 546 MW) would be on line by 2006, even if Otay Mesa is not.

- Staff anticipates the development of new renewable facilities, partly in response to the Renewable Portfolio Standard established under SB 1078 (Sher, Statutes of 2002). While existing facilities may meet a share of the RPS requirements in the short-run, the past year has witnessed both new merchant development and announcements by municipal utilities of new projects. For the purposes of the simulations discussed in this report, staff assumes the addition of roughly 1,000 MW (installed) of new renewable generation during 2004 – 2006. 760 MW of this is wind generation; the remainder is divided between biofuel and geothermal capacity.

### Delays and the Completion of Permitted Plants

With the exceptions of Otay Mesa and Metcalf, staff assumes the large merchant plants permitted by the Commission, but yet to be completed, will not come on line during 2004 – 2006. There are six of these projects (Pastoria, Contra Costa, Mountainview, Russell City, Three Mountain and Midway – Sunset), totaling 3,936 MW. It remains possible that some of these units may be built in 2005 or 2006.

Investment in new generation capacity in California has slowed during the past eighteen months for several interrelated reasons:

- The large amount of new capacity that has come on-line during the past two years, in combination with conservation, has resulted in a capacity surplus and low forward prices. Cancellations and delays are an acknowledgement that the amount of capacity proposed during 2000 – 2002 far exceeded the amount needed to meet demand.

- A deterioration of the balance sheets of large developers, which has limited their access to capital markets, resulting in delays and cancellation of new projects. The short- and medium-term debt of several major developers is large enough to threaten bankruptcy.

- Unsettled regulatory issues have affected the projected revenue streams from new facilities. These include:

  - the possible imposition of price caps in wholesale electricity markets,

  - the nature of resource adequacy requirements that may be imposed on load-serving entities,

  - the evolving rules for direct access and departing load that will affect how much future demand will be served by IOUs,

  - the inability, to date, of IOUs in California to sign long-term contracts for energy and capacity, and

  - uncertainty regarding the role that IOUs and public entities will play in the construction and operation of new power plants.

Staff does not feel that the delays in bringing these six licensed plants under development to completion present a threat to system reliability in 2004 – 2006.

## Supply-Demand Balance in 2004-2006

Dependable reserve capacity in California and the remainder of the WECC is at levels not seen since the late 1980's. The size of this reserve margin, combined with the relatively small reliance on spot markets to meet demand leads staff to conclude that spot markets should yield reasonable prices during the next three years. **Table 2** presents the state's reserve margins for 2004 – 2006.

**Table 2**
**Statewide Supply/Demand Balance**
**2004 - 2006**

| | **Aug-04** | **Aug-05** | **Aug-06** |
|---|---|---|---|
| **Existing Generation** | 57,523 | 56,730 | 59,426 |
| **Forced and Planned Outages** | -3,750 | -3,750 | -3,750 |
| **Retirements** | -1443 | -276 | -1134* |
| **Net Firm Imports** | 5,895 | 5,895 | 5,748 |
| **Additions** | 650 | 2,972 | 834 |
| **Spot Market Imports** | 2,700 | 2,700 | 2,700 |
| **Total Supply (MW)** | **61,575** | **64,271** | **63,824** |
| | | | |
| **1-in-2 Summer Demand** | **53,464** | **54,893** | **56,135** |
| **Projected Operating Reserve (1-in-2)** | **15.17%** | **17.08%** | **13.7%** |
| | | | |
| **1-in-10 Summer Demand** | **56,712** | **58,229** | **59,548** |
| **Projected Operating Reserve (1-in-10)** | **8.57%** | **10.38%** | **7.2%** |
| | | | |
| **Emergency Response Programs/ Interruptible** | **1,102** | **1,102** | **1,102** |

*Mohave 1, 2; Hunters Point 1, 4
These are the assumptions used in the modeling study. They pre-date and are slightly different from the Commission's summer assessment (May, 2003).

The amount of dependable capacity added in California and the remainder of the WECC, relative to observed and forecasted changes in peak demand during 2000 – 2005 has been substantial. Moreover, the share of peak load for which energy and capacity has already been encumbered is in excess of 90 percent statewide. The increasing reserve margins and reduced dependence on the spot market jointly facilitate competitive spot market prices. Industry analysts agree that substantial amounts of capacity chasing a dramatically reduced amount of demand in spot markets has been a significant contributing factor in the price outcomes observed during the past twenty-one months.

Current and anticipated reserve margins, given the reduced share of power being purchased in the spot market, should ensure reliability and competitive spot markets during 2004 – 2006, even in the absence of substantial merchant development.

As reserve margins fall and forward prices rise, load-serving entities (LSEs) will be encouraged to offer contracts and developers will have an incentive to complete construction. Retirements of existing large facilities during 2004 – 2005, while unlikely, would encourage completion of delayed projects. Where developers are unable to move forward due to an inability to raise capital or service debts, these assets may be sold or transferred to other parties, increasingly so as debt becomes due. Recent purchases such as La Paloma (completed by PG&E National Energy Group after ownership transferred to creditors), Mountain View (sold by AES to Intergen), and Fredrickson (majority ownership transferred from Duke to EPCOR) provide evidence that financing can be found by companies with strong balance sheets.

## Generation Retirements

A significant share of the state's thermal generation capacity is more than thirty years old. Much of this capacity is 25 - 50 percent less efficient than the plants currently coming on-line. These facts have led to concerns that a substantial amount of the state's capacity will retire during the coming decade.

Whether these power plant units remain available to provide capacity and reliability services is an economic decision of the owner. This decision is usually determined by the expected net profitability of a unit, that is, the difference between expected revenues and expected operation costs, which include fuel, maintenance, and any necessary capital costs. A number of units have been retired in recent years or are slated for retirement in the near term. These retirements have, for the most part, been associated with decisions by the facility owner to replace older, less efficient units that would have required emission control upgrades with new, more efficient and cleaner burning units.

The information most directly related to the owner's decision, i.e., expected revenues, costs, and profit expectations, are confidential or proprietary. Indirect indicators of profitability such as historic annual capacity factor, annual energy generation, forced outage rates, and permitted $NO_x$ emissions rates could be examined and analyzed to provide more insight as to the potential for specific unit retirements. In addition, identifying which units have guaranteed revenue streams, such as reliability must run contracts or anticipated costly capital requirements, could help identify units less likely or more likely to retire. However, these analyses would still not be conclusive.

With the information currently available to the state, staff cannot accurately predict future unit availability or retirements. Additional analysis and knowledge of power plant performance and usage characteristics would be needed to better evaluate the risk that capacity from older units would not remain available in the future.

At present, staff believes that the risk of sufficient retirements to threaten system reliability during the next three years is minimal, despite the age of the existing generation fleet.

- Whether resource adequacy requirements are imposed upon load-serving entities in California by regulators, or the PUC approves capacity contracts as a component of risk-mitigation strategies pursued by the IOUs, an increasing number of plants are apt to be provided capacity contracts during the next couple of years. The payments from these contracts, to the extent that they cover going forward costs, will encourage older facilities to remain on-line.

- Several older plants have DWR or reliability-must-run (RMR) contracts, including major facilities in the San Diego and San Francisco areas. Those facilities paid under RMR contracts are highly unlikely to shut down unless and until their reliability function is provided a by a new plant or no longer needed due to upgrades to the transmission system.

- The cancellation of numerous development projects and delays in bringing additional capacity on line mitigates against the retirement of existing plants. While short-term revenue projections may lead to temporary shut-downs, staff feels that even these facilities will remain available with sufficient notice. Increased congestion on transmission lines which move power into the greater Los Angeles area, combined with delays in completing several new plants, raises the possibility of a premium in the near-term for generation located in SP15, especially during the summer.

Some older, inefficient units are only marginally profitable. Their owners may decide that they are unlikely to recover the costs of emission control systems. Several plants have retired or will do so during the coming year rather than undertake costly retrofits. Most others, however, have installed required controls. The major facilities currently considering whether to install emission control are Contra Costa 6, Pittsburg 7 and Morro Bay 1 and 2, and Etiwanda 1 and 2, totaling 1,642 MW. In addition, a pending California Air Resources Board guidance may call for tighter restrictions on pollutants from combustion turbines, requiring owners of peaking units to weigh compliance costs against expected revenue streams. This could affect the availability of resources towards the end of the decade.

## Reduced Dependence on the Spot Market

Staff expects that reliance on the spot market for energy needs will continue to fall during the next three years. This assumes that: (a) the PUC will authorize IOUs to enter into forward contracts for energy and capacity, and (b) municipal utilities will add sufficient capacity and contract forward so as to offset retirements and expiring contracts.

Reduced spot market needs, accompanied by increases in reserve margins, both in California and the remainder of the WECC, mean that more megawatts of capacity will be chasing fewer megawatt-hours of demand. This served to discipline the spot market in mid-2001[3]; staff expects it to continue to do so for the near-term.

In the market simulations discussed in this report, staff does not assume a perfectly competitive spot market. Broad classes of generators are assumed to be able to recover a share of their fixed costs during peak hours. Staff estimated the likely size and extent of this premium based on market outcomes observed during the past eighteen months.

## 2004 – 2006: Electricity System Simulation Results

Staff simulated the operation of the WECC electricity system during 2004 – 2006 using MarketSym, ™ a widely-accepted software application (for a description of MarketSym™, see **Appendix D**).

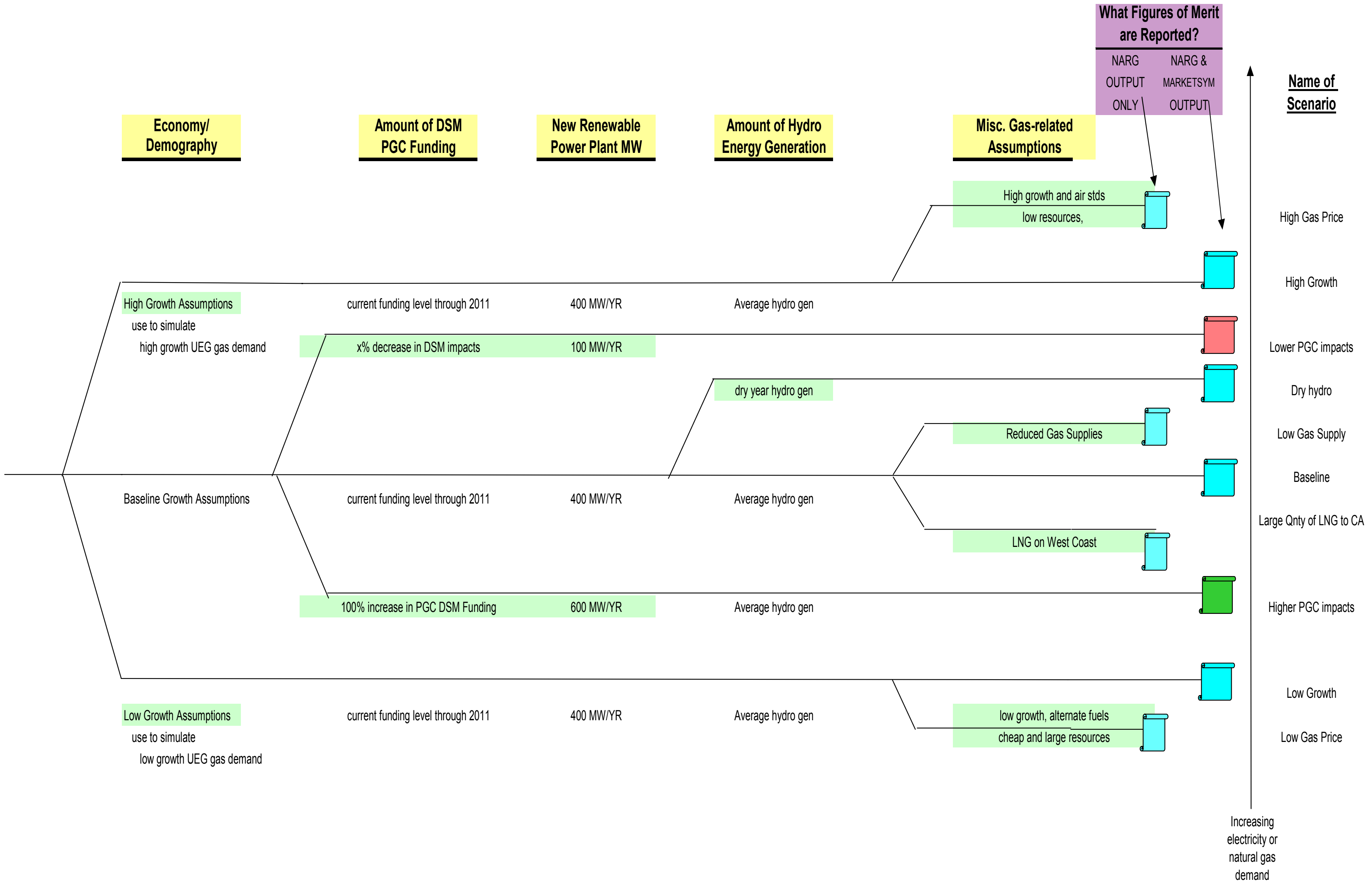
The simulation requires information regarding capacity additions and retirements and forecasts of electricity demand and fuel prices. The capacity additions and retirements assumed in the simulation for California are those discussed above. The net additions assumed elsewhere in the WECC can be found in **Appendix E**. A set of demand forecasts for California were developed by the Commission's Demand Analysis Office; these scenarios differ in their assumptions regarding economic growth. They are presented in **Appendix F**. Demand in the rest of the WECC was forecast by Henwood Energy Services, Inc. Natural gas prices for each area in the WECC were forecast by the Commission's Natural Gas Unit, these are presented in **Appendix H**. The simulations also assumed several upgrades to the transmission grid within California; these are presented in **Appendix A**.

Considering that electricity generation is the key driver in growing natural gas demand, the energy infrastructure study focuses on the potential stresses to the natural gas system. The Energy Commission staff developed electricity consumption scenarios and generation resource development plans to evaluate the potential implications on natural gas demand. **Figure 5** provides a flowchart of the different scenarios that the Energy Commission staff evaluated. The six scenarios presented in **Figure 5** include varied combinations of input assumptions that will have electricity and natural gas system modeling output as partial measures of the scenarios' impacts. Five of the scenarios have different electricity capacity expansion plans developed and reflected in the electricity system modeling results.

In addition to the baseline simulation, staff developed scenarios in which:

- demand is higher in both California and the remainder of the WECC,
- 1-in- 20 year drought conditions prevail throughout the western US and Canada

## Figure 5
## Design and Scope of the E&NG Assessment Scenario Analysis



These scenarios were run in order to assess their impact on reliability, wholesale prices, transmission congestion and natural gas demand. The effect of increases in demand and poor hydro conditions on natural gas demand are discussed in staff's *Preliminary 2003 Natural Gas Market Assessment* (Pub. # 100-03-006, May 2003).

## Baseline Electricity System Simulation Results

In evaluating baseline system performance, we look at whether the system can meet demands, whether key transmission lines are constrained, and whether residual energy sold in the spot market would pay for new generation. These are three key indicators of whether the physical system is adequate.

The results of the simulation indicate that the Western market has more generation than the minimum necessary to meet load and reserves. Reliability metrics indicate that the system has an adequate amount of resources. Expected unserved energy values are zero during all three years, save for in San Francisco. Prior to the arrival of 180 MW of peaking capacity in January 2005, San Francisco has limited import capability and a precarious reliance on a handful of aging plants. There are no expected reserve violations in California. Staff stresses, however, that the model used does not consider the possibility of sustained transmission line outages and the possibility that generators will not participate in the market despite economic incentives to do so.

The results also indicate that transmission congestion remains acute on certain lines over 2004 – 2006. The lines that move power from the Imperial Valley and the Southwest into Los Angeles and San Diego (*e.g.,* Palo Verde – Devers, SWPL) are congested year-round. This reflects the surplus of efficient capacity in the former areas, and the model's efforts to move this power to California load centers. It tries to do so because the power would be cheaper than that currently serving southern California, indicating that there are economic benefits associated with expansion of the transmission grid. By 2006, increasing congestion is also seen southbound on Path 26, which connects central California with the southern half of the state.

Projects currently going forward are primarily those with long-term contracts. Current spot market price projections are insufficient to yield substantial investment at present without a long-term contract. Prices yield "sparkspreads" that do not allow new combined cycles to meet presumed debt service and provide a return to equity with revenues from the energy market alone.

Projected spot prices serve as a benchmark for the value of new generation. The terms of future long-term contracts will be influenced by current and projected spot market prices. Investment will depend upon expectations regarding market rules, the size of the spot market, degrees of uncertainty, etc. Staff does not assert that high spot market prices must be allowed to foster investment in generation, nor does staff even suggest that high spot market prices *should* be allowed to increase to encourage investments. Staff merely asserts that high spot prices would facilitate merchant investment.

**Table 3**
**Monthly Average Wholesale Prices**
**California, 2004 - 2006**

| | All Hours | | | On-Peak Hours* | | |
|---|---|---|---|---|---|---|
| **Month** | **2004** | **2005** | **2006** | **2004** | **2005** | **2006** |
| Jan | 34.2 | 33.4 | 32.6 | 38.7 | 37.2 | 35.4 |
| Feb | 32.3 | 31.6 | 31.6 | 36.8 | 35.3 | 34.0 |
| Mar | 31.5 | 31.9 | 30.5 | 35.3 | 34.4 | 32.8 |
| Apr | 31.5 | 29.0 | 28.3 | 34.0 | 31.5 | 30.8 |
| May | 25.6 | 24.7 | 27.2 | 30.5 | 28.6 | 31.1 |
| Jun | 26.9 | 25.0 | 27.5 | 30.7 | 27.5 | 29.9 |
| Jul | 33.3 | 29.6 | 32.6 | 37.9 | 32.9 | 36.4 |
| Aug | 38.9 | 34.1 | 38.1 | 44.6 | 39.1 | 44.5 |
| Sep | 38.6 | 34.9 | 38.8 | 42.7 | 39.1 | 43.6 |
| Oct | 37.4 | 32.6 | 35.5 | 41.7 | 35.5 | 39.1 |
| Nov | 40.7 | 37.5 | 38.3 | 45.2 | 41.6 | 41.9 |
| Dec | 36.0 | 35.3 | 39.4 | 40.4 | 38.9 | 44.6 |

*Monday through Saturday, 6:00 AM – 10:00 PM
Based on gas prices averaging $4.60 in 2004, $4.19 in 2005 and $4.26 in 2006 (see Appendix H).

## High Growth and Low Growth Scenarios

To test whether a quicker economic recovery would strain the system, staff simulated the electricity market in 2004 – 2006 raising the annual rate of economic growth in California during 2003 – 2006 is 1 percent higher than that assumed in the baseline forecast. This yields a demand for energy that is 6,750 GWh (2.4 percent) higher in 2006 than the baseline forecast and a peak (state-wide coincident) demand that is 1,340 MW (2.4 percent) higher. Similar increases in demand (both peak and energy) were assumed for other regions in WECC (Southwest, 1.1 percent; Northwest, 1.8 percent; Rockies, 2.2 percent)

The increase in demand does not cause reliability concerns. With the exception of San Francisco in 2004, expected unserved energy remains zero and reserve violations are not forecast. The primary impact of the increase is on prices, transmission line loadings and the demand for natural gas. As **Table 4** indicates, prices increase by roughly 5 percent compared to the baseline, with average monthly prices rising more or less uniformly throughout the year.

Staff also simulated a low-growth scenario, in order to illustrate the impacts of slower growth than expected on the wholesale electricity price and natural gas demand (the latter is discussed in staff's *2003Preliminary Natural Gas Market Assessment*).

Although demand was raised or lowered an equivalent amount in the two scenarios, the impact on prices was not uniform. Prices rise more in the high growth case than they decline in the low growth case. The reason is that, at the margin, California depends on a fleet of increasingly expensive units. The supply-demand balance is right on the cusp of requiring higher cost units, so small increases can have a big impact.

**Table 4**
**Annual Average Wholesale Spot Prices (Nominal $/MWh)**
**High and Low Growth Scenarios**
**California, 2004 - 2006**

| High Growth | | | | | | |
|---|---|---|---|---|---|---|
| | All Hours | | | On-Peak | | |
| Year | High Growth | Baseline | Difference | High Growth | Baseline | Difference |
| 2004 | 35.9 | 33.9 | 5.7% | 40.2 | 38.2 | 5.4% |
| 2005 | 32.6 | 31.6 | 3.0% | 36.3 | 35.1 | 3.3% |
| 2006 | 34.7 | 33.4 | 4.1% | 38.8 | 37.0 | 4.8% |
| **Low Growth** | | | | | | |
| | All Hours | | | On-Peak | | |
| Year | High Growth | Baseline | Difference | High Growth | Baseline | Difference |
| 2004 | 33.4 | 33.9 | -1.5% | 37.6 | 38.2 | -1.5% |
| 2005 | 30.9 | 31.6 | -2.4% | 34.2 | 35.1 | -2.6% |
| 2006 | 32.5 | 33.4 | -2.6% | 35.9 | 37.0 | -3.0% |

## Low Hydro Scenario

Staff simulated the WECC market in 2006 under a roughly 1-in-20 year adverse hydro conditions. Based on historic information for adverse conditions, hydro energy in California was reduced to 54 percent of normal from January – September, with October – December values escalating to normal levels by the end of the year. A similar pattern was assumed for the Pacific Northwest (including British Columbia), with January – September values being 82 percent of normal. Hydro power comes from run-of-river systems and the large dams with storage. Storage dams can manage their release of water.

The simulation results indicate that adverse hydro conditions do not threaten reliability, as there is no expected unserved energy. This is not surprising, as available hydro energy is managed to the extent possible to meet peak needs. While there is some reduction in hydro generation during highest load hours due to reduced run-of-river generation, a majority of the reduction occurs during shoulder hours.

The primary impact of poor water conditions is increased natural gas use, due to the need to replace hydro energy with gas-fired generation, and on spot market prices, as increasingly less- efficient gas-fired plants are needed to meet loads. The increase in natural gas use is documented in staff's *2003 Preliminary Natural Gas Market Assessment*; the increase in prices is described in **Table 5**.

**Table 5**
**Average Monthly Wholesale Spot Prices (Nominal $/MWh)**
**Low Hydro Scenario**
**California, 2006**

| | All Hours | | | Peak Hours | | |
|---|---|---|---|---|---|---|
| **Month** | **Low Hydro** | **Baseline** | **Difference** | **Low Hydro** | **Baseline** | **Difference** |
| Jan | 40.1 | 32.6 | 23.0% | 46.5 | 35.4 | 31.5% |
| Feb | 36.8 | 31.6 | 16.3% | 40.9 | 34.0 | 20.4% |
| Mar | 35.8 | 30.5 | 17.6% | 40.4 | 32.8 | 23.3% |
| Apr | 32.1 | 28.3 | 13.7% | 34.3 | 30.8 | 11.5% |
| May | 32.2 | 27.2 | 18.6% | 36.5 | 31.1 | 17.2% |
| Jun | 32.4 | 27.5 | 17.9% | 35.9 | 29.9 | 20.3% |
| Jul | 37.7 | 32.6 | 15.6% | 44.0 | 36.4 | 20.8% |
| Aug | 42.3 | 38.1 | 11.2% | 50.7 | 44.5 | 13.9% |
| Sep | 43.0 | 38.8 | 10.7% | 50.0 | 43.6 | 14.6% |
| Oct | 38.6 | 35.5 | 8.7% | 43.9 | 39.1 | 12.2% |
| Nov | 41.3 | 38.3 | 7.9% | 46.1 | 41.9 | 10.0% |
| Dec | 42.5 | 39.4 | 7.8% | 49.1 | 44.6 | 10.2% |

## 2007 – 2013: Electricity System Simulation Results

Staff used MarketSym ™ to simulate the performance of the wholesale electricity markets in the WECC during 2007 – 2013. The purpose of doing so is (a) to estimate natural gas use by the electricity sector in California and the remainder of the WECC, (b) estimate wholesale prices during 2007 – 2013 and, (c) provide a benchmark for evaluating the likely impact of different assumptions regarding additions and retirements, gas prices, load growth, *etc.*

## Input Assumptions

Electricity demand in California for 2007 – 2013 was forecast by the Energy Commission's Demand Analysis Office (see **Appendix F**). Demand in the remainder of the WECC was forecasted by Henwood Energy Services, Inc.

The set of resource additions and retirements assumed for California and the remainder of the WECC during 2007 – 2013 is presented in **Appendix E**. These do not include capacity added in response to the Renewable Portfolio Standard; this is presented in **Appendix G**. Resources were added in California and elsewhere so as to bring reserve margins down to 1998 – 1999 levels. Staff believes that these levels are sufficient in a market where a majority of demand is served by firm contracts of various durations to provide reliable service.

Staff did not assume the retirement of as much capacity in California during 2007 – 2013 as is likely. To the extent that power plants are retired during this period, additional new capacity will be required to yield the same reserve margins. While little capacity was retired, this does not have a marked effect on either the resulting prices or gas demand. Those units most likely to retire during 2007 – 2013 are older steam turbines which are projected to operate at much lower capacity factors in the future. Given the addition of a substantial amount of baseload capacity in 2001 – 2006 and staff's assumption that similar units will be added as needed in the 2007 – 2013 time frame, these steam turbines are likely to be replaced by gas turbines of equal efficiency, and thus with roughly equal capacity factors.

The set of additions and retirements assumed in simulating 2007- 2013 does not require assumptions about the exact 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.

The Energy Commission's Natural Gas Unit provided the natural gas price forecast for 2007 – 2013 (see **Appendix H).** The price forecasts for other generation fuels were provided by Henwood Energy Services.

## Simulation Results

The wholesale spot market prices for 2007- 2013 are presented in **Table 6**.

**Table 6**
**Average Annual Wholesale Prices (Nominal $/MWh)**
**California, 2007 - 2013**

| Year | On-Peak | Off-Peak | All Hours |
|---|---|---|---|
| 2007 | 40.8 | 30.3 | 36.3 |
| 2008 | 43.8 | 32.0 | 38.7 |
| 2009 | 45.8 | 33.4 | 40.5 |
| 2010 | 48.6 | 35.1 | 42.9 |
| 2011 | 50.8 | 36.4 | 44.6 |
| 2012 | 54.0 | 38.1 | 47.2 |
| 2013 | 56.5 | 40.1 | 49.5 |

Prices rise during 2007 – 2013, due to both declining reserve margins and increasing gas prices. The sparkspread in 2013 is roughly $10 (based on a gas price of $5.70 and a heat rate of 7,100 Btu), indicating that spot market revenues alone would not be sufficient to warrant construction of baseload capacity in the interim. This is an emerging issue that will need to be addressed as reserve margins decline during the next few years.

The importance of natural gas to generators in California increases during 2007 – 2013, as illustrated in **Table 7**.

**Table 7**
**Gas-Fired Generation in California (GWh), 2004 - 2013**

| Year | Generation | Percent of State Demand |
|---|---|---|
| 2004 | 90,674 | 33.7% |
| 2005 | 99,628 | 36.1% |
| 2006 | 109,547 | 39.0% |
| 2007 | 115,616 | 40.6% |
| 2008 | 119,562 | 41.2% |
| 2009 | 123,241 | 42.0% |
| 2010 | 126,679 | 42.6% |
| 2011 | 126,497 | 42.0% |
| 2012 | 130,356 | 42.7% |
| 2013 | 135,271 | 43.9% |

Gas-fired generation in California as a share of the state's demand for electricity grows from less than 34 percent in 2004 to almost 44 percent in 2013. In low-water years, reductions in available hydroelectricity will push this percentage even higher. The implications of this increasing dependence for natural gas prices and the infrastructure needed to deliver gas to end users in California is discussed in staff's *2003 Preliminary Natural Gas Market Assessment*.

## Electricity's Dependence on Natural Gas

Several factors have led to both an increasingly important role for natural gas in California's electricity market and an integration of the natural gas and electricity markets. Natural gas prices increasingly impact wholesale energy costs; shocks are transmitted from one market to the other:

- Well over 90 percent of the generation capacity added in California and the remainder of the WECC during the past twenty years is fueled by natural gas. Environmental and safety concerns have precluded the addition of nuclear, hydro, coal- and oil-fired generation. The declining costs of production using gas-based technologies have offset similar reductions in the cost of generation using renewable energy sources. As a result, the cost of meeting growth in electricity demand is driven by natural gas prices.

- Environmental concerns have limited the use of fuel oil distillates as a substitute for natural gas in power generation. Whereas a large share of California's generation capacity was once able to generate using either fuel oil or natural gas, only a handful of facilities remain able to do so. The use of fuel oil has historically placed a cap on the price of fuel for generation. At high prices for natural gas, generators could burn fuel oil instead, lowering generation costs. This alternative no longer exists, meaning that fuel costs for electric generation will be increasingly linked to natural gas prices.

- Whenever natural gas is "on the margin," the price of every traded megawatt of electricity is driven by the natural gas price. This follows from merchant generators not having an obligation to serve loads: if electricity prices are low relative to the price of natural gas, the generator profits by selling the gas in lieu of generating electricity. This is the case even if the generator has purchased the gas at a much lower price than currently prevails in the spot market, e.g. under a longstanding fixed-price contract.

The link between the prices of natural gas and electricity means that cycles in and shocks to natural gas prices are transmitted to electricity markets:

- Short-term supply shocks (e.g., pipeline disruptions in the western US, hurricanes in the Gulf of Mexico) and spikes in demand (a cold storm in the Pacific Northwest) mean higher spot prices for electricity in California markets. Events in the eastern US affect California as regional gas markets are integrated by the nation-wide pipeline system; gas marketers in western Canada and the Rockies have the option of shipping gas east or west and do so in response to spot market prices. The above-mentioned events need not actually occur for electricity prices to be affected; the gas market will often react in expectation of them. Because of their brief duration and unanticipated nature, these shocks have short-term effects (day-ahead to balance-of-month) but do not impact longer-term markets

- Annual cycles in and shocks in the gas market include higher winter prices due to the use of natural gas to meet heating loads, and price swings resulting from changes in the amount of gas that is put into storage. If storage levels are low during the spring and summer, prices in gas markets increase as a greater storage need competes with immediate consumption. Increased integration has also led the gas market to react to expected conditions in the electricity market: predictions of poor hydro conditions lead to higher spot and forward prices for gas. These swings affect forward markets through the end of the next heating season or water year and, through them, all shorter-term trades.

- Longer-term swings in gas exploration, development and production result in similar cycles in electricity prices. As gas prices fall, producers cut back, driving prices higher. Production and development resume, sending prices down again. This “boom and bust” phenomenon is similar to the one observed in electricity markets, where investment in new generation capacity leads and lag growth in demand. The cycle is arguably shorter in the gas industry as gas can be stored in the ground and “construction” is less capital intensive and has a shorter lead time. This cycle has a substantial impact on prices negotiated for electricity under long-term contracts; even though this may be a two- to three-year cycle it can influence expectations regarding long-run prices. The price volatility associated with this cycle is the primary driver of the premium needed to assume price risk under long-term, fixed-price contracts or, equivalently, the cost of hedging it.

In addition to the above, there is the risk that the price of natural gas will steadily increase over the long-run due to the increasing scarcity of supplies and mounting development and extraction costs.

## Reliability, Risk, and Dependence on Natural Gas

Increased reliance on natural gas as a fuel for electric generation[4] exposes California ratepayers to both delivery and price risks:

- The risk that electricity demand cannot be served due to (a) a sudden disruption that reduces the amount of natural gas that can be delivered to generators, or (b) a spike in gas demand which leaves the pipeline system incapable of providing enough gas.

- The risk that ratepayer costs will rise due to increases in the price of natural gas. These increases may be transient (a price spike), seasonal/annual (due to poor hydro conditions or low storage levels), cyclical (a result of declining investment in production) or a long-run trend (reduced supplies). Increases in the natural gas price translate into almost equal-percentage increases in the cost of generation or electricity traded on the wholesale market. The exception is energy traded under fixed-price contracts, such as those entered into by DWR. As these contracts expire, prevailing natural gas prices will drive the cost of replacing them.

In-state production presently meets 15 percent of the California's need for natural gas. California imports the remainder from several basins in the western US and Canada; it is shipped over more than a dozen pipelines on six separate systems. This diversity reduces the risk that a major disruption to the interstate system will leave the state unable to meet its demand for natural gas. The diversity of California's sources of natural gas also provides some protection against swings in natural gas prices. Nevertheless, the integrated nature of the pipeline system can result in higher prices as a result of events far beyond California's borders.

California policymakers cannot directly intervene in natural gas markets to reduce prices or their volatility. Regulation of the spot market falls under federal jurisdiction. State involvement in the storage of natural gas would require intervention on a substantial scale if it were to substantially reduce price volatility. Moreover, the private sector has responded quickly to recent changes in the natural gas industry that have increased the value of storage by building new storage facilities and increasing the capacity of existing ones.

Reducing the price risks associated with dependence on natural gas can most easily be accomplished by allowing users to hedge their exposure to changes in prices. The use of financial instruments and forward contracts to fix prices and establish price ceilings, the use of storage to draw upon during high-priced periods, and direct investment in gas fields can all be used to reduce the impact of price volatility. As stated in the discussion of price risk in the electricity market, however, the cost of price stability needs to be weighed against the benefits. Accurate volatility estimates are needed to assess the likely frequency, magnitude and duration of price spikes given dynamic market conditions, and consumer tolerance of risk needs to be better understood.

## Reducing Dependence on Natural Gas

The diversity of sources of California's natural gas and the use of forward markets and financial instruments protect end-users against price fluctuations due to transient changes in market conditions, such as those caused by extreme weather, poor hydro conditions and low gas storage levels. They do not address the price impacts of cyclical investment in exploration, drilling and extraction, or risk of long-run increases in gas prices due to dwindling supplies or higher extraction costs.

These risks associated with longer-run changes in the price of natural gas can only be mitigated by reducing the demand for natural gas as a generation fuel. This can be accomplished by:

- reducing the demand for electricity in California

- replacing gas-fired generation with generation from other fuel sources

Programs which reduce the consumption of electricity have the greatest impact on natural gas demand if they are targeted at hours of peak electricity use. During peak hours in the summer, the system's incremental heat rate is 12,000 Btu or greater. Reductions in demand during early morning hours or in the spring runoff season will have less of an impact.

Increased generation using other fuel sources will reduce the demand for natural gas. Given environmental and safety concerns, the development of renewable resources offers the greatest potential for allowing California to reduce the role of gas-fired generation in meeting its energy needs.

The extent to which increased generation from renewable sources affects natural gas demand depends upon numerous factors. As is the case for programs that reduce electricity consumption, renewable generation displaces the most natural gas if it is available during hours of peak electricity use.

## Higher and Lower DSM/Renewable Scenarios

Staff conducted two scenario analyses to evaluate the impact on natural gas use and electricity market conditions of higher and lower (than baseline) levels of DSM savings and renewable generation. The changes in demand and renewable generation are assumed to be a result of changes in Public Goods Charge (PGC) funding. In each scenario, staff simulated the WECC electricity market for the years 2004 through 2013. In the Higher DSM/ Renewable Scenario, fewer new gas-fired power plants were assumed built than in the Baseline. In the Lower DSM/Renewable Impacts Scenario, more gas-fired power plants were assumed. Although the total amounts changed, the capacity factors of new renewable facilities were assumed to remain unchanged in all scenarios.

### Description of DSM/Renewable Scenarios

The Higher DSM/Renewable Scenario assumes that (a) increased PGC funding yields additional demand reductions, and (b) 50 percent more new renewable capacity is added each year under RPS-related contracts. Annually, the Higher DSM/Renewable Impacts Scenario adds about 200 MW more DSM peak reductions and about 1,200 GWh more DSM energy savings than in the Baseline (averaged over the 2004-2013 period.) This scenario annually adds about 600 MW of new renewable capacity (nameplate) per year, compared to about 400 MW per year in the Baseline. The annual capacity factors of new renewable facilities were assumed to remain unchanged. While the Baseline Scenario adds about 2,000 GWh of new renewable energy generation each year, the Higher DSM/Renewable Impacts Scenario adds an annual average of 3,100 GWh.

By the year 2013, the Higher DSM/ Renewable Impacts Scenario has 19,700 GWh more energy from DSM savings and renewable generation energy than does the Baseline. In the Higher DSM/ Renewable Impacts Scenario, future gas-fired resources were reduced by about 2,500 MW by 2013—700 MW fewer new additions and 1,800 MW more retirements. These changes are based on the assumption that the market will respond to a decrease in “residual” demand by cutting back on new additions or increasing retirements of marginally utilized existing units.

Staff also evaluated natural gas and electricity market conditions arising from lower-than-Baseline DSM savings and renewable energy generation. The Lower DSM/Renewable Impacts Scenario assumes (a) reduced PGC funding for DSM and (b) a 75 percent reduction in new renewable capacity compared to the Baseline. Annually, the Lower DSM/Renewable Impacts Scenario reduces by about 200 MW the amount of DSM peak reductions and by about 1,000 GWh the amount of DSM energy savings in the Baseline (averaged over the 2004-2013 period.) This scenario annually adds only about 100 MW of new renewable capacity (nameplate) per year, compared to about 400 MW per year in the Baseline. The annual capacity factors of new renewable facilities were assumed to remain unchanged. While the Baseline Scenario adds about 2,000 GWh of new renewable energy generation each year, the Lower DSM/ Renewable Impacts Scenario adds only an annual average of 700 GWh.

By the year 2013, the Lower DSM/Renewable Impacts Scenario has about 24,000 GWh less energy from DSM savings and renewable generation than does the Baseline. Gas-fired resource additions in the Lower DSM/Renewable Impacts Scenario were increased by about 1,600 MW in this scenario compared the baseline, under the assumption that the market will respond to an increase in “residual” demand by adding more gas-fired power plants. No changes to retirements were assumed.

## Results of DSM/Renewable Scenarios

As expected, having more DSM savings and renewable energy generation decreases the amount of gas-fired energy generation, gas use, average annual electricity spot market price, and air pollutant and greenhouse gas emissions from generation. And conversely, having less DSM savings and renewable energy generation increases the amount of gas-fired energy generation, gas use for electric generation, average annual electricity spot market price, and air pollutant and GHC emissions from generation. The differences in electricity market impacts between the Baseline, Higher DSM/Renewable Impacts and Lower DSM/Renewable Impacts scenarios are discussed below. The differences in gas market impacts between these scenarios are discussed in detail in staff’s *2003Preliminary Natural Gas Market Assessment*. Since the costs and likelihood of achieving the levels of DSM savings and renewable generation in the scenarios was not assessed, nor have disparate categories of benefits (e.g., emissions, fuel savings) been made directly comparable by monetization, staff has not identified which scenarios are achievable or preferable on an overall basis.

## Change in Generation Patterns

The changes in DSM savings and renewable generation levels in the Higher and Lower DSM/Renewable Impacts scenarios affects mostly gas-fired generation, only a very small amount of fuel oil, but little or no coal-fired generation. Most of the changes to gas-fired generation occur in the output of new gas-fired additions, rather than existing gas-fired power plants. The generation changes are spread throughout the hundreds of power plants within the interconnected WECC area and are not confined to California. Since staff does not intend this MarketSym-based analysis to be predictive of site-specific power plant operations, only aggregated results are provided.

The additional DSM savings and renewable generation in the Higher DSM/Renewable Impacts Scenario displaces about 7,600 GWh of gas-fired generation in the WECC by 2007, 14,600 GWh by 2010 and 19,100 GWh by 2013. This gas-fired generation reduction amounts to about 3 percent, 5 percent, and 6 percent of annual WECC gas-fired production, respectively. Of the total WECC gas-fired generation reduction by 2013, 53 percent occurs in California, 32 percent in the Desert Southwest, 11 percent in the Pacific Northwest, and 4 percent in the Rocky Mountain region of the WECC.

The reductions in DSM savings and renewable generation in the Lower DSM/Renewable Scenario increase by about 9,000 GWh the gas-fired generation in the WECC by 2007, by 17,000 GWh by 2010 and by 23,000 GWh by 2013. This gas-fired generation increase amounts to about 4 percent, 6 percent, and 7 percent of annual WECC gas-fired production, respectively. Of the total WECC gas-fired generation increase by 2013, 65 percent occurs in California, 19 percent in the Desert Southwest, 12 percent in the Pacific Northwest, and 3 percent in the Rocky Mountain region of the WECC.

## Change in Electric Generation Gas Use

The additional DSM savings and renewable generation in the Higher DSM/Renewable Impacts Scenario decrease the amount of natural gas consumed for electric generation across the WECC by 3 percent in 2007 and by 6 percent in 2010 and 2013. The percentage decrease in gas consumption for electric generation in California is 4, 7 and 9 percent in 2007, 2010 and 2013, respectively. The corresponding percentages for all generators in the WECC are 3, 5.5 and 6 percent, respectively.

The reductions in DSM savings and renewable generation in the Lower DSM/Renewable Scenario increase the amount of natural gas consumed for electric generation across the WECC by 4 percent in 2007, 6 percent in 2010, and by 7 percent in 2013. The percentage increase in gas consumption for electric generation is also higher for California than for the entire WECC, being 9 percent in 2010 and 12 percent in 2013.

More details about the natural gas market impacts of these scenarios' changes in DSM savings and renewable generation are provided in staff's *2003 Preliminary Natural Gas Market Assessment*.

## Change in Air Pollutant and GHG Emissions

The changes in DSM savings and renewable generation levels in the Higher and Lower DSM/Renewable Impacts scenarios affect power plants' emissions of criteria air pollutants and greenhouse gases. For example, gas-fired power plant emissions of oxides of nitrogen (NOx) and carbon dioxide ($CO_2$) are higher than Baseline amounts in the Lower DSM/Renewable Impacts Scenario and are lower than Baseline amounts in the Higher DSM/Renewable Impacts Scenario.

The additional DSM savings and renewable generation in the Higher DSM/Renewable Impacts Scenario decrease the amount of NOx emissions from gas-fired generation across the entire WECC region by 1,700 tons in 2007, 3,700 tons in 2010, and by 4,700 tons in 2013. Conversely, the reductions in DSM savings and renewable generation in the Lower DSM/Renewable Scenario increase the amount of NOx emissions across the WECC by 1,200 tons in 2007, 2,100 tons in 2010, and by (still) 2,700 tons in 2013. These NOx emission changes associated with displacement or increased use of gas-fired generation, like the displacement or increased use itself, are spread across hundreds of power plants throughout the WECC region. The local air quality implications of these widespread local changes were not assessed.

The impacts on $CO_2$ emissions from gas-fired power plants, directly mirrors the impacts on natural gas use for generation. The Higher DSM/Renewable Impacts Scenario's decrease in WECC-wide generator gas consumption translates into 3,900,000 fewer tons of $CO_2$ emissions in 2007, 7,500,000 fewer tons in 2010, and 9,700,000 fewer tons in 2013. Conversely, the lower DSM/Renewable Impacts Scenario's increase in WECC-wide generator gas consumption increases $CO_2$ emissions by 4,30,000 tons in 2007, 8,200,000 tons in 2010, and by 11,000,000 tons in 2013. The global climate change implications of these changes were not assessed.

## Change in Annual Average Electricity Spot Market Clearing Price

In the High DSM/Renewable Impact scenario, reduced demand and increased generation from new renewables led to a 5.3 percent reduction in the wholesale market price by 2013 (see **Table 8**). In the Low DSM/Renewable scenario, prices rose by 4 percent

Reducing dependence on gas-fired generation is likely to result in lower natural gas prices. Electric generation gas demand will soon be 30 percent of the total demand for natural gas in the western United States. A 6 percent decrease in the natural gas use by generators in the western U.S. would reduce demand in the west by 1.8 percent. The Natural Gas Unit of the Energy Commission estimates the effect of such a reduction on the spot market price for natural gas in California to be about 1 percent; see the *2003 Preliminary Natural Gas Market Assessment*.

**Table 8**
**Average Wholesale Prices ($/MWh) – High and Low DSM/Renewable Scenarios**
**2004 - 2013**

| High DSM/Renewable | | | | | | |
|---|---|---|---|---|---|---|
| | All Hours | | | On-Peak Hours | | |
| Year | High PGC | Baseline | Difference | High PGC | Baseline | Difference |
| 2004 | 33.9 | 33.9 | 0.1% | 38.1 | 38.2 | -0.3% |
| 2005 | 31.3 | 31.6 | -1.0% | 34.5 | 35.1 | -1.7% |
| 2006 | 32.8 | 33.4 | -1.7% | 36.2 | 37.0 | -2.1% |
| 2007 | 35.4 | 36.3 | -2.5% | 39.6 | 40.8 | -2.9% |
| 2008 | 37.3 | 38.7 | -3.7% | 41.8 | 43.8 | -4.5% |
| 2009 | 38.9 | 40.5 | -4.0% | 43.7 | 45.8 | -4.5% |
| 2010 | 41.0 | 42.9 | -4.3% | 46.3 | 48.6 | -4.9% |
| 2011 | 42.5 | 44.6 | -4.8% | 47.9 | 50.8 | -5.6% |
| 2012 | 44.7 | 47.2 | -5.3% | 50.5 | 54.0 | -6.4% |
| 2013 | 46.8 | 49.5 | -5.3% | 53.0 | 56.5 | -6.2% |
| Low DSM/Renewable | | | | | | |
| | All Hours | | | On-Peak Hours | | |
| Year | High PGC | Baseline | Difference | High PGC | Baseline | Difference |
| 2004 | 34.3 | 33.9 | 1.1% | 38.5 | 38.2 | 0.8% |
| 2005 | 32.0 | 31.6 | 1.0% | 35.2 | 35.1 | 0.3% |
| 2006 | 33.9 | 33.4 | 1.8% | 37.6 | 37.0 | 1.6% |
| 2007 | 37.3 | 36.3 | 2.6% | 41.9 | 40.8 | 2.6% |
| 2008 | 39.9 | 38.7 | 3.0% | 45.0 | 43.8 | 2.8% |
| 2009 | 41.7 | 40.5 | 3.0% | 47.3 | 45.8 | 3.1% |
| 2010 | 44.3 | 42.9 | 3.5% | 50.5 | 48.6 | 3.8% |
| 2011 | 46.0 | 44.6 | 3.1% | 52.2 | 50.8 | 2.7% |
| 2012 | 48.9 | 47.2 | 3.7% | 55.9 | 54.0 | 3.5% |
| 2013 | 51.4 | 49.5 | 4.0% | 58.9 | 56.5 | 4.4% |

# Transmission Resources

## Transmission, Supply Adequacy and Spot Market Prices

Transmission can substitute for generation in ensuring reserve margins high enough to guarantee supply adequacy and reduce the likelihood of price spikes in the spot market. It has repeatedly been stated that “California is not an island,” relying on both the Northwest and Southwest for power. Imported power is a component of the state’s reserve margin; to the extent that it can be reliably delivered, it reduces the need for new power plants in California.

Diversity exchanges with the Northwest have allowed California to rely on imported hydro power to meet peak needs during the summer rather than build additional in-state capacity.

Transmission also serves to lower wholesale prices for electricity. Even if in-state capacity is sufficient to meet the needs of Californians, imported power is often less expensive, allowing the state to avoid using older, less efficient plants to meet demand. Regional electricity surpluses resulting from overbuilding of generation - such as that which occurred in the Desert Southwest in the 1970s – allow other areas to benefit from another's excess capacity, as long as sufficient transmission is present. The Southwest Power Link (SWPL) was built between the Palo Verde Nuclear Station in Western Arizona and San Diego to enable San Diego to take advantage of Palo Verde's (then) low cost power.

Both inter- and intra-state transmission can reduce the local generation needed for supply adequacy and provide economic benefits. In transmission-constrained areas, a large share of local generation resources must be relied upon during peak hours to meet load due to an inability to import additional power. Failure of these units, absent the ability to import additional power, is more likely to lead to reliability criteria violations, and necessitate the involuntary curtailment of load. Transmission congestion imposes costs even in areas where there is sufficient local generation, as it prevents the import of cheaper power. In areas where local generation is relied upon to a great extent, transmission constraints can result in an additional cost: that of mitigating market power. Where generators can set prices due to a lack of competition, price spikes can only be avoided using cost-based price caps or Reliability-Must-Run (RMR) contracts. These contracts obligate the generator to provide power at a cost-based price in exchange for an annual payment determined by its fixed capital costs.

The past few years have witnessed an increase in the value of transmission. By the end of 2003, the construction of new power plants in Arizona and Nevada will have far surpassed the needs of the two states, in large part because the developers of these plants have anticipated serving load in California. This illustrates a fundamental difference between the regulated environment prior to 1998 and today's market: an increased reliance on the bulk transmission system to support commerce, rather than simply to ensure supply adequacy.

In addition, load growth and the absence or limited amount of new generation in transmission-constrained areas such as San Diego and San Francisco has made these areas even more dependent on imports. As plants in these areas age, becoming more prone to outages and relatively less efficient compared to newer facilities, the need for and value of transmission increases.

## Constrained Transmission Paths and Local Reliability Areas

This section briefly describes a number of areas were transmission related problems, combined with changes caused by deregulation, have contributed significantly to higher prices and reliability problems on the ISO-controlled grid. These include four major transmission paths—Paths 15, 26, 45 and 46, and two local reliability areas - San Diego and the San Francisco Peninsula. For a map of the major transmission paths and constraints in and into California. see **Appendix A**.

- Path 15 provides an example of how an insufficient transmission infrastructure coupled with poorly designed electricity markets can affect electricity costs. Path 15 enables economic transfers between southern California and the Southwest and northern California markets during much of the year. The path is often constrained during heavy summer peak load periods, limiting the level of transfers between the two areas. When Path 15 is constrained in the south-to-north direction, the CAISO is required to dispatch less efficient, higher cost generation north of Path 15 to meet northern California loads; the resulting "congestion costs" can produce significantly higher electricity price increases in northern California relative to south of Path 15. The congestion problem was exacerbated during 2000 - 2001 as strategically located generators north of path 15 were able to use their location to significantly increase prices. The CAISO has estimated that building a third 500 kV transmission line between Los Banos and Gates to relieve the problems encountered during 2000 – 2001 would pay for itself within five to 10 years.

- Path 26, an extension of Path 15 within southern California, was intended to provide transfers of lower cost power from northern to southern California during periods of high hydro availability in the north. The path, however, is often subject to constraints that limit these economic transfers. Congestion on Path 26 has increased to such a level that the CAISO has designated it as a separate pricing zone within California.

- Path 45 connects Northern Mexico with San Diego and the Imperial Valley. 1,660 MW of new generation has been completed in Northern Mexico near Mexicali and will be ready for operation in June 2003. 1,070 MW of this capacity is intended for export to the U.S.; the remaining 590 MW will be available to Mexico (CFE).[5] The former portion will connect through Path 45 to the Imperial Valley substation, but not all of it will be available to the San Diego area until upgrades at the substation are completed. Increasing transfers into the San Diego will also require reinforcement of the Miguel-Mission transmission line, an upgrade which the CPUC has found needed for economic purposes and is currently moving through an expedited permitting process.

- Path 46 connects Southern California to Nevada and Arizona. Another wave of generation development is currently occurring in the southwest, particularly in central Arizona and the area around the Palo Verde hub. Arizona expects to see over 6,000 MW of new gas-fired generation on line in this area by 2007. Additional generation is being developed in southern Nevada. Most of this new generation capacity is intended for sale in California electricity markets. The existing transmission capacity on Path 46 - linking western Arizona and Southern California markets - is not sufficient to transport this amount of power without significant upgrades. The CAISO has initiated a regional stakeholder process to evaluate transmission expansion options for Path 46.

# Local Reliability Areas

San Diego and the San Francisco Peninsula were both impacted by serious reliability problems during parts of 2000 and 2001. Both areas are characterized by limited generation within their electrical boundaries and limited transmission capacity to access resources outside of those boundaries. This combination of conditions has resulted in limited competition, providing local generators the potential to influence both reliability and electricity prices during heavy summer peak load conditions. To provide local voltage support for reliability purposes, as well as mitigate market power problems, much of the generation in both areas has been designated by the CAISO as RMR. This means the CAISO has required certain generators in San Diego and on the SF Peninsula to enter “must run” contracts that obligate them to operate at specified prices during periods designated by the CAISO.

## San Diego

The San Diego area has about 2,250 MW of local generation. With a projected summer 2003 peak load of about 3,800 MW, it must rely on imports from outside the area to meet the major portion of its load requirements. These requirements are supplied by two major transmission paths, Path 44 and the 500kV Southwest Power Link (SWPL), part of Path 46. Path 44 connects San Diego with the San Onofre Nuclear Generating Station, has a transfer capability of 2200 MW, and is San Diego’s only major link with the CAISO grid. SWPL connects San Diego to generation resources at the Palo Verde hub in western Arizona. With all lines in service, the simultaneous transfer capability into San Diego is about 2,800 MW. As a part of their area reliability studies, the CAISO and SDG&E found that a sequential outage of the area’s largest local power plant and its largest transmission line, SWPL, could result in local-area reliability criteria violations beginning in the 2005 time frame. Based on those findings, they proposed the construction of a 500 kV power line to provide a second major connection to the CAISO-controlled grid in the SCE service area—the Valley-Rainbow project. The CPUC is considering this project.

New generation development in San Diego could contribute to a resolution of SDG&E’s reliability problems. Two large power plants have been planned for the immediate San Diego area that could provide substantial reliability support, if completed. An application for the Otay Mesa power plant (Calpine, 510 MW) has already been approved by the CEC, but the facility is still in the very early stages of construction and there is uncertainty about its near term completion. The proposed Palomar facility (Sempra, 546 MW) is currently in the Energy Commission’s permitting process.

## San Francisco Peninsula

San Francisco, like San Diego, has limited transmission and generation resources. PG&E currently projects area loads of approximately 1,230 MW for the San Francisco/Peninsula area for 2005. Electricity to serve these loads is provided by six transmission lines in a single corridor and three aging and unreliable area power plants. These resource characteristics cause significant reliability risks for future outages on the SF Peninsula.

Local generation is expected to provide 618 MW of power to the SF Peninsula in 2005 (363 MW from the Potrero Power Plant, 215 MW from the Hunters Point Power Plant and 20 MW from the United Golden Gate Cogeneration Plant). All of this generation (except United Golden Gate) is under RMR contract with the CAISO. This existing generation is also highly susceptible to problems because of age and environmental issues. The Hunters Point Power Plant will be shut down as soon as it can be displaced by new generation and/or increased imports from outside the area according to an agreement between the City and County of San Francisco and PG&E. The lack of generators and their vulnerability has also impacted the ability of PG&E to perform maintenance on the transmission facilities.

The remaining 600+ MW of power needed to meet SF Peninsula load requirements is imported over transmission lines from the East Bay. Approximately a third of the generation needed for the San Francisco Peninsula is served by power delivered at San Mateo Substation from 230kV transmission lines connecting the Tesla, Newark, and Ravenswood Substations. The remaining San Francisco Peninsula load is met through power delivered to San Mateo Substation via two 230kV lines crossing San Francisco Bay.

The San Francisco electric reliability problem is being evaluated in several forums. Two major facilities (one transmission line and one power plant) are currently in permitting proceedings at the CPUC and Energy Commission, respectively. A second transmission project is also in the planning stages. The City and County of San Francisco has also looked at the problem and developed an energy plan that includes transmission, generation and conservation options. Finally the CAISO, through a PG&E stakeholder process, is analyzing the long-term (10-years) reliability of the San Francisco and Peninsula region.

Two transmission projects intended to increase electricity imports into the Peninsula have been proposed by planning groups to increase important capability into the SF Peninsula area. The San Mateo-Martin Conversion Project, an upgrade of an existing 60 kV line to 115 kV, could increase area imports by 200 MW by 2004. PG&E has not yet filed an application at the CPUC for this project, however. PG&E has filed an application with the CPUC for a CPCN for the 230 kV Jefferson-Martin transmission line. This project, along with other system improvements, would increase the import capability into San Francisco by approximately 400 MW.

Mirant has proposed a 540 MW expansion of its Potrero Power Plant that would displace existing generation on the Peninsula. This project is currently in licensing review at the Energy Commission, and a decision is currently anticipated in December 2003.

## Major Obstacles to the Development of Transmission Resources

Transmission system planners currently estimate that it takes five to seven years to complete a major upgrade to the bulk transmission system. Demonstrating need, securing environmental permits and rights-of-way, securing financing (for private projects), and time requirements for construction, require that planners anticipate the need for transmission expansion projects ten years and longer before these projects are in service. In California obstacles to timely transmission development are most commonly related to debates over project benefits and the need for the project, project financing difficulties and local opposition related to environmental and property value impacts. These obstacles arise because:

- Permit processes for the various types of transmission projects are fragmented and overlapping, environmental analyses are inconsistent, and the regional and statewide strategic benefits of projects are not adequately considered.

- Total project benefits are not addressed in the permitting process. Economic benefits and costs of projects requiring a Certificate of Public Convenience and Necessity must be viewed by the CPUC in the context of ratepayer benefits. Statewide strategic benefits from a project may not be adequately addressed.

- Projects with economic benefits may face opposition in permitting as not having been put forth in the context of a broader plan and considered in the context of broader, long term transmission planning including project alternatives. Merchant transmission line developers may propose economic projects for consideration in the CAISO process. Publicly owned utilities and federal agencies, for the most part, propose, plan, and build transmission projects to meet their own reliability and economic needs. Consequently, coordination among entities needing transmission may not occur and no statewide perspective is incorporated in transmission planning, regardless of ownership. As a result, the planning process may address issues important to the transmission owners and CAISO, but may overlook issues that are vital to broader interests, such as future right-of-way needs, system reliability, efficient use of the existing system, the environmental performance of the system, and the need for long term strategic expansion of the system.

- Private investment in transmission, although encouraged by FERC, has been slowed by the financial distress of some developers, as well as regulatory and economic uncertainty.

- The benefits of a transmission upgrade are regional, while the physical impacts are local.

- Strong, organized local opposition is common due to visual, other environmental and property value impacts associated with major transmission upgrades.

## Facilitating Development of Transmission Resources

Over the past decade a number of recommendations have been made by various organizations to address California's obstacles to realizing needed transmission system expansion. Actions have been taken most recently by state government, the CAISO and others to remove obstacles and ensure the state permitting and planning processes for transmission projects are coordinated and effective in addressing issues related to project benefits and costs. The most noteworthy of these recent actions are briefly discussed below and will be discussed in more detail in staff's transmission white paper, scheduled to be released on July 25, 2003.

**SB 1389 (2002)** – The Legislature finds that reliable energy is essential and vital to the health and welfare of the state and that government has an essential role to ensure a reliable supply of energy consistent with preservation of public health and safety, a sound economy, conservation and environmental protection. This legislation establishes that at least every two years the Energy Commission conducts assessments and forecasts of all aspects of energy supply, production, transportation, distribution, demand and prices, in collaboration with appropriate state and federal agencies and encourages cooperation among state agencies with energy responsibilities. Results from the Energy Commission assessments and forecasts are made available to state agencies with energy responsibilities and will provide a common basis for decisions on the total benefits and costs of transmission projects.

**State Energy Action Plan** – This 2003 plan is a collaborative effort among the CPUC, Energy Commission and CPA consistent with SB 1389 to in part ensure that the state will invigorate its planning, permitting and funding processes to ensure necessary expansions to the bulk transmission system in a timely manner.

**IEPR Update Process** – This process was initiated in 2002 by the Energy Commission to carry out the mandates of SB1389. The process will provide for collaborative identification of transmission system expansion needs, and state findings on the total benefits and costs of proposed transmission projects that can be used by decision makers in the permitting process.

**Common analytical methods** – Efforts are underway on the part of the CAISO and CPUC to develop a common methodology to determine the value of proposed transmission projects which may be needed to provide economic benefits to the state.

**Strategic, long-term planning –** This effort which is being initiated by the Energy Commission and CAISO is intended to ensure that long term planning and strategic project benefits are included in the CAISO transmission planning process and state IEPR process.

**Locational marginal pricing (LMP) –** This concept is intended to provide real time operation benefits by helping to mitigate transmission congestion impacts. It is a component of both the FERC Wholesale Market Platform and the CAISO Market Redesign (MD02). It divides the state's transmission grid into 3000 nodes, at which energy is generated and consumed, interconnected by transmission lines. More detailed than the current zonal pricing method in use, it more accurately reflects existing transmission constraints and thus provides better price signals for planning and investment in transmission projects and may help to remove obstacles to investment.

**FERC Incentives** - Several steps have been taken by the FERC to facilitate investment in transmission. Public utilities are being provided incentives to invest in new transmission, as well as to join Regional Transmission Organizations (RTOs) or form Independent Transmission Companies (ITCs). These incentives take the form of an additional 50 to 150 basis points in allowable return on equity investment depending on the action taken by the public utility with respect to RTO membership and divestiture of transmission assets

## Coordinating Development of Electric Generation and Transmission

The benefits of generation and transmission resources, from both reliability and economic standpoints, depend upon the other resources that make up the system. The value of a new power plant can be affected by the construction or upgrade of a transmission line. This fact has substantial implications for the extent to which the market can be relied upon to yield adequate and timely investment in an economically efficient fashion.

The past two years have seen a dramatic growth in generation capacity, but much of it located away from major load centers in California. As a result (a) forward prices for electricity have fallen, discouraging new generation in California, and (b) transmission congestion has increased to the point that much of the capacity interconnected at Imperial Valley and Palo Verde is unable to serve California loads during peak hours. The result is a call for additional transmission capacity to connect the Southwest with San Diego and the Los Angeles basin, but an interim need to build new generation capacity in San Diego for reliability purposes in the event that the transmission upgrade is not in place when needed. At the same time, the need for the transmission upgrades that would obviate the need for new generation capacity in San Diego has been questioned by those who assume the new capacity will be built by the market.

Given the substantial uncertainties surrounding the location of generation and transmission, regulatory policy, *etc.*, eight to ten years into the future, the State cannot rely on the market to develop new transmission resources in a timely and efficient fashion. Efficient transmission planning on the part of LSEs and regulators would be facilitated by greater certainty regarding the location of yet-to-be-built power plants. In short, State policy needs to not only facilitate timely investment in generation, but would also promote economic efficiency in many instances if it directed where new facilities were built.

As previously discussed, the CAISO has initiated a stakeholder process to coordinate the development of future transmission resources with existing and planned generation facilities throughout Southern California and the Southwest. In addition, in this IEPR cycle, the Energy Commission is assessing the value of proposed transmission projects in light of assumed generation additions.

## Overview of Staff's Transmission Study Plan and White Paper to Support the Electricity & Natural Gas Report and the Integrated Energy Policy Report

As described in the sections on transmission above, there are numerous obstacles to the effective planning, permitting, construction, and operation of the interstate transmission system. The types of obstacles faced by any given project are a function of several factors, including the type of project proponent, the purpose(s) of the project, the size and location of the project, and the regulatory and economic climate. To that end, staff will analyze in further detail four representative transmission projects in this Integrated Energy Planning Report cycle. These include the following types of projects: (1) a major interstate project proposed for economic reasons; (2) a major intrastate, inter-utility project proposed to address local reliability needs; (3) an intra-utility project proposed to address local reliability needs; and (4) an intra-utility project proposed to address existing and likely future Renewable Portfolio Standard needs. In addition, the selected projects are ones that are of immediate concern to staff because they will (or do) require a Certificate of Public Convenience and Necessity (CPCN) from the CPUC; their ability to obtain a CPCN has been denied or is not yet certain; and staff believes that these projects could benefit from a timely analysis of strategic benefits beyond those analyzed in the current CPCN process.

For each project to be examined, staff will conduct a preliminary economic and/or reliability analysis to assess potential benefits and identify potential critical issues. The results of staff's analysis will be included in a comprehensive Transmission White Paper which will be released concurrent with the July 25 *Electricity and Natural Gas Report.* Staff will then conduct a more comprehensive benefit/cost analysis for these projects (including an examination of alternatives), in the IEPR Update Process in 2004[6]. This comprehensive analysis is consistent with the Energy Commission's SB 1389 mandate[7] and the most recent State Energy Action Plan[8] adopted by the California Power Authority, Energy Commission, and California Public Utilities Commission on April 18, April 30, and May 8, 2003, respectively.

# Endnotes

[1] Staff draft reports can be found on the Energy Commission website at: http://www.energy.ca.gov/energypolicy/documents/index

[2] For 2003, Energy Commission staff forecast a demand of 265,000 GWh for energy and a peak demand under normal temperature conditions of slightly more than 52,000 MW.

[3] Frank Wolak, Lessons from the California Electricity Crisis, CSEM working paper #110, April 2003

[4] This report does not discuss the role of natural gas as a heating or transportation fuel or industrial input. The costs and benefits of policies aimed at reducing the use of natural gas for these purposes are assessed in other Commission reports.

[5] In May 2003, a U.S. Federal Court made a preliminary finding that the environmental reviews for the new projects and associated transmission facilities had not been properly performed, and ordered a stay, preventing power transfers to the U.S. until the issue is resolved.

[6] SB 1389 Section 25302(d) states: Beginning November 1, 2004, and every two years thereafter, the commission shall prepare an energy policy review to update analyses from the integrated energy policy report prepared pursuant to subdivisions (a), (b), and (c), or to raise energy issues that have emerged since the release of the integrated energy policy report.

[7] SB 1389 section 25303(a) states: The commission shall conduct electricity and natural gas forecasting and assessment activities to meet the requirements paragraph (1) of subdivision (a) of Section 25302, including, but not limited to, all of the following:

> (3) …Assessment of the availability, reliability, and efficiency of the electricity and natural gas infrastructure and systems including, but not limited to…western regional and California electricity and transmission system capacity and use.

[8] Section IV of the State Energy Action Plan includes the following actions:

1. The agencies will collaborate, in partnership with other state, local, and non-governmental agencies with energy responsibilities, in the California Energy Commission's integrated energy planning process to determine the statewide need for particular bulk transmission projects. This collaboration will build upon the California Independent System Operator's annual transmission plan and evaluate transmission, generation, and demand side alternatives. It is intended to ensure that state objectives are evaluated and balanced in determining transmission investments that best meet the needs of California electricity users.

2. The Public Utilities Commission will issue an Order Instituting Rulemaking to propose changes to its Certificate of Public Convenience and Necessity process, required under Public Resources Code section 1001 et seq., in recognition of industry, marketplace, and legislative changes, like the creation of the CAISO and the directives of SB 1389. The Rulemaking will, among other things, propose to use the results of the Energy Commission's collaborative transmission assessment process to guide and fund IOU-sponsored transmission expansion or upgrade projects without having the PUC revisit questions of need for individual projects in certifying transmission improvements.

# Appendix A
# Transmission Upgrades Assumed in Simulations

As noted in its February 11, 2003 Staff Draft Report entitled ***Preliminary Electricity and Natural Gas Infrastructure Assumptions***, there are seven major transmission projects conservatively expected in the next ten years which staff modeled in its MarketSym™ simulations:

1. Path 15 upgrade: The addition of a third 500 kV line between Los Banos and Gates would reduce a major intrastate bottleneck that limits economic transfers between northern and southern California. This joint TransElect/WAPA/PG&E project is modeled by increasing the North-to-South capacity by 1,135 MW and the South-to-North capacity by 1,500 MW beginning in January 2005.

2. Path 26 (Midway to Vincent) upgrade: This project would allow an increase in the path rating from 3,000 MW to 3,400 MW by installing a new remedial action scheme (RAS) to drop new generation in PG&E's Midway area in the event of a contingency. Due to an explosion and fire at SCE's Vincent transformer bank 2AA on March 21, 2003, the current transfer capability of Path 26 is 2,500 MW. Because the installation of a fourth transformer at Vincent had already been planned for July 1, 2003, the fourth transformer will now serve as a functional equivalent for transformer bank 2AA, thereby allowing a return to a path rating of 3,000 MW once it becomes operational. The RAS upgrades are being made independent of the transformer installation, and according to PG&E should be operational by November 2003. Staff had previously assumed an effective date of October 2003; the slip of one month will not impact staff's simulations.

3. Path 45 upgrade: The physical upgrades (line reconductoring from the La Rosita Substation in Mexico to the Imperial Valley Substation in California) necessary to increase the entire path rating from about 400 MW to 800 MW have been completed; however, the WECC has not yet approved the increase in the South-to-North direction for the summer months. That approval is expected in mid-July 2003.

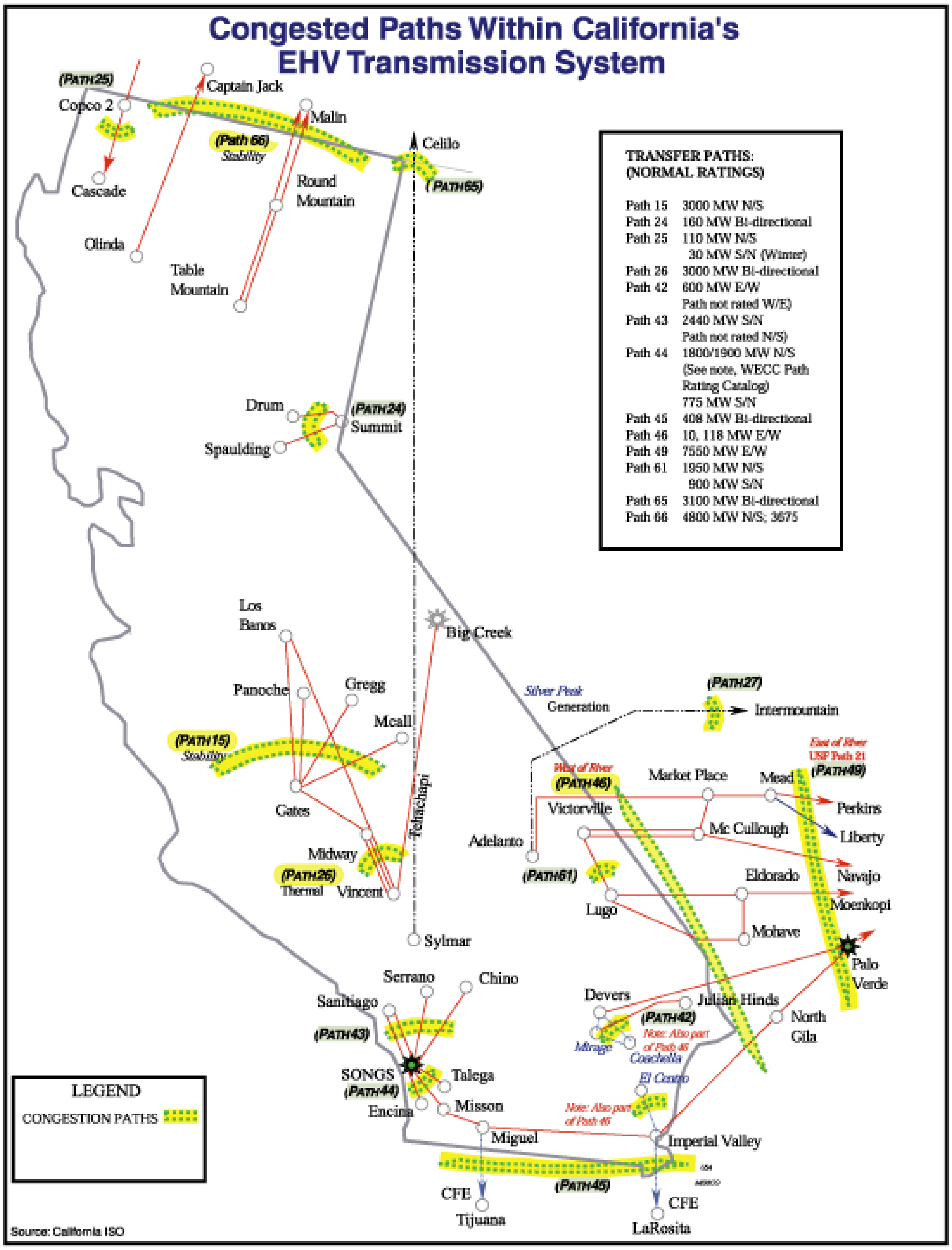
4. Miguel-Mission and Imperial Valley Substation upgrades: The combination of these upgrades will allow for an additional 560 MW of capacity to be delivered to the San Diego load center. The CPUC approved the construction of these projects based on their economic (rather than reliability) merits on February 27, 2003; however, SDG&E must still obtain a Certificate of Public Convenience and Necessity (CPCN) for the Miguel-Mission portion of the project. The CPUC will expedite the CPCN since the economic need for the project has been established and the work will be done within SDG&E's rights-of-way. Staff has assumed an on-line date of January 2005. The most recent SDG&E monthly filing to the CPUC shows an on-line date of June 2005.

5. Path 46 upgrade: Staff has assumed a 1,000 MW increase in the West of Colorado River path from the Imperial Irrigation District area to the SCE area in January 2009. Unlike

the other projects discussed here, this is a generic project assumption that does not reflect an actual proposal by a project proponent, but is assumed to be needed to accommodate the movement of RPS-driven renewable energy from new geothermal facilities in the Salton Sea area.

6. Jefferson-Martin project: This reliability-driven project would increase the transfer capability from PG&E north of Path 15 into the San Francisco area from 700 MW to 1,100 MW. Staff has assumed the CPUC will issue its CPCN and construction will be complete by January 2006. For more information on this project, see the section entitled "Constrained Transmission Paths and Local Reliability Areas."

7. Valley-Rainbow project: Staff has modeled this project as an increase in transfer capability between SCE and SDG&E beginning in January 2009. The CPUC denied SDG&E a CPCN for this project in December 2002. A decision on SDG&E's appeal is currently scheduled for the CPUC's June 5, 2003 business meeting. For more information on the status of this project, see the section entitled "Constrained Transmission Paths and Local Reliability Areas."


Congested Paths Within California's
EHV Transmission System
TRANSFER PATHS:
(NORMAL RATINGS)
Path 15 3000 MW N/S
Path 24 160 MW Bi-directional
Path 25 110 MW N/S
30 MW S/N (Winter)
Path 26 3000 MW Bi-directional
Path 42 600 MW E/W
Path not rated W/E)
Path 43 2440 MW S/N
Path not rated N/S)
Path 44 1800/1900 MW N/S
(See note, WECC Path
Rating Catalog)
775 MW S/N
Path 45 408 MW Bi-directional
Path 46 10, 118 MW E/W
Path 49 7550 MW E/W
Path 61 1950 MW N/S
900 MW S/N
Path 65 3100 MW Bi-directional
Path 66 4800 MW N/S; 3675
(PATH25)
Copco 2
Captain Jack
Malin
(Path 66)
Stability
Celilo
(PATH65)
Cascade
Round
Mountain
Olinda
Table
Mountain
Drum
(PATH24)
Summit
Spaulding
Los
Banos
Big Creek
Panoche
Gregg
Mcall
(PATH15)
Stability
Gates
Tehachapi
Midway
(PATH26)
Thermal
Vincent
Sylmar
Silver Peak
Generation
(PATH27)
Intermountain
East of River
USF Path 21
(PATH49)
West of River
(PATH46)
Market Place
Mead
Perkins
Victorville
Mc Cullough
Liberty
Adelanto
Navajo
(PATH61)
Eldorado
Lugo
Moenkopi
Mohave
Palo
Verde
Serrano
Chino
Sanitiago
Devers
Julian Hinds
(PATH42)
North
Gila
(PATH43)
Mirage
Note: Also part
of Path 46
Coachella
SONGS
Talega
(PATH44)
El Centro
Encina
Misson
Note: Also part
of Path 46
Miguel
Imperial Valley
CFE
Tijuana
(PATH45)
CFE
LaRosita
LEGEND
CONGESTION PATHS
Source: California ISO

# Appendix B
# 2003 Generation Additions Statewide

| Project | Nameplate | Summer Dependable | Online Date | Cumulative |
|---|---|---|---|---|
| Calpine - Creed Energy Center | 45 | 40 | 1/1/2003 | |
| Calpine - Lambie Energy Center | 45 | 40 | 1/1/2003 | |
| Calpine - Goose haven Energy Center | 45 | 40 | 1/1/2003 | |
| Calpine - Feather River | 45 | 40 | 1/1/2003 | |
| | **January** | **160** | | **160** |
| La Paloma 1 & 3 | 562 | 539 | 01/10/03 | |
| Paramount Refinery (Co-gen) | 8 | 8 | 1/15/2003 | |
| Calpine - Wolfskill Energy Center [formerly Milpitas Peaker] | 45 | 40 | 1/23/2003 | |
| | **February** | **587** | | **747** |
| CalWind Resources, Inc., (WIND) | 9 | 0 | 2/15/2003 | |
| Blythe | 520 | 499 | 3/1/2003 | |
| | **March** | **499** | | **1,245** |
| La Paloma 2 & 4 | 562 | 539 | 3/3/2003 | |
| ISG Energy, LLC, Mesquite Lake Resource Recovery Facility (WASTE TIRE) | 30 | 30 | 4/1/2003 | |
| | **April** | **569** | | **1,814** |
| Neo Corporation, Colton (LFG) | 1 | 1 | 4/9/2003 | |
| Neo Corporation, Mid-Valley (LFG) | 3 | 3 | 4/11/2003 | |
| Calpine- Riverview Peaker | 45 | 40 | 4/21/2003 | |
| High Desert | 830 | 796 | 4/22/2003 | |
| Calpine- Los Esteros Critical Energy Facility Units 1-4 | 180 | 160 | 4/30/2003 | |
| Modesto Irrigation District - Woodland 2 | 80 | 77 | 5/1/2003 | |
| | **May** | **1,076** | | **2,891** |
| Neo Corporation, Milliken (LFG) | 3 | 3 | 5/30/2003 | |
| El Dorado Irrigation Dist. (SM HYDRO) | 21 | 21 | 5/31/2003 | |
| GWF - Tracy  (Tesla Substation) | 169 | 150 | 6/1/2003 | |
| Energy Developments, Inc., Keller Canyon (LFG) | 4 | 4 | 6/1/2003 | |
| Elk Hills | 500 | 480 | 6/1/2003 | |

| Project | Nameplate | Summer Dependable | Online Date | Cumulative |
|---|---|---|---|---|
| | **June** | **657** | | **3,548** |
| Anaheim Convention Center | 2 | 2 | 6/15/2003 | |
| FPL Energy, High Winds, LLC Phase 1 (WIND) | 70 | 0 | 7/1/2003 | |
| FPL Energy, High Winds, LLC Phase 2 (WIND) | 80 | 0 | 7/1/2003 | |
| Sunrise Phase 2 [Combined Cycle] | 265 | 265 | 7/1/2003 | |
| County of Santa Cruz, Dept. of Public Works, Buena Vista Landfill (LFG) | 3 | 3 | 7/1/2003 | |
| | **July** | **270** | | **3,817** |
| Mark Tech. Corp./FORAS Energy, Inc., Alta Mesa VII (WIND) | 15 | 0 | 8/1/2003 | |
| AES- Huntington Beach Unit 4 | 225 | 225 | 8/1/2003 | |
| | **August** | **225** | | **4,042** |
| Oak Creek Energy Systems, Inc., Jawbone (WIND) | 53 | 0 | 9/1/2003 | |
| Oak Creek Energy Systems, Inc., Oak Creek 4 | 28 | 8 | 9/1/2003 | |
| Oak Creek Energy Systems, Inc., Deetricity (WIND) | 18 | 0 | 9/1/2003 | |
| Oak Creek Energy Systems, Inc., Oak Creek 3 | 5 | 2 | 9/1/2003 | |
| | **September** | **10** | | **4,052** |
| Energy Unlimited, (WIND) | 17 | 0 | 9/30/2003 | |
| Wintec Energy #2 (WIND) | 4 | 0 | 9/30/2003 | |
| | **October** | **0** | | **4,052** |
| Mark Tech. Corp./FORAS Energy, Inc., Alta Mesa IV (WIND) | 25 | 0 | 10/31/2003 | |
| Keating Associates, (SMALL HYDRO) | 1 | 1 | 11/1/2003 | |
| So Cal Water- Big Bear | 8 | 8 | 11/12/2003 | |
| | **November** | **9** | | **4,061** |
| *No projects in December ranked @ 75% Probability* | **December** | | | **4,061** |

# Appendix C
# California Generation Additions and Retirements
# 2003 – 2013

| Generation Additions | | | | | Generation Retirements | | |
|---|---|---|---|---|---|---|---|
| **Unit** | **On Line Date** | **Installed Capacity** | **Dependable Capacity** | **Region** | **Unit** | **Retirement Date** | **Dependable Capacity** |
| Glenarm GT 3,4 | 9/1/2003 | 94 | 94 | SP-15 | Morro Bay 1 | 9/30/2003 | 171 |
| Valley LADWP CC | 10/1/2003 | 520 | 520 | Los Angeles | Morro Bay 2 | 9/30/2003 | 171 |
| LADWP Wind - SP15 | 7/1/2004 | 140 | 0 | SP-15 | Haynes 4 | 11/30/2003 | 222 |
| Haynes Repower | 12/1/2004 | 575 | 575 | Los Angeles | | | |
| Walnut CC | 12/1/2004 | 250 | 250 | NP-15 | Alamitos GT 7 | 12/31/2003 | 147 |
| Pico | 1/1/2005 | 147 | 147 | NP-15 | Etiwanda 5 | 12/31/2003 | 141 |
| San Fran. Airport | 1/1/2005 | 180 | 180 | San Francisco | Magnolia GT 5 | 1/1/2004 | 22 |
| Magnolia CC | 3/1/2005 | 250 | 250 | Los Angeles | Olive 3,4 | 1/1/2004 | 56 |
| Cosumnes River | 3/15/2005 | 547 | 547 | Sacto. | Valley LADWP 1-4 | 4/15/2004 | 513 |
| Vernon GTs | 5/1/2005 | 135 | 135 | SP-15 | Haynes 3 | 9/30/2004 | 222 |
| Metcalf | 6/1/2005 | 602 | 608 | NP-15 | Magnolia 3,4 | 9/30/2004 | 53.5 |
| Kings River Peaker | 7/1/2005 | 45 | 45 | NP-15 | Mohave 1,2 | 12/31/2005 | 915 |
| Salton Sea #6 | 7/1/2005 | 185 | 170 | IID | Hunters Point 4 | 1/1/2006 | 163 |
| MID Cogen | 12/1/2005 | 80 | 80 | NP-15 | Hunters Point GT1 | 1/1/2006 | 56 |
| Otay Mesa | 12/31/2005 | 510 | 510 | Miguel CA | South Bay 1-4 | 12/31/2008 | 623 |
| Generic CC 1 & 2 | 1/1/2009 | 600 | 600 | SDG&E | **Total Retirements** | | **3,476** |

| Generation Additions | | | | | Generation Retirements | | |
|---|---|---|---|---|---|---|---|
| **Unit** | **On Line Date** | **Installed Capacity** | **Dependable Capacity** | **Region** | **Unit** | **Retirement Date** | **Dependable Capacity** |
| Generic CC 1 | 4/1/2009 | 250 | 250 | San Francisco | | | |
| Generic GT 1 | 4/1/2009 | 150 | 150 | IID | | | |
| Generic GT 1 | 4/1/2009 | 150 | 150 | SP15 | | | |
| Generic GT 1 | 4/1/2010 | 150 | 150 | NP15 | | | |
| Generic GT 1 | 4/1/2011 | 150 | 150 | NP15 | | | |
| Generic GT 1 | 4/1/2012 | 150 | 150 | NP15 | | | |
| Generic GT 1 | 4/1/2012 | 150 | 150 | SP15 | | | |
| Generic CC 1 | 4/1/2013 | 250 | 250 | SP15 | | | |
| Generic GT 1 | 4/1/2013 | 150 | 150 | SP15 | | | |
| **Total Additions** | | **6,410** | **6,261** | | | | |
| | | | | | | | |
| * Does not include RPS renewables | | | | | | | |

# Appendix D
# Description of MarketSym$^{Tm}$

MarketSym ™ is a proprietary model used by the CEC to simulate the WECC electricity markets. A product of Henwood Energy Services, Inc., it is used by utilities, regulators, and market analysts world-wide.

The model uses data on individual power plants, generation fuels, transmission paths and electricity demand to simulate operation of the WECC on an hourly basis. This data includes:

## Thermal Power Plants

- Maximum and minimum operating levels
- Minimum up and down times
- Ramp and run-up rates
- Commit and dispatch constraints
- Fuel use (per start, unit of output)
- Fuel cost (per mmBTu)
- Pollutant emissions (per unit of ouput)
- Generator bids, if other than variable cost

## Hydro Power Plants

- Maximum operating levels
- Monthly energy limits
- Run-of-river constraints

## Transmission Paths

- Transfer capability between transmission areas
- Losses
- Wheeling charges

## Electricity Demand & Reserve Requirements

- Hourly loads in each transmission area
- Required reserves (spinning, non-spinning)

The model commits and dispatches power plants to meet load and reserve requirements in each transmission area at the lowest total system cost. It provides the following hourly output by:

## Transmission Area

- Market clearing price ($/MWh)
- Expected unserved energy

## Power Plant

- Generation (MWh)
- Fuel use (mmBtu) and cost
- Emissions ($NO_X$, CO2, $SO_X$; tons)

## Transmission Path

- Line loading (MW)
- Losses

# Appendix E
# Additions in WECC

| | Net Additions (MW) - Remainder of WECC 2004 - 2013 | | | |
|---|---|---|---|---|
| Year | Southwest & Mexico | Northwest & Canada | Rocky Mountains | Total |
| 2004* | 2,329 | 203 | 601 | 3,133 |
| 2005 | 999 | 450 | 0 | 1,449 |
| 2006 | 0 | -2 | 0 | -2 |
| 2007 | 0 | 150 | 0 | 150 |
| 2008 | 150 | 920 | 0 | 1,070 |
| 2009 | 150 | 1,090 | 0 | 1,240 |
| 2010 | 300 | 1,745 | 0 | 2,045 |
| 2011 | 550 | 1,314 | 150 | 2,014 |
| 2012 | 880 | 950 | 150 | 1,980 |
| 2013 | 1,390 | 1,610 | 150 | 3,150 |
| Total | 6,748 | 8,430 | 1,051 | 16,229 |
| *Net additions during 12 months preceding August 1 or the year indicated | | | | |

| Major Additions Assumed - Remainder of WECC 2004 - 2005 | | | | |
|---|---|---|---|---|
| Name | Owner | Dependable Capacity (MW) | On-line | Location |
| Bonanza Expansion | ? | 80 | 2004 | Utah |
| Payson | UAMPS | 140 | 2004 | Utah |
| MacKay River Cogen | TransCanada | 95* | 2004 | Alberta |
| Pyramid | Tri-State G&T | 152 | 2004 | New Mexico |
| Bighorn | Reliant | 580 | 2004 | Nevada |
| Harquahala | Shaw Group | 972 | 2004 | Arizona |
| Mesquite (phase 2) | Sempra | 625 | 2004 | Arizona |
| Genesee 3 | EPCOR/TransAlta | 450 | 2005 | Alberta |
| Santan | ? | 700 | 2005 | Arizona |
| Generic CC | | 300 | 2005 | Baja California |

* 165 MW installed, 95 MW injected into grid

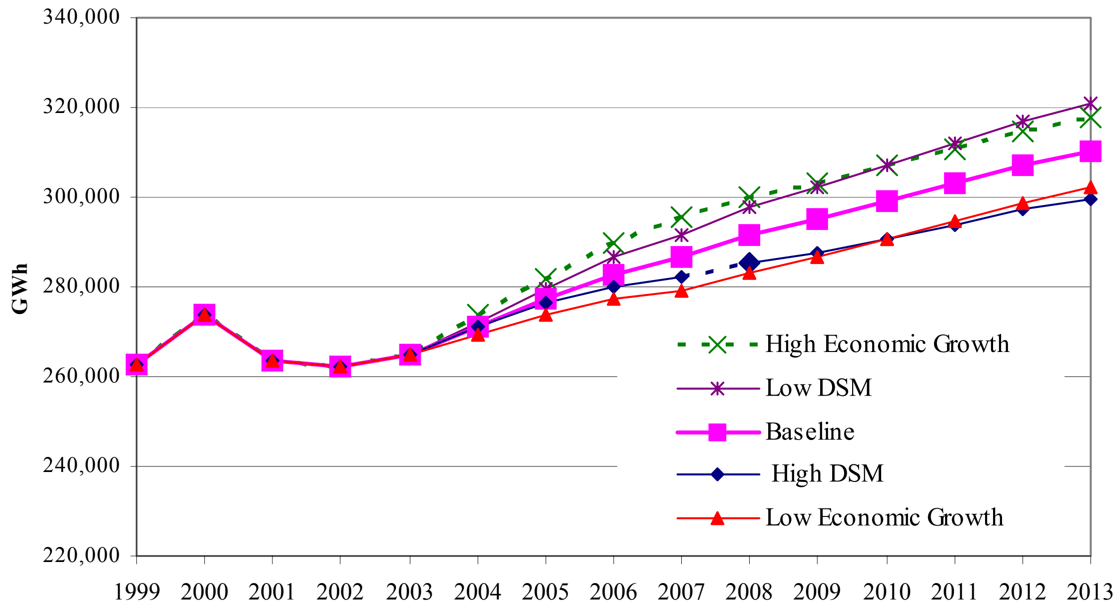
# Appendix F
# Demand Scenarios

In addition to the baseline forecast, staff developed several scenarios to support evaluation of risks to infrastructure and supply adequacy. **Table 1** and **Figure 1** summarize these scenarios and their effects on forecasted demand. In the highest scenario, an increase in economic growth increases peak demand by more than 1600 MW in 2008. In the low economic growth scenario, demand is about 1700 MW lower in 2008. The demand-side management (DSM) scenarios have a somewhat smaller effect.

**Table 1**
**Summary of Demand Forecast Scenarios**

| Scenario Name | Description | Average Annual Peak Demand Growth 2004-2008 | MW Difference in 2008 |
|---|---|---|---|
| Baseline | | 1.7% | 0 |
| High Economic Growth | Economic growth 2004-2008 1% higher than baseline | 2.2% | 1659 |
| Low Economic Growth | Economic growth 2004-2008 1% lower than baseline | 1.1% | -1736 |
| High DSM | Doubling of energy efficiency spending 2004-2013 | 1.3% | -1007 |
| Low DSM | Elimination of energy efficiency spending 2004-2013 | 2.1% | 1073 |

**Figure 1**
**Statewide Demand Scenarios**
**Net Energy for Load (GWh)**




# Assumptions for the Baseline Demand Forecast and Scenarios

## Economic and Demographic Assumptions

Energy use is a function of numerous factors, including demographic growth, economic growth, price trends, and changes in customer behavior. Population and income are key drivers for the residential and commercial sectors. Employment and industrial shipments are drivers for the commercial and industrial sectors.

Staff develops a forecast of households using the California Department of Finance population projections. Population projections are unchanged in the scenarios. Projections of personal income, employment, and shipments are derived from the University of California at Los Angeles (UCLA) Anderson School of Business California forecast of September 2002. This forecast assumes that stronger economic growth will resume in late 2003, followed by steady growth, but at a lower rate than previous recoveries.

The high economic growth scenario models the effects of a more robust economy on energy demand. Over the last twenty years, the average annual post-recession employment growth rate has averaged about 1 percent higher than the growth rate assumed in the baseline employment forecast. To model the effects of a stronger recovery on energy demand, the employment forecast was accelerated to achieve a new forecast with an annual growth of slightly more than 1 percent higher for the years 2004-2007. Other economic drivers for the sector forecasts were also accelerated by one or two years for similar results. After 2007, the baseline forecast trend resumes.

Conversely, to develop a low economic growth scenario, the forecasted growth beginning in 2004 is delayed by one to two years so that growth on average is slightly more than 1 percent lower than the baseline economic forecast. **Table 2** summarizes key economic drivers under each scenario.

**Table 2**
**Comparative Growth Rates of Baseline and Scenario Forecast Assumptions**
**Average Annual Growth Rate (%)**

| | 2003-2007 | | | 2007-2013 | | |
|---|---|---|---|---|---|---|
| | Base case | Low Economic Growth | High Economic Growth | Base case | Low Economic Growth | High Economic Growth |
| Real Personal Income | 3.6 | 2.3 | 4.9 | 3.3 | 2.7 | 2.8 |
| Employment | 2.4 | 1.1 | 3.5 | 2.0 | 2.3 | 1.7 |
| Industrial Shipments | 2.2 | 1.4 | 4.9 | 3.4 | 2.8 | 3.0 |

## Energy Efficiency Assumptions

The baseline forecasts for both electricity and natural gas demand reflect the assumption that current levels of funding for utility energy efficiency programs will continue. To estimate the effect on demand of increased investment in energy efficiency, staff used scenarios developed as part of a recent series of studies of energy efficiency savings potential in California.[1] These studies estimated the amount of cost-effective, achievable potential available statewide, and then estimated how much of that potential would be attained at alternative funding levels. These studies use Energy Commission data as the foundation of their analysis, so the results are largely consistent with the assumptions embedded in the baseline forecast.

The high DSM scenario estimates the effect on demand of doubling the amount of energy efficiency spending statewide beginning in 2004 and continuing through 2013. Increasing PGC spending on electricity efficiency to $572 million per year from $240 million per year (based on average spending 1996-2000), reduces demand by about 1800 MW in 2013.

Eliminating all spending on energy efficiency after 2003 would increase demand in 2013 by about 1900 MW.

# Endnotes

1. "California Statewide Commercial Sector Natural Gas Energy Efficiency Potential Study", Study ID #Sw039a, Prepared For Chris Ann Dickerson, Ph.D., Project Manager; Pacific Gas & Electric Company San Francisco, California, Prepared By Principal Investigators Fred Coito And Mike Rufo, XENERGY Inc., Oakland, California.

   "California Statewide Residential Sector Energy Efficiency Potential Study, Study" ID #SW063, Prepared for Rafael Friedmann, Project Manager, Pacific Gas & Electric Company, San Francisco, California. Prepared by Principal Investigator Fred Coito and Mike Rufo, KEMA-XENERGY Inc., Oakland, California, April 2003. "California's Secret Energy Surplus", Prepared for The Energy Foundation and The Hewlett Foundation, Prepared by Principal Investigators Fred Coito and Mike Rufo, XENERGY Inc., September 23, 2002.

# Appendix G
# Renewable Portfolio Standard

| New RPS Capacity Additions (Cumulative MW)<br>Baseline Scenario 2004 - 2013 | | | | |
|---|---|---|---|---|
| **Year** | **Biofuels** | **Geothermal** | **Wind** | **Total** |
| 2004 | 36 | 0 | 342 | 378 |
| 2005 | 65 | 0 | 549 | 615 |
| 2006 | 129 | 115 | 761 | 1,005 |
| 2007 | 180 | 252 | 973 | 1,406 |
| 2008 | 266 | 366 | 1,184 | 1,816 |
| 2009 | 334 | 503 | 1,394 | 2,231 |
| 2010 | 419 | 616 | 1,615 | 2,651 |
| 2011 | 504 | 707 | 1,825 | 3,036 |
| 2012 | 572 | 775 | 2,047 | 3,394 |
| 2013 | 645 | 843 | 2,262 | 3,750 |
| | | | | |
| Geographic Composition | NP15 - 312 MW SP15 - 294 MW SD - 40 MW | IID - 743 MW NP15 - 100 MW | SP15 - 1,454 MW NP15 - 808 MW | |

# Appendix H
# Natural Gas Prices

### Monthly Factors to Convert Annual Prices to Monthly Prices

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PG&E | 1.06 | 1.06 | 0.99 | 0.97 | 0.99 | 0.96 | 0.96 | 0.96 | 0.96 | 0.96 | 1.05 | 1.09 |
| SoCal Gas | 1.10 | 1.07 | 1.03 | 0.97 | 0.95 | 0.94 | 0.92 | 0.94 | 0.98 | 1.00 | 1.08 | 1.17 |
| SDG&E | 1.09 | 1.04 | 0.96 | 0.94 | 1.00 | 0.97 | 0.92 | 0.97 | 0.98 | 0.98 | 1.09 | 1.22 |
| So. Calif Prod. | 1.10 | 1.07 | 1.03 | 0.97 | 0.95 | 0.94 | 0.92 | 0.94 | 0.98 | 1.00 | 1.08 | 1.17 |
| TEOR | 1.10 | 1.07 | 1.03 | 0.97 | 0.95 | 0.94 | 0.92 | 0.94 | 0.98 | 1.00 | 1.08 | 1.17 |
| Coolwater | 1.08 | 1.05 | 1.02 | 0.97 | 0.96 | 0.94 | 0.93 | 0.94 | 0.97 | 0.99 | 1.08 | 1.19 |
| Alberta | 1.08 | 1.04 | 1.00 | 1.00 | 0.99 | 0.93 | 0.94 | 0.87 | 0.91 | 1.00 | 1.04 | 1.08 |
| British Columbia | 1.23 | 1.06 | 0.88 | 0.93 | 0.87 | 0.83 | 0.82 | 0.83 | 0.87 | 1.00 | 1.21 | 1.22 |
| Colorado | 1.08 | 0.90 | 0.84 | 0.86 | 0.94 | 1.03 | 1.02 | 0.99 | 0.93 | 1.04 | 1.08 | 1.13 |
| El Paso North-Az | 0.98 | 0.98 | 0.90 | 1.02 | 1.02 | 1.02 | 0.92 | 0.94 | 1.06 | 1.00 | 1.13 | 1.03 |
| El Paso North-NM | 1.12 | 0.98 | 0.93 | 0.94 | 0.96 | 0.94 | 0.97 | 1.00 | 0.99 | 1.03 | 1.09 | 1.12 |
| El Paso South-Az | 0.98 | 0.98 | 0.90 | 1.02 | 1.02 | 1.02 | 0.92 | 0.94 | 1.06 | 1.00 | 1.13 | 1.03 |
| El Paso South-NM | 1.12 | 0.98 | 0.93 | 0.94 | 0.96 | 0.94 | 0.97 | 1.00 | 0.99 | 1.03 | 1.09 | 1.12 |
| Kern River | 1.10 | 1.07 | 1.03 | 0.97 | 0.95 | 0.94 | 0.92 | 0.94 | 0.98 | 1.00 | 1.08 | 1.17 |
| Mojave | 1.10 | 1.07 | 1.03 | 0.97 | 0.95 | 0.94 | 0.92 | 0.94 | 0.98 | 1.00 | 1.08 | 1.17 |
| Montana | 1.08 | 0.90 | 0.84 | 0.86 | 0.94 | 1.03 | 1.02 | 0.99 | 0.93 | 1.04 | 1.08 | 1.13 |
| Nevada-North | 0.99 | 1.00 | 0.92 | 1.02 | 0.97 | 1.01 | 0.93 | 0.97 | 1.02 | 1.08 | 1.13 | 1.03 |
| Nevada-South | 0.99 | 1.00 | 0.92 | 1.02 | 0.97 | 1.01 | 0.93 | 0.97 | 1.02 | 1.08 | 1.13 | 1.03 |
| PGT-Kingsgate | 0.98 | 0.95 | 0.99 | 0.92 | 0.99 | 1.06 | 0.97 | 0.94 | 0.92 | 0.99 | 1.09 | 1.16 |
| PGT-Malin | 0.98 | 0.95 | 0.99 | 0.92 | 0.99 | 1.06 | 0.97 | 0.94 | 0.92 | 0.99 | 1.09 | 1.16 |
| PGT-Stansfield | 0.98 | 0.95 | 0.99 | 0.92 | 0.99 | 1.06 | 0.97 | 0.94 | 0.92 | 0.99 | 1.09 | 1.16 |
| PNW | 0.68 | 0.83 | 1.00 | 1.27 | 1.35 | 0.76 | 1.01 | 1.00 | 1.11 | 0.90 | 0.96 | 1.09 |
| PNW-Coastal | 0.68 | 0.83 | 1.00 | 1.27 | 1.35 | 0.76 | 1.01 | 1.00 | 1.11 | 0.90 | 0.96 | 1.09 |
| Utah | 1.08 | 1.09 | 1.08 | 1.05 | 1.00 | 0.98 | 0.95 | 0.82 | 0.88 | 0.98 | 1.08 | 1.25 |
| Rosarito | 1.09 | 1.04 | 0.96 | 0.94 | 1.00 | 0.97 | 0.92 | 0.97 | 0.98 | 0.98 | 1.09 | 1.22 |
| Otay Mesa | 1.09 | 1.04 | 0.96 | 0.94 | 1.00 | 0.97 | 0.92 | 0.97 | 0.98 | 0.98 | 1.09 | 1.22 |

## Natural Gas Prices for Electricity Generation
## Nominal $/mmBtu

| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|
| PG&E | 4.55 | 4.18 | 4.29 | 4.52 | 4.65 | 4.83 | 5.00 | 5.20 | 5.41 | 5.62 |
| SoCal Gas | 4.68 | 4.19 | 4.25 | 4.52 | 4.71 | 4.94 | 5.14 | 5.35 | 5.54 | 5.76 |
| SDG&E | 4.68 | 4.19 | 4.25 | 4.52 | 4.71 | 4.94 | 5.14 | 5.35 | 5.54 | 5.76 |
| So. Calif Prod. | 4.46 | 4.12 | 4.20 | 4.43 | 4.62 | 4.81 | 5.01 | 5.22 | 5.44 | 5.69 |
| TEOR | 4.65 | 4.12 | 4.12 | 4.29 | 4.48 | 4.67 | 4.87 | 5.08 | 5.30 | 5.52 |
| Coolwater | 4.65 | 4.11 | 4.12 | 4.29 | 4.48 | 4.67 | 4.87 | 5.08 | 5.30 | 5.51 |
| Alberta | 3.93 | 3.50 | 3.59 | 3.74 | 3.88 | 4.03 | 4.18 | 4.34 | 4.51 | 4.70 |
| British Columbia | 4.17 | 3.78 | 3.94 | 4.12 | 4.29 | 4.46 | 4.64 | 4.82 | 5.02 | 5.22 |
| Colorado | 4.48 | 3.93 | 4.02 | 4.17 | 4.31 | 4.46 | 4.61 | 4.76 | 4.93 | 5.11 |
| El Paso North-Az | 4.41 | 3.91 | 4.00 | 4.21 | 4.39 | 4.56 | 4.75 | 4.93 | 5.14 | 5.42 |
| El Paso North-NM | 4.43 | 3.94 | 4.00 | 4.21 | 4.39 | 4.56 | 4.75 | 4.93 | 5.14 | 5.42 |
| El Paso South-Az | 4.53 | 4.06 | 4.20 | 4.44 | 4.62 | 4.81 | 5.00 | 5.20 | 5.41 | 5.65 |
| El Paso South-NM | 4.55 | 4.10 | 4.20 | 4.44 | 4.62 | 4.81 | 5.00 | 5.20 | 5.41 | 5.65 |
| Kern River | 4.63 | 4.09 | 4.09 | 4.25 | 4.44 | 4.63 | 4.82 | 5.03 | 5.24 | 5.46 |
| Mojave | 4.85 | 4.36 | 4.41 | 4.62 | 4.81 | 5.00 | 5.20 | 5.41 | 5.62 | 5.87 |
| Montana | N/A | N/A | N/A | 4.20 | 4.36 | 4.51 | 4.67 | 4.83 | 5.01 | 5.20 |
| Nevada North | 4.96 | 4.58 | 4.66 | 4.85 | 5.04 | 5.22 | 5.42 | 5.62 | 5.83 | 6.07 |
| Nevada South | 4.93 | 4.41 | 4.45 | 4.63 | 4.83 | 5.02 | 5.22 | 5.43 | 5.65 | 5.88 |
| PGT-Kingsgate | 3.73 | 3.29 | 3.35 | 3.50 | 3.64 | 3.79 | 3.94 | 4.09 | 4.26 | 4.45 |
| PGT-Malin | 4.13 | 3.72 | 3.80 | 3.96 | 4.13 | 4.29 | 4.46 | 4.64 | 4.82 | 5.03 |
| PGT-Stansfield | 3.90 | 3.48 | 3.54 | 3.70 | 3.86 | 4.01 | 4.17 | 4.34 | 4.52 | 4.72 |
| PNW | 4.87 | 4.49 | 4.62 | 4.81 | 5.00 | 5.19 | 5.38 | 5.58 | 5.80 | 6.02 |
| PNW-Coastal | 4.28 | 3.89 | 3.99 | 4.18 | 4.36 | 4.53 | 4.72 | 4.91 | 5.11 | 5.33 |
| Utah | 4.43 | 4.01 | 3.99 | 4.14 | 4.29 | 4.43 | 4.58 | 4.74 | 4.90 | 5.09 |
| Rosarito | 4.82 | 4.32 | 4.36 | 4.56 | 4.75 | 4.95 | 5.14 | 5.35 | 5.57 | 5.82 |
| Otay Mesa | 4.76 | 4.28 | 4.32 | 4.54 | 4.73 | 4.93 | 5.13 | 5.33 | 5.56 | 5.78 |