

# Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply

1. [Summary](#)
2. [Electricity Reliability Issues in California](#)
3. [Petroleum Refineries](#)
4. [Constraints Outside the Refinery Gate](#)
5. [Petroleum Product Prices and Supply Disruptions](#)
6. [Natural Gas](#)
7. [End Notes](#)
8. [Contacts](#)

## 1. Summary

Industry electric reliability organizations, the California Energy Commission, and the California Independent System Operator, expect California to be subject to rotating electricity outages in the summer of 2001 during the peak afternoon demand hours. These outages are expected to affect almost all sectors of the State's economy, including crude oil and natural gas producers, petroleum refineries, and pipelines.

This report addresses the potential impact of rotating electrical outages on petroleum product and natural gas supply in California. Because the regulatory environment is still constantly changing, the impacts on supply will change as well. However, we try to convey the potential severity of the problem and identify those areas of greatest concern. This analysis is presented in five parts, covering electricity, petroleum refineries, refinery outside services, the historical response of market prices to refinery disruptions, and natural gas.

## Electricity

For the summer of 2001 in California, reliability assessments of the electricity supply and demand conditions likely to prevail have been made by industry reliability organizations, the California Energy Commission, and the California Independent System Operator. These sources agree that electricity demand will exceed supply capability within California this summer and rotating electrical outages will be required. The estimates of electricity outages in California during the summer of 2001 (June 1 through September 30) range from a low of 55 hours to a high of 700 hours. The estimates of involuntary peak demand reduction during electrical outages range from 1,825 megawatts (MW) to as high as 5,500 MW. One of the significant uncertainties in these projections of electricity outages is the amount of electricity demand reduction that is either voluntary or motivated by high electricity prices.

## Petroleum Refineries

Until early this year California refineries were considered exempt from rotating outages because they are connected to the electricity grid at the transmission voltage level rather than the lower distribution voltage level and were not included in rotating outage procedures by the California Public Utilities Commission (CPUC). In April 2001, the CPUC ruled that utilities must include transmission level customers in rotating outages.

The potential impact of rotating electrical outages on individual California refineries ranges from minimal to severe. About one-fourth of the refining capacity in California is protected from electrical outages either because of sufficient cogeneration capacity within the refinery or because it is in an electric utility service area that is not expected to be subject to rotating electrical outages (e.g., Los Angeles Department of Water and Power). The rest of the refineries could be forced to either reduce operating rates or shut down completely during an electricity outage if it should affect their supply of electricity.

About 40 percent of the California refining capacity has some cogeneration capabilities, but not enough to keep operating at full rates. Processing rates at these refineries would need to be reduced by up to 30 percent or selected units shut down in order to continue operating during an electrical outage. Returning to full production can take up to several days. Consequently, the period of reduced production will be longer than the period of the electrical outage.

Finally, up to 27 percent of the California refining capacity is expected to be forced to shut down completely during a rotating electrical outage should it occur in their block. It takes a refinery 1 to 2 weeks to return to full operating rates following a forced emergency shutdown. If electricity outages were to hit one of these refineries frequently, the refinery might choose to remain down for extended periods of time rather than undergo the high costs of repeated emergency shutdowns and restarts.

The refinery and petroleum product supply analysis in this report is based on a mail survey conducted by the California Energy Commission in early May 2001, with a follow-up telephone survey by the Energy Information Administration. The survey covered 13 of the 24 operating California refineries, which represent about 92 percent of the crude oil distillation capacity and over 97 percent of the gasoline and diesel fuel production capacity in the State.

## Outside the Refinery Gate

Refineries are also indirectly exposed to forced processing rate reductions and even complete shutdowns from disruption of services outside the refinery. Services that could require a refinery to reduce operating rates if disrupted include crude oil supply, product pipelines, railroad tank car movements, cooling water supply, waste water treatment, alkylation acid supply and disposal, and hydrogen supply. If disruptions to these services are frequent or prolonged, a refinery could be forced to shut down.

## Petroleum Product Prices

Although we cannot predict the petroleum product price impacts of rotating electricity outages in California this summer, possible loss of production from California refineries could increase petroleum product prices. The size of the price increase is dependent on numerous factors that include the severity and length of the electricity outage.

Past disruptions to California's refinery operations resulted in price spikes ranging from 7 to 52 cents per gallon. The price spikes have varied considerably because of differences in the number, magnitude, and expected duration of the refinery disruptions and the condition of the market at that time. Three important factors that have historically affected the size and duration of price spikes are:

- *Inventory levels.* Product inventories provide a buffer for unexpected supply disruptions. High inventory levels provide a cushion and tend to dampen price spikes. As of June 1, West coast (PADD 5) reformulated gasoline stocks stood at 12.2 million barrels, which compares with 11.4 and 13.2 million barrels in 2000 and 1999, respectively. West coast distillate fuel stocks on June 1 were 12.2 million barrels, compared with 12.8 and 11.6 million barrels at the end of May in 2000 and 1999, respectively.
- *Ability of the refining industry to respond.* The magnitude and duration of price spikes within California are constrained by the capacity of other unaffected California refineries to make up lost production volume and the capacity of refineries outside the region to produce and deliver products that meet California Air Resources Board (CARB) product quality specifications. However, refineries in California are expected to be limited in their capability to make up for lost volumes because they are already operating at or near capacity. Tight gasoline markets in the rest of the United States may restrain the responsiveness of other domestic refineries.
- *The frequency of events and the cumulative loss of volume.* Several refinery disruptions occurring at the same time and/or over long periods of production outages tend to result in bigger price spikes. If electrical outages this summer are frequent and extensive then the loss of production volume could be unprecedented. Five California refineries are vulnerable to complete shutdown and four others are at risk of significant operating rate reductions during rotating electrical outages. Moreover, all California refineries are susceptible to production disruption, and possible shutdown, if outside services such as water supply, waste water treatment, crude oil supply, and product pipelines are unavailable.

## Natural Gas

The outlook for natural gas in California this summer is for continued strong demand and high gas acquisition costs due to existing constraints on the capacity to receive natural gas shipments from outside the State. Electricity outages should not significantly affect the gas supply system within California. Only one compressor station in the intrastate pipeline system operates with electricity and electricity is not typically needed for withdrawals of gas from storage. Electrical outages will result in additional costs to natural gas producers, processors, pipelines and storage operators. There may also be some loss of California gas

production, particularly gas recovered from enhanced oil recovery projects in southern California.

## 2. Electricity Reliability Issues in California

- A. [Summary](#)
- B. [Western Power Grid and California](#)
- C. [Reliability Assessment](#)
- D. [How Electrical System Operators Will Initiate Outages](#)
- E. [Why Operator-Initiated Outages Are Needed](#)
- F. [Outage Rotations and Exemptions](#)
- G. [Outages - Their Timing and Impacts](#)
- H. [End Notes](#)

### A. Summary

For the summer of 2001 in California, reliability assessments of the electricity supply and demand conditions likely to prevail have been made by industry reliability organizations, the California Energy Commission, and the California Independent System Operator. These sources agree that electricity demand will exceed supply capability within California this summer and rotating electrical outages will be required. The estimates of electricity outages in California during the summer 2001 (June 1 through September 30) range from a low of 55 hours to a high of 700 hours. The estimates of involuntary peak demand reduction during electrical outages range from 1,825 megawatts (MW) to as high as 5,500 MW. One of the significant uncertainties in these projections of electricity outages is the amount of electricity demand reduction that is either voluntary or motivated by high electricity prices.

### B. Western Power Grid and California

The State of California and 10 other Western States make up the United States portion of the *Western Power Grid* ([Figure 2-1](#)).<sup>[1]</sup> The electric power industry's [Western System Coordinating Council](#) (WSCC) oversees its operations and planning and it is a member of the [North American Electric Reliability Council](#) (NERC) ([Figure 2-2](#)). These industry organizations are responsible for reliability standards (adequacy of supply, security and system operational practices). The electric utilities (investor-owned, municipal, cooperative, and Federal) all adhere to the operational and planning standards established by WSCC and NERC. Oversight and review of planning done by the electric utilities operating in California are handled by the [California Public Utilities Commission](#) (CPUC), the [California Energy Commission](#) (CEC), and by various municipal governments.<sup>[2]</sup>




[Figure 2-1. Map of the Western Power Grid](#)  
([http://www.wsc.com/files/WSCC Transmission System Map.pdf](http://www.wsc.com/files/WSCC%20Transmission%20System%20Map.pdf))

 [Figure 2-2. NERC Regional Council Map](http://www.nerc.com/regional/)  
(<http://www.nerc.com/regional/>)

As a result of restructuring in California, operational authority for most of the state's transmission system was given over to the [California Independent System Operator \(CAISO\)](#), which also adheres to the WSCC and NERC reliability standards ([Figure 2-3](#)).<sup>[3]</sup> Some electric utilities, like the Los Angeles Department of Water and Power (LADWP), were exempted from joining the CAISO ([Figure 2-4](#)).<sup>[4]</sup> They are responsible for meeting their own supply obligations, but they do coordinate purchases, sales, and other operational actions with the CAISO. They are, however, not currently subject to CAISO's curtailment criteria.

 [Figure 2-3. Map of the CAISO Operating Area](http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/The-ISO-grid.aspx)  
(<http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/The-ISO-grid.aspx>)

 [Figure 2-4. California's Electric Utility Service Areas.](http://www.energy.ca.gov/2007_energy policy/documents/2007-05-15_workshop/presentations/Electric%20Utility%20Service%20Areas%205-10-07.pdf)  
([http://www.energy.ca.gov/2007\\_energy policy/documents/2007-05-15\\_workshop/presentations/Electric%20Utility%20Service%20Areas%205-10-07.pdf](http://www.energy.ca.gov/2007_energy policy/documents/2007-05-15_workshop/presentations/Electric%20Utility%20Service%20Areas%205-10-07.pdf))

Restructuring also impacted the ownership of generating powerplants by investor-owned electric utilities.<sup>[5]</sup> They were required to divest their fossil-fueled powerplants as part of the stranded cost recovery process. As a result, the percentage of investor-owned utility ownership in the State of California dropped from 55 percent to 15 percent.<sup>[6]</sup> These assets were acquired by nonutilities and their share of generating assets has increased from 19 percent to 54 percent in California.<sup>[7]</sup>

## C. Reliability Assessment

Reliability is defined as the adequacy of supply and security of operations. For this summer in California, reliability assessments have been made by industry reliability organizations, the California Energy Commission, and the California Independent System Operator.<sup>[8]</sup> All reports agree that electricity demand will exceed supply capability within California this summer and that rotating electrical outages will be required. However, the reports differ in their estimates of the magnitude of the problem.

### National Reliability Assessment Identifies the West as an Area of Concern

In the *2001 Summer Assessment* released on May 15, 2001, NERC made an assessment of the operational conditions and sources of expected problems that could affect the interconnected power grids covering all of Canada and the contiguous United States.<sup>[9]</sup> This reliability assessment indicated that there would be higher customer demand and constrained electrical supply in the Western Power Grid, with rotating electricity blackouts likely to occur in California.

NERC identifies several potential sources for these problems. [\[10\]](#) They include:

- Higher summer temperatures will increase customer electrical demand.
- Hydroelectric generation will be limited by low water levels and reduced snowpack.
- Planned new generating powerplants may not come online when expected.
- Forced outages of generating capacity may be more than expected.
- Existing powerplant availability may be reduced because of air quality restrictions, especially for those generating facilities that are operated outside the State of California. [\[11\]](#)
- Financial problems (like non-payment to generators) may lower output.

With the exception of California, generating resource availability in the Western Power Grid is expected to be tight, but adequate to meet electrical usage and required operating reserve capacity. However, NERC believes that the ability of other utilities to provide power supplies to California is limited this summer.

Utilities in the Pacific Northwest will not be able to make sustained export sales to anyone outside their region. However, they may be able to offer some electricity for sale during the peak demand hours in California. Power suppliers in Arizona, New Mexico, and Nevada (the Southwest area of WSCC) will have limited ability to export electricity under normal summer temperature conditions. When temperatures are much warmer than normal these power supplies are not expected to be able to export electricity.

For California, NERC believes "that resource deficiencies and transmission constraints are likely to result in the curtailment of interruptible and firm customer demand both during peak periods and at other times due to energy limitations during the 2001 summer within the CAISO operating area unless conservation or assistance from other areas is greater than projected." [\[12\]](#) Conservation is expected to shave peak demand in California and the Western Power Grid. However, the magnitude of the potential savings from conservation is difficult to measure and is not expected to eliminate the need for rotating electricity outages. The municipal and cooperative utilities within California that are not part of the CAISO are projected to have sufficient electricity supply to meet their own demand.

## Reliability Estimates for California - Summer 2001

Assessments of California electricity demand and generating capacity available this summer (June through September) have been published by WSCC [\[13\]](#), CEC [\[14\]](#), CAISO [\[15\]](#), and NERC [\[16\]](#). All sources reached the same conclusion that there is inadequate supply available to meet expected demand in California this summer.

The California Energy Commission (CEC) projected a peak demand for California during the summer of 2001 of 47,703 MW. With a desired 7 percent operating reserve, a total generating capacity of 50,303 MW would be required. The CEC also developed forecasts that examined temperature sensitivity. They found that a warmer summer would raise the



7b	outages Unavailability due to financial concerns	0	0	0	0	0	0	0	0
8	Estimated forced outages/capacity limitations	(2,500)	(2,500)	(2,500)	(2,500)	(4,525)	(4,525)	(4,525)	(4,525)
9	Estimated hydro capacity limitations	<u>(1,000)</u>	<u>(1,000)</u>	<u>(1,000)</u>	<u>(1,000)</u>	<u>(1,200)</u>	<u>(1,800)</u>	<u>(2,400)</u>	<u>(2,800)</u>
10	Total resource capacity (at peak)	40,860	43,063	43,259	43,841	37,165	37,065	38,045	38,145
<b>Generation Imports</b>									
11	Required net imports (line 3 - line 10)	9,443	7,240	7,044	6,462	13,138	13,238	12,258	12,158
12	Forecast net imports at peak	<u>3,500</u>	<u>3,500</u>	<u>3,500</u>	<u>3,500</u>	<u>2,500</u>	<u>2,500</u>	<u>2,500</u>	<u>2,500</u>
13	Estimated resource deficiency before mitigation measures (line 11 - line 12)	5,943	3,740	3,544	2,962	10,638	10,738	9,758	9,658
<b>Definitive Mitigation Measures</b>									
14	UDC interruptible load curtailments	400	400	400	400	700	700	700	700
15	Demand relief programs and conservation	596	596	596	596	1,250	1,250	1,250	1,250
15a	Response to rate increase	0	0	0	0	1,950	1,950	1,950	1,950
16	Conversion of non-spinning reserve to energy	<u>1,300</u>	<u>1,300</u>	<u>1,300</u>	<u>1,300</u>	<u>1,300</u>	<u>1,300</u>	<u>1,300</u>	<u>1,300</u>
17	Estimated resource deficiency after mitigation measures	3,647	1,444	1,248	666	5,438	5,535	4,558	4,458

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Source: North American Electric Reliability Council, *2001 Summer Special Assessment*, (Princeton, NJ, May 2001), pg. 12

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The summer 2001 monthly estimates for generating capacity available to meet peak demand in the CAISO operating area (line 10 in [Table 2-1](#)) range from 41,000 to 44,000 MW in the CAISO study, but are lower in the NERC study (from 37,000 MW in June to 38,000 MW in September). The resulting estimated resource deficiency [\[18\]](#) highlights the difference in the interpretation of the magnitude of impact. The CAISO analysis shows the deficiency in generating capacity before definitive mitigation measures (line 13 in [Table 2-1](#))



dropping from 6,000 MW in June to 3,000 MW in September. NERC projects a deficiency range starting at 10,600 MW in June, rising slightly to 10,700 MW in July, then declining to 9,700 MW in September. When the uncertain conservation and demand mitigation measures are included, the estimated generating capacity deficiencies reported by the two organizations decline but still remain significantly different (line 17 in [Table 2-1](#)). The deficiency margin at peak declines from 3,600 MW in June to 700 MW in September for CAISO, but NERC sees it starting at 5,400 MW and shifts downward by about 1,000 MW to 4,500 MW over the same period.[\[19\]](#)

For NERC, the projected outages or expected hours of unserved energy requirements for California range from a low of 9 percent to 24 percent of the total hours (that is, from 260 to 700 hours out of 2,928 total hours covering the period June 1 through September 30).[\[20\]](#) The average high outage is expected to reach 3,150 MW (with no demand mitigation measures being taken). The low is projected to be an average outage of 2,160 MW, which includes customers responding to tariff rate increases and other demand mitigation measures.[\[21\]](#) CAISO estimates a lower level of 55 outage hours with an average outage of 1,825 MW.[\[22\]](#) NERC also expects that "CAISO may be short as much as 5,500 MW during peak periods."[\[23\]](#)

## D. How Electrical System Operators Will Initiate Outages

CAISO will provide notice about unusual system conditions or emergencies to the electric utility distribution companies it oversees, market participants, and reliability and regulatory agencies. These include alerts (covering day ahead markets), then warnings (usually for one hour ahead markets), and finally 3 stages of emergency status notices describing worsening minimum operating reliability reserve support.[\[24\]](#) For the emergency status, when operating reserves fall to the 7 percent reserves mark, all available power is purchased. When operating reserves go below 5 percent, conservation measures are implemented, interruptible customers are curtailed and emergency assistance requests are made. When operating reserves drop below 1.5 percent or there is a significant emergency event, involuntary load curtailments are initiated.

The geographical location or type of electrical event affecting CAISO operations and causing issuances of emergency notice will initiate different types of actions to address it. The source can be external (e.g., transmission line outages coming from other parts of WSCC or loss of committed generation supply), from a single event (e.g., individual distribution system, loss of a high voltage transmission line or large generating powerplant), and/or a system wide event (e.g., time of day transfer constraints for peak or off-peak, high customer demand for electricity).

Upon identifying the part of California being affected, the electrical distribution systems under oversight of CAISO will be directed to shed a pro-rated share of firm customer load.[\[25\]](#) For 2001, the statewide ratios are: Pacific Gas and Electric (PG&E) at 49.6 percent, Southern California Edison (SCE) at 42 percent, San Diego Gas and Electric (SDG&E) at 7.4 percent, and the Cities of Pasadena and Vernon at 0.6 and 0.4 percent, respectively. In addition, both PG&E and SCE further allocate their share to cover special municipal allocations within their operational area.[\[26\]](#)

## E. Why Operator-Initiated Outages Are Needed

Unlike other commodities, electricity, at the levels used by customers, cannot be stored. Operators of the electrical system must rely on real-time generation matched to their customers' electricity demand. Operators need to keep the whole electrical system operationally viable and under constant control.<sup>[27]</sup> In order to do this, firm customer load has to be dropped on occasions. This particular event is considered to be a 1-day in a 10-year situation by the electric power industry.<sup>[28]</sup>

Specific substation and high voltage transmission line problems affect defined customer groups and are addressed by repair crews once the source of the problem is identified. However, customers that are not under interruptible rate tariffs, that suffer usage interruptions initiated by their electrical system operators, are in this blackout condition because it is a last resort action taken by their electric utility. Besides these sources of concern, extreme weather conditions are often the lead or major cause of distribution system disruptions of service. They usually have local area impacts.

Keeping the electrical system protected is a key operational concern because losing control and suffering a blackout results in a much longer period of outage that affects everyone. When an electrical system operates with these problems as on-going concerns, it affects contingency planning and operational practices of all other interconnected electrical systems.

The normal oversight of the electrical system operators includes:

- Guaranteeing coverage of the load obligations with energy receipts from different generation sources and from loss of transfer or transmission congestion (preventing more delivery of power) and generation powerplant outages.
- Addressing the contingency concerns by having generation immediately available in stand-by operational status that will provide electrical energy until longer-term replacement sources start providing replacement energy for the lost sources.
- Examining alternate routes of transfers constantly to protect against the impact from outages of transmission lines and powerplants.

These operational actions done by the electrical system operators are usually in the background and almost never noticed by the customer. In California this summer, the problems will be evident, but acknowledging calls for conservation will have a beneficial impact on mitigating the disruptions.

## F. Outage Rotations and Exemptions

The California Public Utility Commission (CPUC) describes rotating outages as planned load reductions in which customer power is shut off following predetermined plans. Various customers on distribution feeder lines are grouped together and each takes their turn in

being shut off; which provides the "rotating outages" terminology.[\[29\]](#) Each distribution utility system does this in a different way. For example, PG&E uses 750 MW blocks of customers that cover their whole distribution system. SCE uses different terminology and subdivides its service territory into 100 MW groupings of customers. In all cases, the customers impacted (for each of the individual group or block classifications) are spread throughout the individual electrical systems.

To provide assistance to their customers in coping with the abrupt loss of electrical supply resulting from a blackout, the electric distribution companies are placing the rotational code on the customer's billing documents. This tells each customer that they must pay attention to anticipated emergency problems when announcements are made by CAISO or the State of California 48 hours in advance of expected blackouts. These customer codes are also important because those codes that are prescheduled to be affected by an anticipated blackout will be announced 24 hours in advance. Later, another announcement will be made, 1 hour before the actual start of a blackout.[\[30\]](#)

Exemptions from rotating outages are granted by the CPUC. The CPUC defines essential use customers as those generally providing public health, safety, and security services. They include: hospitals, fire and police stations, prisons, national defense facilities, communication utilities, and air traffic control and sea traffic control, but not water utilities. Other customers will indirectly gain the benefits of avoiding rotating outages if they are served on a common distribution feeder that also covers one or more essential use customers.

The CPUC is concerned that the determination to designate a customer as an essential customer can significantly affect the amount of load available to be shut off and the frequency of outages other customers must face.[\[31\]](#) The CPUC is also concerned about equity issues and the impact on demand-side reduction programs because of reduced incentives to voluntarily participate.[\[32\]](#) [\[33\]](#)

If the CAISO or utility has to take quick action by isolating a transmission line or removing a major substation terminal from service to remove load, all customers will be dropped whether they are in an exempted category or not.

## **G. Outages - Their Timing and Impacts**

Electrical system peak demand normally occurs in the late afternoon to early evening hours of business weekdays. Monthly, yearly, or all-time record usage comes during periods when extreme temperatures affect customers during a prolonged cold spell or when high temperatures and humidity encompass a large geographical area for several continuous days.[\[34\]](#) The response to these types of temperature extremes is a high customer usage of electricity.

For California, the temperature pattern across the State usually breaks into two parts (northern and southern) and this diversity does assist CAISO in its operations.[\[35\]](#) However, when the two parts of the State have a joint coincident peak, that is, the highest usage comes at the same time for all major utilities in the State, then the operation of the overall electrical system is impacted in the strongest manner.[\[36\]](#) During these same periods, the California Energy Commission (CEC) has found that the "climatic conditions that

cause high temperatures across California are also likely to have a similar effect on temperatures in the Pacific Northwest and Desert Southwest." [37] This concurrent impact of high temperatures raises the demand for electricity in the West and reduces the availability of power for export at the same time.

The expectations for the timing of the rolling blackouts in California are for these same extreme temperature-induced usage periods. Other outages will come from sudden losses of powerplants or transmission lines that happen when generating reserves are near the system operational constraint limitations.

CEC staff also noted in their report that in California, the statewide peak demand is very sensitive to small changes in average high temperatures. The average high temperature in a 1-in-40 year scenario (i.e., similar to temperature conditions that occurred in the summer of 1998) was only 5-degrees hotter than the average high temperature under expected "normal" weather conditions. [38] Weather will be one of the key factors that will influence the level of customer load that will have to be matched to available power supplies.

## 3. Petroleum Refineries

- A. [Summary](#)
- B. [Exposure of California Refineries to Rotating Electricity Outages](#)
- C. [High Exposure Refineries](#)
- D. [Moderate Exposure Refineries](#)
- E. [End Notes](#)

### A. Summary

California refineries are concentrated in three areas ([Figure 3-1](#)): the San Francisco Bay Area, Los Angeles, and north of Los Angeles (Santa Maria/Bakersfield). Each of these refineries is served by one of three electric utilities: [Pacific Gas and Electric](#) (PGE), [Southern California Edison](#) (SCE), and the [Los Angeles Department of Water and Power](#) (LADWP) ([Figure 3-2](#)).



[Figure 3-1. Locations of California Refineries](#)

([http://www.energy.ca.gov/maps/powerplants/refinery\\_locations.html](http://www.energy.ca.gov/maps/powerplants/refinery_locations.html))



[Figure 3-2. California's Electric Utility Service Areas](#)

([http://www.energy.ca.gov/2007\\_energypolicy/documents/2007-05-15\\_workshop/presentations/Electric%20Utility%20Service%20Areas%205-10-07.pdf](http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-15_workshop/presentations/Electric%20Utility%20Service%20Areas%205-10-07.pdf))

Until early this year California refineries were considered exempt from rotating outages because they are connected to the electricity grid at the transmission voltage level rather than the lower distribution voltage level and were not included in rotating outage

procedures by the California Public Utilities Commission (CPUC). In April 2001, the CPUC ruled that utilities must include transmission level customers in rotating outages.<sup>[39]</sup> Excluded from this rule are essential use customers and customers who supply power to the grid in excess of their load at the time of an electrical outage. Refineries in the SCE and PGE service areas have been assigned blocks for rotating electricity outages. These refineries are currently exposed to complete shutoff from the electricity transmission grid on very short notice. The direct exposure of these refineries to rotating outages ranges from minimal to severe.

Refineries may petition the CPUC for exempt status if they can demonstrate that being subject to rotating outages presents a significant danger to public health and safety.<sup>[40]</sup> Decisions on exemption applications are expected to be ruled on by the CPUC by August 2, 2001. Four California refiners (Equilon Enterprises LLC, ExxonMobil Corp., Tosco Corp., and Valero Energy Corp.) have been reported to have filed petitions with the CPUC seeking exemption from rotating outages.<sup>[41]</sup> Chevron Corp., however, in a letter to California Governor Gray Davis, said it would not apply for exempt status because it "will never operate its facilities in a manner that jeopardizes the health or safety of its employees or neighbors," but would be "forced to operate our refineries at less than full capacity."<sup>[42]</sup> On June 8, 2001, Governor Davis urged the CPUC to treat refineries and ancillary facilities as essential-use customers, exempt from rotating outages, because the fuels they provide are critical to the public health and safety.<sup>[43]</sup>

About one-fourth of the refining capacity in California is protected from electrical outages, either because of sufficient cogeneration capacity within the refinery or because it is in an electric utility service area that is not expected to be subject to rotating electrical outages (i.e., LADWP). The rest of the refineries could be forced to either reduce operating rates or shut down completely during an electricity outage if it should affect their supply of electricity.

About 40 percent of the refining capacity has some cogeneration capabilities but not enough to keep the refinery operating at full rates. Operating rates at these refineries would need to be reduced by up to 30 percent or selected units shut down in order to continue operating during an electrical outage. Returning to full production rates can take up to several days (and possibly longer if there is equipment damage). Consequently the extent of loss of production volume will be greater than the period of the electrical outage.

Finally, up to 27 percent of the refining capacity is expected to be forced to shut down completely during a rotating electrical outage should it occur in their block. It takes a refinery 1 to 2 weeks to return to full operating rates following a forced emergency shutdown. If electricity outages were to hit one of these refineries frequently, the refinery might choose to remain down for extended periods of time rather than undergo the high costs of repeated emergency shutdowns and restarts.

Unless alternative programs to rotating outages can be implemented, such as exemptions or the California Public Utilities Commission's proposed Optional Binding Mandatory Curtailment (OBMC) program discussed below, the potential loss of petroleum product supply in California could be unprecedented should rotating outages occur at refineries.

This refinery analysis is based on a mail survey conducted by the California Energy Commission in early May 2001, with a follow-up telephone survey by the Energy Information Administration. The survey covered 13 of the 24 operating California refineries. The 13 refineries participating in the survey represent about 92 percent of the crude oil

distillation capacity in the State and about 98 percent of the gasoline and diesel fuel production capacity.

## B. Exposure of California Refineries to Rotating Electricity Outages

California refineries are classified in [Table 3-1](#) below in 1 of 3 categories of exposure to rotating electrical outages based on the refiners' responses to the survey:

1. **High Exposure** - the refinery has been assigned to a rotating electricity outage block and is served by a utility that may require rotating outages (e.g., the PGE or SCE service areas), and does not have dedicated electricity cogeneration capacity necessary to satisfy minimal electricity requirements for operation. A rotating electricity outage at the refinery would require the complete emergency shutdown of the refinery. Full recovery from an emergency shutdown would take about 1 to 2 weeks.
2. **Moderate Exposure** - the refinery has been assigned to a rotating electricity outage block but has cogeneration capacity to meet most of its electricity demand. A rotating electricity outage at the refinery would require a reduction in operating rates and possibly the shutdown of selected individual process units.
3. **Low Exposure** - the refinery is not expected to be exposed to rotating electricity outages because it is in a low risk electric utility service area (i.e., LADWP) and/or has cogeneration capacity to meet all of the refinery's electricity needs.

Ten refineries are not classified in [Table 3-1](#) because they were not included in the refinery mail and telephone surveys conducted by the California Energy Commission and the Energy Information Administration. These refineries represent about 8 percent of the State's crude distillation capacity and produce only small volumes of gasoline and diesel fuel and are primarily asphalt or lubricating oil producers. However, one important product of these refineries is unfinished oils, which are processed at the larger complex refineries into gasoline and other clean fuels.

**Table 3-1. California Refineries and Exposure to Rotating Electricity Outages**

Company	Location	Operating Crude Oil Atmospheric Distillation Capacity Jan. 1, 2000 (mbpsd)	Electric Utility Service Area	Estimated Electricity Demand (1) (mw)	Cogeneration Capacity (2) (mw)
<b>High Exposure</b>					
ExxonMobil	Torrance (Los Angeles)	160	SCE	94	42
Tosco	Carson (Los Angeles) (3)	137	SCE	26	0
Valero	Benicia (San Francisco Bay)	135	PGE	50	0
Equilon	Bakersfield	67	PGE	35	0
Tosco	Santa Maria (4)	44	PGE	6	5
<b>Subtotal</b>		543	(27% of total Calif. distillation capacity)		

<b>Moderate Exposure</b>						
Chevron	El Segundo (Los Angeles)	273	SCE	108	126	(2)
Chevron	Richmond (San Francisco Bay)	240	PGE	135	120	
Equilon	Martinez (San Francisco Bay)	162	PGE	105	90	
Equilon	Wilmington (Los Angeles)	<u>100</u>	SCE	58	60	(2)
<b>Subtotal</b>		<b>775</b>				(39% of total Calif. distillation capacity)
<b>Low Exposure</b>						
BP	Carson (Los Angeles)	260	SCE	82	393	
Ultramar	Golden Eagle (San Francisco Bay)	106	PGE	90	100	
Ultramar	Wilmington (Los Angeles)	79	LADWP	37	0	
Tosco	Rodeo (San Francisco Bay) (4)	77	PGE	40	48	
Tosco	Wilmington (Los Angeles) (3)	<u>0</u>	LADWP	47	54	
<b>Subtotal</b>		<b>522</b>				(26% of total Calif. distillation capacity)
<b>Undefined</b>						
Paramount	Paramount (Los Angeles)	48				
Kern	Bakersfield	25				
Edgington Oil	Long Beach (Los Angeles)	25				
San Joaquin Refg.	Bakersfield	15				
Huntway Refining	Benicia (San Francisco Bay)	13				
Greka Energy	Santa Maria	10				
Lunday Thagard	South Gate (Los Angeles)	8				
Huntway Refining	Wilmington (Los Angeles)	6				
Tenby	Oxnard (Los Angeles)	5				
Golden Bear	Bakersfield	<u>0</u>				
<b>Subtotal</b>		<b>155</b>				(8% of total Calif. distillation capacity)

Notes:

(1) Estimated electricity demand represents average demand. Peak demand is generally not significantly different from average demand. Estimated demands were based on reported 1999 average demand (see sources below) or processing capacity installed on January 1, 2000. Current electricity demand may be different because of changes in processing rates or refinery configurations.

(2) Actual electricity available from cogeneration may be less than capacity where cogeneration operating rates are limited by refinery steam demands. For example, the Chevron El Segundo refinery purchased an average 12 percent of its total electricity requirement from SCE in 1999, and the Chevron Richmond refinery purchased an average 8 percent of its total electricity requirement from PGE in 1999. Refiners were not asked in the survey if it was possible to operate their cogeneration units in excess of refinery steam requirements (i.e., vent excess steam to the atmosphere) in order to satisfy all of their electricity needs.

(3) The Tosco Carson and Tosco Wilmington refineries are an integrated unit with crude and heavy oil processing at Carson and refined product upgrading at Wilmington. The Wilmington plant could continue operations from inventories and purchased feedstocks in the event of a Carson plant shutdown.

(4) The Tosco Santa Maria refinery produces intermediate feedstocks for further processing at the Tosco Rodeo refinery. The cogeneration capacity at this refinery is not expected to be sufficient to maintain operation during an electrical outage.

Characterization of Exposure:

High exposure - complete emergency shutdown of refinery

Moderate exposure - reduction in operating rates and/or selective shutdown of operating units

Low exposure - rotating electrical outages unlikely or uninterrupted operation if outage occurs

Units key:

mbspd - thousands of barrels per stream day

mw - megawatts

Electric utility service area:

LADWP - Los Angeles Department of Water and Power

PGE - Pacific Gas and Electric

SCE - Southern California Edison

Sources:

- Categorization: Based on responses to the question "Can the refinery keep operating if your rotating outage block is taken off-line?" on the California refinery survey, May 2001.

- Operating Crude Oil Atmospheric Distillation Capacity: Energy Information Administration, Petroleum Supply Annual 1999, Volume 1, DOE/EIA-0340(99)/1 (Washington, DC, June 2000), Table 38

([http://www.eia.gov/oil\\_gas/petroleum/data\\_publications/petroleum\\_supply\\_annual/psa\\_volume1/psa\\_volume1.html](http://www.eia.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html)).



- Cogeneration Capacity: California Energy Commission, Database of California Power Plants ([http://www.energyalmanac.ca.gov/powerplants/POWER\\_PLANTS.XLS](http://www.energyalmanac.ca.gov/powerplants/POWER_PLANTS.XLS)) and Energy Information Administration, Annual Electric Generator-Nonutility, Form EIA-860B Database, 1999 (<http://www.eia.gov/cneaf/electricity/page/eia860b.html>)
- Estimated Electricity Demand: Electricity consumption reported in Form EIA-860B referenced above or estimated from reported processing unit capacities and unit electricity consumption reported in [Table 3-2](#) below.

## C. High Exposure Refineries

Refineries in the high exposure category represent about 27 percent of the total California crude oil distillation capacity, about 24 percent of the gasoline production capacity, and about 12 percent of the distillate fuel oil production capacity.

Refineries in the high exposure category will have to perform an emergency shutdown of all of their operations in the event of a rotating electrical outage in their service block. A refinery required to undergo an emergency shutdown will take from 7 to 14 days to return most operating units to full normal operation. [44] The 7 to 14 days estimate for refineries to return to normal service assumes there was no equipment damaged during the emergency shutdown. Unfortunately, the very short notice (possibly only minutes) of a rotating electrical outage and the emergency shutdown procedure a refinery must undergo significantly increases the potential for equipment damage. Fluid coking units can require a complete turnaround following an emergency shutdown. A turnaround on a coker unit may take up to 6 weeks because of the time required to remove the solid petroleum coke from inside the equipment. Refiners indicate that a safe controlled refinery shutdown would require between 4 and 12 hours advance notice. If rotating outages are expected to be frequent then it is conceivable that these refineries would remain down for extended periods of time rather than undergo the high costs of repeated emergency shutdowns and restarts.

Electricity outages in California during the first 5 months of 2001, have occurred in either Northern California or have been statewide ([Table 3-2](#)). If rotating outages should occur only in Northern California, only 1 refinery in the high exposure category (representing about 7 percent of the total California crude distillation capacity) would be exposed to a forced shutdown. If rotating outages should occur only in Southern California, 4 refineries in the high exposure category (representing about 20 percent of the total California crude distillation capacity) would be exposed.

**Table 3-2. History of Electrical Outages in California, 2001**

Date	Start Time	Outage (MW)	Area Affected
5/8	3:12 pm	400	Statewide
5/7	4:45 pm	300	Statewide
3/20	9:20 am	500	Statewide
1/21	20 minute disruption due to transmission line failure		Northern California
1/18	9:50 am	1,000	Northern California
1/17	11:40 am	500	Northern California

Source: California Independent System Operator, Power Watch 2000, <http://www.caiso.com/newsroom/pw2000.html>

The California Public Utilities Commission has proposed an *Optional Binding Mandatory Curtailment* (OBMC) program, which allows facilities to avoid complete electricity outages in return for a firm reduction in electricity demand during every rotating outage that occurs in the utility service area. If refineries choose to participate in this program they may be



required to reduce electricity consumption by up to 15 percent below the previous 10-day average.[\[45\]](#)

To achieve the 15-percent reduction a refiner may have two options. First the refinery may install emergency electricity generators to make up the 15-percent loss during rotating outage periods. Second, without backup generating capacity a refinery must reduce operating rates by as much as 30 percent (the relationship between electricity demand and operating rates is nonlinear) and return to full operating rates immediately following the outage in order to maintain a high 10-day average on which to base their load reduction. But there would still be a significant loss of production volume where the refineries must reduce operating rates during every rotating outage that occurs anywhere in the utility service area.

One refiner in the high exposure category has already applied for participation in the OBMC program and for connection of emergency backup generators. However, neither the application for participation in the OBMC program nor the connection of the backup generators had been approved as of mid-June.

## D. Moderate Exposure Refineries

Refineries that are classified as having a moderate exposure to rotating outages in [Table 3-1](#) above have cogeneration capacity but are still net purchasers of electricity. Moderate exposure refineries are expected to closely monitor weather forecasts and reduce overall operating rates during periods of forecast high temperatures in order to avoid emergency actions associated with rotating outages. In the event of a forced emergency reduction in electrical demand during a rotating outage these refineries may be able to shut down individual processing units rather than the entire refinery.

[Table 3-3](#) below lists the electricity demands of individual units within a refinery. The three process units that consume the most electricity are:

- Catalytic hydrocracker
- Alkylation unit
- Coker

Because these units generally run at maximum capacity during the summer months, the loss of any of these units would reduce the volume of diesel fuel or motor gasoline supply. Catalytic hydrocrackers produce California Air Resources Board (CARB) reformulated gasoline and diesel fuel. Product from the alkylation unit is needed for CARB gasoline.

**Table 3-3. Electricity Demand by a Hypothetical 100,000 barrel per day California Refinery**

	Hypothetical California Refinery Unit Capacity (bpsd)	Electricity Demand (kwh per bpsd)	Total Electricity Demand (kwh per day)
Atmospheric Crude Oil Distillation	100,000	0.5	50,000

Vacuum Distillation	55,873	0.3	16,762
Delayed Coking	19,578	3.6	70,482
Fluid Coking	4,735	13	61,554
Visbreaking	240	0.5	120
Catalytic Cracking (fresh feed)	32,323	1	32,323
Catalytic Hydrocracking	23,972	10	239,723
Catalytic Reforming (low pressure)	8,961	1	8,961
Catalytic Reforming (high pressure)	11,386	1	11,386
Hydrotreater (heavy gas oil)	30,431	1.3	39,561
Hydrotreater (naphtha)	23,569	2	47,138
Hydrotreater (distillate)	20,668	1.7	35,136
Hydrotreater (other/resid)	6,536	1.4	9,150
Fuel Solvents Deasphalting	2,401	2	4,802
Alkylates (sulfuric acid)	7,847	11	86,314
Aromatics	72	0.83	60
Asphalt & Road Oil	3,577	1.5	5,365
Isomerization (isobutane)	1,177	1	1,177
Isomerization (C5s)	3,434	1	3,434
Lubricants	1,566	0.8	1,245
Sulfur (short tons/day)	193	40	7,705
<b>Total</b>			<b>732,397</b>

• The hypothetical California refinery is derived from total unit capacities reported in Energy Information Administration, *Petroleum Supply Annual 1999*, Volume 1, DOE/EIA-0340(99)/1 (Washington, DC, June 2000), pp. 84-87 and 98-99, scaled to 100,000 barrels per stream day atmospheric distillation capacity ([http://www.eia.gov/oil\\_gas/petroleum/data\\_publications/petroleum\\_supply\\_annual/psa\\_volume1/psa\\_volume1.html](http://www.eia.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html)).

• Total refinery electricity demand is greater than the electricity demand estimated from reported refinery process unit capacities and process unit electricity demands reported above. An approximation of total refinery electricity consumption is calculated equal to  $13,717 + 1.171 * \text{sum of process unit electricity demands}$ .

Units key:

bpsd - barrels per stream day

kwh - kilowatt hours

Sources: Maples, Robert E., *Petroleum Refinery Process Economics* (PennWell Books: Tulsa, OK, 1993).

Hydrocarbon Processing, *Refining Processes 2000* (Gulf Publishing Co.: Houston, TX., November 2000) pp.88 - 142.

Although we do not expect the refineries classified as moderate exposure to be forced to shut down their entire operations we do expect that average production rates at these refineries will be less than their capacity over the summer months due to operating at reduced rates during warm weather or from the shutdown of selected operating units.

Coordination between the electric utilities and refineries that are moderately exposed to rotating outages is also important for reducing the risk of equipment damage and minimizing lost production volume that could occur from forced refinery processing rate reductions in the event of sudden unannounced blackouts. For example, refineries could reschedule their operations, change their use of feedstock and product storage, and cut back production over the planned periods to minimize the impact on their operations during rotating outages - particularly if they already have significant cogeneration capacity. Further, the addition of backup generators when the refineries are nearly self-sufficient could provide supplemental power for nearly uninterrupted operations. [46]

## 4. Constraints Outside the Refinery Gate

- A. [Summary](#)
- B. [Feedstock Supply](#)
- C. [Product Pipelines](#)
- D. [Railroad Services](#)
- E. [Cooling Water](#)

- F. [Waste Water](#)
- G. [Alkylation Acid](#)
- H. [H. Hydrogen](#)
- I. [Other Outside Services](#)
- J. [End Notes](#)

## A. Summary

Refineries are also indirectly exposed to forced processing rate reductions and even complete shutdowns from disruption of services outside the refinery. Services that could require a refinery to reduce operating rates if disrupted include crude oil supply, product pipelines, railroad tank car movements, cooling water supply, waste water treatment, alkylation acid supply and disposal, and hydrogen supply. If disruptions to these services are frequent or prolonged, a refinery could be forced to shut down.

## B. Feedstock Supply

Refineries receive crude oil from two sources: waterborne deliveries by ship and domestic production from California crude oil producing fields. About one-half of the crude oil processed at California refineries comes through waterborne deliveries from Alaska or foreign imports, the other half from domestic production. Although refiners expressed concern about supply of waterborne cargoes delivered through third-party terminals, the greatest concern appears over the integrity of pipeline shipments of domestic crude oil, particularly very heavy crude oils such as from the San Joaquin valley.

The refineries that are at high risk of complete shutdown from a rotating electricity outage also are more dependent on California crude oil ([Table 4-1](#)). Refineries in the Bakersfield and Santa Maria region north of Los Angeles receive 100 percent of their crude oil supply from California oil fields.

**Table 4-1. Sources of Crude Oil Supply, 2000**

(barrels per day)

	Number of Refineries	California	Alaska	Foreign
<b>By Refining Region</b>				
Los Angeles	11	432,277	232,437	299,803
San Francisco	6	302,733	186,735	170,475
Bakersfield / Santa Maria	5	133,835	0	0
<b>By Refinery Risk of Exposure to Rotating Outages</b>				
High	5	350,661	96,628	41,434
Moderate / Low	8	420,585	310,328	419,984
Undefined	9	97,599	12,216	8,860

Notes: Classification of refineries by location and risk of exposure to rotating outages is provided in [Table 3-1](#).

Source: Energy Information Administration, EIA-810 Monthly Refinery Report.

Crude oil deliveries from ship (Alaskan or foreign) to shore tanks are not likely to be exposed to power outages because shipboard generators provide the power to pump the crude oil to shore tanks. However, dock operators may suspend ship unloading operations for the duration of an electrical outage because of safety concerns. The exposure that concerned refiners the most was from waterborne deliveries through third party terminals separate from the refinery.

Domestic crude oil supply faces two significant risks. First, pipeline deliveries generally go through several pumping stations and power loss at any one pump station would significantly reduce throughput rates and possibly disrupt shipments completely. Perhaps more significant is that some of this California crude oil is very heavy and requires heated pipelines in order for the oil to flow. Loss of electricity and pipeline flow can cause the heavy crude oil to begin to solidify requiring clearing which could result in an extended loss of service.

Crude oil inventories provide a short term buffer against supply disruptions. The average level of crude oil inventory at California refineries last year was equivalent to 7 days of operation (50 percent of available storage capacity). At individual refineries the end-of-month crude oil stocks ranged from a low of 3.5 days (25 percent of capacity) to a high of 11 days (80 percent of capacity) at individual refineries.

There is also a large volume of trade in unfinished oils between refineries in California. Last year an average 150,000 barrels per day moved between refineries, primarily by pipeline ([Table 4-2](#)). Refineries that face a high risk of complete shutdown in the event of a rotating electrical outage are net suppliers of unfinished oils while moderate and low risk refineries are net consumers. Refineries that lose unfinished oil supply because of the shutdown of a pipeline or supplying refinery have the short-term options of drawing from inventory and/or increasing crude runs and the long-term option of purchasing unfinished oils from outside the region.

**Table 4-2. Unfinished Oil Movements Between California Refineries, 2000**

(barrels per day)

	<b>Number of Refineries</b>	<b>Receipts</b>	<b>Shipments</b>
<b>By Refining Region</b>			
Los Angeles	11	111,250	66,984
San Francisco	6	91,790	29,402
Bakersfield / Santa Maria	5	5,004	53,402
<b>By Refinery Risk of Exposure to Rotating Outages</b>			
High	5	37,601	63,822
Moderate / Low	8	168,437	48,978
Undefined	9	2,005	36,987

Notes: Classification of refineries by location and risk of exposure to rotating outages is provided in [Table 3-1](#).

Excludes shipments between Tosco Carson and Tosco Wilmington refineries.

Receipts exceed shipments because of product delivered from outside California.

Source: Energy Information Administration, EIA-810 Monthly Refinery Report.

## C. Product Pipelines

Virtually all refineries depend on pipelines to move product from the facility. Product pipelines have somewhat greater exposure to rotating electrical outages because each line usually has several pumping stations, which may be in different rotating outage blocks. This increases the probability that a pipeline will be affected during any outage. As a practical matter, although there are exceptions, a significant electrical outage anywhere in a pipeline system typically results in the shutdown of that entire line for the duration of the outage. A pipeline with some reserve capacity (a maximum flow rate higher than the average flow at a particular time) may be able to make up for several hours of downtime in a day, but a line that is near capacity will likely not be able to do so.

The greatest risk arises from the cumulative effect of a pipeline experiencing several outages during a week. The problem evolves as the refineries fall behind in deliveries of product to the end users with each shutdown. With a pipeline running at or near capacity a cumulative loss of volume over a short period could become impossible to make up.

During 2000, refineries carried stocks of finished motor gasoline plus motor gasoline blend components that averaged about 11 days of production, which corresponds to about 50 percent of shell storage capacity. Because pipeline product movements are made in large batches, the end-of month gasoline stocks in individual refineries ranged from an average low of 7 days to an average high of 15 days of production. These simple averages imply that refineries could possibly handle gasoline product pipeline outages of anywhere from 3 to 11 days depending on the initial inventory level before their tanks become full and are forced to shut down production. However, the problem is much more complex since most of the product pipelines are common carrier pipelines that move product for all of the refineries. If several refineries have high inventories and scheduled shipments are disrupted, recovery may not be fast enough to prevent a refiner from cutting back production rates.

Overall, it appears that petroleum product pipelines in California are relatively well positioned to deal with electrical outages of short duration, but as is the case with other segments of the petroleum industry, this situation varies within the State, and according to the unique circumstances of any outage.

Essentially all of the petroleum product pipelines in California are now operated by Kinder Morgan Energy Partners, broken into four systems:

- Northern California Pipelines - system running from San Francisco Bay area south to Fresno, east to Reno, and north to Chico; other lines run from Bakersfield to Fresno, and between various San Francisco Bay area locations
- San Diego Line - Los Angeles area south to San Diego
- South Line - Los Angeles area via Colton (San Bernadino) southeast to Yuma, Phoenix and Tucson, with branch line to Imperial (a second line originates in El Paso, running west through Tucson to Phoenix)
- CalNev Pipe Line - (recently acquired by Kinder Morgan) originates in Colton (east of Los Angeles), and runs to Las Vegas

These pipelines supply not only most of the California markets (the exception being portions of the Los Angeles and San Francisco areas supplied directly from the refineries), but also provide virtually the entire supply for Las Vegas and Reno, Nevada, and much of the supply for Phoenix and Tucson, Arizona.

Kinder Morgan's northern California pipelines appear to be significantly more vulnerable to electrical outages than are the systems in the southern part of the State. The major portions of northern California pipelines operate very close to current capacity during peak seasons, leaving very little opportunity to make up for any volumes lost due to shutdowns. The system is mostly served by Pacific Gas and Electric, under interruptible tariff rates. (The 100 hours per year of allowable interruptions have already been used for this year.) The system can continue in operation (at reduced pumping rates) with one pump station shut down, but cannot operate without power to certain critical origination or junction points.

The three southern California systems operated by Kinder Morgan are generally seen as less vulnerable to electricity supply issues than those in the north, due both to their sources of supply and to a somewhat greater degree of surplus capacity. These systems are largely served by Southern California Edison and are subject to 150 hours per year of interruption, of which about half have already been used. Interruptions this summer are subject to "responsible parameters" as defined by the California Public Utilities Commission, i.e. no more than one event per day lasting up to 6 hours, for a total of no more than 24 hours per week or 40 hours per month.

Over the past several years, Kinder Morgan has undertaken a number of projects to expand capacity through its southern California petroleum product pipeline systems. These expansion projects have included, in various segments, larger pipe diameters, increased pump horsepower, addition of chemical drag reducing agents, crossover piping between parallel lines, and increased storage capacity. Additionally, generators have been added to receiving points to operate valves and safety equipment, allowing shipments to continue without outside power supply to those facilities. In general, Kinder Morgan management expresses the belief that any impact on product pipeline operations from power outages this summer will be less serious than those in early 2001 and will not be likely to result in significant product outages.

## **D. Railroad Services**

Should rail car flows be interrupted due to signal or switch problems or other issues, refinery volumes can be impacted. Refineries depend on receiving feedstocks, blendstocks, chemicals and catalysts (e.g., ethanol, methanol, butanes, and alkylation acid) by rail car and delivering some products by rail car. Serious interruptions to rail car movements would probably result in refineries reducing processing rates rather than being forced into complete shutdowns.

## E. Cooling Water

Refineries process hydrocarbons at high temperatures and pressures. Cooling water is used to control operating temperatures and pressures and the loss of cooling water circulation within a refinery can lead to unstable and dangerous operating conditions requiring an immediate shut down of processing units. Cooling water supply from the outside is used to make up for water losses such as from cooling tower vaporization. Refineries generally maintain small water makeup inventory of about 2 to 8 hours of supply. Loss of cooling water from an outside supplier results in a depletion of the makeup water inventory. A refinery would immediately begin reducing operating rates followed shortly thereafter by a controlled shutdown.

Almost all refineries in California generally receive their process cooling water supply from third parties such as municipal water districts. Supply of cooling water is generally expected to be at low risk from disruption from rotating electricity outages for 3 reasons:

- Water suppliers maintain inventories of water in the event of temporary upstream disruption of supply.
- Many water suppliers maintain backup diesel-driven water pumps.
- Some refineries have access to alternate supplies such as ground water.

## F. Waste Water

Significant volumes of waste water are produced during the refining process. For example, water is removed from crude oil delivered to the refinery, and fresh water is used to wash impurities from the crude. Loss of electricity to waste water treatment or an overload of high organic content wastewater resulting from a refinery disruption can result in a severe decline in treatment plant capabilities and take as long as 2 weeks to return to normal operation.

Some refineries operate their own waste water treatment and others rely on municipal water treatment services. Waste water treatment operated by refineries will be as exposed or protected from rotating electrical outages as the rest of the refinery process units.

## G. Alkylation Acid

About 10 percent of the California gasoline pool comes from a gasoline blendstock called alkylate. Alkylate is a high octane product of an alkylation process unit. The alkylation process unit reacts isobutane with olefin hydrocarbons (e.g., propylene, butylene) in the presence of an acid catalyst, usually sulfuric acid or hydrofluoric acid. Fresh high concentration acid is brought into the refinery by truck, rail car, or pipeline from third party suppliers. Used low concentration sulfuric acid is returned via truck or rail car for regeneration.

Disruption of acid supply or disposal may impact gasoline production in two ways. First, alkylation units are generally run at maximum capacity and the unplanned shutdown of an alkylation unit would represent a loss of volume of this very important gasoline blendstock. Premium California gasoline would be the most severely impacted. Second, refiners may encounter difficulties storing the [olefin hydrocarbon] alkylation unit feedstock that is a byproduct of other refinery process units (primarily catalytic crackers). The shutdown of the alkylation unit may then have a rippling effect through the entire refinery operation. An alkylation unit could take 1 to 2 days to restart while restarting both an alkylation unit and catalytic cracker could take as long as 1 week.

Refineries with sulfuric acid alkylation units report more concern over outside service disruption than refineries with hydrofluoric acid units. The reliability of third party acid service remains uncertain.[\[47\]](#) A sulfuric acid plant may take from 16 to 24 hours to restart following shutdown from a rotating electricity outage. Refineries with sulfuric acid alkylation units can store anywhere from 1 day to 1 week volume of fresh or spent acid depending on storage capacity. Actual inventories and capacity available during a disruption are highly variable because shipments of fresh and spent acid are done in large batches.

## H. Hydrogen

Hydrogen is primarily used to remove sulfur from all refinery products, particularly gasoline and diesel fuel. Most hydrogen is produced within the refinery by the reforming unit, although several California refineries produce additional hydrogen from natural gas.

Most refineries are self-sufficient in their hydrogen supply. But several refineries report receiving hydrogen from outside the refinery. A temporary loss of outside hydrogen supply would require storing untreated product until hydrogen was restored. Longer disruptions would require cutbacks in refinery production rates. Outside hydrogen supply is not expected to be a significant refinery risk issue. The major hydrogen producer in the Los Angeles area has a cogeneration plant and is likely to be protected from disruption.

## I. Other Outside Services

Other outside services received by refineries include:

- Nitrogen
- Caustic soda
- Byproduct exports to petrochemical plants (e.g., polypropylene)

Refiners indicate that these particular outside services are not expected to present a significant risk of disruption to refinery operations. In the event of the shutdown of the primary supplier of nitrogen or caustic to a refinery we assume that emergency supplies of nitrogen and caustic can be delivered by rail or truck before local stocks are depleted. With the shutdown of a petrochemical plant we assume that alternate disposition of the refinery byproduct can be found (e.g., burned as fuel).



# 5. Petroleum Product Prices and Supply Disruptions

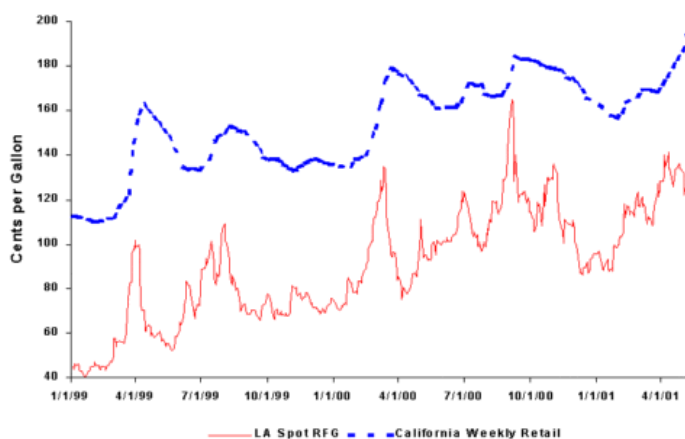
- A. [Summary](#)
- B. [West Coast Market Characteristics](#)
- C. [Past Product Price Response to West Coast Refinery Disruptions](#)
- D. [Relationship Between Wholesale and Retail Prices](#)
- E. [Impact of West Coast Supply Disruptions on the Rest of the U.S.](#)
- F. [End Notes](#)

## A. Summary

We cannot predict the impact of rotating electricity outages on petroleum prices in California this summer because we have no historical experience of such outages and their affect on the petroleum supply system. However, any loss of production from California refineries could increase product prices. The size of the increase is dependent on numerous factors that include the severity and length of the electricity outage.

Although the past is not considered a good predictor of California petroleum prices this summer, it is informative to look at that history. This history shows that relatively small disruptions in supply can cause significant increases in prices. Past disruptions to California refinery operations have resulted in price spikes ranging from 7 to 52 cents per gallon ([Figure 5-1](#)). The price spikes have varied considerably because of differences in the number, magnitude, and expected duration of the refinery disruptions and the condition of the market at that time.

**Figure 5-1. California Spot and Retail Gasoline Prices**  
Jan. 1999 - May 16, 2001



Source: Energy Information Administration, *Petroleum Marketing Monthly*, Regular Gasoline Prices, All Sellers.  
([http://www.eia.doe.gov/oil\\_gas/petroleum/data\\_publications/petroleum\\_marketing\\_monthly/pmm.html](http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_marketing_monthly/pmm.html))

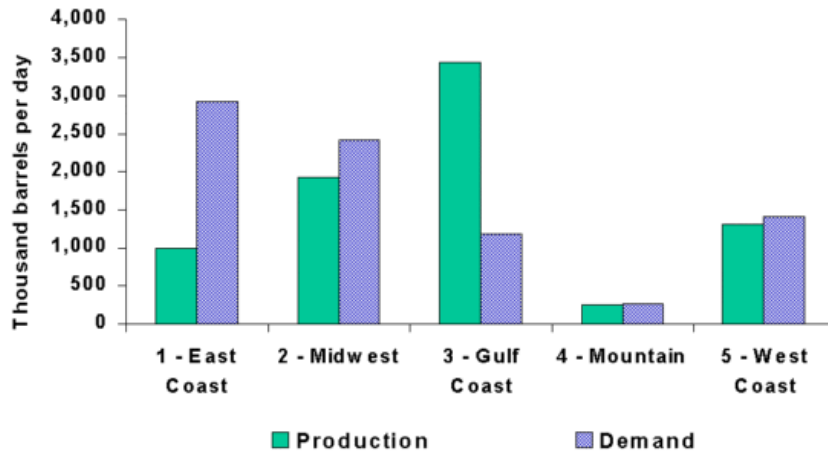
Three important factors that affect the size and duration of price spikes are:

- *Inventory levels.* Product inventories provide a buffer for unexpected supply disruptions. Higher inventory levels provide a greater cushion and tend to dampen price spikes. As of June 1, 2001, West coast (PADD 5) reformulated gasoline stocks stood at 12.2 million barrels, which compares with 11.4 and 13.2 million barrels in 2000 and 1999, respectively. West coast distillate fuel stocks on June 1 were 12.2 million barrels, compared with 12.8 and 11.6 million barrels at the end of May in 2000 and 1999, respectively.
- *Ability of the refining industry to respond.* The magnitude and duration of price spikes within California are constrained by the ability of other unaffected California refineries to make up lost production volume and refineries outside the region to produce and deliver product that meets California Air Resources Board (CARB) product quality specifications. However, unaffected refineries in California are expected to be limited in their capability of making up for lost volumes because they are already operating at or near capacity. Tight gasoline markets in the rest of the United States may restrain the responsiveness of other domestic refineries.
- *The frequency of events and the cumulative loss of volume.* Several refinery disruptions occurring at the same time and/or long periods of production outages tend to result in bigger price spikes. If electrical outages this summer are frequent and extensive, the potential loss of production volume could be unprecedented. Five California refineries are vulnerable to complete shutdown and four others are at risk of significant operating rate reductions during rotating electrical outages. Moreover, all California refineries are susceptible to production disruption, and possibly shutdown, if outside services such as water supply, waste water treatment, crude oil supply, and product pipelines are unavailable.

## B. West Coast Market Characteristics

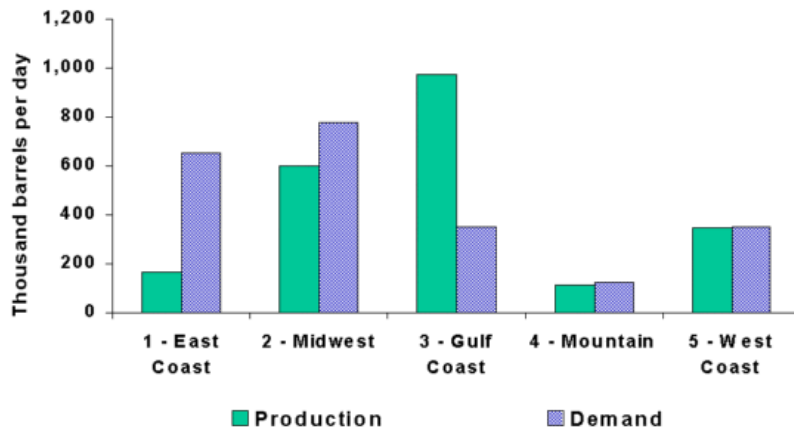
The most notable characteristic of the west coast (PADD 5) petroleum product markets is that PADD 5 is almost self-sufficient in the refinery supply of finished motor gasoline ([Figure 5-2](#)) and low-sulfur diesel fuel ([Figure 5-3](#)) compared with other areas of the country. Product imports and shipments from refineries on the U.S. Gulf coast satisfy only about 6 percent of finished gasoline demand ([Figure 5-4](#)) and about 3 percent of low-sulfur diesel fuel demand ([Figure 5-5](#)).

Figure 5-2. Finished Gasoline Balance by PADD  
5-Year Averages (1996 - 2000)



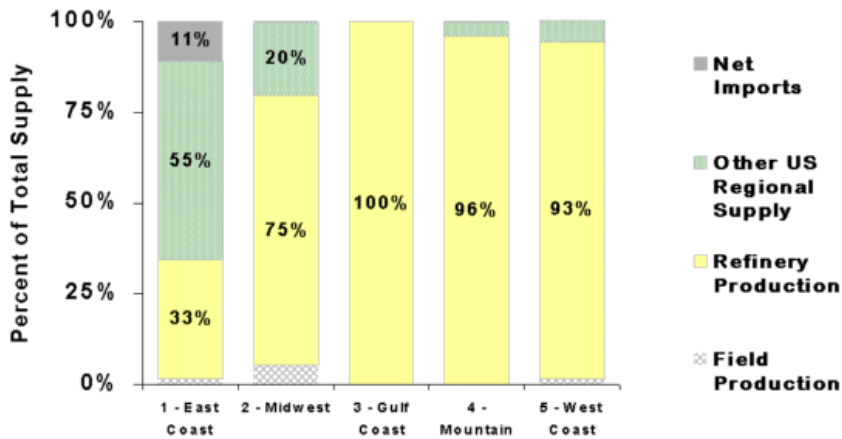
Source: Energy Information Administration, *Petroleum Supply Annual*, Volume 1, DOE/EIA-0340 (Washington, DC, various issues), Tables 5, 7, 9, 11, and 13. ([http://www.eia.doe.gov/oil\\_gas/petroleum/data\\_publications/petroleum\\_supply\\_annual/psa\\_volume1/psa\\_volume1.html](http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html))

Figure 5-3. Low-Sulfur Diesel Balance by PADD  
5-Year Averages, 1996 - 2000



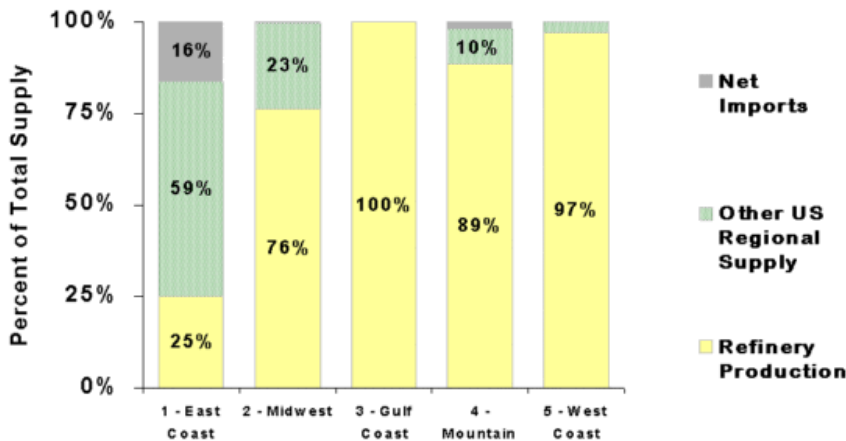
Source: Energy Information Administration, *Petroleum Supply Annual*, Volume 1, DOE/EIA-0340 (Washington, DC, various issues), Tables 5, 7, 9, 11, and 13. ([http://www.eia.doe.gov/oil\\_gas/petroleum/data\\_publications/petroleum\\_supply\\_annual/psa\\_volume1/psa\\_volume1.html](http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html))

**Figure 5-4. Sources of Finished Gasoline Supply by PADD  
5-Year Averages (1996 - 2000)**



Source: Energy Information Administration, *Petroleum Supply Annual*, Volume 1, DOE/EIA-0340 (Washington, DC, various issues), Tables 5, 7, 9, 11, and 13. ([http://www.eia.doe.gov/oil\\_gas/petroleum/data\\_publications/petroleum\\_supply\\_annual/psa\\_volume1/psa\\_volume1.html](http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html))

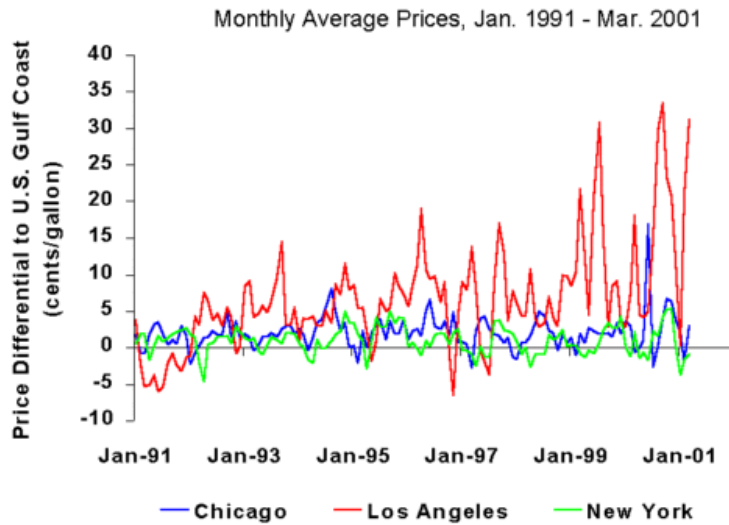
**Figure 5-5. Sources of Low-Sulfur Diesel Supply by PADD  
5-Year Averages (1996 - 2000)**



Source: Energy Information Administration, *Petroleum Supply Annual*, Volume 1, DOE/EIA-0340 (Washington, DC, various issues), Tables 5, 7, 9, 11, and 13. ([http://www.eia.doe.gov/oil\\_gas/petroleum/data\\_publications/petroleum\\_supply\\_annual/psa\\_volume1/psa\\_volume1.html](http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html))

Although PADD 5 appears to have a good supply-demand balance compared with the U.S. East coast (PADD 1), the recent history of wholesale product prices reveals the opposite. Wholesale gasoline prices on the West coast have been the most volatile in the country (Figure 5-6). While monthly average conventional gasoline prices in PADD 1 (New York harbor) have risen to at most 5 cents per gallon over the U.S. Gulf Coast (Houston) during the last 6 years, the West Coast (Los Angeles) has experienced several price spikes of as much as 50 cents per gallon over Gulf Coast prices.

**Figure 5-6. Wholesale Conventional Gasoline Price Differentials**



Source: McGraw-Hill Co., *Platts Oilgram Price Report* (New York, NY, various issues)

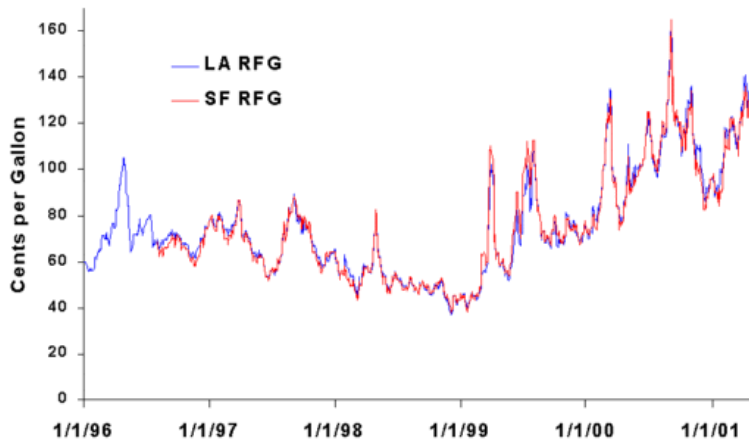
There are two principal reasons for the greater price volatility in California. First, only 13 refineries in California supply the gasoline and diesel fuel markets in that State. The unexpected loss of supply from one of the larger refineries represents the loss of a significant share of supply. Second, the California Air Resources Board (CARB) product quality requirements for both reformulated gasoline and diesel fuel are more stringent than any other in the United States and all other countries. Because California does not routinely receive product supply from outside the region, refiners in the U.S. Gulf Coast and other countries that may be able to supply CARB quality products do not maintain inventories of these products and any possible response to meeting California supply shortfalls will be delayed. Consequently any unexpected disruption of supply from a California refinery results in short-term price increases.

## C. Past Product Price Response to West Coast Refinery Disruptions

To evaluate the price response to an unexpected loss of supply of product for California we identified past refinery disruptions and examined the size and duration of the resulting price increases. We examined daily spot prices for CARB reformulated gasoline (RFG) in Los Angeles and San Francisco from 1996 to date and identified 20 separate instances of price "spikes," that can be linked to refinery problems that were reported in the trade press. Prices in either or both Los Angeles and San Francisco rose by 7 to 52 cents per gallon over a period of 3 to 47 days ([Figure 5-7](#) and [Table 5-1](#)). In some of the identified spikes, a single incident appears to have started or sharply accelerated upward price movement, while in others a combination of existing circumstances and/or successive events contributed to the price run-up.

**Figure 5-7. California Reformulated Gasoline Prices**

Daily Prices, Jan. 1, 1996 - May 11, 2001



Source: Reuters Ltd., reported in Energy Information Administration, *Weekly Petroleum Status Report*, Table 13 ([http://www.eia.doe.gov/oil\\_gas/petroleum/data\\_publications/weekly\\_petroleum\\_status\\_report/wpsr.html](http://www.eia.doe.gov/oil_gas/petroleum/data_publications/weekly_petroleum_status_report/wpsr.html))

**Table 5-1. California Gasoline Price Spikes**

Start	Peak	Cents/Gallon	Days from Start to Peak
03/29/96	04/23/96	30	25
05/16/96	05/23/96	8	7
11/20/96	01/06/97	22	47
01/20/97	01/23/97	7	3
03/03/97	03/25/97	16	22
08/08/97	09/03/97	20	26
04/14/98	04/28/98	28	14
02/22/99	03/02/99	18	8
03/16/99	03/29/99	52	13
05/20/99	06/11/99	36	22
06/22/99	07/13/99	42	21
07/21/99	08/03/99	27	13
02/16/00	03/10/00	43	23
04/25/00	05/02/00	26	7
06/21/00	06/27/00	17	6
07/25/00	08/09/00	22	15
08/17/00	09/05/00	52	19
10/16/00	11/02/00	28	17
01/23/01	02/08/01	33	16
03/19/01	04/10/01	33	22

**Sources**

Refinery Disruptions: Oil Price Information Service, "Refinery Watch" (Rockville, MD., various issues).

Prices: Reuters Ltd., reported in Energy Information Administration, *Weekly Petroleum Status Report*, Table 13 (Washington, DC, various issues)

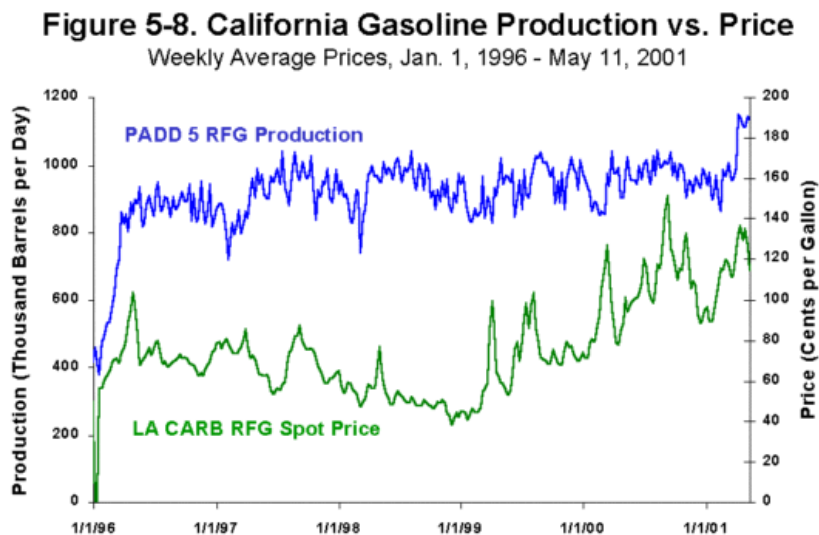
([http://www.eia.gov/oil\\_gas/petroleum/data\\_publications/weekly\\_petroleum\\_status\\_report/wpsr.html](http://www.eia.gov/oil_gas/petroleum/data_publications/weekly_petroleum_status_report/wpsr.html))

Each spike had its own unique set of ambient conditions, including time of year, inventory levels, crude oil price levels, prices for gasoline in other markets, etc. These pre-existing conditions appear to be a very important factor in price spikes, given that they can

determine whether a given incident creates a short-term supply shortage or merely reduces an existing surplus.

It is important to recognize that a price spike actually reflects the perception of potential supply/demand impacts on the part of market participants, not necessarily consistent with the actual size or duration of the impact. If buyers or sellers believe that an event is likely to make product more scarce, and thus more expensive in the near future, they are likely to bid prices higher immediately, often making the run-up a sort of "self-fulfilling prophecy."

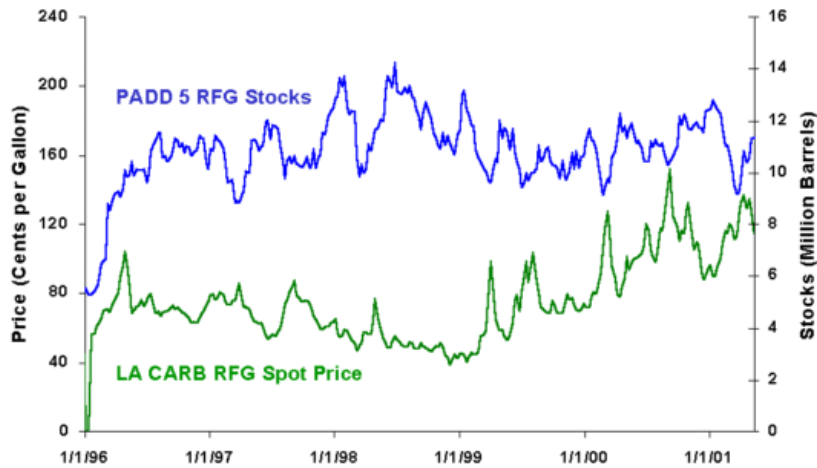
Market behavior in response to refinery incidents is not at all consistent. Depending upon previous conditions, price spikes can occur with no single discernible cause, and at other times, the size and/or duration of a spike can appear out of proportion to the observed drop in gasoline production (Figure 5-8).



Sources: Prices - Reuters Ltd., reported in Energy Information Administration, *Weekly Petroleum Status Report*, Table 13  
Production - Energy Information Administration, *Weekly Petroleum Status Report*, Table 10  
([http://www.eia.doe.gov/oil\\_gas/petroleum/data\\_publications/weekly\\_petroleum\\_status\\_report/wpsr.html](http://www.eia.doe.gov/oil_gas/petroleum/data_publications/weekly_petroleum_status_report/wpsr.html))

The importance of pre-existing conditions in determining the magnitude of a price spike appears in the stronger correlation between California RFG stocks and spot prices than between production and prices (Figure 5-9). This presumably reflects the fact that the impact of one or more incidents on gasoline production, coupled with pre-existing conditions that may have resulted in rising or falling stock levels, are jointly reflected in the net stock changes in the period following the incident(s). Thus, if a given refinery incident occurs when stocks are otherwise rising, resulting in a less significant drop in inventories, it is likely to precipitate less price response than an incident with a similar production impact that occurs when stocks were already low and/or declining.

**Figure 5-9. California RFG Stocks vs. Price**  
Weekly Average Prices, Jan. 1, 1996 - May 11, 2001



Sources: Prices - Reuters Ltd., reported in Energy Information Administration, *Weekly Petroleum Status Report*, Table 13  
Stocks - Energy Information Administration, *Weekly Petroleum Status Report*, Table 10  
([http://www.eia.doe.gov/oil\\_gas/petroleum/data\\_publications/petroleum\\_supply\\_monthly/psm.html](http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_monthly/psm.html))

## D. Relationship Between Wholesale and Retail Prices

In general, retail gasoline prices in California exhibit a lagged and somewhat smoothed response to spot price movements. This lagged response pattern is observed in all other sections of the United States. [\[48\]](#)

As spot prices change at major buying centers in Los Angeles and San Francisco, prices further along the distribution chain will begin to reflect these changes. Changes in motor gasoline prices travel relatively quickly from the spot to retail markets. In a prior study, EIA has explored how prices at the retail end of the distribution chain reflect spot prices at the major buying center of Los Angeles. That analysis showed that 56 percent of a spot price change was passed through to retail within 4 weeks, with an additional 30 percent pass-through occurring in the next 4 weeks. That is, if the spot price rose 10 cents from one week to the next, retail customers would see about 6 cents of the increase 4 weeks later, and about 9 cents of the increase 8 weeks later.

Close examination of the price relationships in [Figure 5-1](#) above reveals a number of important observations.

- Retail prices typically do not increase as much as the corresponding spot price impulse.
- Retail prices begin movement after and at a slower rate than the spot price impulse. Retail prices have a lagged relationship to spot price changes.
- Retail prices peak weeks after the spot price reaches its maximum.

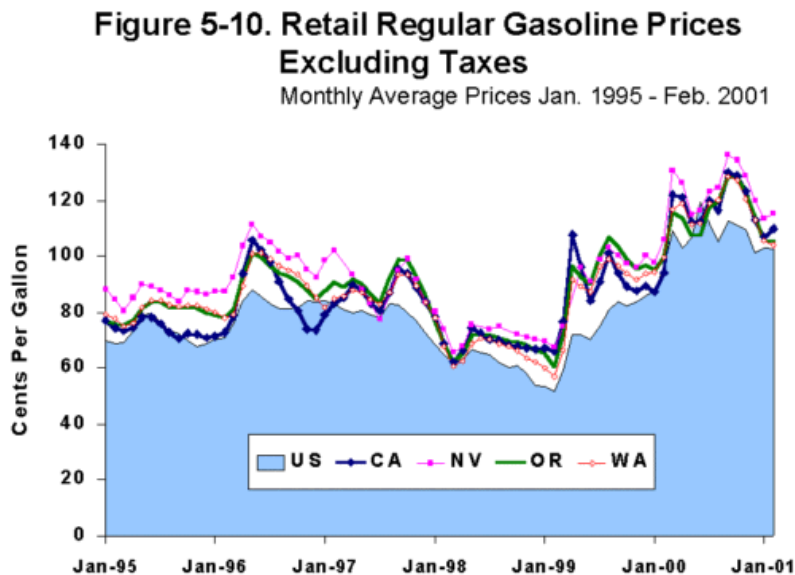


- Retail prices take longer to fall than spot prices. (This is an effect of the lagged response which results in an averaging of sudden spot price changes over a longer period of time through the distribution chain until they reach the retail level. This averaging tendency of prices at the retail level can induce an asymmetrical price response due to the fact that all the spot price impulses are positive.)

The time lag of the retail price response behind spot price movements is readily visible on price graphs such as [Figure 5-1](#) that show the retail price rising slow and peaking later than spot prices. This lag effect, which means that the current retail price change is a moving average of prior spot price changes, creates a distortion that makes it seem as though the retail price is remaining at an elevated level longer than it should. Over a longer period of time, however, the average difference between spot and retail prices has not changed over the last 5 years.

## E. Impact of West Coast Supply Disruptions on the Rest of the U.S.

California's problems are not isolated to that State. California refineries are important suppliers of product for the West Coast, and, as such, can impact prices in other PAD District 5 states. [Figure 5-10](#) shows how West Coast prices tend to move more closely to each other than to the national average price. Thus, if the electricity outages in California this summer create any refinery problem that causes California gasoline prices to surge, the surrounding states could experience price increases as well.



Source: Energy Information Administration, *Petroleum Marketing Monthly*, Regular Gasoline Prices, All Sellers.  
([http://www.eia.doe.gov/oil\\_gas/petroleum/data\\_publications/petroleum\\_marketing\\_monthly/pmm.html](http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_marketing_monthly/pmm.html))

If California prices are high enough relative to prices on the Gulf Coast, some Gulf Coast suppliers may ship gasoline components to the West Coast, which can increase price pressure in the Gulf Coast market as well.

EIA performed statistical tests to determine whether California spot CARB gasoline prices historically could be shown to consistently affect U.S. Gulf Coast RFG prices. The evaluation consisted of regressing weekly average U.S. Gulf Coast spot gasoline prices on the previous week's average Los Angeles spot prices and the previous week's U.S. Gulf Coast spot gasoline prices (Granger causality test). The Los Angeles prices provided no additional explanatory power above that provided by the Gulf Coast prices, which implies that California prices did not systematically "cause" Gulf Coast RFG prices to change during the last five years.

However, the methodology does not rule out the possibility that an occasional large price fluctuation in California can affect prices on the U.S. Gulf Coast. Nor does it rule out simultaneous price movements, in which price pressure in California could simultaneously cause price changes in California, U.S. Gulf Coast, and New York Harbor (which can also affect Gulf Coast) spot prices.

## 6. Natural Gas

- A. [The California Market for Natural Gas](#)
- B. [Background](#)
- C. [How Do Current Gas Market Conditions in California Compare to Last Summer?](#)
- D. [Impact of Electricity Outages](#)
- E. [Conclusion](#)
- F. [End Notes](#)

### A. The California Market for Natural Gas

The expanding economy of the 1990's and the increasing demand for natural gas helped bring about a 19-percent growth in United States natural gas consumption between 1991 and 2000.<sup>[49]</sup> During that time, enough additional natural gas pipeline capacity was installed in the United States to satisfy the market as it expanded. Few instances of capacity constraint or bottleneck occurred and gas service has been reliable. But in 2000 the demand for natural gas in some areas of the country, particularly in California, approached capacity limitations.

In 2001, the natural gas market in California has been substantially affected by a drop in hydropower resources in the Northwestern United States and, consequently, a drop in electric power generation from that source. As a result, greater demand has been placed on the gas-fired electric power plants in the West, especially in California. Increased demand for natural gas to power these plants has brought about a corresponding demand for natural gas that has strained the capabilities of both interstate pipelines that transport gas from outside the State, and intrastate pipelines that transport gas to markets within the State. The combination of increased demand and strained delivery systems has contributed to the large increase in gas prices in California during the past year.<sup>[50]</sup> With the higher prices

and greater demand has come a call for new pipeline capacity to be built into and within the State.

Efforts to increase natural gas supply within California could be dampened somewhat by the expected electricity outages in the State during the summer of 2001. Rotating outages of electricity have occurred in California in recent weeks in an effort to reduce electricity load. These outages have averaged about 2 hours in duration, per occurrence, and are expected to continue throughout the summer. One question that arises is what impact, if any, will the electricity outages have on the natural gas supply and delivery system in the State.

Unless electricity outages become frequent, the impact on the natural gas industry is likely to be minimal, in terms of natural gas supply storage and transportation. All firm loads are expected to be satisfied. The outages may have a financial impact on natural gas producers, processors, pipelines and storage operators in that additional costs will be incurred during the electricity outages.

- Electricity outages for short periods of time (1-2 hours per instance), if they are infrequent, should have a minimal impact on natural gas deliveries to consumers in California. The costs to produce, transport and deliver gas may increase because of electricity outages. These cost increases depend on a number of factors including the period and frequency of the interruption, the ability of the affected companies to adjust their operations, and characteristics of the affected companies including size and back-up generation facilities.
- The largest impact on gas supply in California from electricity outages, although still small in relative terms, is likely to be a decrease in natural gas produced as a co-product with oil. In 1999, approximately 14 percent of the gas supply in California (about 80 percent of gas production in the State) was produced as a co-product from oil wells in the State. To the extent there are interruptions in electrical service to producers in California, there may be a proportional decrease in the amount of gas produced in the state. A 2 hour interruption of electricity could result in an approximate 8 percent, or more, reduction in the production from the oil or gas well for that day.
- Within-state production of oil in 1999 was about 310 million barrels (849 thousand barrels per day), representing about 50 percent of total oil consumption in California. About two-thirds of the oil produced in California in 1999 is considered heavy oil that is predominantly produced through enhanced oil recovery (EOR) steam methods that use natural gas to generate the steam, and also produce natural gas as a co-product.[\[51\]](#)

Producers, particularly those using enhanced oil recovery methods in southern California, rely heavily on electricity, and production may be impacted for the duration of each electricity outage, and perhaps a bit longer. Oil producers, particularly small operators, currently rely more on the grid for their electricity rather than distributed generation to power their operations.

- Temporary, infrequent electricity outages should have a minimal impact on natural gas storage operations. Electricity is not typically needed for withdrawals from storage, so, in the event of an electricity outage, storage withdrawals are possible. Although electricity is used for monitoring and control equipment at storage facilities, virtually no storage facilities in the state require electricity for compression to inject

gas into storage. At least one storage facility in California uses electric-driven compressors to inject gas into storage, but with short-term electricity outages, the gas intended for injection most likely could be absorbed into the system and injected at a later time.

- It appears that the delivery system for natural gas into and within the state of California is capable of continuing operations during temporary electricity outages that might occur during 2001. Pipeline companies delivering gas in California, both interstate and intrastate pipelines, report that they expect, this summer and beyond, to serve all of their customers that have firm, guaranteed service. The intrastate pipeline delivery system within California currently has only one compressor station that is electricity-driven. Other facilities, such as the stations themselves and dispatching centers, have emergency backup generators in place. The operation of the affected pipelines may suffer a decrease in efficiency and additional personnel may be needed during an electricity outage, at a cost to the operator. However, transportation service can continue.
- The natural gas transportation system in California may become more dependent on electricity in future years in order to satisfy environmental restrictions in the State. New or retro-fitted compressors that are powered by electricity will increase the reliance on the electric grid and, absent a back-up power source, may increase the potential for a decrease in pipeline throughput during an electric outage. For example, the new Doggett Compressor Station on the Kern River Pipeline will be gas-fired until the summer of 2002, at which time it will be converted to use electric-driven compression due to environmental restrictions. A 24 hour loss of electricity after the conversion in 2002, will, according to a company executive, reduce throughput by about 350 million cubic feet per day, a 25 percent reduction in throughput capacity at that location.

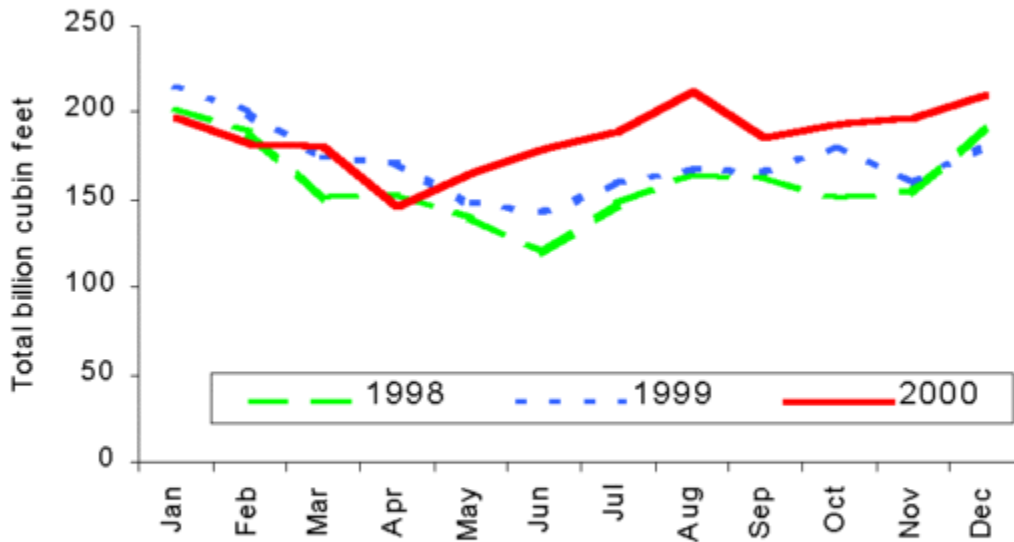
## B. Background

California relies heavily on natural gas to satisfy its energy needs. In 1999, approximately 29 percent of the total energy consumed in the State was natural gas. In addition, the State's natural gas market, which is dominated by industrial (including electricity generation by non-utilities) and residential use, has been growing at a robust rate in recent years. Deliveries to consumers in California increased at an annual average rate of 4 percent between 1995 and 2000. Between 1999 and 2000, end-use consumption of gas in California increased by 8.1 percent. In contrast, the annual growth in end-use consumption of gas in the United States was considerably less than the California rate -- only 1.2 percent between 1995 and 2000, and 5.2 percent between 1999 and 2000. Industrial uses (including cogeneration and non-utility generation applications) accounted for 43 percent of end-use gas consumption in California in 2000. Residential consumption accounted for about 28 percent, while commercial and electric utilities each accounted for about 14 percent of the State's end-use consumption in that year.

In 2000, the pattern of monthly gas consumption in California differed from the single winter peak, seen in 1998 and 1999, to a dual peak. In 2000, the California gas market had a summer peak nearly as high as its normal winter peak ([Figure 6-1](#)). The winter peak results from heating load by residential consumers while the summer peak stems from the

effects of high cooling demand on output requirements from electric generators (both utilities and cogenerators).

Figure 6-1. Total Natural Gas Deliveries to California



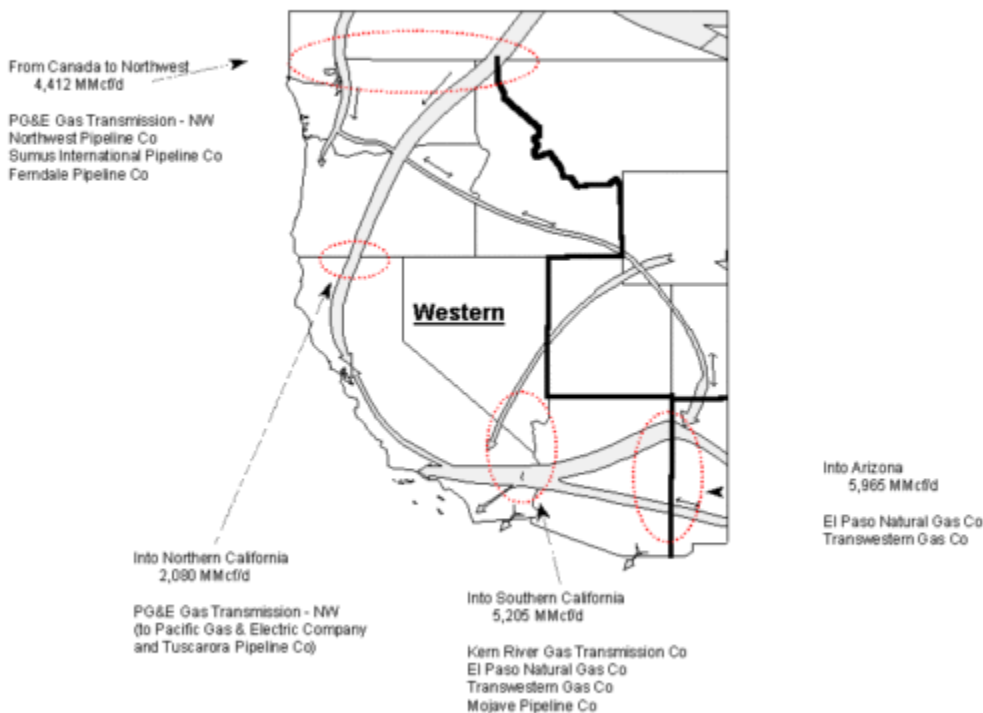
Source: Energy Information Administration, *Natural Gas Monthly*, April 2001  
[http://www.eia.doe.gov/oil\\_gas/natural\\_gas/data\\_publications/natural\\_gas\\_monthly/ngm.html](http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_monthly/ngm.html)

The majority of natural gas supplies to the California market are transported from other States. In 1999, California produced 372 billion cubic feet of gas, about 18 percent of the gas delivered to customers in the State. The remaining 82 percent was transported to the State by five interstate pipeline companies [52] that collectively brought gas produced in Canada, the Rocky Mountain area, and the Permian and San Juan basins in the U.S. Southwest. [53] Interstate pipeline capacity into California is estimated by EIA to be 7.3 billion cubic feet per day (Figure 6-2, Table 6-1). [54] This compares to the California Energy Commission (CEC) estimate of 7.0 billion cubic feet per day. [55] There appears to be an imbalance between the ability of the interstate gas pipeline system to deliver gas to California and the in-State pipeline capacity to receive gas at the border. The CEC has estimated the imbalance at 300 million cubic feet per day (MMcf/d), or about 4 percent of interstate delivery capacity. EIA estimates that the shortfall in receipt, or take-away, capacity is 590 MMcf/d, or 8 percent of EIA's estimated interstate delivery capacity (Table 6-1). The EIA estimate was derived by comparing interstate capacities at specific border crossings with the CEC estimates of intrastate receipt capacity.

Approximately 80 percent of gas produced in California is extracted as a co-product from oil wells in southern California. Non-associated gas accounts for the remaining 20 percent of gas production. In 1999, dry marketed production of natural gas in California totaled 372 billion cubic feet (bcf), approximately 294 bcf from oil wells and approximately 78 bcf from gas wells. [56] As a share of deliveries to consumers, gas from oil wells in California satisfied

14 percent of deliveries to consumers in 1999, whereas gas from gas wells in the state satisfied only 4 percent of consumer deliveries. The remaining 82 percent of gas deliveries to consumers is transported from sources outside the state.

**Figure 6-2 Major Natural Gas Pipeline Transportation Routes and Capacity Levels at Selected Key Locations in the Western U.S., 2001**



Source: Energy Information Administration, EIA GIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of December 2000.

**Table 6-1. Key Natural Gas Pipeline Capacity Levels into the State of California, by Location and Pipeline**

Region/ Delivering Pipeline	Interstate Delivery Capacity <sup>1</sup> (MMcf/d)	Receiving Pipeline	Intrastate Receipt Capacity <sup>2</sup> (MMcf/d)	Shortfall in Receipt Capacity (MMcf/d)
<b>Southern California</b>				
<i>Topock, AZ.</i>				
El Paso Natural Gas Co	540	SoCal Gas Co	540	
El Paso Natural Gas Co	1,140	PG&E Gas Co	1,140 <sup>3</sup>	
El Paso Natural Gas Co	400 <sup>4</sup>	Mojave Pipeline Co	400	
Transwestern Pipeline	225	PG&E Gas Co	0 <sup>3</sup>	
Transwestern Pipeline	190	SoCal Gas Co	50 <sup>5</sup>	
<b>Subtotal Topock, AZ.</b>	<b>2,495</b>		<b>2,130</b>	<b>365</b>
<i>Ehrenberg, AZ.</i>				
El Paso Natural Gas Co	1,210	SoCal Gas Co	1,210	0
<i>Needles, CA.</i>				
Transwestern Pipeline	750 <sup>6</sup>	SoCal Gas Co	750	0
<b>CA/NV line</b>				

Kern River Trans Co	<u>750</u> <sup>7</sup>	Kern River Transmission Co	<u>700</u>	<u>50</u>
<b>Subtotal Southern California</b>	<b>5,205</b>		<b>4,790</b>	<b>415</b>
<b>Northern California</b>				
<b>Malin, OR.</b>				
PG&E Gas Transmission - NW	1,970 <sup>8</sup>	Pacific Gas & Electric Co	1,905	
PG&E Gas Transmission - NW	<u>110</u> <sup>9</sup>	Tuscarora Pipeline	<u>0</u>	
<b>Subtotals Northern California</b>	<b>2,080</b>		<b>1,905</b>	<b>175</b>
<b>Total California</b>	<b>7,285</b> <sup>10</sup>		<b>6,695</b>	<b>590</b>

<sup>1</sup> Capacity levels shown in this column are based upon data independently compiled by EIA from company sources. In many cases the design capacity (as listed on the company's web site, for instance) for a particular delivery point is greater than that listed here due to operational variations on the pipeline system and/or contractual volume levels. For example, Kern River Transmission's CA/NV State line capacity is listed as 780 MMcf/d on its web site vs 750 MMcf/d level reported as the average by other sources.

<sup>2</sup> Capacity levels shown in this column are based upon information made available in the California Energy Commission's May 2001 study of "Natural Gas Infrastructure Issues (Draft)".

<sup>3</sup> PG&E has an interconnect with two interstate pipeline companies at Topock, Arizona (El Paso Natural Gas Co. and Transwestern Pipeline Co.). PG&E's 300 Line (from Topock, Arizona to Kern River Station near Kramer Junction, California) can carry only 1,140 MMcf/d out of Topock, AZ, but could receive as much as 1,365 from El Paso and Transwestern (1,140 + 225 MMcf/d) if the Line 300 were expanded.

<sup>4</sup> The Mojave system is supplied by the El Paso System (which can deliver up to 400 MMcf/d) and Transwestern (150 MMcf/d) at Topock, Arizona, although only a maximum of 400 MMcf/d can be delivered at one time and carried into California.

<sup>5</sup> Includes the receipt capacity reported for the Hector Road/Mojave Pipeline interconnect within California.

<sup>6</sup> In the California Energy Commission's report the capacity for the "Transwestern at Needles" is reported as 1,090 MMcf/d but does not list any corresponding receipt capacities for Transwestern at Topock, for either SoCal, PG&E, or Mojave.

<sup>7</sup> Non-winter average capacity level. Summertime capacity is 700 MMcf/d while during the winter months Kern River Transmission capacity can be as high as 800 MMcf/d.

<sup>8</sup> Summertime capacity level. Amount that can be delivered to Malin, Oregon during the winter months drops due to increased demand for natural gas in the States north of California.

<sup>9</sup> About 90 MMcf/d of the 110 MMcf/d capacity entering California on the Tuscarora Pipeline feeds into Nevada. However, the California Energy Commission's report does not include Tuscarora in its list of Interstate suppliers to the State.

<sup>10</sup> The California Energy Commission's report presents 7,040 MMcf/d as the total interstate natural gas pipeline delivery capacity compared with the EIA's 7,125 MMcf/d (7,285 MMcf/d adjusted for Tuscarora's 110 MMcf/d and Kern River's 750 vs 700 summertime capacity), a difference of 85 MMcf/d.

Note: MMcf/d = million cubic feet per day.

Note: Actual capacity levels on any given day will vary due to operational conditions and to such variables as ambient temperature and elevation.

Sources:

*Interstate pipeline capacity:* Energy Information Administration, EIAGIS-NG Geographic Information System, State Border Capacity Database;

*Intrastate pipeline capacity:* California Energy Commission, "Natural Gas Infrastructure Issues," Draft, May 2001.



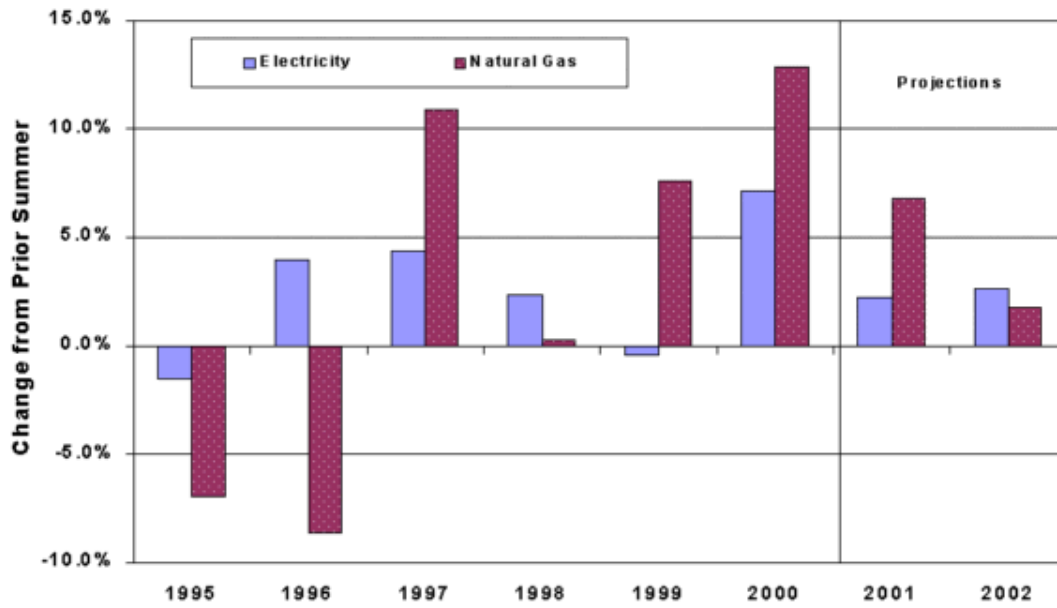
Storage is an important component of the California natural gas market, and one that is increasing in importance to supplement pipeline capacity and serve as a backup supply source. During peak consumption periods, the industry combines supplies from the producing regions, including imported supplies, with supplies from underground storage to meet customer demands. California storage facilities were utilized extensively this past winter (2000-2001).<sup>[57]</sup> Weekly storage inventories in the Western region averaged 30 to 40 percent below the 5-year average level throughout the winter.<sup>[58]</sup> From November 2000 through January 2001, net storage withdrawals in California totaled 73 billion cubic feet (Bcf), or about 11 percent of consumption during the period. This compares with net storage withdrawals of 47 Bcf (about 9 percent of consumption) during the same period a year earlier. Withdrawals from storage in California occur during the summer months because of spikes in consumption, particularly for electric generators.

### **C. How Do Current Gas Market Conditions in California Compare to Last Summer?**

The outlook for natural gas in California the summer of 2001 is for continued strong demand levels and continued high gas acquisition costs due to the existing constraints on the capacity of the California intrastate pipelines to take delivery of natural gas from other regions and the high utilization rates of interstate pipelines serving the California market.<sup>[59]</sup> Summer gas demand in California, leaving aside the potential impacts on demand from reductions in gas use due to power outages, is expected to grow by 6.8 percent this summer from the 2000 level ([Figure 6-3](#)). While still quite high (more than 3 times the expected national growth rate for this summer), this rate of growth is far below the torrid pace in California seen last summer (12.8 percent). A likely slowing in the rate of economic growth in California this year is expected to be offset somewhat by continued strong growth in power-sector demand due to continuing declines in the availability of hydroelectric resources in the region ([Figure 6-4](#)). Absent a declining hydroelectric share, summer gas demand would be expected to grow at a rate closer to that expected for electricity demand or about 2.3 percent.

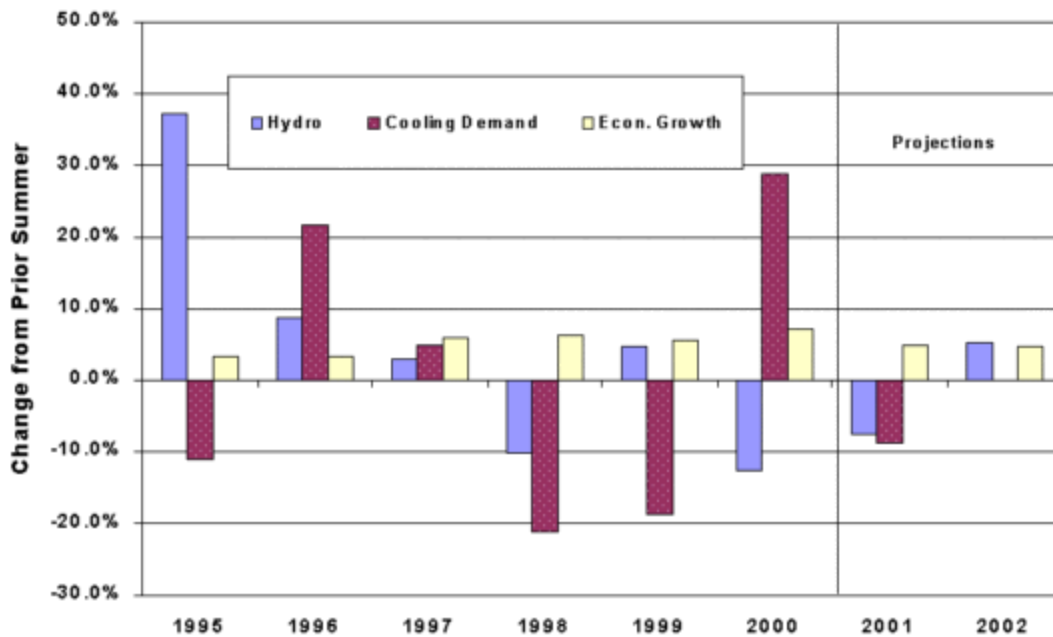


**Figure 6-3. California Summer Natural Gas and Electricity Demand**



Source: Energy Information Administration calculations based on EIA's *Short-Term Energy Outlook* (<http://www.eia.doe.gov/emeu/steo/pub/contents.html>)

**Figure 6-4. California Summer Natural Gas and Electricity Demand Factors**



Source: Energy Information Administration calculations based on EIA's *Short-Term Energy Outlook* (<http://www.eia.doe.gov/emeu/steo/pub/contents.html>)

Interstate capacity into the California market is approximately the same as it was last year, 7.3 billion cubic feet per day. Although there are several expansion projects underway (discussed later in this analysis), they are not likely to have much impact until later in the year. Utilization rates on interstate pipelines serving the State are expected to be high this summer, even under normal weather conditions. The El Paso line that was disrupted by an explosion last August, although not fully operational, does not result in less gas moving into the State. According to a company spokesperson, shippers are purchasing their gas at other places on the El Paso system and the same amount of gas is going into California as before the disruption, only by different routes [60].

It should be noted that even during peak consumption periods during 2000 and the first few months of 2001, there were no curtailments of natural gas service for the core market in California. According to the California Energy Commission, curtailments have been limited to interruptible customers, including electric generators that have chosen this level of service. Customers who chose firm, guaranteed service continued to receive that level of service and are expected to receive that level of service in the upcoming months.

Although reliable service is anticipated for all core customers in California, it will probably cost more than it did last year. The price of natural gas to residential customers averaged \$12.10 per thousand cubic feet in January 2001, a 90-percent increase from the price in January 2000. Prices have dropped considerably since January, but the price of natural gas service will likely be higher this summer than last. The Henry Hub spot price for natural gas in May 2001 is only 20 percent higher than the year-earlier level (\$4.25 vs. \$3.50 per million Btu), however, citygate prices at California border points are still at high levels, over

\$8 per million Btu, as of late May 2001. California citygate prices have been subject to extreme volatility over the past year and reached as high as \$60 per MMBtu in December 2000.<sup>[61]</sup> For additional discussion of California natural gas prices refer to Energy Information Administration, *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future*, SR/OIAF/2001-02 (Washington, DC, May 2001) pp. 21-24.

## D. Impact of Electricity Outages

### Production/Processing Operations

The largest impact on gas supply in California from electricity outages, although still small in relative terms, is likely to be a decrease in natural gas produced as a co-product with oil, particularly in enhanced oil recovery production in the southern part of the State. In 1999, approximately 14 percent of the gas supply in California (about 80 percent of gas production in the State) was produced as a co-product from oil wells in the State. To the extent there are interruptions in electrical service to producers in California, there may be a proportional decrease in the amount of gas produced in the state. A 2 hour interruption of electricity could result in an approximate 8 percent, or more, reduction in the production from the oil or gas well for that day. If the well was not producing at maximum rate, it may be possible that some or all of the reduction in production could be recovered after electric service is restored. Nevertheless, if the electricity outages become routine or frequent, it would lead to a decrease in oil production, gas production, and gas produced as a co-product of oil.

Electricity outages for short periods of time (1-2 hours per instance), if they are infrequent, may be more an inconvenience or a nuisance for the producers and processors, albeit one that increases the overall cost of production as it may require additional resources to work around or adjust production operations. Advance notice of a planned outage is important, as it enables producers to adjust their operations accordingly to lessen the impact of each outage. Information is not readily available regarding whether producers have back-up generators (for instance powered by diesel fuel) to enable continued operation during a rotating electricity outage. Even with back-up generators, however, the efficiency of their operations would likely be reduced during the period of interruption and perhaps for an hour or two after electricity service is restored. According to industry sources, the starting and stopping of production operations is not as simple as "flipping a switch." This means that a 2-hour outage of electricity may translate to a 3-hour or up to 4-hour period of no or minimal production. As a result, production from the affected wells would be reduced by one-eighth to one-sixth of production for that day (assuming a constant production rate in the absence of the electricity outage).

The impact of electricity outages for producers that already have interruptible electricity supply contracts should be small. Some California producers have determined that they are able to tolerate electricity outages and reportedly have elected interruptible service from their electricity provider, in response to the escalating electricity prices, with the understanding that their electricity service may be curtailed during periods of peak load.

If the electricity outages become frequent, the effect on the production operations in the State will intensify. Some producers are reporting that the routine curtailment and constant stopping and restarting of production equipment pose a threat to the integrity of their

wells.[\[62\]](#) This could necessitate additional reconditioning of the wells, which would further escalate the already high cost of producing gas in California. For some producers, electricity costs represent the bulk of their production costs.[\[63\]](#)

Because of State environmental restrictions, oil and gas producers in California rely more heavily on electricity in their operations than do producers in other states. Electric-driven compression is used in producing natural gas to increase pressure within the well, if the ambient pressure in the well is insufficient to extract the gas.[\[64\]](#) Electric motors have no major emissions, are easier to monitor, maintain and control, and may cost less to install. Electricity is also used by both producers and processors of natural gas for control systems and operations and measuring activities. In addition, electricity is used in drying activities of processing plants, during which liquids and other impurities are extracted from the gas before it enters the pipeline system.[\[65\]](#)

Natural gas and oil production in California has been a subject of concern since last year. Indigenous production in 1999 accounted for only about 18 percent of California natural gas supply and about 50 percent of oil supply in the State. There has been a significant drop in the production of oil and gas in the State. The State Onshore and the State Federal (not including Federal Offshore) preliminary oil production data for the months of December 2000, January and February 2001 are 739.1, 713.5, and 725.6 thousand barrels per day (mbpd), respectively. The 25.6 mbpd drop from December to January is currently attributed to the electricity blackouts and high electricity and natural gas prices.[\[66\]](#)

Producers, particularly those using enhanced oil recovery methods in southern California, rely heavily on electricity and natural gas. Production will be impacted for the duration of each electricity outage, and perhaps a bit longer. Oil producers, particularly small operators, currently rely on the grid for their electricity rather than distributed generation to power their operations. Natural gas is used in the generation of steam to be injected in the heavy oil recovery projects. As the price of natural gas skyrocketed, some (perhaps even many) of the small independent operators opted to discontinue the use of gas for the generation of steam and instead sold it to utility companies and other preferential customers. Some operators shut down or reduced their production and cogeneration operations in recent months because of high gas prices and non-payment by the utilities for the electricity sold to the grid.

## Storage Operations

Electricity outages for short periods of time are expected to cause only minor problems at storage facilities. Some storage facilities in California use electric-driven compressors to inject gas into storage. (Compression is needed during the injection cycle but not during the withdrawal cycle.[\[67\]](#)) If injections were planned and an electrical outage occurred, the gas intended for injection would need to be absorbed by the system and, if possible, injected when electricity service resumes. Electricity is also used in storage for operations and facility control including valving systems and monitoring (measuring) purposes, although back-up generators (likely gas-fired) are generally in place. If storage injections requiring electric compression are not scheduled to occur at maximum injection rates, the storage injections can be rescheduled for when the power is available. Overall, the impact of brief, infrequent electricity outages on natural gas storage facilities and operations in California would be minor to non-existent.

A considerably more serious concern for storage operators than electricity outages is the extent to which storage stocks can be built up over the summer. If storage injections are

low, withdrawals over the summer will lead to exceptionally low storage stocks in the West at the start of winter 2001, adding pressure to the already high gas prices. Rising energy costs and maintaining reliability in energy supply are areas of concern for consumers in California as well as the rest of the nation.

## Natural Gas Pipelines

It appears that rolling electric power blackouts in California would have little or no effect upon the operations of either of the two major gas distribution companies located in the State. According to a spokesperson for Southern California Gas Co. (SoCal), none of the company's pipeline system compressor stations run on electricity and all other facilities, such as the stations themselves and dispatching centers, have emergency backup (generators) capability in place.[\[68\]](#) The same can be said for the Pacific Gas & Electric Co. (PG&E) pipeline system, except for one compressor station just south of the San Francisco area that operates two compressors with electricity. In the event of a rolling blackout at that station, up to 50 million cubic feet (MMcf) of service could be lost to the south during a 2-hour disruption (the average of the recent blackout intervals). According to a PG&E spokesperson, the electric compressors are reportedly already on a voluntary load reduction program with the utility and subject to interruption. PG&E also has one electric power compressor unit located at one of its underground storage facilities but says that would only halt injections for a short time.[\[69\]](#) Any flows lost due to a lack of withdrawal capability would be small.

### ***What about natural gas pipeline capacity levels within the State itself?***

In California, there is an imbalance between the ability of the interstate gas pipeline system to deliver gas to the California border and the in-State pipeline capacity to receive gas at the border. This imbalance means the ability of take-away capacity at the State border constrains the amount of gas that can be delivered into California by interstate pipeline companies. The California Energy Commission estimates that at least 200 MMcf/d less gas can be picked up at the State border than can be delivered to the State. EIA estimates the total imbalance at about 590 MMcf/d ([Table 6-1](#)).

On the PG&E system, which serves northern California above Kern County, capacity levels are in excess of current customer needs even on peak days. According to a company spokesperson, PG&E's daily requirements during the summer are usually below the certificated capacity at the northern California border (at Malin, OR, from PG&E Transmission - NW) by 20-to-30 million cubic feet per day (MMcf/d), while during the winter season that rises to 90+ MMcf/d. Nevertheless, PG&E plans on upgrading and expanding its system in the near future to accommodate a planned increase in capacity on the PG&E Transmission - NW system of more than 300 MMcf/d in 2002 ([Table 6-2](#)). The company believes demand will grow sufficiently by then to justify the expansion. It has no plans, however, to increase its capacity on its southern route, which transports gas into California from Arizona, since the current capacity on that section is adequate to meet current customer needs.

The SoCal system, on the other hand, is often operating at or above full capacity. The high spot gas prices currently posted at southern California citygates seem to indicate a lack of adequate pipeline capacity from the Southwest into the State. Although it has been speculated that SoCal may be hesitant to expand its system because, once the hydropower resources return to normal (most likely in 1 to 2 years), less natural gas will be needed for electric power generation, SoCal has in fact announced several projects to expand delivery

capacity within the State. SoCal recently filed for two expansion projects, both to be completed in late 2001 (Table 6-2). The first project would increase take-away capacity at three critical points on its system. Although capacity would increase by only about 50-60 MMcf per day at each point, one would increase access to growing California gas production while the other two would upgrade currently constrained interconnections with the interstate network. The second project involves the building of a new 200 MMcf/d, 32-mile lateral that would link the southern part of the SoCal system with an interconnect with the Kern River-Mojave Pipeline located on the northern part of the SoCal system.

**Table 6-2. Natural Gas Pipeline Projects Proposed for Development in the Western United States, 2001-2004**

State	State	Project	Pipeline Name	FERC Docket Number	Service	Type of Project	Status	Scheduled Service	Cost (million \$)	Miles	Added Capacity (MMcf/d)
<b>Projects that may impact California in Summer 2001</b>											
CA	TX	Line 2000 Project	El Paso Natural Gas Co	CP00-422	Interstate	New	Appr	8/2001	204	1088	230
CA	WY	Mainline 2001 System Expn	Kern River Transmission Co	CP01-106		Exp	Appr	6/2001	81	922	135
<b>Subtotal</b>									285	2,010	365
<b>Projects that may impact western States and Mexico in late 2001</b>											
CA	BC	2001 System Expn	PG&E Gas Transmission-NW	CP01-141	Interstate	Exp	Appl	2001	na	21	207
CA	CA	Kern River Interconnect Expn	Southern California Gas Co	Not applicable		New	Appl	2001	40	32	200
CA	CA	2001 System Expn	Southern California Gas Co	Not applicable	Intrastate	Exp	Appl	2001	15	0	175
<b>Subtotal</b>									55	53	582
<b>Other 2001</b>											
OR	OR	Coos Bay Project	Coos County Pipeline Co	Not applicable	Intrastate	New	Ann	2001	30	65	na
WA	BC	Power Plant Import	Sumas Energy 2	CP99-320	Interstate	New	Appr	2001	na	4.5	140
MX	AZ	Ductos De Nogales Project	El Paso Natural Gas Co	CP01-41	Export	New	Appr	2001	0.42	1	8.5
MX	AZ	Willcox Lateral	El Paso Natural Gas Co	CP99-322/323	Export	New	Appr	2001	30.2	68	130
<b>Subtotal</b>									60	138	278
<b>Total 2001</b>									360	2,169	1,025
<b>Proposed 2002 Projects</b>											
AZ	AZ	Red Rock Expn	Transwestern Pipeline Co	CP01-115	Interstate	Exp	Appl	2002	93.3	0	150
CA	CA	Long	Kern River	Not yet		New	On	2002	na	na	na

		Beach Lateral	Transmission Co	filed			Hold				
CA	WY	Mainline 2002 System Expn	Kern River Transmission Co	CP01-31		Exp	Appl	2002	80	922	124.5
CA	MX	Otay Mesa Project	Otay Mesa Generating Co	CP01-145	Import	New	Appl	2002	na	0.3	110
CA	NM	Southern Trails Pipeline	Questar Pipeline Co	CP99-163	Interstate	New	Appr	2002	155	705	120
									<i>Subtotal</i>		
NV	CA	2002 System Expn	Tuscarora Pipeline Co	CP01-153	Power Plants/LDC	Exp	Appl	2002	60	1,623	345
OR	OR	Mist Storage Link Phase IV	Northwest Natural Gas Co	Not applicable	Storage Link	Exp	Appl	2002	35	32	145
WA	WA	Everett Delta Lateral	Northwest Pipeline Co	CP01-49		New	Appl	2002	17.2	9	130
WA	WA	Gray Harbor	Northwest Pipeline Co	Not yet filed	Power plant	New	Ann	2002	na	48	160
									<i>Subtotal</i>		
MX	AZ	North Baja Pipeline Project	North Baja Pipeline LLC	CP22/24/25	Export	New	Appl	2002	230	215	500
									<i>Total 2002</i>		
									670	1,943	1,533
<b>Proposed 2003 Projects</b>											
CA	UT	Ruby Pipeline Extn	Colorado Interstate Gas Co	Not yet filed	Interstate	New	Ann	2003	400	850	750
CA	WY	Mainline 2003 System Expn	Kern River Transmission Co	Not yet filed	Interstate	Exp	Ann	2003	1,000	0	900
									<i>Total 2003</i>		
									1,400	850	1,650
<b>Proposed 2004 Project</b>											
OR	OR	Mist Storage Link Phase IV	Northwest Natural Gas Co	Not applicable	Storage Link	Exp	Appl	2004	23	20	145
									<i>Total 2004</i>		
									23	20	145
									<i>Total 2001-2004</i>		
									2,494	5,015	4,554

### Key to Abbreviations

Type of Project: Exp = Expansion

Status: Ann = Announced; Appl = Applied; Appr = Approved

Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database, as of May 2001.

### Interstate Pipelines Serving California

Since the beginning of 2001, at least six projects have been proposed to bring additional pipeline capacity into California. Two of these projects--the Kern River Transmission



Company 2001 Expansion (135 MMcf/d) and the El Paso Line 2000 Project (230 MMcf/d)-- are slated for completion this summer and therefore could have an almost immediate impact on the state's energy market. Currently, Kern River Transmission is delivering only about 500 MMcf/d into California although it is capable of delivering up to 750 MMcf/d (summertime capacity). The reason for this is that about 200 MMcf/d is being diverted to power plants in the Las Vegas area. To help rectify this situation, Kern River will expand its overall system especially north of Las Vegas, which will allow more gas to enter California. This "emergency" expansion is scheduled to be in service by June 2001, perhaps in time to help mitigate the expected high demand for natural gas during the upcoming summer months.

Most of the other proposals will not have an impact on the California capacity market until 2002 and beyond. Meanwhile, the interstate natural gas pipelines serving California have adequate capacity to meet current demand within the State, although all but Kern River and Mojave have been operating at full capacity much of the time during the past several months. The interstates have the capability to deliver more than 7.3 billion cubic feet per day to the State if needed. According to the California Energy Commission, the major in-state natural gas service providers, PG&E and SoCal Gas, are fully utilizing their receipt capacity at the State border.

Several of the interstate pipeline projects proposed to increase capacity to California will not terminate at the State border, but will extend into territories previously the domain of SoCal Gas. Questar's Southern Trails and Kern River Transmission's expansion proposal will both terminate in the Long Beach-Los Angeles area (although this segment of both projects is on hold due to an inability of both pipelines to interest customers who may be subject to price penalties from SoCal under current State-imposed restrictions).

Currently about 17 percent of California's gas demand is met from in-state production compared to 14 percent in 1998-99. Higher prices for natural gas have helped bring about a large increase in production within the State over the past several years (by more than 8 percent in 2000 alone). If this growth in production is sustainable then it should help alleviate the increasing demands placed on the interstate pipeline system. However, the other States in the region do not have this resource and are almost entirely dependent upon the interstate pipeline network for their natural gas supplies.

## **E. Conclusion**

Electricity outages for short periods of time would likely have only minimal effects on the natural gas supply and delivery system within California. All firm service contracts are expected to be met and production and storage operations will be relatively unaffected. Of concern are cost-related issues that affect production and storage stock builds. For example, California producers using enhanced oil recovery methods are particularly affected by high energy prices as their operations require both electricity and natural gas. As a result, some of these producers have curtailed operations. This is leading to reduced production of both oil and natural gas within the State, reduced cogeneration of electricity by these qualifying facilities, and therefore less electricity sold to the grid by these producers.

## 7. End Notes

[1] The States include: Washington, Oregon, California, Idaho, Montana, Wyoming, Nevada, Utah, Colorado, Arizona, and New Mexico. In addition, the western tip of Texas and portions of South Dakota and Nebraska are part the WSCC reliability council and Western Power Grid. However, the eastern edge of Montana and New Mexico are part of the Eastern Power Grid. The Provinces of British Columbia and Alberta and portions of the Mexican State of Baja California are also part of the WSCC.

[2] The State of California also oversees the Department of Water Resources and several transmission and public power agencies.

[3] The CAISO map depicts their coverage and it should be noted that the northern edge of California is physically overseen by utilities operating in Oregon.

[4] Public utilities - mostly municipals and cooperatives - were not required under California Assembly Bill 1890 to join the CAISO.

[5] The three investor-owned electric utilities are: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric.

[6] The associated percentages did not change much for public utilities and qualifying facilities. California Utilities Emergency Association and Department of Energy, Office of Critical Infrastructure Protection, *RED HEAT Interdependencies Workshop - Summary of Discussion and Key Issues* (Sacramento, CA, May 18, 2001), p. 4.

[7] Energy Information Administration calculated from data collected on the Form EIA-860 and EIA-860A.

[8] These reports include:

- California Energy Commission, *Summer of 2001 Forecasted Electricity Demand and Supply*, (Sacramento, CA, November 2000) ([http://www.energy.ca.gov/reports/2000-11-20\\_300-00-006.PDF](http://www.energy.ca.gov/reports/2000-11-20_300-00-006.PDF));
- California Independent System Operator, *California 2001 Summer Assessment*, (Folsom, CA, March 22, 2001) (<http://www.aiso.com/docs/09003a6080/0c/af/09003a60800cafcd.pdf>);
- Western System Coordinating Council, *Assessment of the 2001 Summer Operating Period*, (Salt Lake City, UT, Issued April 6, 2001, Revised April 13, 2001) (<http://www.wsc.org/files/wisrrptg.pdf>);
- North American Electric Reliability Council, *2001 Summer Assessment*, (May 2001, Princeton, NJ) ([ftp://www.nerc.com/pub/sys/all\\_updl/docs/pubs/summer2001.pdf](ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/summer2001.pdf));
- North American Electric Reliability Council, *2001 Summer Special Assessment*. (May 2001, Princeton, NJ). [ftp://www.nerc.com/pub/sys/all\\_updl/docs/pubs/summer2001-special.pdf](ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/summer2001-special.pdf)

[9] North American Electric Reliability Council, *2001 Summer Assessment*, (May 2001, Princeton, NJ). This evaluation included a review of available generating resources, determination of what electrical energy would be available from other members of the power grid to provide support for each other, and an examination of the rapid growth in electrical demand experienced in the Western States.

[10] North American Electric Reliability Council, *2001 Summer Assessment*, (May 2001, Princeton, NJ), p. 29.

[11] Air quality restrictions were expected to be relaxed in California but not the other Western States. For example, on June 12, 2001, California Governor Gray Davis signed an Executive Order to allow natural gas-fired power plants to operate in excess of their hourly, daily, quarterly and/or annual emission limitations if the additional power is sold to the California Department of Water Resources; serves a local load; or is sold to another California-based utility. The gas-fired plants must pay a mitigation fee to the local air districts of \$7.50 per pound of oxides of nitrogen (NO<sub>x</sub>) and \$1.10 per pound of carbon monoxide emitted. These mitigation fees will be used to clean-up or retire other sources of pollution in the same air basin. California Office of the Governor Press Release, "Governor Davis Signs Order Allowing Gas-Fired Power Plants to Operate at Maximum Levels" (Sacramento, CA., June 8, 2001).

[12] North American Electric Reliability Council, *2001 Summer Assessment*, (May 2001, Princeton, NJ), p. 29.

[13] Western System Coordinating Council, *Assessment of the 2001 Summer Operating Period*, (Salt Lake City, UT, Issued April 6, 2001, Revised April 13, 2001).

[14] California Energy Commission, *Summer of 2001 Forecasted Electricity Demand and Supplies*, (Sacramento, CA, November 2000).

[15] California Independent System Operator, *California 2001 Summer Assessment*, (Folsom, CA, March 22, 2001).

[16] North American Electric Reliability Council, *2001 Summer Special Assessment*. (May 2001, Princeton, NJ). The NERC report was released later than the CAISO report, so additional information was available for consideration in development of the findings.

[17] *Ibid*, p. 9.

[18] This is calculated after addressing net import assumptions, but before taking into account mitigating measures (interruptible load curtailments, demand relief programs, and conversion of non-spinning reserves to energy).

[19] Refer to the California ISO (<http://www.caiso.com/SystemStatus.html>) and Lawrence Berkeley National Lab (<http://energycrisis.lbl.gov/>) for current information on hourly electricity loads and other relevant data pertaining to California.

[20] The summer covers June through September or 2,928 hours.

[21] *Ibid*, p.13.

[22] *Ibid*, p.11.

[23] North American Electric Reliability Council, *NERC 2001 Summer Outlook for Electricity Reliability* Briefing, (Princeton, NJ, May 15, 2001) presented on May 14, 2001 in Washington, DC.

[24] Rapid changes in operating conditions will cause the CAISO to use the appropriate notice first. Minimum operating reliability criteria covers the sum of regulation and contingency reserves plus reserves covering interruptible imports and on-demand obligations to other entities or control areas.

[25] The pro-rated shares are based on the electrical distribution system respective ratios of: demand to total control area, demand at the time of control area annual peak, and demand for the previous year.

[26] If a statewide reduction was ordered, then 49.6 percent would be allocated to PG&E. PG&E itself would take responsibility for 79.2 percent of this share with the remaining being assigned in the following manner to: Sacramento Municipal Utility District-9.4 percent, Modesto Irrigation District-2 percent, SNCL-2 percent, Northern California Power Agency-3.8 percent, Turlock Irrigation District-1.4 percent, CCSF-0.8 percent, and the Western Area Power Administration-1.5 percent. For this same statewide reduction, the SCE portion is 42 percent. Then SCE would take responsibility for 93.9 percent of this share and the rest would be allocated to the Cities of Anaheim-2.6 percent, Riverside-2.4 percent, Colton-0.4 percent, Azusa-0.3 percent, Banning-0.2 percent, and to the Southern California Water Agency-0.2 percent. SDG&E and the Cities of Pasadena and Vernon, as noted above, would be assigned their 2001 ratio percentage. California Utilities Emergency Association and Department of Energy, Office of Critical Infrastructure Protection, *RED HEAT Interdependencies Workshop*, (Sacramento, CA, April 24, 2001), CAISO presentation.

[27] U.S. Department of Energy, "Report of the U.S. Department of Energy's Power Outage Study Team: Findings and Recommendations to Enhance Reliability from the Summer of 1999" (Washington, DC, March 2000); and U.S. Department of Energy, "Report to the President: Electric Power Outages in the Western United State, July 2-3, 1996" (Washington, DC, August 1996).

[28] This criteria of 1-day in 10-years will not be practical in California this summer and is effectively suspended.

[29] California Public Utilities Commission, *Energy Division Report on Interruptible Programs and Rotating Outages*, (San Francisco, CA, February 8, 2001), p.63.

[30] The CAISO will issue a 48-hour forecast for blackouts, then the electric distribution utilities will announce 24 hours in advance the areas that will be affected. One hour before the start of a blackout, the individual utilities will provide notification about the exact time and location of the blackout to its customers. This is part of the 3-tiered alert system that was implemented under the orders of Governor Davis of California. American Public Power Association, *Public Power Daily*, (Washington, DC May 25, 2001), p. 1.

[31] *Ibid*, pp.70-71.

[32] California Public Utilities Commission, *Energy Division Report on Interruptible Programs and Rotating Outages*, (San Francisco, CA, February 8, 2001), p. 72.

[33] The hours available for use in the interruptible program for Northern California were exhausted on May 31, 2001. For Southern California, there is only a limited amount of contracted load reduction that is expected to be available from Southern California Edison

and San Diego Gas and Electric customers. California Independent System Operator, *CAISO 2001 Summer Assessment*, (Folsom, CA, March 22, 2001), p. 10.

[34] California Energy Commission, *High Temperatures and Electricity Demand - An assessment of Supply Adequacy in California*, (Sacramento, CA, July 1999), p. 10. The Commission report indicates "staff have found a strong correlation between peak electricity demand and a buildup of high temperatures over several days."

[35] *Ibid*, p.11.

[36] *Ibid*.

[37] *Ibid*, p.18.

[38] *Ibid*, p.2.

[39] California Public Utilities Commission, Decision 01-04-006, Section 6.1.2, "Include Most Transmission Level Customers in Rotating Outages" (Sacramento, CA., April 3, 2001), pp. 46-48.

[40] The deadline for applications was June 4, 2001. Late applications will be accepted by CPUC until June 15, 2001, and will be considered by CPUC at a later time. California Public Utilities Commission Announcement, "Public Health and Safety Rotating Outage Exemption Application Process" (Sacramento, CA., May 21, 2001) (<http://www.rotating-outages.com/>)

[41] Richard Valdamis, "California Refiners Say May Drop Power If Output Cut," Reuters (New York, NY, June 5, 2001).

[42] Letter from David J. O'Reilly, Chairman and Chief Executive Officer Chevron Corp., to California Governor Gray Davis, June 1, 2001.

[43] California Office of the Governor Press Release, "Governor Davis Sends Letter Urging That Refineries Be Exempt From Rotating Outages" (Sacramento, CA., June 8, 2001).

[44] Refiners were asked in the survey, "How long would it take to rebalance the refinery and continue operations at normal production levels following an emergency shutdown of the facility? The assumption for this question is that no damage has resulted from the shutdown." Refiners generally gave a range of estimated time to restart and return to normal operating rates. The 7 to 14 days represents the median of the low and high estimates provided by refiners.

[45] California Public Utilities Commission, Decision 01-04-006, Section 5.8, "Optional Binding Mandatory Curtailment Program" (Sacramento, CA., April 3, 2001) pp. 37-40. Optional Binding Mandatory Curtailment plans: Southern California Edison, Cal. PUC Sheet No. 28821-E\*; and Pacific Gas and Electric Co., Cal. P.U.C. Sheet No. 18065-E\*.

[46] Refiners were asked in the survey if they "have plans for back-up generation capability for this summer?" Only one moderate exposure refinery had installed some backup capacity (1 MW). However, this backup capacity is not expected to be sufficient for the refinery to maintain normal operating rates during rotating outages.

[47] The Rhodia sulfuric acid regeneration plant in Martinez (San Francisco Bay area) has a 4 megawatt cogeneration unit that supplied about 90 percent of its electricity demand in 1999. Energy Information Administration, *Annual Electric Generator-Nonutility, Form EIA-860B Database*, 1999 (<http://www.eia.gov/cneaf/electricity/page/eia860b.html>). The Rhodia acid plant in Los Angeles, however, does not have cogeneration capacity and would likely have to shut down during a rotating outage in its service block.

[48] See for example, Energy Information Administration, *Assessment of Summer 1997 Motor Gasoline Price Increase*, Appendix E, DOE/EIA-0621 (Washington, DC, May 1998) (<http://www.eia.gov/FTPROOT/petroleum/0621.pdf>).

[49] Total natural gas consumption in 2000 was 22.7 trillion cubic feet, *Natural Gas Monthly*, DOE/EIA-0130(2001/04) (Washington, DC, May, 2001), Table 3. Total natural gas consumption in 1991 was 19.04 trillion cubic feet, *Annual Energy Review*, DOE/EIA-0384(00) (Washington, DC, July 2000), Table 6.5.

[50] Additional upward pressure was put on prices as a result of a disruption of flow along one segment of the El Paso Gas Co. system, but a combination of market adjustments, including alternate transportation, gas from storage, and fuel switching, avoided the occurrence of widespread shortages.

[51] According to the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, oil production in 1999 was 311.5 million barrels. Of that total, 193.6 million barrels was produced in 1999 using three enhanced oil recovery techniques: thermal-steam (143.9 million barrels), waterflood (45.1 million barrels) and gas injection (4.6 million barrels).

[52] Interstate pipeline companies that deliver gas to California are: El Paso Natural Gas Company, Transwestern Pipeline Company, Kern River Transmission Company, Mojave Pipeline Company, and Pacific Gas and Electric Gas Transmission - Northwest Pipeline Company and PG&E Transmission - Northwest Company.

[53] According to the California Energy Commission, in 1999 Canada supplied 28 percent of gas receipts in the State, the Southwest supplied 46 percent, and the Rockies supplied 10 percent. *California Natural Gas Market Analysis and Issues*, California Energy Commission, November 21, 2000.

[54] The California Energy Commission reports that a total of 7.0 bcf/d of interstate natural gas pipeline capacity reaches the California border. That figure differs from the 7.3 Bcf/d used by EIA within this report. Among the reasons for the difference is that the CEC does not include the pipeline capacity (110 MMcf/d) of the Tuscarora Pipeline System that receives supplies from the PG&E Gas Transmission - Northwest pipeline at Malin, Oregon, for delivery to Nevada via California. In addition, the Commission reports a lower figure than EIA's 1,970 MMcf/d for PG&E at Malin, Oregon, and for Transwestern Gas Company's deliverability at Topock. Except for the Tuscarora omission, the differences reported between EIA and the CEC are attributable mainly to seasonal capacity variations and to some minor differences in pipeline data compiled by EIA compared with the CEC.

[55] California Energy Commission, "Natural Gas Infrastructure Issues", Draft, May 2001.



[56] In 1999, gross withdrawals of natural gas (defined as full well-stream volume, including all natural gas plant liquids and all nonhydrocarbon gases, but excluding lease condensate) from oil wells was 342 billion cubic feet and from gas wells was 90 bcf. Marketed production represents gross withdrawals less gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations. (Natural Gas Annual 1999, DOE/EIA-0131(99), October 2000) A significant portion of the oil produced in California is heavy oil (20 degrees gravity or less) produced through enhanced oil recovery (EOR) steam methods.

[57] Also known as working gas inventory.

[58] Weekly storage data are available for three regions in the U.S. - the Producing Region, the Consuming East Region and the Consuming West Region. The Consuming West Region consists of all states west of the Mississippi River less Texas, Oklahoma, Kansas, New Mexico, Louisiana, Arkansas, Mississippi, Alabama, Iowa, Nebraska and Missouri.

[59] Projections for California presented in this section are illustrative and are based on statistical analysis of the relationships between State gas demand data and State economic and weather data collected by the Energy Information Administration, the Bureau of Economic Analysis, the Census Bureau, and Bureau of Labor Statistics. Weather is assumed to be at normal levels in the State this summer. Hydroelectric power availability in the Pacific Census Division (California, Washington, Oregon) is taken from EIA's May 2001 Short-Term Energy Outlook. The analysis was performed by EIA's Office of Energy Markets and End Use.

[60] *Public Utilities Fortnightly*, March 1, 2001 "Gas and the Power Crises: Chicken or the Egg?"

[61] The average spot price at the SoCal citygate was \$59.42 per million Btu (*Gas Daily*, December 12, 2000).

[62] Blackouts Crimp California Crude Production, *Oil Daily* (May 9, 2001).

[63] According to industry sources, for some independent producers in the State, electricity accounts for up to 60 percent of production costs. (California Independent Producers Association).

[64] Some wells are under enough pressure that the oil and gas will flow freely from them without a pump or lifting system. There are only a small number of these formations, and even these usually require a lifting system at some point in their active lives. Most wells, however, require some sort of lifting method to extract the oil and gas present in their formations. The lifting method depends on the depth of the well and whether or not the well has multiple completions. Lifting requires motor-driven pumping. (<http://www.naturalgas.org/Product.htm>)

[65] Natural gas is processed in some manner to remove unwanted water vapor, solids and/or other contaminants that would interfere with pipeline transportation or marketing of the gas. In addition, and equally important, most natural gas is processed to separate from the gas those hydrocarbon liquids that have higher value as separate products. The casinghead gas and/or gas-well gas must be gathered, treated in the field, compressed and



pipelined to a central facility for the final processing that will produce pipeline quality natural gas and marketable natural gas liquids.

[66] Blackouts Crimp California Crude Production, *Gas Daily* (May 9, 2001).

[67] Based on conversations with Mr. Rusty Cates, International Gas Consulting, and staff at the California Energy Commission and Gas Technology Institute.

[68] Electricity is also used for supervisory control and data acquisition (SCADA) systems which are remote controlled equipment used by pipelines and LDCs to operate their gas systems. These computerized networks can acquire immediate data concerning flow, pressure or volumes of gas, as well as control different aspects of gas transmission throughout a pipeline system.

[69] Natural gas is compressed during transportation and storage. The standard pressure that gas volumes are measured at is 14.7 Pounds per Square inch (psi). When being transported through pipelines, and when being stored, gas is compressed to save space. Pipelines have compressing stations installed along the line (one about every 100 miles) to ensure that the gas pressure is held high while the gas is being transported. Current pipelines can compress natural gas to nearly 1500 psi, but most tend to operate at closer to 1000 psi.

## 8. Contacts

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