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WSPA Comment Letter Appendix 02 - Historical Record of 2002-2003 Strategic Fuel Reserve Assessment

Appendix 02: WSPA is submitting the entire available record of the CECâ€™s 2002-2003 Strategic Fuel Reserve Assessment because it is no longer available on the CECâ€™s website. The record contains significant and detailed information that should be helpful to the public in understanding the breadth and complexity of the issues. We believe the public deserves to know about and to be able to review in detail the diverse and technically sophisticated analyses that were conducted in order to support the conclusions that the Commissioners reached at the time, i.e., that a SFR would not serve the interests of the consumers of the State of California.

Additional submitted attachment is included below.

CALIFORNIA ENERGY COMMISSION

CALIFORNIA STRATEGIC FUELS RESERVE

CONSULTANT REPORT

MARCH 2002
P600-02-004CR

Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

Prepared By:
Stillwater Associates, Inc.
3 Rainstar
Irvine, CA 92614
Contract No. 500-00-002

Prepared For:
Sherry Stoner
Contract Manager

Gordon Schremp
Project Manager

Pat Perez
Manager
Transportation Fuel Supply & Demand Office

Nancy Deller
Deputy Director
Transportation Energy Division

Steve Larson
Executive Director

DISCLAIMER

ACKNOWLEDGEMENTS

This report is the result of a cooperative effort between key staff personnel of the California Energy Commission and Stillwater Associates acting as their contractor. In particular, the authors would like to thank Messrs. Gordon Schremp and Ramesh Ganeriwal of the California Energy Commission for their invaluable contributions and insights, without which this study would not have been possible.

Valuable contributions to this report were also made by Anthony J. Finizza, Ph.D., who contributed his insights on the market dynamics and price elasticity, as well as the economic impact of market shortages on the California economy, and by J. Drew Laughlin, who provided the US Gulf Coast supply perspective with regard to California's supply/demand balance for transportation fuels.

Equally, this study is based in large part on information received during meetings with industry stakeholders, such as the California refiners, representatives of the international trading community, independent marketers, trade associations, government organizations such as the State Lands Commission and Port Authorities. The authors wish to thank all those who readily volunteered information and opinions, for their contributions and the openness with which information was shared.

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GLOSSARY

ANS	Alaska North Slope, term used to designate crude oil of that region
ARB	Air Resources Board
CAA	Clean Air Act of 1977
CAAA	Clean Air Act Amendments of 1990
CAAA Title V	Section of the CAAA requiring Operating Permits, promulgated in 1992
CARB	California Air Resources Board
CARBOB	California Reformulated Gasoline Base Oxygenated Blendstock
CEC	California Energy Commission
CMAI	Chemical Markets Associates, Inc.
cpg	Cents per Gallon
CSLC	California State Lands Commission
EIA	Energy Information Agency
EPCA	Energy Policy and Conservation Act of 1976 as amended
ETBE	Ethyl Tertiary Butyl Ether, an oxygenate produced from ethanol and isobutylene
FCC	Fluidic Catalytic Cracker, primary gasoline producing unit in a refinery
IEA	International Energy Agency
Jobber	Independent distributor of petroleum products
MB	Thousand barrels
MOTERP	Marine Oil Terminal Engineering Regulations Project of the CSLC
MTBE	Methyl Tertiary Butyl Ether
NHOR	Northeast Heating Oil Reserve
NYMEX	New York Mercantile Exchange
OPA 90	Oil spill Prevention Act of 1990
OPIS	Oil Price Information Service
p.a.	Per annum
PADD	Petroleum Administration for Defense District. PADD V includes Hawaii, Alaska, Washington, Oregon, California, Arizona and Nevada
PoLA	Port of Los Angeles
PoLB	Port of Long Beach
RFG	Reformulated Gasoline meeting the requirements of the CAAA
RVP	Reid Vapor Pressure, a measurement of the volatility of gasoline
SARA	Superfund Amendments and Reauthorization Act of 1986
SCQAMD	South Coast Air Quality Management District
SFR	Strategic Fuels Reserve

TBD	Thousand Barrels per Day
TEU	Twenty-foot Equivalent Unit, standard used for cargo containers
TPY	Ton Per Year, usually referring to US short tons of 2000 lbs
USGC	US Gulf Coast
VLCC	Very Large Crude Carrier, a tanker capable of carrying 1.5 – 2 million barrels
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compound(s), and emissions thereof

CHARTER

In 1999, following a series of refinery outages that caused significant price spikes in the California fuels markets, the Attorney General's office created a taskforce to investigate causes and recommend solutions to prevent recurrence. The efforts of this taskforce resulted in Assembly Bill 2076, which called for the California Energy Commission:

> "..to examine the feasibility of operating a strategic fuel reserve and to examine and recommend an appropriate level of reserves. If the commission finds that it would be feasible to operate such a reserve, the bill would require the commission to report this finding to the Legislature and request specific statutory authority and funding for establishment of a reserve."

The bill also provided general directions for the work to be performed

> (a) By January 31, 2002, the commission shall examine the feasibility, including possible costs and benefits to consumers and impacts on fuel prices for the general public, of operating a strategic fuel reserve to insulate California consumers and businesses from substantial short-term price increases arising from refinery outages and other similar supply interruptions. In evaluating the potential operation of a strategic fuel reserve, the commission shall consult with other state agencies, including, but not limited to, the State Air Resources Board.
>
> (b) The commission shall examine and recommend an appropriate level of reserves of fuel, but in no event may the reserve be less than the amount of refined fuel that the commission estimates could be produced by the largest California refiner over a two week period. In making this examination and recommendation, the commission shall take into account all of the following:
>
> (1) Inventories of California-quality fuels or fuel components reasonably available to the California market.
>
> (2) Current and historic levels of inventory of fuels.
>
> (3) The availability and cost of storage of fuels.
>
> (4) The potential for future supply interruptions, price spikes, and the costs thereof to California consumers and businesses.
>
> (c) The commission shall evaluate a mechanism to release fuel from the reserve that permits any customer to contract at any time for the delivery of fuel from the reserve in exchange for an equal amount of fuel that meets California specifications and is produced from a source outside of California that the customer agrees to deliver back to the reserve within a time period to be established by the commission, but not longer than six weeks.
>
> (d) The commission shall evaluate reserve storage space from existing facilities.
>
> (e) The commission shall evaluate a reserve operated by an independent operator that specializes in purchasing and storing fuel, and is selected through competitive bidding.

This Study was performed within the specific framework of the Legislation, to answer as a minimum the questions asked, by the stated deadline. In addition, in cooperation with the consultant retained by the Commission for this study, Stillwater Associates of Irvine, CA, the Commission deemed it appropriate to evaluate other factors that contribute significantly to the volatility of California's fuel markets, such as breakdowns in market mechanisms for gasoline, and the inadequacy of the logistics infrastructure serving the fuels market.

APPROACH

The approach taken by Stillwater and the CEC for this study is to:

(i) Conduct a survey amongst industry stakeholders, such as refiners, traders, logistic survey providers, and other concerned parties such as industry associations representing independent gasoline marketers, port authorities, and market intelligence providers. The purpose of the survey was not only to gather relevant information and data such as supply and demand factors, but also to gain a full understanding of market mechanisms and barriers to entry that contribute to the price spikes that a reserve aims to prevent.

(ii) Using the requirement of AB2076 for two week's capacity of the largest refinery as the basis, evaluate requirements for the reserve other than size, and with these, derive such factors as optimal location, infrastructure needs, and costs for several options meeting the initial requirements. Since the study did not include funding of actual engineering work, costs are treated at order of magnitude levels only.

(iii) Evaluate the effectiveness of the selected options for the reserve in terms of their anticipated capacity to mitigate price spikes in the California fuel markets due to unplanned refinery outages, using historical statistical data to predict the probability and duration of occasions when reserve volume would be drawn down. If warranted by the predicted effectiveness, adjust the design reserve volumes from the suggested two week's capacity basis and reiterate.

(iv) Using insights gathered during the survey meetings, design release mechanisms for the reserve volumes, also taking into account experience gathered with strategic reserves operated elsewhere.

(v) Develop derivative opportunities such as using a reserve to create forward liquidity in the California fuel markets.

(vi) Evaluate next steps and implementation plans, and identify potential barriers to implementation, such as delays in permitting processes.

(vii) Collect feedback from the industry in an open forum workshop, and adjust where necessary the recommended alternatives.

(viii) Present the final conclusions and recommendations to the legislature.

Initially, it was assumed that this study would be based on a supply/demand scenario for which the issue of the impending phase out of MTBE in terms of timing and impact would have been resolved. When it became clear that additional efforts would be required to provide decision tools for this critical issue, the CEC charged Stillwater Associates to conduct a parallel study specifically focused on the MTBE phase out.

Where necessary for the sake of clarity and consistency, the reports issued by Stillwater Associates for this Strategic Fuels Reserve Study and the MTBE Phase Out Study make extensive use of the same materials.

EXECUTIVE SUMMARY

The initial phase of the study consisted of interviews and survey meetings with a total of 44 oil industry participants, including major refiners, suppliers from outside the State, traders, independent retailers, logistic service providers and other stakeholders. The primary conclusions from these meetings are that:

(i) Overall, the industry opposes the concept of a state-run reserve and fears that the existence of a reserve may be counterproductive to resolving long-term supply/demand imbalances.

(ii) If a reserve is to be created, the industry strongly prefers that it will not use already scarce existing storage, is privately operated, has clear and fair release mechanisms, and is deployed in such a way as to improve import opportunities and market liquidity.

(iii) The California gasoline market suffers from insularity caused by its unique specifications, a subsequent lack of liquidity, inability to lock in future pricing, and impediments to market entry by outside sources. These factors contribute significantly to price volatility, in addition to the supply interruptions identified as a cause of price spikes in the legislation that led to this study.

(iv) California's infrastructure for petroleum products, comprising of pipelines, terminals and dock facilities, has insufficient capacity to handle current and anticipated demand. Capacity additions are hampered by lengthy and costly permitting procedures, and by policies practiced by the ports that favor other land uses over bulk liquid storage.

Subsequent work confirmed that:

(v) The output of California's refineries has not been able to keep up with demand growth in recent years and the State has become a net importer of all categories of petroleum products. Moreover, the outlook is that permitting restraints will make it more difficult for refiners to continue to realize small gains in production capacity, which have averaged approximately 1% per year since 1995, when refineries first started to run at or near maximum sustainable operating rates.

(vi) The growing import dependency is met primarily through foreign imports, with supplies from the US Gulf coast refineries stagnating because this capacity is fully utilized serving other US markets, while Jones Act shipping capacity is unavailable and faces significant further reductions as single hull product tankers are phased out.

(vii) Not only are foreign imports of gasoline and blending components indeed constrained by lack of tank capacity in marine terminals, but in addition significant commercial barriers exist because of lack of hedging opportunities which forces importers to incur significant risk in the volatile California markets.

(viii) Additional barriers to entry are also formed by the Unocal patents, which discourage traders or independent importers from attempting to bring finished products to the market, leaving only the California refiners capable of blending around the patent or absorbing the cost of licensing fees. The detrimental effects of the Unocal patents extend also to loss of production capacity, because refinery streams that might have been accretive to the gasoline pool are diverted to avoid patent infringement, while blending around the patent results in gasoline qualities that have sub-optimal emission performance.

(ix) The chronic shortage of gasoline in the California market will be aggravated to unprecedented levels by the proposed phase-out of MTBE by year-end 2002, in particular in the LA Basin. The prognosis is that a temporary shortfall of 5 to 10% will result, causing prices in California to rise to double that of world markets. This in turn will attract other supplies, and prices are expected to level off at premiums over world markets of 20 – 30 cents per gallon.

(x) Under this scenario, the impact of temporary supply disruptions caused by refinery outages will be significantly more pronounced, since some of the initial price elasticity has already been absorbed.

(xi) The expectation is that the import dependency and chronic undersupply will cost gasoline consumers in California between $3 – 5 billion per year over what they would pay in a market where supplies are unrestrained. In addition, it is expected that on average, one major and several smaller supply disruptions will occur every year, resulting in a temporary price spikes that add another $1 billion to California's collective gasoline bill. It is estimated that for the largest part, the incremental revenues from gasoline sales will flow to energy companies outside the State.

The recommendations formulated at this stage are:

(xii) The State of California is to issue a tender for the creation of 5 million barrel of versatile petroleum product storage under long-term lease agreements, 3 million of which would be in the LA basin and 2 million in the Bay Area. In both locations, this storage is to be provided with deepwater access and connections to the main product distribution pipeline systems.

(xiii) The 5 million barrels is twice the proposed volume of actual reserves, and as part of the storage lease agreements, the State will require the contract operator of this tankage to sublease half of the new capacity to interested third party market participants under short-term contracts, with the State only providing a minimal guarantee in case storage is not occupied for a certain amount of time.

(xiv) The State of California will purchase 2.5 million barrels of gasoline and gasoline blending components to form the basis for a Fuels Bank, from which qualified industry participants can withdraw volumes against a fee, with an obligation to re-supply the borrowed volumes within an agreed time span. Potentially, some of the State's obligations to purchase power can be exchanged for purchases of fuels using hedging and exchange mechanisms to offset corresponding intrinsic energy values.

(xv) The fee for the temporary usage is to be determined in daily electronic auctions, whereby the qualified participants can bid for the privilege of the time value of the product. Minimum fees should be set such that the operational cost of maintaining the State's share of the inventories is largely covered. In times of shortage, i.e., when a refinery outage has been announced, these fees can be expected to be bid up sharply, but as a derivative, their overall impact on the cost of supply is expected to be considerably less than run ups in the price itself in times of shortage.

(xvi) In this way, not only is a reserve created that will suppress price excursions in a cost effective way, with savings to California gasoline consumer far outweighing the cost to the taxpayer, but a physical delivery point and hedging mechanism is created that will facilitate imports and significantly reduce the State's risk of import dependency for its transportation fuels.

1 CALIFORNIA FUELS MARKET

The California market for petroleum products is insular in nature, isolated from the main US continental markets by the Rocky Mountains to the East and from most other major fuels markets by the Pacific Ocean in the West. The geographical isolation is aggravated for gasoline and diesel by the unique fuel specifications that were mandated by the State in the past decade to protect its air quality, a process that is still continuing with the anticipated introduction of CARB Phase III reformulated gasoline specifications in the near future.

Even within the California market, a certain amount of insularity occurs. The Northern California market, with the Bay Area as it main center, and the Southern market structured around Los Angeles, are not linked by pipelines for petroleum products and behave in many ways semi-autonomously. A third production center around Bakersfield has only limited capacity for gasoline and distillates. Within the San Joaquin Valley, other insular niche markets exist such as the markets for diesel in agricultural centers. External and internal insularity are major factors when evaluating the effectiveness and optimal locations for an eventual Strategic Reserve.

In the past California exported small excess quantities of certain fuels. In recent years however, the State has become a net importer of all petroleum products including finished gasoline, blend stocks, diesel and jet fuel, and the State's shortfall is expected to increase significantly over the coming years[1]. The State receives limited supplies from refiners in nearby Washington, but California has to cover the bulk of its shortfall of petroleum products with imports from remote sources such as the US Gulf Coast, the Canadian East Coast, the Caribbean, Europe, Asia, and the Middle East. It is important to note that the shortfall is not only caused by demand for fuels within the State, but that the California refiners also supply markets in Nevada and parts of Arizona, including fast growing population centers such as Las Vegas and Phoenix.

The proposed phase out of MTBE, currently scheduled for year-end 2002, concurrent with the introduction of the more stringent CARB Phase III requirements, will cause a reduction in supplies by 5 to 10%. This shortfall will predominantly affect the LA Basin market and is as yet not covered. Even if available import sources were to be identified within the global refinery network, the State would lack the infrastructure to handle a diverse mixture of blending components. Under scenarios in which the State is chronically undersupplied, the volatility of fuel pricing can be expected to grow progressively worse. Below, supply and demand will be analyzed for several scenarios, in particular with regard to imbalances that will increase price volatility and hence, the value of an eventual SFR.

[1] *Energy Outlook 2020*, California Energy Commission Staff Report, Docket No. 00-CEO-Vol II, August 2000

1.1 Current Supply

Forecasting the supply of clean petroleum fuels into California requires an analysis of its refineries and their capability for expansion, and an evaluation of import opportunities in terms of sources, logistical infrastructure and economical feasibility.

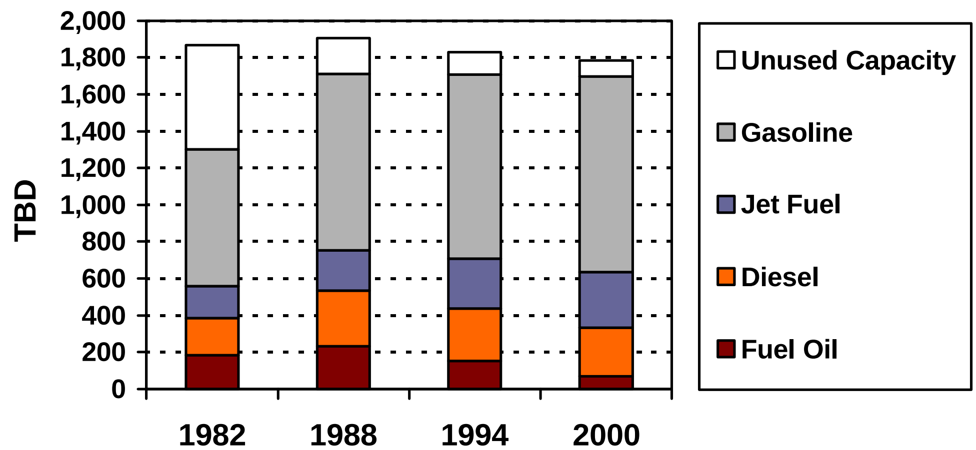
1.1.1 Refining Capacity in California

Historically, two factors have contributed to rationalization and concentration of refining capacity in California:

- The deregulation of the markets for petroleum products in 1981[2], which accelerated the closure of many uneconomic refineries nationwide.
- The requirements of the Clean Air Act Amendments (CAAA) of 1990, which for several refineries could not be achieved economically.

The concentration of production that took place from the mid 80-ies through the mid 90-ies has not only resulted in high utilization rates of remaining capacity, but the investment programs to meet the requirements of the CAA and subsequent amendments also led to a significant increase in gasoline production of lighter components at the expense of heavy fuel oil. As a result, the remaining gasoline-producing refineries in California are highly sophisticated full conversion facilities.

Figure 1.1 – CA Refinery Capacity Utilization[3]



[2] Executive Order 12287, Providing for the Decontrol of Crude Oil and Refined Petroleum Products, Jan 28, 1981.

[3] Source EIA and CEC data. Stream day capacities.

Figure 1.1 shows how since the mid 90-ies, unused refining capacity in California is less than 5%, indicating that all remaining refineries in California have essentially been running at the maximum practically feasible operating rate given the average age and the mechanical complexity of the installations. It also shows that the remaining refining capacity is predominantly geared towards production of gasoline at the detriment of fuel oil output, as a result of heavy investments into cracking and coking capacity in the late 80-ies and early 90-ies.

Out of the 15 refineries currently operating in California, only 12 facilities, owned by 7 companies, are capable of producing California specification gasoline and diesel. The capacities of these refineries are summarized below in Table 1.1 below.

Table 1.1 – California Fuels Production 1995-2001[4]

TBD	1995	1996	1997	1998	1999	2000	2001
NORTHERN CA							
CARB RFG	48.4	320.1	381.3	387.0	369.1	392.2	402.0
Oxygenated Gasoline	106.1	22.1	0.2	-	-	-	-
Other Finished Gaso	277.1	110.6	62.9	68.7	33.5	51.7	58.3
CARB Diesel	128.8	126.5	133.0	2.2	81.8	104.9	115.4
EPA Diesel	n/a	n/a	n/a	115.3	30.1	19.0	22.5
High S Diesel	19.2	15.1	4.3	2.4	7.7	8.1	5.2
Jet Fuel	97.0	111.6	111.5	102.0	84.5	94.5	101.4
SOUTHERN CA							
CARB RFG	405.1	464.4	493.2	399.0	584.9	548.6	552.3
Oxygenated Gasoline	3.6	-	0.8	n/a	3.9	5.5	3.1
Other Finished Gaso	126.3	71.6	61.5	65.9	52.9	52.5	40.2
CARB Diesel	122.7	125.1	127.3	1.7	56.8	69.4	74.1
EPA Diesel	n/a	n/a	n/a	139.6	102.4	76.8	81.4
High S Diesel	19.8	19.4	12.8	10.8	4.6	6.3	1.5
Jet Fuel	148.2	169.0	164.4	157.4	143.6	149.4	139.0
TOTAL CA							
CARB RFG	453.4	784.5	874.5	786.0	954.0	940.8	954.4
Oxygenated Gasoline	109.7	22.1	1.1	n/a	3.9	5.5	3.1
Other Finished Gaso	403.4	182.2	124.4	134.6	86.4	104.2	98.5
CARB Diesel	n/a	n/a	n/a	3.9	138.6	174.3	189.5
EPA Diesel	n/a	n/a	n/a	254.9	132.5	95.8	103.9
High S Diesel	39.1	34.4	17.0	13.3	12.3	14.4	6.8
Jet Fuel	245.2	280.6	275.9	259.3	228.1	243.9	240.4

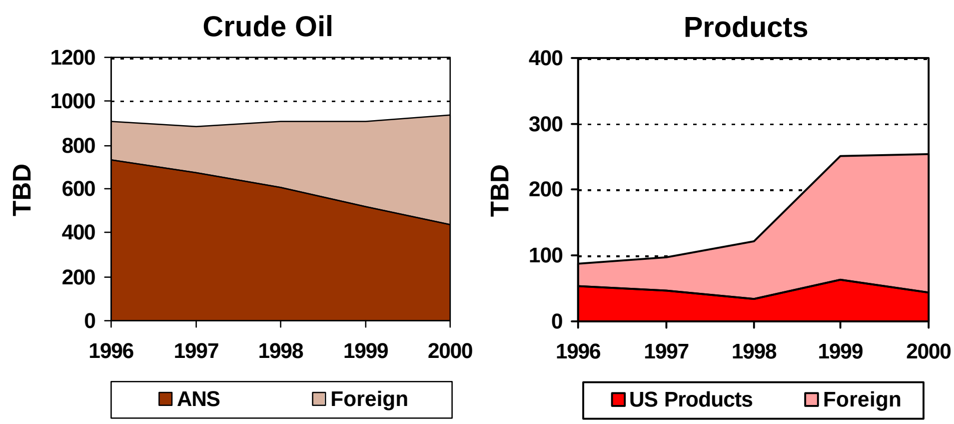
The production numbers for gasoline cited in Table 1.1 include blending components and unfinished gasoline blend stocks imported by the refineries. These imports play an increasingly important role in the refiner's abilities to meet California's fuels demand, and a detailed analysis of the imported petroleum products will be provided below.

[4] Data from CEC weekly reported production numbers.

1.1.2 Imports of Petroleum Products

In the past, California was a net exporter of petroleum, either as crude oil or as refined distillates and partially refined feedstocks. In recent years however, internal demand has grown, and even though the refineries have become more sophisticated as California crude oil production has declined, the net effect is that imports of both crude oil and refined products have grown substantially, making the State a significant net importer of foreign crude and petroleum products, as shown in Figure 1.2.

Figure 1.2 – CA Foreign Imports of Crude & Products



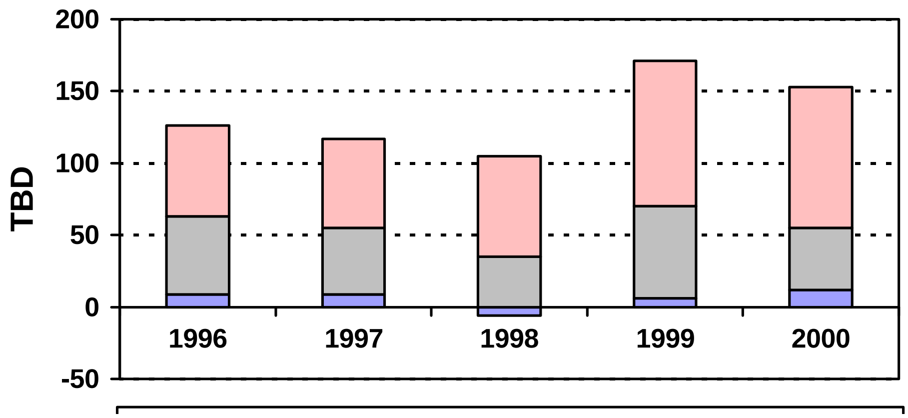
Over the past 5 years, imports of foreign crude oil into California have effectively tripled, from about 177 TBD in 1996 to nearly 500 TBD in 2000. While refinery crude runs have been nearly constant, the increased foreign imports are replacing both Alaska North Slope crude (ANS), as well as California crude production. The impact of the increased imports of foreign crude is relevant for the need to create a Strategic Fuels Reserve because:

- Foreign crude is sourced increasingly from remote locations such as the Middle East, requiring Very Large Crude Carriers (VLCCs) to achieve economical freight rates. The logistics of receiving larger cargoes from more remote locations increases the risk of supply disruptions.

- At many terminals and refineries, crude and product receipts share common infrastructure such as docks, transfer lines and sometimes even tankage. The additional maritime receipts of crude oil create an additional strain on product import capabilities.

Net product imports have grown from a small volume that resulted as the net sum of almost balancing imports and exports, to more than 220 TBD of net imports. Figure 1.3 shows the details of net imports by product category and origin.

Figure 1.3 – CA Imports of Petroleum Products [5]



*** Components include oxygenates such as MTBE, ETBE, etc**

As can be seen from Figure 1.3, the increase in imports is most significant in jet fuel, but in all major fuel categories including diesel and miscellaneous other fuels (fuel oil, distillate blendstocks, lube stocks and additives), California has become import dependent, with gasoline and gasoline blending components forming the largest import category.

Imports of petroleum products are a function of refinery performance and regional demand. The California refineries operated reliably in 1998, but significant refinery problems were encountered in 1999. The large increase in imports from 1998 to 1999 as seen in Figure 1.3 reflects this difference in refinery performance. The underlying trend is an annual increase in waterborne imports of petroleum products in California of 30 TBD per year, or approximately 1.6% per year of the total fuels capacity of the State's refineries.

Figure 1.3 also shows that, while in 1996 California still was a net exporter of distillates and miscellaneous refined products, it now has a net import requirement in all product categories. Moreover, while in 1996 foreign imports accounted for approximately 50% of California's imported shortfall of gasoline and blending components, by 2000 the share of foreign imports had grown to almost 70%.

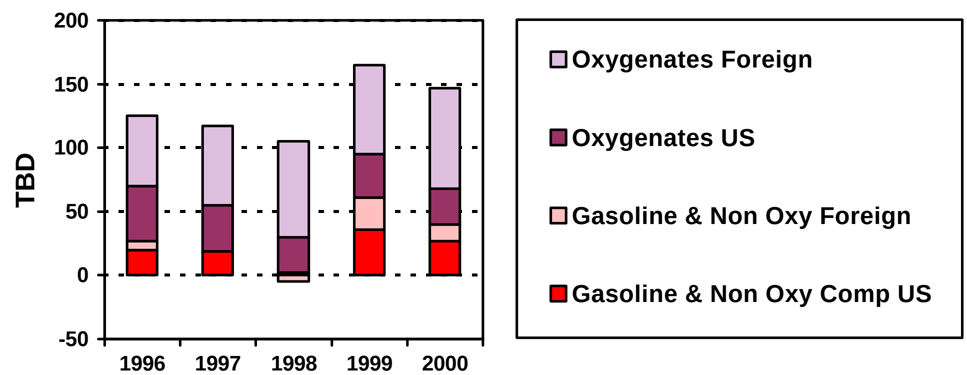
[5] Based on EIA data and Port Statistics collected by the US Army Corps of Engineers

Gasoline imports peaked at about 66 TBD in 1999, and remained at high levels in 2000. Although better refinery performance in 2000 was one of the reasons that import volumes leveled off after peaking in 1999, other factors also played a significant role in limiting imports in 2000:

- Refinery capacity in the US Gulf Coast tightened up substantially, reducing the availability of blending components from one of the major export centers.
- Jones Act shipping capacity became further restricted as first OPA 90 vessel retirements started.
- California terminal capacity capable of receiving waterborne imports became increasingly hard to find, and in several instances, importers were unable to offload cargoes.

The imports into the gasoline pool are a combination of finished gasoline, blending components and oxygenates. Components include alkylate, naphtha, reformate, raffinate, and natural gasoline. Oxygenates in the form of MTBE and ethanol make up the largest part of the imported shortfall of gasoline in California, with MTBE representing over 90% of these volumes. Indigenous Californian production of MTBE, TAME and ethanol is less than 12 TBD, underscoring the import dependency of California for this fuel additive. Figure 1.4 shows gasoline imports by component.

Figure 1.4 – CA Gasoline and Component Imports [6]



As can be seen in Figure 1.4, foreign imports accounted for approximately 50% of California's imported shortfall of gasoline and blending components in 1996. By 2000,

[6] Based on EIA data and Port Statistics collected by the US Army Corps of Engineers

the share of foreign imports had grown to 70%, and it is important to note that in fact, the entire increase in California's imports of gasoline over the period has been met by foreign imports rather than imports from other US refining centers.

The increasing dependency on foreign imports represents significant exposure for the future capability to keep the State supplied with gasoline because only a limited number of foreign refineries is capable of producing CARB spec fuels, and this number will shrink even further as some of these refiners will not be able to produce CARB Phase III CARBOB. To the foreign refiners, exports to California are only an incidental occurrence with uncertain margins given the shipping delays, the volatility of the Californian market, and the lack of a futures market. Under these conditions, it is difficult for these refiners to justify investments in the necessary upgrades.

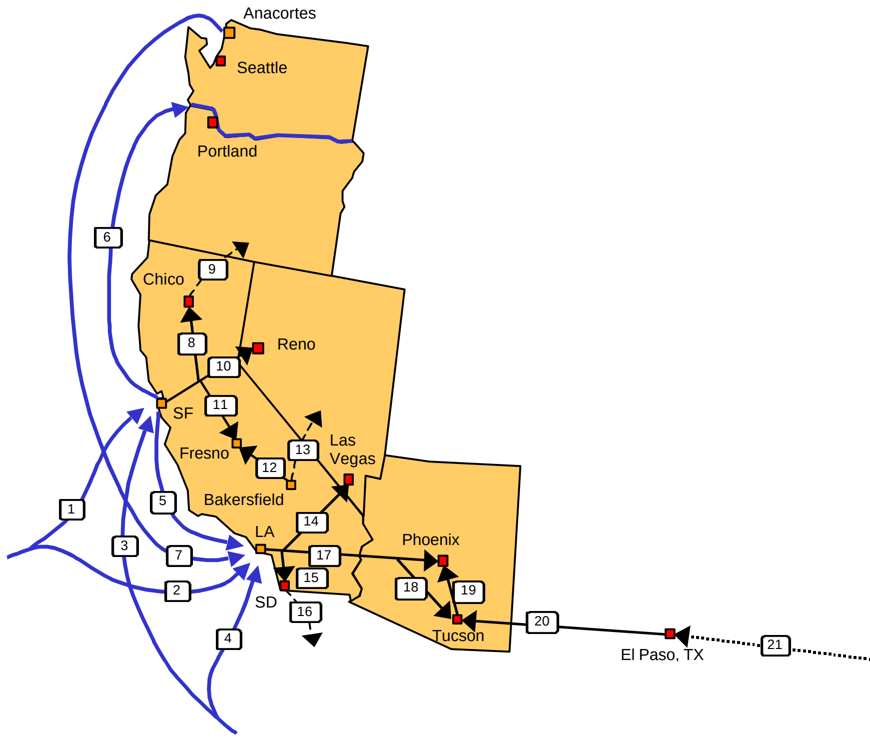
1.1.3 Interstate Product Movements

The import volumes shown in Figure 1.4 for the West Coast represent the balance of imports and exports to the Pacific Coast states, which have a considerable volume of petroleum movements between the various producing and consuming enclaves. Refineries in the Bay Area ship conventional gasoline to the Pacific Northwest, primarily to Portland, OR. The refineries on Puget Sound send somewhat larger volumes of reformulated gasoline or components down to San Francisco or Los Angeles by tanker or barge.

Besides maritime imports, pipeline and truck movements play an important role in the supply of California and the neighboring states for which California refineries provide a significant share of their fuels demand. There are two major pipeline systems, both owned and operated by Kinder Morgan Energy Partners LLC, one exporting products from the Bay Area refiners to Northern and Central California, as well as Northern Nevada, and the other taking products from the LA Basin refiners to Southern California, Southern Nevada and Arizona.

Kinder Morgan also owns a pipeline system that moves products produced in Texas and New Mexico from El Paso to Tucson and Phoenix. Capacity on this system is oversubscribed, and capacity for users of this line is prorated. Figure 1.5 gives an overview of movements on product pipelines and other means of transportation between California and its neighboring states. Numbers are for the year 2000 and are based on data obtained from EIA, CEC and the US Army Corps of Engineers.

Figure 1.5 – CA 2000 CA Product Movements



Year 2000, TBD	Gasoline	Diesel	Jet
1 Foreign Imports into N-CA	29.8	0.6	13.0
2 Foreign Imports into S-CA	68.4	19.0	71.9
3 PADD III Imports into N-CA	6.8	n/a	n/a
4 PADD III Imports into N-CA	22.1	n/a	n/a
5 Ship/barge SF to LA	24.5	31.1	n/a
6 Ship/barge SF to Portland	28.0	2.7	n/a
7 Ship/Barge WA to LA	38.0	16.2	n/a
8 Kinder Morgan SF to Chico	17.6	n/a	n/a
9 Truck Chico into S-OR	0.4	0.5	n/a
10 Kinder Morgan SF to Reno	17.3	13.2	5.6
11 Kinder Morgan SF to Fresno	n/a	n/a	n/a
12 Kinder Morgan B'field to Fresno	n/a	n/a	n/a
13 Truck Bakersfield to W-NV	2.5	5.0	n/a
14 CALNEV LA to Las Vegas	45.9	32.3	32.7
15 Kinder Morgan LA to San Diego	n/a	n/a	n/a
16 Truck SD to Mexico	n/a	n/a	n/a
17 Kinder Morgan LA to Phoenix	60.9	28.4	29.5
18 Kinder Morgan LA - Tucson	4.1	2.6	0.5
19 Kinder Morgan El Paso - Phoenix	41.0	3.2	3.6
20 Kinder Morgan El Paso - Tucson	28.0	7.4	4.9
21 Longhorn	n/a	n/a	n/a

1.1.4 Supply Reliability Factors

When refiners state calendar day capacity (actual expected annual production divided by 365 days) and stream day capacity (highest operating rate sustainable on a single day), the difference for major refinery units such as distillation or cracking is typically around 5%. This means that refiners expect that on average, these installations will be out of service for 18 days per year for scheduled inspections, preventive maintenance, operational activities such as catalyst changes, and project work. Since 1995, the California refineries have been running at operating rates equal to 95% of published nameplate capacity, which means that effectively, they have been running as close to their maximum sustainable rates as can be expected, given the age and complexity of the installations, and this operating record reflects favorably on the skill level and experience of operating personnel and refinery management.

Nevertheless, unplanned outages occur, sometimes for reasons that are completely outside the scope of control of the refinery management. For all of California's refineries combined, evidence was found in publicly available information that in the last 6 years, at least 54 outages occurred with measurable effect on production capacity. Of these, most are relatively minor events, with a production loss averaging 20 TBD over a period of less than 4 weeks. However, over this period there were 7 major events involving production losses ranging from 50 to 160 TBD and lasting up to 8 weeks.

With inventories on hand that average only 10 days of supplies, and with long supply routes requiring lead times of 6 to 8 weeks for imports, the effect of supply disruptions is to cause temporary shortages that in turn result in market driven price spikes, with prices running up until demand will be reduced to a level that corresponds with the reduced supplies. Given the very un-elastic price/demand behavior of gasoline, even small shortfalls in supply can cause very significant price swings. There is also ample evidence, as will be shown in Section 8 of this report, that even if incidents are confined to only one of the California refining centers, the entire California gasoline market moves up.

Supply reliability factors are not the only cause of price volatility. For instance, the lack of liquidity leaves the market vulnerable to sharp increases or decreases in posted prices on only a few reported deals. Yet in the majority of the cases, a real or imagined supply disruption is at the root of price volatility. In the most severe example, the refinery incidents in 1999 resulted in a capacity loss of 5 – 10%, and caused prices to double.

In general, price volatility in the California gasoline market has significantly worsened in recent years, as the insularity of the market increased while the spare capacity available within the California refining system to make up for supply disruptions decreased.

Figure 1.6 – Gasoline Spot Price Differential LA – US Gulf Coast [7]

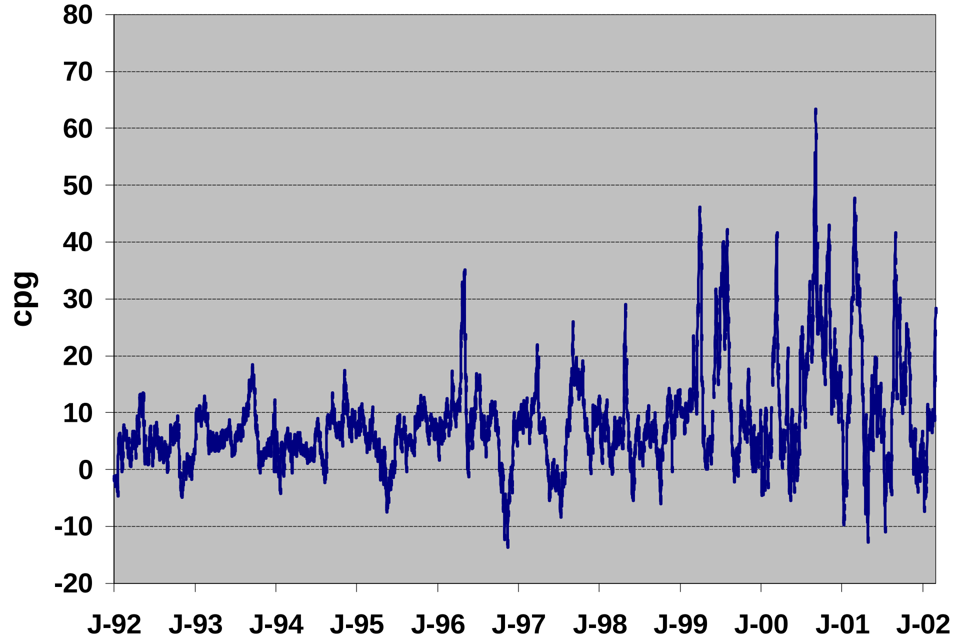


Figure 1.6 shows the premium of the LA conventional spot gasoline price over the spot price at the US Gulf Coast, the latter being a highly relevant marker price for gasoline worldwide. It is clear that the CA prices have gradually increased over world market levels, and that the volatility has significantly increased since 1995, when CARB Phase II was introduced.

Whereas an earlier price spike in 1996 led promptly to additional shipments from the US Gulf Coast to California at a rate equivalent to 50 TBD, more recent price spikes that far exceeded that of 1996 in amplitude and duration have failed to attract more than 10 to 15 TBD. Although the market still functions in so far that no actual shortages have occurred at the pump, it must be concluded from Figure 1.6 that currently, the California gasoline market is not adequately supplied. In a well functioning market, supplies would be attracted at levels just above transportation and sourcing cost differentials, and prices would not have to run up until demand is reduced to match the insufficient offering.

1.2 Demand

To estimate future demand for transportation fuels in California, this report will make extensive use of the results of a separate study launched by the CEC concurrently, with the specific

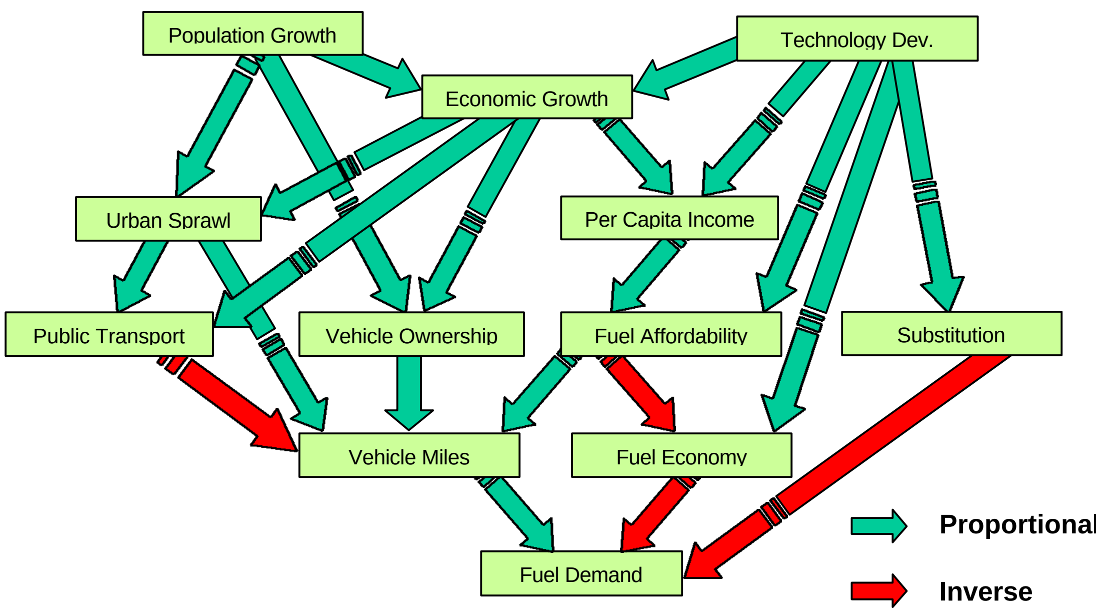
[7] EIA Daily gasoline spot prices Los Angeles and US Gulf Coast.

purpose of forecasting energy demand in the State[8]. The main findings of this study are summarized below.

1.2.1 Growth Drivers

Demand for transportation fuels is the product of the total miles driven by all vehicles and the average fuel consumption per vehicle over the entire fleet. These two key factors, in turn are impacted by a complex set of interdependent factors as shown in Figure 1.7 below.

Figure 1.7 – Drivers for CA Gasoline Demand



For the key factors, the following historical and forecasted numbers were used:

- **Population Growth**. Over the past two decades, California's population grew by an average of 1.9% per year, a rate that is expected to slow to 1.4% per year over the next 20 years, resulting in a total population of 45 million people in the State by 2020.

[8] Base Case Forecast of California Transportation Energy Demand, CEC Staff Report, December 2001

- **Population Density**. Land development patterns in California are characterized by urban sprawl, leading to jobs and communities that are increasingly further apart. This trend is expected to continue.

- **Fuel Affordability**. Over the past 20 years, the average annual increase in per capita income in California was 3.1% per year, for an aggregate real increase of 45% (1.9% per year). Over the same period, the real cost of gasoline in the State fell by 30%. Per capita income is forecasted to increase on average 1.5% per year, and primary energy cost to stay flat in constant dollar terms (the price of gasoline in CA may vary significantly depending on supply scenarios, but this effect is taken into account separately).

- **Vehicle Miles Traveled (VMT)**. The factors cited above contributed to an increase in total Vehicle Miles Traveled of 3.3% annually over the past 20 years. For the immediate future, the forecast is for an annual increase of 1.8%.

- **Substitution**. Public transportation and alternative fuel vehicles can substitute demand for conventional gasoline powered personal cars. However, the CEC estimates do not show a significant impact of alternative technologies in the near future.

1.2.2 Scenarios

For near term future gasoline demand scenarios, i.e., forecasts that extend up to five years out, the most leveraging differentiators are general economic climate and basic energy price levels, in particular the price of crude oil. Other factors, such as demographic changes of changes in fleet composition and average fuel efficiency, move too slowly to have a significant impact within a five-year time horizon.

Three scenarios were evaluated:

- A base case that assumes the current economic slowdown to level off, with a moderate recovery over the next two years and slower growth afterwards than seen over the past five years, resulting in an average increase in gasoline demand of 1.6% per year

- A high growth scenario that assumes rapid economic recovery to similar levels as seen over the past five years, averaging 2.1% per year.

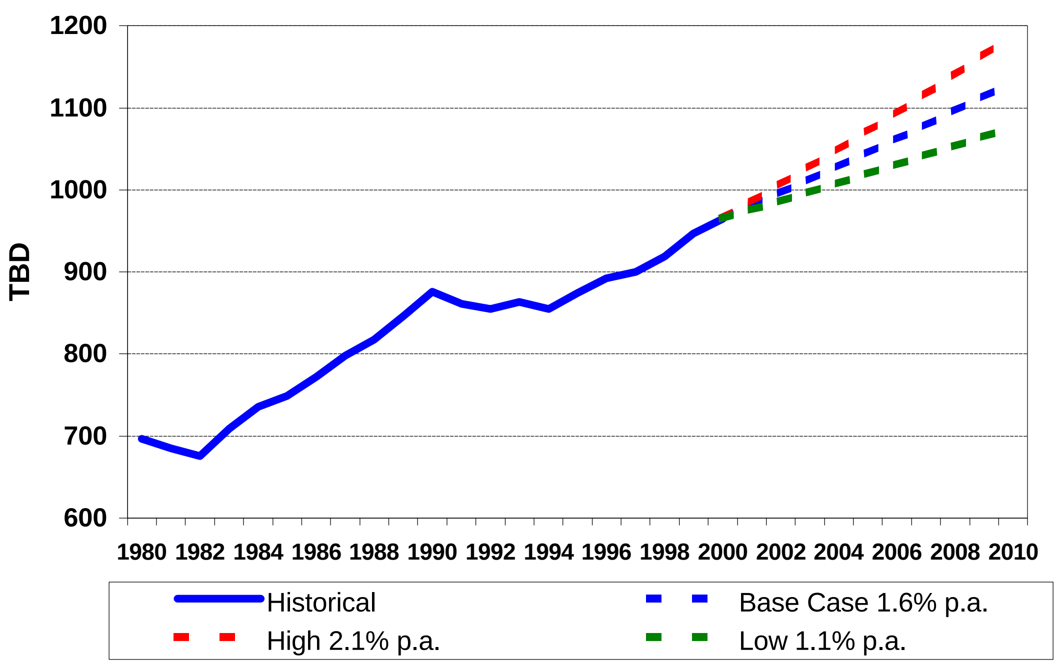
- A low case assuming a deepening and longer lasting recession, with gasoline demand growth slowing to 1.1% per year

All scenarios assume that crude oil prices will stay moderate, i.e., in a range of $20 per barrel, plus or minus $5. Because crude oil pricing is an almost straight direct cost pass through in gasoline prices, higher and lower crude prices will impact gasoline demand with virtual the same price elasticity as gasoline price excursions caused by local market supply imbalances. A high growth scenario could therefore also occur when economic recovery is delayed but crude prices revert to the low prices seen in the late nineties. It would take a combination of very high crude prices and a severe recession, similar to what was observed in the early eighties and early nineties, to cause gasoline demand to stay flat or show negative growth. The probability of this reoccurring is deemed extremely unlikely.

1.2.3 Demand Projections

Figure 1.8 shows the historical demand of gasoline in California, excluding the gasoline demand for those parts of Arizona and Nevada that are supplied out of California.

Figure 1.8 – California Gasoline Demand Forecast



The base case growth forecast is a close approximation of the long-term average annual increase over the entire period 1980 through 2000, while the upside and downside cases represent periods of rapid economic expansion and moderate recession respectively. Only a severe recession caused by or coinciding with crude oil prices in excess of $30/bbl have led in the past to scenarios in which gasoline demand in California stayed flat, or even showed modest decreases. This was the case in 1980 and in 1990 – 1993, but current signs of economic recovery as well as a stated policy by OPEC and non-cartel producing states to manage crude oil prices within ranges that do not harm world economies make a return of similar conditions unlikely in the immediate future.

1.2.4 *Arizona/Nevada Demand*

As shown in Section 1.1.3, California refiners supply fuels to Nevada and Arizona, which includes some of the fastest growing urban centers in the US. Table 1.2 shows the demand forecast for the California sourced demand in these states.

Table 1.2 – Arizona and Nevada Gasoline Demand

Growth Drivers											
Northern Nevada Growth (1)	2.9%	2.8%	2.7%	2.6%	2.5%	2.4%	2.3%	2.2%	2.1%	2.0%	1.9%
Southern Nevada Growth (2)	6.4%	5.2%	4.5%	3.9%	3.4%	3.0%	2.7%	2.4%	2.2%	2.1%	2.1%
Arizona Population Growth (4)	2.4%	2.4%	2.3%	2.3%	2.2%	2.2%	2.1%	2.1%	2.0%	2.0%	2.0%
Gasoline Demand (TBD)											
Nevada											
Northern NV (3)	21.0	21.6	22.2	22.7	23.3	23.9	24.4	25.0	25.5	26.0	26.5
Southern NV (3)	41.0	43.1	45.0	46.8	48.4	49.9	51.2	52.5	53.6	54.8	55.9
	62.0	64.7	67.2	69.5	71.7	73.8	75.6	77.4	79.1	80.8	82.4
Arizona											
West Line Sourced	87.0	89.1	91.1	93.2	95.3	97.4	99.4	101.5	103.5	105.6	107.7
East Line Demand	75.0	76.8	78.6	80.4	82.1	83.9	85.7	87.5	89.3	91.0	92.9
East Line Supply (5)	75.0	75.0	75.0	75.0	75.0	75.0	185.1	189.0	192.8	196.7	200.6
Total West Line Supply (6)	87.0	90.9	94.7	98.6	102.4	106.3	0.0	0.0	0.0	0.0	0.0
Total California Sourced Demand	149.0	155.6	161.9	168.2	174.2	180.1	75.6	77.4	79.1	80.8	82.4

1 Nevada State Energy Office estimate 2.8% in 2001 vs. 2.9% in 2000, a decline assumed to continue
2 As per Clark County Advanced Planning Division - "Clark County Demographics Summary"
3 Lynn Westfall, UDS presentation to CIOMA, April 2001
4 AZ Dept of Economic Security data - http://www.de.state.az.us/links/economic/webpage/page16.html
5 Assumes replacement of West Line supplies by Longhorn extension to Phoenix in 2006
6 Assumes all AZ pipeline growth until start up of Longhorn extension to be put on West line due to East Line proration

The main event that will impact the supply of California sourced gasoline to Arizona is the anticipated completion of a new parallel or “looped” pipeline from Tucson to Phoenix, which will allow US Gulf Coast refiners to substitute California supplied volumes. The assumption here is that the US gulf coast refiners, who currently operate at capacity, will be able to make these volumes available through refinery expansions, or by shifting products away from their current markets, which in turn would have to look for imports from foreign sources.

1.2.5 Total Demand

The total demand for gasoline to be supplied from California is shown in Table 1.3 below.

Table 1.3 – Total Demand for California Sourced Gasoline

TBD	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Base Case											
Northern California	372	378	384	390	396	403	409	416	422	429	436
Northern Nevada	17	18	18	19	19	20	20	21	22	22	23
Oregon	28	28	29	29	30	30	31	31	32	32	32
	417	424	431	438	445	453	460	468	476	483	491
Southern California	591	600	610	620	630	640	650	660	671	682	693
Southern Nevada	41	43	45	47	48	50	51	53	54	55	56
Western Arizona	87	91	95	99	102	106	0	0	0	0	0
	719	734	750	765	781	796	701	713	725	737	749
Total CA Base	1136	1159	1181	1204	1226	1249	1161	1181	1201	1220	1240
High Growth Case											
Northern California	372	380	388	396	404	413	421	430	439	449	458
Northern Nevada	17	18	18	19	19	20	20	21	22	22	23
Oregon	28	29	29	29	30	30	31	31	32	32	33
	417	427	435	445	453	463	472	483	493	503	514
Southern California	591	603	616	629	642	656	669	684	698	713	728
Southern Nevada	41	44	45	47	49	50	52	53	54	55	56
Western Arizona	87	92	96	100	103	107	0	0	0	0	0
	719	739	757	776	795	813	721	737	752	768	784
Total CA High	1136	1165	1192	1220	1248	1277	1194	1219	1245	1271	1298
Low Growth Case											
Northern California	372	376	380	384	389	393	397	402	406	410	415
Northern Nevada	17	18	18	19	19	20	20	21	22	22	23
Oregon	28	28	29	29	30	30	31	31	32	32	32
	417	422	427	432	437	443	448	453	459	464	470
Southern California	591	598	604	611	617	624	631	638	645	652	659
Southern Nevada	41	43	45	46	48	49	51	52	53	54	55
Western Arizona	87	90	94	98	101	105	0	0	0	0	0
	719	730	742	755	767	779	682	690	698	706	715
Total CA Low	1136	1152	1169	1187	1204	1222	1129	1143	1157	1171	1185

Since no official scenarios were developed for demand growth in Arizona and Nevada, it is assumed that high growth in these states would be 1% per year above base case growth, while a reasonable assumption for low growth is 1% below base case.

1.3 Forward Looking Supply/Demand Balance

Ignoring inventory effects, supply and demand will have to balance. The total demand shown in Table 1.3 above is the latent demand, i.e., the demand that will exist if sufficient product is available to meet the demand at prices that are not significantly different from historical numbers. The main event impacting the supply is the phase-out of MTBE.

1.3.1 Impact of MTBE Phase Out

Table 1.4 below shows the impact of the MTBE phase-out by region.

Table 1.4 – Impact of MTBE Phase Out[9]

TBD	N-CA	S-CA	Total CA
MTBE Balance			
RFG production	386	549	935
Ethanol Based CARB RFG	40	70	110
MTBE Based CARB RFG	346	479	825
MTBE Required @ 11%	38	53	91
MTBE imports foreign	24	51	75
MTBE imports US Gulf Coast	7	10	17
MTBE production	7	3	10
Total MTBE supply	38	64	102
Excess MTBE	0	11	11
Direct Impact			
Removal of MTBE	-38	-64	-102
Ethanol addition for oxygen requirement	21	34	55
Removal of butanes & pentanes	-17	-29	-46
Other Losses to meet distillation specs	-4	-6	-10
	-38	-65	-103
Capacity Compensation			
Major refinery capacity additions	22	0	22
Small CARB III mods, MTBE C4 to alky	3	2	5
Capacity Creep 2001 - 2002, 1%	4	6	10
Identified blendstock imports by refiners	0	10	10
	29	18	47
Net Shortfall	**-9**	**-47**	**-56**

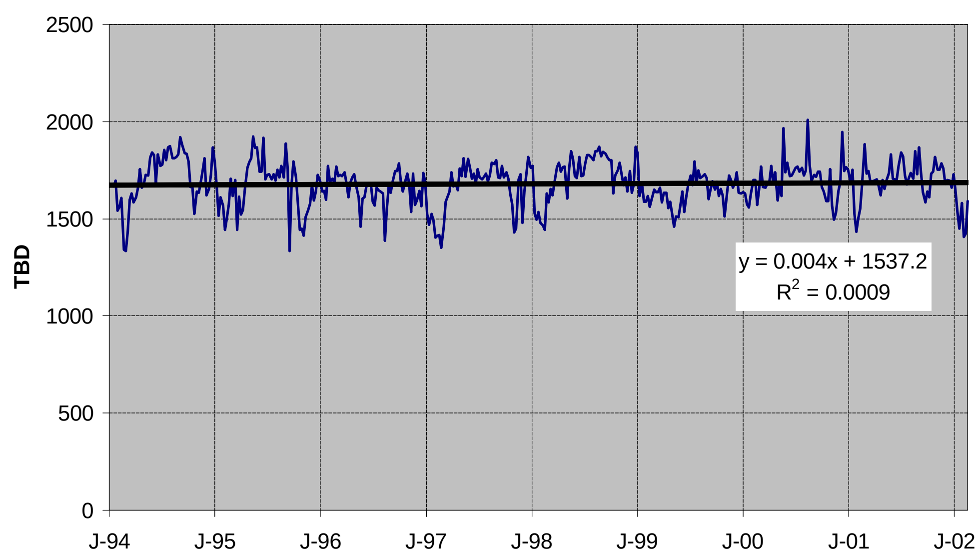
The 11 TBD shown in Table 1.4 as excess MTBE is the sum of 3 TBD shipped down the Kinder Morgan pipeline to Phoenix, an unknown quantity that was used because of supply problems with ethanol for the current substitution of MTBE by some refiners, and a significant quantity, possibly as high as 6 or 7 TBD of MTBE used by LA refiners to make up for volume and quality problems by blending in more than 11%.

The major addition in refinery capacity of 22 TBD shown in Table 1.4 above is not a net addition, but a partial conversion of conventional gasoline production into CARB Phase III grades [10]. It is clear from Table 1.4 that the southern California market will be impacted much more severely by the MTBE phase out than its northern counterpart. Moreover, the LA Basin is more constrained in terms of import capabilities than the Bay Area, making the south more vulnerable to supply shortages.

1.3.2 Capacity Creep

Capacity creep is the term used for the result of ongoing small plant improvements in refinery operations. Even though small, capacity creep is an important phenomenon because it can compensate for a significant portion of demand growth. In the absence of major expansion projects, capacity creep can be derived from production numbers over time. Figure 1.9 shows the weekly reported crude runs of California refineries.

Figure 1.9 – Reported Crude Runs by CA Refiners



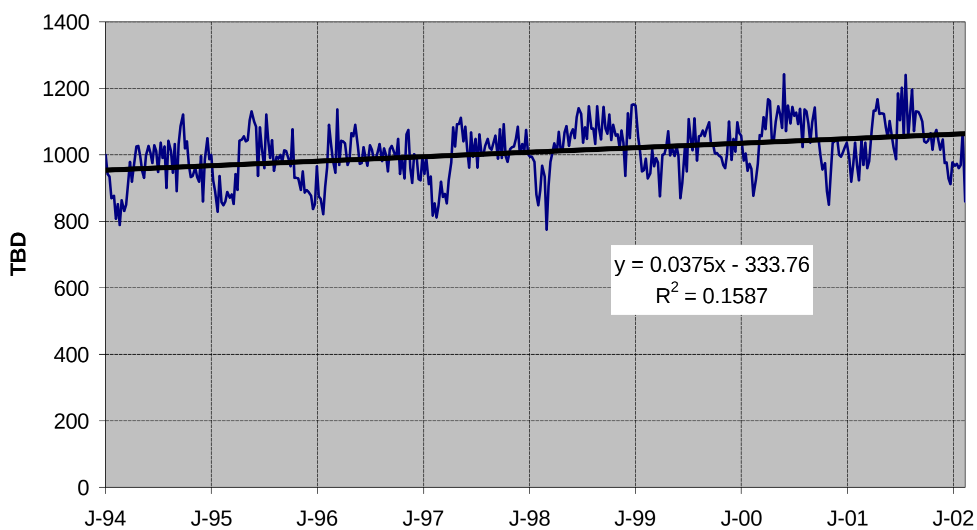
[9] Source of Data: CEC, CARB Phase III Compliance Plans as submitted by refiners Q4, 2001

[10] Information received during Stakeholder Meetings.

Although crude runs by California refiners have stayed virtually flat over the last 8 years, gasoline production has seen a small but significant increase in production, as shown in Figure 1.10 below.

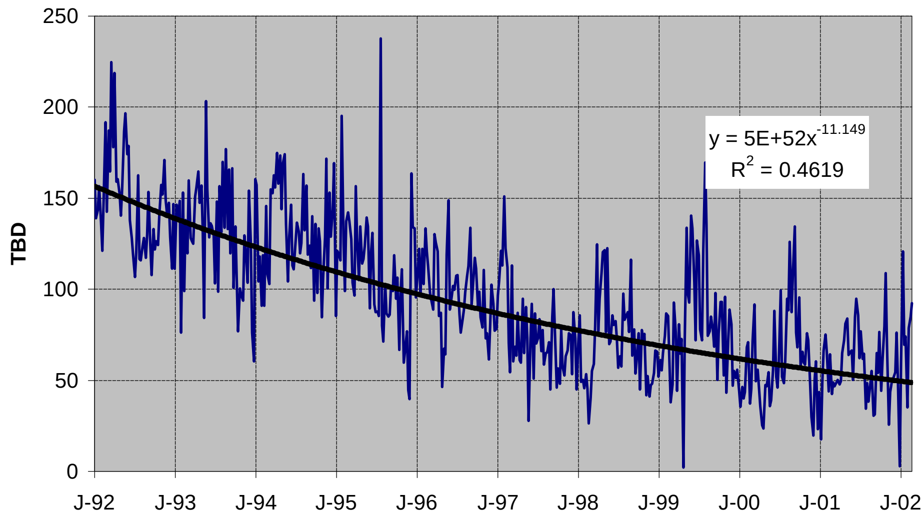
Gasoline supplies by California refineries have grown on average by 1.3% per annum over the period 1994 through 2001, for an overall increase in average reported gasoline production of close to 100 TBD. Of this additional volume, approximately 40 TBD is due to increased receipts of imported blending components, which get reported as production after being blended off. The remainder, or 60 TBD, is the effect of the result of minor expansion projects and ongoing improvements in operations, which equates to approximately 0.6% per year. Although insignificant as fraction of total supply, capacity creep is important because it can represent up to half of the anticipated increase in demand.

Figure 1.10 – CA Weekly Reported Gasoline Production



As can be seen in Figure 1.10 and 1.11, the increase in gasoline production by California refiners by about 100 TBD was accompanied by a corresponding decrease in production of residual fuels, confirming that within the virtually flat crude conversion, refiners have been able to convert more of the heavy end of the barrel into gasoline. A small shift in distillate production can also be observed, but is not shown here. It is clear from Figure 1.11 that the capability to convert more heavy components into gasoline is reaching a point where further improvements are not physically possible.

Figure 1.11 – CA Weekly Reported Production of Residual Fuels



In a market where supplies are tight, and where economic justification for small improvement projects can readily be found, capacity creep is likely to continue at historical rates. However, it is becoming increasingly difficult for refiners to expand capacity even by small increments because of restrictions imposed by their CAAA Title V operating permits, and the costs of additional emission credits in the absence of feasible offsets.

For the base case projections, the annual increase of gasoline production is assumed to 1.0% per year. This rate of increase does not include known or expected discrete capacity additions through major debottleneck or expansion projects, nor does it account for the impact of specific programs such as the CARB Phase III compliance.

1.3.3 Major Refinery Projects

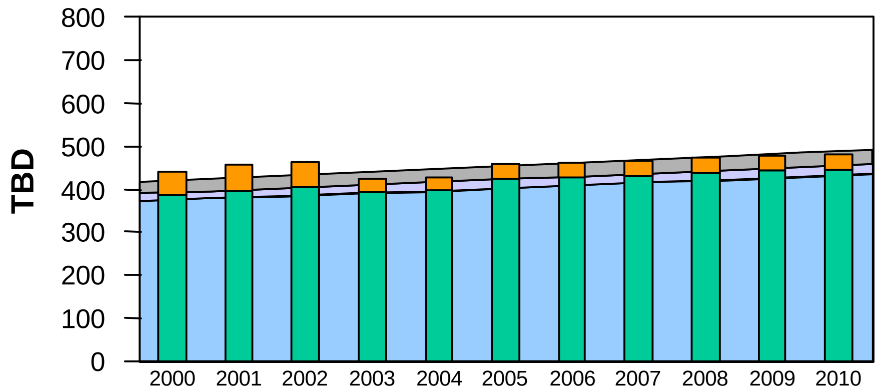
Other than the project to convert 22 TBD of conventional gasoline into CARB RFG in the Bay Area, there are few other major expansion projects that have been announced. It is estimated that a prolonged period of high price levels will provide a justification for other capital projects and may result in an additional 23 TBD of gasoline in the Bay to come on stream in 2005, which is the reason for the increased supplies shown in Figure 1.11 below for Northern California.

Other major projects, such as the expansion of a crude unit in LA and the restart of the idled Powerine refinery by CENCO, met with strong environmental opposition, which, in conjunction with marginal economics, has caused these projects to be abandoned.

1.3.4 Northern California Supply/Demand Balance

For the base case demand, Figures 1.12 and 1.13 show the supply/demand balance for Northern and Southern California respectively.

Figure 1.12 – Northern CA Gasoline Supply/Demand Balance



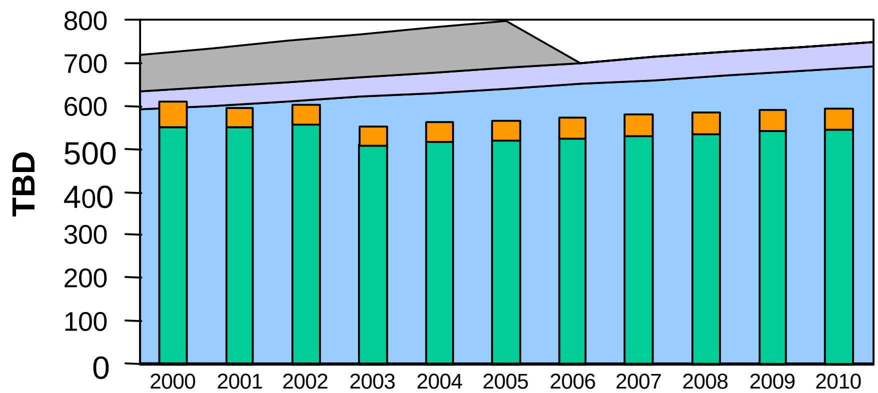
Demand

OR	28	28	29	29	30	30	31	31	32	32	32
N-NV	17	18	18	19	19	20	20	21	22	22	23
N-CA	372	378	384	390	396	403	409	416	422	429	436

Supply

CONV	52	58	54	31	31	32	32	32	33	33	33
RFG	386	398	404	395	399	425	429	433	438	442	447

Figure 1.13 – Southern Gasoline CA Supply/Demand



Demand

AZ	87	91	95	99	102	106	0	0	0	0	0
S-NV	41	43	45	47	48	50	51	53	54	55	56
S-CA	591	600	610	620	630	640	650	660	671	682	693

Supply

CONV	58	43	44	44	45	46	47	47	48	49	50
RFG	549	552	558	511	516	521	526	532	537	542	548

From Figures 1.12 and 1.13 it will be clear that whereas northern California is only minimally impacted by the MTBE phase out, southern California will see its import dependency – which is represented in the charts as the difference between the areas and the bars – approximately double. More importantly, the south currently depends for its shortfall in CARB RFG on barge imports from the Bay Area to the LA Basin by barge.

While the Bay area will be roughly balanced again once the all planned major refinery projects are completed, the south will still be significantly short even when the Longhorn pipeline will be extended to Phoenix. The shortfall will be even more acute when a rapid economic recovery will spur the demand to growth rates of 2% and more, as seen in 1996 – 2001.

1.3.5 Price and Volatility Effects of Shortfall

The effect of price on demand of gasoline, often referred to as the price elasticity of gasoline demand, is defined as the percentage change in the demand of gasoline divided by the percent change in price. Thus, a price elasticity of – 0.1 for example, suggests that a 20% increase in price would correspond to a 2% fall in demand.

The price elasticity for gasoline is not a constant number over a wide price range, but will be a function of other factors. For instance, the overall price level will play an important role: at low overall price levels, i.e., when crude oil and energy prices are low, the same percentage price increase will not have the same impact on demand than an increase when prices are already high. Also, general economic conditions and regional factors such as ready availability of public transportation alternatives will play a significant role. For instance, in the Bay Area, where a well functioning public transportation alternative exists, short-term responsiveness will be different from the LA Basin.

Moreover, there will be a significant difference between short-term responsiveness and long-term elasticity. Longer term, the effect of continued high pricing, such as that caused by fuel tax policies in many parts of the world, will have an impact on overall vehicle fleet fuel economies, use of alternatively powered cars, additions of public transportation infrastructure, and changes in demographic factors such as urban sprawl. Most of these factors take between 5 and 10 years to have a noticeable effect on consumer behavior. Short-term, the effect of these factors is negligible. Therefore it is not surprising that estimates given in table 1.5 below have fairly wide ranges.

Table 1.5 – Gasoline Price Elasticity

	Short-Term	Long-Term
FTC (2001) Midwest Gasoline Investigation	- 0.1 to - 0.4	Not reported
WSPA (2001) (PIRINC study)	- 0.05	Not reported
API (Porter) (1996)	- 0.19	- 0.71
Haughton & Sarkar (1996)	- 0.12 to - 0.17	- 0.23 to - 0.35
Espey (1996)	Not reported	- 0.53
Goel (1994)	- 0.12	Not reported
Goodwin (1992)	- 0.27	- 0.71 to - 0.84
Sterner (1992)	- 0.18	- 1.0
World Bank (1990)	- 0.04 to - 0.21	- 0.32 to - 1.37
Dahl (1986)	- 0.13 to - 0.29	-1.02

The reported numbers put short-term elasticity in the range of – 0.04 to – 0.40, and long-term elasticity in the range of – 0.23 to – 1.37. Observed behavior in the California market in 1999, when a 5 -10% shortfall in supply caused prices to double before demand again matched the reduced supply, suggests a short-term elasticity of – 0.05 to – 0.1. Essentially, in 1999, a series of major and minor unplanned refinery outages caused shortages ranging from 50 to 80 TBD. Although most of these outages occurred in the Bay Area refining center, spot prices in both Northern and Southern California quickly rose to more than double the prior level. The elevated price levels were sustained over periods of 4 to 6 weeks at the time, with severe price volatility in between, and only came down after one of the affected refiners applied to the California Air Resources Board for a waiver to supply non-conforming gasoline.

For the purpose of this study, which is primarily concerned with price volatility, only the short-term elasticity is of interest. Moreover, in the case of a supply disruption such as a refinery outage, the causality is often price-based. Once an outage is known in the market, traders and refiners will take positions that rapidly drive up the spot market price. Although somewhat sheltered, retail markets follow, especially if the supply disruption is significant in magnitude and duration. The higher prices will thus cause demand to drop following established price elasticity mechanisms as described above, even before demand exceeds the available supplies, including the draw-down of inventories. This market behavior will be analyzed in more detail in Section 7 below.

1.4 Alternatives to make up Shortfall

In the absence of any real possibilities to increase production within California over the capacity creep and discrete projects already taken into account in the base case supply, alternative supplies to make up the projected shortfall consists in the short term of increased imports from other US producing regions, or from foreign sources. Longer term, supplies can be anticipated from pipeline projects now under development.

1.4.1 Supplies from US Gulf Coast

The US Gulf Coast is the largest refining center in the US, and as such is a logical place to consider when looking for alternative supplies to meet California's shortfall. It has always been recognized that the CARB Phase III requirements would make sourcing finished product or CARBOB from the PADD III refineries difficult, but it is the availability of other blendstocks that needs to be evaluated, as well as the capabilities of the transportation system to move any available product to the West Coast.

Currently, several US Gulf Coast refineries are capable of producing gasolines that at or near CARBOB II specifications, and most of these have made occasional shipments to California in the past. However, it is not economical for these refineries to invest in the necessary upgrades to be able to produce Phase III base blendstock, because of the limited overall production capability of the boutique quality material, the incidental nature of the export shipments, and the emergence of other premium markets for the these type of blendstocks such as the Chicago market, where high margins can be realized without the need for additional investments[11].

Not only is there no justification for Gulf Coast refiners to upgrade their capabilities to meet California specifications, there is also not much spare capacity in the PADD III system overall. Much like the refineries in California, the refining centers on the Gulf Coast are currently also operating at or near maximum sustainable operating rates. Refineries in the US as a whole and on the Gulf Coast in particular, have seen a steady increase in overall capacity utilization as expressed in total crude runs, from average levels of 85% in the early nineties to at or even above calendar day capacity during the seasonal peak demand periods in recent years[12]. Similarly, capacity utilization in the main gasoline-producing unit within most Gulf Coast refineries, the

[11] Information received during a Stakeholder Survey Meeting conducted for the CEC's Strategic Fuels Reserve Study.

[12] Source data: EIA

Fluidic Catalytic Cracker (FCC), has seen a steady increase and the total FCC capacity is fully utilized. In fact, demand now consistently exceeds capacity, and New York harbor depends on foreign imports to balance supply and demand. This means that any product shipped from the Gulf Coast to California will back out pipeline volumes to New York and will result in additional foreign imports into the Eastern states.

Besides finished gasoline or near finished blendstocks, a key gasoline component exported from the US Gulf Coast is alkylate. The choice blending component, which best fits the particular needs of the California refiners, is C7 alkylate, which is produced by combining propylene and butanes in a reaction that is catalyzed by sulfuric acid or hydrofluoric acid in a process that requires some of the most stringent safety and environmental precautions of any refinery installation.

Because alkylation units are inherently more hazardous than most other refinery operations, they have been more difficult to build and to expand because permitting is not always possible. Also, the uncertainties surrounding feedstock availability and alternative market values make investment decisions difficult. As a result, while the Gulf Coast refiners have been able to increase their capacity in FCCs and cokers, alkylate capacity has remained virtually flat. Moreover, alkylation units compete with many chemical industries for propylene, which usually commands much higher prices in chemical applications than its value in the automotive fuel pool.

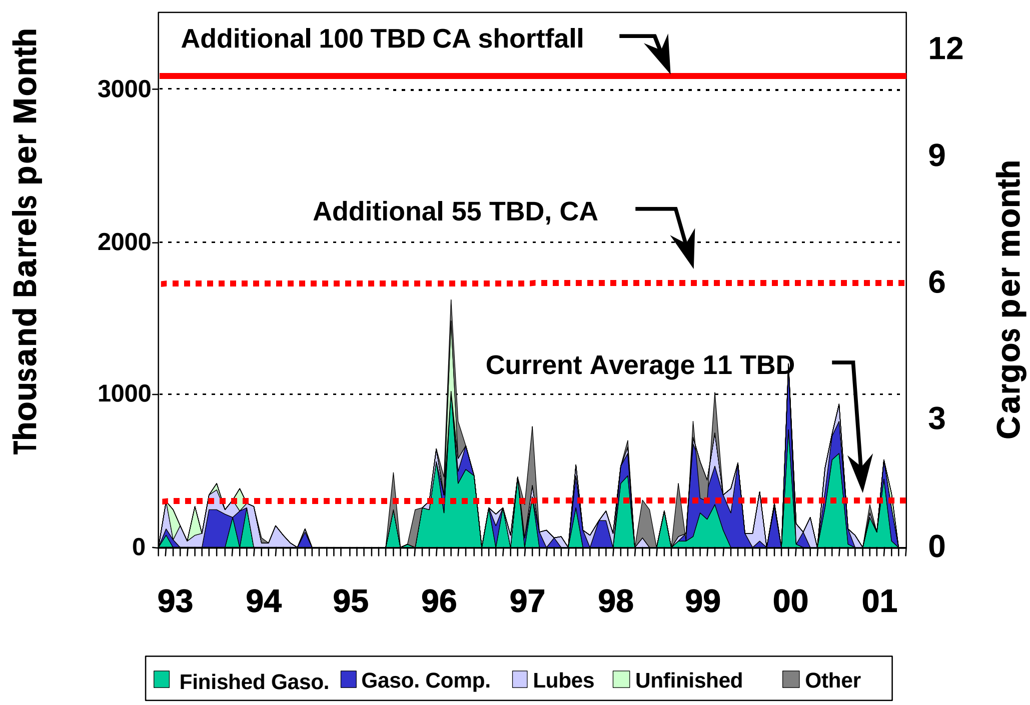
The issue of competing uses for propylene impacting the availability of C7 alkylate, and the difficulty of substituting C8 alkylate given current T50 restrictions, was extensively discussed by Cal Hodge[13] in the context of a CARB workshop held November, 2000. The conclusion drawn at the time still seems valid, in that alkylates may play some role in meeting California's projected shortfall, but their overall contribution is likely to be limited to small volumes, i.e. one cargo per month, at a significant premium.

Finally, even if the US Gulf Coast were capable of producing additional gasoline blendstocks or components, there would not be sufficient Jones Act (prohibits the use of foreign flag vessels between US ports) product tankers available to transport quantities of 55 to 100 TBD, which is five to 10 times higher than the current volumes moved from the USCG to California. The impending phase out of single hull product tankers under OPA 90 severely reduces the availability vessels even further, making it necessary to rule out the US Gulf Coast as a short-term supply source.

[13] Letter by Cal Hodge, A2Opinion, to Alan C. Lloyd, Ph.D., Chairman of CARB, December 15, 2000

It was shown earlier in Figure 1.6, that there is a rising trend with increasing volatility in the premium that California is paying over the Gulf Coast for its gasoline supplies. But while a price spike in 1996 was able to attract volumes from the US Gulf Coast at a rate corresponding to approximately 50 TBD, (see corresponding spike in shipping volumes in Figure 1.14 below), subsequent sustained and higher price differentials in recent years have triggered only moderate volumes to be shipped from the Gulf Coast. This confirms that increasingly, the US Gulf Coast and California have become disconnected markets, with quality requirements and lack of logistical means acting as barriers to supply.

Figure 1.14 – Maritime Movements of Petroleum Products USGC – CA



The conclusions that can be drawn from the analysis of US Gulf Coast supply options are that:

- Finished or near finished gasoline will not be available for CARB Phase III.
- Components will be available at premiums that correspond to local blending value plus replacement imports costs.

- The choice blending component, C7 alkylate, is not available as a segregated stream and can only be sourced as a blend of mixed alkylates at premiums corresponding to alternate use of propylene as chemical feedstock.

- Even if blendstocks can be located, there will not be sufficient shipping capacity to move the products from the US Gulf Coast to California

The development of the gasoline price differential between California and the Gulf Coast over recent years supports these conclusions.

1.4.2 Supplies from Other West Coast States

The State of Washington has a major refining center on Puget Sound. In 2000, the Washington refineries shipped around 47 TBD of gasoline and blending components to California, while California exported 35 TBD to Oregon of conventional gasoline [14]. California refiners, who own three out of four of the major refineries in Washington, often move products between Washington and California in order to optimize their material balances. Given prevailing market incentives, it appears that the current volumes represent the maximum feasible interstate exchanges, i.e. if significant spare capacity had existed, it would have been used. It is anticipated that a chronic shortage of fuels in California will lead to further optimization of these inter-refinery balances and that Washington refineries, after investments, may be able to increase their exports to California by 10 TBD.

1.4.3 Foreign Imports

Imports of foreign gasoline and blending components other than oxygenates have increased from erratic small net exports or imports in the early nineties to a level of 20 to 25 TBD in recent years. As with US Gulf Coast supplies, the availability and the logistics will have to be examined in order to establish what role foreign sources can play in alleviating a California supply shortfall.

Currently, several foreign refiners are capable of producing conforming CARB Phase II gasoline or "near-BOB", base-stock gasoline that only needs the addition of MTBE to be on spec. Most of these have shipped occasional cargoes to California over recent years. A survey of these refiners completed as part of the Strategic Fuels Reserve Study currently underway revealed that only the Irving refinery in New Brunswick will

[14] US Army Corps of Engineers Waterborne Commerce Statistics Center

be able to supply Phase III CARBOB, in quantities of up to two cargoes per month or the equivalent of 18 TBD. These supplies do not require Jones Act shipping and can therefore be delivered at competitive freight rates (8 cpg) and at relatively short notice (3.5 weeks transit). It is likely that most or all of this material will find its way to California if supply shortages will cause prices in California to depart substantially from East Coast levels, where the New Brunswick refinery currently sells most of its output.

Another potential source of Canadian material is Alberta's Envirofuels, which is likely to convert its 18.5 TBD of MTBE production into an estimated 11 TBD of isooctane. This material is targeted for the California market, and the project is likely to be driven by the need to move condensates from natural gas production rather than stand-alone economics, which would have forced Envirofuels to require significant premiums, given the conversion cost and the complicated logistics to move product from Edmonton, Alberta, to CA. Chevron, who is part owner in this venture, is likely to keep their share of the output within the Chevron system and use infrastructure released from MTBE service, while shareholder Neste may put their volume onto the open market.

In the Middle East, a new venture currently produces approximately 10 TBD of Phase II RFG, based on blends of isomerate and reformate. This facility has plans to increase production to 25 TBD, and make improvements to meet CARB Phase III specs. With current freight rates of 10 to 12 cpg, first supplies from this source have started moving into California in the fall of 2001.

Other than the three specific foreign sources of CARB Phase III blendstocks, it can be safely assumed that the international majors such as ExxonMobil, BP and Shell, will be able to optimize the availability and usage of high quality blending components within their global refining systems, such that these materials will be routed to California when a price departure offers an opportunity to maximize corporate revenues on a global basis.

All in all, it would appear therefore that additional supplies up to 50 TBD could be mobilized at premiums over world market pricing that are not too different from price levels at which California currently buys its incremental barrel, although this volume does not appear to be committed to California at this time. Whether global availability of premium blendstocks will allow sourcing of 100 TBD seems a little more doubtful at this stage, but given sufficient incentive, i.e., if California's prices were to remain for a pronged period at levels of more than 50% over world markets, then it is likely that the State will attract every available conforming barrel that refiners around the world can segregate and ship. *The problem therefore becomes one of import logistics, and herein* *lies one of the key contributions a Strategic Fuels Reserve can make, provided it is designed to increase the State's capacity to imports fuels.*

1.4.4 *Pipeline Supplies*

One of the alternatives to supply California's shortfall is to transport products by pipeline from the US Gulf Coast. The issue here is not just that it requires pipelines that will move finished products from the refining center on the US Gulf Coast to the West Coast across 1500 miles of distance, but also that the availability of West Coast quality products on the US Gulf Coast is uncertain.

The bulk of West Coast sourced demand in Arizona goes to Maricopa County – Phoenix and the surrounding cities. The stringent quality of gasoline for this area is very similar to California's gasoline quality. The issue is that demand for low sulfur gasoline will increase dramatically East of the Rockies (EOR) when the EPA reduces sulfur levels of all grades of gasoline in 2005. In the face of increasing local demand, supplies of low sulfur RFG will have to be bid away from local markets in order to move them to Arizona. This supply equation will be further complicated if Arizona decides to blend ethanol with gasoline in Maricopa County in the summer. An ultra low RVP blendstock, similar to CARBOB will be required.

The existing pipeline network for Southern California, Southern Nevada, and Arizona originates in Los Angeles. Product is moved by Kinder Morgan Energy Partner's pipeline from Los Angeles to San Diego, Las Vegas, and Phoenix. The LA to Phoenix system is known as the West Line. Some volume from Los Angeles also moves past Phoenix to Tucson.

Longhorn Pipeline is in the process of building a line from the refining center in Houston to El Paso. The company expects to have construction completed early 2002, although the progress of the project has been significantly hampered by objections of the City of Austin, Texas. These issues now appear to have been resolved and the first products could delivered into El Paso by the middle of 2002. Initial rate will be 75 TBD. The line's capacity can be expanded to 225 TBD with the construction of additional pump stations [15].

Because demand for the existing Kinder Morgan East Line from El Paso to Tucson and Phoenix exceeds its capacity, with flows for each customer being prorated, this line will

[15] Meeting with Longhorn Pipeline, CEC, CARB, Interliance, and Stillwater Associates, December 12, 2001

have to be de-bottlenecked or a separate pipeline will have to be built to move the product that Longhorn can deliver to the Tucson and Phoenix markets. It is estimated that this separate line, or loop, in pipeline terms, could be completed by 2005. If products are available from the Gulf Coast, they could displace all or part of the 93 TBD forecasted to be exported from California in 2006.

2 GENERAL REQUIREMENTS FOR A STRATEGIC RESERVE

The assignment contained in State Assembly Bill AB2076 is to evaluate the feasibility and costs of a reserve equal to two weeks of production of the largest refinery in California. Based on incidents occurring in recent years, a period of two weeks was considered to be a good order of magnitude fit with observed unplanned outages of refineries in California. For CARB gasoline, two week's worth of the largest individual production by a refinery in the State corresponds approximately to 2.3 million barrels. For CARB diesel and jet fuel, this number is 0.6 million and 0.9 million barrel respectively.

Because of unusable space in tanks (i.e., a tank will have a "heel", the minimum amount of liquid necessary to keep a floating roof from landing on the bottom, and a "freeboard" which is a minimum height to be left at the top), the nominal shell capacity of the tankage will be closer to 2.5 million barrels. Additional requirements for the reserve need to be formulated to ensure that the reserve is adequate to satisfy not just the letter of the Bill, but also the intention of the lawmakers, namely to ensure a certain degree of price stability at reasonable cost.

2.1 Requirements for Price Stability

A more detailed analysis of the effectiveness of a reserve based on two week's capacity of the largest California refinery will be provided in Section 8. However, some general operational requirements for a reserve can be formulated even when assuming that the two week's capacity requirement is a given. For instance, price spikes currently are almost instantaneous reactions in the spot market to supply disruptions that often last only days or weeks. If an unplanned refinery outage occurs at a time when industry inventories are already low, an intervention with volumes drawn from a reserve will have to be quick, i.e., within days rather than weeks, in order to have effect in stabilizing prices.

The need for reserve inventories to be immediately accessible translates into requirements not only for release procedures, but also for the logistics of moving product from the reserves into the markets. Even before conducting a detailed analysis of the reserves interaction with market mechanisms, it can be concluded that in order to bring price stability to a market where prices can move up by as much as 20 cpg on the same day that an announcement is made about a refinery outage, the reserve should have the capability, credible to the marketplace, to deliver product into the market within at the most one or two days at rates comparable to the lost capacity.

2.2 Fuel Quality Requirements

Typically, a California producer of gasoline may have to store and blend as many as 6 different qualities of gasoline during each of two separate seasons, a winter season which in most parts of California lasts from November into February, and a summer season which lasts the remainder of the year and is characterized by more stringent vapor pressure requirements. The diversity of gasoline grades, the seasonal changes, and other quality aspects such as the limited shelf life of gasoline in general, impose particular challenges for the eventual creation of a strategic reserve.

Moreover, given the likelihood of imports needed to replenish the reserve after a drawdown of stocks, and the fact that such imports will largely consist of blending components rather than finished products, the reserve will have to be designed in such a way that it offers flexibility in terms of storing various grades of unfinished products and blending components, and the ability to blend final products to customer specifications prior to delivery into the common carrier pipeline grid.

For this reason, it is recommended that tank sizes will be limited to 150,000 bbl, a size generally considered as not too big to store blending components cost effectively, and not too small so that at most two tanks are needed to receive waterborne shipments in full cargo loads. The tanks will have to be designed for multiple product use with drain-dry bottoms. Also, blending and circulation pumps will be highly desirable, as well as a Vapor Destruction Unit (VDU), that will enable collection and incineration of vapors displaced under a floating roof when it is refilled after the tank has been fully drained, with the roof landing on its supports. When considering those alternatives that involve newly built storage, the costs of the above facilities will be taken into account.

Even if the reserve is built as part of larger new storage terminals in which state-sponsored tankage is made available against commercial rates to qualified third parties, i.e., built 5 million barrels of capacity, keep 2.5 million for the reserve and lease the other half to commercial third parties to create a large commingled pool of gasoline and components, it is recommended to augment the number of tanks rather than the tank size. This will allow individual storage for all commonly used blendstocks and components, and will create the operational flexibility to maintain reserve inventories that can be blended to meet the specific requirements of a particular supply disruption.

2.3 Logistics Requirements and Site Selection

In determining the best location for the reserve, it is necessary to evaluate the logistics of delivery of fuels from the reserve into the market, as well as those of restocking the reserve after drawing down inventories. In order for the reserve to effectively compensate for an unplanned outage of a major refinery, it is important that fuels released from the reserve can reach the markets quickly, as concluded under 2.1 above. This translates into infrastructure requirements that will prevent the logistics involved of becoming a bottleneck in itself and still cause price spikes in the market.

Since California effectively consists of two separate markets served individually by the main refining centers in the LA Basin and in the Bay, a single location for the reserve would greatly reduce its effectiveness. In the absence of a pipeline link for products between the Northern and Southern refining centers, a single reserve would only be able to provide immediate relief to the market in which it is located, whereas a significant logistics effort would be required before product could be delivered to the other market. For instance, if a reserve were to be located in the Bay Area, and a supply disruption such as an unplanned outage of a major refinery occurred in the LA Basin, then at least 100 TBD of products would have to be transported over an average distance of approximately 400 miles, for a total transport requirement of 40 million barrel-miles per day.

Very little gasoline moves by rail in California and as a consequence the rail infrastructure in terms of tank cars and handling facilities is incapable of playing any role whatsoever in moving barrels from a reserve to market. Equally, the probability is low of finding and positioning a US flagged product tanker within days, the timeframe required to respond to a refinery outage before prices would be affected, also ruling out this transportation mode as an option. This leaves trucks and barges as the only remaining alternative, but here the issue is whether or not the transport system can mobilize sufficient additional capacity at short notice.

On average, delivery of gasoline to the retail stations involves an estimated 30 million barrel-miles per day of tank truck movements, while shipments of petroleum products and crude oil by coastal barge along the West Coast were 4.6 billion ton-miles[16] in 1999, or approximately 100 million barrel-miles per day. Clean product movements make up approximately one third of this volume. This means that to transport fuels from a reserve location in the Bay Area to LA or vice versa in case of a major refinery outage would require more than doubling daily truck and barge movements. It is not realistic to expect so much transport capacity to be available at short notice (i.e., as spare capacity, not otherwise utilized).

Given these logistical constraints it will be clear that if a reserve is to be created, it will have to consist of at least two separate storage centers, one for each main market. Other locations

[16] US Maritime Administration, *"Highlights Coastal Tank Barge Market",* Staff report, May 2001.

may be considered in addition, for instance at the existing staging terminals for the main long distance pipelines. However, if reserve volumes are located further downstream in the distribution system, they should not exceed the demand of the downstream market over the time period to be covered. If larger reserves were to be created further downstream in the distribution system, the volumes in excess of local demand would require reversal of normal distribution flows in order to be of any use, which in most cases is impractical if not impossible.

In general, given the high degree of utilization of the California infrastructure for fuel deliveries (terminals, gathering systems, long distance pipelines, truck, rail and barge fleets), it will vastly increase a reserve's effectiveness if it can be integrated into the refining centers in such a way that in order for the reserve volumes to reach the market, they will use the same logistical assets as the refinery volumes they replace.

Another important logistics consideration in determining suitable locations for a reserve is that of re-supply. Since California is overall short in production capacity for all its fuels, with refineries running at maximum capacity and achieving utilization rates of 95% or more, any lost production due to an outage of a major refinery must either be made up by imports or balanced by reduced demand caused by price increases. Since the latter is the undesired effect the reserve hopes to prevent, it follows that any volumes drawn from the reserve will have to be made up either directly or indirectly by imports, while additionally any short-notice delivery from the reserve must utilize existing infrastructure capabilities. Therefore the logistical requirements for an eventual reserve can be summarized as follows:

- The separate northern and southern California markets will each have to be served by its own reserve.

- The reserves will have to be integrated into the two refining centers in such a way that product from the reserve can be delivered to the market using the existing infrastructure, seamlessly replacing the lost volumes.

- The reserves will have to be provided with deepwater access so that they can be restocked directly with imported products.

The locations that meet these requirements are (i) in the North, the Eastern Bay area within the gathering system connecting the local refineries and commercial terminals with the Kinder Morgan pipeline head in Concord, and (ii) in the LA Basin, the Wilmington/Carson/Watson area with access to all major refineries, and tied into the feeder system for the Kinder Morgan pipelines at Colton. Further downstream, additional storage can be provided at Concord and Colton, or other pipeline hubs.

The problem that arises when locating separate reserves in each of the major refining centers is that of the distribution of the volume. If the requirement for two week's production of the largest refinery is applied to each of the centers, then the LA Basin reserve would have to be 2.2 MM bbl, and the Bay Area reserve 1.7 MM bbl. However, if a first reserve can provide immediate relief to the market in which it is located, volumes from the second reserve can be brought in over time across the distance separating the two markets within the restraints of the available logistical means. For the purpose of further evaluation, it will therefore be assumed that the total volume of all reserves will be kept at two week's capacity of the largest refinery, or 2.2 MM bbl, to be split into 1.3 MM bbl in the LA Basin and 0.9 MM bbl in the Bay Area, volumes that not only correspond to the ratio of gasoline consumption in the respective markets, but also to the ratio of the production capacity of the largest refinery in each center. These volumes would allow approximately one week's of autonomous coverage within each region, which provides adequate time to mobilize logistic resources to utilize reserves stocked in the other region if necessary.

2.4 Requirements for Extraordinary Events

Besides unplanned outages of California's refineries, there are other events that can cause even more severe supply disruptions and price spikes, i.e., earthquakes, acts of terrorism, crude oil supply disruptions resulting from environmental disasters (as was the case after the Exxon Valdez disaster), or geopolitical events such as embargoes and wars. In fact, as will be shown in Section 3 below, most countries that maintain a Strategic Fuel Reserve do so for reasons of national security rather than market stabilization. In such cases, the reserve volumes are much more substantial, i.e., in the range of several months of total consumption rather than two week's capacity of a single refinery.

While the creation of a reserve for reasons of national or State security is not included in the scope of this study, it is relevant to look at the potential value of a reserve in case of an earthquake. Whereas events such as wars and embargoes will have an impact on a national scale that requires very large reserves, the effects of an earthquake tend to be local and previous reserve studies were specifically commissioned to cover this event.

When evaluating the potential value in the event of an earthquake of a smaller reserve designed for commercial market stabilization, it becomes quickly apparent that the locations identified above for logistical reasons render the reserves vulnerable. The East Bay Area and the Watson/Wilmington/Carson area essentially share the same geologically unsound coastal structures as the major Californian refineries, and in that respect, they are not ideal because they too are likely to be affected to some extent by the same quake that might damage one of the refining centers.

Yet, to design a reserve capable of providing adequate coverage of fuel needs in the wake of a major earthquake is not practical and was evaluated in earlier studies as not cost effective. The reserve in that case would have to provide for many weeks of equivalent capacity to not one but likely several major refineries, for events that have a very low probability of happening during the technical and economical lifespan of the reserve.

For extraordinary events, for which the extent of the shortfall and the duration of the outage are likely to require a very large amount of fuels in reserve to mitigate the effects of the outage, but which have a very low probability of ever happening, a better approach than the creation of a reserve is a temporary relaxation of California fuel quality requirements, so that alternative supplies can be brought in from a wide array of supply options outside the State.

3 DESCRIPTION OF OTHER STRATEGIC FUEL RESERVES

National Petroleum Reserves became part of an overall emergency response plan orchestrated by the International Energy Agency (IEA) under the 1974 Agreement on an International Energy Program (EIP) of which the United States is a signatory. Every five years the IEA publishes an exhaustive report on its Member countries' preparations to respond to major oil supply disruptions. Most of the 28 countries maintain oil stocks well above the 90 days of net imports to which they are committed. IEA countries also have viable demand restraint programs and are monitored for weaknesses in their response systems. Those response mechanisms include: stock drawdown, demand restraint, fuels switching, extra oil production and the sharing of oil supplies.[17] Below, several of the domestic and international reserve initiatives will be evaluated in order to see whether experience gained with the creation and operation of these reserves has relevance for the situation in California.

3.1 General Aspects of Strategic Fuel Reserves

Some of the key aspects of strategic fuel reserves in general are the sizing, inventory management and release mechanisms

3.1.1 Sizing of Strategic Fuel Reserves

Almost all national SFRs are maintained by countries that are significant net importers of petroleum products, and the size of the inventories is designed to protect these countries from being held hostage by their supplying nations. Usually, such reserves are sized as a function of the total fuels demand of the nation as a whole, with typical quantities of fuels stored ranging from 90 to 120 days.

There are only a few instances where, as would be the case for California, a reserve is designed for price stability. Examples are the Northeast Heating Oil Reserve and the Massachusetts Heating Oil reserve, which were designed to protect their populations against price spikes as well as the physical dangers from running out of heating oil in abnormally cold winters.

There is no known example of a reserve specifically created to counteract supply disruptions caused by internal production problems, although the reserves created in other island economies such as Korea and Japan used to have, will have a somewhat dampening effect on prices, as will be discussed below.

[17] International Energy Agency website – http://www.iea.org

3.1.2 Inventory Management of Reserves

Many countries store petroleum products in addition to or instead of crude oil as part of their oil stockpiling programs. A broad range of stockholding mechanisms have been adopted by IEA and European Union (EU) members, none of which match the commercial or logistical features of California but are useful to consider as points of reference. There are three primary mechanisms:

- **Government Stocks**. These stocks are owned and controlled by member governments and account for 26 percent of stocks in IEA counties. Germany, Italy, Ireland, Japan and the United States hold government stocks.

- **Agency Stocks**. These stocks are held by agencies created by members for purposes of holding stocks and collaborating between government and industry. Agency stocks are much the same as government stocks, in that they fall under government procedures, are segregated, are of the same quality as government stocks, and are subject to government control. Agency stocks account for 5 percent of stocks in IEA countries.

- **Company Stocks**. These are privately held stocks, which count toward a member's IEA reserve commitment. In 1993, company stocks accounted for 69 percent of stocks in IEA countries. The only IEA member countries that do not impose compulsory stockholding requirements on companies are the two net oil exporters, Canada and Norway, and Australia, the United States and New Zealand. Under this approach, strategic stocks may be held by the oil industry on behalf of the government, usually as a legal requirement. Obligations are calculated and monitored by the government. Strategic stocks are part of or considered alongside operational stocks.[18]

The U.S. opted for a centralized government reserve, rather than the "industrialized petroleum reserve" or agency concept. Advantages of a government reserve are complete control over storage with release and use of stocks under central control with minimum disruption to the oil industry. Disadvantages are high initial set-up costs and administrative and technical burdens to the government. An amalgamated system provides flexibility but makes it difficult for the government to know how much oil is available in an emergency.

[18] Report to Congress on the Feasibility of Establishing a Heating Oil Component to the Strategic Petroleum Reserve, June 1998, Appendix F.

The U.S. differs from many other IEA countries in its means of financing the Reserve. In contrast to the United States, where the costs of the reserves are borne fully by the Government and financed out of general revenues, in countries such as Japan, Germany, and Italy, the costs are shared by the petroleum industry and the end-user.

Advantages of the agency approach to stockpiling are use of oil industry expertise for management, increased consideration of oil industry interests and flexibility in storage and distribution arrangements. Disadvantages are the high costs to set up such a program unless existing stocks and storage are already available, and the need for arbitration of various industry interests. In the case of a California SFR being adopted, this model had the strongest positive feedback among the stakeholders. Unanimously, the industry did not want to see the government operating a petroleum reserve. An Agency arrangement would be more responsive to California's unique supply, scheduling and pricing environments.

3.1.3 Trigger Mechanisms

One of the most critical components of any SFR is its trigger mechanism for release of inventory. For most national strategic fuel reserves, the authority to release inventories is vested at high levels in a country's executive branch, under conditions that meet a number of predefined criteria, which are usually so narrowly defined that the existence of the reserve is not really a factor in day-to-day market considerations.

For a reserve whose aim it is to prevent price spikes rather than to be there for national emergencies, a trigger mechanism needs to be broader defined. There is a widespread concern that if this vital element is mismanaged then price spikes could be prolonged rather than remedied. Uncertainty over when SFR inventories might be sold into a tight and rising market could actually inhibit out-of-state suppliers from sending cargoes to California. They would fear that after putting a California-bound cargo on the water, the SFR might dump product, driving down the price and undermining the value of their cargo position. Since there is no futures market in the State, an offshore supplier would be subject to this unintended risk.

The same concern was voiced by a number of participants in the Federal Petroleum Products Reserve (FPPR), during the feasibility assessment phase of the Heating Oil project. Even today, with the FPPR a well-defined and ongoing operation, a number of prominent companies believe that unfettered supply and demand forces are still the best antidotes to skyrocketing prices. They assert that when prices rise sharply, an immediate commercial incentive is created to deliver new supplies into that market from NW Europe, the Caribbean, from the US Gulf Coast and South America. Technical analysis of the efficacy of the Federal HO trigger mechanism still reveals flaws in the internal logic of that program.[19] *An eventual California reserve must be designed such that its use does not invoke an arbitrary, event driven trigger mechanism that caused importers to withhold shipments*.

3.2 Federal Strategic Petroleum Reserve

The Strategic Petroleum Reserve (SPR) was created in 1975 in the aftermath of the first oil crisis when President Ford signed the Energy Policy and Conservation Act [20] (EPCA42 U.S.C. §6231, et seq.). Several earlier attempts to create a national oil storage reserve during WWII and the Suez Crisis, and lastly by the Cabinet Task Force on Oil Import Control in 1970, all had failed. The SPR was commissioned in 1977 and it still is the largest emergency oil stockpile in the world, with a design capacity of up to 1 billion barrels. Together, the facilities and crude oil represent more than $20 billion in national investment. The emergency crude oil is stored in caverns created deep within the massive salt deposits that underlie most of the Texas and Louisiana coastline. The caverns offer the best security and are the most affordable means of storage, costing up to 10 times less than aboveground tanks.

The EPCA gives the Department of Energy (DOE) statutory authority to implement the Plan for a Strategic Petroleum Reserve, which is to acquire and operate the storage facilities. Equally, the DOE has the authority to acquire petroleum products for the SPR. The EPCA also authorizes the establishment of Regional Petroleum Reserves (RPR) as part of the SPR, and requires that the SPR Plan provide for the establishment of an RPR for each Federal Energy Administration region that relies on refined product imports for more than twenty percent of its demand.

Finally, the EPCA authorizes the Secretary of Energy to establish an Industrial Petroleum Reserve, which is defined as that part of the SPR consisting of petroleum products owned by importers or refiners (rather than owned by the Federal Government), and grants the Secretary discretionary authority to require refiners and importers of petroleum products to maintain readily available inventories equal to three percent of the previous years' throughput or imports.

The volumes of the SPR may only be used when the President determines that implementation of the Distribution Plan foreseen by the EPCA is required by a "severe energy supply interruption or by obligations of the U. S. under the international energy program", i.e., when

[19] PIRA report

[20] DOE Fossil Energy – Strategic Petroleum Reserve: Website – http://www.fe.doe.gov/spr/spr_facts.shtmal

the President determines that there is a significant reduction in supply, causing such a severe increase in the price of petroleum products that it is likely to cause a major adverse impact on the national economy.

Two exceptions permit sales from the SPR without a Presidential declaration under the emergency conditions, either as test sales in amounts not to exceed 5,000,000 barrels, or in amounts not to exceed 30 million barrels in total or for more than 60 days, both under narrowly defined conditions.

Relevance for California: The relevance of the EPCA for an eventual California Fuels Reserve lies in the federally mandated requirement for the creation of a Regional Strategic Petroleum Product Reserve for regions that are dependent on imports for more than 20% of their fuel requirements. California's foreign imports currently amount to approximately 25% of its crude and 15% of its petroleum products, percentages that are both expected to increase significantly. Thus, if the State were to constitute a region in its own right, it would have to create reserve for crude now and one for products in the not too distant future.

3.3 Northeast Heating Oil Reserve

The Northeast Heating Oil Reserve (NHOR) was created as a Regional Petroleum Product Reserve (RPPR) under EPCA, at the initiative in 1996 of several Members of Congress who were concerned that low inventory levels of heating oil might cause severe price spikes or outages in case of a severe winter[21].

The basic volume requirement for the reserve was set by estimated heating oil consumption in the Northeast during a severe winter, with a duration and with temperatures that can be expected to occur only once every 100 years, based on the statistic evidence of meteorological data collected for the region since the middle of the 19th century, which happened to correspond to conditions that prevailed in 1989. This calculation resulted in a volume requirement of 6 million barrels, but since only 2 million barrels could be placed in existing terminals in the Northeast itself, it was decided to limit the regional reserve to this volume, while provisions such as a waiver of the Jones Act would enable quick re-supplies from other inventories available in the SPR caverns in the Gulf Coast.

Three private companies were selected to store and manage the NHOR in leased storage at three terminals, located in New Haven, CT and Woodbridge, NJ. The reserve is commingled with commercial volumes in active tanks to avoid quality problems with aging inventories. Also,

[21] Department of Energy, *Heating Oil Component to the Strategic Fuel Reserve,* Report to Congress, June 1998

the commercial operators are occasionally allowed to dip into the reserve volumes with prior approval of the DOE.

The Northeast Heating Oil Reserve has special relevance for this study because it is one of the few examples of a reserve created specifically to provide price stability, rather than for reasons of national security. Moreover, the reserve was designed to meet certain criteria of cost effectiveness, and the methodology used in the study that justified its creation was based on sophisticated statistical evaluations.

During stakeholder survey meetings (see section 9), the issue was raised with companies that market fuel oil on the East Coast, and several meetings were dedicated specifically to this subject. The conclusion from these discussion is that, even though the reserve has not yet been put to the test of the once in a 100-year winter for which it was designed, the reserve is not expected to be effective in the opinion of the industry involved in the heating oil business in the region. The perceived shortfalls are:

- The 2 million barrels of reserves equate to only three days of average winter demand in the Northeast, less than two days in case of peak demand during a cold snap.
- The reserve occupies existing tankage that was well used by the industry and usually would be kept full at the onset of the winter heating season anyway (this argument was addressed in the heating oil study and was one of the reasons for only using up 2 million barrels of space).

Relevance for California: Because the Northeastern Heating Oil Reserve is one of the few reserves specifically designed to mitigate price volatility, and was executed within similar size tankage as would be the case for a California SFR, this reserve merits a more detailed comparison. In table 3.1 below, a comparison is made between the various factors that together constitute the framework for requirements and effectiveness for a Regional Petroleum Product Reserve.

From the comparison below, it will be clear that the requirements for an eventual California Strategic Fuels Reserve are far more complex but also more urgent than those of the Heating Oil Reserve in the Northeast. It would seem that if a reserve for heating oil in the Northeast could be justified on economic grounds, then a gasoline reserve in California could also be warranted by an economic justification. In this context it is interesting to note that the inventories for the Northeastern Heating Oil were in part funded at federal level by selling off equivalent quantities of crude oil from the Federal Reserve.

Table 3.1 – Northeast Heating Oil Versus CA Gasoline Reserve

	Northeast HO*	CA Gasoline
Demand	0.7 MM BPD winter average	1.0 MM BPD year round
Available Inventory Range	20 to 60 MM bbl = 40 MM bbl	18 – 10 MM bbl = 8 MM bbl
Effective days inventory	70 days av. winter demand	8 days regular demand
Product Fungibility	Readily fungible	Unique to CA
Product Grades	One	Multiple Summer and Winter
Blending restrictions	None	Unocal Patent, CARB cert.
Market Liquidity	1000+ trades/day	<20 trades/day
Futures Market	Broad, up to 1 year deep	Narrow, next month only
Market participants	Large Community	Closed Market
Pricing	Transparent	Limited reporting
Demand	Seasonal Only	Year Round
Import options	100s of refineries worldwide	3 – 5 refineries
Shipping time	1 – 2 weeks	5 – 8 weeks
Import terminals	68 in 26 ports	16 in 2 ports (incl. refineries)
% of Population Affected	11% (54% in Maine)	>90%

* basis: 1996 DOE Study

3.4 Massachusetts

Shortly after the initiation of the Federal Heating Oil Reserve, the State of Massachusetts adopted a somewhat different program to ensure adequate supplies for the state through the winter of 2000, 2001.[22] Discussions with consultants involved in crafting the alternative plan, and review of the provisions of the actual program adopted, reveal a deliberate departure from the "hold, auction and sell" philosophy that underpins the two million barrel Federal Reserve described above. The view was that incentives could be offered to private sector companies to hold certain minimum target inventories through the potentially high-demand months of

[22] Commonwealth of Massachusetts Office of Consumer Affairs and Business Regulation – Heating Oil Inventory Program, A Report by the Division of Energy Resources, March 2001

December through March. The supply, demand and general market pricing factors that compelled the Governor of Massachusetts to urge the Legislature to fund an emergency inventory program were these:

- Heating oil inventories were at historic low levels and only about one-fourth the level at the start of the previous heating season.
- Crude oil prices were extremely high and there was uncertainty if they would increase or drop.
- In October, Massachusetts retail heating oil prices were 50% higher than the previous year.
- Increases in world crude oil production would not eliminate heating oil market vulnerability.
- The market was in 'backwardation' (a term used when prices in future markets are below the prompt market) and Massachusetts heating oil suppliers did not want to store heating oil if they might lose money.
- Cold to colder-than-normal temperatures would also lead to price spikes and increases in consumer heating bills.

Innovative Program: Rather than the State leasing storage and holding inventory, the program establishes a price insurance program for winning bidders that takes the backwardation out of the market for the key months. Essentially, the winning bidders were expected to purchase and store a minimum block, or 10,000 barrels of heating oil. The bidder could submit bids for one or more blocks, and had to specify a bid price and specific storage location for each block. Winning bidders were required to hold the oil until January 16, 2000. Thereafter, the winning bidders could release the oil for sale to Massachusetts's consumers. The decision to release oil before the program date was left to the winning bidders. If the market dictated a need for oil, and winning bidders decided to use the program oil, winning bidders could sell the oil before the program end date (early release). Notification of an early release had to be provided to DOER on the date of the early release. Because early release of program inventory was contrary to the goals of the program, an adjustment would be made to reduce the payment to a winning bidder that executed an early release. The payment adjustment provided an incentive to winning bidders to store the oil until the program end date.

A review of the success of the program after the winter showed:

- Heating oil inventory levels were higher than expected despite colder weather.
- Wholesale prices in Massachusetts were 2-3 cents lower than in surrounding states.
- Massachusetts' retail heating oil prices remained around $1.50 per gallon in December and January with no price spikes even though the weather was about 10% colder than normal.

The entire scope of the program is described in detail on the Massachusetts Energy Website[23].

Relevance for California: Storage for heating oil by winning bidders under the Massachusetts program is distributed in independent terminals around the State. In California, there is no such distributive storage in the hands of independents. As will be shown in Section 4 below, inventory capacity for fuels in California is extremely tight already. Consequently, an incentive program such as that adopted by the State of Massachusetts is not practical in California. It should be kept in mind however, that if the SFR initiative leads to new tankage being built, then a Massachusetts style incentive program might have to be revisited.

3.5 European Reserves

The fundamental purpose that underlies all European and IEA Strategic Reserves is that of national emergency and supply interruption preparedness, with systems designed and maintained for major events such as wars, sabotage, and natural disasters. The Reserves are part of a more comprehensive emergency civil response plan under which the EU requires its members to hold emergency stocks of oil products for three major categories (gasoline and related feedstocks, middle distillates, and heavy fuel oil) equivalent to 90 days domestic consumption of the previous year. The level of 90 days must be maintained for each category. Members may substitute crude oil for product stocks, but the crude oil and feedstocks are converted into finished product equivalents in the three categories for purposes of meeting the EU requirements.

The European systems range from distributive stocks held by the private sector but under government supervision in Italy, to complex mechanisms that have evolved over time in countries as diverse as France and the Netherlands. In Germany, Italy and Ireland, the government owns the Strategic Reserves. Denmark, France and the Netherlands hold agency stocks, with some agencies established under pressure from the industry rather than by government on its own accord.

[23] Massachusetts Department of Energy Website: http://www.state.ma.us

Relevance for California: Most European countries store their reserves in large volumes kept outside the normal distribution channels, in salt dome caverns (Germany, France) or in cavities excavated in granite and other hard rocks (Scandinavia), or in extensive aboveground tank farms (The Netherlands). Because for the most part, the European reserves are not operational, the inventories need to be periodically rotated to prevent product degradation. For many years, for example, straight run (non cracked) gasoline was held in tank without rotation in the Netherlands. After a change of specs was introduced and various streams of cracked hydrocarbons entered the gasoline pool, the reserves had to be commingled with industry stocks for rotation purposes. The turning of large volumes of old inventory created artificial price collapses and volatility, a lesson to be learned for California.

Because the release mechanisms for the European product reserves are designed for exceptional circumstances only, the presence of very large reserves does not affect normal market mechanisms in terms of supply and demand, with its associated volatility, other than the impact from the occasional stock rollovers for reasons of quality control.

3.6 Japan

Japan has a history of oil stockpiling going back to 1972 after the first oil shock, when the government introduced the “Petroleum Reserve Law” creating a 60 day reserve supply, which was increased to 90 days in 1976 and relaxed in April 1996 to 70 days. These requirements apply to all producers and importers, and to crude oil as well as to refined products, with quantities based on actual import levels for the preceding twelve months.

The change in 1996 was part of a deregulation effort when the country repealed a law that restricted imports. Since then, non-refiners are allowed to import gasoline, diesel and kerosene into Japan, so long as they maintain a rolling inventory that complies with the Law [24]. The idea behind this policy is that some level of reserves must be maintained for emergency situations, but in normal times the competition on the international petroleum markets should prevail, even in Japan.

Relevance for California: The parallel with California is that for petroleum products, both are de facto island economies. But while Japan is moving away from its self imposed isolation by opening its markets for imports while maintaining certain minimum reserve requirements, California has been moving the opposite way when it imposed unique fuel specifications and

[24] Petroleum Association of Japan: http://www.paj.gr.jp Annual Report “Overview of the Japanese Petroleum Industry”

lost import infrastructure assets in the ports. The market lessons from Japan will be discussed in more detail in Section 7.

3.7 Korea

In South Korea, the Minister of Commerce, Industry and Energy has wide ranging powers under the "Petroleum Business Act" [25], which grants rights to set the target amount for petroleum reserve not just for major events but also for price stabilization and control of the petroleum markets. It is important to note that Korea has some of the largest refineries in the world with capacities at LG Caltex, Yosu and Yukong (SK) in Ulsan, each in the range of 800 to 900 TBPD. Refinery capacity is overbuilt and geared toward export markets. Consequently the Korean Strategic Reserve has been set aside for crude oil rather than petroleum products.

Relevance for California: Because the markets for petroleum products in Korea is only just now starting a process of deregulation with import opportunities opening up and arbitrage pricing mechanisms linking these markets to world supply and demand, it is too early to tell whether or not the presence of the reserves and the way in which the reserves were managed, had any stabilizing effect on pricing, or caused imbalances between natural supply and demand.

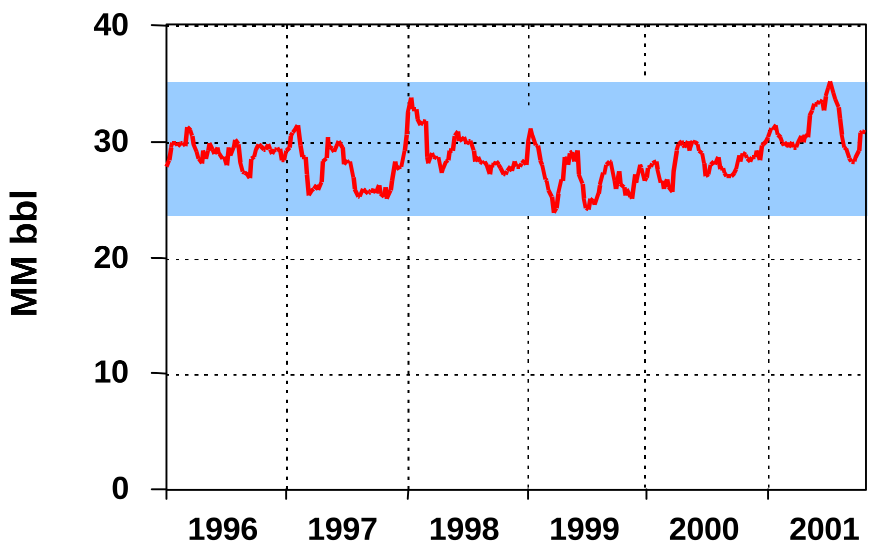
[25] Korea's Petroleum Business Act – Article 15; http://www.petronet.org/english/law/pact.htm

4 OVERVIEW OF INVENTORY CAPACITY AND USAGE

Besides the refiners, several traders and some of the larger buyers currently maintain their own inventories of fuels in California. The refiners also retain title to most of the products in the downstream distribution system, i.e., product in transit in pipelines and kept in distribution terminals.

The refiners and some of the terminals report their inventories on a weekly basis to the EIA and to the CEC. Unfortunately, most refiners consolidate their numbers for PADD V and do not separately report data by state.

Figure 4.1 – Weekly Reported Total Gasoline and Components PADD V



As can be seen in Figure 4.1, the total reported PADD V gasoline and blendstock inventories move in a fairly narrow band around 30 million barrels. When inventories fall below 27 million bbl, the market begins to anticipate shortages and product in general will be hard to find. When inventories start to climb over 30 million barrel, spot prices will be reduced until refinery runs are cut.

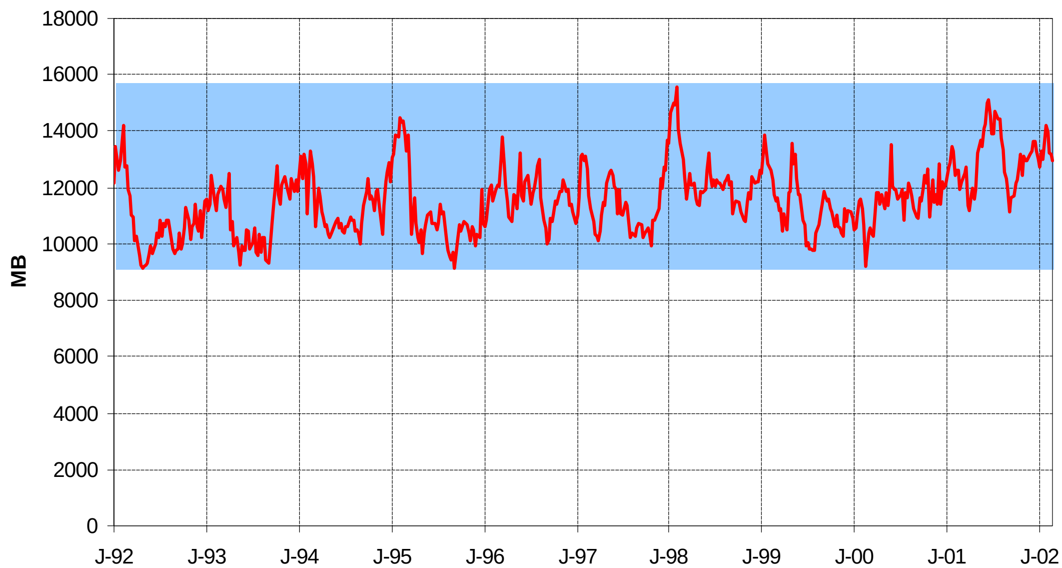
The industry therefore attaches great importance to these inventory numbers as they are reported on a weekly basis, notably to determine whether the market is long or short, i.e., what the short-term trend in the supply/demand balance is. Yet it is generally not well understood how these inventories are distributed between the States, or between the various parts of the distribution chain. Nor is it well understood what the total holding capacity was in the distinct northern and southern California markets, and how the industry manages inventory levels. Moreover, the current reporting system to the CEC does not capture all inventories held in the system. Yet to evaluate the effectiveness of a potential Strategic Fuels Reserve, the total current inventory capability in the State must be known, and current operational aspects must be understood. This Section addresses these questions.

Another interesting observation around Figure 4.1 is that of the narrowness of the range in proportion to the absolute inventory levels. The explanation is that the total number of tanks included in the PADD V inventory numbers is in excess of one thousand. Inventories in most of these tanks are driven by operational reasons, i.e., inventories in distribution tanks or tanks at refineries will cycle between full and empty on a regular periodic basis, sometimes as frequent as several times per week, with the time-weighted average equal to 50% of the workable range. The sum of a large number of such inventories will narrowly approach the average.

4.1 Refinery Inventory Capacity

California refinery inventory data are collected separately by the CEC. These inventories as reported also include certain inventories held at commercial terminals in the Bay area, but not in the LA Basin, and are shown in Figure 4.2.

Figure 4.2 – CA Refinery Inventories of Gasoline and Components [26]



As can be seen in Figure 4.2, gasoline and component inventories held at the California refineries move within a range of 8 to 16 million barrels. The total shell barrel capacity for tanks at the refineries dedicated to gasoline and gasoline components is approximately 13.3 million barrels for the Bay area refineries and 13.7 million barrels in the LA basin [27]. At their highest historical reported level, actual inventories represented therefore approximately 60% of the total available shell capacity, and at their lowest 30%. This percentage confirms that most

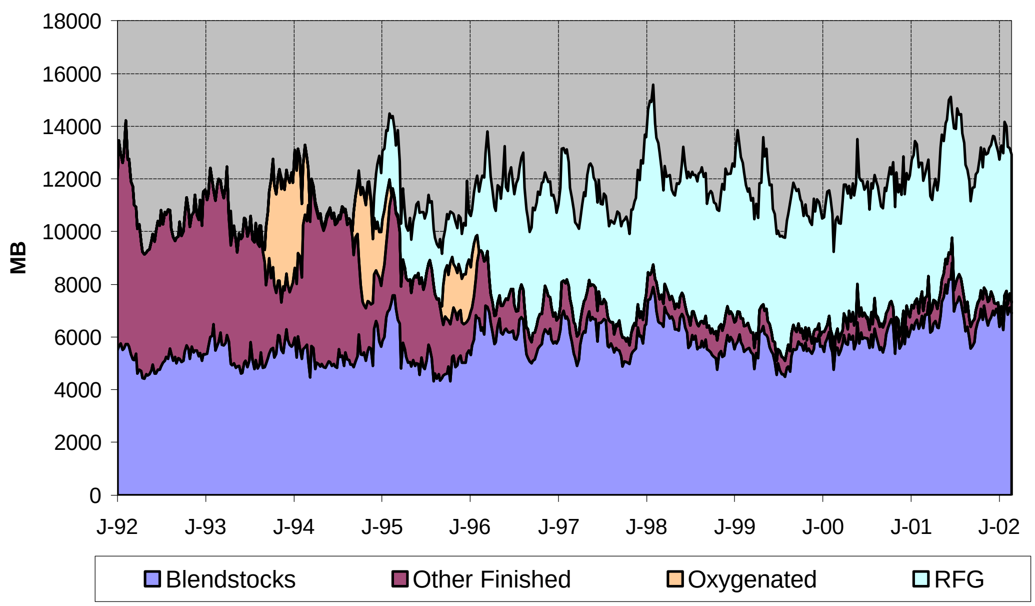
[26] CEC Weekly Reported Inventory Data

[27] Based on information received during the Survey Meetings conducted for this Study

refiners cannot use the tankage at their refineries as an internal reserve for strategic purpose or market tactics, but that operational considerations determine how tankage gets used, with most tanks cycling between full and empty as production is run down into tanks before a batch is pumped out on a pipeline.

For instance, in 1999 when prices were high at the time when major refinery outages occurred, refiners would have had every incentive to use available inventories to the maximum extent possible. That actual inventories never dipped below 8 million barrels confirms that this level represents a collective operational "heel", the minimum stock of blendstocks and finished products that is needed to maintain operations.

Figure 4.3 – Breakdown of CA Refinery Gasoline & Blendstock Inventories [28]



As can be seen in Figure 4.3, blendstock components, including oxygenates, make up over half of the total reported inventories at any point in time. Also noteworthy is that although Other Finished Gasoline constitutes only a small fraction of total inventories, supplying two distinct types of gasoline means that some tankage each in different octane grades, means an inherently less efficient use of tankage.

4.2 Commercial Terminals

Most of the capacity in commercial bulk liquid petroleum terminals in California is concentrated in the Bay Area and in the Los Angeles Basin, where several commercial storage companies

[28] CEC Weekly Reported Refinery Inventories

operate facilities, most of which are tied in to deepwater berths as well as the refinery pipeline infrastructure. In addition to the commercial terminals, there are a few terminals owned by the refiners that provide commercial services to third parties if capacity allows.

Table 4.1 – LA Basin & Bay Area Commercial Petroleum Terminal Capacity [29]

MM bbl	Total Tank Capacity	Clean Product Tanks	Gasoline & Components
Bay Area			
Commercial Operator	8.5	5.7	3.8
Owned by Refiner	0.6	0.6	0.6
Total	**9.1**	**6.3**	**4.4**
LA Basin			
Commercial Operator	22.0	5.7	4.6
Owned by Refiner	7.7	7.2	6.8
Total	**29.7**	**12.9**	**11.4**
Total	**38.8**	**19.2**	**15.8**

Within clean product tankage, terminals cannot change service easily from gasoline to distillates unless the tanks are relatively new and designed as “drain/dry” tankage. On average, market information indicates that at any point in time, approximately 80% of tanks permitted for clean products at the major commercial terminals are in service for gasoline or blending components, including oxygenates.

It is important to note how in Southern California, refiners own the majority of the commercial storage for clean products. This is a legacy of two events, the closure of a refinery with tankage being retained as terminal, and the discontinuation of ANS pipeline exports, which freed up storage at the head of the pipeline. In both cases the refiners decided to monetize these assets by making them available to third parties in commercial service. Now that the LA storage market has grown very tight, while for these refiners internal demand for tankage has grown, this storage increasingly is only available to third parties when the refiner’s own operations allow. Moreover, most of the storage at the commercial terminals is leased out to refiners under long-term contracts, because commercial operators prefer the security of longer-term agreements with highly creditworthy customers over potentially higher rates from short term agreements with trading companies or importers.

[29] Souces: OPIS Petroleum Terminal Handbook, ILTA Handbook, and Survey Meetings with Stakeholders

4.3 Distribution Terminals

Besides the inventories kept at the refineries and in the main commercial terminals, most integrated producers and marketers of gasoline maintain inventories of finished gasoline in the distribution system. Typically, these distribution terminals are connected to the main pipelines, and the facilities include loading racks to serve local distribution by tank truck to retail stations or large consumers. In addition, the pipeline operators maintain storage at strategic locations along the pipeline to serve their own operational requirements as well as customers' needs for distribution tankage.

Table 4.2 – CA Tank Capacity at Distribution Terminals [30]

MM bbl	Total Tank Capacity	Clean Product Tanks	Gasoline & Components
Northern California			
Commercial Operator	3.3	3.0	2.4
Owned by Refiner	3.5	3.2	2.6
Total	**6.8**	**6.2**	**5.0**
Central California			
Commercial Operator	0.6	0.6	0.5
Owned by Refiner	0.1	0.1	0.1
Total	**0.7**	**0.7**	**0.6**
Southern California			
Commercial Operator	2.2	2.2	1.8
Owned by Refiner	4.6	4.5	3.6
Total	**6.8**	**6.7**	**5.4**
Total	**14.3**	**13.6**	**11.0**

Again, within the total clean product tankage available, it is assumed that at any given point in time, approximately 80% is in gasoline service.

4.4 Pipeline Inventories

Long distance transportation pipelines for petroleum products will hold considerable volumes of distillates and gasoline that are in transit. For instance, a 300-mile long, 16" diameter pipeline will hold approximately 400,000 bbl of product, typically consisting of two or three sequential batches of diesel, jet fuel and gasoline.

Pipeline inventories are sometimes included in reported stocks, but overall, total gasoline hold-up at any given time is likely to be less than one million barrels. This volume cannot be readily manipulated to play a role in working inventories in times of shortages and price spikes,

[30] Source: OPIS Petroleum Terminal Handbook, ILTA Handbook, and Survey Meetings with Stakeholders.

although in theory, temporary substitution of batches of gasoline by other products might free up gasoline at the head of the pipeline. In practice however, given the limited storage for diesel and jet along the system in comparison with gasoline and the time, cost, and undesired operational consequences of changing tanks in service, pipeline inventories are not a factor in the total consideration of workable ranges for gasoline inventories in the State, and will not be taken into account here.

4.5 Reconciliation of Reported Inventories and Total Storage Capacity

The total storage capacity of tanks in service in California for gasoline and blendstocks appears to be around 53 million barrels, of which 26 are within the refineries, 16 million are at commercial terminals, and 11 million barrels are spread throughout the State at distribution terminals.

Reported actual inventories for PADD V on the other hand cycle between 25 and 35 million barrels. If inventories are assumed to be distributed in proportion to gasoline production and consumption, then California's share of these reported inventories would be around 70% of the total PADD V numbers, or between 18 and 25 million barrels. These numbers are low in comparison with the total shell capacity of 53 million barrels for all identified gasoline storage in California. However, a number of factors need to be taken into account when comparing reported actual inventories with total shell barrel capacity:

- Published industry tankage capacities are mostly based on nominal shell barrel capacity. Most tanks in gasoline service are of a floating roof design. To minimize the vapors that would be displaced by a rising liquid level under a fixed roof and thus cause hydrocarbon emissions, such tanks have a roof that floats on the surface of the liquid by means of pontoons, with specially designed seals between the shell and the roof edge that prevent the escaping vapors to cause emissions. The roofs have legs that will support it on the bottom when liquid levels drop to a minimum, in order to protect the pontoons and to keep the roof structure above other tank internals, such as suction lines or mixers. In normal operations however, the roof has to be kept afloat, which means that floating roof tanks cannot use the lower 5 to 10% of their shell height. On a statewide basis, this represents 3 to 5 million barrels of unusable capacity.

- Under applicable industry standards (API 653) tanks in gasoline service are required to be inspected on a 10-yearly cycle, although some operators will extend inspection intervals longer. Given the average duration of such inspection, which is often used to upgrade or modify tanks at the same time, as well as outages for operational reasons such as grade changes, up to 5% of the available storage can be expected to be out of service at any given point in time. This effectively removes 3 million barrels of listed capacity.

Most operational tankage in gasoline service sees heavy use and will cycle between full and empty on a continuous basis, with some of the tanks being turned over more than once a week. Other operational considerations also cause average inventories to be around half of the total available range:

- In the production process, enough empty tank space has to be available to allow continued rundown, even if a downstream process fails. Buffer tanks between processes that produce gasoline components and the final blending tanks cannot be kept full, but will typically be run between 40 and 60% of their capacity, to allow upside as well as downside swings.
- In the distribution chain, the same barrel passes through many tanks in a sequential process whereby each tank cycles between full and empty, with the average over a prolonged period being close to 50%. For instance, a blending tank in which a batch is prepared for pipeline dispatch will be empty, or only contain a minimum heel, before the batch is prepared. Once blended, the batch is pumped out to on a pipeline, where an empty tank must be awaiting it at the other end. To have all three tanks in the chain being full would result in an un-operable situation.
- Gasoline tankage is fragmented over as many as two-dozen components and blendstocks and for some refiners up to nine grades of final products. This fragmentation inherently causes tank space to be used less efficiently. For instance, a tank in service for a high octane blending component maybe almost empty, but will not help in storing rundown of treated naphtha.

Based on the above assumptions, it is now possible to reconcile the overall tank capacity for gasoline and blending components in California with the reported inventories for the State:

Nominal Tank Capacity California	53 MM bbl
Ullage, heels, non-operable capacity, 15%	- 8 MM bbl
Effective Total Capacity	45 MM bbl
Expected Average Inventory, 50%	22 MM bbl
Expected Average for CA as 70% of PADD V	21 MM bbl

Similarly, storage capacity and reported inventory numbers at California refineries can be reconciled:

Nominal Tank Capacity Refineries	26 MM bbl
Ullage, heels, non-operable capacity, 15%	- 4 MM bbl
Effective Total Capacity	22 MM bbl
Expected Average Inventory, 50%	11 MM bbl
Reported Average Inventory	12 MM bbl

Overall, despite apparent discrepancies, reported inventories can be reconciled with installed shell capacities. Some interesting conclusions now present themselves when looking at these inventory numbers:

- Inventories at refineries and in the distribution system are almost entirely determined by operational considerations, with tanks cycling continuously between their minimum and maximum practical inventory limits, averaging a little less than 50% of shell capacity.

- The only storage capacity that could be used to serve inventory strategies is that contained in commercial terminals, but total capacity is limited and is largely owned by or contracted out to the refiners.

4.6 Inventory Planning

Inventory planning is different of each group of inventory holders, refiners, traders and large jobbers:

- The refiners balance financial, operational and commercial requirements. On the one hand, they would like to minimize inventories in order to reduce the costs of working capital, while on the other hand they have to resort to very costly measures when they are threatened running out of product. Operational flexibility demands that they leave themselves sufficient room to operate, both on the upside and the downside.

- Unlike refiners, traders usually do not own their tankage, but lease it from commercial service providers. The predominant operational requirement for most traders is that the size of the storage is determined by the cargo sizes of vessels. Traders sometimes want to hold on to inventory until market conditions are favorable to a sale. Often the costs of renting storage and the working capital costs are lesser considerations than the gain or loss on the cargo traded.

- The jobbers who maintain fuel inventories do so in order to reduce their vulnerability to market volatility. They have to offset the cost of working capital and rented storage against the advantage of being able to buy when prices are low, and to stay out of the market when supplies are tight.

Since the refiners control by far the largest inventories, and as producers and importers control the volume swings that are to a large extent the cause of market volatility, a more detailed analysis is provided below of factors that impact refinery inventory management.

4.6.1 Inventory Management for Planned Outages

An oil refinery is made up of a number of processing units that require routine maintenance, such as inspection and repairs, catalyst replacement or regeneration, or upgrading for new technology and replacement of equipment that has reached the end of its service life. A process unit that is down for maintenance is said to be in turnaround. The turnaround cycle for each unit can vary from as little as three months to as long as four years depending on permitting requirements, severity of operating conditions, market conditions, unit performance, and the like.

Normally the maintenance on the units is grouped together such that a number of units are in turnaround simultaneously. A major turnaround typically occurs every three to four years when a refiner brings down its crude unit, catalytic cat cracker, hydrocracker, and/or coker. The duration of a major turnaround normally is 30 to 40 days, although the planning may have started eighteen months earlier.

The turnaround timing and duration are established well in advance. Refiners time their turnarounds so that they occur during the slack demand season. In California the major turnaround season occurs in the period January through March so that the refineries are back in operation for the summer's peak gasoline demand. A secondary turnaround season happens in October/November, after the peak demand.

Refiners do not coordinate the timing of turnarounds with one another, due to anti-trust concerns, but they do track one another's activities. Maintenance contractors frequently have to fulfill a role of go-between and coordinate the refiners' operations because their people and equipment will be at work in a number of refineries at the same time.

The impact of the turnaround on the refinery's fuel production is forecasted and managers responsible for supply and planning are charged with ensuring that sufficient fuel supplies are arranged to meet the refinery's demand forecasts, usually through pre-staging inventories through increased own production, purchases from other refiners or traders, or imports. Rented storage may be arranged when available, and external supplies are scheduled to be delivered through the refinery's own systems during the turnaround.

Generally, planned turnaround coverage does not create price spikes. The coverage is well planned and spaced out. A recent example was seen in the Los Angeles market during the spring of 2001 when a major refiner had an FCC turnaround. The Fluidic Catalytic Cracker (FCC) is the biggest producer of regular gasoline in most refineries. Industry publications reported that the refiner brought its FCC down suddenly, which normally means that the market will spike up as the refiner's traders scramble to cover the unplanned shortfall. In this case the market showed little reaction because the FCC went down on a planned turnaround, for which the refiner's Supply Department had planned adequate coverage, so that they did not have to go into the market at the last minute to cover demand [31].

Prices frequently will rise if the turnaround is extended past the scheduled completion date and the refiner's traders have to go into the spot market to cover the additional supply shortfall. One can observe, for example, that prices frequently rise in late March or early April as refineries are struggling to complete their maintenance.

4.6.2 Inventory Planning Processes

The planning processes can be thought of in three different time horizons. These are strategic, tactical, and operational. Strategic inventory planning is long range, one year or greater, and is normally done for the purpose of financial modeling by central corporate planning departments. At this level, turnaround planning is coordinated between a company's different refineries, and the basis is provided for long-term crude oil and feedstock supply contracts, tanker fleet charters, and other long-term commitments. At this stage, inventory targets are set as a function of overall working capital costs and as financial targets for management to achieve.

Tactical planning for inventory is usually the purview of middle management and generally covers the current month and out three to six months. It covers actual volume planning around turnarounds, crude runs, and expected market movements, such as those caused by seasonal specification changes. At this level, planning involves optimization using Linear Programming (LP) models of the refineries.

Operational inventory management is the responsibility of schedulers and occurs in the current timeframe, from right now to out six weeks or the duration of the scheduler's time horizon. It is the scheduler's job to keep product moving out of the refinery to the

[31] Information received during Stakeholder Meetings.

terminals to ensure that customer demand is met. At this stage, an actual forecast is made showing inventories for each tank, based on production and blending operations, ship and barge movements, pipeline cycles and demand forecasts.

4.6.3 Reactions to Unplanned Supply Reductions

With most refiners, the Supply Department is not located in the refinery. Therefore, it may take the Supply Department some time to discover that their refinery has had an unplanned supply disruption. Supply disruptions could be as dramatic as a refinery explosion or as subtle as the loss of the pump that delivers product to the pipeline.

When a supply disruption occurs, the refiner's supply department will try to cover their requirements quickly and in such a way as to minimize the impact of the disruption on its own financial bottom line. This implies that if the disruption is not immediately apparent to the public, as is the case for most outages that do not involve a fire or explosion, the refiner will keep a tight lid on information related to its operational difficulties, and go into the market through parallel channels, either directly with its own traders approaching other refiners, or indirectly through multiple brokers and traders, in order to cover its shortfall before a market run-up occurs.

Eventually, the refiner's problems will become known in the market and, depending on the total inventory situation, this news will usually result in a price spike.

5 GOVERNMENT ISSUES

There are a number of current regulatory initiatives in the State of California that will negatively impact the supply capability of the petroleum industry in the State, either temporarily or permanently. This section will attempt to quantify the impact of each of these initiatives and their relevance for the creation of an eventual Strategic Fuels Reserve.

5.1 CARB Phase III and MTBE Phase Out

On February 19, 2002, a public workshop was held by the CEC to discuss the impact of the phase out of MTBE by year-end 2002, as mandated by the Governor's Executive Order of 1999. The conclusions of a separate study by Stillwater Associates were discussed at this workshop. The scope of this study was limited to the impact of the phase out on gasoline supplies and infrastructure, and the main conclusions of the report are no different than the points raised in the supply and demand section of the Strategic Reserve Study:

- Phase out by year-end 2002 will cause a 5 – 10% reduction in supply. The bulk of the supply shortfall occurs in the LA Basin. If left unfilled, such shortfall is likely to cause a 50 to 100% increase in prices.
- There are no suitable substitutes available from the US gulf Coast, and even if there were, US flagged shipping would not be available in sufficient numbers.
- Sources for suitable blending components can be identified abroad, but given the currently already constrained import logistics, it is inevitable that the already severe pricing volatility will be aggravated.
- The economic impact of the initial price spike and the subsequent increased volatility were estimated to cost the California gasoline consumer between $1 and 3 billion per year.
- The recommendation was to delay phase out of MTBE by three years, until additional infrastructure for imports can be realized, and exports to Arizona can be kept within the State as pipeline supplies from the US Gulf Coast reach Phoenix.

As far as the actual scope of the study was concerned, comments during the workshop centered on the economic assumptions, projections of production capacity in the State, and impact of price spikes. Comments outside the scope mainly focused on the adequacy of ethanol supplies, and various environmental issues with viewpoints largely depending on the particular interest of the party.

The result of the various reports and briefings has been that the Governor will take a decision on the proposed delay in the course of April.

5.2 AQMD 1178

As part of a consent degree that resulted from the settlement of a lawsuit brought against the South Coast Air Quality Management District (SCAQMD) by several environmental organizations, the SCAQMD agreed to create new regulations that will result in further reductions in emissions of Volatile Organic Compounds (VOCs) in the Los Angeles basin by 8 short tons per year (8 TPY).

Of these target emission reductions, a total of 3 TPY are to be achieved in three consecutive phases through additional control measures in large-scale petroleum and petrochemical industrial installations. After an initial evaluation of the options, the SCAQMD decided that in the first phase, between 1 and 1.5 TPY of VOC reductions could be achieved by measures that will reduce evaporative emissions from bulk liquid storage tanks. The proposed measures included improving the tightness of roof fittings and constructing domed roof over open floating roof storage tanks containing high vapor pressure petroleum products. Subsequently, the SCAQMD instigated a workgroup with participants from the affected industries in order to discuss feasibility, cost effectiveness and implementation schedules for the proposed regulation.

The new regulation as proposed by the SCAQMD, which initially was referred to as Rule 1173.1 and later designated Rule 1178, called for doming of all crude oil and product tanks at facilities with total VOC emissions greater than 20 TPY, under a program of which the first phase, comprising of the vast majority of all crude oil and product tanks at the LA refineries and at some of the main commercial terminals, was to have been completed by 2006. The cost effectiveness of the program was questionable for the larger tanks, in particular for those containing crude oil, and the 4-year implementation schedule was deemed unfeasible and considered a risk to supply security. Feedback from the affected parties, industry organizations and the CEC (assisted by Stillwater Associates), caused the SCAQMD to reconsider the scope and implementation schedule.

The regulation, as adopted by the District's Board in a public hearing on December 21, 2001, requires that 75% of the tanks for gasoline and gasoline components are to be domed by December 31st, 2006 and the remainder by December 31st, 2008. The rule no longer includes a requirement for doming of crude oil tanks because it is not cost effective. Even with this extended schedule, there is still cause to be concerned that supply reliability in the LA basin may be impacted by the number of crucial storage tanks that will be out of service at any given moment for project work. Under the applicable standard, API 653, aboveground atmospheric storage tanks are normally taken out of service for internal inspection and maintenance on a 20-year schedule, and the 7-year schedule with additional project work extending the down-time, means that on average during the next seven years, the amount of storage that is not available to accommodate demand swings or refinery problems is 3 to 5 times more than normal.

There is no doubt that the creation of a Strategic Reserve, or any other measure that will enable more storage to become available to the LA refiners within the extended timeframe of the new Rule, will help to alleviate the pressure on an already very tight market for bulk storage of petroleum products in the LA Basin and lessen the impact of Rule 1178 on the availability of storage.

5.3 Ports of Los Angeles and Long Beach

Although joined by common waterways and infrastructure, the ports of Los Angeles and Long Beach are separate entities, each governed by a Board whose members are appointed by the elected officials of the two cities, with authority derived under a mandate from the State Lands Commission. The management mandate for both Port Authorities resides within a Master Plan for land use and development that is approved by the State Lands Commission (CSLC). Even within the Master Plan, certain decisions concerning land use and development will be subject to review by the City Council of each port and the CSLC.

Current policies in both ports do not favor bulk liquid operations for petroleum products, and the closure of existing facilities and lack of development opportunities for new capacity could severely impact the capability of the State to meet future requirements for fuels through imports. Almost all terminals in both ports are built on leased land, and as the leases come up for renewal, the ports will reassess the land usage, with the result that over time, more terminals will have to make way for large scale container operations or other land uses with higher revenue than can be offered by bulk liquids.

5.3.1 Port of Los Angeles

The current long term Master Plan for the Port of Los Angeles (PoLA) provides for the creation of a common bulk liquid terminal for crude oil and petroleum products on the newly created landfill area of Pier 400. The plan assumed that some of the existing petroleum terminals that were located in areas for which the PoLA had other plans would be relocated to this new bulk liquid terminal area on Pier 400 when their current leases expired. This plan, which dates back over 10 years, never gained acceptance within the industry, mainly because the proposed site at Pier 400 is remote, requiring significant investments in pipelines in order to provide access into the existing refining infrastructure.

Given the lack of interest from the side of the industry, the PoLA has meanwhile granted most of the land of Pier 400 in leasehold to container terminal operators, with only a limited footprint remaining for bulk liquid facilities. The remaining area of 25 acres would allow building at the most three tanks of 0.5 million barrels each, which in combination with an 80-foot draft berth and a large capacity crude oil pipeline connection to the inland refineries will enable offloading of a fully loaded VLCC. The PoLA and several potential users are still evaluating the options for development of a crude oil terminal at Pier 400. In any event, it is very unlikely that any future development scenario for the site will include facilities for handling of clean products, and the net result will be that several clean products and black oil facilities will have been shut down in the PoLA without the anticipated replacement at Pier 400 being realized.

There are two other developments in the PoLA that could negatively impact the port's capability to handle imports of fuels. The first is formed by heightened community concerns about the safety of bulk petroleum storage as potential targets for terrorist attacks, which has led to a request by Council members to study the closure or relocation of three terminals in San Pedro and Wilmington. The second issue is that of Environmental Justice, a term used by NGOs protesting the disparity between the exposure to pollutants in the communities surrounding the Ports, with the poorer, largely minority populated communities bearing the brunt of the exposure.

Although understandable from a local perspective, these initiatives, if carried through, could lead to a further reduction in fuel receipt facilities in the PoLA and will make future expansion very difficult.

5.3.2 Port of Long Beach

The Port of Long Beach (PoLB) faces problems that are to a certain extent different from those in Los Angeles. Both ports face an increasing demand for container handling – in fact, the projections for the PoLB call for a doubling of containers from the current 5 million TEU (Twenty-foot Equivalent Units) to 10 million by 2010 and then to double again to 20 million by 2020. Much of this growth will be realized by creating mega-terminals, container facilities with at least 400 acres of storage yards and capable of handling the new 10,000 TEU container vessels.

However, Long Beach does not face the same pressure from individuals or action groups concerned about safety or environmental justice. Yet the need to create space for container terminals is so acute that it is still uncertain whether the PoLB will be able to accommodate two existing bulk liquid storage facilities in the plans it has for expansion of the Pier A container terminal.

As is the case for the PoLA with its Pier 400 project, the Port of Long Beach has plans for a new deepwater receipt facility for crude oil at Berth 123, adjacent to the current crude oil berth shared by three refiners. The footprint for the new facility is expected to be very limited in size and in fact, would not include any storage at all. As for the LA Pier 400 plans, there are no plans for additional receipt facilities for petroleum products.

5.3.3 Summary of Port Issues

In Section 1.1.4 of this study, it was shown how California has become increasingly dependent on imports for its requirements of crude oil and petroleum products, and how the sources of these imports are shifting from domestic sources to remote foreign locations requiring larger scale receipt facilities. In section 1.3 it was shown how predominantly, the shortfall occurs in the southern California market, which relies on the ports of LA and Long Beach for its imports.

The current trends and policies in the ports of Los Angeles and Long Beach are not favorable to bulk liquid storage facilities, and although plans exist in both ports to accommodate future requirements for crude oil imports, there are no established plans for increases in clean petroleum products such as gasoline and gasoline components.

5.4 Military fuels

Jet fuel was not part of original study, especially military jet fuel, but the terrorist attacks have changed this outlook. Defense Energy Supply personnel in California would like to meet with staff and contractors. Proposed work would examine quantities and locations of military jet that should be stored and will examine delivery infrastructure constraints.

5.5 MOTERP

After the 1994 Northridge earthquake, and other earthquakes in which marine terminal facilities were damaged, the California State Land's Commission initiated a project to create a set of uniform engineering standards that would ensure that marine oil terminals would be equally resistant to earthquakes as the refineries to which they are linked.

Currently the CSLC has a final draft in preparation of new regulations that will require the owners of a high-risk facility (risk of a spill of more than 1,200 bbl of petroleum products in a standardized accident scenario), to inspect their docks and shore facilities within 30 months after the regulations take effect. These inspections will follow a detailed protocol and an action plan must be developed to mitigate any findings. Lower risk facilities have 48 months in which to carry out the inspection program.

The CSLC will evaluate each plan on an individual basis, and in general, does not impose a hard time limit for completion to allow the concerned terminal operator to design a workable schedule, which minimizes impact on operations. In general, the CSLC believes that most facilities can be remediated within 6 to 8 years.

Given the scheduling flexibility, it is not expected that MOTERP implementation will lead to an immediate reduction in available import facilities, as is the case for SCAQMD Rule 1178. Nevertheless, there are likely to be facilities for which the cost of the upgrades cannot be justified by the operator, and which will therefore close down.

6 OPTIONS FOR A STRATEGIC FUEL RESERVE

A fundamental choice for creating a Strategic Fuels Reserve is whether to use existing inventory capacity or to build new tankage. As seen in the previous Section 4, by conventional logistic standards existing tankage is already inadequate for the volumes currently handled. Moreover, during the stakeholder meetings, the shortage of existing storage capacity was widely reported as one of the major problems the industry currently faces (see Section 8.1). This study will therefore focus on adding new storage capacity or converting existing tankage currently not in petroleum products service as the only viable way to create an eventual reserve in California.

This study does not attempt to develop any of the considered options to a level of detail where cost estimates can be prepared with the accuracy normally required for an investment decision. At this stage of early feasibility analysis, order of magnitude estimates are used, where possible based on factorial comparison with known costs for similar projects, or based on published information and industry practice.

6.1 New Tankage

For new tankage, the primary considerations is the selection of a location, in particular whether the storage needs to be built as a grassroots project requiring its own infrastructure development, or whether it can be built as an extension to existing facilities and share in already available infrastructure such as roads, docks, pipeline connections, and utilities. For the first option, reference will be made to existing studies, while for the latter two locations are examined in more detail.

6.1.1 Findings of 1993 Study

In 1993, an extensive study was carried out by Invictus Corporation of Wilton, CA, to determine the feasibility and cost for a single reserve of petroleum products, capable of holding an inventory of 5 million barrels [32]. The costs of the project, including acquisition of a 215 acre site and connections to the main product distribution pipelines, but excluding the cost of an initial fill of the reserve, were estimated at $131 to $143 million (1995 $). Operating cost for the facility were evaluated at $6.6 to $7.9 million per year, with the high end of the range representing a location in Stockton that included operating a dock. The other locations that were evaluated for the reserve besides Stockton were Fresno and Roseville. These three locations were retained after

[32] *Feasibility Study of a Regional Petroleum Product Reserve in California*, December 1993, Invictus Corporation, Wilton, CA, Resource Decisions, San Francisco, CA, and Capital Research, Chevy Chase, MD.

an initial survey that included a total of 15 sites, mainly inland and chosen for reasons of earthquake security rather than connectivity with existing petroleum infrastructure.

If escalated for inflation from 1995 to current [33], the construction cost for the Stockton option would amount to $154 million, or $31 per barrel of shell capacity, and operating cost of $0.16 per shell barrel per month. These numbers are similar to numbers quoted by major oil companies as fully loaded costs. In general, commercial terminal operators reported substantially lower numbers for new grassroots construction, claiming that they are able to build and operate terminals cheaper than the major oil companies or the State because of their specialized knowledge and lower overheads. If the project were to be realized as an expansion of an existing facility, with infrastructure already in place, costs could fall to half the numbers used by Invictus, based on information received from commercial terminal operators currently involved in expansion projects.

In addition to the construction and operating costs, Invictus evaluated the cost of filling the reserve at more than $150 million at then prevailing fuel prices. The conclusion of the Invictus study, using an economic model to predict the price moderation effect of the reserve in case of a major supply disruption, was that the costs of building, filling and operating the single 5 million barrel reserve was not warranted by the increase in security of supply.

The 1993 study did not address the logistics of moving product in and out of the reserve, other than the pumping costs for the initial fill, and as has been shown in section 2.1.3 above, the concept of the single, central reserve would have been flawed because of the inability of the existing transportation system to deliver products to the different markets in a timely manner. Also, the concept of tying the reserve into the distribution grid with a single 8" line would have proven impractical, since it would have taken almost two months to draw down or replenish the reserve. Yet the cost estimate is representative for grassroots investment, and will be used in the build-or-buy analysis below.

6.1.2 New Storage Built and Operated by the State

For new storage to be built and operated by the State, the following overall scope will be assumed to meet requirements for full integration into local refining centers and import capability:

[33] Bureau of Labor Statistics Data, *Producer Price Index All Industries*. 1995: 124.2; 2001(p): 133.5

- Bay Area: 6 x 150,000 bbl drain-dry open floating roof tanks, 15 acre site owned fee simple, dock 800 feet long, 35 feet draft, VDU, 5 mile 16" pipeline connection to main grid.

- LA Basin: 9 x 150,000 bbl drain-dry floating roof tanks with dome, 20 acre leased site, use of 3rd party dock, 2 mile 16" connection to main grid.

The differences in scope between the Bay Area storage and the LA Basin facility reflect a reasonable estimate of prevailing local conditions, i.e., leased versus owned land and SCAQMD requirements.

If the reserve is to be part of a larger project, i.e., if double the volume is deemed necessary, or if additional storage were to be built simultaneously for lease to third parties as part of a larger, commingled terminal in which both the State and private entities maintain inventories, then there will be certain economies of scale from which the State would benefit on a proportional basis. For the time being, as a conservative first approach, the costs for building the reserve will be calculated on an individual project basis.

Summary of construction and operating costs (for details see Attachment __):

Table 6.1 – Cost Summary of State Owned and Operated Reserve

	Bay Area	**LA Basin**	**Total**
Investment, $ MM	39	36	75
Fixed Costs, $ MM/year	8	9	17
Throughput Cost, $/bbl			
Pipeline In/Pipeline Out	0.34	0.34	
Pipeline In/Barge Out	0.25	0.44	
Vessel In/Pipeline Out	0.23	0.41	

The total investment costs of $75 MM for 2.2 MM bbl are consistent with the figure of $154 MM of escalated costs for the 5 MM bbl storage of the earlier Invictus study, in that it would imply an exponential scaling factor of 0.88, which is conservative when compared to the value of 0.7 to 0.8 generally used in the industry for this type of installation (a higher number means a more linear relationship between scale and costs, a lower number means that on a per unit basis, smaller installations are more expensive).

The throughput costs are the cost related to moving material in and out of the reserve, such as the fees for using the 3rd party owned pipeline gathering systems, port fees, dock fees paid to 3rd parties for options where the dock is not owned, and the cost of physical losses associated with the movement of the material, such as evaporative and trans-mix losses, which are estimated to average 0.1%.

6.1.3 *New Storage Built and Operated by a Commercial Service Provider*

Market information obtained during the survey meetings has confirmed that commercial terminal operators in the Bay Area and in the LA Basin are willing to build new storage capacity under a long-term, i.e., 10 year contract at currently prevailing market rates of $0.45 to $0.55 per barrel of shell capacity per month.

Table 6.2 – Cost Summary for Leased Reserve

	Bay Area	**LA Basin**	**Total**
Investment, $ MM	0	0	0
Fixed Costs, $ MM/year	5.4	7.2	13.6
Throughput Cost, $/bbl			
Pipeline In/Pipeline Out	0.33	0.33	
Pipeline In/Barge Out	0.25	0.44	
Vessel In/Pipeline Out	0.23	0.41	

The fixed costs are based on the minimum fixed tank rental of $0.50/bbl/month, which under the terms customary in the industry includes the right to store and withdraw the tank volume once per month (one “turn”). Any excess throughput in a given month incurs an additional throughput fee, usually in the order of $0.20/bbl. However, no excess throughput charges are included in the Through Put Costs as listed, since it is unlikely that a reserve could be utilized and replenished more than once during one month. The throughput cost for the leased tankage in terms of pipeline and port fees, and inherent product losses, are virtually equal to those for owned tankage. The slight reduction for the pipeline in/out option is due to the energy cost for pumping, which are included in the base cost for leased storage.

It will be clear from a comparison of Tables 6.1 and 6.2 that it will be difficult to justify building state-owned and operated tankage, given the very competitive prevailing market rates of commercial service providers. The disparity between commercial rates and fully loaded costs incurred by large corporations is further explained below and is consistent with market information received during the survey meetings with industry stakeholders as conducted for this Study (Section 10.1).

6.2 Incentives for Increased Inventories by Current Inventory Holders

An idea that was floated during the stakeholder survey meetings was that of an industry-held component to an eventual reserve, i.e., that by providing incentives to compensate for the cost of working capital associated with larger stocks, the current holders of inventories could be enticed to increase the amount of product held at any point in time, and would only dip into a certain portion of their inventories under pre-agreed conditions or when specifically authorized to do so. On reviewing inventory data and from feedback received during the stakeholder meetings, it became immediately clear however that there is little or no room to increase inventories within the California refining and distribution system.

The same arguments that apply to inventories at refineries also apply to those held at commercial terminals: space is tight and even when provided with incentives to compensate for working capital cost plus tank rental expense, owners of fuels would not be able to find more space.

This leaves the option to provide incentives to the industry that will result in more storage capacity being built. These incentives can take the form of providing financial aid, such as investment guarantees or subsidies, but can also include measures to remove the barriers that currently prevent normal free market mechanisms to cause supply to match demand,

6.2.1 Financial Incentives to Increase Storage Capacities

Currently the contract rental rates for petroleum product tankage are around \$0.45 to \$0.50 per bbl per month in the Bay Area, and \$0.50 to \$0.55 per bbl per month in the LA Basin. Spot contracts can be between 5 to 10 cents higher. At these rates, commercial terminal operators have reinvestment economics, but large refiners would need higher numbers to justify building new tankage for themselves under the criteria that most of these companies apply for internal rates of return.

There are several reasons why a large refiner’s costs are higher, and they are relevant when considering what incentives may be needed to promote infrastructure investments:

- A large refiner's project costs are generally substantially higher than those of smaller specialized firms because of allocated corporate overheads, more elaborate company standards, and higher cost of the owner's project management team.

- Required internal rates of return are higher in oil companies where projects generally carry significant risk and therefore need higher rewards, versus the service industry whose projects are usually backed by long term contracts with low risk and are therefore acceptable at utility level returns.

- Oil companies do not benefit from certain tax advantages available to most commercial terminal operators, who are often structured as Master Limited Partnerships (MLP).

- Capital resource allocation decisions in oil companies will favor investments in core businesses such as exploration, production and refining, rather than in infrastructure projects.

These factors have led to a proportional under-investment by refiners in storage, causing their inventory capacity to lag behind their increases in production capacity. In general, storage capacity will only be added at refineries when justified by operability issues rather than economic reasons.

Trading companies or large purchasers of fuels, who also maintain inventories, face similar obstacles to investment in wholly owned terminals and pipelines. In addition, these companies are generally not well equipped to run capital projects of this nature, have even higher internal hurdle rates for investment, and have a forward demand that is not always predictable.

The logical conclusion would be for refiners, traders, and large buyers to outsource their storage requirements to specialized third party service providers. For short-term requirements that can be met with existing capacity, this is indeed how the industry functions. However, this solution of choice becomes more complicated when the service provider has to invest in new facilities to meet the demand. For new investment, given their inherently lower utility level rates of return, the service companies need long-term commitments from the principals before they can invest, usually in the order of 5 to 15 years.

Unfortunately, it is almost as difficult for refiners, traders and buyers to commit to a long-term contract, as it is to obtain approvals to spend the capital internally. Long-term capital commitments are also referred to as pseudo-capital commitments, which have to be footnoted in financial statements and may impact a company's borrowing capability in a similar way as debt incurred to finance investments. Thus the problem becomes a vicious cycle, in which the holders of inventory are reluctant to invest in owned infrastructure, nor eager to commit to long-term contracts, and the service providers unable to invest without such commitments.

A measure available to the State to promote new infrastructure investment in the petroleum sector would be to offer guarantees for certain projects under well-defined conditions. For instance, rather than renting storage for 0.9 MM bbl of state-owned reserve in the Bay and 1.3 MM bbl in LA, the State could:

- Offer a tender for commercial storage operators to build the required volumes of tankage.
- The commercial storage operators rent out tankage at normal rates to refiners, traders and marketers under short-term agreements.
- If for some reason, tankage is not rented out for longer than a certain minimum delay period, the State would reimburse the operator for the fixed cost and capital recovery part of the monthly rental fee, but not the profits.
- Contracts for the guarantees would be awarded to those commercial terminal operators offering the lowest required monthly guarantee, after the longest delay, over the shortest overall number of years of validity of the guarantee.

The advantage of this option is that it is unlikely that it will ever require the State to spend any real money, but that it will allow the commercial operators to build tankage without long-term commitment from customers. This solution can be combined with other initiatives, whereby the State would rent part of newly built reserves itself and fill it with State owned reserves, while allowing the commercial terminal operator to rent out the remainder under the guarantee program in commingled tankage. The resulting combination is one of the solutions of which the economic effectiveness will be evaluated in Section 8.

6.2.2 Removal of Barriers to Infrastructure Projects

The main reason why normal laws of supply and demand do not function in the market for bulk liquid storage for petroleum products is the formidable efforts that must be undertaken to obtain the necessary permits. Even permits for a relatively modest expansion took over three years to obtain. This project was located in a heavily industrialized area, for tankage that was in fact a replacement of military fuel storage removed nearby, and was undertaken by one of the leading companies in the field [34].

Several factors complicate the permitting process:

- In the refinery centers in the Bay and the LA Basin, the areas where storage is most in demand, the permitting process for new tanks involves approval processes with multiple regulatory agencies. These processes are largely sequential and involve public review at several stages.
- Even when approved after all due regulatory review, projects can be held up indefinitely in court by Non Government Organizations (NGOs) representing interests of communities, even if projects are located in remote areas zoned for industry with no residential habitation in the direct vicinity.
- The NGOs that represent the local interest operate nationwide, are relatively well funded, and benefit from better central coordination and more favorable press relations than the industry.
- Permit applications for individual projects may require a lengthy procedure to update the Master Plan for land use in the ports as laid down in the State Land grants under which the Ports operate, while granting an exemption leaves the Port Authorities vulnerable to suits filed by opponents.
- The Port Authorities and other local regulatory agencies that have control over land use are not always aware of the greater interests at stake, and may have to give priority to interests of local electorate.
- The momentum in the Ports is building against bulk liquid terminals, with several terminals in the Bay and in the LA Basing closed down in recent years, and several more currently under scrutiny.

In summary, the current regulatory environment is such that it is easy and cheap to prevent infrastructure from being built, while filing project applications is uncertain and costly. Measures that the State could consider as options to ensure an adequate infrastructure for fuels, including a Strategic Fuels Reserve, are:

[34] Information received during Stakeholder Meetings.

- Centralizing the permitting process for bulk liquid storage and pipeline projects for fuels ("one stop shopping")

- Preparing blanket Environmental Impact Reports (EIR) for major changes, such as CARB Phase III implementation, whereby the overall macro-environmental impact factors are defined centrally, so that for individual projects, only local factors need to be considered.

- Introduction of a fast track procedure for fuels infrastructure projects that improve overall fuel supply reliability in the State.

These measures will enable normal market supply to meet the inherent demand without direct intervention or significant expenditure of taxpayer money. Similar measures were enacted for the power generation and transmission infrastructure, but only after 13 years had passed in which no new capacity was added, and a real crisis had sprung up. The challenge is to implement this type of program as a preventive measure rather than in a crisis environment, given the political hurdles at local level.

6.3 Recommissioning of Idle Tankage

Given the tightness of the bulk liquid storage market in California, there is no tankage that is currently left idle that does not have some significant problems associated with it that prevent its re-commissioning.

6.3.1 Idle Tankage linked to Refinery Infrastructure

A survey of the LA Basin and the Eastern Bay Area, the primary areas for location of an eventual strategic fuels reserve, revealed some terminals with decommissioned or otherwise idle storage with sufficient capacity to be considered for service as a Strategic Fuels Reserve. This tankage is mainly associated with power stations and closed-down refineries.

Table 6.3 – Summary of Idle or Decommissioned Tankage

	Bay Area	**LA Basin**	**Total**
Tankage at Closed Refineries	0.0	1.7	1.7
Fuel Oil Storage at Power Plants	4.0	3.5	7.5
Total	**4.0**	**5.2**	**9.2**

Several factors make it unlikely that the idle storage identified in Table 6.4 can be brought on-line again economically:

- For 1.0 MM bbl of refinery storage in the LA Basin, rates quoted by the owner for rental of the recommissioned tanks are 60 to 80% higher than the cost of new built tankage. This high cost is likely to be due to the factors quoted in Section 6.2.1 listing some of the reasons why large refiners incur substantially higher net project costs.

- The remaining 0.7 MM bbl of idle refinery tankage is associated with a refinery that may still be reactivated and its storage is not separately available.

- In total, 3.5 million barrels of idle power station fuel oil storage was identified in the LA Basin, and up to 4 million barrels in the Bay area. This idle tankage consists for the most part of older tanks that are neither suitable nor permitted for storage of high vapor pressure products. To make these tanks suitable will require significant investments, and the permitting process will be similar to that for new tankage. Moreover, the individual tanks are usually very large, i.e., in the range of 300,000 to 500,000 bbl per tank, which renders them less useful for product storage (see Section 2.2), while pipeline connections with the clean products distribution system would have to be created using whatever black oil lines are available.

Despite the obstacles, it seems likely that using existing tankage will result in some savings in time and project costs versus building new tanks for the reserve. Evaluating each of these options in sufficient detail to quantify cost savings versus new construction requires a level of engineering work not foreseen in the scope of this study. At this stage of early feasibility evaluation, it seems reasonable to assume that if a tender for the creation and operation of a reserve were issued to service industries operating in the LA Basin and in the Bay Area, and if those companies would be able to offer services at more competitive cost by using the idled power station tankage, then normal market forces would drive inclusion of these alternatives in the proposals to the State. For now, no significant cost reductions will be assumed.

6.3.2 Tankage Not Tied to the Distribution System

Only a few instances have been identified of idle tankage outside the refining centers, not connected to the main distribution system.

- In Ventura, 800,000 bbl of tank capacity associated with the former USA refinery. This tankage has been out of service for 15 years and would require major investment to be brought up to code. Moreover, dock facilities have been removed and substantial investment would be involved in converting a idled crude pipeline to products.

- In various coastal power stations, a total of 3 million barrels of former fuel oil tankage has not yet been removed. Most of these tanks are in poor shape, have no longer access to single point moorings or dock facilities, and are in locations where pipeline connections to the refining centers would require new pipelines through environmentally sensitive areas.

In total, the volume of such tanks that could in theory still be rehabilitated and made fit for service in light products may exceed the 2 million bbl required for the reserve. For all of the sites however, it makes no economic sense to attempt upgrade and connect the storage by pipeline to the refining centers, because even grassroots investment within the refining centers is bound to be more cost effective.

6.4 Conversion of Tanks Currently in Black Oil or Crude Oil Storage

In both the northern and southern refining centers, some tanks are currently used in black oil service (heavy fuel oil, VGO, bunkers, crude oil) that are capable of and permitted for storage of clean petroleum products. While surveys did not produce a complete inventory of all tanks with dual capability in California, with 1.5 MM bbl of identified tankage with commercial terminal operators in the LA Basin and at least 0.5 MM bbl in the Bay, it is estimated that total volume of such tankage exceeds the proposed volume of a Strategic Fuels reserve in each area.

However, using these tanks for a Strategic Reserve in light petroleum products is unlikely to bring an overall improvement of supply reliability in the State. Storage for black oil and crude is also very tight in both refining centers, and although commercial terminal rates for these products tend to be slightly below those of clean products in the current markets, the actual costs of the facilities that can handle the heavy products is higher. More often than not, black oil tanks and pipelines have to be heated and insulated, and pumps and other equipment have to be designed for highly viscous products.

If 2.3 MM bbl of tankage that has dual capability were to be removed from black oil and crude service to create a Strategic Reserve, this would represent less than 10% of available storage volumes for these products in the State. However, at less than 15 days of storage, crude oil inventory capability in California is already dangerously low by standards applied in most other parts of the world. Especially with the crude supply situation changing rapidly and the State becoming increasingly dependent for its crude oil supplies on foreign imports from remote locations requiring Very Large Crude Carriers (VLCC), it would not be prudent to recommend creating a Strategic Fuels Reserve for light products in current crude oil tankage with light product capability.

Black oil storage capacity, in contrast, seems more generous, with more than 20 MM bbl of tankage available in commercial terminals alone. However, black oil storage requirements are not determined to the same extent as gasoline or crude oil in terms of days of throughput, but rather by operational requirements for intermediate product storage allowing refinery units to function somewhat independently from each other, in particular to enable partial shutdowns and turnarounds of upstream units such as cokers and distillation units, and downstream upgrading sections. As it is, black oil storage available to refiners has declined by over 8 MM bbl over the past years, with aboveground tankage being scrapped or converted to crude oil, and the last of the large inground reservoirs has been decommissioned. It is therefore not recommended to attempt creating a Strategic Fuels Reserve in either black oil or crude oil storage capable of handling lighter products.

6.5 Floating Storage using Converted Tankers

Worldwide, many instances can be found where laid-up or obsolete tankers have been used to provide floating storage, usually as a floating dock and surrogate marine terminal, capable of receiving cargoes through a board-board transfer from a similarly sized or smaller vessel.

To evaluate this option as an alternative for a Strategic Fuel Reserve in California, a number of factors need to be considered, such as size and availability of vessels, the logistics of moving product in and out of the floating storage, and of course the approximate cost of maintaining tankers as storage.

Table 6.4 below compares a number of alternatives. From this table, it will be clear that it is not practical to assume that a reserve can be created using product tankers, simply because of the number of vessels that would be required and the cost involved. Even though availability is not the issue (it is estimated that in the next two years, 11 single hull US flagged product tankers will be retired [35]), the cost of maintaining the vessels at anchor and operating them as a floating terminal are likely to be prohibitive at an estimated $24,000 per tanker per day. Moreover, at least in LA, the space is simply not available to anchor 5 of these vessels.

[35] MARAD, *OPA Schedule for retirement of Single Hull Product Tankers*, Jan 2001

Table 6.4 – Alternatives for Floating Storage

	VLCC	Product Carrier	Reserve Fleet
Provenance	Foreign, newly retired vessels	OPA single hull retirement	NDRF
Size (DWT)	250 – 300,000	35 – 40,000	18 – 35,000
Draft (feet)	50 - 60	35 - 40	30 - 35
Capacity (bbl)	1.5 – 2 MM	250 – 300,000	175 – 300,000
Vessels required, Bay / LA	1 / 1	3 / 5	3 / 5
Costs ($/bbl/month)	$0.75 - $1.00	$2 - $2.50	?
Cost product in/out ($/bbl)	>$0.75	>$1.00	?

While also expensive, the use of one retired VLCC in the Bay and one in the outer harbor of Los Angeles, both permanently moored and equipped with fenders and loading arms for board-board transfers, is at least doable from a practical point of view. The difficulty here will be to obtain a waiver for the Jones Act requirement, since no US flagged VLCCs were ever built, and to obtain permitting for a single hull vessel to be used as floating storage. All these factors, as well as the high cost, make this an option of last resort, since it has the advantage of being able to be implemented at short notice, i.e., in less than 4 to 6 months.

6.6 Incentives to Increase Fuel Production in California

The need for an SFR is borne out of a chronic supply shortage of gasoline in California, where refiners run close to or at maximum capacity with import options limited by commercial and physical barriers. In such a situation, each unplanned refinery outage immediately translates into a price spike. If somehow, production capacity could be increased so that a healthy margin of spare refining capacity existed, as was the case up to the mid-nineties (see Figure 1.1), other refiners would be able to take up the slack and compensate for the loss of production due to unplanned outages.

It is clearly not within the mandate of AB2076 to evaluate whether the State should enter into the refining business. However, there are measures the State could consider with regard to increasing refinery capacity that could achieve the same goal of suppressing price spikes at potentially comparable or lower cost than are likely to be incurred in the creation of an SFR. In particular, the State could contemplate measures to streamline and expedite the permitting process for projects that increase fuel production in California similar to the legislation introduced in order to accelerate capacity additions for power production.

Currently, the political climate in California is not conducive to the expansion of fuel production in the State. The consensus opinion amongst industry participants is that no new refineries will ever be built, although CEC forecasts of gasoline demand require the supply equivalent of an additional two refineries to be built between now and 2020, despite expected advances in fuel economies of cars [36].

Problems that refiners face when contemplating even small capacity additions are:

- Many refiners are up against hard constraints in their CAAA Title V Operating Permit. Even a small debottleneck of one unit may require applying for a new overall operating permit. In many cases, this renders the project uneconomical.

- Emission credits are expensive and offsets are hard to achieve, which again means that small projects are often not attractive.

- NGO's have proved to be adept at slowing or eliminating needed expansions. Part of the decision that CENCO Refining made to abandon plans to restart the Powerine refinery can be attributed to lawsuits brought by environmental groups. Unions have delayed the permitting of CARB Phase III projects in refineries in Northern California.

Government agencies have enforced their own agendas to the detriment of fuel production and logistics. The Port of Los Angeles has tabled the relocation of terminals in their port. The South Coast Air Quality Management District's Rule 1178 will put pressure on the distribution system, risking supply disruptions because of tankage that is taken out of service for doming. Permitting is a time consuming process. It took Kinder Morgan two years to get permits for the construction and operation of three new jet fuel tanks at their tank farm in Watson.

Government can create incentives to increasing fuel production by reducing the barriers that government has created. These include a coordinated permitting process, a new look at permitting requirements, and one-stop shopping for all energy related projects, not just electrical power.

[36] *Energy Outlook 2020*, California Energy Commission Staff Report, Docket No. 00-CEO-Vol II, August 2000

7 MARKET CONSIDERATIONS

The California markets for gasoline, diesel and jet fuel are each different in key aspects such as structure, liquidity, and forward trading opportunities. Of the three major liquid fuels, the gasoline market is not only the largest market by far, but also the most complex because of such factors as the uniqueness of the fuel specifications, the overall tightness of supplies and the relative inelasticity of demand. These and other factors underlie the severe volatility of the gasoline market and will be evaluated below, with the other markets, in particular the market for jet fuel, used only as a frame of reference.

7.1 General Description of the California Gasoline Markets

The California gasoline market has a layered structure, formed by four separate but interrelated markets:

- **Spot**. The spot market consists primarily of the trade at the refinery level. Traded gasoline volumes are typically 25 MB (approximately 1 million gallons, also referred to as a “piece”) and are delivered into a pipeline at a place and time specified by the buyer. Most deals are “prompt”, meaning the first open cycle on the pipeline, usually within one or two weeks. There are some twenty to thirty participants in the West Coast spot market, including refiners who buy and sell products between themselves to balance out volume requirements, trading houses, brokers, and the large independent marketers. The spot market moves with the perceived change in refinery supply and demand.

- **Rack**. The rack market consists of wholesale buyers such as independent retailers and bulk customers who operate their own truck fleet (“jobbers”) and who take delivery of their product at a truck loading rack situated at a terminal, or sometimes directly at the refinery. Rack market participants may buy branded products destined for branded stations, or unbranded products destined for independent service stations or commercial/industrial accounts. In general, branded rack prices tend to move in relation to street prices. Unbranded rack prices tend to move with the spot market.

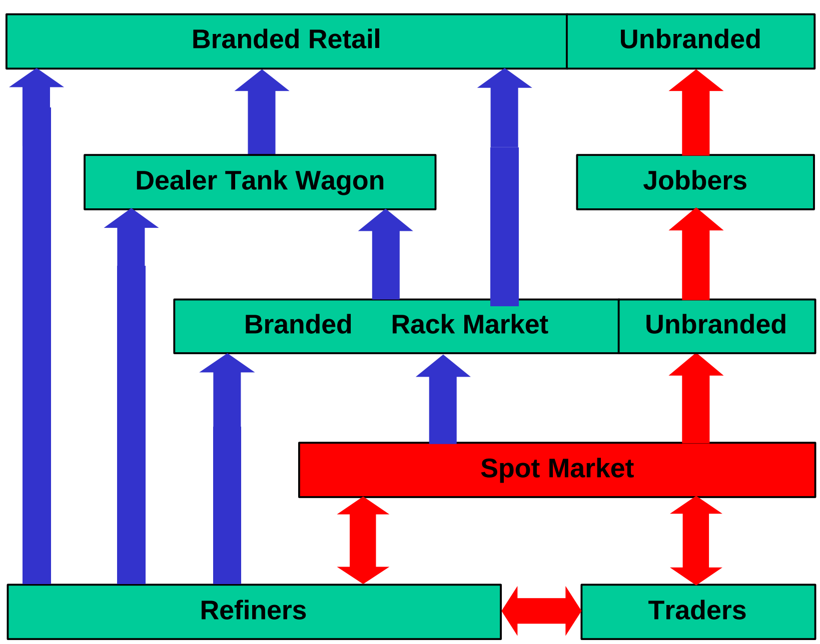
- **Dealer Tank Wagon**. The price of gasoline delivered to a branded retail site is termed Dealer Tank Wagon (“DTW”). In a stable market, DTW is set by review of competitive prices. In an unstable market, DTW tends to move with the change in spot prices, although the magnitude and duration of the changes can be different than those of the spot market.

- **Retail Market**. The retail market is where pump prices are posted. Street prices are normally set relative to prices of other local gasoline stations. Recently, a new force in retail is emerging in the form of High Volume Retailers ("HVR"), which are operated by large chain stores aim at large volumes at low margins. HVRs tend to price their gasoline on cost, rather than local competition.

7.2 Pricing Mechanisms

The spot market is essentially an over the counter market, with deals negotiated on an individual basis between participants. Reporting of deals and posting of pricing by reporting services such as OPIS or Platt's occurs when both buyer and seller confirm the deal. In the California spot market, which includes deals made for supplies into Nevada and Arizona, there are between 20 and 30 active participants, and a "liquid day" is a day that sees four or five deals being concluded. More typical are days with only one or two deals. Not all reported deals are physical deals: pieces can be bought and resold several times, and become physical only when delivery is due by the final seller in the chain at the scheduled slot in the pipeline cycle.

Figure 7.1 – CA Gasoline Market Structure



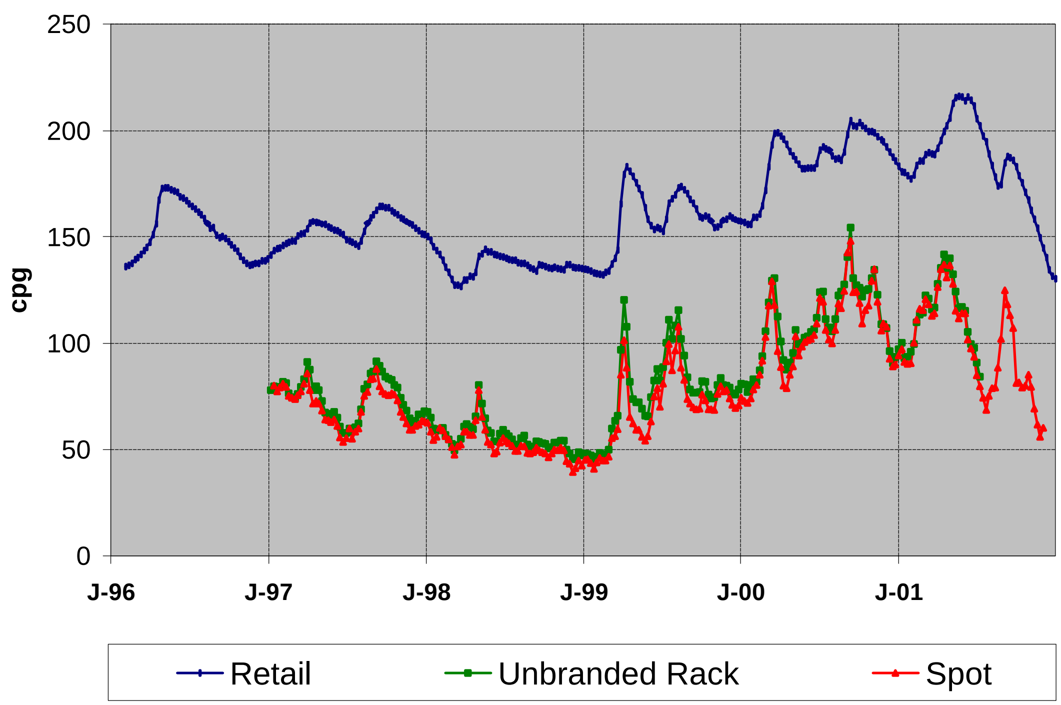
Daily spot prices are driven by prompt market imbalances in supply and demand that are brought to a head by the weekly pipeline schedule requiring prompt physical delivery. Every spot purchase by definition is a one-time event. The buyer and the seller incur no obligation for future transactions, although forward deals may be transacted as adjunct to, or independently from, the spot purchase. The cumulative effect of these transactions propels the price up when markets are tight, with several buyers chasing limited supply. In down markets, the price will descend in the absence of firm deals as sellers look for buyers at lower prices, while buyers back away. These imbalances can be as small as ten thousand barrels (10MB), with 25MB being the average 'piece'. If a refiner, marketer or trader is 'short' that amount of product and must 'cover', or purchase in the prompt spot market in order to meet physical delivery obligations, that transaction can push the spot price, as reported by OPIS up five to seven cents per gallon in a tight market. In other words, 25MB moves the deemed value of the entire gasoline inventory in the State because it represents, "the last deal done".

Rack pricing for gasoline is broken into two segments: Branded and Unbranded. Pricing of gasoline for these two classes of trade is complex, dynamic and interrelated. Branded gasoline wholesalers are subdivided into classifications of "jobbers" and DTW (Dealer Tank wagon) accounts. DTW prices represent the wholesale price paid by the dealer to a refiner for gasoline delivered in bulk to that dealer's retail outlets. Often the DTW price is higher than the unbranded rack, plus transportation. The branded dealer has, in effect, traded off the opportunity to take advantage of steep wholesale price declines during periods of oversupply, for a greater consideration of security of supply and an acceptable guaranteed margin over the long term. Imbedded in the DTW price is the deemed value of the supplying company's brand name.

Jobbers are those companies that service the market sector from the refiners' truck loading racks to end-user retail and consumer accounts. They establish credit lines with the refining companies sufficient to service their customer base and pick up their loads against pre-negotiated contracts. A jobber may service both branded and the unbranded accounts. They take title to the product as it passes the truck flange but may be restricted by contract to deliver certain loads only to branded customers in particular market zones. The refiners structure their contracts with the jobbers to prevent the delivery of 'unbranded rack' priced truckloads to 'branded dealers' when the unbranded and spot market prices are weaker. Conversely, they are not allowed to 'over-lift' branded gasoline during tight market and deliver those loads to the unbranded sector. Because of differences in zone pricing, even in the 'branded' sector the same jobber may pick up several loads from the same refiner on any given day and be charged a different price for each through a long-established value of TVA discounts (Temporary Voluntary Allowance).

Competition among the major brands in various metropolitan and even outlying areas rises and falls in intensity based on market-share strategies and promotions. Each market zone will be charged a price approximating what that particular market will bear, given its demographic position and a number of secondary factors such as traffic count, corner location and deemed price-elasticity, nearest competitor, etc. The integrated refiners also operate their own truck fleets dedicated to branded gas station deliveries under the DTW system. Surveys of the major refining & marketing companies in the state have found that most do not post a meaningful 'unbranded rack' price. They remain balanced to short with respect to their refining capacity and their branded dealer downstream demand. Through recent mergers, the number of refiners supplying the unbranded rack market in significant quantities has been reduced from two to one.

Figure 7.2 – CA Gasoline Spot and Retail Prices



It is clear from Figure 7.2 that the unbranded rack price closely tracks the spot price, and that retail pricing, which includes a significant mark-up from federal, state and local taxes, follows the movements of spot and rack not only with a slight delay, but also with movements that are somewhat dampened by the fact that the refiners will protect their branded retail to some extend on the upswing, while holding on to margins a little longer on the downward slope.

Another important element of pricing is that of the transfer pricing policies within the integrated refining and marketing companies. The integrated oil companies produce crude oil, refine it, and distribute the products through their branded retail locations. None of major oil companies operating in California are completely integrated, since all of them are somewhat dependent on other companies (or countries) for crude oil supply upstream of the refinery and product supply or offtake downstream of the refinery. In order to help measure their performance, the refiners have to have a benchmark for the crude oil and products markets. In general, they use the spot market for this gauge. They assume they are buying crude oil from their producing company at the spot, refining it, and selling the products to their retail organization at spot prices. The retail organization receives product at a spot price and sells it at retail. Their relative profitability can be described as DTW or Rack Price minus Spot Price minus expenses. This permits a company to quantify the relative profitability of each link in its supply chain.

7.3 Effect of Insularity

For petroleum products, California is an insular market, separated from world markets not just by geographical distance, but also by product quality aspects, commercial barriers and infrastructure limitations, all of which cause price differentials above mere transportation cost. There are many examples of markets that are insular in nature, sometimes because they literally are islands, such as is the case for Hawaii or Japan, sometimes because of protective tariffs, and sometimes, as is the case for California, because of a complex set of factors that prevent a free flow of goods when price differentials would dictate they do.

The relationship between price differentials between markets and the total cost to move goods between them, including transportation, duties, storage, time value of money, etc., is referred to as geographical arbitrage, or “arb”. The arb is said to be open when the differential is large enough to leave a profit to the importer, and the arb is closed when differentials do not justify movements.

In closed economies, local prices can be substantially above world market plus transportation costs because of restrictions on imports or duty barriers. Usually, high local prices then are indicative of inefficient production or limited competition, or a combination of the two.

In open economies, such as is the case for California, local prices should be at world market prices plus transport cost. However, sometimes for prolonged periods, California prices are substantially higher. Since California refineries are amongst the most sophisticated in the world, and since temporary situations of oversupply during winter months immediately result in severe price drops – as was the case as recently as December 2001 through January 2002 – it can be concluded that the insularity of the California market has not resulted in inefficiencies or uncompetitive practices. The only remaining explanation for the prolonged price excursions above world market plus arb is therefore that import options are indeed restrained by physical reasons (terminal capacity) and commercial factors (price volatility), It is important to note that because on average, California refineries are efficient and low-cost, and are engaged in open competition, imports are not necessarily going to lower the average price. Rather, the import dependency has caused an increase in the incremental cost of supply, which in turn raises the price of the entire market and increases refining margins. The effect of an eventual SFR maybe to lower the cost of imports and reduce price spikes, but it will not lower the price of gasoline to the incremental cost of production within the State itself.

7.4 California Fuels Forward and Futures Markets

A forward market is a market in which a buyer and seller agree to a physical transaction with a future delivery date, but for which prices and delivery terms are agreed at the time of the transaction. The advantage of a forward market is that it allows a buyer and seller to lock in margins over cost on a specific shipment. However, both buyer and seller take a risk that the market may shift and either party to the agreement stands to lose or gain substantially on the deal when compared to the market conditions that may prevail at the time of physical delivery. A forward transaction implies integrity on the part of both parties to honor the commitment despite market changes. The spot market in Los Angeles currently has only a very thinly traded forward market component, i.e. only one or two forward trades are typically conducted per week , and rarely for more than one month into the future.

A futures market is a market in which non-physical trades are conducted using standardized contracts under which factors such as product specifications and delivery terms are defined. Futures are transacted between licensed traders in open auctions on a trading floor rather than directly between principals, with the exchange acting as the clearinghouse for all transactions. Futures markets, such as the NYMEX (New York Mercantile Exchange) in New York and the IPE (International Petroleum Exchange) in London are subject to government regulation. Since buyers and sellers do not deal directly with each other, but rather through the institution, or clearing house, a system of margin calls and allowable “open interest” (total number of contracts, long or short, in a given month for a given company) is strictly enforced to ensure the integrity of the Exchange. At the NYMEX, futures are traded for crude oil, gasoline, and heating oil. The advantage of a futures market is that it allows parties to a forward contract not just to lock in prices and margins over costs, but also to lock in prices relative to prevailing market conditions at some future point in time. Using standardized futures, a seller can hedge a physical forward sale by offsetting it with a non-physical forward buy of another commodity that generally moves in the market at a fixed differential to the commodity he wants to sell at some future date. The process of reducing future market risk by entering into offsetting selling and buying agreements is called hedging.

A thinly traded forward paper market does exist in California but with insufficient volume to provide a bridge to a traditional futures contract. In the absence of a forward or futures market, a trader or importer bringing products into California takes a significant gamble, given the volatility of the market. The importance of the existence, or rather lack thereof, of future or forward markets for the California fuels situation lies in the insularity of the California markets in general. A potential importer of a cargo of gasoline typically has to take a decision to produce and load a cargo 6 to 8 weeks before it will reach the market. Even though the spread between production costs plus shipping costs and the California market price may be very attractive at the moment a decision has to be taken, the situation may be reversed by the time the cargo finally reaches the market. Many importers would prefer to lock in a known margin of 1 or 2 cpg at the time of shipment, rather than take a gamble that a 20 cpg price spike in the California market will last until their cargo arrives [37]. A cargo of gasoline arriving on Friday could be valued at twenty cents per gallon lower than one arriving on Monday of the same week, a potential loss of millions of dollars.

Because the lack of forward price protection inhibits out-of-State suppliers from delivering cargoes to California, price spikes are exacerbated and become long plateaus of relative price elevation. A futures market would enable hedging and liquidity, which in turn will attract cargo re-supply when needed.

The question now becomes, what can be done to promote liquidity and create forward and futures markets for California gasoline. A survey of a broad range of market participants, including Futures Markets planners and administrators, confirmed that the prerequisites for a commodity futures contract to take root in any market are:

- **Market Liquidity**. There must be a minimum number of buyers and sellers in the market, each with different business orientations, who together form sufficient critical mass to conduct a minimum number of transactions daily.

- **Fungibility**. There needs to be an established transaction flow in a product with a common specification or with established price differentials to other commonly traded commodities. Heating oil, for example, has been a very successful NYMEX commodity because its specifications can cross over to a number of markets: Jet fuel, transportation diesel, home heating oil, kerosene, etc. Diversion from this basic commodity spec can be evaluated in the physical market between buyers and sellers. The NYMEX contract can still be used as a basis for exchange after factoring in such value differentials. California

[37] Information received from all traders and importers during the Survey meetings with industry Stakeholders.

gasoline and CARB diesel, on the other hand, are unique formulations that contribute to the isolation of the State and to price volatility. This is one of the major obstacles for establishing a liquid futures market in California.

- **Physical Delivery Point**. A futures contract buyer, also known as ‘a holder of a long position’ retains the legal right to demand physical delivery of the commodity upon expiration of that contract. Without a basis in guaranteed physical delivery, a commodity futures market would be merely an arena for speculating on price movement in the absence of underlying value. Given this necessity for physical delivery, California has never been seen as a fertile field for a traditional futures market, such as NYMEX to take root. There is no common storage available to non-California refiners or international traders. It has been noted that the Kinder Morgan (KM) pipeline gathering system could serve as such a delivery point, if it were to be linked to common storage accessible to various classes of trade. Existing refineries and most product terminals are already connected to the KM gathering system. A State sponsored SFR commingled with private sector inventories could provide the common storage that could form the physical delivery point for a standardized futures commodities contract.

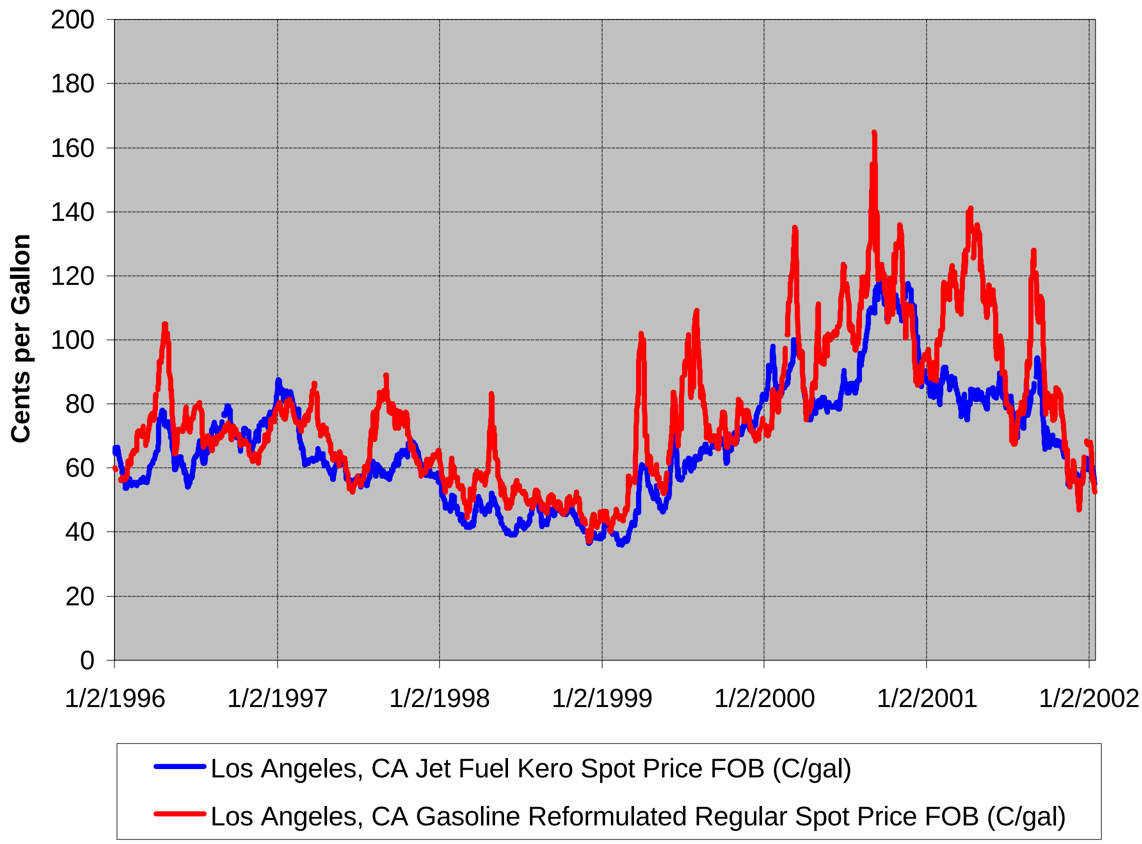
- **Multiple Supplies**. There should be a variety of supply points into the locus of the futures contract. NYH is easily accessible by vessel from such diverse points as Northwest Europe, South America, the US Gulf and Caribbean areas.

- **Diversity of participants**. Besides diversity of geographical supply points, the participants should also represent a diversity of interest in order to ensure market liquidity. For example, in New York Harbor (NYH), besides the refiners and global traders, there are over twenty-five local companies involved in shipping, blending, trading, marketing, etc. These spot-market oriented companies tend to depress price spikes by blending batches to meet local demand. Gasoline blending is not feasible in California outside the refining systems due to the lack of available storage, the Unocal Patent barrier and the severe penalties attached to off-test blends. The greatest part of a futures market’s liquidity actually comes from non-integrated traders and energy companies. The integrated majors tend to regard their integrated supply chains (i.e., Crude ⇒ Refinery ⇒ Distribution System ⇒ End Customer), as a natural hedge against price aberrations that occur at any point in the value chain, such as local price spikes in gasoline or heating oil.

- **Day-to-Day Participation.** A commodity market is most effective when buyers and sellers enter the market every day. A stop and start system, as would be engendered in a boutique fuels market such as California gasoline, does not lend itself to a viable futures market.

One finds most of these prerequisites fulfilled in connection with the Los Angeles jet fuel market, but not in gasoline where there is no common specification, no common storage and no established transaction flow from alternate sources. Consequently, the price volatility for jet fuel is far lower than for gasoline as illustrated in Figure 7.3. While jet fuel tracks the same underlying trend as gasoline, which is mainly related to crude oil pricing, the jet prices do not show the spikiness and volatility of gasoline.

Figure 7.3 – LA Spot Prices for Jet Fuel and Gasoline[38]



It should be noted that futures trading has sometimes failed in other markets. The NYMEX U.S. Gulf Coast Heating Oil and Gasoline contracts, for example, could not generate enough liquidity (transaction volume) because the Gulf Coast is essentially a supply center rather than a consuming center. In theory the contract had a chance to work, in that Gulf Coast refiners might want to hedge their production locally. Instead, they preferred to continue using the

[38] Source: EIA daily spot prices

destination market of NYH on a net back basis (NY price minus a differential). Singapore crude oil was another failed experiment. A Brent vs. Dubai (European vs. Asian) crude contract was established in the mid nineties to capture more efficiently the international flow of cargoes and prices. The contract was ultimately under-subscribed, largely because of an Asian business culture that prefers negotiated deals to anonymous, electronic transactions. Basically, these experiments lacked one or more of the prerequisites indicated. Nonetheless, a California futures market for gasoline, diesel and perhaps blend stocks could emerge in the private sector through the operation of an SFR if the following strategic elements are incorporated into it:

- SFR inventories are commingled with private sector inventories.
- The tankage is connected to the Kinder Morgan gathering systems in the Los Angeles basin and in the Bay Area.
- Use of the SFR inventory is triggered by time-trades, or buy-sell agreements rather than outright sales.
- Access to the SFR inventories is open to various, pre-qualified classes of trade.
- The SFR has direct waterborne access for incoming cargoes and can serve as the physical delivery point for a futures market.

8 DESIGN AND EFFECTIVENESS OF THE RESERVE

Based on the above, the most effective design of a reserve will be that which will function not as a stagnant inventory set-aside program, but as highly liquid physical delivery point for imports, fully integrated into the refining infrastructure, marine terminals, and distribution pipeline systems, with its volume accessible to qualified participants as a "bank" from which supplies may be drawn against a fee, with repayment in kind within a specified time frame.

The very existence of such a bank will provide a center for discharging incoming products cargoes. By virtue of being located at the head of the distribution pipeline systems the SFR will provide a clearing center for price and transaction liquidity. By commingling any State-owned inventory with private sector supplies (similar to the Heating Oil Reserve in NYH), a double benefit can be gained. First, the commingled product will be constantly "turned over" in the normal flow and scheduling process. This will insure seasonal quality integrity and prevent quality degradation. Whether release of State-owned SFR inventories are to be triggered by pre-defined price formula, or unscheduled refinery events under one model, or by a regular withdrawal allowance system as an "oil bank" under an alternative model, the effect of such release will be to draw the island of California more rationally into regional price and logistic patterns (geographic arbitrage).

8.1 Tank Space

Based on the findings of Section 6 above, tank space will have to be newly created, and the most cost effective way of doing so is by issuing a tender for bids by qualified commercial storage operators for a long-term, i.e., 10-year contract for storage space. To suppress the cost of the State's share and to help create storage space for use by third parties not normally capable of entering into the long-term agreements tank operators need as financing prerequisites for new storage, the State could request double the amount of tankage to be built, but offering only minimal guarantees for the excess capacity, with would oblige the commercial operator to exercise best efforts to find lessors.

Assuming that the base 2.5 MM bbl can be leased for $0.50 per bbl per month for a cost of $15 million per year, and that the State's guarantee for the additional 2.5 MM bbl will be $0.35/bbl/month, and the guarantee on average will be evoked for 10% of the time, costing the State an additional $1 million per year, then the total cost for the storage will be $16 million per year.

With the tanks operated as a fuel bank, all additional operating costs identified in Section 6 above, such as volume losses and pipeline fees, will be absorbed by the parties drawing from the reserve and replacing it.

8.2 Initial Fill

Based on a recent-years historical range of gasoline prices from 50 to 130 cpg, the initial fill of 2.5 MM bbl can cost anywhere from $50 to $140 million. There are however several alternatives open for the State to minimize the upfront capital outlay for this purchase.

Firstly, a partial offset can be claimed against the Federal Petroleum Reserve, because volumes held in reserve as products in California need not be covered by a corresponding amount of crude oil in the Texas caverns. This mechanism was also used in part to fund the Eastern Heating Oil Reserve.

Secondly, the fuel will not be consumed, but will remain substantially in place as collateral, with guarantees in place from qualified participants for volume lent out at any point in time. It should therefore be possible to secure debt against the collateral, possibly subject to margin calls if the underlying risk of fuel price fluctuations cannot be entirely secured by forward rolling hedge mechanisms.

A reasonable estimate therefore seems to be that the costs of the initial fill can be reduced to the cost of the debt service on part of the purchase costs, possibly in the range of $5 to $10 million per year.

In order not to cause a market disruption, it will be important to purchase the initial fill quantity gradually, preferably during the winter season and from remote sources. Contrary to what has been suggested in AB2076, it is recommended to include local refiners in parties allowed to bid on tenders for the initial fill. During the winter season, some spare capacity usually exists in the California refining system, and the local refiners would be able to use imported blendstocks to complement local capacity to produce CARBOB for storage in the SFR.

8.3 Participants

Access to the reserve volumes is one of the key questions that was raised during the Stakeholder Meetings. The options on this issue range from an entirely open forum, whereby even non Industry participants capable of posting financial guarantees would be invited to an SFR auction, to a highly selective core group of major oil companies. Each of these options is discussed in detail below.

- **Open Forum.** It can be argued that a truly democratic approach to operating the SFR would be to open the bidding for supply to all financially capable applicants. This approach was tried with the Federal Crude Oil Reserve with disastrous results. The winner of the initial purchase bid turned out to be a non-industry party who was not capable of performing under the terms of the contract upon winning the bid. This caused confusion, and became an embarrassing waste of time and money. Since the recommended solution for the California SFR is a "time swap" mechanism rather than an outright sale of product, (see "Operating Mechanism below), the system will require a high degree of familiarity with contractual and operational issues, such as scheduling pipelines and vessels, product quality details, etc. There will be an obligation incumbent upon any successful bidder to physically perform the contracts on both the inventory drawdown side and the product replacement side. Product will move into and out of the SFR on a contractually binding schedule. This will require a measure of professional expertise with the California supply and distribution system. Financial ability alone will not suffice to qualify an applicant to participate in the auction process.

- **Refiners Only**. Another theory advanced has been that only California refiners should be allowed to draw product from the reserve. Since price spikes are primarily caused by unscheduled events in a refinery, such as fires, explosions, unit downtime, etc. it could be argued that it is the refiners alone who should avail themselves of the product held in reserve by the State. If not limited to the particular refiner suffering the problem, then the field of auction participants should at least be narrowed down to the Refining class of trade. On the other side of this argument stands the widely acknowledged fact that a price spike caused by a supply interruption at a particular refinery impacts the statewide gasoline market, to some degree. The laws of 'force majeure' do not relieve a commodity supplier from delivery obligations under contract, so long as alternative supplies of that commodity are available, at some price, in the market. So too, a refinery suffering an unscheduled event that causes production curtailment and a price spike remains bound to cover his contract obligations so long as alternative supplies can be purchased or acquired through trade. That refiner, and the refining class of trade as a whole, should have the right to bid for product from the SFR, but it is not an exclusive right any more than California petroleum products are an exclusive market. Business Interruption Insurance is available to the manufacturing sector of any industry.

- **Qualified Stakeholders**. The balanced approach is to invite Industry professionals to participate, subject to predefined financial and performance criteria. Under this scheme all market sectors in California would be allowed to compete for product released from the SFR in volume increments consistent with their operational needs and credit limits. It may be necessary to install volume limits for individual companies in order to prevent too much of the SFR falling into too few hands, thereby creating a market control situation. A concerted effort must be made to ensure that qualified Independents have access to the SFR system.

8.4 Effect of Mobilizing Reserve Volumes

When the creation of the Northeast Heating Oil Reserve was being discussed, there was speculation that inventory managers would take the government's inventories into account when planning their inventories [39]. The theory was that creating a reserve could lead to lower inventories because the government would be there as a backstop. Similarly, during the Stakeholder meetings, several companies suggested that a fuel reserve could reduce commercial inventories.

In the course of the Stakeholder Meetings conducted for this study, a number of companies who are participants in the Northeast Heating Oil Reserve were interviewed. None of them thought that the existence of the Reserve impacted commercial inventory planning practices. However, the Northeast Reserve has only been in existence since the fall of 2000 and seemed to be a non-factor in the heating oil market after it was filled.

Given that the workable inventory range for gasoline at the refineries is only 8 million barrels (see Figure 4.1), which equates to a mere 8 days of production, it is clear that the primary consideration in setting inventory targets are operational. This is borne out by information received during the Stakeholder Meetings, in which refiners without exception reported that their operational considerations are paramount, with inventories resulting from fluctuations in demand and production that are largely unplanned.

The presence of a reserve can be a concern however to importers, who may be reluctant to commit to a cargo that would arrive 6 to 8 weeks after the onset of a price spike if volumes from a reserve are overhanging the market. To avoid these concerns, criteria can be formulated for release mechanisms:

- Release mechanisms must be clearly formulated and strictly applied.
- Trigger prices must be set high enough above prevailing levels so that imports would start to flow well before reserve volumes would be released.
- Access to the reserve must be open to all classes of regular suppliers and distributors of gasoline and components, with an option to borrow and repay in kind (time swap).

[39] Statement of Neal L. Wolkoff, Executive VP, NYMEX before the US House of Representatives Committee on Commerce, Subcommittee on Energy and Power, October 19, 2000

Although some "gaming" of the release rules can be expected, it should be possible to design release mechanisms such that economics will drive inventory managers to control their inventories without regard to an eventual SFR.

8.5 Operating Mechanisms

After evaluating several event driven trigger mechanisms, including those whereby a price spike of "x" cpg in the spot market sustained over a "y" number of days, and is caused by an identifiable event, would trigger a time-swap auction of volumes from the SFR, the proposal is to operate the reserve volumes as a base volume for time-swaps. This trigger mechanism has distinct advantages over event driven triggers, which have the problem that hurdle levels can be set either too low (preventing normal market re-supply), or too high (requiring real economic damage to occur first). The time-swap operation also answers best to the requirements formulated in AB 2076:

> "The commission shall evaluate a mechanism to release fuel from the reserve that permits any customer to contract at any time for delivery of fuel from the reserve in exchange for an equal amount of fuel that meets California specification and is produced from a source outside California that the customer agrees to deliver back to the reserve within a time period to be established by the commission, but no longer than six weeks." [40]

The current proposal therefore is to create a mechanism for daily auctions, preferably in a fully transparent format, i.e., on an electronic exchange, whereby a pre-qualified participant can bid on a fee to pay for prompt lifting with redelivery within 6 weeks.

To prevent an early stock-out, the quantities that can be auctioned off on a daily basis must be limited to a prorated portion of the reserve. For instance, a workable solution may be to limit the amount of gasoline and blending components to be auctioned of for prompt lifting with redelivery 6 weeks later, to 50 TBD. Then, because there are 30 working days with auctions in the intervening period, on average 1.5 million barrels will always be on the water, with a remaining reserve of 1 million barrels in storage.

A volume of 50 TBD daily is relevant to the predicted shortfall, but would not allow all California imports to be hedged through forward swaps using the reserve volumes. Moreover, a limit of 50 TBD will not allow an importer to cover a full cargo of up to 300,000 bbl in one transaction.

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[40] California Assembly Bill 2076, Chapter 8.2, Section 25720, para (4) (c)

However, not all imports need to be covered through forward transactions in order for the material to make its way to California. For instance, the major refiners currently bring significant volumes to the State from within their global refining systems, and will average out gains and losses over the long term.

By leaving the market slightly short with regard to the forward time-swap options, it will limit the use of the facility to those deals that otherwise would not have been possible because of the risk, and will enable the State to collect a reasonable fee for the risk elimination.

8.6 Fees

Based on comparable costs for hedging cargoes of commodities for which futures can be used to hedge the price risk, it is not unreasonable to assume an average fee of 2 cpg for eliminating a 6-week price risk. At this rate, and assuming 250 trading days with an average of 50 TBD in volumes, the gross revenues for the State from the reserve's operation as a bank for forwards time-swaps will be approximately $10 million per year.

8.7 Reserve Management and Oversight

There is currently no State agency that has the necessary experience or qualifications to perform the operational duties involved in managing a petroleum product terminal. In order to be cost effective, the function of managing the SFR will therefore have to be outsourced to private industry on a competitive bid basis. Operating the SFR means both managing its physical aspects, such as safety, quality assurance and scheduling, as well as managing the auctions, credit and collections of the State-owned inventory. For the latter, the best suited private industry entities are not the same as those who can run the terminals, and the best approach is likely to be for the State to issue separate tenders for each of the two functions.

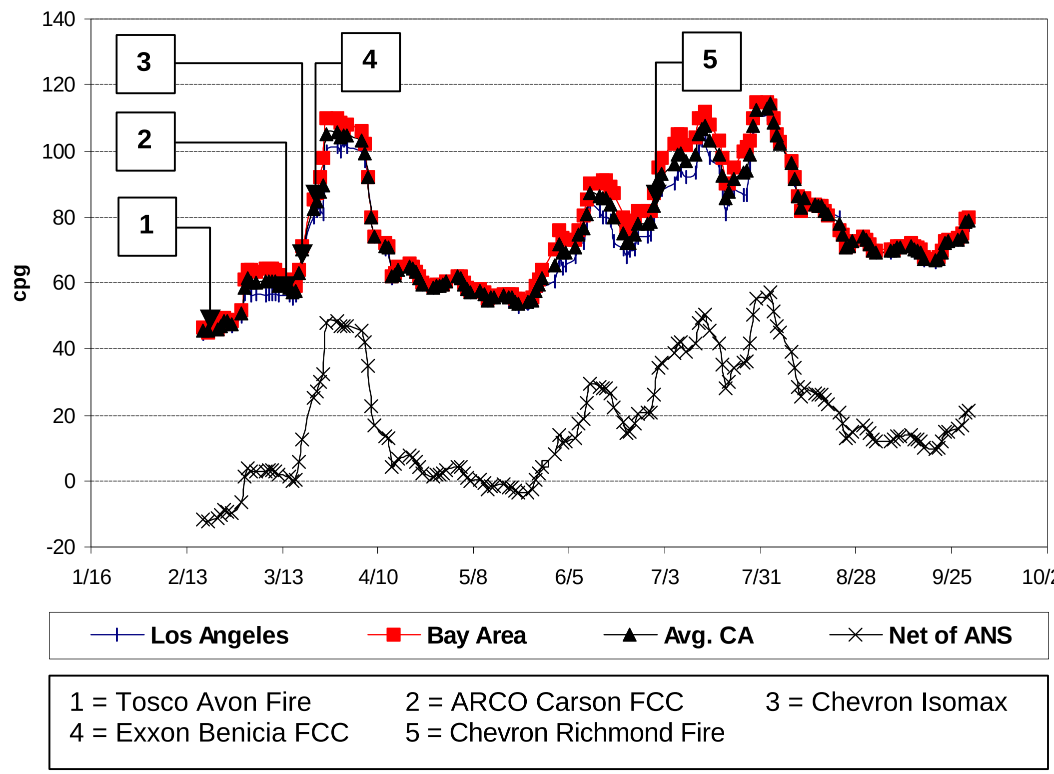
Even when the State will outsource both the physical and commercial management of the reserve, the requirement will remain to create an oversight function within a suitable State Agency, that would be empowered to supervise the reserve's operations, with authority to issue the tenders for building or converting the required terminal capacity under long-term contracts, and for the purchase of the initial fuel inventory. This Agency will further need the authority to regulate the auction process for the forward time-swaps of fuels in the reserve, to qualify participants and to oversee the usage of the fuels by the participants, with the powers to revoke trading privileges in the event a participant is delinquent on timely redelivery of borrowed volumes, or is caught using the reserve volumes for speculative purposes.

8.8 Effectiveness

At 2.5 million barrels, of which an estimated 2.3 million are effectively usable, the proposed reserve represents only little more than 2 days of the combined demand of gasoline supplied out of California. If the time-swap mechanism is adopted to create a forward market and stimulate imports, then the inventories at hand at any point in time may be as low as 1 million barrels only, with 1.5 million barrels on the water on its way to California.

Moreover, this volume will be divided between the two refining centers in the Bay area and the LA Basin. To evaluate the potential effectiveness of such a relatively small reserve, the events that marked the worst year in the recent history of refineries in California will be analyzed. In 1999, a series of fires and operating problems at several refineries caused two significant price spikes.

Figure 8.1 – 1999 CA Refinery Outages and Price Spikes



As can be seen in Figure 8.1, a series of refinery events, two fires and several minor outages, caused a rapid run-up in prices between February and April. Although prices had almost returned to normal by late May, they started moving upward under pressure of the summer driving season while supplies and inventories had not fully recovered from the earlier supply disruptions. When in July another major refinery fire occurred, the market reacted with a prolonged run-up in prices.

Figure 8.2 shows to what extend supplies and inventories were affected during these events.

Figure 8.2 – 1999 CA Gasoline Inventories and Weekly Production[41]

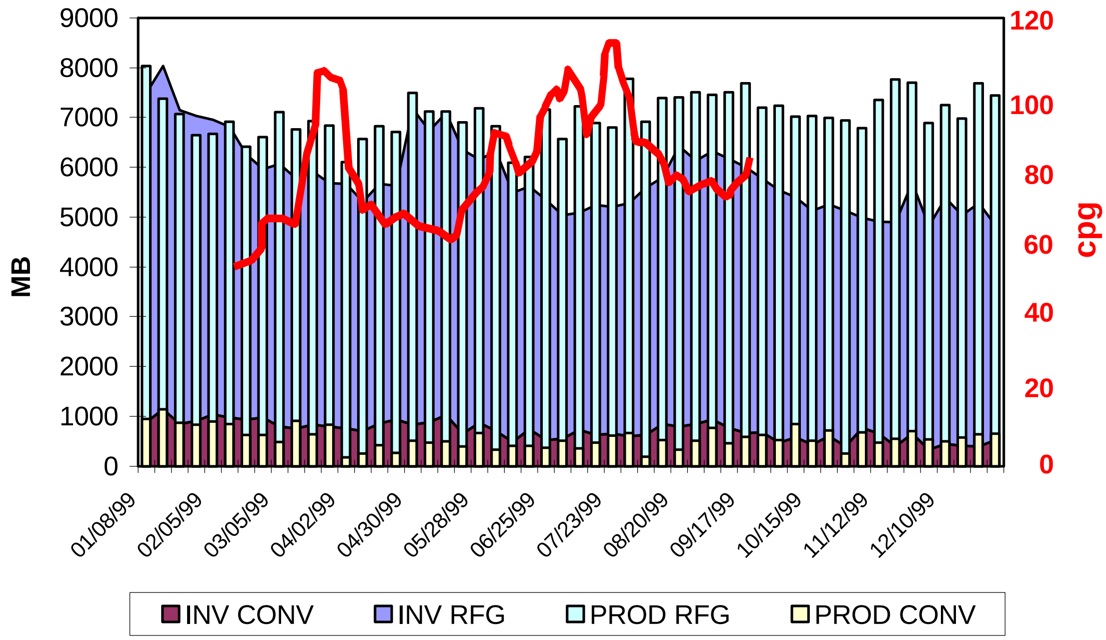


Figure 8.2 shows how the inventory swings of finished RFG and non-RFG gasoline during the 1999 price spikes was in a range of 5 to 7 million bbl, while the variations in total weekly production of RFG and conventional gasoline were from a high of around 8 million barrels per week to a low of 6 million (1140 to 850 TBD). Equally important is that the average rate of decline in inventories during the first series of events was125 MB/week, and in the second price spike 200 MB/week.

If a reserve of 2 million barrels had been available, it would have enabled an additional supply of 200 MB/week over a period of 10 weeks, well beyond the delay within which additional imports could have been mobilized. Moreover, with the forward time-swap mechanism offering price protection to importers, cargoes would have been launched earlier. By contrast, without forward protection, an importer who would have bought a cargo in mid March 1999, at the while

[41] Source of Data: EIA, CEC, Weekly Fuels Watch

a steep run-up was in progress, could have lost a substantial amount of money by the time his cargo arrived in late April.

The conclusion is that a modest reserve of 2 to 3 million barrels can be effective in mitigating the effects of even severe supply outages if it is deployed in such a way that it will facilitate imports. If a reserve were to be created as an offline pool that is not part of the normal flow of imports and trades, it is likely that its deployment during the first price spike would have prevented any imports from coming in. In the absence of imports, there would have been no way to replenish either the reserve or industry inventories before the second series of events, and at the height of the summer driving season, the result might well have been even more onerous for the California gasoline consumer than was the case in 1999.

9 OVERALL COST/BENEFIT EVALUATION

For the purpose of this study, which is to establish the conceptual feasibility and does not yet incorporate engineering level cost estimates nor detailed information on refinery reliability, costs and benefits will only be valuated at an order of magnitude level.

9.1 Cost

Summarizing the results of Sections 6 and 8, and taking into account the costs of tank leases, estimated paid out lease guarantees, debt service cost for the initial fill, and the offset by fees from time-swaps, the net costs of creating and maintaining a reserve, enabling a forward market through the creation of a fuels bank, and facilitating the building of additional tankage for use by occasional importers, as proposed, are likely to be in a range from $15 to $20 million per year.

9.2 Benefits

Two primary benefits of the reserve will be evaluated, the first being the mitigation of price spikes caused by supply disruptions, and the second the improved flow of imported products needed to prevent a shortfall in supply and demand balance.

9.2.1 Mitigation of Price Spikes

There is ample historical evidence to suggest that a major refinery outage, i.e., an unplanned event that causes the loss of the facility's entire production of gasoline for several weeks, happens in California with a frequency of somewhere between once per year and once per two years, with a small but real probability of two such events happening within a single year, as they did in 1999. This statistic implies that the probability for an individual refinery to suffer a major outage caused by an unplanned event such as a fire, explosion or major equipment failure, is of the order of magnitude of once per 10 to 20 years.

Taken over all refineries in California, minor events that cause a refinery to lose part of its capacity for periods of up to one or two weeks, appear to happen at a frequency of 2 to 4 times per year [42]. Even these minor outages currently can cause price spikes, but these tend to be short lived and primarily affect the spot market without translating into a corresponding increase in branded retail prices.

Table 9.1 – Sample of California Refinery Incidents 1996 - 2001

Date	Refinery	Incident	Impact
04/01/96	Shell, Martinez	FCC Hydrocracker Fire	Major
01/21/97	Tosco, Avon	Hydrocracker Fire	Minor
04/28/98	3 Refineries LA Basin	Power Failure	Minor
07/28/98	Tosco, Avon	Crude Unit Fire	Minor
02/23/99	Tosco, Avon	Crude Unit Fire	Major
03/18/99	ARCO, Carson	FCC Outage	Minor
03/25/99	Chevron, Richmond	Isomax Unit Fire	Minor
03/31/99	Exxon, Benicia	FCC Problem	Minor
07/10/99	Chevron, Richmond	Fire	Major
07/30/99	Mobil, Torrance	Fire	Minor
06/06/00	Tosco Avon	Tank Fire	Minor
04/24/01	Tosco, Wilmington	Coker Fire	Minor

The major events tend to cause a run-up in prices that generally seems to follow published price elasticity data. As shown before in Section 1.3, the 1999 multiple events that caused a production loss of 80 TBD [43] initially led to a 50% increase in prices and later, when the shortages had exhausted available reserves and additional minor events occurred, price rose to 100% over previous levels.

In Section 1.3 above it was shown how a single significant outage can result in a price spike that causes gasoline consumers to collectively spend more than $1 billion in excess of what they would have paid if a price spike had been limited to the level corresponding to incremental imports. If a chronic shortage results from an inadequate import infrastructure and commercial

[42] Based on information from Stakeholder Surveys – Not all refiners provided information

[43] ARB data published July 15, 1999, relating to approval of temporary variance to sell non-conforming gasoline

barriers such as the lack of a futures market, then a prices will remain over sustained periods at levels that are substantially of those that can be expected in a well supplied market.

Figure 9.1 – CA Refining and Branded Retail Margins[44]

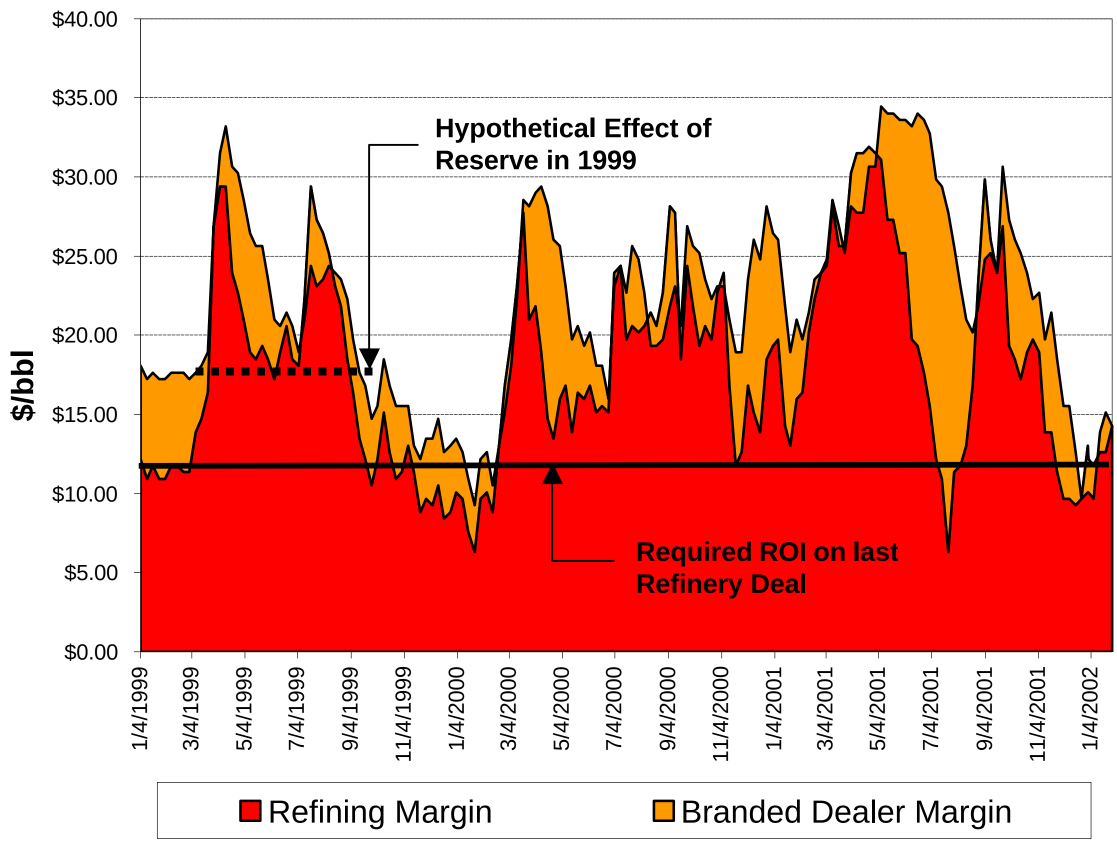


Figure 9.1 shows the estimated refining and branded retail margins in the California gasoline market over the period 1999 through present, derived at after backing out federal, state and local taxes from retail gasoline prices, and subtracting estimated crude oil cost. What is immediately clear from this graph is that with a few exceptions around the brief winter season, refining and branded retail margins have been significantly higher than the level that was published by a refiner as needed for investment recovery on the most recent California refinery acquisition [45]. Over this 3-year period, the net sum of margins in excess and below this investment recovery level represent a value to the gasoline consumers of California of approximately $3.5 billion dollars.

[44] Source: CEC Data

[45] Press conference materials Tesoro Petroleum Corporation, February 5, 2002, $11.62 crackspread (3:2:1).

The effect of the Reserve, if it had been available in 1999 and would have promoted an early stream of imports and limited the prices to a level corresponding to high world market plus transportation, would have saved the gasoline consumers in California between $0.5 to 1 billion dollars.

Regardless of the details in these numbers, it will be clear that the costs of chronic undersupply and price spikes caused by supply disruptions is several orders of magnitude higher than the costs of the proposed fuels reserve.

10 RESULTS OF MEETINGS AND WORKSHOPS

One of the primary considerations of the study was to fully involve the various stakeholders in the industry. In the early stage of the study, the objective was to collect opinions and ideas through a series of meetings with individual stakeholders, whereas at a later stage, feedback was solicited on concepts and alternatives through a workshop, open to all interested parties.

10.1 Survey Meetings with Industry Participants and Other Stakeholders

From late August through early October 2001, the CEC and its contractor, Stillwater Associates, met with representatives of:

- All eight gasoline-producing refiners in California. For some of these, separate meetings were held with individual operating entities, while for others, a single meeting was held with corporate staff and/or representatives of several facilities.
- Six refiners operating facilities outside California, but selling blendstocks or finished products into the California market.
- Ten major international traders who regularly import fuels and blendstocks into CA and who have representation in the State, and one major brokerage house.
- Five independent marketers of gasoline in CA.
- Four major logistic service providers, owning and operating terminal facilities and pipelines for clean petroleum products in California, two of which are subsidiaries of major oil companies.
- Stakeholders from miscellaneous backgrounds, including the State of Arizona, an industry association, two publications, and the Southern California Port Authorities.

A separate confidential report was prepared by the CEC and its consultant to document the individual discussions held with the selected stakeholders. Although supply and demand for diesel and jet fuel were discussed as well, the discussions heavily focused on the gasoline markets, and in particular jet fuel was often used in the discussions only by way of example of a well functioning, stable market. Moreover, the discussions were generally qualitative in nature, with most parties reluctant to share numbers or referring to data already available in the public domain through other reporting channels.

A summary of some of the main issues raised during the meetings by the various constituents is given below.

10.1.1 Strategic Reserve

The broad consensus opinion of industry participants is that the California market is not broken and does not need the fix of a Strategic Reserve. Virtually all supply-side market participants expressed a clear resentment of intrusion by the government into the private market, and thought that an intervention in the natural forces of supply and demand would be detrimental to the long-term development of new sources.

Despite this initial aversion, most survey participants freely contributed constructive ideas once it was clear that the study will evaluate a broad range of alternatives, including some that might improve market liquidity as a whole, or solutions whereby the government's role might be limited to that of a facilitator of private industry efforts. The most frequently heard contributions are summarized below.

- **Location**. Although a few participants favored locations downstream in the distribution system, the more commonly held view was that the Strategic Reserve, if it were to be created, should:

  a) Be in more than one location, with as a minimum separate coverage for the Northern and Southern California markets;

  b) Be directly tied into the refinery supply and distribution system, i.e., at the head of the Kinder Morgan pipeline networks; and

  c) Have access to deep water in order to be able to receive direct imports in order to be replenished from outside sources after a supply interruption, and to improve supply options in general.

  The locations that meet these criteria are Concord in the Bay Area, Watson and Carson in the LA Basin, and to a lesser extent (because it lacks direct deep water access), Colton at the head of the Southern and Eastern pipeline systems. The industry insights are born out by this Study's analysis of location options and logistics requirements in Section 2 above.

- **Tankage and Inventory Options**. All participants, without exception, reported a shortage of tank capacity. For operational reasons, most refiners would not be able to increase on-site inventories in existing tankage, even when compensated through special incentives for the higher costs of working capital and other operating and marketing costs associated with larger inventories. Traders and importers complained about their inability to find storage to land products. Given the shortage of tankage in the main distribution centers, the overwhelming consensus of the participants was that if an SR were to be created, it should not use existing tankage. This industry opinion confirms the results of Section 4 and 6 above.

- **Release Mechanisms**. None of the participants had a specific proposal for release mechanisms for eventual inventories held in the reserve. However, several stakeholders warned that whatever release mechanisms were chosen, they had to be "fair", and "clear". Concerns were voiced that if threshold price levels for release were set too low, the existence of a reserve would prevent the influx of additional supplies, and could cause an early stampede on the reserve by anybody with empty storage space who could then hoard the supplies until a delayed price spike occurred. Most participants stressed that a reserve should only be released to prevent real stock-outs at the pump, when prices had risen already sufficiently to ensure additional supplies from higher cost sources.

- **Quality Aspects**. With the different vapor pressure requirements for gasoline in summer and winter, and because of other quality and performance parameters for gasoline that are affected by the time over which it is stored, it will be necessary to turn over the reserve at least twice per year. This is one of the reasons why most participants favored locations within the current distribution system, so that the reserve effectively would be a bulge in the pipeline that could see continuous throughput if required.

10.1.2 Barriers to Entry into the California Gasoline Markets

With the exception of some of the major refiners and the refiner-owned logistic service providers, all industry participants complained about barriers that currently prevent the influx of products from outside the State. Since the Bay Area is currently a net exporter of products while the LA Basin is short, these problems are more relevant for the Southern California market than for the north. The major concerns can be summarized as follows.

- **Lack of CARB Spec Fuels outside CA**. The single most important difficulty mentioned by current or potential importers and out-of-state suppliers are the unique quality requirements for California gasoline and diesel. This problem is going to be aggravated by the introduction of CARB Phase III. Of the five out-of-state suppliers that were interviewed, only one claimed to be capable of producing CARBOB for Phase III. None of the others thought that the investments required to comply with Phase III would be justified given the incidental nature of export shipments to California, and the increasing opportunity to realize premium values for higher quality fuels in other markets. Moreover, few would be able to avoid contamination with MTBE above the *de minimis* requirements for MTBE post Phase III, given the nature of the storage and the costs of draining and cleaning tanks and ships for incidental shipments.

An additional complication when bringing in finished gasoline is that certain quality requirements, notably low sulfur levels, require analytical tools that are rarely available in surveyor's laboratories outside California. Material certified in a foreign port as in compliance with the specifications, may fail a retest on arrival resulting in significant financial risk to the importer.

- **Infrastructure**. All potential suppliers of out-of-state gasoline or blending components, as well as some of the major refiners with limited on-site tankage, mentioned lack of adequate infrastructure as a major obstacle to bringing in cargoes and efficiently distributing products to meet market shortages. The providers of commercial services in this area all complained of permitting barriers that prevent investment in facilities despite a viable demand. Common themes were:

  a) There is an acute shortage of bulk liquid storage space in the ports of Los Angeles and Long Beach, which is aggravated by current policies of the Port Authorities favoring other land uses such as container and car terminals over bulk liquid storage.

  b) Terminal facilities owned by refiners which in the past provided third party commercial services now have ceased to provide such services under the short term contracts that typically fit the needs of occasional importers.

  c) Commercial pipeline systems are approaching capacity, especially in the gathering systems.

  d) Projects to increase infrastructure capacity, such as additional storage or increasing pipeline capacity, meet with considerable delays in the permitting process. Increasingly, such delays are caused by well financed, nationally operating interest groups. Delays of up to three years were mentioned.

e) Several new legislative initiatives currently in development threaten to make this situation even worse. Of particular concern is the recently adopted Regulation 1178 of the South Coast Air Quality Management District, which will require installation of domed roofs over all open floating roof storage tanks, and the Marine Oil Terminal Environmental Review Process (MOTERP) proposed by the State Lands Commission. Both initiatives will result not only in very significant cost increases, but require key assets such as storage tanks and docks to be out of service for prolonged periods. These comments were the reason that this Study was expanded to include regulatory developments in Section 5.

The shortage in storage capacity, and the breakdown of normal supply and demand mechanisms in the storage market because of permitting delays for new projects were compared by several participants to the situation in the power industry, where years of lagging investments contributed to the power crisis.

- **Unocal Patent.** Most potential importers expressed a concern that even when finished CARB spec products were to be available outside California, they would be reluctant to attempt importing the finished product because of the risk of infringement of the Unocal patent and the associated punitive penalties. For occasional importers, licensing fees would add a prohibitive cost to an already risky trade.

  Also mentioned was that the Unocal patent puts a further strain on the already scarce tankage. Blending around the patent leaves only very narrow margins, and refiners typically now need more time to prepare an on-spec blend whereas previously, final blends were prepared just-in-time before scheduled pipeline dispatch. This requires more tank space, while off-spec or near-spec batches resulting from an incomplete blending operation might take a longer time to blend off.

  One participant mentioned that a patent recently awarded to Snamprogetti of Italy on blends of isooctanol and ethanol may add similar difficulties post CARB Phase III implementation, and aggravate the blending tankage situation even further.

- **Difficulties of Blending Finished Products**. With finished gasoline meeting CARB specs hard to find outside the state, importers resort to bringing in blending components. The possibility to do so is limited by a number of factors.

  a) As stated above, the Unocal patent presents a significant risk that only a refiner with alternative resources and multiple blending options can afford to take.

  b) Certification of the final blended product requires in-depth knowledge of complex administrative procedures.

  c) The lack of adequate infrastructure makes it difficult for occasional importers to find cost effective blending and storage facilities.

  As a result of these restrictions, traders bringing in blending components will sell such cargoes to the major refiners, who will produce the finished gasoline.

- **Lack of a liquid Futures Market**. All participants, without exception, reported the lack of liquidity in the forward market for gasoline as an impediment to imports. The inability to negotiate a price in advance for when imported product arrives, exposes the importer to considerable price risk. To produce a cargo of CARBOB, a producer typically requires two weeks lead time to schedule blending components and tankage within the refinery. Typically, this is also the time required to find shipping space. Sailing times from the closest out-of-state sources (Caribbean, US Gulf Coast and Eastern Canada Seashore) range between two and three weeks. An importer would therefore need a futures market with enough liquidity for next month or two months out in order to lock in a margin.

10.1.3 Market Mechanisms

The California gasoline market has a layered structure, formed by four separate but interrelated markets: Retail, DTW, Rack, and Spot, which are described in detail in Section 7.1.

The feedback received from participants in the various markets stresses the spot market as the primary source of volatility in the event of supply disruptions. This is the market where pricing is “made”, and as such would be where a reserve would have to intervene if it is to be successful in reducing volatility. Participants confirmed that the spot market can move as much as 5 cpg on one or two trades, and instances were quoted in which market shifts of 20 cents or more have occurred with no more than 40,000 bbl of product changing hands.

The prices in the spot market translate almost directly to the rack market, while the retail market is often sheltered against abrupt price spikes by the major refiners, who are afraid to lose market share if they increase pump prices ahead of competitors. When the retail price lags the spot price too much, rack and spot based DTW customers are sometimes caught in an “inversion”, when their purchase price exceeds the pump retail price. On the other hand, on the down slope of a temporary price spike, branded retailers often manage to hold on to margins for a while, with pump prices only coming down slowly over several weeks after the spot prices has already returned to pre-spike levels. In these periods, rack and DTW customers make up for losses incurred at the onset of the spike.

It is clear from this input that release mechanisms from an eventual reserve will have to be designed to fit the needs of the spot market.

10.1.4 Futures Market

One message that came across loud and clear from the participants is that the lack of liquidity in forward markets for California is a major impediment to imports, and a significant contributing factor to instability, since virtually all trades are done on a prompt basis.

Several participants pointed to the jet fuel market as an example of a well functioning futures market, with forward deals possible as far as 6 months or even one year into the future. In the opinion of most participants, the main reasons why the forward market for jet fuel works, whereas for gasoline it does not, are:

- **Fungibility**. Jet fuel is a readily fungible product, with only a few different specifications shared on a worldwide basis.
- **Liquidity**. Because of its fungibility and ample storage facilities, many traders and importers can participate in the jet fuel market.
- **Hedging**. Because of fixed differentials between jet fuel and heating oil based on alternative uses and transportation cost, forward trades of jet fuel can be pegged to fuel oil futures, which allows traders to hedge their risk.

- **Future Demand**. Airlines have a need to buy a certain quantity of fuel forward because they also sell a certain fraction of their capacity well into the future through advance bookings. Moreover, they like to work against fixed budgets whenever possible.

Given the fact that California gasoline is not a readily fungible product, that there are no suitable forward traded commodities against it can be hedged, and that the largest market sector, the retail market, is not well suited to forward commitment on price, creating mechanisms for a futures market will be a challenge.

Many participants however thought that if a reserve was to be created in which market participants were to be allowed to use the top half of the inventory to lift product prompt and replace it within a certain period, with a bidding process to establish a value for the use of the product over time, then this would not only establish liquidity, but also offer importers a mechanism to obtain fixed forward values for product before it is put on the water.

10.1.5 Inventory Planning Practices

Current inventory planning practices varied considerable between industry participants. For some refiners, operational considerations are the dominant factor, and those refiners generally prefer to run with relatively low inventories. Other refiners, especially those who sell a significant portion of their production into the merchant market rather than into their own branded retail, will set inventory targets according to their expectations of market trends. These refiners will run their tanks as full as operationally possible if they expect prices to go up. In any case, most refiners have very little room to play with and most dismissed the concept of creating a reserve by compensating refiners to hold more inventory as not feasible.

The way market participants interpret reported industry inventory numbers is currently undergoing some changes, according to feedback received. Whereas previously the market would begin to feel tight when PADD V inventory levels fell to 25 million barrels, currently supply begins to tighten at levels around just below 30 (these numbers include finished gasoline, as well as blendstocks and unfinished products). Since the highest reported inventories are in the range of 34 to 35 million barrels, this means that effects of blending around the Unocal patent and increases in production capacity without corresponding increases in storage, apparently do affect the buffering capability of inventory.

Most participants use public sales and inventory data as provided by API and EIA, the accuracy of which was sometimes questioned. Not all were aware that the CEC provides more detailed, State specific information.

10.2 Meetings with CEC Staff

To be completed after key presentations have been made.

10.3 Workshops

To be completed after workshops are held.

11 CONCLUSIONS AND RECOMMENDATIONS

Based on the findings of this study, both in qualitative and quantitative terms, a number of conclusions and recommendations are formulated below. In addition, a long-term outlook will be formulated for a scenario in which no pro-active measures are adopted, and compared with the expected long-term results of the proposed measures.

11.1 Conclusions

The major findings of the study are listed below in a sequence that is in part causal, whereby increasing shortfalls, market insularity and infrastructure deficiencies combine to produce partially dysfunctional and unstable markets, in particular for gasoline, which result in significant damage to the State's economy.

11.1.1 Increasing Shortfall

California's refineries have not been able to keep up with demand growth over recent years and California has become dependent on imports for all categories of petroleum products. Most of the growth in import requirements has been satisfied from foreign sources, because refining capacity and transportation options from within the US are also constrained. The outlook is that in-state capacity additions will be increasingly difficult to realize because of permitting restrictions. The chronic shortfall has led to market instability and increasing vulnerability to unplanned supply disruptions. The phase-out of MTBE as currently foreseen by year-end 2002 will increase the need for imports beyond the current infrastructure capabilities.

11.1.2 Market Insularity

The California gasoline market suffers from insularity caused by its unique specifications, a subsequent lack of liquidity and inability to lock in future pricing, and impediments to market entry by outside sources. These factors contribute significantly to price volatility, in addition to the supply interruptions identified as a cause of price spikes in the legislation that led to this study.

11.1.3 Inadequate Infrastructure

California's infrastructure for petroleum products, comprising of pipelines, terminals and dock facilities, is currently already constrained and has insufficient capacity to handle and anticipated incremental demand. Capacity additions are hampered by lengthy and costly permitting procedures, and by policies practiced by the ports that favor other land uses over bulk liquid storage. Import terminals are predominantly owned or leased under long-term contracts by the refiners, and access to markets has become increasingly difficult for traders and importers whose business interest are short-term in nature.

11.1.4 Restrictive Patents

The Unocal patents are a significant additional burden on California's ability to meet growing demands for transportation fuels while improving air quality. The licensing fees and punitive damages are such that incidental importers will not dare to attempt to blend finished gasoline, while refineries who blend outside the patent's envelope lose capacity by diverting products from the gasoline pool and in doing so actually increase evaporative emissions.

11.1.5 Limited Classes of Supply

There is no indication of unlawful market practices and competitive forces do still result in deep price cuts at times of temporary oversupply in the market. However, for gasoline in particular, supply of finished product is limited to the in-state refiners, and despite the fact that the market has become import dependent, with the incremental import barrel determining the price of the market as a whole, neither independent importers upstream of the refiners nor independent marketers of finished product downstream of the refiners currently have the means to bypass the refinery controlled infrastructure.

11.1.6 Economic Impact

The increasing import dependency of California requires incremental supplies from remote foreign sources that meet unique specifications and carry significant manufacturing and transportation cost. These supplies will set the market price, and the premium that California will have to pay for its import dependency is likely to be in the range of 20 to 30 cpg. This represents a value of $3 to $4.5 billion per year, but this is not a number that will be affected by the creation of a reserve. The economic impact of a price spike of 50 to 60 cpg over a period of 4 to 6 weeks is $0.6 to $1 billion. The effect of these incremental expenditures on the State's economy is somewhat similar to the legacy of the higher electricity prices caused by the power crisis: a significant portion of the gross impact will flow to out-of-state corporations or foreign entities at the expense of discretionary spending by California households and businesses.

11.2 Recommendations

Will be formulated after the workshop.

California Strategic Fuels Reserve

Stillwater Associates

March 13, 2002

Agenda

- Background
- Current Supply Issues
- Strategic Reserve Do’s & Don’ts
- Current CA Inventories
- Markets
- Options
- Effectiveness & Cost/Benefits Analysis
- Conclusions

Background

- Supply disruptions in 1999 caused severe price spikes
- AG taskforce recommended creation of Strategic Fuels Reserve
- State Assembly orders CEC to establish feasibility of SFR and pipelines from US Gulf
- Stillwater Associates was retained by CEC in August 2001 to conduct Reserve Study
- Study started out with extensive survey meetings with industry Stakeholders
- Subsequent work led to Stillwater's involvement in SCAQMD Rule 1178 and MTBE Phase Out
- Preliminary conclusions and proposed solutions now presented for comments – focus is on gasoline

What is at Stake?

California has never run out of gasoline yet, but:

- California Gasoline has the highest price volatility of any commodity traded in the US, except for California power
- The California petroleum industry operates with smaller inventories in terms of days of supply than any other major market worldwide
- California is becoming increasingly import dependent for all its petroleum products
- Physical and commercial barriers to entry are currently already an impediment to imports
- CARB Phase III and the phase out of MTBE will make things more difficult

What is proposed?

A unique solution that minimizes State interference:

- State creates one stop-shopping, fast track permit procedures for petroleum infrastructure related projects
- State facilitates additions to tank capacity for use by the industry
- State holds small inventory not as stagnant reserve but as a mechanism for the industry to conduct forward trades
- Flexible approach to a complex problem

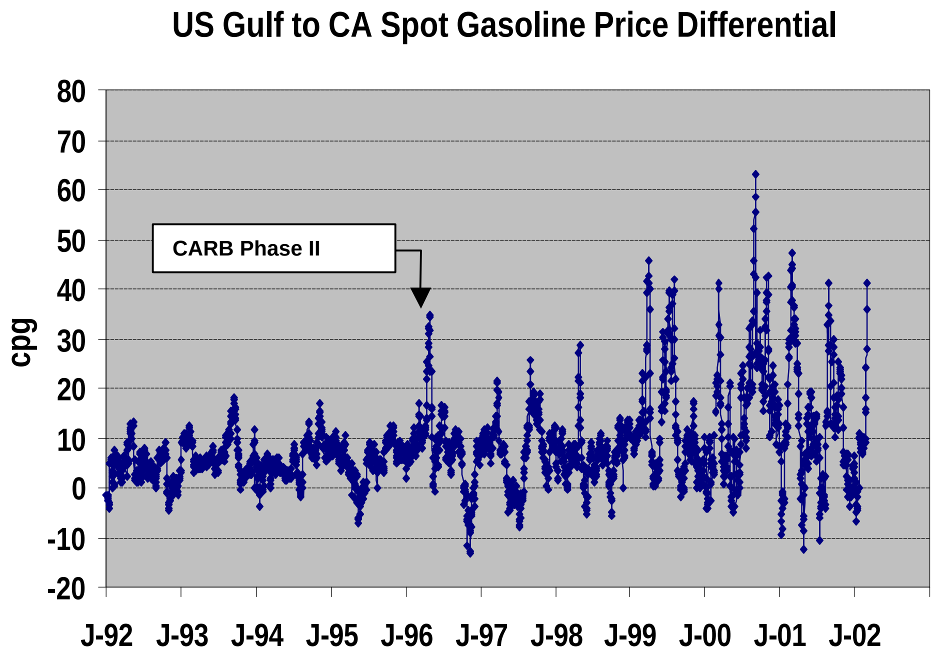
What the Proposals are NOT

- Not a large reserve with arbitrary release trigger overhanging the market
- Not involving Government Price Controls
- Not an impediment to supply/demand interaction
- No unfair competition with those deeply invested in California markets
- Not built and operated by government
- Not exclusive to any particular market segment

Agenda

- Background
- Current Supply Issues
  - Supply/Demand Balance
  - Impact of MTBE Phase Out
  - Imports
- Strategic Reserve Do's & Don'ts
- Current CA Inventories
- Markets
- Options
- Effectiveness & Cost/Benefits Analysis
- Conclusions

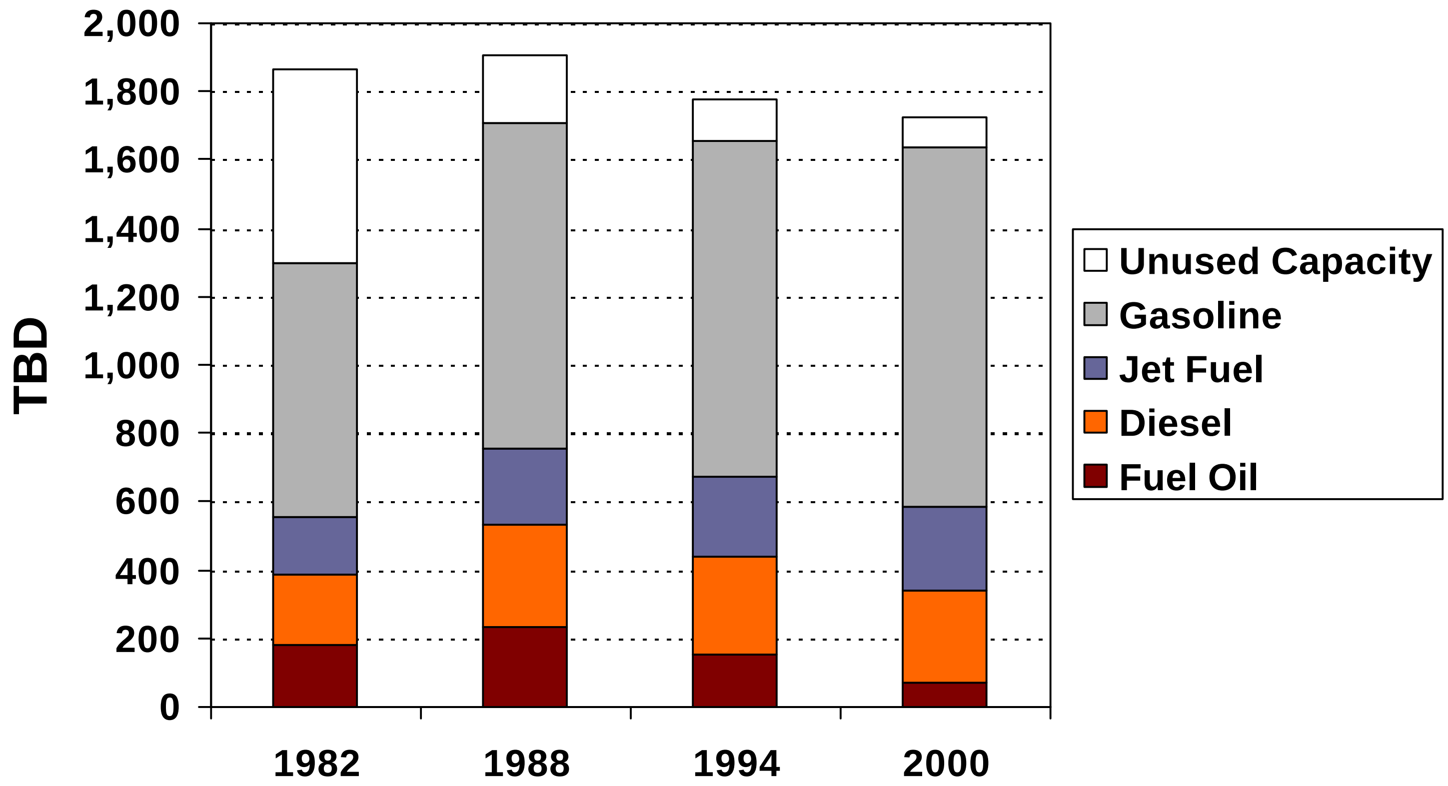
Current Market Instability



- Supply problems increased since 1996
- Rapidly increasing volatility indicates supply problems
- Underlying differential exceeds transportation cost, but little material moves
- Problems will become much worse with phase out of MTBE

Houston, we have a problem

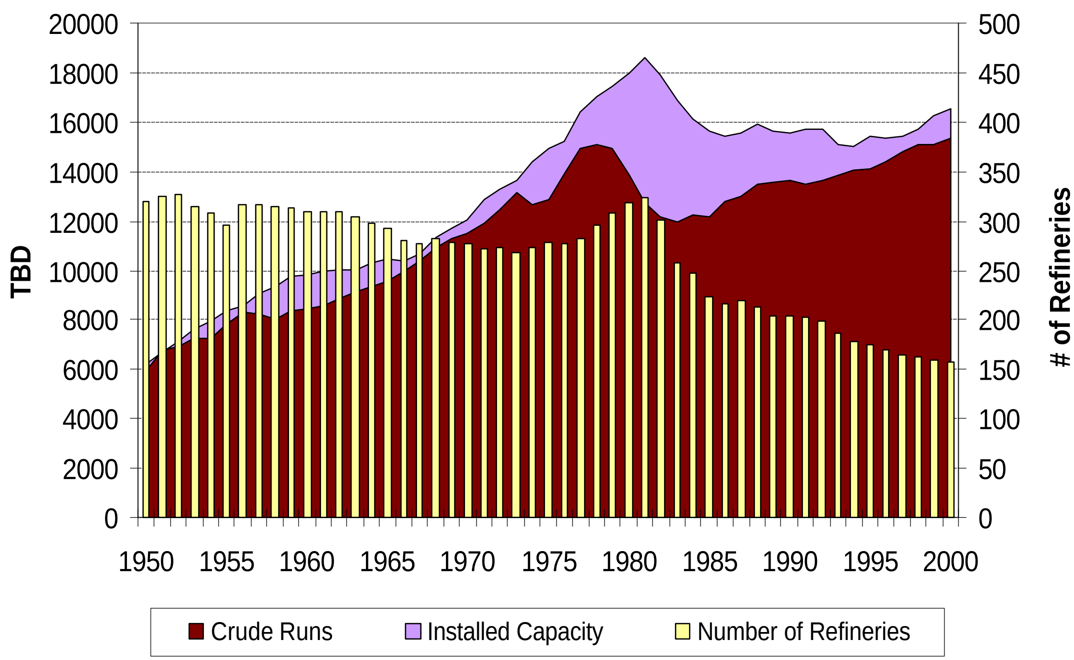
CA Refinery Capacity



CA refinery runs, gasoline production are at maximum capacity

Historical Analysis of US Refining Capacity

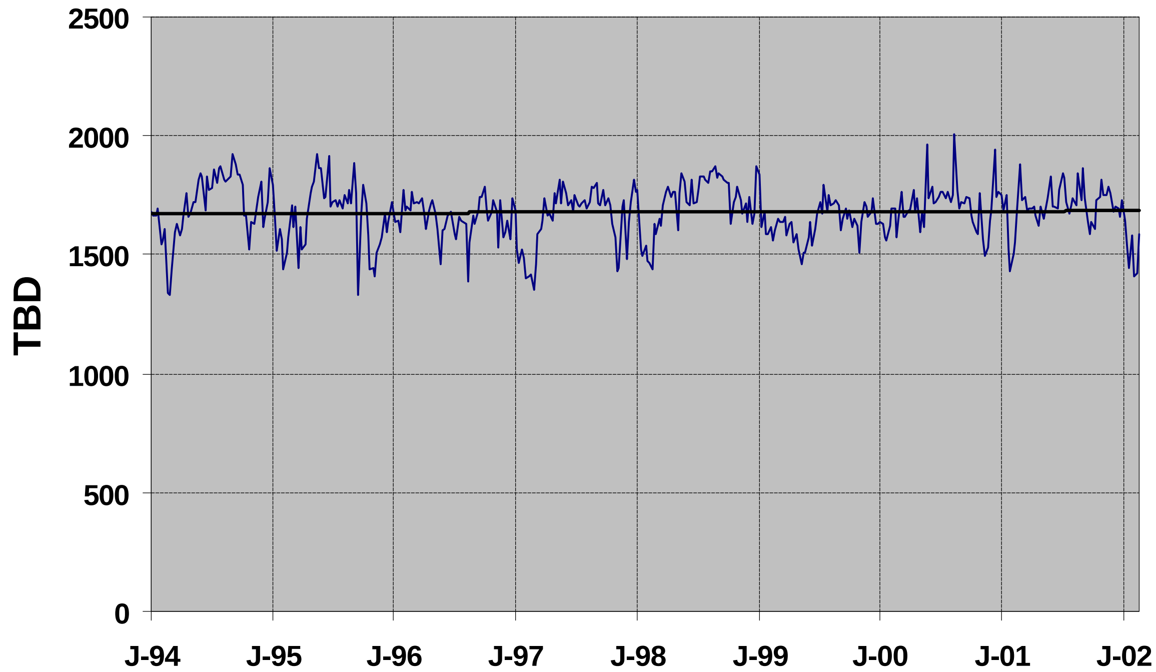
US Refineries – Installed and Used Distillation Capacity
1950 - 2000



- **Regulated environment of late 1970s led to over-building of capacity**
- **1981 Deregulation caused shutdown of non-economical refineries**
- **Last new refinery was built in US in 1981**
- **Over half of the then existing refineries have since been shut down**
- **Since 1984, distillation capacity has remained flat**

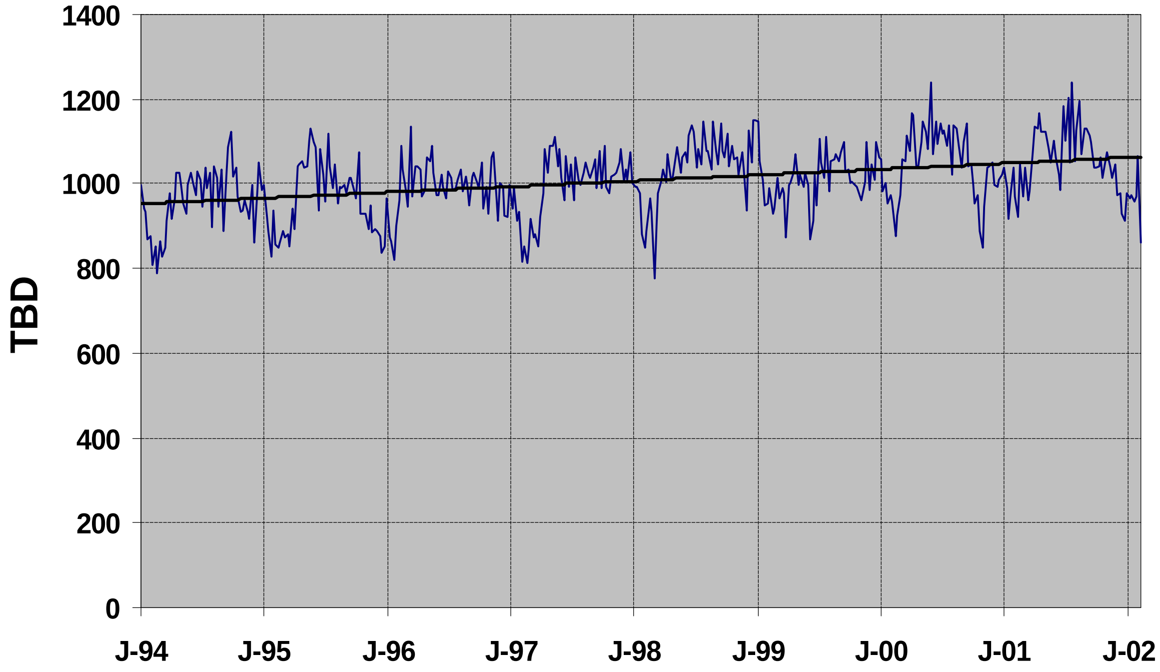
Refineries in US as a whole are at capacity

CA Refinery Crude Runs 1994 - 2001



CA refinery crude runs are essentially flat

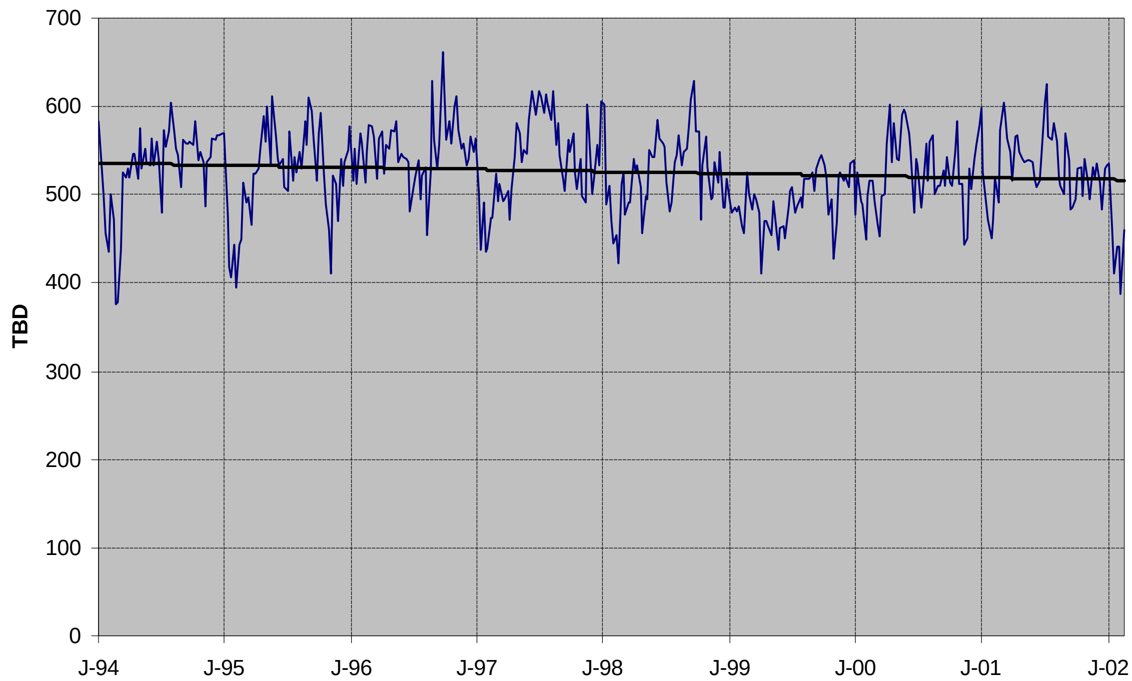
Gasoline Production by CA Refineries 1994 - 2001



However, CA gasoline output has increased 1.3% per year

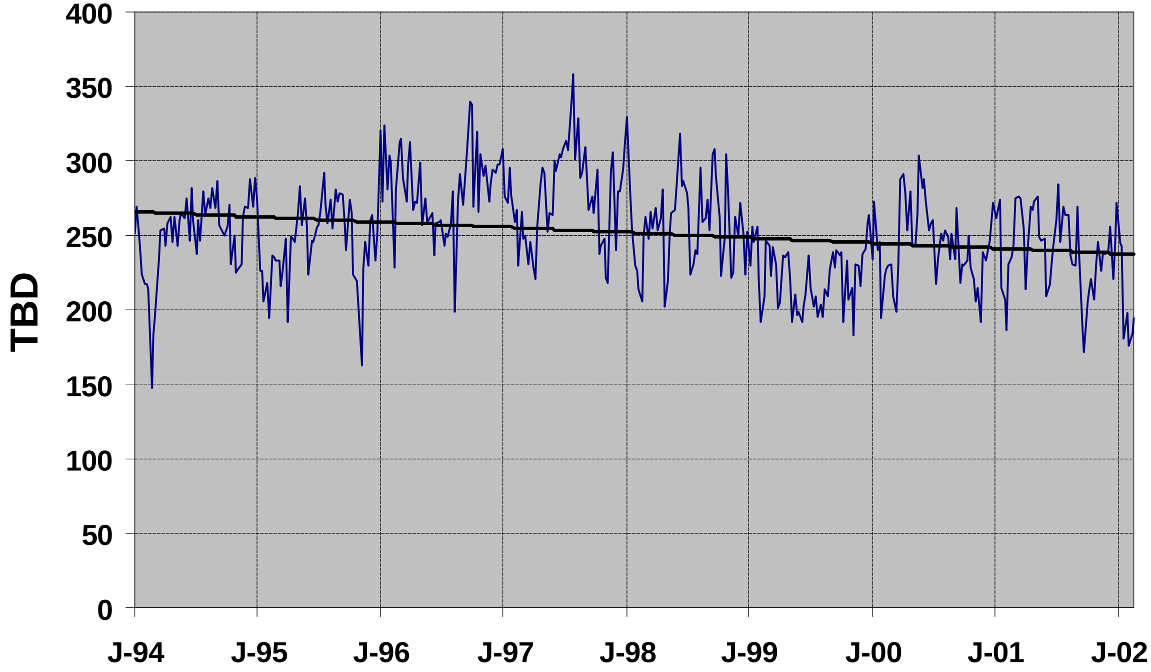
CA Production of Diesel 1994 - 2001

Stillwater Associates



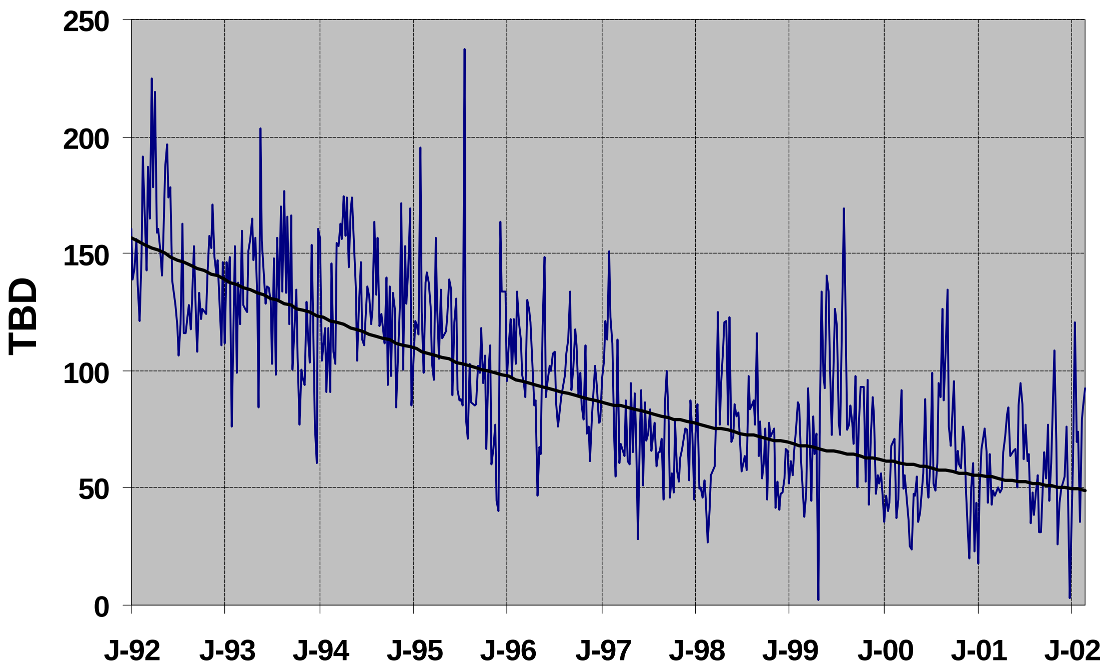
Over the same period, diesel decreased 0.4% per year

CA Production of Jet Fuel 1994 - 2001



Decrease is largest for jet, the easiest product to import

CA Production of Residual Fuels 1992 - 2001



CA refineries are close to reaching the bottom of the barrel

Refinery Disruptions

The underlying data for the disruption section have been provided to me by the US DOE and derived from third party sources and should not be quoted without my knowledge. The data have not been corroborated by the companies involved. Some, but not all, of the incidents have been verified in the public press.

Source: A. J. Finizza Ph.D.

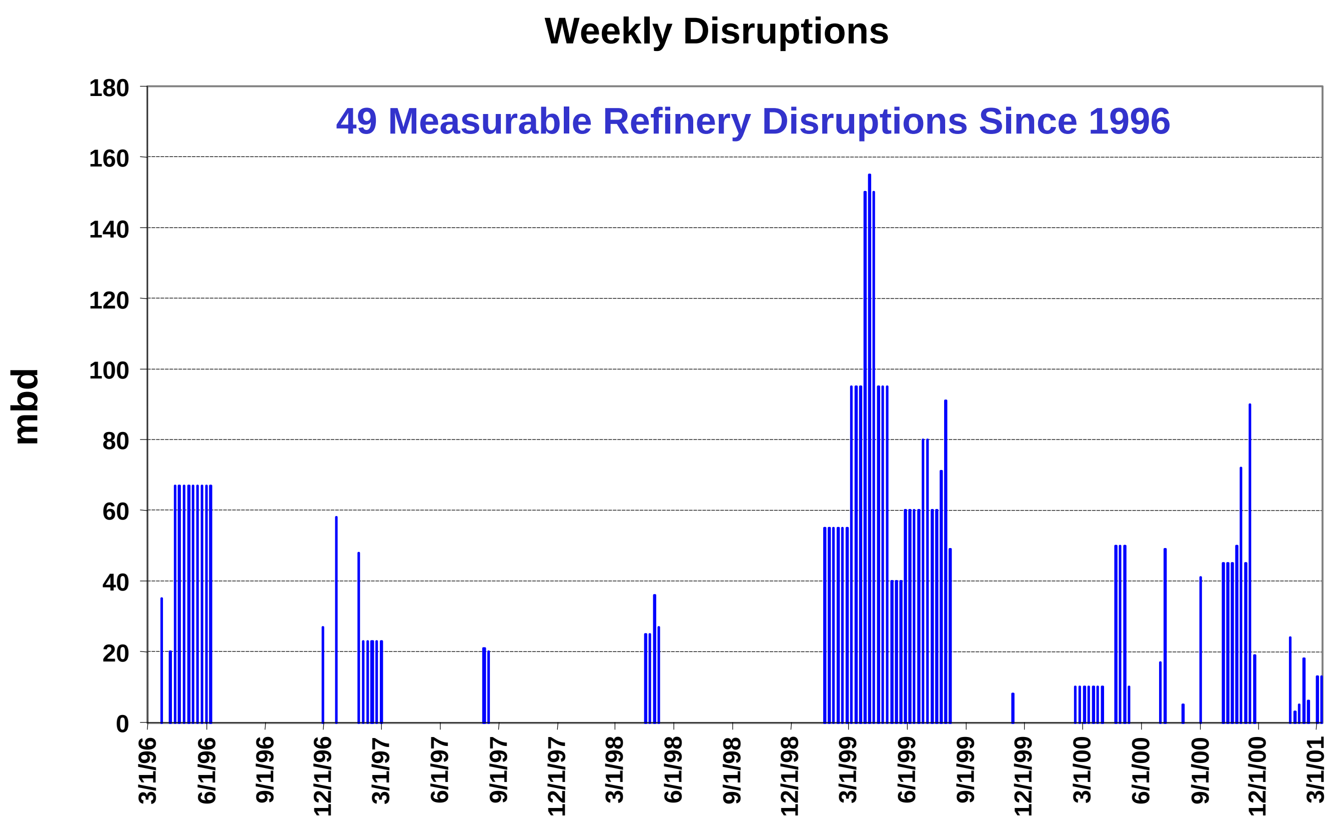
DOE Disruption Data March ’96 – March ’01

- DOE identified 65 Disruptions
- Only 49 contained Size and Duration data from OPIS reports
- Price data suggests potentially 15 other disruptions, not identified in the DOE database (of which 3 may have been turnarounds)
- Potential total number of disruptions is 80

Only the 49 confirmed outages were included in this analysis

Source: A. J. Finizza Ph.D.

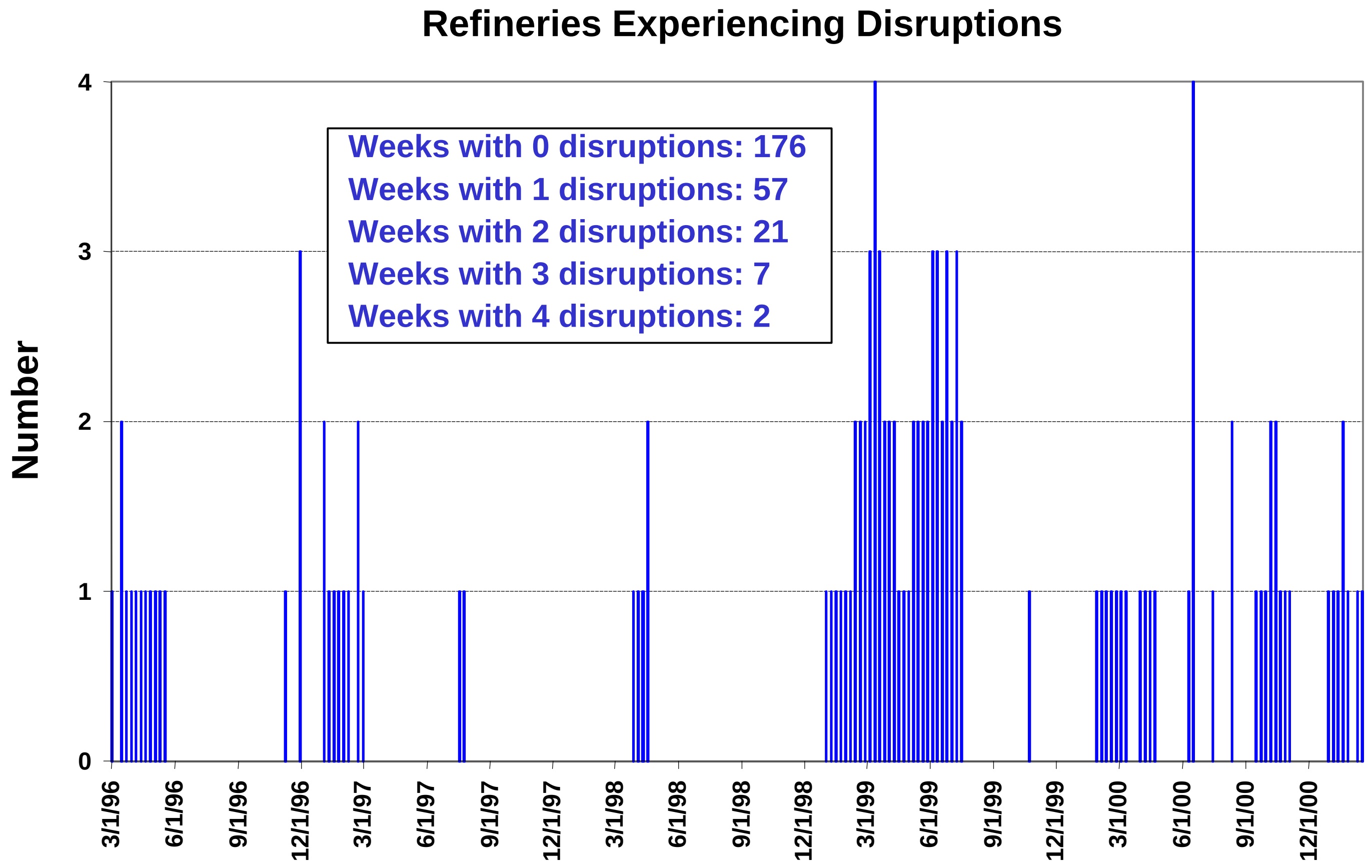
Occurrence of Refinery Disruptions



On average, refinery disruptions occur once a month since 1996

Source: A. J. Finizza Ph.D.

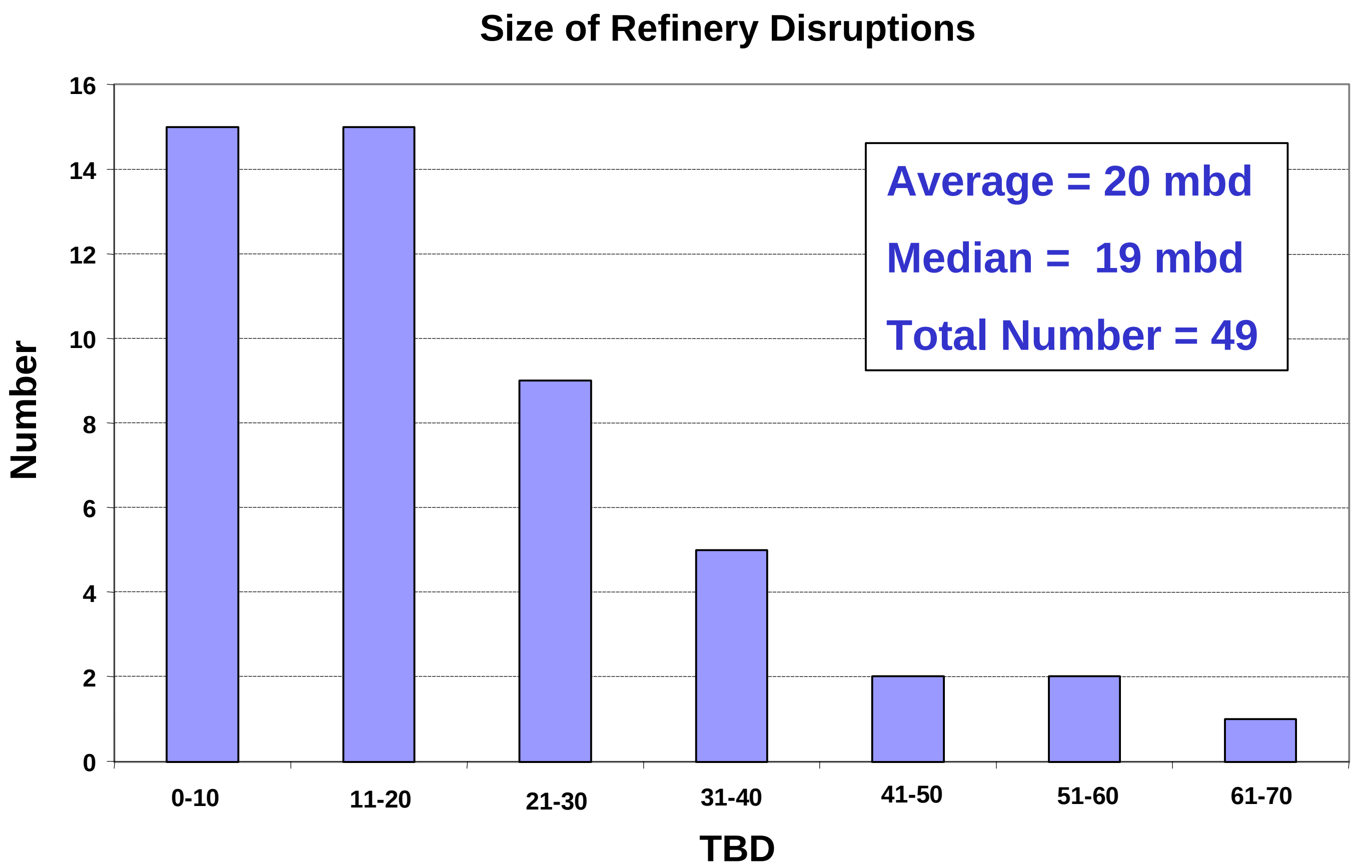
Probability of Simultaneous Events



Multiple refinery disruptions can be ongoing simultaneously

Source: A. J. Finizza Ph.D.

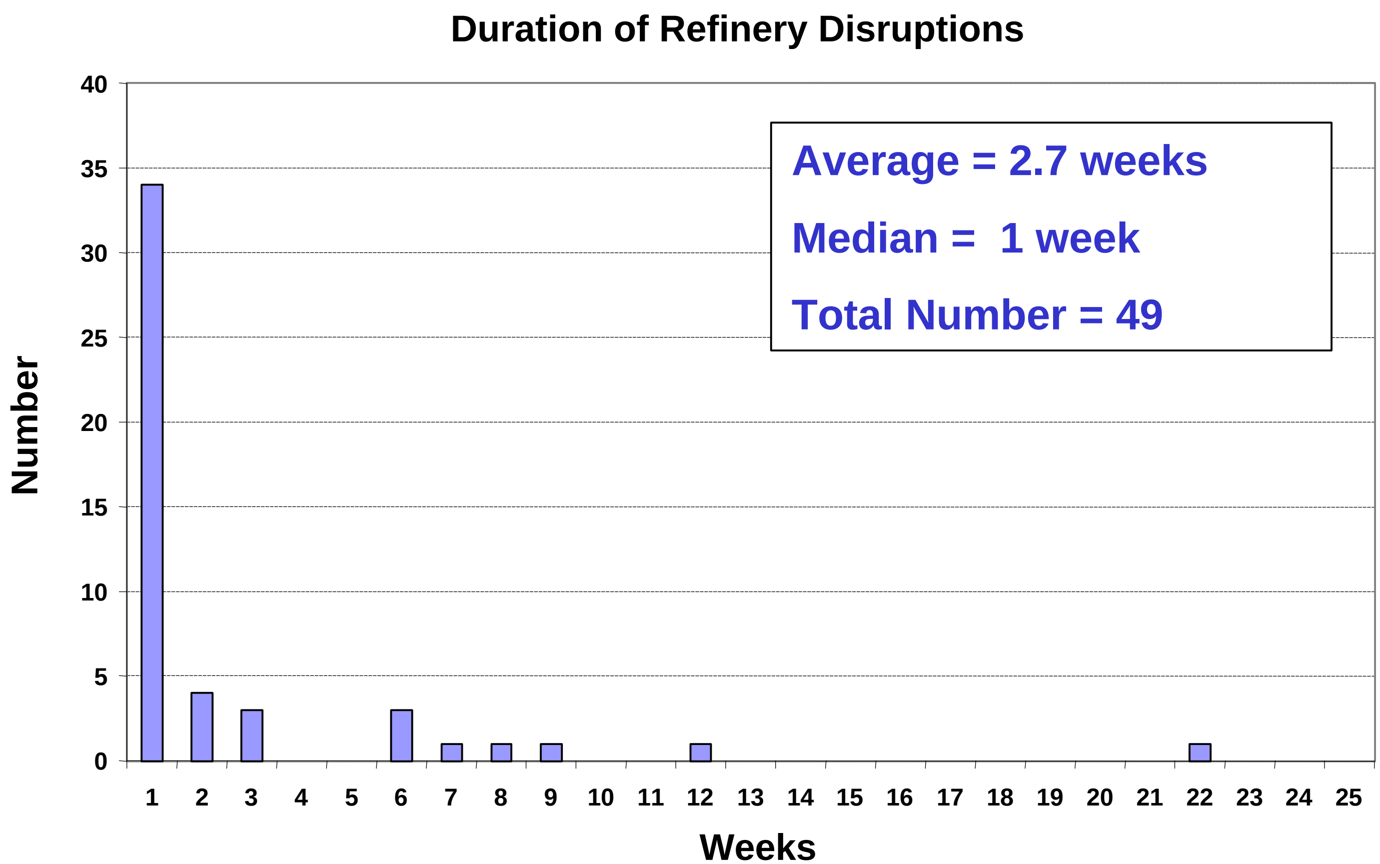
Frequency and Magnitude of Disruptions



Refinery disruptions average 20 TBD with several larger episodes

Source: A. J. Finizza Ph.D.

Frequency and Duration Refinery Disruptions

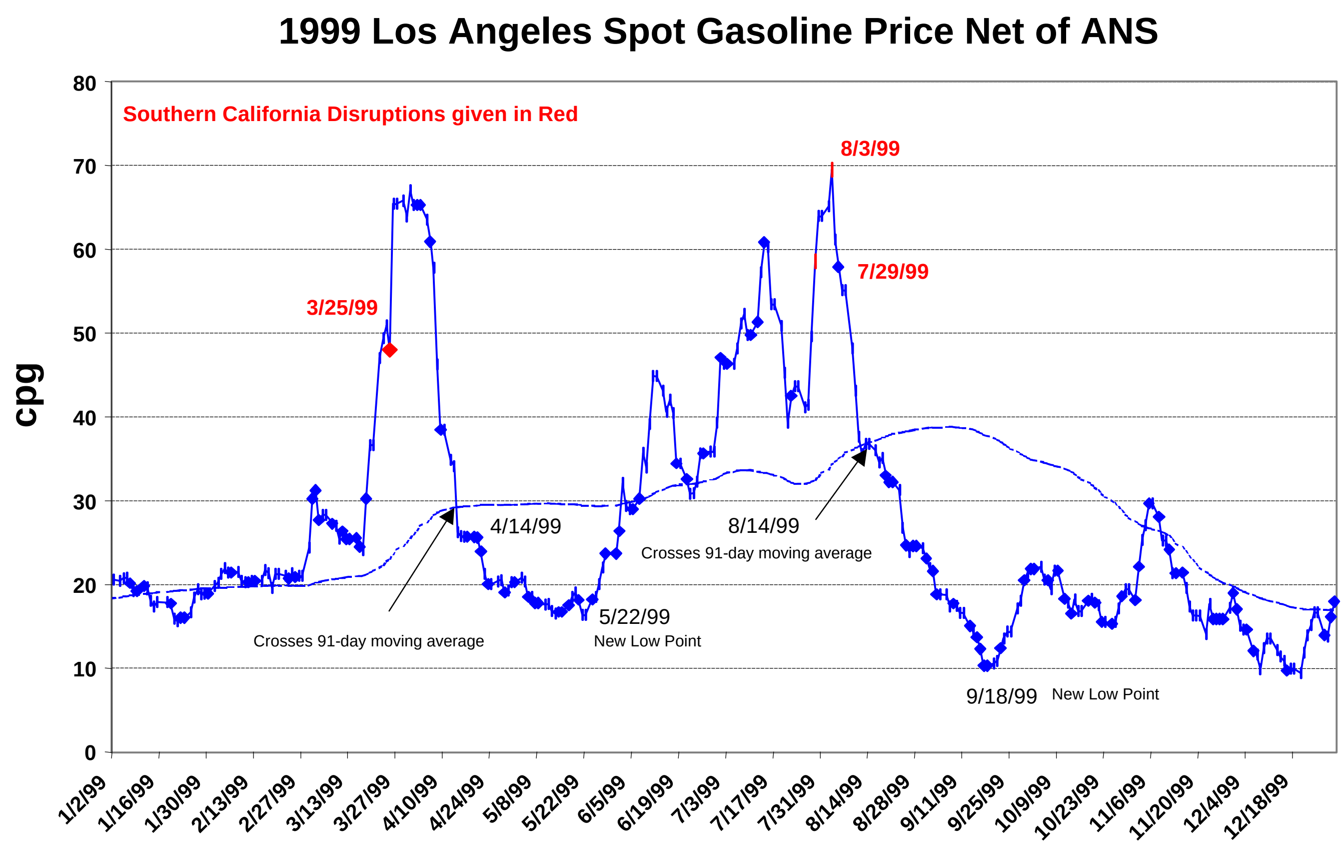


Refinery disruptions average 3 weeks with several longer episodes

Source: A. J. Finizza Ph.D.

Duration of Disruption Effect

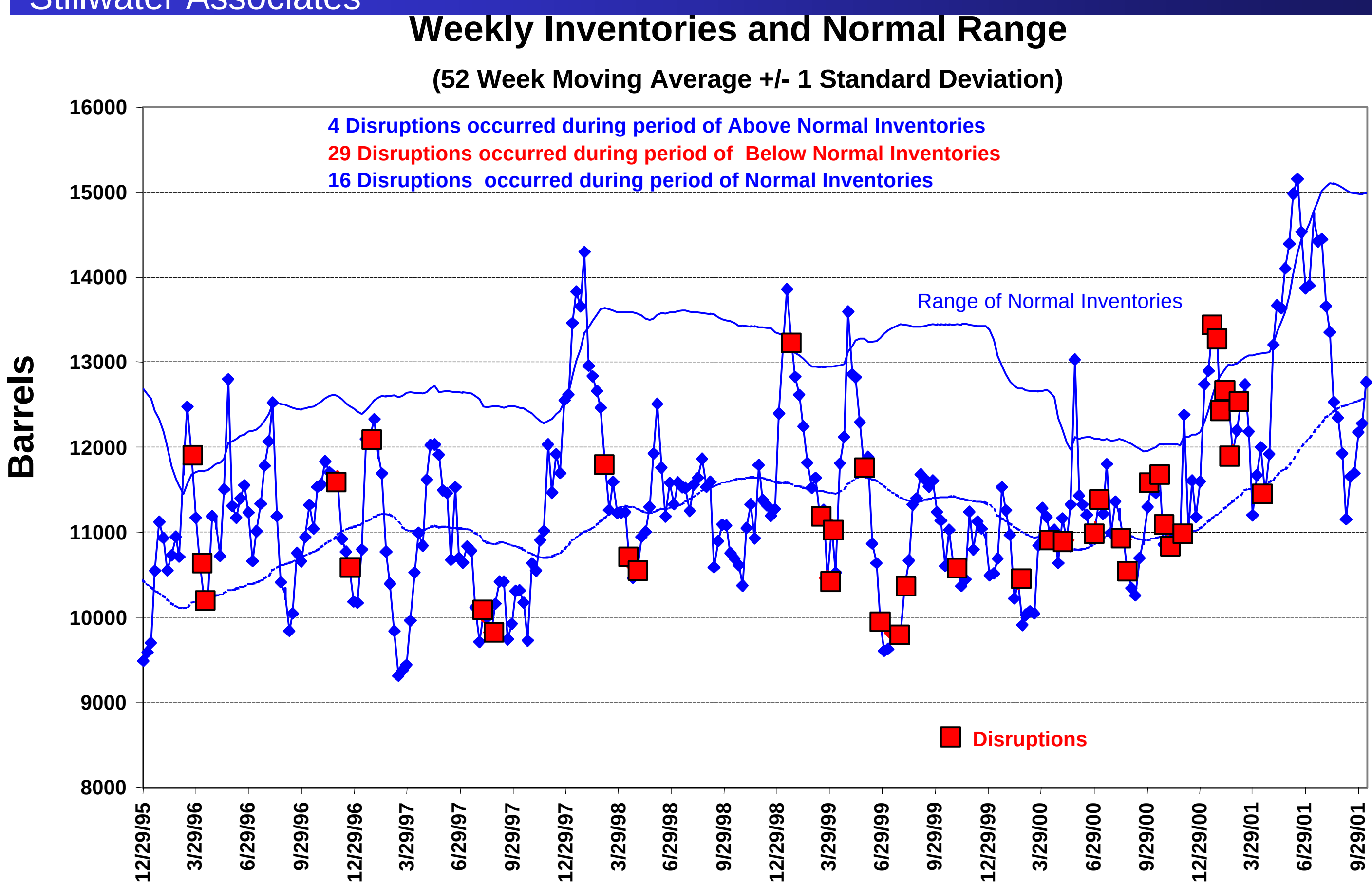
Stillwater Associates



Disruption Effect Lasts 6-8 Weeks

Source: A. J. Finizza Ph.D.

Disruptions and Inventories



Most disruptions occur when inventories are below normal

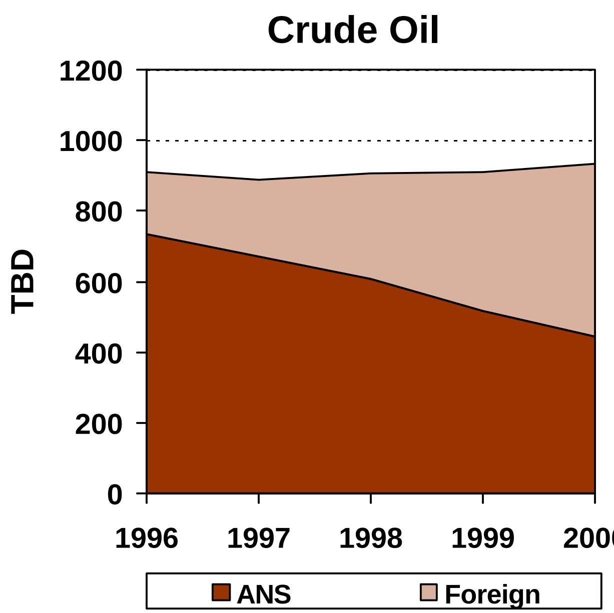
Source: A. J. Finizza Ph.D.

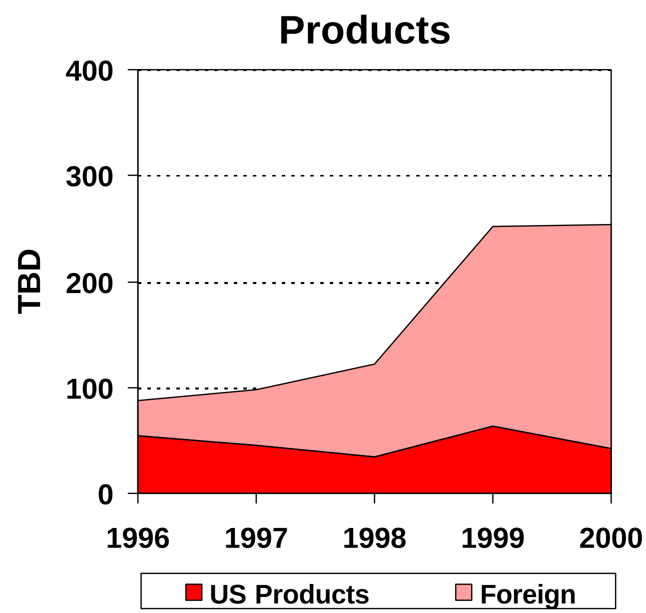
Summary of Supply by CA Refineries

- Refineries are operating at capacity
- 1994 – 2001 CA Refinery Output: annual increase 1.3%
- 0.6% is increase in component imports, 0.7% is refinery operations
- Many refineries have reached limits of Title V Operating Permits
- Small increase will require costly, difficult new permitting
- Even though at 95% of nameplate, overall performance is good, unplanned outages occur almost every month

Demand growth in excess of creep and any lost production must come from imports

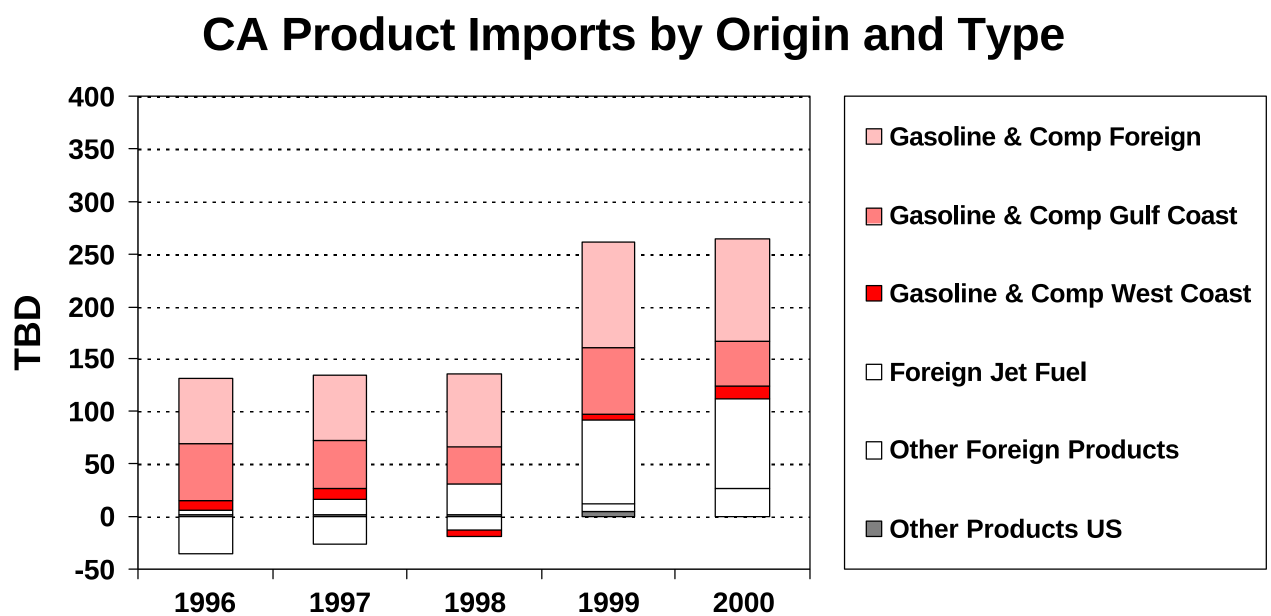
California Petroleum Imports





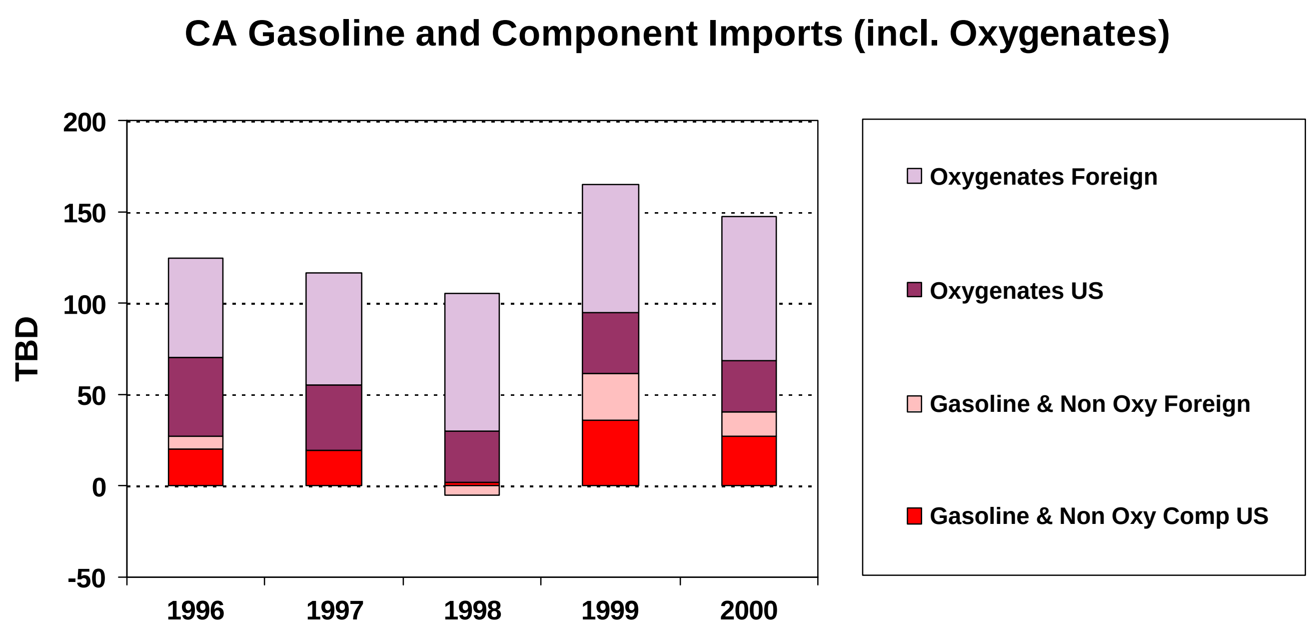
CA is increasingly import dependent for its petroleum products

CA Imports of Petroleum Products



CA has become a net importer for all products
Increase in imports is met from foreign sources

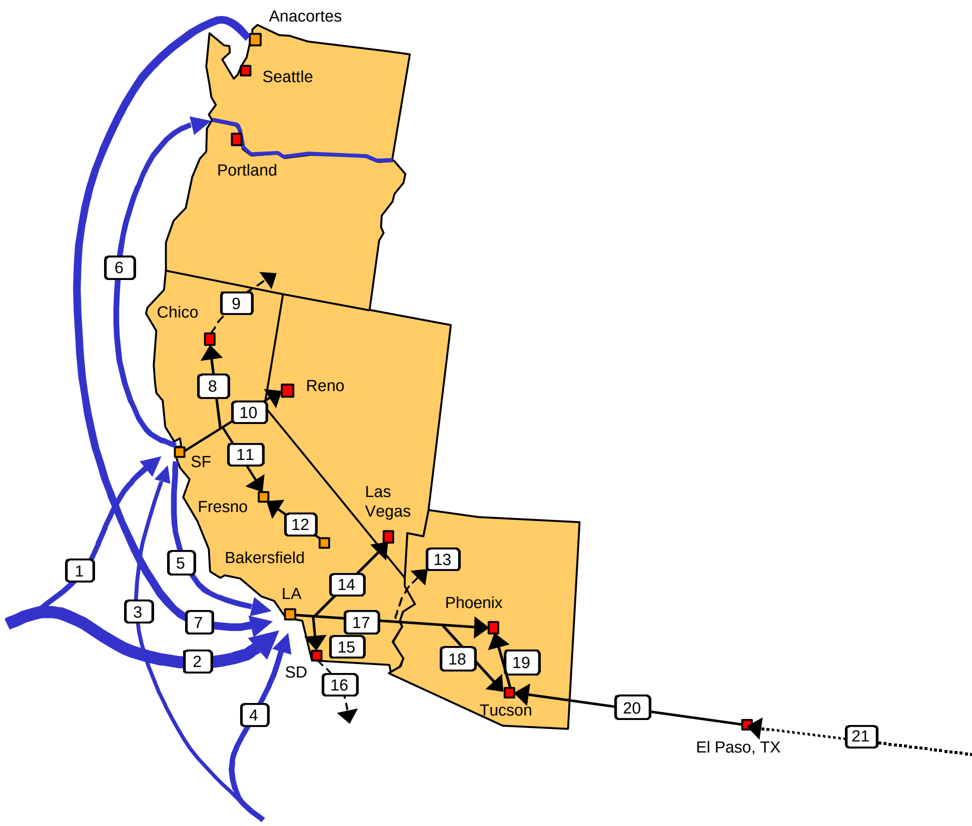
Breakdown of CA Gasoline Imports



Largest share of imports into CA Gasoline Pool is MTBE

CA Gasoline and Component Movements

Stillwater Associates



Year 2000 Volumes		TBD
1	Foreign Imports into N-CA	29.8
2	Foreign Imports into S-CA	68.4
3	PADD III Imports into N-CA	6.8
4	PADD III Imports into N-CA	22.1
5	Ship/barge SF to LA	24.5
6	Ship/barge SF to Portland	28.0
7	Ship/Barge WA to LA	38.0
8	Kinder Morgan SF to Chico	17.6
9	Truck Chico into S-OR	0.4
10	Kinder Morgan SF to Reno	17.3
11	Kinder Morgan SF to Fresno	n/a
12	Kinder Morgan B'field to Fresno	n/a
13	Truck S-CA to W-NV, AZ	2.5
14	CALNEV LA to Las Vegas	45.9
15	Kinder Morgan LA to San Diego	n/a
16	Truck SD to Mexico	n/a
17	Kinder Morgan LA to Phoenix	60.9
18	Kinder Morgan LA - Tucson	4.1
19	Kinder Morgan El Paso - Phoenix	41.0
20	Kinder Morgan El Paso - Tucson	28.0
21	Longhorn	

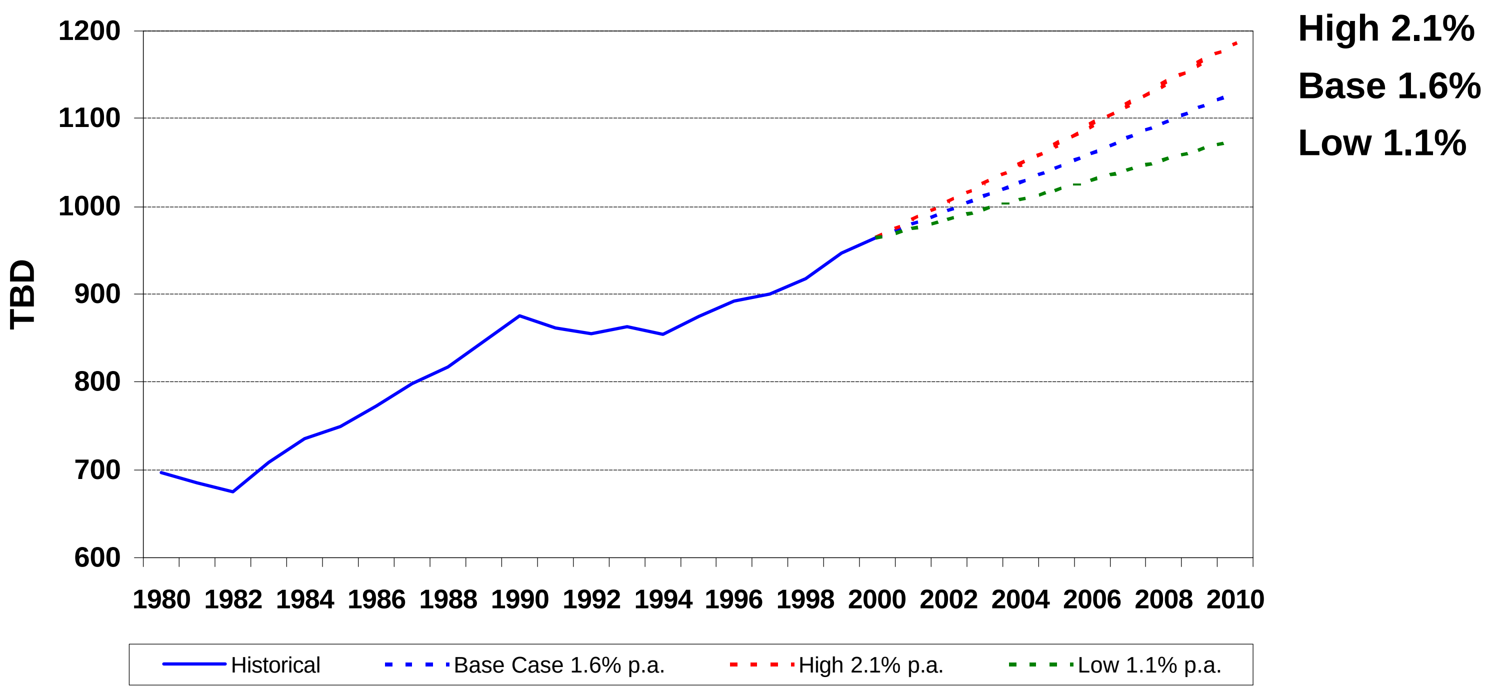
S-CA is most dependent on imports

CA Gasoline Demand – Growth Drivers

- **Population**
  - Growth CA 1980 – 2000: 1.9% per year; forecast 2000 – 2020: 1.4% per year
  - CA also supplies fuels to fast growing urban centers in NV, AZ
- **Population Density**
  - Land development in CA shows second highest urban sprawl in nation
  - Trend expected to worsen given disparate location of jobs and cheaper housing
- **Fuel Affordability**
  - Per capita income 1980 – 2000 increased 3.1% per year
  - Constant dollar cost of gasoline fell 30% in past 20 years
  - Trends expected to level, but not reverse in next 5 years
- **Vehicle Miles Traveled**
  - Increase 1980 – 2000: 3.3% per year
  - Forecast 2000 – 2020: slow down to 1.9% per year
- **Fuel Economy**
  - Average light duty vehicles improved from 12.6 mpg in 1980 to 20.7 mpg in 2000
  - Current trend is slight reversal due to popularity of light trucks, SUVs

Source: California Energy Commission Study on Transportation Fuels, December 2002

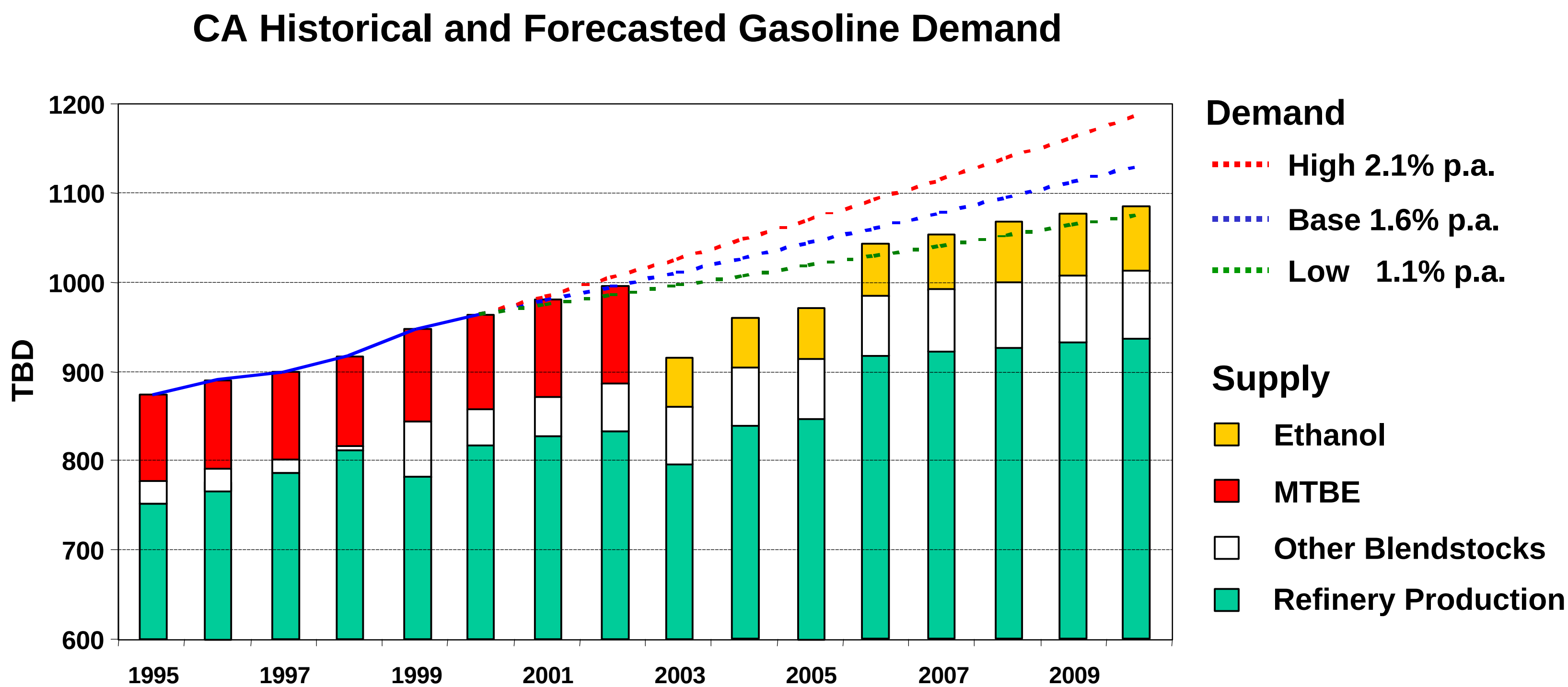
CARB RFG Demand



Current indicators show no sign of diminishing demand

Supply/Demand Forecast

Stillwater Associates



2003: MTBE Out - 110, Ethanol In + 55, Refinery Cap Loss - 45, Additional Blendstocks + 10, 1% Creep
2003: Avon + 23; 2006: Longhorn substitution + 70
All other years: Imports other than oxygenates highest historical + 10%, capacity creep 1%

Impact of 2003 MTBE Phase Out

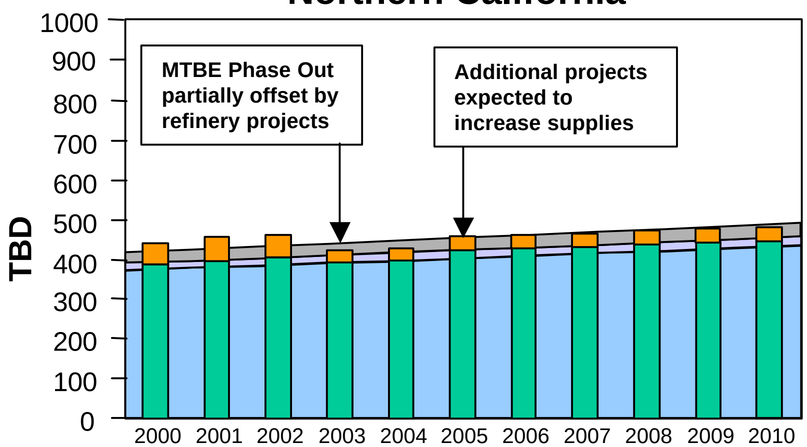
TBD	N-CA	S-CA	Total CA
MTBE Balance			
RFG production	386	549	935
Ethanol Based CARB RFG	40	70	110
MTBE Based CARB RFG	346	479	825
MTBE Required @ 11%	**38**	**53**	**91**
MTBE imports foreign	24	51	75
MTBE imports US Gulf Coast	7	10	17
MTBE production	7	3	10
Total MTBE supply	**38**	**64**	**102**
Excess MTBE	0	11	11
Direct Impact			
Removal of MTBE	-38	-64	-102
Ethanol addition for oxygen requirement	21	34	55
Removal of butanes & pentanes	-17	-29	-46
Other Losses to meet distillation specs	-4	-6	-10
	-38	**-65**	**-103**
Capacity Compensation			
Major refinery capacity additions	22	0	22
Small CARB III mods, MTBE C4 to alky	3	2	5
Capacity Creep 2001 - 2002, 1%	4	6	10
Identified blendstock imports by refiners	0	10	10
	29	**18**	**47**
Net Shortfall	**-9**	**-47**	**-56**

Southern CA most impacted by MTBE Phase Out

Regional Supply/Demand Balance – Base Case

Stillwater Associates

Northern California



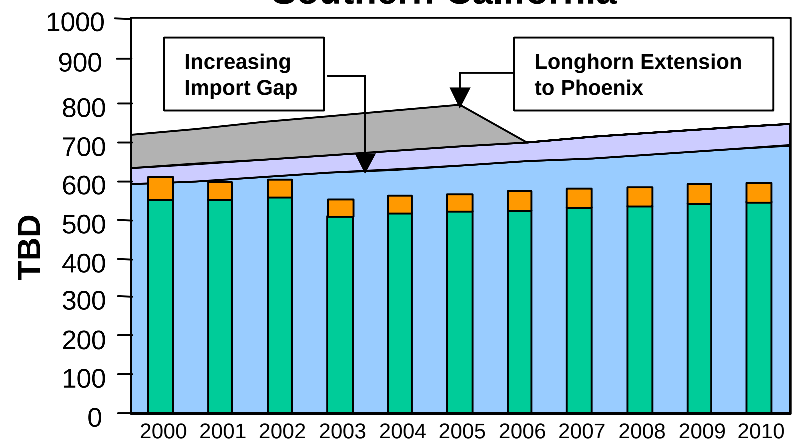
Demand

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OR	28	28	29	29	30	30	31	31	32	32	32
N-NV	17	18	18	19	19	20	20	21	22	22	23
N-CA	372	378	384	390	396	403	409	416	422	429	436

Supply

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
CONV	52	58	54	31	31	32	32	32	33	33	33
RFG	386	398	404	395	399	425	429	433	438	442	447

Southern California



Demand

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
AZ	87	91	95	99	102	106	0	0	0	0	0
S-NV	41	43	45	47	48	50	51	53	54	55	56
S-CA	591	600	610	620	630	640	650	660	671	682	693

Supply

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
CONV	58	43	44	44	45	46	47	47	48	49	50
RFG	549	552	558	511	516	521	526	532	537	542	548

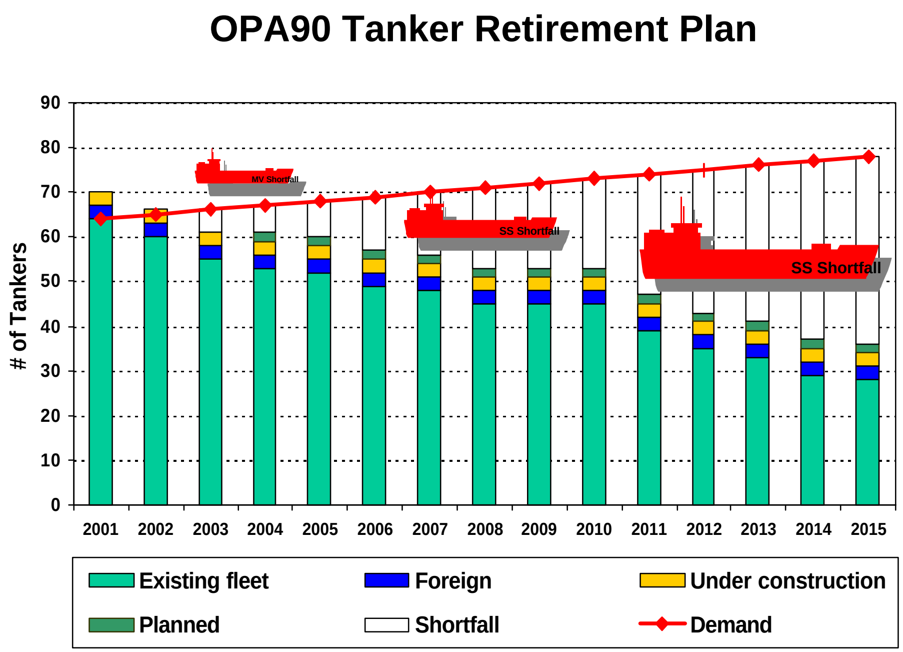
So-CAL supplies need to increase by 50 – 100 TBD

Increased Supply – US Gulf Coast Options

- There is no large surplus ready to ship to CA
- There are no producers capable of producing Phase III CARBOB
- Existing production of premium blendstocks will have to be bought away from East Coast markets
- Supplies of alkylate, the prime blending component to replace MTBE, will tighten when the economy recovers
- In the past, alkylate prices have been 30 to 40 cpg over gasoline because of chemical demand for its key ingredient, propylene

Even if the product where to be there, can we ship it?

Increased Supply – Jones Act Shipping Factor



- Current imports from US Gulf Coast to CA 11 TBD
- To increase by 55 TBD would require 8 additional ships
- OPA90 (double hull requirement) will phase out 20 ships in near future
- New launches unlikely due high cost and uncertain future

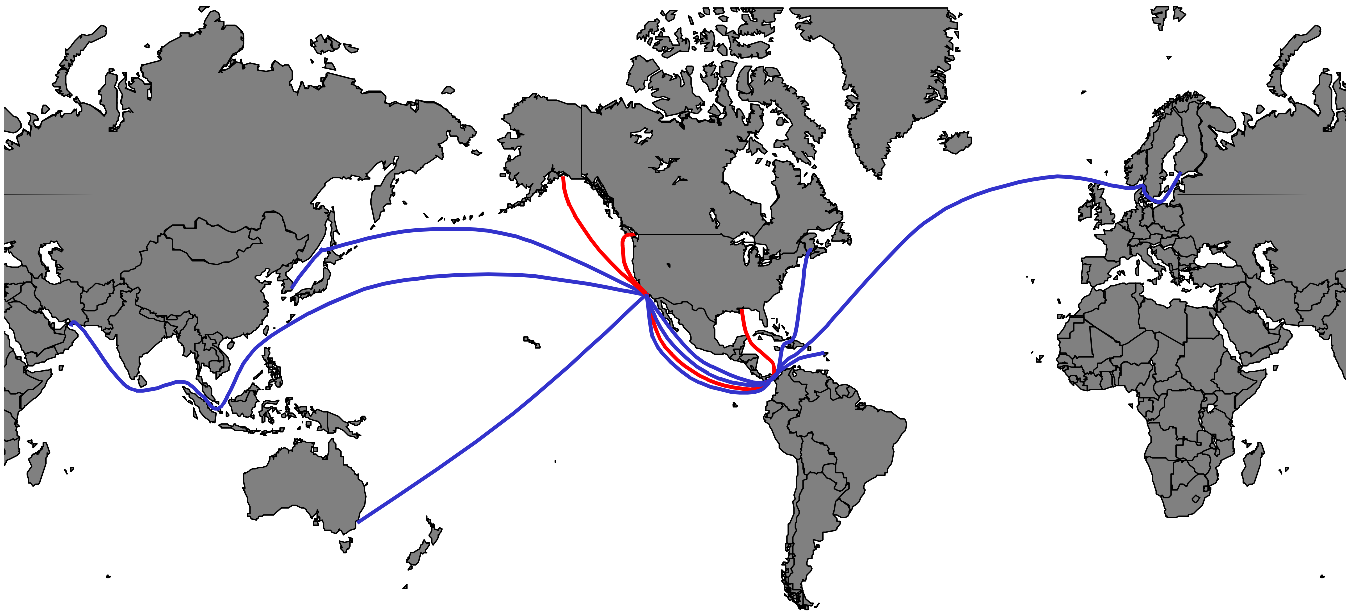
US Gulf Supplies to CA: Product Not There, Ships Not There

Increased Supplies – Identified Foreign Imports

- Only one foreign refiner identified who will be capable of producing Phase III CARBOB (Irving, New Brunswick, 2 cargoes/month, or 10 TBD)
- Other foreign refiners currently capable of producing Phase II CARBOB have alternative markets, and lack investment incentive
- Envirofuels (Alberta) likely to convert 18.5 TBD of MTBE into 11 TBD of isooctane
- Dubai venture likely to increase production of near CARBOB Phase III quality material from 10 to 25 TBD
- Global majors operating in CA market are likely to optimize worldwide sourcing (10 TBD already included in Phase III compliance plans)

At sustained high CA prices, imports will be mobilized
Question is: How will these products reach the market?

California's Gasoline Import Routes



Arabian Gulf	**11 cpg**	**33 days**	**Alaska**	**10 cpg**	**8 days**	**Caribbean**	**7 cpg**	**14 days**
Korea	**7 cpg**	**16 days**	**Washington**	**4 cpg**	**4 days**	**Canada E/C**	**8 cpg**	**21 days**
Australia	**9 cpg**	**20 days**	**USGC**	**12 cpg**	**18 days**	**Finland**	**10 cpg**	**30 days**

Physical Barriers to Entry in CA Market

Barriers identified by CEC Strategic Fuels Reserve Study:

- Lack of deepwater storage terminals, particularly in LA Basin
- Over half of capacity in hands of majors
- Ports of LA, Long Beach favor container and car terminals
- City officials, action groups want removal of several terminals
- SCAQMD Rule 1178 will cause 10% of LA tanks to be temporarily out of service over next 7 years
- Significant capacity lost, more threatened by non-renewal of leases
- New capacity faces hostile permitting environment
- New capacity can only be built with bankable contracts
- Traders unable to sign long-term, i.e., 10-year, commitments

Lack of storage is main barrier to import

Summary of Supply/Demand Situation

- CA refineries are running at maximum practical operating rates
  - 95% of nameplate is very high given age and complexity of installations
  - Remaining 5% is taken up by maintenance, breakdowns, supply issues
  - Running flat-out precludes rebuilding inventories after outages
- Opportunities to increase capacity diminish
  - CAAA Title V Operating Permits are limiting unit capacities
  - NOx credits unavailable
- MTBE Phase Out will create 50 - 100 TBD shortfall, mainly in S-CA
- Shortfalls have to be made up by imports but
  - Domestic and foreign avails are limited
  - Increases in domestic sourcing outside CA are limited by shipping
  - Import receipt capabilities are restricted by infrastructure and port policies
  - Global competition for key blending components increases
  - New capacity requires investment grade long term contracts

Agenda

- Background
- Current Supply Issues
- Strategic Reserve Do's & Don'ts
  - Other Reserves
  - Release Mechanisms
  - Requirements for CA SFR
- Current CA Inventories
- Markets
- Options
- Effectiveness & Cost/Benefits Analysis
- Conclusions

Other Reserves – Federal Petroleum Reserve

- 1974 International Energy Agency, 28 signatory countries, response to first oil crisis
- 1975 Energy Policy and Conservation Act (EPCA)
- 1977 FPR commissioned, 1 billion barrel capacity
- EPCA provides for creation of Regional Petroleum Product Reserves
- NE Heating Oil Reserve was created as an RPPR using FPR crude oil sales to purchase heating oil

FPR may provide means to partially fund CA SFR inventory

Other Reserves – Northeastern Heating Oil Reserve

	Northeast HO*	CA Gasoline
Demand	0.7 MM BPD winter average	1.0 MM BPD year round
Available Inventory Range	20 to 60 MM bbl = 40 MM bbl	18 – 10 MM bbl = 8 MM bbl
Effective days inventory	70 days av. winter demand	8 days regular demand
Product Fungibility	Readily fungible	Unique to CA
Product Grades	One	Multiple Summer and Winter
Blending restrictions	None	Unocal Patent, CARB cert.
Market Liquidity	1000+ trades/day	<20 trades/day
Futures Market	Broad, up to 1 year deep	Narrow, next month only
Market participants	Large Community	Closed Market
Pricing	Transparent	Limited reporting
Demand	Seasonal Only	Year Round
Import options	100s of refineries worldwide	3 – 5 refineries
Shipping time	1 – 2 weeks	5 – 8 weeks
Import terminals	68 in 26 ports	16 in 2 ports (incl. refineries)
% of Population Affected	11% (54% in Maine)	>90%

CA Gasoline more vulnerable than NE Heating Oil

Other Reserves – More Lessons for CA

- SFRs usually designed for reasons of national security, with very large capacities (60 – 90 days)
- Only one other know example of SFR designed to mitigate price spikes (NE Heating Oil)
- Event driven triggers, especially those with discretionary authority for release, are an impediment to supplies (FPR, Northeast Heating Oil)
- SFRs can play an important role in opening up markets (Japan, Korea)
- SFRs must be fully integrated, with continuous throughput for quality reasons (various European countries)

Release Mechanisms

Event Triggered

- Even when conditions and authority are well defined, can create market uncertainty
- Best suited for large national Strategic Reserves, with events defined in terms of national security
- Can be misused by political powers

Price Triggered

- Requires complex pricing formulas
- Even when criteria for release are well defined, creates significant market uncertainty
- Can form impediment to normal supplies
- Can be misused through gaming
- Costly to maintain because of sell-low, buy-high factors

Continuous Access

- Any qualified party can always borrow from reserve
- Use is time-swap only
- Requires well defined operating procedures
- Can stimulate normal supplies
- Can form basis for forward market
- Cost of initial fill only, all usage replacement in kind

Logistics Requirements for SFR

- Starting point is AB 2076 requirement for 2 weeks supply of largest refinery, or 2.3 MM bbl effective (2.5 MM bbl gross)
- Separate N-CA and S-CA markets cannot be served effectively from a single location, proposed split 0.9 MMB North, 1.4 MMB South
- Logistics requirements dictate that SFR must be
  - Integrated into the infrastructure of the Bay Area and LA Basin refining centers
  - Connected to Kinder Morgan Pipeline Systems
  - Have deepwater access
  - Have flexible drain-dry tankage suitable for multiple grades, components, plus blending capability

Commercial Requirements for SFR

- Reserve cannot occupy scarce existing tankage without severely impacting the current fragile supply/demand balance
- Reserve must be accessible to all qualified parties
  - CA Refiners
  - Qualified Traders, Importers
  - Independent Marketers
- Release mechanism must be
  - Clearly defined
  - Designed such that imports are facilitated rather than hampered

Agenda

- Background
- Current Supply Issues
- Strategic Reserve Do's & Don'ts
- Current CA Inventories
  - Inventories
  - Available Tankage
  - Outlook
- Markets
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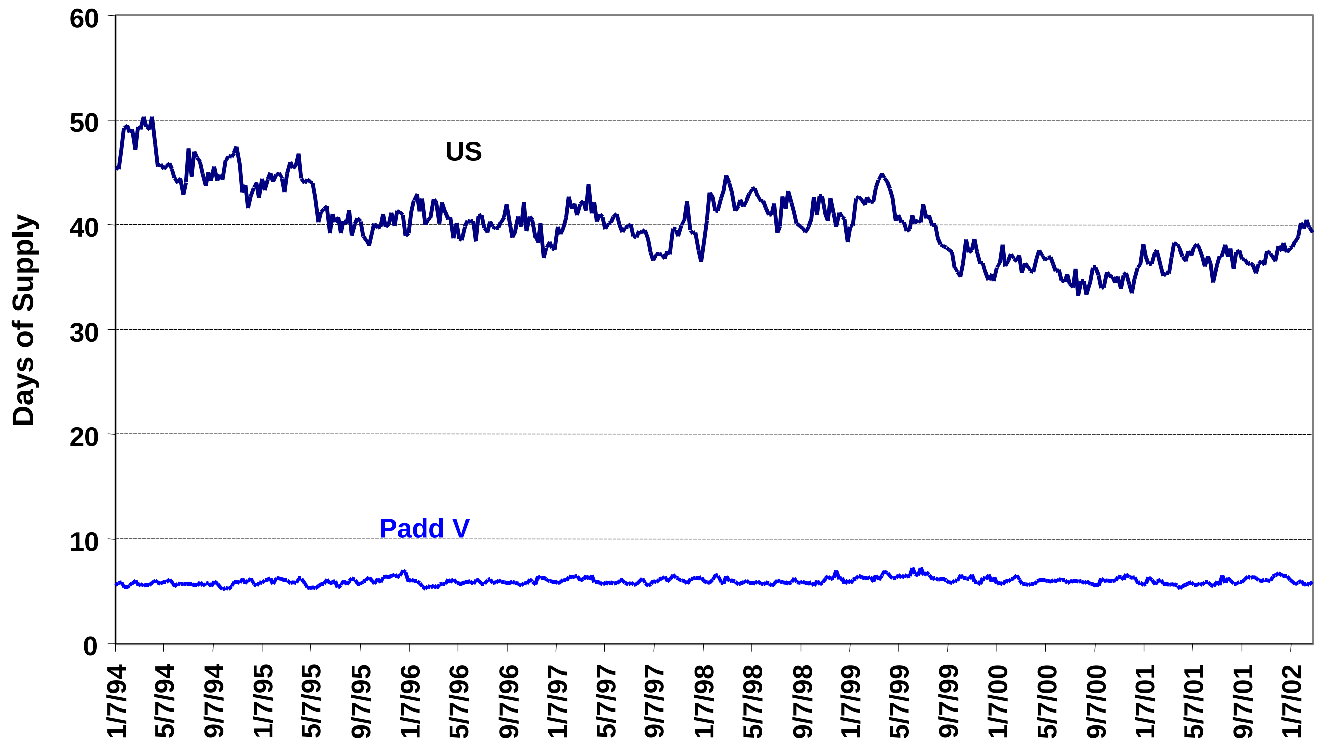
West Coast Gasoline Stocks

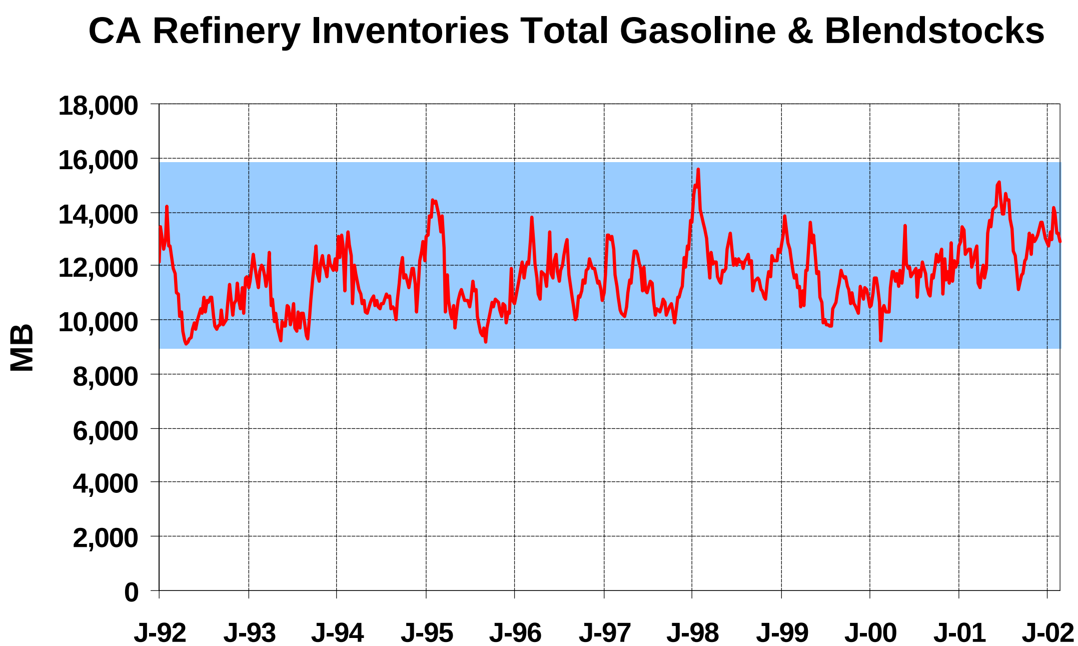
Days of Supply (Consumption/Stocks)



Gasoline Stocks on the West Coast are considerably lower than in the rest of the US; California's are lower still

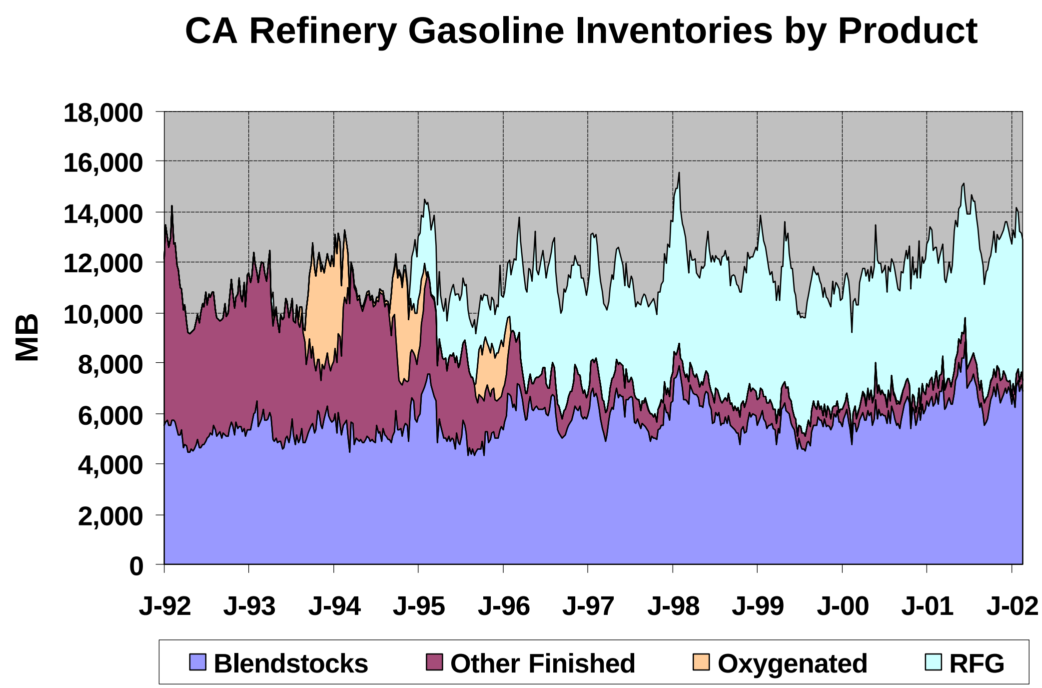
Source: A. J. Finizza Ph.D.

CA Refinery Inventories – Gasoline and Components



CA Refinery inventory working range represents only 8 days usage

CA Refinery Inventories – Gasoline and Components



Refinery finished gasoline represents only 4 – 6 days usage

CA Inventories – Capacity Reconciliation

Total Gasoline & Component Tankage

Nominal Tank Capacity Total CA	53 MM bbl
Ullage, Heels, non-operable tanks, 15%	- 8 MM bbl
Effective Total Capacity	45 MM bbl
Expected Average Inventory	22 MM bbl
Expected Average for CA as 70% of PADD V	21 MM bbl

Refineries

Nominal Tank Capacity Total CA	26 MM bbl
Ullage, Heels, non-operable tanks, 15%	- 4 MM bbl
Effective Total Capacity	22 MM bbl
Expected Average Inventory	11 MM bbl
Reported Average Inventory	12 MM bbl

CA Inventories – Inventory Planning

- Refinery inventories determined by operational requirements
- Number of tanks (“bottoms”) equally as important as capacity
- Few refiners have many options for strategic inventory considerations
- Average cycle time full to empty for tanks in distribution system (pipelines, truck racks) is weekly
- Commercial terminals offer some capacity for holding strategic inventories
- Main consideration at import terminals is cargo size for vessel deliveries

Current CA tankage offers no options to increase inventories

CA Inventories – Commercial Terminals

MM bbl	Total Tank Capacity	Clean Product Tanks	Gasoline & Components
Bay Area			
Commercial Operator	8.5	5.7	3.8
Owned by Refiner	0.6	0.6	0.6
Total	**9.1**	**6.3**	**4.4**
LA Basin			
Commercial Operator	22.0	5.7	4.6
Owned by Refiner	7.7	7.2	6.8
Total	**29.7**	**12.9**	**11.4**
Total	**38.8**	**19.2**	**15.8**

- In LA Basin, two refiners own terminals that were put in commercial service in mid 1990s
- This capacity is now increasingly needed for internal use
- Large majority of tanks in commercial terminals is leased to refiners under long-term contracts
- Capacity is no longer readily available on a spot basis

CA Inventories – Impact of MTBE replacement

MTBE Phase Out will free up tank space in import terminals but:

- MTBE is fully fungible single component, landed in few tanks with high throughput
- Replacement is plethora of specialty blendstocks, each needing segregated storage
- Waterborne ethanol, although smaller in volume, will need tanks too
- Tank size is set by cargo size rather than throughput
- MTBE de minimis requirements and sulfur specs may result in more off-spec batches requiring segregated storage
- Blending around UNOCAL patent will be more difficult

MTBE infrastructure is incapable of handling CA shortfall

CA Inventories – Commercial Tank Market

- Current shortage has increased tank rental rates to above reinvestment economics
- However, little new capacity is on the books
  - Permitting is lengthy, costly
  - NIMBY action groups and nationwide NGOs are more powerful than local industry
  - Security concerns post 9/11 cited by Ports as reason to hold applications
  - Commercial Operators base rate on utility type returns, but require long-term, bankable contracts to do so
  - Traders, importers prefer to rent tanks on a spot basis
- Closure of tank terminals in PoLA/Long Beach may continue

Agenda

- Background
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- Current CA Inventories
- Markets
  - Mechanisms
  - Forward/Futures
  - Price Volatility
- Options
- Effectiveness & Cost/Benefits Analysis
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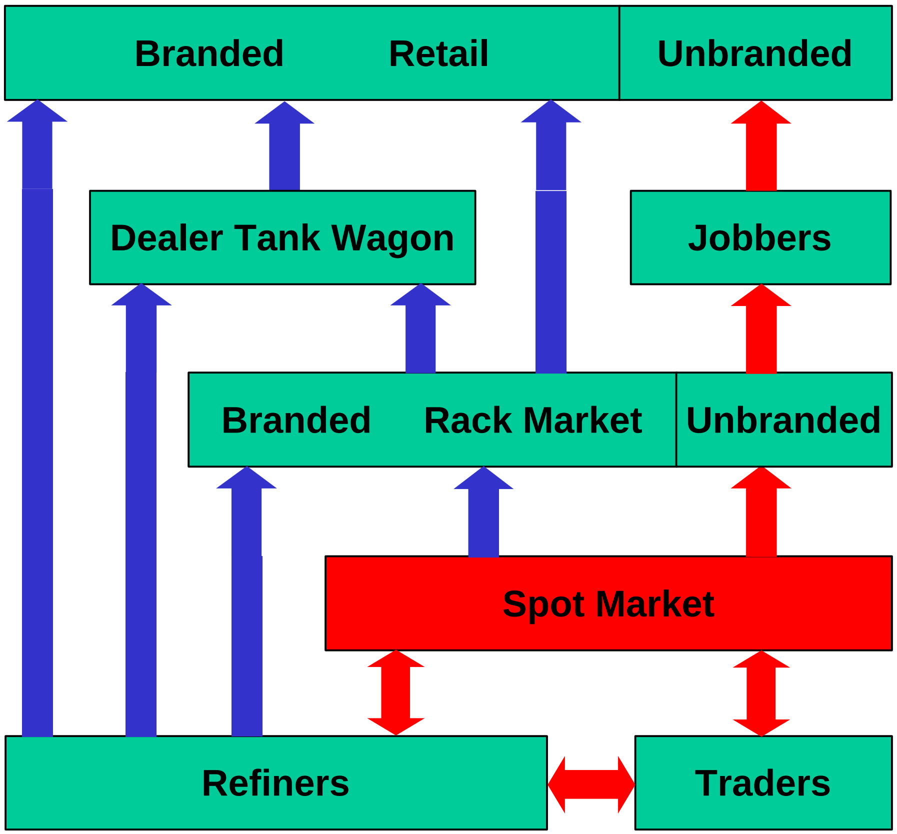
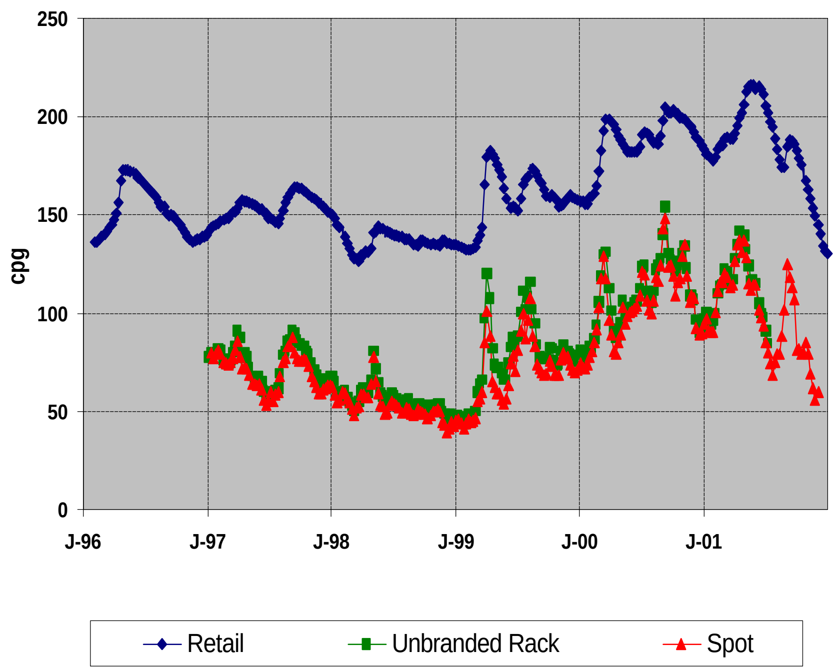
Market Mechanisms



- CA spot market is illiquid:
  - Only 20 - 30 participants
  - Fewer than 5 trades/day
- Spot market is where price spikes first occur
- Spot prices are highly volatile
  - Can move 5 cpg on rumors
  - Up 20 cpg on few trades in one day following an event
- Pricing not transparent
- Last bbl sets entire market
- Branded retail somewhat sheltered from spot spikes
- Unbranded rack buyers get pinched between spot and retail on the upswing

CA Market Mechanisms – Spot vs. Retail

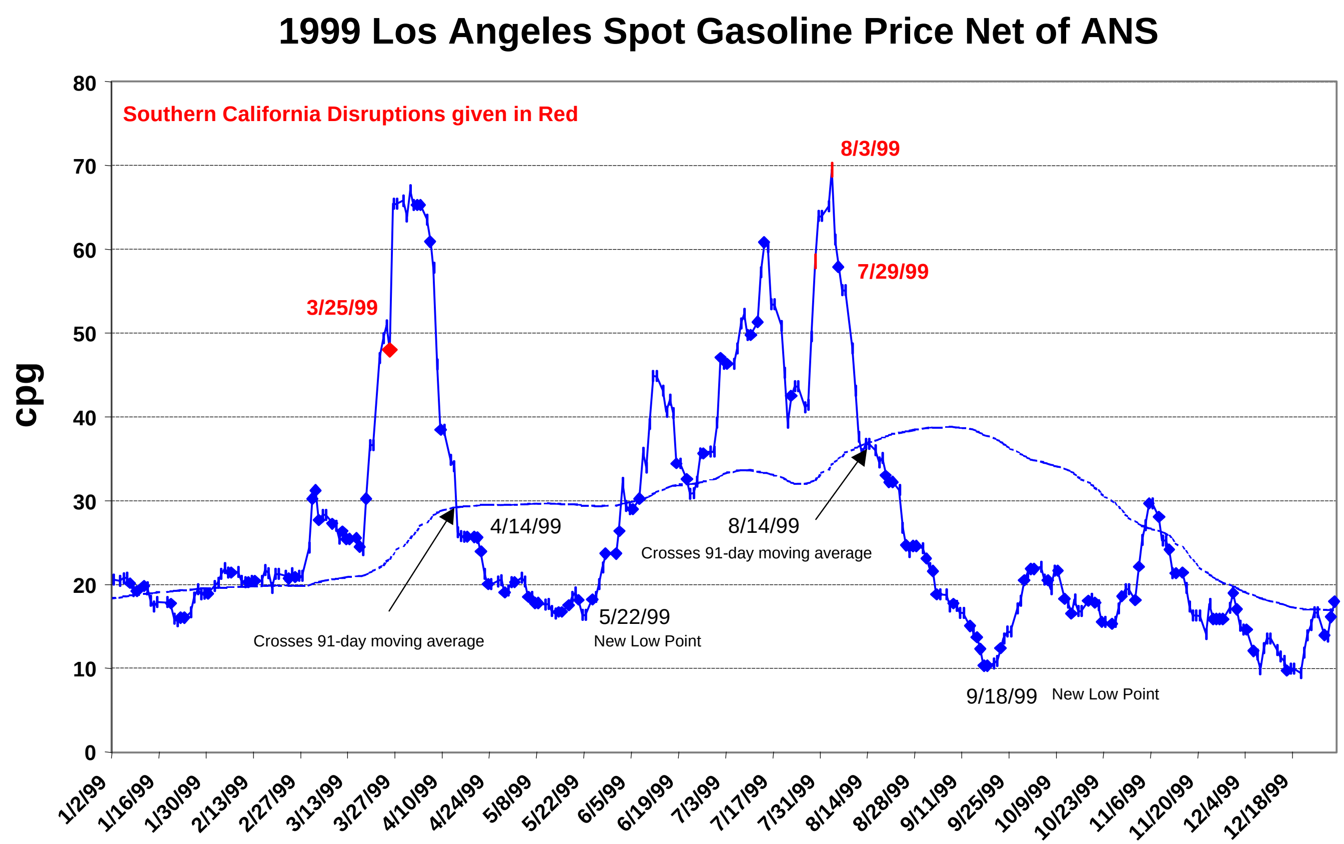
CA Gasoline Spot & Retail Prices



- Price volatility is primarily expressed in spot and rack market
- Retail somewhat sheltered by refiners
- Independent marketers get caught between rack and retail on the upswing
- Downswing offers opportunity for independents to recoup losses

Duration of Disruption Effect

Stillwater Associates

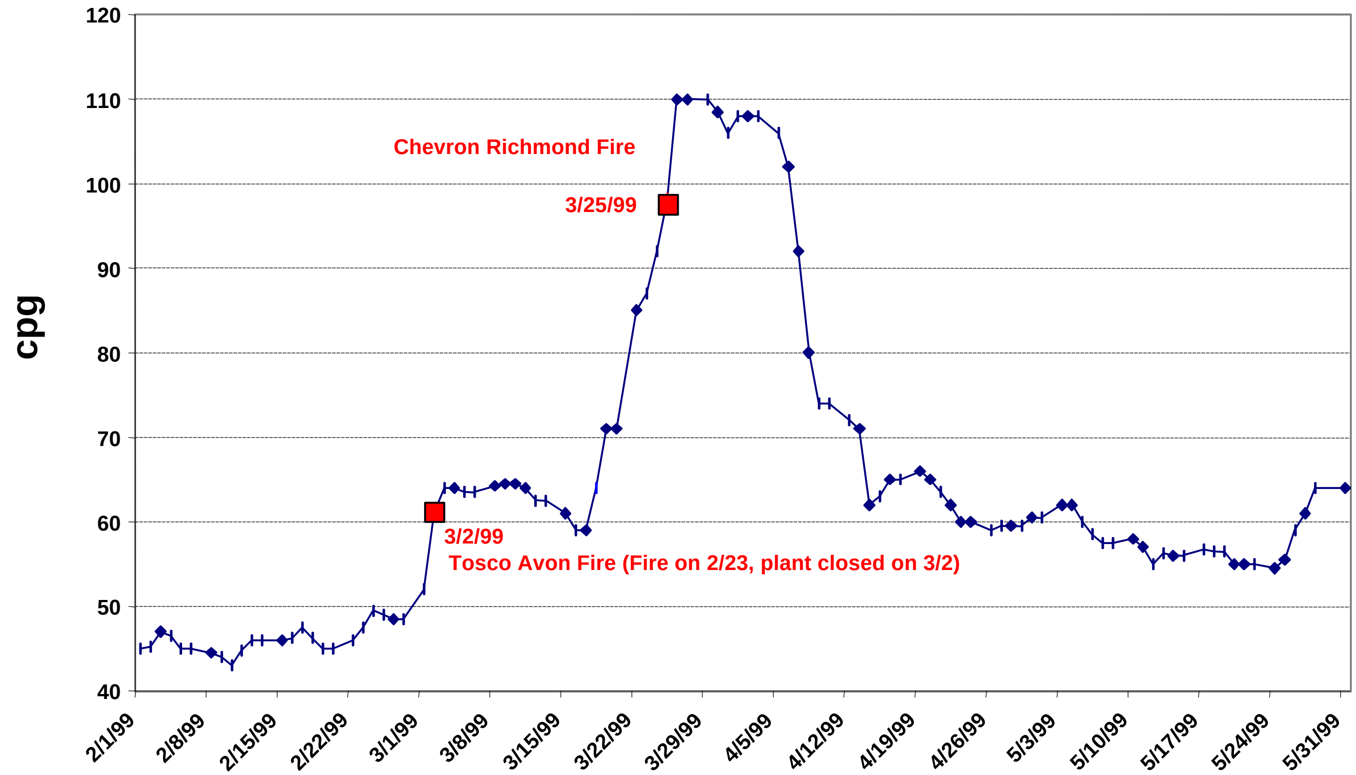


Disruption Effect Lasts 6-8 Weeks

Source: A. J. Finizza Ph.D.

Effect of Disruptions on Pricing

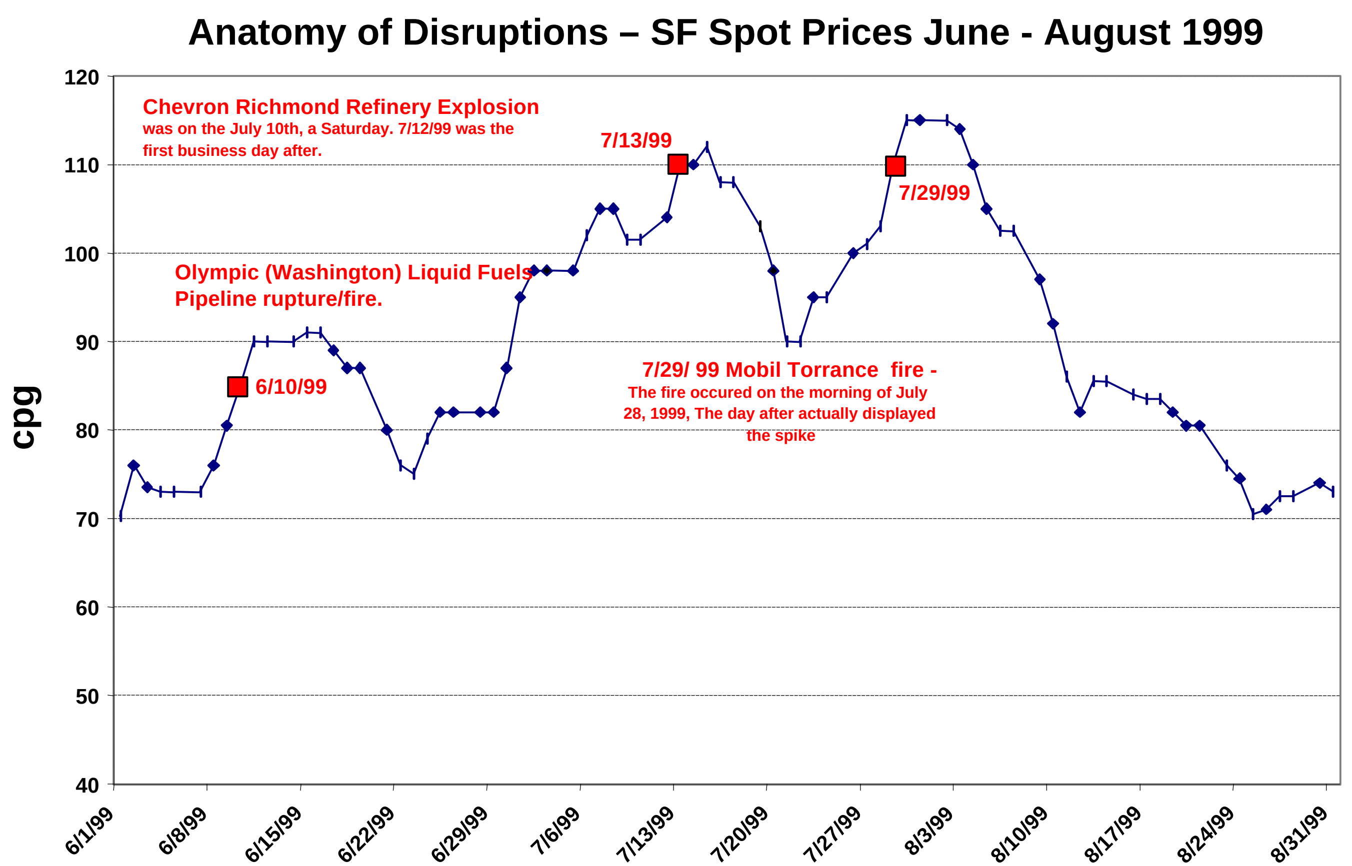
Anatomy of Disruptions – SF Spot Gasoline Prices Feb – May 1999



Refinery Disruptions Have An Immediate Impact on Prices

Source: A. J. Finizza Ph.D.

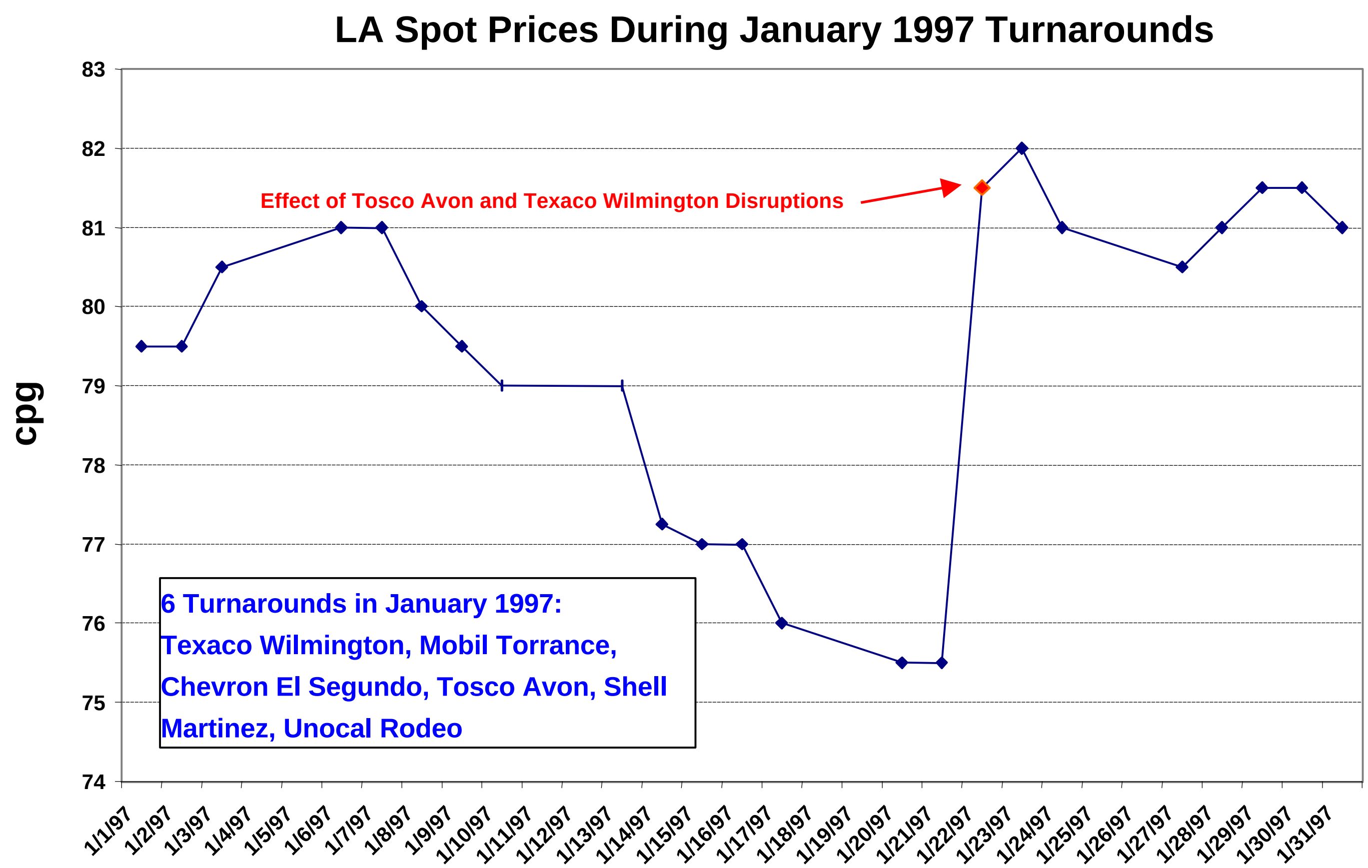
Effect of Disruptions on Pricing (Cont'd)



Refinery Disruptions Have An Immediate Impact on Prices

Source: A. J. Finizza Ph.D.

Effect of Planned Turnarounds on Pricing

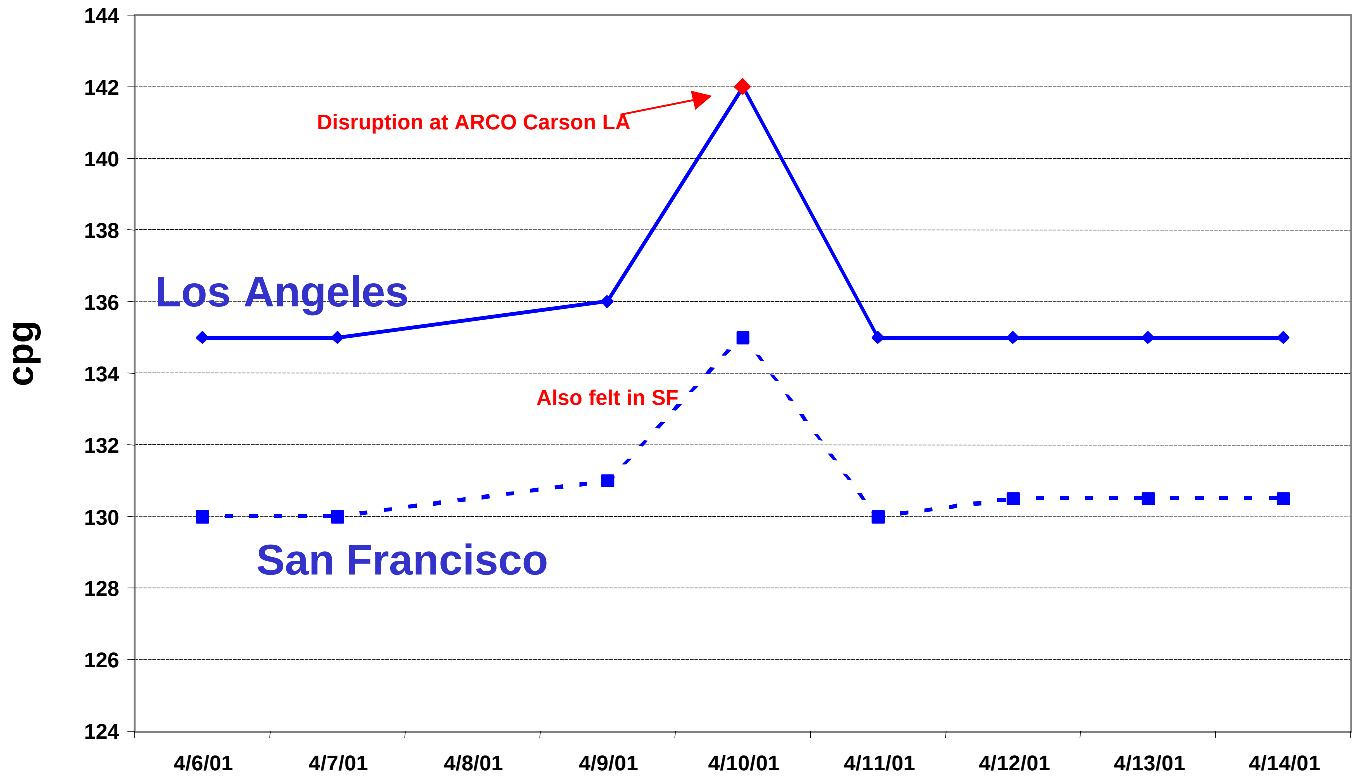


Planned turnarounds do not affect prices unless coinciding with a disruption

Source: A. J. Finizza Ph.D.

Regional Effects

LA and SF Spot Gasoline Prices – Week of April 6, 2001

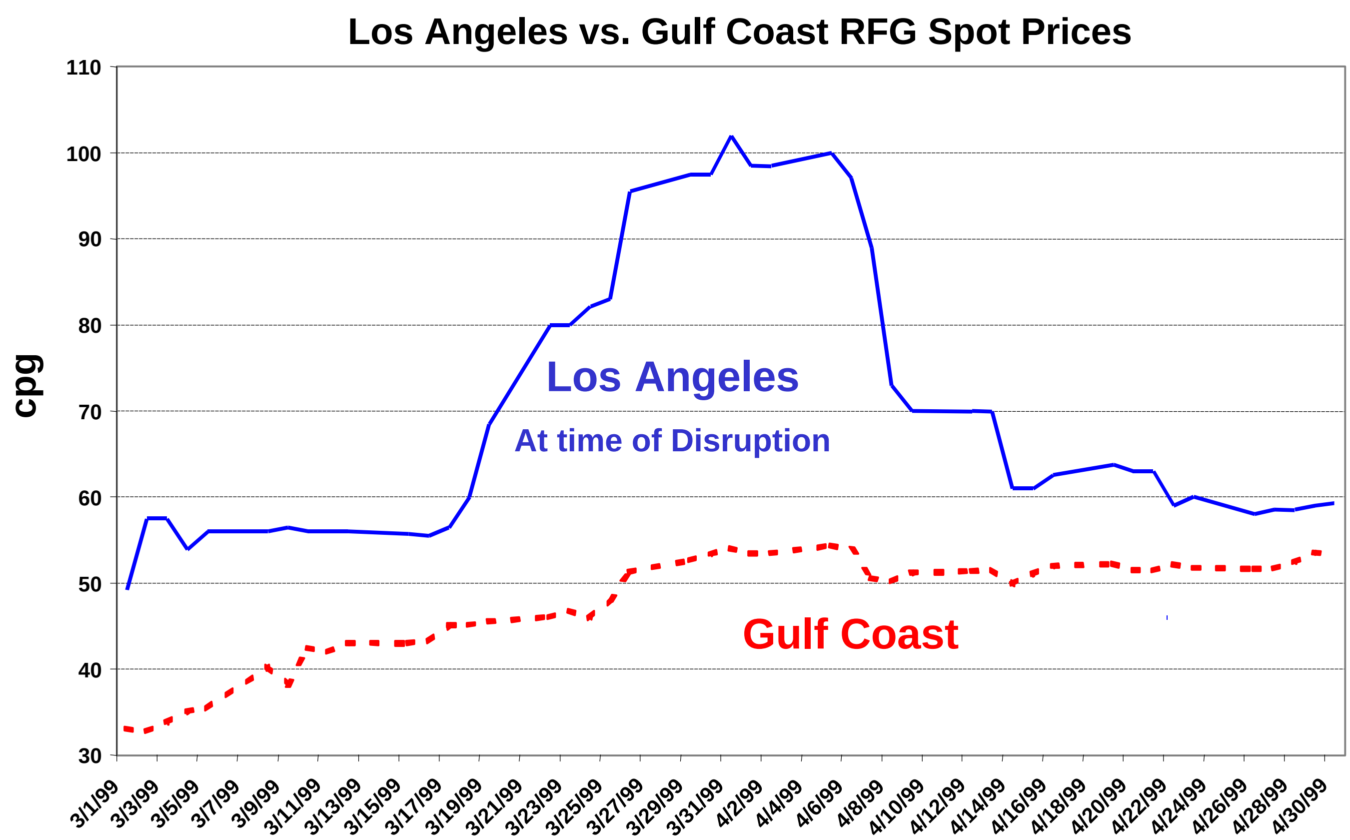


A refinery disruption in either part of California affects all of California

Source: A. J. Finizza Ph.D.

Effect of CA Disruptions Outside the State

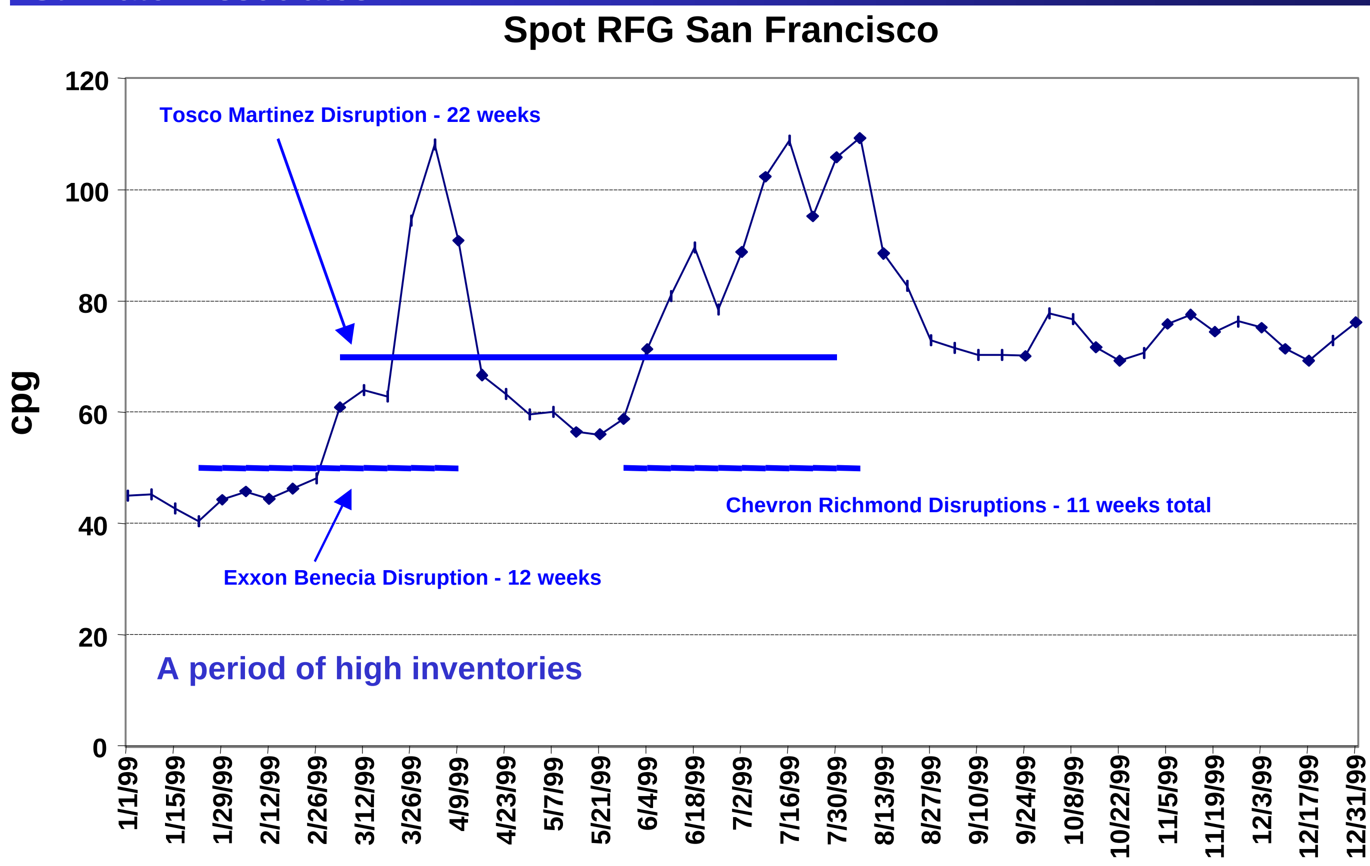
Stillwater Associates



Price Spikes are not transmitted to other areas outside of California

Source: A. J. Finizza Ph.D.

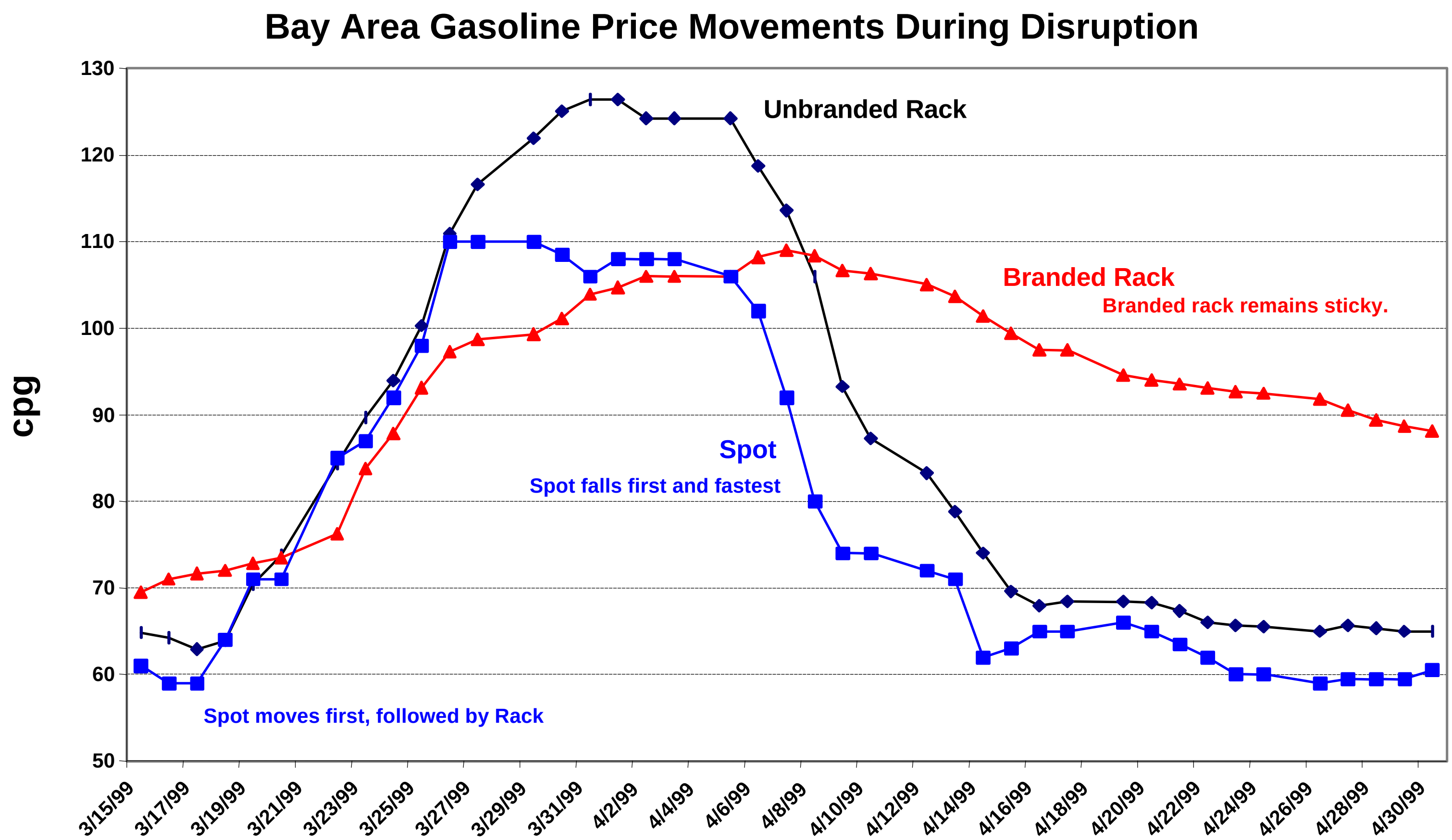
Disruptions and Price Spikes



Not all disruptions lead to price spikes

Source: A. J. Finizza Ph.D.

Gasoline Price Movements during Disruption

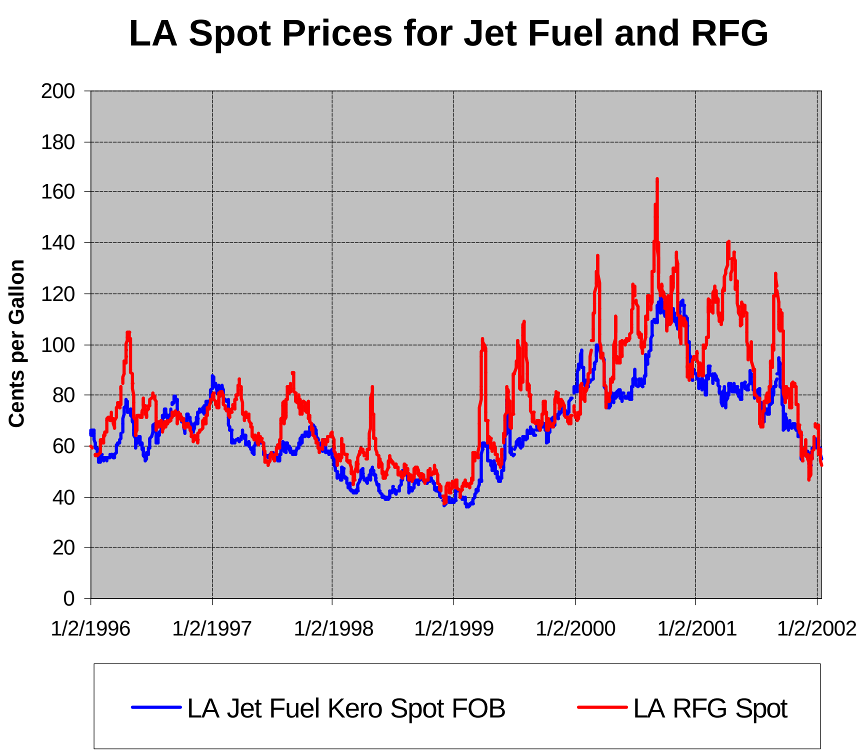


The rise and fall of prices during a disruption is asymmetric

Source: A. J. Finizza Ph.D.

CA Market Mechanisms – Distillates vs. Gasoline

Stillwater Associates



- Jet fuel is a readily fungible worldwide commodity
- Jet has broad and deep forward market
- Jet fuel can be hedged against heating oil futures
- Storage for jet in LA is ample, and is controlled for a large part by a consumer consortium
- Jet follows same underlying crude oil price curve as gasoline
- Jet has some fluctuations as supply and demand adjust
- Jet prices do not have the extreme spikiness of gasoline

Commercial Barriers to Entry

Besides physical barriers, commercial hurdles are also significant:

- Spikiness of gasoline market is not conducive to imports, time needed to locate and ship product (4 – 6 weeks) usually exceeds duration of spike
- Lack of liquidity in futures or forward market exposes importers to significant risk
- Often only blendstocks are available for imports
- Only major refiners can prepare and certify final blend
- Independent traders locked out of market, cannot link sources to end markets without physical and commercial cooperation with refiners
- Of the CA refiners, only a few are actively sourcing and trading globally
- Combination of commercial and physical access in hands of few players leaves market exposed

Commercial landscape not conducive to supplying shortfall

Creation of Forward Liquidity

- Forward Liquidity requires:
  - Minimum number of diverse buyers and sellers
  - Physical delivery point with sufficient inventory capability to act as pool and market sink
  - Fungible products, well defined specs
  - Multiple supplies
- Only when a market has deep and broad forward liquidity can a standardized, regulated future derivatives market emerge
- Only when a futures market exists can trades be effectively hedged
- Hedging is a pre-requisite for long-lead time imports by independent traders

Forward liquidity will benefit all market participants

Advantages of a California SFR

Current Situation

- No hedging mechanism
- No physical location for discharge
- No access to pipelines from offshore
- No storage for components
- Thin forward market
- Unmanageable Price Volatility
- Insufficient liquidity
- Price discovery based on limited transactions and reporting

SFR Benefits

- SFR is physical receiver based on auction differential
- SFR provides access for waterborne cargoes
- SFR enables storage flexibility in private tanks
- SFR provides physical location for forward market
- SFR enables free market to discover and hedge market value
- SFR enhances liquidity
- SFR linked to transparent electronic auction system

Disadvantages of Extreme Volatility

For Refiners

- Bad for industry image
- Increased scrutiny and oversight
- Unpredictability and cyclicality are not rewarded by Wall Street
- Long term consumer behavior is negatively impacted

For Independents

- Inversions at the leading edge of a spike
- Unable to keep customers supplied
- Unable to source supply from outside California

For Consumer

- Pays more at the pump
- Lower income levels most affected
- Has to compromise convenience and lifestyle to realize reductions in consumption

Agenda

- Background
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- Markets
- **Options**
  - Alternatives
  - Proposed solution
  - Operating Principles
- Effectiveness & Cost/Benefits Analysis
- Conclusions

Options for CA SFR

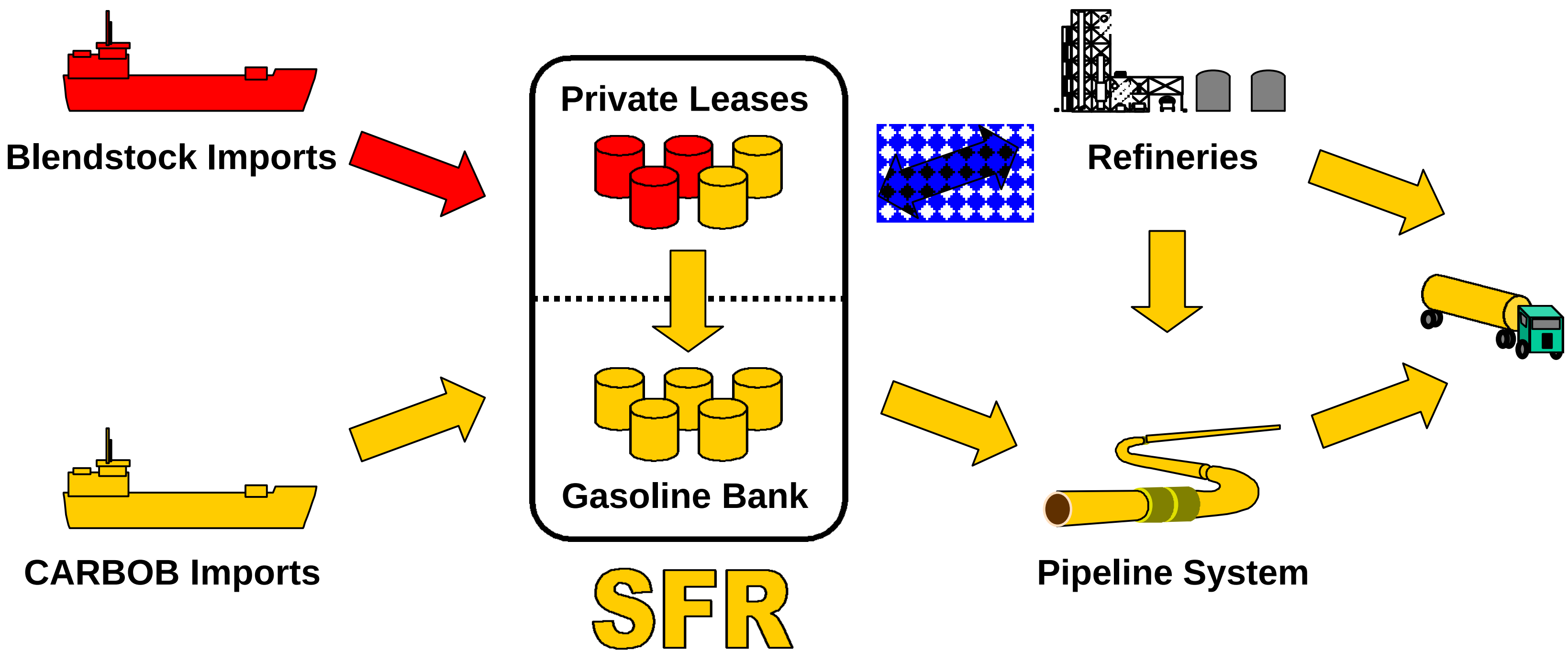
- New tankage built & operated by State
  - $75 MM investment, $17 MM fixed/costs
  - Still significant throughput costs for 3rd party pipelines, docks, etc.
  - Not cost effective
- New tankage built and operated by commercial terminal company
  - Competitive bid process to ensure lowest rates
  - Market indications are $0.45 - $0.55/bbl/month, 10 – 15 year contract
- Options could include conversion of idle fuel oil storage at power stations
- Floating storage, other idle tanks non-starters

Proposed Configuration

- Facilitate building 5 MM bbl of total storage capacity, 1 - 2 MM in Bay Area, 3 - 4 MM bbl in LA Basin
- Issue tender to qualified parties to build and operate the tankage
- State to lease approximately half of the new tankage for Reserve
- Remainder available for short term use by industry under normal commercial terms
- Industry tankage surrounding can be used for receipt of blendstocks, components and blending
- Reserve tanks to be used in summer grade CARBOB only

Net Cost to California Consumer $20 – 30 MM/year

Operating Principle

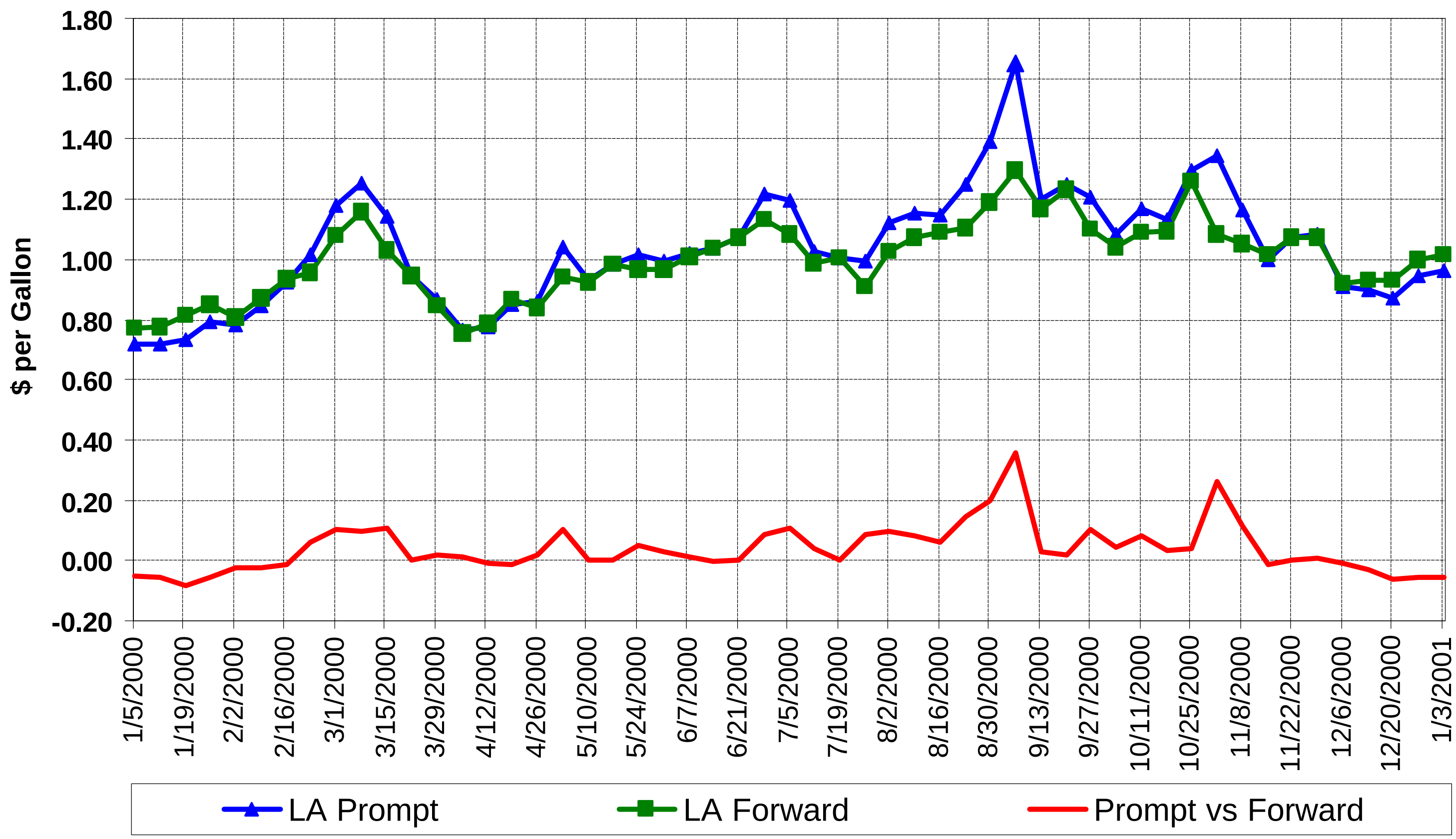


Operating Principle for SFR

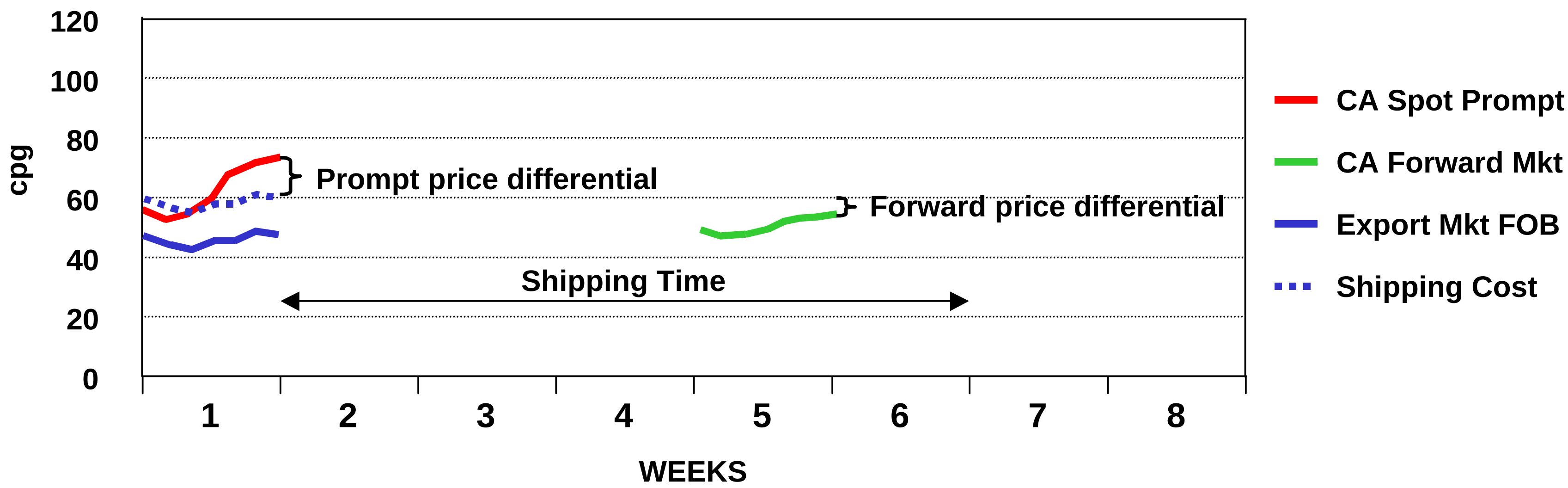
- Initial fill 2.5 MM bbl to be purchased as Phase III CARBOB gradually and over time so as to not upset the market
- Use offsets from FPR to finance part of SFR, evaluate possibility of power for gasoline swap for rest
- Conduct daily electronic auction for 50 TBD of CARBOB and components for prompt lifting, 6 weeks max redelivery
- Speculative use of reserve volumes limited by physical lifting & re-supply requirements and quantity limitations
- Any qualified participant can participate

Create *The Gasoline Bank of California*

LA Spot Prompt versus Forward Markets 2000

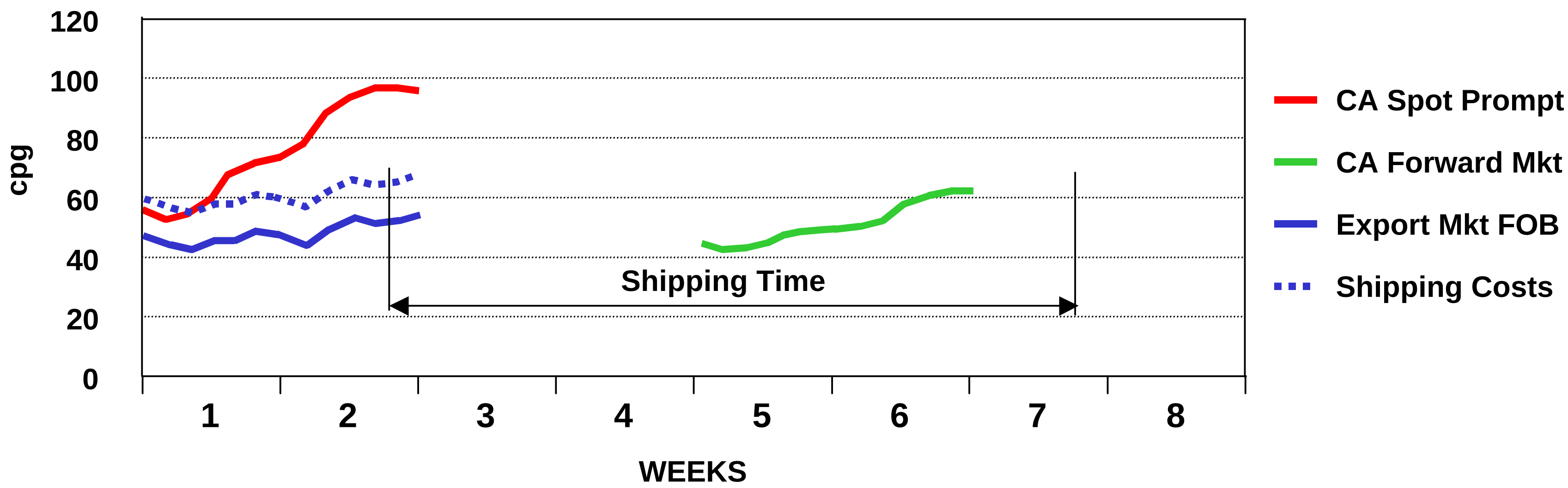


Analysis of a Price Spike – Current Practices



- In Week 1, Company A's refinery has a fire
- As the extend of the damage becomes clear, and Company A and traders start buying in the spot market, prices move up sharply. The market becomes more backwardated, since forward prices don't follow
- On a prompt basis, it now pays for an importer to bring in a cargo, but a forward sale timed for the arrival of the cargo would still result in a loss

Analysis of a Price Spike – Current Practices

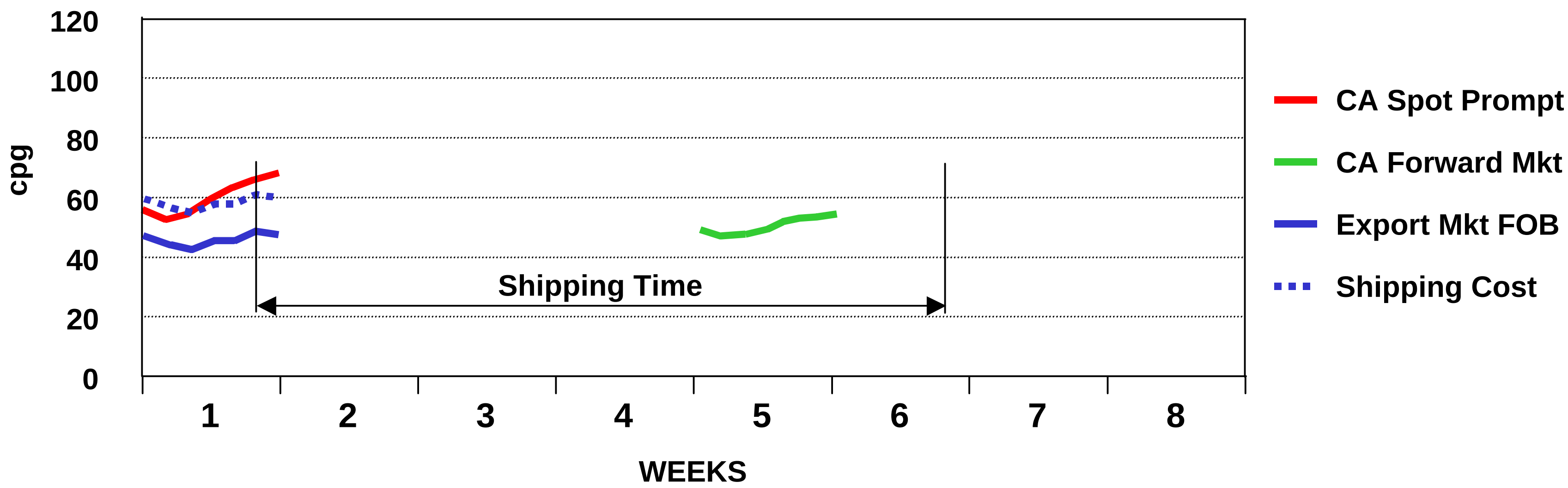


- In week 2, Company B announces a delay in the restart of a refinery that was down for maintenance
- Prices now rise sharply to double that of world markets. The forward market also starts to move up, but is still backwardated and does not allow to lock in a forward contract
- World market prices are not moving up much and the gap widens to 40 cpg based on landed costs CA. Importer C has found tankage and decides to float a cargo

Analysis of a Price Spike – Current Practices

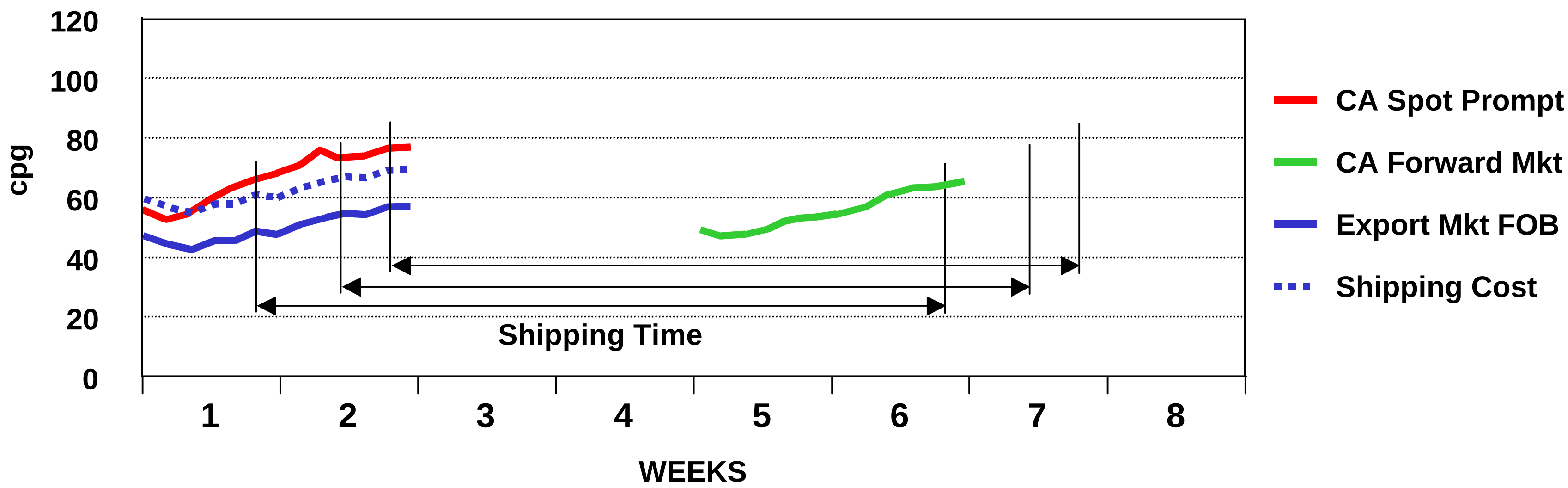
- In week 4, refiner B finally completes the turnaround and starts up their refinery. Spot prices start to drop.
- In week 5, refiner A is able to bring some production back on line from the damaged unit. Prices now fall rapidly.
- By the time importer C's cargo shows up, the market has fallen well below his cost.

Analysis of a Price Spike – SFR In Place



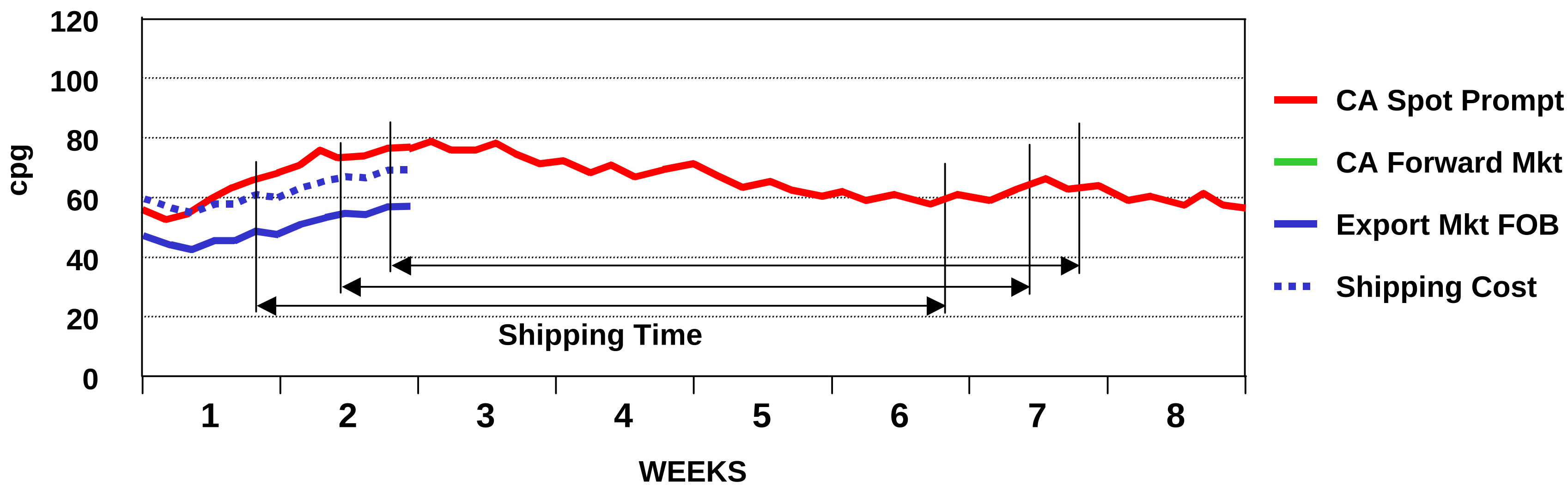
- In Week 1, Company A's refinery has a fire.
- As the extend of the damage becomes clear, and prices start to move upward to where they exceed costs of imports, Company A lifts product from the reserve and books import shipments to backfill the time swap.
- Prices do not move up significantly above import levels. The forward market follow SFR bid action rather than anticipation of the duration of the price spike.

Analysis of a Price Spike – SFR In Place



- In Week 2, Company B announces a delay in the restart of a refinery that was down for maintenance.
- Company B now also starts lifting from the reserve and buying import blendstocks to backfill. Trader C also is chasing some imports and imports markets go up in price.
- Prices do not move up significantly above import levels. The forward market follow SFR bid action rather than anticipated of the duration of the price spike.

Analysis of a Price Spike – SFR In Place



- Cargoes arriving in weeks 6 – 8 replenish the reserve and have no impact on the market

Effect of SFR is to peg CA to world market + import cost, without forward price risk or physical barriers
Scarcity of suitable imports remains an issue

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  - Effectiveness
  - Costs
  - Benefits
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Elasticity Approach

	Demand Price Elasticity	
	Short-run	**Long-run**
Range of estimates	**-.04 to -.4**	**-.23 to -1.37**
Individual studies:		
FTC (2001) Midwest Gasoline Investigation	-.1 to -.4	Not reported
WSPA (2001) (PIRINC study)	-.05	Not reported
API (Porter) (1996)	-.19	-.71
Haughton & Sarkar (1996)	-.12 to -.17	-.23 to -.35
Espey (1996)	Not reported	-.53
Goel (1994)	-.12	Not reported
Goodwin (1992)	-.27	-.71 to -.84
Sterner (1992)	-.18 (.03)*	-1.0 (.15)*
World Bank (1990)	-.04 to -.21	-.32 to –1.37
Dahl (1986)	-.13 to -.29	-1.02
Her medium term estimate:		-.6

* the standard error of estimate is in parentheses

The Literature suggests a Wide Range of Demand Price Elasticities

The Literature is light on estimates on Supply Price Elasticities

Source: A. J. Finizza Ph.D.

Combined Demand-Supply Effect

Shock Price elasticity = Price Supply elasticity – Price Demand elasticity

- FTC used -0.2 in Midwest Gasoline Study
- Berkeley's Borenstein uses -0.15
- Brookings' Perry uses -0.05

Plausible estimates of of shock price elasticity:

-0.1 to -0.2

An elasticity of –0.1 means that a 10% increase in price causes a demand change of –0.1 x10%= -1%.

Source: A. J. Finizza Ph.D.

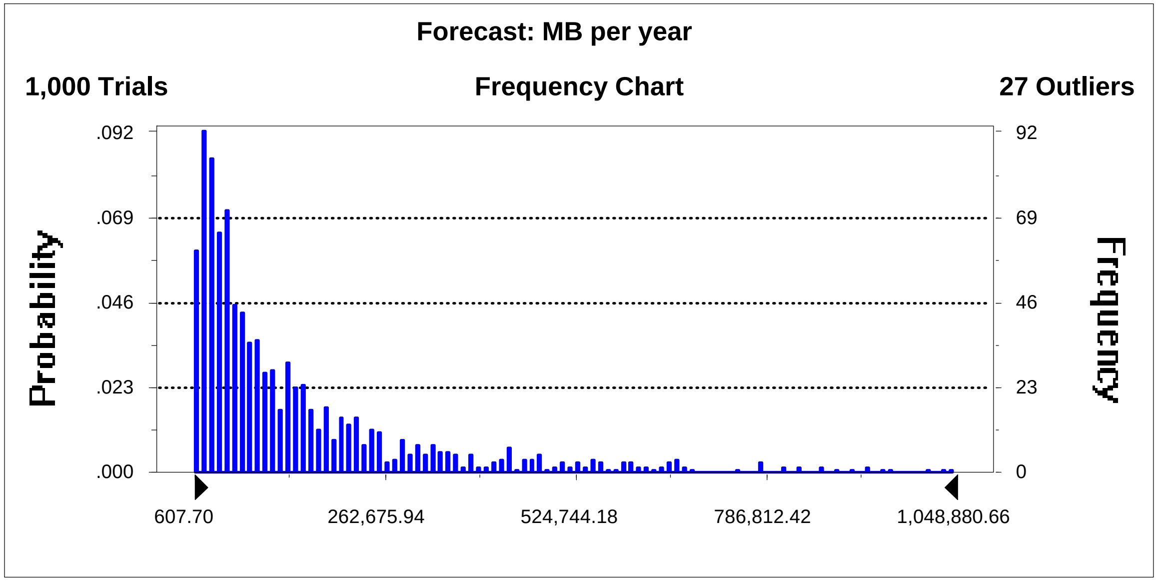
Assumptions for Monte Carlo Analysis

- Chance of a refinery having a measurable disruption in a week is 0.017 (Binomial distribution approximated by the Normal distribution)
- Distribution of disruption sizes (in MB): Lognormal with mean of 20 and standard deviation of 15
- Distribution of Disruption lengths (weeks): Lognormal with mean 2.7 and s.d. 3.8

(Data derived from Historical records March 1996 to March 2001)

Source: A. J. Finizza Ph.D.

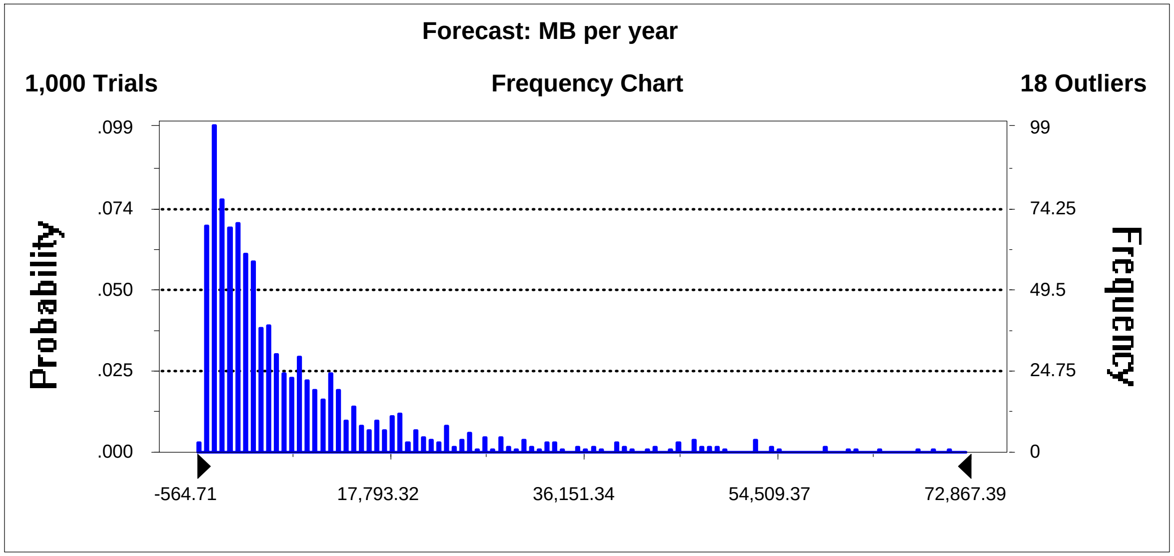
Distribution of Disrupted Barrels (Averages)



	MM bbl	% of Production
Expected Value (mean)	**4**	**1.2**
80^{TH} percentile	**5**	**1.5**
90^{th} percentile	**9**	**2.7**

Source: A. J. Finizza Ph.D.

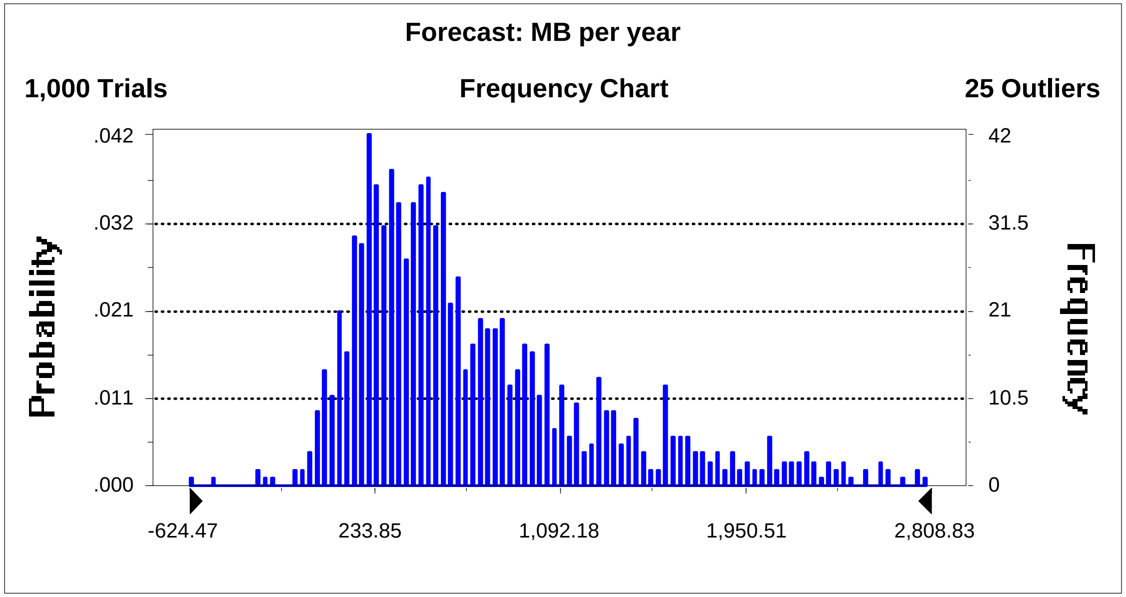
Distribution of Disrupted Barrels (Lows)



	Millions of Barrels	% of Production
Expected Value (mean)	11	3.5
80TH percentile	14	4.3
90th percentile	25	7.6

Source: A. J. Finizza Ph.D.

Distribution of Disrupted Barrels per Year (lows)



	MM bbl	% of Production
Expected Value (mean)	**.8**	**.2**
80TH percentile	**1.4**	**.4**
90th percentile	**1.7**	**.5**

Source: A. J. Finizza Ph.D.

Implications for Additional Consumer Costs

Expected Value - Billions of Dollars

Assumed Elasticity	Low Year Parameters	1996-2001 Average Parameters	1999 Parameters
-0.1	1.75	2.10	6.13
-0.2	.88	1.05	3.06

Assuming retail gasoline = $1.25 per gallon

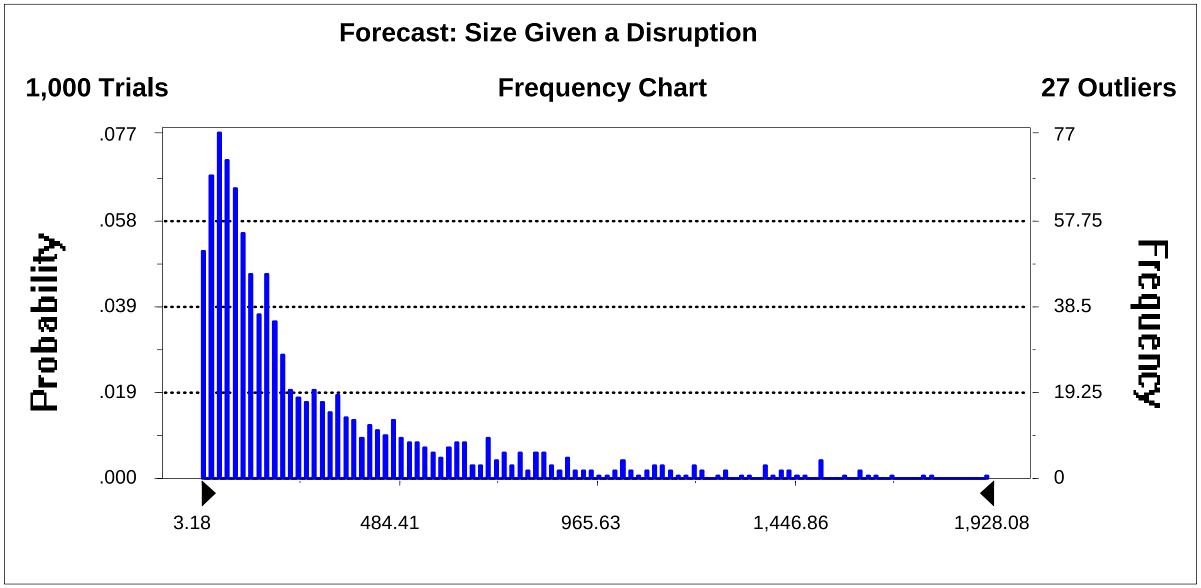
Source: A. J. Finizza Ph.D.

How To Size The Strategic Fuel Reserve?

- Legislative Prescription = ~ 2300 mb
- Assume one refinery suffers a 20 disruption (average) for 2.7 weeks (19 days) = 380 mb
- Cover maximum disruption in 1999 = ? mb
- Use Monte Carlo solution ⇒

Source: A. J. Finizza Ph.D.

Expected Size of a Disruption (Impact x Length)



Distribution of Size of Disruption - MB

Expected Value (mean)	**385**
80TH percentile	**525**
90th percentile	**870**
95th-percentile	**1380**

Source: A. J. Finizza Ph.D.

Probability of Coinciding Disruptions in Same Month

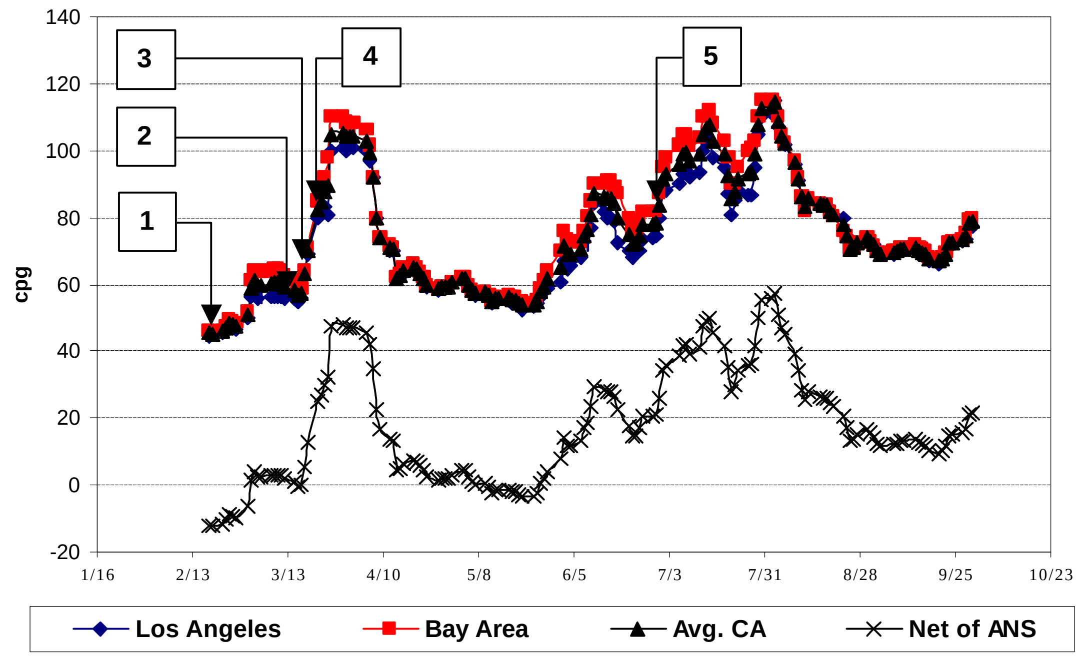
Number of Refineries Disrupted At Same Time	Probability
0	0.838
1	0.157
2	0.014
3	0.001
4+	0.000025

Note: Assumes Independence

Source: A. J. Finizza Ph.D.

Effectiveness of SFR – Design for 1999 outages

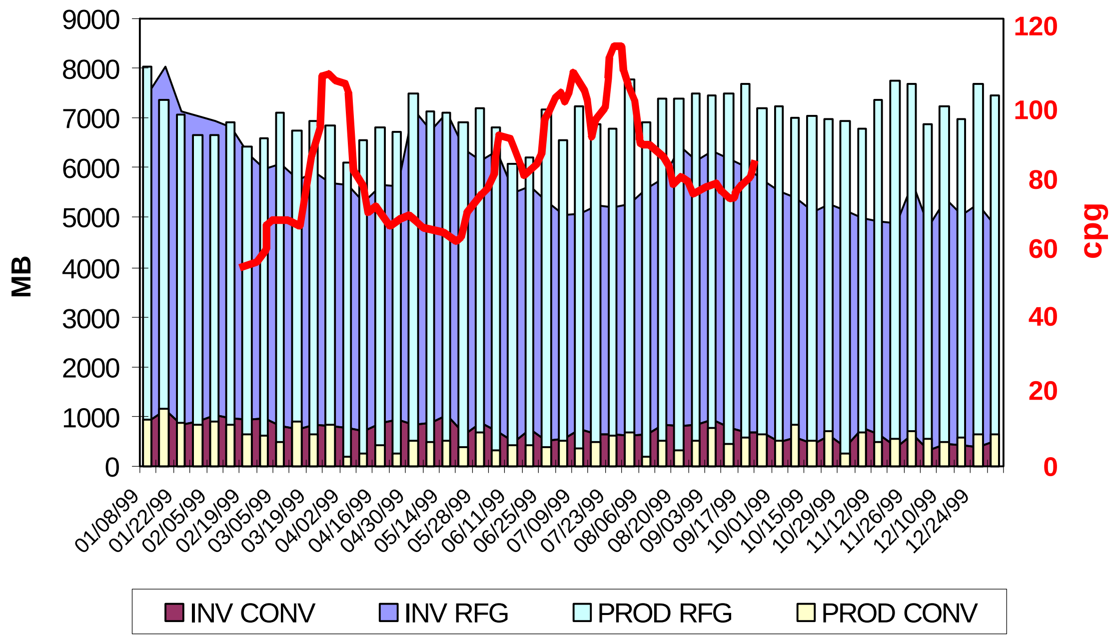
1999 CA Refinery Outage and Price Spikes



1 = Tosco Avon Fire
2 = ARCO Carson FCC
3 = Chevron Isomax
4 = Exxon Benicia FCC
5 = Chevron Richmond Fire

Effectiveness of SFR – 1999 Inventory & Production

1999 CA Gasoline Inventories and Weekly Production



- Av. lost production: 95 TBD
- Additional imports: 11 TBD
- Net ex refinery: - 84 TBD
- Inventory drawdown: 25 TBD
- Average net loss: 59 TBD
- Spot prices +100%
- Retail Prices + 45%
- Demand: - 6%
- Implied elasticity: - 0.13
- 2 MM reserve would have covered 7 – 10 weeks of inventory drawdown
- Imports would have been easier

Forward Gasoline Bank would have been effective in 1999

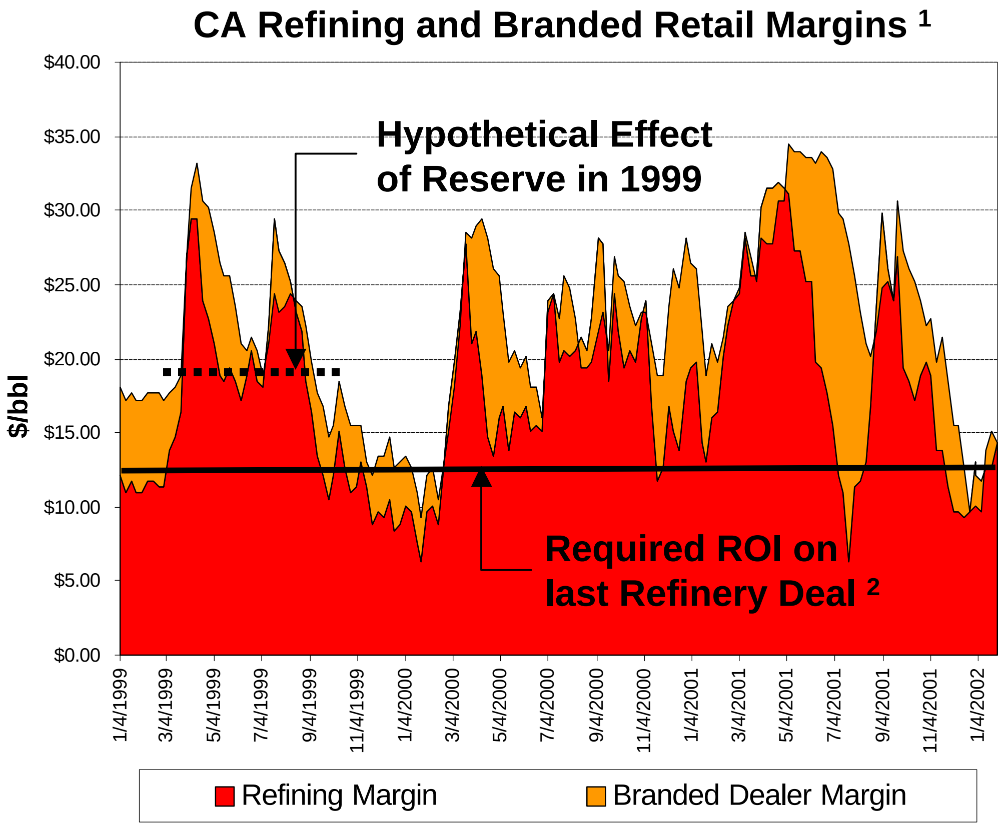
Cost of Reserve

- Lease and operating cost of reserve in rented new tankage $20 MM per year
- Cost of debt service on initial fill if purchased by State $5 – 10 MM per year
- Cost of initial fill may be substantially lower if obtained with FPR offsets
- Fees for daily auctions may contribute up to $10 MM per year
- Net cost of maintaining and operating the reserve are likely to be less than $30 MM per year

Consumer Impact – Price Elasticity

- 5 – 10% shortfall translates into 50 to 100% price spike
- If high prices are sustained over longer periods, more supplies are attracted
- Even with sub-optimal logistics, supply and demand will find new equilibrium
- Incremental barrel will set price level for entire market
- Incremental barrel likely to be an exotic blending component shipped in from remote source
- Chronic shortage will absorb initial price elasticity
- Supply disruptions under these circumstances will cause more severe price spikes

Cost Effectiveness – Benefits to CA Consumer



1. Based on branded retail prices minus taxes and cost of crude oil
2. Tesoro Press Information Feb. 05, 2002

- Presence of reserve in 1999 might have saved consumers on average $5/bbl (12 cpg) over 90 days, or $0.5 BN
- Cumulative effect over 1999 through 2001 is $4.7 BN
- Even with reduction of peaks, prices remain based on imports

Agenda

- Supply/Demand Balance
- Requirements for SFR
- Other Petroleum Reserves
- Current CA Inventories
- Alternative Solutions for SFR
- Commercial Aspects
- Effectiveness
- Cost/Benefits Analysis
- Conclusions

Conclusions

- CA has become increasingly import dependent
- Infrastructure currently inadequate to handle imports, especially in LA Basin
- MTBE phase out will cause 50 – 100 MTBE shortfall which will have to be met through imports
- Price volatility will increase when supply disruption occurs when market is already chronically short and initial price elasticity has been absorbed
- SFR as proposed can be a cost effective way to increase market liquidity and lower import barriers
- Volatility can be substantially mitigated without impacting supply side factors such as import flows and refinery returns

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

FUELS AND TRANSPORTATION COMMITTEE WORKSHOP

ON THE

CALIFORNIA STRATEGIC FUELS RESERVE

HEARING ROOM A

CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, MARCH 13, 2002

9:45 a.m.

Reported By:

Peter Petty

Contract No. 150-01-005

COMMITTEE MEMBERS PRESENT

James D. Boyd, Commissioner, Presiding Member

Susan Bakker, Commissioner Advisor

Mike Smith, Commissioner Advisor

STAFF PRESENT

Pat Perez

Gordon Schremp

CONSULTANTS

David J. Hackett
Thomas E. Gieskes
Gregg Haggquist
Stillwater Associates

Anthony Finizza
AJF Consulting

I N D E X

P R O C E E D I N G S

PRESIDING MEMBER BOYD: Good morning, and welcome. My name is Jim Boyd, I'm the Presiding Commissioner of the Fuels and transportation Committee. Commissioner Keese, the Second Member of the Committee, is out of town dealing with a power plant siting hearing today and is unable to be with us. I'm not quite sure whether I'd rather be there or here. Having just done one of those two days ago that went about 15 hours, why, I think this is a much better place to be.

With me here today, on my right, is Susan Bakker, my advisor. We expect to be joined momentarily by Mike Smith, who is advisor to Chairman Keese. And also, of the Staff, Pat Perez and Gordon Schremp.

I think, as everybody knows, we're here today to discuss the work of the Commission's contractor on the question of the subject of feasibility of developing and operating a Strategic Fuels Reserve in California, presumably, or allegedly, to insulate California business, California consumers, et cetera, from large short-term price increases that can arise from refinery outages and various and sundry other types of supply interruptions.

The Energy Commission was requested, or required, literally, by the legislature, through Assembly Bill 2076, to examine this issue following a series of refinery outages that caused fairly significant price spikes in the California fuel market in 1999. The Energy Commission has retained Stillwater Associates and Drew Laughlin as its consultants to assist in evaluating this feasibility of establishing and creating a strategic petroleum reserve.

One important matter of, I guess almost housekeeping. We recognize that many, if not most of you, have not had a lot of time, we have not provided a lot of time to review the contractor's report in advance of this workshop. And I'm sure something as important a subject both deserves and people would like more time. So the Committee has agreed that we will hold a second workshop on this report in several weeks, and we want to allow you more review time and to soak up the discussions that take place here today. So we want to provide plenty of time to get public and stakeholder input on the subject of today's hearing, and on the contractor's report.

Perhaps for some, or many of you, this will be the first time that you will see or learn about the contents of the contractor's report. So we request everybody here to listen, to pay close attention to today's presentation, to please, in this afternoon's open forum, ask any and all questions. And in turn, then we urge you to send any additional written comments or questions that you may have on the report, your impressions of today's presentation, or just your impressions on the entire subject, please send comments to the Commission by March 22nd, if possible. I'll strike the "if possible". Please send comments by March 22nd.

Comments, obviously, on a subject like this, will be very helpful in us formulating and formatting this second workshop that we've promised to have.

Another housekeeping item. For those, if any, listening to this workshop today via Webcast, I'm told that copies of the power point presentation that our contractors will be presenting and other draft reports are available on the Energy Commission's Web site, at www.energy.ca.gov.

With that, I'd like to take just a moment to go over with you the agenda for today's workshop, and then we'll get under way.

It is our plan to have the contractor's presentations for what will probably be the balance of the morning, followed by a lunch break of roughly an hour, or at least an hour. We will then open the forum to public and stakeholder questions, comments, et cetera, on the report. And then wrap up at the end of the afternoon, whenever we've finished all the business.

As I mentioned earlier, I've proven my endurance earlier this week, with regard to workshops and hearings, with sitting through 15 hours, so we'll go as long as you want. But I don't anticipate that this subject will go outside the bounds of the normal workday, so hopefully we can finish in that timeframe.

I guess, with that, I'd like to turn the microphone over to our contractors, and I guess we're starting with Stillwater.

MR. HACKETT: Mr. Commissioner, CEC Staff, stakeholders, good morning. I'm Dave Hackett, President of Stillwater Associates.

Stillwater Associates is a consulting company that focuses on downstream issues in the oil industry, and that means transportation, refining, and marketing.

I'm formerly a 20-year veteran of Mobil Oil Corporation, where I was the Distribution Manager for Mobil on the west coast, and led Mobil's transitions to oxygenated -- the transitions to oxygenated gasoline, CARB diesel fuel, the CARB Phase II gasoline, and to Arizona cleaner burning gasoline. So I'm experienced in the California and Western Region markets.

On our agenda this morning we're going to discuss the background of this, and Commissioner Boyd touched on that. We'll talk about current supply issues, we'll talk about strategic reserves, give an overview of other strategic reserves, not only here in the United States but around the world. We'll talk about current inventories in California, and California's fuels market, and we're focusing on gasoline in this conversation.

We'll talk about options for various types of reserves, and trigger mechanisms, as well as effectiveness and cost benefit analysis.

As background. As Commissioner Boyd said, 1999 was a rough year for refinery performance in California. A number of unplanned supply outages occurred and prices spiked up. The Attorney General created a task force that looked at a number of the issues around these price spikes, and recommended creation of a Strategic Fuels Reserve.

The Assembly then passed several bills to have the California Energy Commission look at a number of issues, the Strategic Fuel Reserve, the pipeline study, which will be the subject of a workshop tomorrow, and then a project to look at reducing dependence on fuel here in California.

Stillwater Associates was retained by the Energy Commission back in August to begin this study. The first step in our process was a series of stakeholder meetings, where we sat down with more than 50 participants in the California fuels market, and that included refiners, logistic service providers, traders, trading companies, government agencies, publications, marketing associations, and individual marketers, in order to create a comprehensive and complete view of the issues that face the California and the western region market.

In the midst of all of that, and early on, we came upon a couple of issues that we spent additional work with. The first was South Coast Air Management District's Rule 1178, where we assisted the Energy Commission in looking at the rule from a security of supply perspective. And then the second was the MTBE phase-out, which was the subject of a workshop about a month ago, where Stillwater Associates recommended that the phase-out of MTBE be delayed by three years.

We're going to touch on those issues today, but that's not the focus of today's workshop. And so today, you are going to see our preliminary conclusions and proposed solutions. And, again, the focus is on gasoline.

Okay. What's at stake? California has never run out gasoline. However, the gasoline market in California is more volatile than any other market in the world, with the exception of California electricity. The petroleum industry in California is very efficient and runs with smaller inventory, in relative terms, than any other market. And we discovered in the course of our analysis that this market is becoming more and more import dependent.

There are physical and commercial barriers to entry that are impediments to imports, and then, again, our opinion is that CARB Phase III and the phase-out of MTBE will make things more difficult. And for those on the Webcast, I'm now going to page 5.

So, what the proposals are not. We're not proposing a large reserve with an arbitrary trigger overhanging the market. We're not proposing government price controls. We do not see this as an impediment to supply/demand interaction, nor as unfair competition to firms that already have deeply invested in the California market.

This won't be built or operated by the government, although there will be some government oversight. And we don't see this as favoring one market segment over another.

Going to page -- so that was 6, and now on 7. I'm going to turn the mic over to Thomas Gieskes, who is a Vice President with Stillwater.

MR. GIESKES: Yeah. Thanks, Dave.

Commissioner, ladies and gentlemen, my name is Thomas Gieskes, and I'm a 20-year veteran with ARCO. I joined them in Europe, was with them in Asia, and although my experiences have mainly been on the chemical side, I do have extensive experience in logistics.

I shall walk you through some of the details behind the current supply issues. To those of you who have been in the MTBE workshop recently, some of the information is the same, so please bear with me. I'm going to -- and we did do some further work, notably on that.

And as Dave pointed out, the California market has never run out of gasoline, but it's an extremely volatile market, and is certainly cause for concern. This graph probably tells it better than any other graph, and for the Webcast listeners, I am now on slide number 8.

This shows the price differential between the US Gulf Coast market, which is a very representative marker for gasoline prices worldwide, and the LA spot market. And as you can see, there are two trends in here. One is the underlying trend for the California market to move slowly away from the US Gulf Coast, in terms of average prices, and then it's obvious for anybody to see that there is an increasing volatility.

We call this, between ourselves, our cardiogram chart. If you see this sort of thing, you know that the patient is imminent to suffer a serious heart attack, and that's what we are here to prevent.

So, moving on to the next slide. This shows the California refinery capacity over a period of 20 years. And what it shows is a breakdown of that refinery capacity in gasoline production, jet fuel, diesel, and heavy fuel oil. And as you can see, the two trends here are the increasing capability of refiners to get more gasoline out of that barrel, and at the same time a diminishing overall capacity, and I'll come back to that later when we discuss the -- the treatment detail.

The other thing to note here is that the remaining spot capacity in the California refining system is currently less than five percent, and that is about as close as you can expect anybody to operate.

And what is particularly worrisome, and this moving on to slide 10, is that as California goes today, so goes the nation tomorrow. And if you look at the refining capacity in the US as a whole, then you'll see that with a brief exception in the period of the late seventies, when the industry was regulated and there was an almost guaranteed return on new investment in refining capacity, and which, of course, resulted in over-capacity being built, after the '91 deregulation took place, a lot of the non-profitable refineries were closed down, refining capacity in the nation as a whole has not -- and this is crude runs, mind you -- has not increased. The number of refineries has gradually diminished.

And what this translates to is that of the current refinery basis, there has been a two percent capacity creep in the United States steadily since 1991. However, the nation as a whole is currently also within, say, its maximum production capability out of those refineries. It's not just the crude sales that are running at 95 percent capacity, but also most of the core units, such as FCCs, et cetera. So the United States, as a whole, has gone from a gasoline exporter to a gasoline importer.

This goes rather quickly. Moving on to slide 11. This shows what the crude runs have done in California over a representative period.

And I've taken '94 through 2002, because since '94 that's when the refiners started preparing for the CARB Phase II phase-in, including quite a few refinery projects. So if additions had been made, they would show up in this graph.

What it shows is that crude runs effectively have stayed flat over that ten-year period. However, gasoline production -- and this is moving on to slide 12 -- gasoline production has steadily increased. We first looked at a slightly shorter period, and were of the impression that the capacity was 1.6 percent. It's actually closer to 1.3. And in this 1.3, there is a certain amount of this capacity that's generated within the fence, and another part of that is actually due to increased imports of blending components. And I will detail that later.

Over that same period, the production of diesel has actually diminished a little bit, about .4 percent per year, and the product that's easiest to import, jet, have decreased by about 1.4 percent a year.

So where did the increase in gasoline production come from. It came mainly from the --

as we saw in that first graph with the decreasing production of residual fuel -- it mainly came from the refiners being able to convert more out of the barrel, and it went to the detriment of residual fuels.

And as you can see in this graph, and I'm on slide 15 now, is that there clearly is a physical limitation as to how much you can get out of your residual fuel production and be able to convert it to gasoline. And that point, we estimate, is actually around 30 to 40,000 barrels, so pretty soon that sort of incremental production of gasoline will come to an end.

And with that, I'm going to turn it over to Tony Finizza, who will talk about what I've discussed, the five percent being very close to the maximum capacity and what it means for the vulnerability of the market supply disruptions.

MR. FINIZZA: Good morning. My name is Tony Finizza. I also, like Tom, used to work for ARCO. I was Chief Economist, and retired in 1998 from ARCO. Since that time I've been doing consulting, and teaching at UC Irvine.

My task is to talk a little bit about the character of disruptions, and then later on, I'll talk about the economic impacts of some of the disruptions we've seen.

We're starting on page 17. What I'll be showing you next are some data that I acquired from a DOE study of disruptions, in the context of the power shortages in California last year.

In the database, there are 80 total disruptions, refinery disruptions identified. I could only find 65 of these where it was possible to measure both the timing and the impact. So this database that I'm going to be using here has 49 disruptions that come from OPIS reports.

This is a histogram, on chart 18, that describes the 49 measurable refinery disruptions since early 1996. You'll see there's a couple of clusters. The one that's most important, the one in 1999, when we had a number of refinery disruptions in northern California, and a scattering in the year 2000, which were primarily southern California. These are in thousand barrels a day.

Another way of looking at this disruption is by examining the frequency that these disruptions -- which they occur, and one can see from this chart, number 19, that there are often simultaneous disruptions. Of the 49 disruption categories here, we had some that had four refineries out at a time. There were two of those. Seven refineries were out three at a time, and et cetera. So they can occur simultaneously.

Chart 20 examines a frequency distribution of the size of the disruptions. As you can see, there are a lot of disruptions that are in the small end, between one and ten, and ten and twenty in thousand barrels a day. There are some that are fairly large, but they occur less frequently.

As a way of postscript, I should mention that I've been hired separately from Stillwater Associates by the California Energy Commission to do this analysis, and to make this a seamless presentation all of my slides have been integrated into this presentation, and you can identify my slides by my name at the lower right-hand side.

This chart, number 21, examines the duration of refinery disruptions. And as you can see, there are a large number that are short-lived, one to two and three weeks. In fact, the mean of this time series is 2.7 weeks. And there's a cluster of eight or so refinery disruptions in this range, and a couple of very large outlines of 12 and 22 weeks. But primarily, refinery disruptions seem to have a short life, one to three weeks.

This is a picture of a particular disruption in 1999. It describes and shows that durations of some of these disruptions can occur somewhere in the six to eight week range, and that can vary, of course, because they get simultaneous with other disruptions that occur.

The important thing to remember is what I've plotted in graph 23 is a range -- this is a weekly line here -- range of normal inventories for California. This is on a weekly basis. And also, I plotted the actual inventories at a point in time at these various weeks.

One can observe that of the 49 disruptions in this time period, most of them occurred at a period under this line here at the bottom, which reflects lower than normal inventory, 29 of them. Sixteen of the disruptions occurred within the band, periods of relatively normal inventories. And only a few, four, in fact, at above normal inventories. This in part could be because when there's strong -- high inventories, disruptions can be accommodated by drawing from inventories.

At this point I'm going to turn it back to Thomas. I will come back later to discuss some of the economic impacts of these disruptions.

MR. GIESKES: Thanks, Tony.

So we've seen that the refineries are operating at capacity, and even though refiners are doing a great job to keep these units running, disruptions happen quite frequently.

The annual increase of 1.3 percent that we saw actually exists for about .6 percent -- and I'm on slide 24 now -- of increases in component imports. These are of imports from the US Gulf Coast and all other parts of the world. And that's only .7 percent is within the fence capacity increase in the refinery.

The reason that -- and this is based on feedback that we obtained in our stakeholder meetings -- the reason why the .7 percent is -- it's fairly low when we compare it to the two percent average capacity creep in the United States as a whole over the last 20 years, is that many of the refiners are up against the Title 5 operating permits, and very often a small increase will trigger a re-permitting of the entire facility, or maybe part of the facility, which is a very costly procedure.

And another reason is likely that the California refiners, by comparison with refineries in the rest of the US, have a much greater complexity factor, are very, very highly integrated also on their heat side. And small projects are more difficult to realize for technical reasons, as well.

Moving on the import side of the equation. Since we are at capacity and since capacity additions are difficult to realize, California has become a net importer of just about every petroleum product that you can find. What this graph on page 25 shows is two things. Even though we're primarily concerned with fuels, it's good to take a look at crude oil, and what's happening in crude oil is a shift from imports from Alaska to imports from more remote locations.

A lot of these new imports are coming out of the Arabian Gulf and require, for shipping economics, to be carried in very large crude carriers, VLCCs. That puts a strain on the logistic system, in particular in the Ports of LA and San Francisco, that these ports were never designed for, and these logistics are currently suboptimal, with lighting offshore and putting strain on the logistics system in general.

And to a certain extent, and even though that's minimal, these logistics facilities and this additional strain competes with the possibilities to import products.

On the right-hand side, you see over that same period, '96 through 2000, the imports of petroleum products. And what is clear is that the big increase is almost entirely for the account of foreign sources.

MS. BAKKER: Thomas, on that slide, that's the right-hand side, there's a really fast ramping up, even if, you know, you look at it in total, or even in the US product imports. Is there some market condition that led to our importing product in 1998?

MR. GIESKES: Yes, Susan. And we'll come back to that. 1998 was a more or less a disaster year for the California refiners. And so that was also the subject of the slide that Tony showed, with these very sharp price increases. And so in '99, refiners were very successful in locating imports to backfill that lost capacity, in part, and it still caused substantial price spikes.

What we don't have yet, because these data are in part based on not just data from EIA and the CEC, but also on the import statistics, port statistics from the US Army Corps of Engineers, and the US Army Corps of Engineers publishes these data with half a year to a year's delay so we don't have the 2001 data yet. But what we know from foreign import statistics in 2001 is that the increase from the foreign imports from 2000-2001 was about 20 percent. Again, sort of the underlying curve here, you get a very steep increase in '99, then it leveled off in 2000 because the refiners had a better performance, and 2001 is likely to be here again.

Thanks for the comment, Susan.

And the imports by origin and type. What this graph on page 26 shows is that whereas in '96 there was still small exports in mainly some residual fuel, and those have disappeared as well, and California is now a net importer of all products.

And the imports of gasoline and gasoline components, as shown in graph 26 -- or 27, is mainly MTBE. And that is going to pose a particular problem when MTBE will be phased out, sooner or later. And this has been the subject of much discussion in our previous workshop.

So overall, and this is page 28, how does gasoline flow in and out of California amongst states of the West Coast. And what 28 -- and I won't go through all the numbers here in detail -- but what is very clear to see is that the main import center is the Los Angeles Basin. The Bay Area is actually currently still a net exporter, shipping gasoline to Portland, and shipping some gasoline down to LA.

And what is also shown, and this will be the subject of the workshop tomorrow, is the future pipeline connection into El Paso by Longhorn, and then the potential supplies coming in from the US Gulf Coast into Arizona, and potentially displacing volumes that are currently supplied into Arizona by the California refiners.

On to demand now. And demand growth is something that has been the subject of a separate recent study by the California Energy Commission. We borrowed heavily from those data. And there are the usual growth drivers. I won't go through all the numbers here, we've been over this before in the previous workshop.

At that time it was pointed out to me why didn't you look at substitutes and replacement for gasoline, and those are all very good and well. In this case, and particularly with the MTBE phase-out looming within the next two or three years, most of these factors, such as substitution, alternative fuels, et cetera, do not come into play. And even fuel economy factors usually play out over periods of six or seven years, and you don't see much impact in three years.

So, with that, and I should also add that I'll move on to slide 30, which shows the historical and forecasted demand of gasoline in California. Our base case of 1.6 is a good fit with the sort of underlying average over the past 20 years in the State of California. The most recent economic indicators show a stronger growth than the 1.6 percent, and especially with the economy likely to recover quickly, the growth is, I would say, more likely to be around the high end of the scenarios that we considered than around the low end.

So we've looked at 1.6 percent as being the current CEC base case forecast. It looks, based on the last nine months, more likely to be around two percent, or even higher. The first nine months in 2001, prior to the September 11th incident, actually was an almost three percent growth. And we believe that the September 11th events have not impacted gasoline demand very much. There might have actually been some increase in driving because people are starting to drive short distances rather than take a plane.

Slide 31 shows the demand forecast overlaid on the production of gasoline and the various gasoline components in California, as a whole. And what you'll see is the red bars represent the MTBE use, and there is a small white bar that represents the imported blendstocks other than MTBE. And then the green bar is the end refinery production.

A phase-out, as currently foreseen, of MTBE by year end 2002, would then result in a gap of between 50 to 100,000 barrels per day, depending on what demand scenario is actually in play. And this gap, and we'll talk about the numbers in more detail, is why we proposed in a separate workshop that the phase-out of MTBE should be delayed.

Here is the phase-out of MTBE in numbers. And this is making a split between northern California and southern California, on page 32. What you'll see here is that -- and once again, I won't go through all the numbers in detail -- is that very clearly, the phase-out of MTBE does not impact the north and south to an equal extent. We actually believe that the numbers that we have here might be -- for northern California, might be off by about 4,000 barrels a day, actual MTBE use is even lower. That makes it even more of a problem in southern California.

So how does this then play out, and this is the sort of same slide that we saw before, with the demand curve, and then the bars represent the production.

And this is a busy chart, and I apologize. But in the -- on the left-hand side, we see northern California, with the solid area in the background being the demand curve for the base case. And then on top of that is the demand of Oregon and northern Nevada that's still supplied out of the Bay Area refining center.

And as seen in the previous slide, northern California really is not the problem. There might be a small shortfall, or they might stay balanced, but that is really not the issue.

If we look on the right-hand side to southern California, however, you see that there is a very substantial gap between the demand areas and the bars which represent production. And that indicates that the supplies by pipeline, and this is -- we called it the Longhorn Extension, but there might be other companies that would be involved in it, as well, Kinder Morgan is likely to look at that line from El Paso to Tucson and to Phoenix -- if that project does not materialize within the timeframe that we, and this is a fairly optimistic estimate, that we foresee, then it will be clear that this supply shortfall will be even more substantial.

And moving on now, and this will be discussed in much more detail tomorrow, but that supply shortfall, where is that going to come from. In previous studies, the CEC had assumed that that supply shortfall would be largely made up by imports of blendstocks, and particularly alkalytes, C7 alkalytes from the US Gulf Coast. As it appears, and there have been very detailed studies to investigate that, there is no such thing as a separate stream of C7 alkalytes available in the US Gulf Coast. The US refiners, as a whole, and the US Gulf coast refiners, in particular, are running at capacity currently. So there is no big supply overhang ready to be shipped from the US Gulf Coast to California.

And even if there were, who would be available to ship it, and that's also the subject of a separate study tomorrow, but I'll quickly show, steal some of Drew Laughlin's thunder here. Even if the supplies were there, the shipping situation is such that with the phase-out of single hull tankers, and there are over 90, by 2005, that really starts to bite, and a large segment of the US tanker fleet will be retired with very little new building on the horizon.

So as we look to the US Gulf Coast as a supply source, the current outlook is the product is not there, and the ships are not there. The product not being there is also a factor in the pipeline study that will be discussed tomorrow in more detail.

And then, of course, you look at foreign imports, and -- as the next available replacement for a shortfall of gasoline in California. And we looked fairly extensively, talked to current producers of CARB Phase II gasoline grades, regular shippers and importers and traders, and our belief if that if you had to summarize it in one sentence, 50,000 barrels a day of suitable component imports, in addition to what's currently being shipped in, yes, it will probably be there.

If the shortfall is 100,000 barrels a day, it is probably going to be very, very difficult and very, very tight.

More important even than the question of the imports there, because I also think that in the worldwide refinery system, if the premiums of California gasoline over world market prices are sufficiently high, people will scramble and scrape and do whatever they can to make product available because it's so attractive, what it boils down to then is can we actually get these products in the market. And if we think back to that earlier slide that I called the electrocardiogram of the State of California's gasoline heartbeat, what is very significant is that at the height of those price spikes, no material gets shipped. So even at price differentials of 40, 50 cents per gallon of California over world market prices, very little product actually moves away and gets actually put on the water. And the reason for that will be discussed in more detail.

Let's move on here. That screen is -- technology sometimes works, and when it doesn't, it's a nuisance.

So California's gasoline's import routes, and we'll come back to that later as well, but it's interesting from several perspectives. One is the length in terms of days, the duration, and these are just pure shipping times. So if you look at, for instance, a shipment of blendstocks from the Arabian Gulf to California, 33 days. Finland, which is another remote destination, 30 days. The closest, in our view, is Gulf Coast, and with the Panama Canal delays it might add plus or minus two days to the number. If it's really bad, I think at the worst, delays could be as high as a week or ten days.

But on average, it takes a while for product to get here. Not only that, most of these producers, foreign producers of California grade materials, don't produce those materials on a continuous basis. So if a California supply disruption happens, you'd have to be extremely lucky for a cargo to be somewhere on the water already, and to be able to divert the cargo into California.

Most of the time, somebody will have to go out and then say well, let's -- they'll first want to wait and see a little bit better the price spike lasts, and if it does last then they'll say well, let's produce a batch of CARBOB, find a suitable ship, and get it on the water. So on top of these sort of five to six weeks of shipping time, you have to add one or two weeks of production time, and some time to do a deal and try to ship.

The other interesting thing to note here is how the shipping rates are very heavily impacted by the fact of a, say, the international vessel versus the US Flag Jones Act vessel. It is as expensive to ship a cargo from the US Gulf Coast as it is to ship it in from the AG. That's cartel.

So the barriers identified by this, that currently already make it very, very difficult to bring products in to the California market despite these price spikes of 40 and 50 cents, really, really tremendous differentials that should see an armada of tankers coming our way, is first and foremost the lack of deepwater storage terminals, particularly in the LA Basin.

The fact that -- and this is not meant to be detrimental or insinuating in any way -- but that the capacity of those terminals is mostly controlled by the majors either directly owned or under a long-term lease, rented out to the major refiners, the current port policies in Long Beach and LA play a major role in this, as well. There's been a decrease in capacity of terminals, rather than an increase, and that is because container terminals take up more and more land. These mega-terminals of 500 acres each keep gobbling up container land, terminal land.

And in actual fact, the city officials in San Pedro and in LA are currently looking at the removal of terminals, rather than the addition.

Then there are initiatives such as the South Coast Air Quality Management District's Rule 1178, which, I mean, all of this is intended to create cleaner air, which is good, but it goes to the detriment of the infrastructure of the industry over the next seven years, and if it hadn't been for our gallant efforts, it might have been 40 years. But over the next seven years, some ten percent of all LA gasoline type tankage will be out of service for doming of the roofs and other modifications.

So there is significant capacity loss, with more threatened by non-renewal of leases, and new capacity certainly faces a very difficult permitting environment.

So there are some commercial barriers, as well, surrounding the addition of new tankage, and the same argument is true for additions of new capacity or additions of new ships, is that any of those major capital investments need to be backed by a long-term commitment. And if you're a foreign refiner or if you're a local California storage company, you cannot do a multi-million dollar investment without a bankable contract backed by a creditworthy company. The trading companies typically are not in a position to provide these sort of guarantees, and that is one of the major obstacles to addition of new tankage.

So with that, let me summarize the supply and demand situation. California refineries are running flat out, the opportunities to increase capacity diminish, the MTBE phase-out will certainly not make this situation easier. The shortfalls will therefore have to be made up, at least in part, by imports. But the infrastructure is currently already severely constrained. That about sums it up.

Why is this important for the gasoline reserve? All these factors contribute to the increasing instability of the California market, and towards the justification of a radically different solution.

So with that, I'm going to turn it over to Gregg Haggquist, who will tell us something about other reserves.

MS. BAKKER: Before you go, Thomas, one of the things on your slide, if you go back to -- I guess slide 33 is probably the best one, where it has the two graphs. It strikes me, from seeing, looking at the first 2000 and 2001, southern California in particular, that really without regard to the MTBE phase-out there is a challenge facing southern California.

MR. GIESKES: There is. I mean --

MS. BAKKER: Which is consistent with your first summary point, we're at 95 percent of maximum today.

MR. GIESKES: Yes, Susan, that's absolutely right. And I think our whole approach, for instance, to the MTBE phase-out would've been totally different if California's market currently had a free flowing supply of imports, and you didn't have that spikiness already, extreme volatility in the market. That extreme volatility is a clear sign of a not fully functioning supply and demand mechanism. You should not have to curtail demand in order to meet supply and demand match-up. And that is indeed a cause of great concern.

So our starting point currently is already not very healthy, and we're going to do -- I mean, we're going to face a lot of additional demand, and we're going to phase-out MTBE. And that will make it worse.

MS. BAKKER: Thank you.

MR. HAGGQUIST: Thank you, Thomas.

Thank you, Commissioner, ladies and gentlemen. I'm Gregg Haggquist. I've been in this oil industry for about 30 years. I spent a -- for the first decade, with the majors, with Texaco and BP North America Trading. I understand that side of the market. The last 15 to 16 years I was the founder and the President, Chief Operating Officer of Mieco, one of the more active domestic and international oil trading companies, concentrating in the Pacific Rim and east of the Rockies, and the west coast.

With that, the first thing that strikes me that I'd like to mention here is that in taking this assignment, in the context of 30 years in the business, I have never seen this done before, and I don't know if anyone in the room has before. That is, an overview of the situation in the State of California.

And I started reflecting on that, what does that mean, why is that. And one reason, I believe, is structural. That, you know, the WSPA members, the large refiners, you know, they're limited in what they can say to each other at gatherings and meetings. They really cannot sit down and have this -- compare notes on infrastructure, market share, and all of that. That's against the law, frankly. And on the government side, on the government side, the agencies are aligned in a certain way that the local decisions are made without a direct channel or oversight.

For example, 1178, that Thomas mentioned, that's the rule that requires the removal, the installation of domes on tanks, and would've taken 20 percent or more of the tankage out of service in southern California, without oversight by the Energy Commission, on the basis of decisions that were made in southern California by the -- it doesn't matter who made them. There is no channel to have this sort of comprehensive look at the market.

Okay. So with that in mind, what I thought would be most useful would be to place our study in a context, a context means a geographical context, a historical context, and a qualitative context.

Let's see here. We skipped two here, didn't we. Just have to touch this easy. Right? There we go. Is that right?

In the historical context, we're starting here with the United States, but there's a lot of information that's not in studies you have in your hands. I call it on the cutting room floor. And the finished DVD will give you a lot more depth to the studies that you have in your hand, including the history and the specifics of other strategic reserves.

It started back in -- in the United States, the first mention was back in 1944, by the Secretary of the Interior, who pressured the President to try to build a crude reserve. And then in '52, Truman, with his Department of the Interior, tried to push a reserve through. And after the Suez Crisis in '56, Eisenhower tried to get a reserve put in place. But it never really happened until the energy crunch in '74, when the international countries, 28 signatories, responded to there first oil crisis. And we're on slide 41, for people listening in.

And we all know what that was all about. In the United States, under President Ford, we finally got to the point where we passed the Energy Policy and Conservation Act, that both emphasized conservation and the possibility of strategic reserve. And the strategic reserve finally came in place in '77. We all know about that, that was -- that is in the Gulf Coast, in salt domes. And the salt domes, of course, are ten percent of the cost of an above-ground storage tank, and they are highly secure, from a military point of view. So from those points of view, that made some sense.

But we draw attention to these sort of issues only for contrast and context, and how these apply or don't apply to California's situation.

The next most similar situation was the Regional Petroleum Product Reserve established under the provisions of the EPCA, the Energy Policy and Conservation Act. The Regional Petroleum Product Reserve, better known as, in today's terms, the New York Heating Oil Reserve, and that was created as part of the national reserve, using the crude oil stored in the national reserve as a swap basis to get around the funding shortfall, frankly.

That may be significant to us, if we go forward with a reserve in California. What is significant, what is not significant. That may become significant.

But with respect to that heating oil reserve on the east coast, we, in the spirit of contrast and comparison, let's just take a look at this. The demand in New York Harbor is 700,000 barrels a day during the winter, on the average, for heating oil. And in California, it's a million barrels a day year-round. The effective days inventory on the east coast is 70 days during the winter; eight days during regular demand season on the west coast, in California. In California.

Obviously, heating oil, especially, has created the NYMEX as a fungible commodity. We, in California, have multiple grades of gasoline non-fungible. We call them boutique fuels, even though we don't like that name. There's no blending restrictions on the east coast. The very robust blending, thereby being a market equalization activity in the east coast, and there's no blending here. We have the Unocal patent for California gasoline inhibiting us.

There are a hundred-plus transactions a day on the NYMEX, and in physical over the counter markets back east. Out here, 20 trades a day, probably, if you capture the trades done between the major refiners. Out in the independent market, brokers tell us, in the markets that are reported by OPIS and Plattz, those markets, five, maybe ten a day is all you're going to see.

So, and as a broad and deep futures market, the NYMEX, the whole world uses out here, there's no forward market. The pricing is transparent back east, and it's opaque out here, to say the least. Who knows what the price is? Talk to five brokers, you get five numbers.

Demand, seasonal only, back east. Year-round, out here. And shipping time is one to two weeks back east, and only five to eight weeks out here. I mean, it's five to eight weeks out here. Now, that's significant again, in the terms of context. The heating oil reserve that has been established did take into account the ten-day voyage, they said, maximum, to re-supply New York Harbor in the event of a problem with the Colonial Pipeline, or other supply availabilities. So they picked a ten-day supply for their inventory. Their strategic reserve inventory.

They have, there are 68 terminals in 26 ports back east, and there are only 16 terminals here in two ports. Most of them, as Thomas mentioned, in the hands of the refiners. There's nothing wrong with that, but it's just structural fact. We're talking about structure here.

And the population, percent of the population that is affected back east is about 11 percent. A big part of it is in Maine. And out here, everybody drives. It's something we can't get rid of. We can't stop driving.

MS. BAKKER: Gregg, before you go forward, I think you said that under the category of market liquidity, that there were 100-plus per day in the northeast. And the slide says a thousand-plus, per day.

MR. HAGGQUIST: Oh, that's correct. I made a mistake.

MS. BAKKER: And is the slide a typo, or is your --

MR. HAGGQUIST: It is a thousand. No, it's my error.

MS. BAKKER: Okay.

MR. HAGGQUIST: It's my error.

MS. BAKKER: Thank you. I'm sorry to be nit-picky, but --

MR. HAGGQUIST: That's good. No, that's good, because once again, back east is the NYMEX, and it's used as a hedging mechanism and a physical delivery mechanism for the whole world.

Good point. Thank you.

So in this contextual spirit, the strategic reserves in these other countries have been put in place for national security reasons. I won't go into a lot of depth, but one thing that's in historical play of these strategic reserves, and as a person who's traded in those markets, we see stagnant ideas. We see stagnant inventories. We see bugs growing. We see markets convulsing. And, you know, they're stagnant ideas because they just put the product in a tank and it sits there until the bugs grow on it. That has literally happened. Or, until they start to mix cracked product with uncracked product and create a quality problem, and dump it on the market, convulsing the market. These are the kind of things we want to avoid, if we ever put a strategic reserve in in California.

The only strategic reserve put in place to mitigate price, rather than for security issues, was the Heating Oil Reserve in New York, and there was one experiment in Massachusetts that was quite successful. We won't go into in detail here, but the Massachusetts one was more in the spirit that we're talking about, but we won't go into it here. We don't have time for that.

The east coast and all of the other reserves are event triggered, a national catastrophe or an event of war, or an explosion. Whereas the mechanism that we're going to be talking about today is less reliant upon these sort of events.

We did learn from these contrasts that the strategic reserves can, in fact, play an important role in opening up markets. Japan and Korea, ironically, are examples of this. You know, it's strange to say that, but Japan historically, people in this room have traded petroleum in Japan, will remember that old Japan, and old Japan, I mean prior to 1996 and '97, was non-accessible. You could never bring gasoline into Japan. Forget it, you go to jail.

But their liberation of the market, they tried to open the market, and they did that by allowing importation of gasoline by non-refiners, as long as the non-refiner parties were able to demonstrate that they in fact had matching volumes in reserve in the country. This was sort of a balancing situation. That was their solution.

The point is that by virtue of them

allowing gasoline to come into the island of Japan, and we're talking about the island of California, since that time we have seen refinery rationalization, we have seen consumer prices come back more in line with regional prices, and we have seen a very robust forward and futures market open in Tokyo, that no one ever thought would happen. And it all comes back to physical capability, and that's all we're talking about here today. Physical capability to physically bring in a physical cargo and stick it in a physical tank, and therefore, by doing that, the market will create its own momentums.

In order for that to happen, they must be -- the strategic reserves must be fully integrated, with continuous throughput for quality reasons, as it tells us in slide 43. And our plan does allow for that. We don't want bugs to grow, we do not want markets to convulse.

How can we prevent markets from convulsing, if we ever do build a strategic reserve here? And that question is an open question for everyone in the room and everyone listening, everyone interested. We categorized the three ways, looked at three ways to trigger a reserve, if we put one in place.

One is by event. And the problem we wrestled with on that consideration is that what is the event? How serious does it need to be, and who can play? So we're saying here, on this slide, even when conditions and authorities are well defined, you can still create market uncertainty. We were sitting -- we were sitting here in CEC several months ago, during one of those events that happened in a refinery out here, and the market had in fact run up 18 cents a gallon that particular day, on the back of that event.

Well, would that be the kind of event that would trigger the reserve? We can have a long debate on that one, when you people in the room take the floor, and the people listening write in.

So we think that these event triggered releases are probably better for these large strategic reserves. If we were thinking about 9/11 issues here, rather than price and market, you know, balance here, then we might think about event triggered release mechanisms.

Now, price triggered release mechanisms

also carry their own complexities. For example, the price mechanism that governs the heating oil reserve in New York has a very detailed definition of the price mechanism, a 60 percent increase over the five-year rolling average of the heating oil contract in New York Harbor, which triggers what? Well, that triggers an oversight by the Secretary of Energy, which in turn triggers a discussion with the President of the United States, which in turn triggers a decision or a non-decision. We, in California, we recommend that we don't follow that kind of sequence of uncertainties.

So price triggered, we think is also difficult, particularly if the price trigger means that if we decide on a price trigger, that means we're going to sell barrels from the strategic reserve, dump barrels on the market, kill the market, suppress the market, if that's what it means. We don't want it to mean that, we don't intend it, we don't think that's a good idea.

So if we do come back to a price triggered mechanism, in any event, we always will be pushing for a trade of the strategic reserve barrels, a time swap. Any barrel that leaves the reserve must be replaced. Any book that you borrow from the public library, you need to bring it back. The public library is not in competition with Barnes and Noble. And the strategic reserve is not in competition with the refiners.

So we think that the best way is some system of continuous access to the strategic reserve, when we put it in place. Any qualified party can play. How do you qualify? We've gone through various iterations of who they might be. Some of our -- some of the stakeholders suggested only refiners should be allowed to play. That has its own difficulties we can discuss when it's open forum here.

Others said that anyone could play, it's a democracy. Well, that also has its own difficulties. Obviously, you'd have to be financially qualified. So you have to be financially qualified, and you have to be able to perform.

But once you establish who can play, then we're thinking we're only going to have a time swap all the time in the strategic reserve, and we will govern this very strictly on the operational side. We believe that by having product taken from the strategic reserve and put back, taken and put back, this activity will stimulate the private sector to do what it always does best, and the government's role is not even there. The invisible hand of the government is, in fact, the invisible hand of the government.

In order for this dream, or vision, to take place, we have to think in concrete terms or physical terms. Where does it have to be, and how big does it have to be. The Assembly bill that put us here in this study suggests that a two week supply of the largest refinery being taken out would be the volume that we want to put into this reserve. And we'll need a separate north and a south reserve, based upon some pro rated analysis of the problems in the north and in the south. We're suggesting less than a million barrels in the north, maybe one and a half million barrels in the south, in the strategic reserve.

And, of course, the logistics requirement would be -- must be integrated in the infrastructure of the Bay Area and the LA Basin. And we've thought of everything. We talked to everybody. We even talked to Mexico, you know. Why not build it in Baja. Well, once again, if you're -- September 11th and you're worried about a disaster, maybe that's enough. But this, we believe, should be nestled into the heart of the industry in order that it can, by just being there and being used, will put us in connection with the rest of the world, which we are not, right now. We're an island.

We need to be connected to the pipeline system. We need deepwater access. And the tankage must be drained dry and suitable for multiple grades and components. And blending capacity, that's an open question, because we are proposing that private sector tanks be erected right beside the strategic reserve, or connected to the strategic reserve. You know, if there's ever any blending it'll be taking care of the private sector, not by the strategic reserve.

On the commercial side, we cannot take any tankage out of service. As Thomas has pointed out, there's a shortage of tank space in California. So a strategic reserve is not going to occupy existing tankage. On the east coast it was a different story. The heating oil reserve put in place by the federal government did, in fact, occupy tankage owned by the -- and still is there, in the private sector, commingled together in three different terminals.

The reserve must be accessible to all parties, as we say, qualified parties. We don't want to have, you know, the Bank of Switzerland, even though they're financially qualified, bidding on -- trying to participate here, not knowing how to ship a tender or unload a boat. So you need qualified traders, importers, refiners, independent marketers, and the release mechanism must be clearly defined and designed in such a way that imports will be helped, rather than hampered.

So, where are we here.

MR. HACKETT: My turn.

MR. HAGGQUIST: Your turn. Come on back up here, Dave.

MR. HACKETT: Thanks, Gregg. For those of you out there, we are now on the agenda page number 47, moving to -- and we're going to talk about the inventories here in California.

All right. Moving on to page 48. Dr. Finizza put together this view of relative inventories for us today. And where we're looking at days of supply, that's essentially consumption divided by stocks. And so this gives you a relative picture of the capacity of the industry outside of California to hold gasoline, versus California -- or, actually, PADD V, I'm sorry. So the US data are PADDs I to IV, which is the east coast, the midwest, the Gulf Coast, and the Rocky Mountains, where PADD V is Washington, Oregon, and California.

MR. GIESKES: Actually, the US as a whole.

MR. HACKETT: It is the US as a whole.

MR. GIESKES: So the numbers for the US, the rest of it is even higher.

MR. HACKETT: Oh, okay. Thank you, Thomas. Thomas, for those of you out there that couldn't hear it, I -- Thomas corrected me. The US data that you see here on slide 48 include the PADD V inventories. In fact, if you back PADD V out, that US line would be higher than you see on this graph. And at least in the scale that PADD V day supply are, you know, essentially flat.

And so the message here is the gasoline stocks in the west coast are lower than the rest of the country.

Turning to slide 49. What you see here is a representation od weekly California refinery inventories. What we discovered when we did our analysis is that the federal government collects inventory data at the Petroleum Administration Defense District level, the PADD level, which, of course, is Washington, Oregon, California, and Nevada, Arizona, Alaska and Hawaii. And so it's difficult to get California only data. The data that the California Energy Commission collects are primarily refinery inventory. So there's a bit of a discrepancy between those, and we've worked on some resolution you'll see in a moment.

But the message in this slide is that the inventories vary in range of a band that's about eight million barrels. And given that demand in California is roughly a million barrels a day, then the total normal working capacity of these tanks is about eight million barrels.

One of the questions that we had for the inventory stakeholders, that is to say, primarily refiners, but other stakeholders, as well, is what about this issue of just in time inventory management. And universally, they said, look, we don't manage inventories just in time. We manage inventories, but sometimes we need plenty of it, and sometimes we don't need a lot. And other responses were, you know, inventory is something that's the result, the results after you're done with production and demand. So we saw no -- none of this, you know, just in time inventory management issues.

We also asked stakeholders if they would be willing to increase inventories if they're compensated for that. That is to say, perhaps the state would provide some kind of compensation, time, value, money, or whatever, to holding higher inventories. And across the board, the answer that we got was we have to manage our inventories the way we have to manage them, and even if you pay us we don't think that we can guarantee that we could come up with higher gasoline inventories.

All right. So now I'm at 50, and I hope that's the next one, given the way this thing is flipping around.

This particular layer cake view of inventory we put up just to sort of demonstrate how the inventory has changed over time. And what you see in the lower solid blue area, for those of you that can see it in color, are blendstock inventories. In general, there's been some increase in blendstock inventories as the requirements for the cleaner burning fuels have increased. But one of the issues, certainly, that you see with blendstocks is that it takes more tanks. Each one of those blendstocks, alkalyte, reformate, heavy FCC gasoline, light FCC gasoline, light, straight, or naphtha, and the like, there's this whole laundry list of things, needs its own tank in order for the refiner to be able to test the qualities of all of those materials and then to accurately calculate the very tight specifications required in order to blend gasoline in California.

The sort of red hatched area here is described as other finished, that's primarily conventional gasoline. And you can see that the volume of that inventory has dropped as reformulated gasoline has come in. The sort of orange areas are oxygenated gasoline. Those were wintertime gasoline, in general, that you see that the oxygenated gasoline has gone out of the market, and then completely replaced by RFG.

Now, we did look at capacity reconciliation. This sort of comes back to in the trading world for PADD V, for west coast gasoline, it's well known that sort of the middle of the tank is about 30 million barrels. That's more than, say, the 12 to 14 million that we showed for California. So the ranges here, once inventory gets -- approaches 32 million, then the tanks are full. You tend to see that as a reduction in the spot market price.

When you got down below 29 or 28 million, then that tends to be a cause for concern. Inventory is getting low, and then the bottom of the tank seems to be about 25 or 26 million, where the market is very unstable because there's a shortfall in inventory.

What we did here was try to look at total California capacity, back out the typically unavailable portion of that capacity, because of tank bottoms and the tank tops and tank maintenance, and the like, and then calculate an effective capacity. Our expectation is that this market tends to run half full, and -- of about, say, 22 million, and when we look at California as it's proportioned to PADD V, roughly 70 to 75 percent, then we think that the average for California ought to be about 21.

So that, what that says is there's more inventory in the tanks out there than just the stuff we showed you for the refinery, and we did a

-- and then we use that same logic, applied to the refineries, where we expected an average inventory of about 11, and we're seeing about 12 million barrels.

Just turn to the inventory planning for a moment. The refinery inventories are determined by operational requirements, and the message that we got loud and clear from the stakeholders. The issue of the number of tanks, that is to say the bottoms of tanks, is almost as important as the total capacity. Many of these tanks will go into a particular service, and because there's some unavailable inventory in the bottom of the tank, that if you wanted to change service on that tank, you wanted to go from, say, gasoline to jet fuel, then there is a fairly extensive clean-up process that's associated with getting that unavailable inventory out of the tank.

There are a few tanks out there, we're starting to see them, that are called drain dry, where the tank is built to accommodate the issue of being able to change the service fairly quickly. But there are not many of those.

We see the refiners don't have many options for strategic inventory considerations.

It's our opinion that they -- this sort of comes back to our work that we did for the Energy Commission around the Rule 1178 work. We could see the throughput in the tanks in the refineries in southern California. And let me tell you, there's nobody loafing down there. Those tanks are moving up and down fast. There's not a lot of capacity to build additional inventory, other than to some extent in the -- in the commercial terminals that are down there, but that seemed to be somewhat limited.

Now, the average cycle time on this inventory capacity is roughly a week, and that corresponds with Kinder Morgan's cycle time, where over a week everything gets pumped out, and then they start again on the next week, and go at it.

And as I said, commercial terminals do offer some capacity for strategic inventories, but those are limited. And then there are considerations at the port terminals, not only for cargo size, but also it comes back to this issue of tank bottoms.

So there are very limited, this says no options to increase inventories, but essentially, very limited opportunities to increase inventories in those markets.

Okay. Now, turning to 53, we're going to look at commercial terminal inventories. Again, you know, sort of the focus here is that there -- California, from a oil industry infrastructure perspective, downstreams to these two markets, the Bay, San Francisco Bay Area, and the Los Angeles Basin. And so what we're showing here are those data in the LA Basin. Refiners have brought terminals on to commercial service, but our observation is that as demand has grown here in California, and as imports have picked up and these terminals are starting to, or are at the point where they appear to be running at high capacity utilization.

We also see that a majority of the capacity down there is leased out on long-term contracts. And there's very little capacity available on a short-term basis.

Okay. Now I'm on 54. California inventories, the impact of MTBE replacement. The MTBE phase-out will free up tank capacity at import terminals. But there are some issues around this.

The first is that MTBE is a fully

fungible single component that's landed in a few tanks with high throughput. A way to think about that is the tanker comes in, drops the MTBE off either directly at a refinery that's tied to the water, or at a terminal that the refiner owns or leases on the water, and then the material's pumped up to the refinery where it's blended into the gasoline.

We see that the replacement volume for the MTBE will be a wide range of imported components. It would be alkalytes of different flavors, potentially iso-octane, raffinate, CARB -- Phase III CARBOB. CARBOB, of course, is California Reformulated Blendstock for Oxygenate Blending, and the like. And so many of those will need segregated storage, and putting those, this plethora of blendstocks through what had been a dedicated system won't be necessarily smooth.

There will be waterborne ethanol, so that'll create an additional segregation beyond the gasoline, the CARBOB and the components that come in. And then, the MTBE de minimis requirements and other specs, stringent specifications can lead to potential of problems and additional storage to solve those blending problems.

And then, finally, we're told that blending around the Uno-Cal patent will become more difficult, although we've heard recently that the patent office has a bind on the Uno-Cal patent, so some of you have a better, more current knowledge of what's going on with that, and we'd appreciate hearing about that a bit later.

So it's our opinion that the MTBE infrastructure is not capable of handling the California import shortfall.

As far as the commercial tank market is concerned, how do you know that Stillwater is right when Stillwater says this market's tight? Well, certainly a good way to do that is go look at the market, and not only look at it today, but go back in time and look at it. What we've seen is a dramatic increase in tank rental rates. And so the reason that tank -- service providers get more money for the tanks is because there's either more demand, or less supply.

Okay. Well, on the less supply side, we've seen a lot -- we've seen, I think we calculated some two million barrels of storage in the LA Basin go out of service over the last few years. We see that existing terminal operators are under increased pressure to move away from the harbor. And this is both on, frankly, on the Port of Los Angeles and Port of Long Beach side.

We see that there are applications for increased capacity that are not being processed by the ports. One terminal operator we know of had an application in for a relatively small expansion back in June, and it's still sitting on some administrator's desk, waiting for the proper political climate before they can take forward an expansion and bump up the terminal operations.

There are security concerns have come up, and the like. And then there is the issue of what does a commercial operator need in order to build new tanks. And some way or other, they need the commitment. It's sort of difficult to go to the bank and say I need $100 million to build a bunch of tanks, but I'm not really sure if I'm going to have customers. And so getting commitments from customers at this point has been somewhat difficult.

Okay. And, you know, in our view, the trend is that, you know, continued decrease in capacity in the Ports of Los Angeles and Long

Beach.

Okay. That finishes that section. We'll go into markets next.

MS. BAKKER: Dave, could I ask you one question on your slide 53. I'm coming to the conclusion that I'm misunderstanding the labels on this table, because I was thinking that, let's say you say Column A, B, C, D, that column C plus D equals A -- B, and that clearly that's not the case. So, because none of the numbers add up. And so can you distinguish these three numerical columns for me?

MR. GIESKES: Yeah, I guess I can handle it. The -- within the total tank capacity there's a certain amount of variation of what you can put in there. So total tank capacity has in there also some black oil and things, and then within what the tanks are clean product capable, within that there is a gasoline and components. So what's missing from the total is that column with, say, black oil tankage, and some other --

MS. BAKKER: Okay. So, like gasoline and components is a subset of clean tank --

MR. GIESKES: Subset, but the -- yeah.

MS. BAKKER: -- is that a subset of

total?

MR. GIESKES: Yeah.

MS. BAKKER: Okay. Thank you.

MR. GIESKES: At any point in time, those numbers can change. So this is almost like a snapshot of the market at any one point in time.

MS. BAKKER: Oh.

MR. HACKETT: And Gregg now will talk about markets.

MR. HAGGQUIST: Thank you, David.

This is perhaps one of the most sensitive areas of discussion. We certainly don't encourage the government to get involved in the markets in California, and I'm sure no one in this room or listening wants that to happen. However, we tried to look at structure, and what the strategic reserve might mean. We're not going to lecture you on, you know, the marketing structure here, just a brief review so we recognize how it works now.

We're on page 57, for those listening. The California spot market is illiquid, there's not that many deals done, as we said earlier. And yet, that illiquid marginal market, the spot market, tends to set the price, it does set the price for the entire unbranded sector of the market every day. And what does it take to push that market up or down, or down.

Based on our 50-some odd stakeholder interviews and our experience in the market, 25,000 barrels, 50,000 barrels deals reported can set the market at that new level. And if you go up another nickel, go up another dime, 15 cents, 20 cents, if we get up to 20 cents a jump can happen on just a few deals. Just a few deals.

And there's no real transparency in the forward market, so you really don't know what the price is next month in this market with any degree of confidence. A thinly traded forward market does exist.

Now, how does this affect the retail and the unbranded sector of the market and the branded sector of the market. Once again, this is not going to be an exhaustive discussion of these areas, but common sense tells us that we know that the unbranded sector has to buy at the rack, on the rack daily price, and that price is set by the spot market. So if a deal is done for 25,000 barrels it jumps that market up, the whole market jumps up 25 cents, I mean five cents a gallon, and that's the new price. And that is passed on to the unbranded sector, and the unbranded retailer, independent retailer, immediately.

The branded sector, of course, cushions the market from those media's price spike to some degree, but as a later analysis, I think Tony will come back up here and show us that there is a connection between the unbranded -- not the unbranded, the spot, the spot price and the branded over time. There's a lag factor.

Our concern has been, in connection with the strategic fuel reserve, is its effect on the spot market, and the smoothing out, somehow taking the tops off of this extreme spikiness in this market here, because the pricing here is not transparent. The last deal done sets the entire market, and that's very similar to what was going on in electricity last year during that catastrophe we had, where the last megawatt or last kilowatt sold in the market set the entire market. And this may not be too good.

The unbranded rack buyers get inched between the spot and the retail on the upswing. It's not, you know, we're not here to judge that. We're just here to point to that, and to ask ourselves, from a physical, almost -- I call it plumbing, you know, think like a plumber. If we bring gasoline into a strategic reserve and it can get into this market from a global arbitrage of that commodity, as I described Japan has done, well, maybe that will have some moderating effect on this spikiness, and maybe on the unbranded sector.

Although, let me emphasize, we're not favoring one sector or another in this study. We're just looking at this as objectively as possible.

We do have a little chart here on page 58 that shows the relationship between the branded retail and the unbranded retail and the spot price. You can see this clearly is a correlation. This is our high level map, and graph, so when you see the ones that Tony has you'll see how this plays out and more closely analytically.

So the independent markets get hit, and the downswing for the independents, to be fair, when the market drops, they have a chance to recoup whatever they lost on the upswing. So we're not saying this is fair or unfair. We're just saying it's a reality, and we're looking at it from the point of view of a plumber looking at a system.

Okay. And here's where Tony will come in. Tony Finizza, you want to step back up?

MR. FINIZZA: Thanks, Gregg.

Actually, this is a repeat. Starting on page 60 for the next few slides, I'd like to just describe behavior of prices during disruptions.

Page, slide 60, I call this an anatomy of disruption. It turns out that the spot price jumps pretty much immediately upon the occurrence of a disruption. That, I don't think, is a big surprise to anyone. You see the same thing here in the later part of 1999, that's page 61.

You can also see that this is a picture in the winter, where a number of refineries had planned turn-arounds. They planned for it, were quite capable of weathering the fact that part of the refinery was down. In fact, here you see the spot prices fell during the turn-around period, except when a disruption occurred. So, in fact, planned turn-arounds, if properly done, don't have a real big impact on disruptions; certainly the unplanned ones do.

This is chart 63, illustrates that when

a disruption occurs in Los Angeles, it gets transmitted through spot prices to the rest of the state. This is not a big surprise. We are not -- although California is an island, we're not an island within the state.

This chart, number 64, illustrates that the effect of a disruption in California, as given by the blue line in the top of this graph, you do not see that transmission to the Gulf Coast.

Finally, this chart 65 needs a little bit of explanation. This is a picture on a weekly basis of spot prices in San Francisco during a period of three refinery disruptions in early 1999 to the middle of 1999. We started the winter with a period of high inventories, and in fact the -- you see here at the first disruption, the Benicia disruption, which starts right here in early January and lasted 12 weeks, spot prices did not increase because there was probably enough inventory to cover that disrupted amount.

We didn't see a rise in spot prices at that point, until the second refinery disruption occurred, which, in fact, that was the longest one, it lasted 22 weeks. You see that the spot price went considerably far up there. It fell as soon as this first refinery disruption ended, and then started increasing again when the third refinery, the Richmond refinery, had a disruption.

There are three total disruptions, only two refineries at the time, and the spot price traced out almost perfectly those disrupted periods. And again, in the early part of the period, when you had enough inventory to cover it, you did not see the price spike until the second one required some scramble for supplies.

Page 66 illustrates what Gregg was mentioning about the behavior of prices during a disruption. There are a number of colors here to illustrate that.

What we first see is that the spot price generally moves first, followed by the rack, the unbranded rack, as Gregg had described, goes this early above all the other prices. You'll notice that the price rise occurred much faster than the fall, and certainly as the branded rack declines very gradually over time. You can show that empirically by visual observation, as well as statistically.

I have now reached the point for Thomas to -- excuse me, Gregg to come back.

MR. HAGGQUIST: Don't worry, this is my last act. I think.

Well, in looking at this California gasoline market, we looked for analogs or comparisons, as we said, to put it context. One of the comparisons of the jet fuel market, and one of the advantages of being an old guy, like I am, is that you happen to have been around when the jet fuel consortium actually built their own tanks and decided that they were not going to be reliant upon local refiners for their supply only. That would be part of their supply mix, and the consortiums, we're well aware that they have their own tankage in Los Angeles, and they buy from all over the world.

And as a result, you can see that the price volatility for that commodity, jet fuel, is -- the blue line is far less volatile than the gasoline that's spiking all over the place. It has -- because jet fuel does have a broad and deep forward market, as that shows us on slide 66, for those listening in. And jet fuel is hedge-able. It's hedge-able against the NYMEX, because of the close correlation to heating oil, and the storage is available and controlled by the consumers.

Available, because they made it available. And jet fuel tends to follow the same price as -- generally curves as crude oil does. So as a result, we don't have the extreme spikiness.

That's simply an example. We're not saying that gasoline is going to be like jet, because we know there are many differences. Specifications, one of them. We are concerned with price more than specification, of spikiness. Spikiness. But before we talk about that, let's just look at spikiness as part of the total -- price spikiness as part of the total barriers.

MR. PEREZ: Gregg?

MR. HAGGQUIST: Yes.

MR. PEREZ: Just for our viewing audience and those that are listening in, on page 67, I think the clarification we'd like to make up there in the title for that figure is that it's jet fuel, not distillates up there, just to avoid any confusion with diesel, on page 67.

MR. HAGGQUIST: Jumping over. There you go.

MR. PEREZ: There you go, up on top.

MR. HAGGQUIST: Oh, that should be jet fuel. Yes. Very good, Pat. Thank you very much.

Yeah, this is jet fuel.

Although, you know, we don't have one for diesel up here. If we put a diesel comparison chart it would be similar to this. You would see that it is far less spiky, more closely resembling this jet fuel line than the gasoline line.

What are the commercial barriers? We've been talking all this time about the physical barriers to entry, to lack of tankage and infrastructure. The spikiness of gasoline, who cares about the spikiness of gasoline, as long as the street is moving at a lower level of volatility.

Well, one of the problems is it's a self-fulfilling, a vicious circle. Spikiness is a factor of no means for hedging an offshore cargo, a cargo from outside of California. As we said earlier, it takes us three weeks to get a cargo, at minimum; four, five, six weeks to bring a cargo into California from offshore, and there is no forward market. So any potential supplier offshore has to deal with a high level of risk while their ship is on the water. By the time he gets here, the 20 cent increase is going to be a 30 cent decrease, and that does happen.

So lack of liquidity in the futures, forward markets, exposes the importers to significant risks. Who cares? Well, we're not here to protect the importers. We're here to look at structural elements, and to consider these in terms of other islands where commodities need to be imported.

Also contributing to this spikiness is the fact that only blendstocks are available, not finished gasoline, for a number of reasons. That implies, and actually means that you need to bring those blendstocks through the hands of local manufacturers. And once again, thinking of manufacturers in any commodity, on any island.

So the manufacturers are the ones that can certify the final blend. There's no other way to get in here. Independent traders and marketers are locked out from accessing the global economy, if you want to put it that way. That's -- all of those doors are closed. And, you know, the refiners here do have global systems, some of them, and they have access to global systems. That's nothing wrong with that, that's good. That is good. The point is that there's no access other than the local manufacturers.

So there are fewer players able to participate in this market, which differentiates it profoundly from Singapore, from Rotterdam, from New York Harbor. And in an important commodity such as gasoline, and the State of California reliant upon driving, reliant upon the automobile, it begs the question of whether it is acceptable or not acceptable.

So how do you establish forward liquidity? What is forward liquidity? People in the room or listening who have not ever traded a commodity might wonder what that means. This is where you need to think physically here. We're not talking about stocks or an abstract forward price. We're talking about ways to sell a physical commodity in a -- when it gets to the marketplace. You need a minimum number of buyers and sellers. This is -- these factors, by the way, are coming to us from the experts in NYMEX, in ICE, the Internet Continental Exchange; IPE, which is the great exchange in Europe, and from Singapore players and players in Asia. These are needed to create or have any kind of a forward market.

You need a physical delivery point with

sufficient inventory capable to act as a place, a market, we call it a sink on this slide, slide number 70. You need a bazaar, a place where the commodity can change hands. We have no such place.

You need fungible products and well defined specs. You will find a little later on that this is what we are proposing, our recommendations will take care of that. You need multiple supplies from -- our proposal will take care of that, also.

So when you have a forward capability in a marketplace, so that when you bring -- futures markets were born by farmers trying to bring grain into Chicago, into the market in Chicago. But while the railcars were en route, of course the railroad itself would gobble up all the profit, and there was no knowing what the final market was going to be in Chicago. And so anyone who wants to look at the history of futures markets can go back to that and the establishment of the Chicago Board of Trade, just for an analog.

So we need a forward market. Only when a futures market exists can remote supplies be hedged into the destination market. And if you look at the biography of Rockefeller you'll find out how he made his money, by making sure no one else could hedge except him. Hedging is a prerequisite of long lead time imports by independents. Those are just facts.

What are the disadvantages of extreme volatility. Well -- did we skip -- yeah, I'm sorry, ladies and gentlemen. Where's our map?

MS. BAKKER: The positive first, advantages.

MR. PEREZ: The next one.

MS. BAKKER: There.

MR. HAGGQUIST: Sorry, people. It is extremely volatile.

There we go. Here's the map. Now, the reason we're bringing this map up again is to --

MR. HACKETT: And Gregg, you might point out to the folks listening in that we've inserted an additional slide. We brought up that map of the world called California's Gasoline Import Routes, to illustrate the geographical issues. But we did that late this morning, and so we apologize to those of you out there. That's now 69. We'll be one number off on our slide count.

MR. HAGGQUIST: Okay. And you've seen

this map earlier. But we want to look at it from a different point of view here, because once again, we're emphasizing the concreteness, the specific-ness of this potential strategic fuel reserve here in Los Angeles. All lines lead to Los Angeles. We've become the center of the universe for the purpose of this strategic reserve.

I invite you to put yourself in the position of an offshore supplier. Let's go to a convenient place like the Caribbean island down here. It's very realistic. Cargoes come from the Caribs into Los Angeles. It's a 14-day voyage through the Panama Canal. In today's shipping market it costs you about seven cents a gallon to make that voyage. Let's suppose we have a price spike here in LA, a refinery goes down, and the price jumps up to a dollar a gallon in the spot market. Dollar a gallon in the spot market.

Let's suppose New York Harbor is, at that point in time is at 85 cents a gallon, because we've jumped up, you know. And the Caribs, that puts it at New York minus, down in the Caribs it's New York minus, so you're probably be at 82 cents, 83 cents. Eighty-three cents.

Your freight is seven cents a gallon. You get all the way to LA for 89 cents in what is today a dollar a gallon market. That's a tremendous deal. You want to just put that cargo on the water and go to LA.

The problem is, while you're en route, that market collapses, as it often does, and that nice, tidy, profitable cargo becomes a disaster, as it often does. And as a result, you're inhibited until you find a collection of buyers on the other end who will be there to actually take the whole cargo from you. And who are those buyers? Do you have access to them? Can an independent retailer buy from you, can a trader buy from you? No. There's a handful of companies who can buy from you, and they are the companies that have storage.

So there's no storage, no place to bring it, except for the gatekeepers, which are the companies that have the storage. This is just the way things have evolved. Unintended consequences. There's no conspiracy here, there's no collusion here. This is just the way things have evolved over time.

So this supply guy down here, or girl

down here, this lady or whoever it happens to be, may not put her cargo -- her or his cargo on the water today, waiting and waiting and waiting. And it doesn't happen, so this price spike of a dollar a gallon in LA stays up there and stays up there. And it never comes in.

At the same, very same time, a remote supplier, like down in Australia, he's 20 days away, which is one week later, he's got even a cheaper FOB price when he adds his freight to it, because, as Thomas pointed out earlier, international freight rates are much lower than American flag freight rates. So the Australian supplier can get all the way to LA for nine cents a gallon, and he might be at 79 cents a gallon FOB, and he might get here cheaper, at 88 cents. But he won't come either, because that's a longer haul. He won't come until he can organize enough buyers on the other side to come here.

So this center of the universe, this strategic fuel reserve, will be a place, a place, first of all, where these ships can come and unload. And we'll talk about that a little bit more later on.

So the advantages of having such a

strategic reserve, the current situation is there's no hedging mechanisms. And as I just walked you through, what does that mean. It puts you in a state of fear if you're outside and you want to go to California with your commodity.

A benefit of a strategic reserve is the strategic reserve is a physical receiver, based on the auction or the tender differential. And we'll explain that later.

The current situation, there is no physical location for discharge. The SFR does provide the physical location that you need. Then today, there's no access to come into a pipeline from offshore. Pipeline is the way price -- the commodity moves all over the state. But the strategic reserve would be connected, as we've emphasized over and over, to the pipeline.

There's no storage for components in LA. Well, we are going to suggest, we're going to recommend that private storage be encouraged alongside the strategic fuel reserve. Imagine a bulls-eye with a second ring around the bulls-eye being the private sector tanks, the center of the bulls-eye being the strategic fuel reserve.

Very thinly traded forward market,

compared to what a strategic fuel reserve would produce, would be physical location and mechanism by which trades could take place forward.

Unmanned price volatility today -- unmanageable price volatility today, compared to a transparent -- the free market can discover and hedge market value, because it will be a transparent tender auction.

There's not enough liquidity. We will create -- this will create liquidity. And price discovery today is limited on limited transaction phone calls and hearsay, and as best as we can do. Nothing wrong with it. But this will create, SFR will create transparent electronic tenders or auctions that will tell us what the forward value really is.

So who cares about extreme volatility? Why should we care about that? You know, we'll hear from every sector of the market, I'm sure, but we don't think it's good for the industry's image. It becomes a public issue, when price jumps up overnight. And I'd like to point out here, what was thought about this, we went through last year's electricity crisis. Electricity crisis is an amorphous, difficult to understand commodity. Who, other than Einstein and Edison, understands the flow of electricity?

However, if we have a problem in gasoline supply, everyone -- it lends itself to the Ross Perot chart, you know. We having a problem out here? Why is that? We just don't have enough tanks. You know. There's no tanks, no way to get it here. You know.

You want to see a price spike? You come to Los Angeles.

(Laughter.)

MR. HAGGQUIST: And, you know, it lends itself to the boat, the tank, the truck, the gas station. Everyone can understand that supply chain. So there's really no excuse whatsoever for this island of California to remain an island if it doesn't want to.

So it's not good for the industry's image. It creates increased scrutiny. That's why we're here today. You know. Unpredictability. It's not good even for Wall Street. They don't like these, you know, huge jumps up and down in the value of a stock. Long-term consumer behavior is negatively impacted. Well, we can argue about that. But, you know, if you're going to buy a bigger car and you have a volatile price and you don't know whether it's going to be $2 or $3 or $1, you're going to change your family behavior.

For independents, who cares. We're not here favoring independents. We're just saying that if we're going to have an independent market in this California, we must recognize that they're, as we call it, the edge of the spike, the edge of the spear. They get hit first. They take -- they have an advantage on the downside, but it's a very dicey situation here.

Unable to keep customers supplied is a problem with the independents. And unable to source supply from outside California. This is not healthy, we propose, when we look at other islands, and other commodities on other islands, if the local marketers can't get their commodities from anywhere else.

The consumer pays ultimately at the pump, as Tony Finizza has shown us. So these other impacts at the consumer level will need much more analysis than we're going to do in this study.

So at this point I'd like to turn it back to Thomas Gieskes, to show us how a forward trade will actually work, and what the options are.

MR. GIESKES: Thanks, Gregg.

So in this next section we'll try to show you how this reserve would actually work.

We looked at a number of alternatives. The first alternative that had been looked at in the past, as well, is simply for the state to go out and build tankage. And we quickly came to the conclusion that the state is not necessarily best equipped to do that, that it would not be cost effective. And what we foresee is that this reserve would take the form of tenders to be issued to the industry, and that the established service providers, some of whom are represented in the audience today, would then come forward and bid on this.

In any case, the volumes that we propose, given the restrictions of land, et cetera, et cetera, require, in all likelihood, multiple locations for this reserve. So even if, say, we propose something like three or four million barrels to be built in the LA Basin, then I don't think that any of the individual parties would have sufficient land available to do that, and multiple locations might be good from a spread of risk perspective, as well.

And, anyway, the tankage would then be built under tenders, and if we look at current market indications, and actually prices have moved up on a short-term basis, if you can find tanks on a short-term basis, above 60 cents per barrel per month now. But indications that we received during our feedback process initially, in stakeholder interviews, is that you could likely contract something in the Bay Area for around 45 to 50, and maybe in the LA Basin around the 55 cents per barrel per month. And those are the numbers that we've taken forward in our further economic evaluations of this, as in our proposal.

We've also looked at the conversion of fuel oil tankage that's still idle at some of the power stations. There are a couple of those in the Bay Area, and there's one or two left in the LA Basin. Probably costs are not all that dissimilar from building new tankage. These tanks are large, they're old, they would need to be re-permitted, would need new -- you know, for the roofs, new bottoms, et cetera, et cetera. So costs would not be substantially different.

Should, however, one of the parties bidding on these tenders find that to be a cheaper alternative, then the market would do its usual work.

We've also looked at floating storage, and some of the other idle tankage that's still available in the state, and all of those were really non-starters.

So the proposed configuration for the SFR would be for the state to facilitate building of about five million barrels of tankage, and we're still not completely sure on how the tankages need to be distributed, but the range would be to build one to two million barrels in the Bay, because that's where the problems are not quite as severe, and then three to four million barrels in the LA Basin.

As I said, they would be based on a tender to be issued to qualified parties. The state would actually itself only lease directly about half of the tankage for the strategic reserve. The remainder would be available for short-term usage by the industry.

One of the reasons that we pointed out before is why doesn't more tankage get built at the moment, is that most of the interested parties that, say the traders, the importers, et cetera, are interested in short-term leases. Most of the tankage that is built was built a long time ago, where somebody needed tankage bad enough to do a long-term deal, at the end of that long-term deal, say a 10, 15 years contract, such tankage then becomes available for the -- this rental market.

The state, in this case, would issue a guarantee, a long guarantee that would cover only the financial charges to get the tankage built, and would allow a builder to go out and obtain a favorable loan rate, but it would not cover the operating expense. So the onus would really be on the commercial operator to lease out that tankage.

And as Gregg pointed out, that industry tankage would surround, as the outer ring, the tankage that would actually contain the physical reserve. And we foresee that tankage to be primarily then used for blendstocks, et cetera, used to produce the CARBOB that has to go in the strategic reserve itself.

Moving on to slide 75 on the screen, slide 74 in the handout and the Web pages -- oh, that is actually -- it's doing it again.

The operating principle for the SFR, and at this stage, and we're at a sort of the stage of a conceptual study. We by no means claim that we have all the details sorted out --

MR. HACKETT: It skipped one. You're back up to the picture.

MR. HAGGQUIST: Oh, yeah. I'm going to pull out -- let's go to the -- there we go.

So this is a pictorial, a picture is worth a thousand words, of how the strategic reserve would work. As I said before, about half the tankage, which is the yellow part, that's the bottom in the -- for the black and white viewers, would be the SFR volume itself. And we've dubbed that the Gasoline Bank of California.

Imports of CARBOB would go directly into the tankage. Blendstock imports would go into the private leased tankage surrounding the SFR. Refineries, since these would be connected into the gathering system and into the long distance transportation CARBOB system, would have a possibility then to either lift from the reserve if they need stuff, or put stuff back in. And, of course, deliveries from the gasoline bank would go directly into the distribution system, ultimately to the truck racks.

The operating principle, and as I was saying before, before I realized that I had skipped a slide, and we're now on 76, us that the initial fill, roughly two and a half million barrels, would have to be purchased very, very carefully in order not to create a shortage all by itself. So the way we envision this to take place is during the winter months, where foreign producers would have the opportunity to supply CARBOB, this once will again also be done on tenders.

Supplies might come, for instance, from Irvine in East Canada, and certain of the local refiners would have excess capacity in the wintertime. And not everybody is capable of producing both summer and winter grade at the same time but I'm sure that could be managed, and rather than having to cut back production, as was the case in January and February of this year, you would have the opportunity to supply material into the reserve.

We foresee the reserve to be a summer reserve only, so it would contain low RVP gasoline year-round. The price spikes and the -- all the supply disruptions having a severe effect on prices, are strictly a summertime event. Price spikes in the winter are rare. Should a serious outage occur in the -- in a winter month, and you'd have to dip into the reserve in the winter, there might have to be some blending going on to increase vapor pressure, or, alternatively, you would be able to swap material around within the state so that the low RVP material would stay in those counties where low vapor pressure is not a problem. And you would reserve the remaining high vapor pressure material for the mountains and the colder regions.

But, as I said, we do not claim at this point that we have resolved all the practical operating problems. There's a serious round of further work that needs to go on to figure all this out. We've asked the refiners, for instance, what their opinion would be on the shelf life of the CARB Phase III gasoline. We think it should be fairly good, because you remove some of the olefins and sulfur, et cetera. But those are still unresolved questions at this stage.

On the auction mechanism that Gregg pointed out, we envision at this stage that a daily electronic auction would be conducted, a little bit similar to what's happening in Singapore with their 5:00 o'clock, and maybe here at 9:00 o'clock in the morning, an electronic auction would take place where a participant, qualified participants could bid on the lifting right to do a forward time swap for a prompt lift, and then a replacement in kind within four to six weeks.

And that quantity of 50,000 barrels a day at the moment is purely an arbitrary number. That might actually be a range, depending on certain circumstances or the level of interest in the market. The 50,000 was chosen with the idea that if you have two and a half million barrels and you have, say, 20 auction days in a month, then -- and every single day the full 50,000 would be lifted, which is not always going to be the case -- then you would have one million barrels on the water, so almost half your reserve, 40 percent of your reserve, would be sitting on the water pointing back at you, and you would still have 50 percent left in the tank. And the 50 percent average inventory is probably right smack in the middle of the work, that's where you want to be.

The other thing is that the 50,000 barrels a day, as we will see later when we look at the effectiveness of the reserve, would have covered substantial outages in the past, and is the order of magnitude that we've seen that can swing the entire market around. I mean, currently, the market moves on a single piece of, say, 25 to, say, 50,000 barrels a day, can indeed have a significant impact on the total market.

Speculative use. There will be gaining around the reserve, but we think you can limit it by putting in a requirement for physical lifting, and also the physical re-supply requirements and the quantity limitations. The 50,000 barrels a day certainly would be significant barriers to effectively gaining this reserve.

The development of derivative trades or trades surrounding the, say, a party, party A might have lifted some material from the reserve and then has an obligation to re-supply. He could trade that obligation to re-supply off to another party, and we foresee that that is just very beneficial. That will create an active and forward trading market, and will help to establish a liquidity in that forward market.

As Dave has pointed out before, and Gregg, as well, the participants would have to be qualified. You cannot have the situation that you had when the volumes were released from the strategic petroleum reserve recently, where the winning bidders were totally unqualified. It's -- somebody operating from his bedroom putting in a low bid is not what we envision as suitable for the California market. But they would certainly include the refiners, the major traders, independents, anybody who has a proven track record of being able to physically re-deliver barrels to the reserve. Besides financial qualifications.

And how would this all play out. And this graph here, we show the differential between the prompt and the forward markets. And as Gregg pointed out, forward market is -- currently is a very thinly traded market, very few deals. The deals are not always reported. This is based on private information, but it shows that at the time of a price spike, as you could expect -- and for the people that listen in we are now on slide 77 -- the LA prompt market is in blue, which you can't see, but it has, as the markers, the little triangles, and the forward market is the green line that has little squares as the marker.

And what you see is that when a price spike occurs, and I'm looking, for instance, at September 27 in 2000, a significant price explosion occurred, that's, when a price spike occurs, the prompt market loses sharply, the forward market is then severely backward dated, as it's called, it stays much lower. And that is because people have no idea how long this price spike is going to last at that point. And it moves up a little bit, but usually much, much slower.

And now I'm going to move on to a series of slides that are animated, so for those people that look at the handout, or at the Web pages, this is slide 78, they get to see the whole thing at once, and here I'll walk the people step by step through the analysis of a price spike.

So what we see here is a sort of animated feature of what happens if Refiner A has a problem in week one. What typically happens then is that as soon as the market gets wind of this, and the extent of the damage becomes clear, Company A will have to go in the market and they try to do it as long as possible, hide the problem, gobble up any available piece that's out there on a prompt basis, and nevertheless, the price starts to move and then some other trader gets wind of it and says oh, Refiner A is in the market. And before you know it, you have a really severe price excursion that is not followed in the forward market.

And, of course, the export markets, which are the blue line here, and then the dotted line above it represents the shipping cost, don't move, either.

And so on a prompt price differential, there would be sufficient incentive to put a cargo in the market, and this is what Gregg pointed out earlier. You're sitting there in the Caribbean, seven cents freight differential, 20 cents price differential, you could make a million dollar on the single cargo. Sounds very attractive to me. There have been days when that would've come in handy.

Since the forward market is not moving up, you are still on the water on the forward market at that point in time, and since your shipping time is -- this is not the case for the

Caribbean, but it is the case, say, for the AG or some of the more remote export locations like the Canadian East Coast, you're looking at say four weeks to put that cargo on the water. Your shipping time would come in well after even, say, the most forward deal that you currently can do in the forward market. So you have no idea at that point in time what your trade would be valued at.

And so what will happen in week two. And as Tony has pointed out, the probability of coinciding disruptions is quite real, and often it's only in, say, when the second event happens that the market really takes a hike. So in week two here, Company B announces that unfortunately, the start-up of their refinery after a planned event has been delayed.

Sorry, that's not good. I actually got all the way back here. Sorry about that. There we go.

So in week two, another refinery problem occurs, another disruption, and the market then responds quite -- is quite severe. At this point in time, the forward market also starts to move up considerably, and the export markets are still where they were, more or less. So now an importer decides to take the risk and float a cargo. So his cargo is sent out there, booked at a price slightly above 60 cents per gallon, and expected to come in in week seven sometime.

And then, obviously, things take their usual turn. Refiner B finally completes the turn-around. In week five Refiner A brings back his installation online. First, other cargoes, because this is only one incident, usually in terms of refinery incidents you'll see four or five cargoes coming in at the same time, but prices start to drop in anticipation of that material sitting on the water and coming in, and refiners being back online. So prices have dropped. And by the time a refiner -- sorry, importer sees cargo shows up, the market has fallen to well below his cost, and he has a net loss of a million dollars, where he was thinking of -- or maybe two million dollars, even, where he was thinking of making a million. This is a severe barrier to imports currently.

So what would happen if the strategic fuel reserve would have been in place, the way Stillwater is proposing.

Start out with the same scenario. At

Week A there is a refinery fire. The extent of the damage becomes clear, et cetera, et cetera, and prices start to move up above import level. I'm on slide 81 now. So as soon as the spot market has moved up above the level where imports become attractive, somebody can now do a forward time swap, can go to the ticket office at 9:00 o'clock, open up and bid on the -- on a time swap, put in, say, a two or three cents bid for the forward, regardless of whether the forward market would have been there, that little green line, at that point in time.

So he bids on the value of that backwardation. And as soon as he has a bit of orders, he could float a cargo in the expectation that he would have other volumes as well, 50,000 barrels a day, but he could do other volumes as well, and could get to the size that he needs for a cargo.

So the reaction of the importer is immediate. As soon as you have an arb that works, you don't have to wait for that, how long will this price spike hold, you could take a decision to float a cargo immediately. That's a major differential.

This, of course, will go all the way through, and the forward market then becomes more closely related to the export markets, will go all the way through in that scenario. In week two Company B has an upset, announces a delay, and what you might then expect is that actually, the export markets, because the export markets for -- the markets in the export location, let me put it differently, that are capable of supplying product suitable for the California market, are not all that broad, either.

What you might see in that case is that the export markets start to track the California market a little closer. So where currently you see no linkage between export markets and the California market, in the case of a price spike, as Tony has pointed out, you might anticipate some tracking there, but only to the extent that the arb stayed open. The arb is the net trading differential.

But in any case, when Refiner B has their problems, they can decide also, right there and then, to float a cargo, identify a possibility to bring material in, and supply that shortfall. Importer C sees the same thing. The forward market starts to track now very closely what the actual physical value of the material coming in will be.

And the long and the short of it is that by the time these cargoes actually come in to the market in week six to eight, there has been no significant price increase over and above what import values represent. So it starts to track the global market for gasoline components suitable for delivery into the California market quite closely.

Also, when finally these components, these ships do show up, they have no impact on the market. You don't see the deep swing on the downside, either. If now four, five, six vessels are on the water all aimed at LA, and they finally do get offloaded, all they do is a physical replacement of inventories already lifted. So you don't see the deep downswings, either, and there is not that significant loss.

So instead of gambling on the plus 20 cents, minus 20 cents, and very few people are willing to take that gamble, what you see is a lot of people being very happy indeed, making a couple of cents profit on a cargo that is locked in.

So that, in essence, is how we foresee these market mechanisms to work. And if we look in summary on this, the market mechanisms, there is no doubt that California has become increasingly import dependent, that refiners are probably quite interested in adding capacity, but that the infrastructure is currently inadequate to handle those imports. With the MTBE phase-out, we'll aggravate that situation.

MR. FINIZZA: Thomas, you jumped into 101. You're stealing my speech.

MR. GIESKES: Oh, yeah.

(Laughter.)

MR. GIESKES: I don't want to do that. That's --

MR. PEREZ: Appreciate you trying to stay on time.

MR. GIESKES: Yeah. Yeah, yeah. Oh, man. I thought it looked funny. There, the conclusion.

So the effect of the SFR is to peg California to the world market. And to, once that is done, once you peg California to the world market by established mechanisms, you can also hedge California gasoline then to much more liquid future markets, like the New York NYMEX. If California starts tracking export markets in a regular way, without that extreme spikiness, you can envision that whole new level of liquidity will emerge in forward markets.

The scarcity of the imports of suitable blendstocks will remain an issue, but I think that -- and we've shown that in some anticipation of upward movements in those cases, as well, but you have a much broader basis to work in. And once potential exporters of volumes to California see that exports can become a regular issue, they have more incentive to invest in increases of their capacity, as well.

That, then, does conclude this.

We move on now to the effectiveness of these words, and I'll turn it over to Tony Finizza, who will walk us through that.

MR. FINIZZA: Thank you, Thomas. Can you explain to me how you'd avoid going to 101?

MR. GIESKES: Well, no, that's very difficult. But if you hit that button it'll do it. If you hit the button just next to it, you're at the end.

MR. FINIZZA: Oh, my.

This next part I'm going to try to model the impact of future disruptions on the market. And I believe it's a pretty safe forecast to say that disruptions in the future will occur.

The database I showed you earlier, the average days between disruption is 38 days, and the actual longest period was 259 days. So it's pretty safe to say that we will see some disruptions in the future.

That estimate is going to be a function of four facts. How likely is a disruption going to happen, how big will it be, how long will it last, and what is the price responsiveness to those disruptions.

Thomas, I want to go back to the old technology. Let me do it in reverse order.

The first point I'd like to talk about is the price responsiveness. And, of course, it's going to be both a combination of the demand elasticities and supply elasticities. Demand and supply are both highly inelastic when it comes to gasoline. And inelastic means that a small change will, of course, cause a very large price impact. And what I'm going to try to model is the combination of both those effects.

Now, we have some help in that. This table on page 85 gives a range of estimates from the literature. I think I've encompassed most of them. I think perhaps I missed one study.

The ones at the top, the range of estimates given that are cited for the Federal Trade Commission Midwest Gasoline Investigation, actually the numbers they used are capturing both effects. The others are strictly demand elasticities.

The literature is unfortunately very light on estimates of supply price elasticity. We know it's not entirely inelastic, like a lot of people assume, but it's fairly close to that. We do know that when there's a supply disruption people can grab stuff from inventories, and things of that nature.

So the question is, what is the combination of these effects. And what I've settled on is a range of minus .1 to minus .2, so that a disruption would have a multiplier effect of ten times or five times the volume percent that's disrupted. And, of course, that disruption volume is the net effect of lack of production and drawing from inventories.

Others recently have used numbers, and these are all to try to capture the full effect, numbers that are in certainly, at least the top two, in this range. So I feel somewhat comfortable presenting this range. Also, when you look at data in some of the disrupted periods, they seem to fit into this range, as well. I've calculated numbers of about minus .15 to minus .22. So this range is, I think, fairly appropriate.

I'll be the first to admit that it's always been that wide a range. This could be a little bit higher on that end, of course.

The next step is to -- not good, that old technology didn't help me again. What is the probability of a refinery having a disruption in the future. Well, we can model it as the average that's occurred in the last four years. I'll also show examples of if we were going to be lucky and not lucky, and we can do those as sensitivities.

The chance of a refinery having a measurable disruption in a given week is roughly two percent. Of course, there are more than one refinery around, so, in fact, the chance of a week going by without a disruption is something like 86 percent. These are binomial, they either have a disruption or you don't. With a lot of observations, which we do have, you can approximate that by the normal distribution.

The distribution of sizes of disruptions, you can flip back to the table, or the chart on 20 and 21, if you wish. But these disruption sizes are tilted towards the small end. I've modeled that with a lognormal distribution, with an actual mean that you observe, which is 20,000 barrels a day. The standard deviation is quite high, 15.

The length of disruption. You will -- also could go back to the chart on 21 to see the kind of figure that I drew from. That distribution says the mean is roughly 2.7 weeks. There's a long tail to it. Large, long distributions do happen, but very infrequently. I've modeled that with a lognormal distribution with a mean that you find in the data, plus a high standard deviation.

For the statistical geeks in the world, you want to use a lognormal, because you can't have minus numbers here. You could get some funny numbers.

So, if I look on the next chart, called Distribution of Disrupted Barrels, I've run a Monte Carlo. Assuming we get a thousand repetitions of a year, using these parameters, this would be the distribution of all potential trials that nature might give us. And it turns out that the expected value, the mean of that distribution says that on average, you would get 1.2 percent of production disrupted over a number of time periods. So this is per year.

If you want to look at the distribution of that, of course, some of it looks like the distribution that you find historically. Obviously, you could see numbers as high as one and a half to 2.7 percent of production. You could then apply those elasticities to that distribution, and actually calculate the economic cost, incremental economic cost, to the consumer.

Some people may be optimistic and say let's assume, rather than use the average, we use an example period like that was -- that occurred in 1998, so let's use the low probability, the small duration, the small disruptions. I think we have this backwards, don't we?

MR. GIESKES: Yeah. You're right.

MR. FINIZZA: Somehow we changed the title after this. Excuse us.

This actually is the highs. This is modeling, page --

MR. GIESKES: It's 89.

MR. FINIZZA: -- 89, in your handout, and for those on the Web. It's called Distribution of Disrupted Barrels, Lows. These are actually modeled after the 1999 year, in fact, and production is expected to have 3.5 percent of production disrupted.

This one is truly as labeled, the distribution of worlds if we use the low assumptions of disruptions. And there, you get numbers, fractions of percent, .2 to .5 percent.

Economists love to give you ranges, and I will not disappoint you. This table catalogs, given the two extreme values of the shock elasticity used, plus the three types of parameters for the size, length, and occurrence of the disruptions, you can see in this column here, labeled 1996 to 2000 average parameters, that the range of additional consumer costs in these worlds would be roughly one to, say, two billion dollars. If you had the optimistic low end, it'd be .9 to

1.8 billion dollars. In the, God forbid, repeat of the 1999 world, you'd get three to six billion dollars.

These all assume a retail gasoline price of $1.25 a gallon, which is hard to find. It actually isn't that terribly sensitive to that, since it changes off that. I guess the Sacramento prices are near 1.50 today. So these numbers would go up a little.

Well, I decided to do something in addition to this, and that is to examine the possibility that we have the right size of inventory. And the question is, how should we -- does this tell us anything about the size of a strategic fuel reserve. Of course, the legislative prescription calls for 2.3 million barrels. Some people might be tempted to say just assume one refinery suffers a average disruption, and then you need 380,000 barrels. What would you have needed to cover the maximum disruption, it's certainly higher, and I didn't know the number so I used the famous question mark.

But I decided to model it with historical distributions, and see if that could help us out. So, this distribution, called expected size of a disruption, impact times length, is not time dependent. It is at a point in time. What is the distribution of those disruptions, both impact and length. So in other words, the number of total barrels in a disruption. It appears on slide, I think, 93.

Here it says the expected value, if you were to model it according to the historical parameters, the size of the disruption would be -- the average, the disruption would be 385,000 barrels. Of course, you want to make sure that you can cover more than just the average, so if you went to the, say, 90th percentile of that distribution, you'd need 870,000 barrels to cover the future possibilities of disruptions.

I just want to remind everyone that this assumes independence, which I believe might be an accurate assumption. The chance during a given week, a given time period that no refinery is disrupted, is something like 84 percent. And so that leaves the sum of approximately 16 percent for the chance that at least one will be disrupted. Most of that will be one, but there are some times when you get two, three, and four.

I'd like to turn it back to Thomas.

MR. GIESKES: Thanks, Tony.

And this is that real famous year, 1999, in more detail. It shows several things that we've already discussed before, how, even though most of these refinery problems occurred in the Bay Area, both the spot price in the Bay and the spot price in LA closely tracked. It had nothing to do with underlying crude oil changes, as shown in that bottom line. That's the line with all the little crosses in it, that's the line with the crude oil backed out.

And I know that we should not look at the spot price as the marker to determine the economic impact on the California gasoline consumer, and that there is a big time lag in the spot price between the -- between the spot price and the retail price. But on that ridge, though, those arrows work out quite the same. So the area under the spot curve, in terms of price increase over the price before, and the area underneath the retail price curve actually happen to track quite closely.

On slide 96, we are looking in more detail at what happened in that ill-fated year, 1999. And what you see here, and this is a pretty complex graph, it shows the production is as bars, and it shows the inventory as area. And what you can see here is that there was a drop in production, and then the inventory started to decline. And in both of these events, and then in subsequent events after that, you see periods where inventory recovered, and inventory declined. And the inventory curve is very directly related to the price spikes.

And that confirms a piece of market information that Gregg was telling earlier, is that traders very closely watch the inventory movement. If inventories are in decline, that's when the spot price goes up. When the inventories are going up again, that's when the spot price falls.

So inventory movements are quite crucial market indicators at this stage, and that's why the spot price, which is the primary indicator of price, is highly relevant here.

The lost production, on average, through these two series of events, was about 95,00 barrels a day. We've identified 11,000 barrels per day of additional imports that are actually then reported as production by the refineries, because most of the reported production numbers include imports of blending components and products by the refiners themselves.

And that, the net ex refinery production in those periods fell by about 84,000 barrels a day, as reported. The inventory drawdown over that period, and the inventory drawdown in that first sequence of events between -- and the dates are very squiggly here -- but between the first events in April through June, averaged about 20,000 barrels a day. In that second series of events, where the inventory drop was steeper, it's about 30. But the average inventory drop was about 25,000 barrels a day. That means that during that period, the average net loss to the market, the net loss of supply, which by definition equals the net reduction in the amount, was about 60,000 barrels a day.

In that period the spot prices doubled, but the retail prices went up only 45 percent. So this is -- and it got all pieces of information that confirms what Tony was referring to earlier as the price, the shock price elasticity. This implies an elasticity of about minus .13, which is well in that range of minus .12, minus .2, that

Tony used in his modeling.

Now, the big question, of course, is how effective would a 2.3 million barrel reserve have been, if it had been available in 1999? And as Tony pointed out, from a theoretical point of view you can show that -- I think it was 1.3 million barrels would already have covered the 95 percentile series of events, of disruptions quite effectively.

What you need to take into account, of course, is that we propose to split the reserve between the north and the south, but so that a million barrels up in the north and a million barrels in the south quite nicely fit within that 1.3 million barrel range. So how effectively would a, say, would it have been if you had a million barrels in the LA Basin, and then another 1.3 or so in LA at a point in time.

With the inventory drop being the most, say, watched parameter of market behavior, if you had been able to feed the 50,000 barrel a day that we propose as the max limits from a strategic reserve to the market, you would have been able to effectively compensate for the inventory drop. And the -- this would not have resulted in a lessening of the additional imports to the tune of 11,000 barrels a day, or maybe slightly higher, as the case may have been. But that would probably have enabled an even more rapid backfilling by imported barrels into the reserve, so the net inventory drop in that case might well have been lower than the 20 to 30,000 barrels a day right off the bat.

So in addition to the, say, supplying 50,000 barrel a day, the capability of supplying 50,000 barrels a day into this inventory drop of 20 to 30, you also would have seen more imports materializing to backfill that. So that number of 11 would have been substantially higher.

And, also, the effectiveness of a reserve, of a relatively small reserve, I think most of the price spikes, as Tony pointed out, had a duration of less than a week. Still, very often those price spikes have extreme results because of the volatility of the trading, and the lack of reporting, the lack of transparency, et cetera. And there is no doubt in my mind that the sheer presence of a reserve, of any reserve of any kind, would have been effective to prevent, say, the spurious price increases such as we've seen last week, for instance.

So the effectiveness of the reserve, and even though there's a lot more work to possibly do, a lot more modeling studies, a lot more detail, but just from the, sort of the back of the envelope probe, this is the worst year in California history. This is the equivalent of the hundred year winter that was used to justify the northeast heating oil reserve. There's no doubt in my mind that if you had been able to supply 50,000 barrels a day into these inventory declines of 20 to 30, you would have done a world of good.

Now, how does that translate into, say, cost effectiveness. If you know that it works, that's fine. Is it cost effective. And we have looked at the, say, the cost of tank leases, the cost of the initial fill, et cetera, et cetera. And we believe that you could effectively operate a reserve at a cost between 20 and $30 million a year, cost to the taxpayer. It's a significant cost. It's a nice, like I said before, it's the sort of money that would come in handy on a rainy day. But it pales in comparison to the cost to the consumer of the current extreme volatility of the California gasoline prices.

Now, this is a fairly complex graph, and --

MR. HACKETT: Thomas, you're one ahead again.

MR. GIESKES: One, again. Well, this effectively has been covered. This is slide 98, I might as well skip this because it -- much of this has been dealt with by Tony already. The only thing I would like to add to that is in case we do see a chronic shortage, as might be the case when MTBE is phased out before adequate alternative supplies can be lined up, is that if you do have a chronic shortage, that will remove some of that initial price elasticity. And if that's the case, then the volatility in the market will no doubt be more severe.

That really doesn't want to show that -- ah, here we go.

So I'm on slide 99 now, and that's a slide that, for those that listen in, we have some problems here with the switching mechanism between slides, and the machine didn't want to show it, and probably for good reason. It's a rather controversial slide, and we've referred to this, in our internal discussions, to this slide as the flames of hell.

(Laughter.)

MR. GIESKES: But let me walk you through what this is. This is the retail prices, the branded retail prices, minus Texas and minus the cost of crude oil to the refiner, estimated cost of crude oil to the refiner. And over a period that stretches from beginning of '99 through current, or almost current.

And what that shows is the branded price, and then subtracted from -- so that we've subtracted under graded, rec price from the net retail price, and that gives you the net margin to the refiner. What we know from recent publication, this is the single largest refinery deal done in California. This was the $1.1 billion acquisition by Tesoro of the Avon Golden Eagle Refinery, and the public information surrounding that event, investor information, said that this particular company needed $11.62 of crack spread on the three to one basis, that's three gasoline, two diesel, one jet. And just for the sake of information to show the relative order of required crack spreads for economic grants, we've plotted in this black line.

So this line by no means infers that we think that the prices ought to be managed at that level. There are refiners that have -- that are quite happy with lower crack spreads, there might be small refiners that actually need higher numbers. But this is the order of magnitude of a crack spread at which a refiner should be quite happy, and a refiner can justify a $1.1 billion investment in the acquisition of a refinery.

What you see is that the market over very substantial periods, has been quite high above those levels, and that has to do with that extreme volatility, the lack of backfill behind a price increase. So prices in California can be substantially above those levels without adequate supply being mobilized. Normally, supply and demand would do their usual destructive work, and as soon as you see these sort of margins you would expect that more supplies would come in to the market, and then bring prices down quicker. That fact that that is not happening is largely due to the barriers to import that we outlined before.

Now, to show what a reserve might have done, and if reserves would have limited, and I'm only looking at the price effect in those two events that we looked at before, in '99. And we say if you had had the reserve, you would have been able to limit that excursion to the branded cost of very high cost import materials, at that point in time. Alkalytes from the Gulf at 30 to 40 cents above Gulf Coast gasoline, or some other exotic imports from Finland. Then it would have brought that down to about $19 per barrel.

The area under the curve, so the area under the curve above that $19 per barrel level, and those single two price spikes in '99, represent a value to the -- so that's about $5 per barrel average, 12 cents per gallon over 90 days, equates to about half a billion dollars. And projected over a longer period, over all three years, the value is considerably higher, and is actually closer to 4.7.

Once again, this is a very good fit with the theoretical approach by Dr. Tony Finizza, who calculated that the effectiveness of the reserve, in terms of savings to the California gasoline consumer, on an average basis would have been between one and $2 million per years. In a really, really bad year, maybe order of magnitude three to $6 million a year. So these numbers are fairly consistent with, say, the theory, and I think they're real.

And, of course, this can be defined in a lot more detail. We can do a lot more studies around this sort of thing, but when you see that the $30 million of expenditure, the net savings to the California gasoline consumer are in the order of magnitude of, say, half a million dollar a year, if we approach it conservatively, then you are orders of magnitude apart. And that's exactly at the stage where we are. We've done these studies at a conceptual level, so far. There have not been data engineering estimates behind it, there have not been any tenders out to the industry yet to do any of this. There's a lot more study that needs to go on to define the operating principles of a reserve. It's a very novel concept.

But we believe that when you see the costs and the benefits being orders of magnitude apart, with very, very significant benefits, not just for the California gasoline consumer but, I believe, also for the industry as a whole, we have sufficient grounds to move on.

And with that, I'd like to hand it over

to Dave.

MR. HACKETT: There we go.

And so, with slide 102 up, I assure you this is the last one. We're just about done, we can go to lunch. And then I think we'll be able to come back and mix it up. We're looking forward to some good dialogue.

The conclusions here, I think, are fairly evident. This market has become import dependent. It used to be an export market, it's not, anymore. It's an import market. There are infrastructure problems in this market. In many respects, what we're talking about here, frankly, is it's the logistics, stupid, to paraphrase a presidential campaign of some years ago. This is about nuts and bolts and hardware, in many respects.

We see the market has been volatile, and we expect that the MTBE phase-out will increase that volatility because of the requirement for much higher levels of imports into facilities that aren't designed necessarily for those imports. And then we also maintain that as -- are as proposed, it can be a cost effective way to increase the liquidity and lower import barriers.

And so these are things, lowering import barriers, increasing liquidity, are vehicles that improve supply, and then, in our view, will reduce the volatility in gasoline prices. And that -- and I think I hit the conclusion at the wrong point.

The issue is volatility. The issues are supply. But we think that the overall ability of the state to improve the supply into the state will reduce volatility, and we think that's good for the consumers.

Mr. Commissioner, I turn it back to you.

PRESIDING MEMBER BOYD: Thank you, Dave. And I want to thank Dave, Tom, and Gregg, and Tony, for that very comprehensive, in depth, and interesting and provocative presentation.

As indicated earlier, we will break for lunch, and return for a roundtable discussion this afternoon.

I'm not going to try to summarize the morning, as I did at the last workshop, or state any particularly cogent points, although there was one comment that Gregg made, that I did make note of, as I do every meeting make at least note of one of Gregg's comments, but --

(Laughter.)

PRESIDING MEMBER BOYD: And I still have Chouxiang here, Gregg, from last time, and I thought it was almost appropriate if I said that right, almost appropriate to your comments about the overview of this subject never having been undertaken before. For those of you who missed the last workshop, that has something to do with a Chinese proverb that boils down to inhaling an elephant.

But, in any event, Gregg also said, you know, and from his standpoint, from his viewpoint, based on all the facts he'd reviewed to that point in time, there is no excuse for California to remain an island if it doesn't want to. And I thought that was a particularly relevant and provocative comment.

So I'll close the morning on that point, and we'll return at 1:30 to begin the roundtable discussion.

(Thereupon, the luncheon recess was taken.)

AFTERNOON SESSION

PRESIDING MEMBER BOYD: I guess we can get started again. I was kind of waiting for -- oh, he is here. He was hiding. I was waiting for a special guest, I was about ready to say he's not here, and then somebody moved and all of a sudden I could see him.

So this, I want to open the meeting to the public and stakeholder questions, answers, and just kind of a roundtable discussion. And we agreed to accommodate one stakeholder who is in the midst of another meeting across town, and asked if possibly we give him a time certain, so that time certain is now. So I'd like to ask Mr. Henderson of WSPA to come to the podium.

MR. HENDERSON: Thank you very much, Commissioner Boyd. I very much appreciate your flexibility to accommodate my schedule difficulty. I mean that a lot, I appreciate it.

PRESIDING MEMBER BOYD: Oh, Doug, you know how flexible I am.

(Laughter.)

MR. HENDERSON: Commissioner Boyd, ladies and gentlemen, thank you very much for the opportunity to comment here today. I will be brief.

I'm the president of the Western States Petroleum Association that represents a broad spectrum of refiners, marketers, and producers in this state. We are still in the process of developing specific comments on the Stillwater report for submission to your -- by your deadline of March 25th. We have, however, identified some issues which I'll briefly mention for you today.

We're extremely concerned about the hasty nature of your process, which I understand is driven by the legislative timetable. But nonetheless, this is a serious enough matter that any decisions made on your Strategic Fuels Reserve will have far-reaching and long-term impacts on our industry, and we fear a hasty approach will lead to outcomes that are not good for us or our customers.

Second, there are a number of complex practical issues which have yet to be addressed, such as will usage be enough to regularly roll over your inventory; how will supplies be replaced; how will terminal operators be assured of always being able to make a finished product from the components; will your SFR worsen price instability during seasonal turnovers; is the reserve -- if the reserve is built as proposed, will it reduce incentives for others to hold inventories; and we think those are a beginning list of those kinds of concerns that we hope we will articulate for you a little better later.

We also are concerned that the Stillwater report overestimates the benefits of a reserve, based mainly on the events of 1999, which we don't think is a typical year for that kind of evaluation. A broader spectrum of data we think needs to be evaluated before you reach a conclusion based only on the 1999 experience.

In conclusion, we very much appreciate the work of this Commission and your Staff's hard work. But we also appreciate the enormity of the effort that we have undertaken together. And that's a concept I want to leave you with. Our industry hopes that we can provide good information to help this process along in a useful and meaningful way, and we're committed to do our part to do just that.

We very much look forward to working with you and the Staff to make this a good outcome for all Californians. Thank you.

PRESIDING MEMBER BOYD: Thank you, Mr. Henderson. I appreciate your comments, and we'll take your few comments into consideration. I don't know if you have been advised by any Staff yet that this morning, we, I, in my introductory remarks, in recognition of the enormity and complexity of this issue, we did indicate, and since we had not provided people much advance look at this particular document, that we are going to hold yet another workshop on this topic, and we've extended the time period for written comments on this, as well.

And I also appreciate the overall concern about the issue of timeliness. This is a very large and complex issue, and, you know, we always dance on the head of the pin. We, the public servants, when the legislature asks for something and establishes a deadline, we try to take as much time as possible and needed, but if we take too much time they'll get you other ways, like whack your budget or something. So we will do everything in our power to afford everybody as much time, until it begins to threaten our existence, let's just say.

So hopefully, we can all work together

on this.

MR. HENDERSON: Thank you.

PRESIDING MEMBER BOYD: Thank you.

Now, the floor is open. I have no sign-up sheet, and it's going to be hopefully just kind of an informal whoever wants to say something, and the first one to rise or get their hand up is welcome to come to the mic and identify themselves, and make a statement or put questions to our consultants.

So, have at it, folks. Anybody who wants to be next? Somebody, somebody to break the ice. Thanks, Jay.

MR. McKEEMAN: Well, I can't pass up this opportunity, since our segment of the market was prominently mentioned in the report, you know. I do want to say that we've had a very good working relationship --

PRESIDING MEMBER BOYD: Can you -- excuse me -- identify yourself and your association?

MR. McKEEMAN: I'm sorry. I am Jay McKeeman, with the California Independent Oil Marketers Association.

The report is, I think, an excellent

report. As has been commented upon earlier, it is, I think, the first time that a lot of different elements of the California market, especially the market, the recent California market, have bee pulled together in a very effective way. It gives us a significant confidence in the conclusions of the report, in the fact that it's based upon what we observe day to day in the market, and what we observe in the literature and the trade press, and in other reports that have come out about the California market. This kind of pulls all of those elements and bits and pieces together in a very effective manner, and describes the current condition of the California market.

It gets to the heart of the problems that are faced by the independent marketers, especially regarding the chaotic condition of the pricing in the California market, and the problems that independent marketers have in surviving those sudden and rapid price spikes. We don't have a lot of -- our members don't have a lot of capital to withstand extended periods of being behind the market in a significant way, both wholesale and retail. So the more frequent the spikes, the longer in duration the spikes, the harder it is for the independent marketer to remain in business in California.

And we think something needs to be done. There was a lot put on the table this morning, and certainly I'm going to have to take this back to my membership and go through it carefully. We, I think we, like many other participants in the fuel markets, are just basically intuitively disposed towards not having government get involved in any manner. And that's that, you know, there is a definite element of government intervention in this, but at the same time, the dilemma that we are facing is, number one, this is a market that was in many parts created by government, because of the unique fuel specifications. So government created the problem, in many ways, and maybe there is a reason for them to be involved in the solution.

But secondly, anything that can be done to moderate the spikiness of the market is going to be helpful to our members. The balancing act that we're going to have to try to go through is what do we give up to get a more desirable solution. And I don't have that answer today. I think in taking a look at what's been prepared today, and in the draft report, we'll be able to give you some more cogent remarks in the future.

But I would like to comment on a couple of things that the report talks about, but doesn't really get to the bottom line.

The first issue, and this was certainly brought up in the MTBE discussion a few weeks back, there's an infrastructure problem. There is an infrastructure problem. It's there, regardless of whether there's a reserve or regardless of any other things that are going on in the market, there is a problem with infrastructure.

We need to look at ways that we can get that infrastructure built. Even if government was involved in developing a super terminal, or super terminals, they'd still have the same problems that private individuals have, in many ways, in that they'd probably have to go through CEQA, they'd have to be building facilities in places of -- in proximity to low income neighborhoods, and all the things that the refiners have to face in terms of dealing with -- and the pipelines, and the terminals, that our members have to face in developing infrastructure.

So I would encourage a very strong look at how, not only, you know, the -- the tangible aspects of where the -- what tanks are needed and where they're located, how do we get them put into place quickly and effectively. And I think the fact that the Energy Commission was a leader in getting power plants sited quickly and effectively gives us at least a path to look at, in terms of getting infrastructure located quickly. And this is beyond just the Strategic Fuels Reserve. This goes deeper into just having the adequate infrastructure to deal with California's fuel future.

The second issue is supply. And in many ways, this is just moving the shells around on the table. It doesn't fundamentally affect supply, getting more supply into California, except that you hope that the import markets will be stronger players here. And there's a certain element of, you know, rationality to that. But at the same time, I guess I get to the infrastructure issue. We ought to be looking at ways that we can help increase the capacities of our California refineries in the state. And then, you know, what can we do to get that more rapidly implemented so that we build a stronger infrastructure here.

And this is all predicated on the presumption that California will need to have a different fuel standard than everybody else. I don't see really any difference in that, at least in the short term.

Finally, there's an irony here, and it was discussed by the consultants. And I refer back to the flames of fire, or flames of hell graph.

The profit motive of refiners is clearly defined in that graph. The refinery margins are really good when you have a spiky market, and a market that's -- that is not evenly supplied. So the conundrum is how do you get people that are going to benefit from those chaotic conditions to acquiesce that they're going to have to, you know, cut some of that margin to get into a smoother condition. That's more of a philosophical question than it is a pragmatic one. But it is, I think, really an issue that's going to be a difficult one to resolve.

And just from the observation of the independent marketer, it's certainly something that we think needs to be resolved, and we're here to try to think of creative ways to do it. But, you know, we're looking at entirely market driven incentives. There is that question mark that lays out there of how to get the refiners to basically agree that the refinery margins would be less if we had a more stable fuel supply.

That's it. Any questions?

PRESIDING MEMBER BOYD: Thank you, Jay. Stick around, let me make a couple of comments, then I'm going to ask our panel of consulting experts if they want to say anything.

Your three points, just my own personal comments, infrastructure, that, of course, is something that I think is well identified, and the idea that perhaps this Commission can assist in the permitting and the permit streamlining associated with infrastructure is something we've talked about, and it's certainly a very valid point and very relevant in this state. And your analog is quite good.

Supply. You said look to increase capacity of California refineries. I invite the audience to testify later on their willingness, their desire to increase the capacity of California refineries. I think I, for one, have been waiting for California refiners to say they really want to increase the capacity of their refineries, and help us do so. I would welcome such a request.

I think I mentioned at the last workshop such a challenge was put to this industry more than a year and a half ago, and no response ever received. So it's an interesting question that you bring up. But I call three of your points are on point and very interesting.

Your last one, I titled chaos. And basically, I didn't hear it as a question. I heard you make a -- I heard you identify an issue, or a problem we have to deal with, and I think you referred or alluded to the fact that perhaps some people like chaos. So yes, that is a hurdle that we need to deal with, and I think, as indicated earlier by one of the consultants, the fact that there's a broad overview being taken of this entire system, perhaps for the first time, will help shed light on some of these points. So I thank you.

Now, I throw it open to our panel of real experts. I'm just an amateur.

MR. HACKETT: First of all, Jay, thanks

for your comments. There is an awful lot of work that we've sort of laid on you in a hurry. You know, that report's 130 pages, there's a hundred slides, and the rest of that. And so it's going to take some time to digest.

And I guess all I want to say is that please touch base with us, with any questions that you have. If you need a meeting, a conference call, that sort of thing, and this goes for the rest of the stakeholders, as well. I mean, we've been having a continuing series of stakeholder meetings, and we want to continue to do that.

I know Doug Henderson addressed some concerns that the refiners have. Some of those have been worked out but not articulated. Others are still somewhat open questions. So we do see this as kind of a continuing process at this point.

MR. GIESKES: Jay, I'd like to add something, too. Maybe we didn't make it sufficiently clear, but certainly in the one recommendation that we had where we said there has to be a comprehensive approach towards infrastructure projects, the one stop shopping, the fast track, that was meant to include all sorts of infrastructure projects, including capacity increases. So that's not limited to the strategic reserve itself, those two projects, or three projects.

The -- I think I'll leave it at that.

MR. HAGGQUIST: I would like to say that we were searching around for analogs, I said, to California, other places, so we don't make up our own fuzzy stories. And in that spirit, we looked at other island economies, Hawaii, in gasoline, it's out there. You can look in there. People know about it, where there was no way in. And once the way in was established, it changed the market entirely.

The same thing in Australia. In Australia, it happened five years ago, or so. I was involved in that. And in Australia, there was no way in. And so it the Wickland people who built the shore terminal, actually opened the terminal there. Changed that market entirely. Changes that market entirely.

And Japan, an island, there was no way in until the terminals opened and access was allowed. And the UK was closed to only the refiners, until blenders on the Thames River got involved, and markets got involved. It became connected, each of these islands became connected to the global arbitrage of value.

And if you were to go back and look at these one by one, you would see that these markets did correct themself. You're never going to remove volatility, but you'll remove chaotic volatility. And because the, once again, the physical basis and the flow of the product and the flow of the value, it's the flow that's blocked. It's the flow that's blocked. If you open the flow, things will change.

MR. McKEEMAN: Thank you very much.

PRESIDING MEMBER BOYD: Thanks, Jay.

Next? Is there anyone else?

MR. KOEHLER: Neil Koehler, with Kinergy Resources, representing the ethanol interests. I was going to sort of sit in the back and let the old guys say what they had to say, but I guess they're not too responsive at this moment. So it's, I'm not here to argue the relative merits or demerits of a strategic petroleum reserve, because that's sort of beyond the scope of our industry. But I would take exception with -- or, not exception, but just point out that the disconnect that I have between the last workshop on the MTBE phase-out and the public comment and subsequent written comments, with the information in this report, that is the basis upon which to then recommend a strategic petroleum reserve; namely, specifically, on number nine in the -- on page 2, where the chronic shortage of gasoline in the California market will be aggravated to unprecedented levels by the proposed phase-out of MTBE by the year 2002.

And that was the subject of the workshop that we had on, I believe, the 19th. And since then, both in verbal testimony then and in written comments, there was a complete cross section of stakeholders that strongly disagreed with the conclusions of that report that comes to this same conclusion being restated.

Now, I know there has been some response to those comments, and that there is another report in the works which we've not yet seen, so I don't have the benefit of seeing how maybe those comments have been incorporated. But since it was so -- such a very strong and, you know, again, complete cross section of people that commented, saying that this is a conclusion that we do not think is supported by facts on the ground, and facts in the future, I'm just concerned that essentially we are restating the same conclusions from that report, or draft, and we don't have a final report, we don't have a Commission report on that, and that we're restating those same conclusions as the basis, one of the bases upon which to recommend a strategic reserve.

So it's just a disconnect for me, personally, and I just would like to know exactly how we are going to be addressing those comments and how then that will be a part of this current analysis. So that's my most important point that jumps out at me.

I would also like to add two other points. One is that the, you know, in the comments right now, there is very active debate and movement towards adoption of renewable fuels standard on the fuels side that would replace the oxygenate standard. That clearly has very significant implications to the supply/demand analysis in California. It's the elimination of the oxygenate requirement, and this is a bill that's supported by virtually all of the main stakeholders back in DC, and that it certainly meets the needs of California, as stated by the governor, in terms of flexibility, and it might also have a very significant bearing on some of these conclusions.

So given that that's not law, it may be hard to incorporate. But it's certainly a very relevant factor, because it looks like it has some major momentum.

Third, and I know this is part of other proceedings, but to the extent that we are trying to integrate this into a systems analysis, there in this report is no mention of the demand side considerations. And clearly, if we're going to be able to accommodate the, you know, the growth in population and be able to moderate what would be, and is projected to be in these various graphs, this unprecedented growth in demand for fuel, we have to deal with demand side to fuel economy -- meet economy standards, alternative fuels, conservation, et cetera.

And as there is some potential corollaries between what's going on in the fuel side and the electric side, I would point out, while nobody thought it would be possible, the one most significant thing that happened was conservation. That people, individually and collectively, responded to the request for conservation, and in a way that I think surprised everybody, came through, and I think saved, you know, kept the lights on in California due to the conservation efforts that were part of that.

So those are my comments, and I would, I'd like some guidance on how we are dealing with this, you know, this conclusion that I think is really unwarranted, that the MTBE phase-out at the end of the year is going to be causing this unprecedented shortfall, and just how that process is being incorporated, and the response to that report is being incorporated into this analysis.

Thank you.

PRESIDING MEMBER BOYD: Thank you, Mr. Koehler. Let me just state again kind of the position of the Energy Commission.

First, this is a workshop to hear the consultants' point of view on the subject today, so they're entitled to their point of view. As to integrating their point of view with other people's points of view, well, that's, I guess, the responsibility of the Commission overall, so you leave us with that charge and that is our responsibility, and that wasn't an item for today's forum.

MR. KOEHLER: I understand.

PRESIDING MEMBER BOYD: So you'll have to wait like the rest of us on that point. But I want to relieve the consultants of that piece of the responsibility, and they can state their own opinion on the subject if it's not changed since the last time.

Congressional debate, that was your second point. I would agree with you that that's very relevant, and based on a lot of years in government I'll say I'll believe it when I see it.

(Laughter.)

PRESIDING MEMBER BOYD: So we'll wait and see when they finally decide something.

And lastly, your reference to one of my favorite things, systems analysis. The point, you know, I'm with you all the way on demand side aspects of these kinds of issues. We talked about it at the last workshop. We haven't talked about it much yet today. I would agree with you that demand side conservation is very important. Yes, it saved our bacon in the electricity business, and the American public, and the California public like them, are very good at responding to declarations of emergencies.

And while some of us may feel in this room, or who are related with the subject, that we're flirting with an emergency, perhaps, until that emergency is declared it's a little hard to motivate the public to reduce their BMT, et cetera, et cetera. I spent 20 years of my life in a different forum trying to do -- use social engineering to reduce air pollution, and I've never abandoned the idea, but after getting sanctioned by the federal government two or three times for not getting the air clean, it kind of drove one into engineering solutions to the problems.

So that is a very valid point. It's something this organization will continue to consider and ask for. The effectiveness is a product of a lot of things, including, you know, the willingness of the public to receive the message and to respond to the message, and perceive that it's in their own self interest to deal with the message. And so either a lack of something or the price of something tends to really motivate people.

And, while you and I may feel we're on the threshold of an emergency, we don't declare emergencies until they're really emergencies. So, anyway, good points. Thank you.

And now, David, you're --

MR. HACKETT: Neil, thank you for your points. I'd say on the first one, about the disconnect, yes, we got considerable stakeholder input on the MTBE phase-out recommendation, from a wide range of groups, and we've taken all that in, and our opinion remains that MTBE phase-out this year would be a problem. That's been communicated to the Energy Commission, and they're working on their timetable for the Staff report.

The second is, you know, whatever Congress do, I'm not qualified to judge, I don't know about that. On the consideration of the demand side, the demand forecast that we've used is essentially the one that the Energy Commission developed. And so I'll throw that hot potato back in their lap. It's essentially their number.

MR. KOEHLER: Right. I understand that. Thank you very much.

PRESIDING MEMBER BOYD: Anybody else? I can't believe this. I think I made a strategic mistake at the beginning of this meeting by advising the fact that there'd be another chance for public presentations, we'd have another workshop. I should have let everybody just stew on the idea this is it, so you better speak today, because I think, like so many of us on our income tax, you know, you're going to wait until April 15th, or the equivalent thereof.

Certainly there must be some point of view out there. Some comment, some -- well. Anybody have any good jokes?

(Laughter.)

MR. HACKETT: Let me interject that we focused an awful lot on the -- on the supply side of this, how to improve supply. And we feel very confident about how it got to the point of our recommendations around infrastructure and the like.

And then, as well, I mean, you know, I started my career in the Navy, and when I got an order I said aye, aye, sir, and I did it. And when the legislature or the Energy Commission said figure out how to make a strategic fuel reserve work, well, I think we did it. But what we've not told you yet, what we haven't gone through thoroughly, is just exactly how this Gasoline Bank of California is going to work. And so there's guys sitting out here who trade every day, and I can two or three of my friends who are in this category, who wonder now, just exactly what does that mean. Okay.

We have not laid out all those rules and given you all that criteria, and sort of shaped it all. And that's -- we're going to be giving that more definition between now and the next workshop. And we may very well be asking some of you sitting out there to come and give us your opinion and some help with this thing, on an offline sort of basis. I mean, I'm at this point pretty confident that what we are considering, but haven't told you about in great detail yet, is something that's workable.

So, I know that some of you are out saying, you know, what the heck is this thing, and how is it going to work. And we've got some more work to do on that. I admit it. And we're going to be asking for some help.

MR. HAGGQUIST: I'd just like to add a little to that, because it seemed to me that we spent a lot of time leading up to setting the scene for why we believe that some kind of strategic reserve is needed. That scene setting took a lot of time out our time budget, and it's going to take time for you to absorb it and buy into it, or not buy into it. We believe that everything that we've presented to you is factual, as far as infrastructure and barriers to supply. That brings us to the doorstep of the question of the strategic reserve and how it will be operated.

So we really are at the doorstep. And it seemed to me, I don't know how the procedure's going to work, Commissioner, but the next meeting with stakeholders ought to be some sort of shirt-sleeve environment in which we picture this thing. We say here it is, let's start putting oil through it, and let's start tearing it apart and building it up. And if there's no participation, then speak now or forever hold your peace, so to speak.

MR. HACKETT: Of course, now, our fundamental assumption on all this is that you agree with us that there are infrastructure issues. These infrastructure issues have got to get solved before you start doing some -- taking the next step and working on the strategic reserve.

So if you disagree that there are, in fact, there are not infrastructure issues, I want you to come up here and tell us that.

Note the stampede to the mic.

PRESIDING MEMBER BOYD: Yeah, I noticed that.

(Laughter.)

PRESIDING MEMBER BOYD: To fill the quiet just for a moment or two, let me go back to a couple of points that just crossed through my mind.

One, the discussion with Neil Koehler about demand and demand side, and his correct reference to the fact that looking at the whole system, we said that in the last workshop, we've get so many activities going on here concurrently that relate to this overall topic, and the -- I recall that, and I've been reminded that the demand side discussions have been reasonably extensive within the context of the dependence component of the study, AB -- the rest of AB 2076. And there's yet another workshop on that subject in --

MS. BAKKER: I believe it's the 28th.

March 28th.

PRESIDING MEMBER BOYD: March 28th. It escapes me, there are so many of late.

Anyway, there are multiple forums for that discussion to take place, and we are trying to see that this is an integrated view of the world. And I've lost my second point, so, in any event.

Oh, no, I haven't totally lost it. It was Jay's comment about government intervention, which I was reminded of by the discussion of creating a market and assumptions that maybe there's -- that there is an infrastructure issue out there that'll help perhaps create a market.

I'm certainly one who is very reluctant to want government to step in and fool around with things, unless it's for the greater good. Jay seemed to agree with that; however, pointed out that it was government that may have steered us in the direction and helped create the problem. So I appreciate his acknowledgement of the fact that maybe there is a role for government here.

As one who's invested too much of my recent life in the consequences of the electricity market experiment, and government's doing the best it could, in my opinion, to step in and keep the lights on when they were probably going to go out within the next 72 hours of a certain date early last year, for better or for worse, yeah, we need to very cautiously approach creating markets and making sure that the vehicle is designed with the wheels on securely, and that adequate safeguards, and that too many people don't get at it, and the committee process ends up, you know, with a camel when they're trying to get a horse.

But by the same token, there's a lot of economics out there that does say that these gentlemen have a good point with regard to what it might -- what it might take to mitigate to some degree, not to a point of, you know, maybe indecent profits, to mitigate to some degree the adverse effects of what's happening out there now, based on actions that California State government has. The nation State of California has an economy it cares a lot about, and has to make sure it functions without getting too deeply involved.

In any event, some free-flowing observations.

Somebody was going to say something, or were they. Ah.

MR. MOYER: I'm Craig Moyer, I'm with Manatt, Phelps and Phillips. I represent the Western Independent Refiners Association.

I'm just a dumb lawyer trying to figure all this out, but I have just a couple of thoughts.

PRESIDING MEMBER BOYD: Come on, Craig, you've been around a long time.

(Laughter.)

PRESIDING MEMBER BOYD: Like me. You and I have been looking at each other like this for a lot of years.

MR. MOYER: And I guess a couple of observations on the logistical side. I don't want to lose sight of the fact that refineries are attempting to, and I have worked with refineries who are increasing their capacity. Certainly it comes across that they're increasing the amount of gasoline, they're drawing from a barrel of crude, but refineries are also increasing their crude throughput marginally, as well, and I think that that's an important point, one not to be lost in this whole system. Because clearly, domestic refining capacity is still cheaper than importing this product.

Then I guess, if I can -- tell me if this is a wrong sound bite. But essentially, the idea is that this strategic petroleum reserve would reduce spikiness -- which is a new word that I just learned today -- through increased liquidity in the form of increased storage capacity. And I think if that's the actual premise -- I'm not sure if I am the right person to answer that question -- but I think that if that is the premise, then we really do -- I'm not, we certainly haven't seen that every time in the past. To have more capacity may just mean you have lower prices for terminaling product, or crude, or whatever, terminaling materials around.

And let me get into sort of the detailed questions. And we'll need a lot of talk about this, but I want to make sure again, if I just start with a premise here. We're talking about summer gasoline that'll be in this Strategic Fuel Reserve. And if -- I think it was page 23, or maybe 38, it's clear that there are also spikes in the wintertime. I shouldn't say that. There are refinery disruptions that occur in the wintertime. They're not limited there. So I don't know whether the assumption is that well, we just won't use the Strategic Fuel Reserve in the winter, or you just think other things will take care of that. So I was wondering what the thinking was on just having summer CARBOB.

And then I suppose the other point is, how did we decide that a five million barrel reserve was the right number, when I think you guys are showing that, Tony's fine work statistically at least suggests that a very much smaller reserve would do the -- and therefore, much less government involvement, because, as a Libertarian, I want to see as least government as we possibly can here.

(Laughter.)

MR. MOYER: One of the reasons that my membership is so much smaller than it was a few years ago is because they were unable -- many of the small refiners were unable to make the changes necessary to make reformulated gasoline. And even if they are still producing, refining crude oil, they are generally now making it into asphalt and other products. Only one small refiner continues in gasoline production.

So those are my Gestalt observations.

(Laughter.)

PRESIDING MEMBER BOYD: Very good. Appreciate that. Let me turn it right over to David and his group.

MR. HACKETT: Hey, Craig, thanks for those questions.

Yeah, we did sort of wonder if we bid out for an increased terminaling it might hurt the margins on people that are already in the terminaling business. And so I'm sort of waiting for them to step up and say whether or not they want to bid for the opportunity to run one of these things and build more capacity, or if they think that this is going to hurt their margins. We're looking, you know, looking for their opinion on that.

Sort of the second thing is the summer gasoline. Here's the issue, and that is that -- there's a number of things. One is what we said was we put summer gasoline in this. Some of this, too, is sort of our southern California view on these things, where summer in southern California, if you're a gasoline blender, is eight and a half months. So that's most of the year, okay.

If you look at the data, the spikes are almost -- the problems are almost always during summer grade gasoline. There are some issues that happen in the November/December --

MR. MOYER: The price spikes, you mean?

MR. HACKETT: Price spikes, yes. The unplanned supply outages where there seems to be a shortfall in supply, and therefore a big run up in price, regardless what happens to crude oil, is generally a summertime blending season phenomenon.

So there's not a lot of demand for the winter -- won't be a lot of demand for the winter stuff, to start with. Then you, if you do bring in winter stuff and then you have to transition it in the spring, and so you would be faced in that case with having to dump the winter season gasoline right at the end of the season, and then refill with summer gasoline.

And so that clearly has a negative impact on the market. I mean, that's intuitive. But also, you can observe that in places like Germany, where in Germany, when the inventory goes bad it starts to grow bugs, as Gregg describes it. Well, they dump it in the market, which drives the market down, and then they come back and refill and that drives everything up, and, frankly, nobody's going to put up with that.

So if you -- and then there's another issue of shelf life of gasoline. We've asked industry for their opinion on that. We guess that because CARBOB is going to be highly refined, low sulfur and the like, it's likely to be fairly stable, and therefore have a good shelf life. But we don't know that, so we've asked for an opinion from the experts on that.

So what we see -- and then, finally, to address, you know, what if we do have a problem in the wintertime, it's likely that the refiners can deal with that. They can take the -- pump from the strategic reserve over to the refinery, the refiner will fix it up so it's winter grade, and then it can go from there. And so there may be some costs associated with that, but likely they're lower than this total issue of dumping it at the end of winter and refiling with summer grade.

Is that enough detail?

MS. BAKKER: I have one question that he brought up, that I had wondered about before, and I got an answer about. And that was, why don't you just increase throughput? What is it about the fact that you take out more MTBE, and therefore you have lower production. And the answer I got was Title 5, the Clean Air Act amendments. And so could you explain that, please?

MR. GIESKES: Yeah. That, Susan, was indeed the feedback that we got from several refiners during the stakeholder meetings. And that deals more, I think, with small capacity increases, the capacity creep, than with major refinery expenses. And I think what was invited by Commissioner Boyd and what's being discussed here, is, I think, why don't we see more major refinery projects. Why, if you look at all the refinery projects that are on the books in the United States, there's actually an encouraging lot of refinery projects that mainly deal with sulfur removal upgrades and quality and capacity in the refining industry in general.

But I think a major refinery project in California, if -- just imagine this, and I don't want to be flip here, but you'll have to justify a major amount of capital. And during that, looking forward, you'd have to do price projections. The spikiness in the curve price projection. If anybody walks into, say, the board of a major oil company and shows a forward projection at premiums that we currently see, you would probably be laughed out of the room.

So even though those current spikes have tremendous profitability for the refiners, they provide very scant justification for a refinery project. And I think actually, the -- if we bring market stability to California with the reserve -- and I want to make some additional comments on the reserve -- it might actually further the investment climate, because these use fluctuations, if you had been standing up there in a board room defending a refinery project for, say, maybe a couple of hundred million dollars of expense and capacity, and you go through your usual winter bit, it would have been a difficult case to sell.

So stability is actually, I think, good for investment. And the scenario that I can imagine is that we build the storage. The storage is very, very much needed in California. We operate on such small inventory capacity that it's amazing that the system works as well as it does overall.

So we build the storage. And the

industry, I mean, may not like it, but say we put an inventory in there, you create some forward market liquidity. The market stabilizes, and now all of a sudden you see that behind the imports, people will start backfilling. But what you will have created is a fairly stable California market where the incremental barrel is a fairly expensive import barrel coming from a pretty remote location, and exotic quality. That will create an investment climate that is very, very attractive.

And here is a final comment to capacity versus storage to mitigate price range. And I don't want to sound flip here, but if I were a refiner, I wouldn't want to build too much capacity. If you want to create market stability through additional capacity where you could actually compensate for a refiner going out of service for awhile, you have to have a significant amount of capacity. That capacity is not going to sit idle during the rest of the year. So what you then see is, typically, your commodity business cycle of boom to bust. And those cycles move in Biblical terms, it's about seven years of famine and then one year of profit, and then seven years of famine. I came out of a business where that was the mode.

And so if I were a refiner, I would actually welcome the addition of storage capacity, and some market stability at a fairly high level behind which I could add capacity in a regular way, without overbuilding the market. And that is, I think, a very likely scenario.

Once you get to that stage, and say now we are maybe five years out, and the reserve has been in operation for a couple of years, it's a very small -- it's two days of supply. I mean, it's not really a major quantity. And you get sufficient liquidity, you get sufficient imports, you get a market that becomes so predictable that you can actually hedge California gasoline to New York futures, and there is a pipeline connection that will also, once you get a link, pipeline link between east and west, it will also help as an arbitrating mechanism. You can pretty well imagine that the state says well, we don't need to incur these expenses of the reserve anymore. Let's abandon it.

But from the perspective of the state, I think this reserve is a very low risk type of investment, $20, $30 million a year for a couple of years, bring stability to the market. This deal is not a waste. It's much needed. The inventory is peanuts, and that money is not lost. It's just sitting there, and you could, if you withdraw regularly, get out of it without upsetting the market.

I think it's actually much more beneficial to the industry than the industry cares to realize.

MR. MOYER: A couple of years, Commissioner Boyd. What do you think, a bureaucracy that survives for a couple of years?

(Laughter.)

MR. HAGGQUIST: I know you've been out there a long time, but I just want to address the specific questions you raised, which -- and, you know, a poor lawyer with good common sense question, that's what we really need.

The question of whether increased storage is going to increase liquidity, that was what you asked. Right?

MR. MOYER: That's the premise.

MR. HAGGQUIST: That's the premise, and that's correct. And this is -- to answer that, once again I go to examples. And as an example of being an old guy. Having been there when the NYMEX was invented for heating oil into New York Harbor. I was one of those heating oil traders for BP, North American trading, and east of the Rocky Mountains. The way things were done then, there was no futures market. It was something like things are today, non-transparent market. And these guys came around with this crazy idea of setting up a futures market. And this was in the early eighties -- early eighties, right.

And, you know, who knows what a futures market is when you're, you know, at certain points. But the initial reaction, particularly from the refining and marketing sector established, entrenched interests, was this will never work, and this is kind of crazy. And that might work for grain or cocoa beans, but certainly not this precious commodity of heating oil, you know.

But lo and -- and what was the question that they asked most, that came to see me and other traders in the room. The first question that NYMEX didn't -- the inventors had to answer was, where is the terminal. Where's the delivery point, show me the delivery point. Once they identified those terminals, the North Hill terminal in New York Harbor, other terminals, these are the delivery points. Here's where it happens. Here's where title and risk changes hands. That's what we do not have in California.

Now, same thing in Singapore. There was -- being an all night trader, we'd send cargoes out to Singapore. It was like going into the Bermuda Triangle. You don't know what the price is going to be when you get there, you really took your chances and held on for dear life. It's kind of of like you do over here with gasoline coming into California. And they had the added cultural bias of not really trusting these future mechanisms in Singapore. But once again, the question was where can this happen. And once terminals came into Singapore, expanded terminal space, Singapore has become the most robust trading hub in the world, because of terminals' liquidity.

This has been good for the economy of Singapore. The NYMEX is good for the economy of New York and for the nation. And, yeah, arguably, I won't say it'll be of that magnitude, but once the games start in the private sector, and we -- we provide the jumper cables, you don't know where it's going to go, but it should be good.

Finally, one more thing from history, from real experience. I was also, besides being with Noah on the Ark, I was -- I told you up here in this talk, but you have to build consortium. I was a major company, I was Texaco in those days, during the oil shortage. These international -- I remember, it was Braniff Airline and Pan American and United Airline, they would come knocking on your door. I've got a cargo of jet fuel in Singapore, let me bring it in. Let me bring it in. We're dying, you've got to supply us jet. We couldn't do it, you know, because we had to sell that jet based on our refinery's production in Seattle, or in San Francisco or in Hawaii, or in Alaska. And we didn't want this alien jet fuel from beautiful downtown Singapore or Korea, you know. We didn't want this stuff.

So, we wouldn't take it in. And they had bought it much cheaper, brought it there basically on the arbitrage I showed you. So the airlines got together, came in, got their own tanks, and said, by golly, we're going to be in this market, we need tanks. We're going to do it. And that's what happened. So now there is a balance in the jet fuel market that we showed you on the slide.

So these are concrete specific examples of history and real locations. We think these can happen here in California.

MR. MOYER: All of those are private sector, I note. They're --

MR. HAGGQUIST: There's reasons for that. We won't go into that here, but maybe next time.

MR. MOYER: I can't help but --

MR. HACKETT: Gregg, I'm going to torture you just for one more second. You asked about why did Stillwater say five million and Dr. Finizza say one. A couple of reasons. One is that it's only been in the last few days that the two studies have intersected, and that we've seen the results of Dr. Finizza's analysis. So that's one answer.

The second one is that the legislature said two weeks of production, and that's 2.3 million barrels. And we said look, there's got to be more tanks than just the stuff that we build for the Strategic Fuel Reserve, so that's how we got five million on our numbers.

And there'll be some reconciliation back and forth on that, as we go forward, ahead of the next workshop.

MR. SCHREMP: And Dave, I just might add that that portion of Tony's analysis, that slide that was in there, was average. Now, if he had also inserted the 1999 base case that was shown, then this would be much more than the one million barrels. I just want to point that out. And that's part of the process of just how you --

MR. MOYER: That was the 1.3 million number; right?

MR. GIESKES: Well, yeah. I'd like to play in on this, because this, indeed, we -- Tony's and our numbers got together the last couple of days, one of those rare instances where the back of the envelope practical approach and the theoretical approach actually match up.

The 1.3 number is for a particular price disruption of a certain magnitude. But if you look at, like we said, we have to split this reserve in two parts, north and south, because the logistics in California, if you say you do a single reserve somewhere, you don't have sufficient trucks and barges to compensate for a shortfall in the other refining center, if your reserve happens to be in the wrong place.

We also looked at a central reserve somewhere, a linking of the pipeline systems is also more costly option, and not practically feasible. So you have to divide, you know, to conquer here. And the thing that you do then, is if you have, say, a one million barrel reserve in the north and a slightly larger one in the south, and you have just sufficient volumes.

Also, because we applied this reserve as a mechanism to set up forward liquidity, a lot of your barrels are actually going to -- you're going to be out of pocket. You will have 50 percent that's actually sitting in the tank, and another 50 percent are sitting on the water, coming towards LA or the Bay.

And if you had a really serious disruption, and this is not something we had in our mandate, but we looked at it briefly, like a local earthquake or that sort of thing, knocking refining capacity out for a prolonged period, or some other security issues, it really is -- comes in quite handy to have a few more barrels on hand than the bare minimum. Because in actual fact, we seriously looked at it. We said from a lot of these spurious price increases that -- where the market moves 18 cents on the rumor, all we need is 50,000 barrels. You don't need that big of a reserve. So we looked at the smaller numbers, as well. But we think that actually the legislature had the right of a general order of magnitude number in the bill.

MR. MOYER: One of the slides that you showed said that yes, we do have a California, separate California market, but it doesn't look like there's a big split between northern and southern California now. And then certainly, we know that if at ten cents a gallon, you're going to see, you know, guys in their trucks driving north and south. So the idea of needing 100 percent north and 100 percent south is a non-question.

MR. GIESKES: I -- no, we just looked at the -- how many barrel miles of transportation would be out there in case of a major refinery disruption and you had your reserve in the wrong location. And you would have to double the trucking capacity. And you would have to double the amount of barges that are currently in circulation. There's not that much capacity in the transportation system to compensate for that. So we did look at that.

MR. FINIZZA: We do need to get our act together on that one. I kind of think that perhaps we have to decide whether we really need to protect against the '99 type year. That's the hundred year flood, and perhaps we don't. Perhaps a smaller amount is all you need.

MR. MOYER: Well, that was fun. Thank you.

PRESIDING MEMBER BOYD: Thank you, Craig. You provided interesting fodder.

Is there anyone else who has any questions or comments?

MR. HEINE: I'm Bruce Heine, with Williams.

A technical comment for Dave on slide 54, as it relates to the de minimus MTBE concentration, and the translation that that would create additional challenges of infrastructure and storage.

My question is really related to last week's workshop at the Air Resources Board, where that issue was addressed. And the ARB has decided to propose an amendment in the existing regulation regarding the de minimus MTBE levels, and there are a number of folks in this room that participated in that process. But it appeared, and it was fairly clear that those changes were made to try to minimize the possibility of rejecting any incoming cargoes of gasoline that would contain those trace levels of MTBE.

So my question is, is your slide before that workshop was made, or did you take into consideration what the Air Resources Board had done just last week?

MR. HACKETT: No, I think that the Air Board was having a workshop while we were doing the stakeholder meeting. And so we weren't able to attend that, and we don't have the latest update. So, and you're right, there are several -- a number of people here that'll bring some spiel in. Thanks for pointing it out.

MR. HEINE: Okay. That's my only question. Thank you very much.

PRESIDING MEMBER BOYD: Thank you.

MR. WHITE: Commissioner Boyd, Board Members, Panel Members, Jim White, with White Environmental Associates.

I'm glad that Bruce brought that up. I really should have planned on giving a comment on that. As some of those of you attended that workshop know, last week I got up and gave some comments on the de minimus level. I think the Board should know, the California Energy Commission should know that the basis for that very, very low level, de minimus level, which they're shooting at .05, is artificially low. It's low because of political reasons. There's no technical reason behind it, there's no environmental protection reason behind it.

And I think someone in the administration needs to take a close look at that, because it is, as Dave has pointed out, it is a further restriction to people trying to bring products, blending components and so forth, here to California. And it's a serious, serious matter, in my opinion.

Thank you very much.

PRESIDING MEMBER BOYD: Thank you.

MR. HAGGQUIST: I think you're very right about that. It's -- it is not inconsequential. It's just about immeasurable, technically.

MR. WHITE: Absolutely.
MR. HAGGQUIST: And --
MR. WHITE: As a matter of fact, today it is.
MR. HAGGQUIST: Yeah, we --
MR. WHITE: They don't have a way to measure it at that level.
MR. HAGGQUIST: So, talking about barriers to supply in California, the de minimus ought to be in there as a barrier to supply.
PRESIDING MEMBER BOYD: Anyone else? Craig, you're -- you look like you were ready to rise up out of your chair.
MR. MOYER: I am, to leave.
(Laughter.)
PRESIDING MEMBER BOYD: Oh, okay.
Well, with that segue, let me thank everyone for being here today. Let me particularly thank our consultants from Stillwater, Dave Hackett, Gregg Haggquist, and Tom Gieskes, and our independent consultants, Drew Laughlin and Tony -- didn't say that right? Finizza, I can say that right. Gee, and I knew my Italian so well.
And the Staff and everyone else, and

look forward to your written comments, your in depth analytical view of the work that we've been presented, and shortly will be announcing -- we can't do it today, unfortunately, because we can't get calendars straightened out, but we'll be announcing the time for the next workshop, Committee meeting, whatever context we do it in to meet legal requirements. It'll still be a roll up your sleeve, loosen your tie, as informal as we can get it, workshop discussion of people's points of view, so we can move on with this.

So thank you all, and look forward to our next meeting.

(Thereupon, the Committee Workshop was concluded at 2:43 p.m.)

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said Workshop, nor in any way interested in the outcome of said Workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 22nd day of March, 2002.

PETER PETTY

CALIFORNIA
ENERGY
COMMISSION

CALIFORNIA STRATEGIC FUELS RESERVE

REVISED CONTRACTOR REPORT

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JULY 2002
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Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

Prepared By:
Stillwater Associates, Inc.
3 Rainstar
Irvine, CA 92614
Contract No. 500-00-002

Prepared For:
Sherry Stoner
Contract Manager

Gordon Schremp
Project Manager

Pat Perez
Manager
Transportation Fuel Supply & Demand Office

Nancy Deller
Deputy Director
Transportation Energy Division

Steve Larson,
Executive Director

CALIFORNIA STRATEGIC FUELS RESERVE

Study Conducted By

Stillwater Associates

For

The California Energy Commission

Pursuant to California State Assembly Bill AB 2076

July 3, 2002

Gregg Haggquist David J. Hackett Thomas E. Gieskes

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ACKNOWLEDGEMENTS

This report is the result of a cooperative effort between key staff personnel of the California Energy Commission and Stillwater Associates acting as their contractor. In particular, the authors would like to thank Messrs. Gordon Schremp and Ramesh Ganeriwal of the California Energy Commission for their invaluable contributions and insights, without which this study would not have been possible.

Valuable contributions to this report were also made by Anthony J. Finizza, Ph.D., who contributed his insights on the market dynamics and price elasticity, as well as the economic impact of market shortages on the California economy, and by J. Drew Laughlin, who provided the US Gulf Coast supply perspective with regard to California's supply/demand balance for transportation fuels.

Equally, this study is based in large part on information received during meetings with industry stakeholders, such as the California refiners, representatives of the international trading community, independent marketers, trade associations, government organizations such as the State Lands Commission and Port Authorities. The authors wish to thank all those who readily volunteered information and opinions, for their contributions and the openness with which information was shared.

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GLOSSARY

AG	Arabian Gulf, aka Persian Gulf
ANS	Alaska North Slope, term used to designate crude oil of that region
API	American Petroleum Institute
ARB	Air Resources Board
Bbl	Barrel
BOE	Board of Equalization, the California agency that collects taxes, including fuel taxes
BPD	Barrels per Day
CAA	Clean Air Act of 1977
CAAA	Clean Air Act Amendments of 1990
CAAA Title V	Section of the CAAA requiring Operating Permits, promulgated in 1992
CARB	California Air Resources Board
CARBOB	California Reformulated Gasoline Base Oxygenated Blendstock
CEC	California Energy Commission
CIOMA	California Independent Oil Marketers Association
CMAI	Chemical Markets Associates, Inc.
cpg	Cents per Gallon
CSLC	California State Lands Commission
DOE	US Department of Energy
DOER	Massachusetts Division of Energy Resources
DTW	Dealer Tank Wagon
DWT	Deadweight Ton
EIA	Energy Information Agency
EIR	Environmental Impact Report
EPCA	Energy Policy and Conservation Act of 1976 as amended
EOR	East of the Rockies
EPA	US Environmental Protection Agency
ETBE	Ethyl Tertiary Butyl Ether, an oxygenate produced from ethanol and isobutylene
EU	European Union
FCC	Fluidic Catalytic Cracker, primary gasoline producing unit in a refinery
FOB	Free on Board
FPPR	Federal Petroleum Product Reserve
FTC	US Federal Trade Commission
HO	Heating Oil
HVR	High Volume Retailer

ICE	Intercontinental Exchange
IEA	International Energy Agency
ILTA	Independent Liquid Terminals Association
IPE	International Petroleum Exchange
Jobber	Independent distributor of petroleum products
KM	Kinder Morgan
LP	Linear Program
MB	Thousand barrels
MLP	Master Limited Partnership
MM	Million
MOTERP	Marine Oil Terminal Engineering Regulations Project of the CSLC
MTBE	Methyl Tertiary Butyl Ether
NHOR	Northeast Heating Oil Reserve
NGO	Non Governmental Organization
NYH	New York Harbor
NYMEX	New York Mercantile Exchange
OPA 90	Oil spill Prevention Act of 1990
OPEC	Organization of Petroleum Exporting Countries
OPIS	Oil Price Information Service
p.a.	Per annum
PADD	Petroleum Administration for Defense District PADD V includes Hawaii, Alaska, Washington, Oregon, California, Arizona and Nevada
Platt's	An international energy pricing service
PoLA	Port of Los Angeles
PoLB	Port of Long Beach
RFG	Reformulated Gasoline meeting the requirements of the CAAA
RPPR	Regional Petroleum Product Reserve
RPR	Regional Petroleum Reserve
RVP	Reid Vapor Pressure, a measurement of the volatility of gasoline
SARA	Superfund Amendments and Reauthorization Act of 1986
SCAQMD	South Coast Air Quality Management District
SFR	Strategic Fuels Reserve
SPR	Strategic Petroleum Reserve
T50	Temperature at which 50% of components will evaporate from a gasoline
TAME	Tertiary Amyl Methyl Ether, a type of oxygenate
TBD	Thousand Barrels per Day
TEU	Twenty-foot Equivalent Unit, standard used for cargo containers

TPY	Ton Per Year, usually referring to US short tons of 2000 lbs
TVA	Temporary Voluntary Allowance
UDS	Ultramar Diamond Shamrock
USGC	US Gulf Coast
VDU	Vapor Destruction Unit
VGO	Vacuum gas oil
VLCC	Very Large Crude Carrier, a tanker capable of carrying 1.5 – 2 million barrels
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compound(s), and emissions thereof
WSPA	Western States Petroleum Association
WTI	West Texas Intermediate

CHARTER

In 1999, following a series of refinery outages that caused significant price spikes in the California fuels markets, the Attorney General's office created a taskforce to investigate causes and recommend solutions to prevent recurrence. The efforts of this taskforce resulted in Assembly Bill 2076, which called for the California Energy Commission:

> "..to examine the feasibility of operating a strategic fuel reserve and to examine and recommend an appropriate level of reserves. If the commission finds that it would be feasible to operate such a reserve, the bill would require the commission to report this finding to the Legislature and request specific statutory authority and funding for establishment of a reserve."

The bill also provided general directions for the work to be performed

> (a) By January 31, 2002, the commission shall examine the feasibility, including possible costs and benefits to consumers and impacts on fuel prices for the general public, of operating a strategic fuel reserve to insulate California consumers and businesses from substantial short-term price increases arising from refinery outages and other similar supply interruptions. In evaluating the potential operation of a strategic fuel reserve, the commission shall consult with other state agencies, including, but not limited to, the State Air Resources Board.
>
> (b) The commission shall examine and recommend an appropriate level of reserves of fuel, but in no event may the reserve be less than the amount of refined fuel that the commission estimates could be produced by the largest California refiner over a two week period. In making this examination and recommendation, the commission shall take into account all of the following:
>
> (1) Inventories of California-quality fuels or fuel components reasonably available to the California market.
>
> (2) Current and historic levels of inventory of fuels.
>
> (3) The availability and cost of storage of fuels.
>
> (4) The potential for future supply interruptions, price spikes, and the costs thereof to California consumers and businesses.
>
> (c) The commission shall evaluate a mechanism to release fuel from the reserve that permits any customer to contract at any time for the delivery of fuel from the reserve in exchange for an equal amount of fuel that meets California specifications and is produced from a source outside of California that the customer agrees to deliver back to the reserve within a time period to be established by the commission, but not longer than six weeks.
>
> (d) The commission shall evaluate reserve storage space from existing facilities.
>
> (e) The commission shall evaluate a reserve operated by an independent operator that specializes in purchasing and storing fuel, and is selected through competitive bidding.

This Study was performed within the specific framework of the Legislation, to answer as a minimum the questions asked, by the stated deadline. In addition, in cooperation with the consultant retained by the Commission for this study, Stillwater Associates of Irvine, CA, the Commission deemed it appropriate to evaluate other factors that contribute significantly to the volatility of California's fuel markets, such as breakdowns in market mechanisms for gasoline, and the inadequacy of the logistics infrastructure serving the fuels market.

APPROACH

The approach taken by Stillwater and the CEC for this study is to:

(i) Conduct a survey amongst industry stakeholders, such as refiners, traders, logistic survey providers, and other concerned parties such as industry associations representing independent gasoline marketers, port authorities, and market intelligence providers. The purpose of the survey was not only to gather relevant information and data such as supply and demand factors, but also to gain a full understanding of market mechanisms and barriers to entry that contribute to the price spikes that a reserve aims to prevent.

(ii) Using the requirement of AB2076 for two week's capacity of the largest refinery as the basis, evaluate requirements for the reserve other than size, and with these, derive such factors as optimal location, infrastructure needs, and costs for several options meeting the initial requirements. Since the study did not include funding of actual engineering work, costs are treated at order of magnitude levels only.

(iii) Evaluate the effectiveness of the selected options for the reserve in terms of their anticipated capacity to mitigate price spikes in the California fuel markets due to unplanned refinery outages, using historical statistical data to predict the probability and duration of occasions when reserve volume would be drawn down. If warranted by the predicted effectiveness, adjust the design reserve volumes from the suggested two week's capacity basis and reiterate.

(iv) Using insights gathered during the survey meetings, design release mechanisms for the reserve volumes, also taking into account experience gathered with strategic reserves operated elsewhere.

(v) Develop derivative opportunities such as using a reserve to create forward liquidity in the California fuel markets.

(vi) Evaluate next steps and implementation plans, and identify potential barriers to implementation, such as delays in permitting processes.

(vii) Collect feedback from the industry in an open forum workshop, and adjust where necessary the recommended alternatives.

(viii) Present the final conclusions and recommendations to the legislature.

Initially, it was assumed that this study would be based on a supply/demand scenario for which the issue of the impending phase out of MTBE in terms of timing and impact would have been resolved. When it became clear that additional efforts would be required to provide decision tools for this critical issue, the CEC charged Stillwater Associates to conduct a parallel study specifically focused on the MTBE phase out.

Where necessary for the sake of clarity and consistency, the reports issued by Stillwater Associates for this Strategic Fuels Reserve Study and the MTBE Phase Out Study make extensive use of the same materials.

Throughout the work done for this Study, Stillwater Associates has closely collaborated with Dr Tiny Finizza, who in a parallel effort, developed a rigorous statistical analysis of refinery disruptions and price volatility in the California gasoline market, in order to quantify the potential benefits of a Strategic Fuels Reserve.

EXECUTIVE SUMMARY

Stakeholder Survey

The initial phase of the study consisted of interviews and survey meetings with a total of 44 oil industry participants, including major refiners, suppliers from outside the State, traders, independent retailers, logistic service providers and other stakeholders. The primary conclusions from these meetings are that:

(i) Overall, the industry opposes the concept of a state-run reserve and fears that the existence of a reserve may be counterproductive to resolving long-term supply/demand imbalances.

(ii) If a reserve is to be created, the industry strongly prefers that it will not use already scarce existing storage, is privately operated, has clear and fair release mechanisms, and is deployed in such a way as to improve import opportunities and market liquidity.

(iii) The California gasoline market suffers from insularity caused by its unique specifications, a subsequent lack of liquidity, inability to lock in pricing for forward trades, and impediments to market entry by outside sources. These factors contribute significantly to price volatility, in addition to the supply disruptions identified as a cause of price spikes in the legislation that led to this study.

(iv) California's infrastructure for petroleum products, comprising of pipelines, terminals and dock facilities, has insufficient capacity to handle current and anticipated demand. Capacity additions are hampered by lengthy and costly permitting procedures, and by policies practiced by the ports that favor other land uses over bulk liquid storage.

The findings of the interviews and survey meetings with stakeholders were a key consideration throughout the further analysis and when drafting the proposals.

Data Collection and Analysis

Extensive analysis of market data and underlying commercial and technical principles, as shown in this report, confirmed that:

(v) The output of California's refineries has not been able to keep up with demand growth in recent years and the State has become a net importer of all categories of petroleum products. Moreover, the outlook is that permitting restraints and technical limitations will make it more difficult for refiners to continue to realize small gains in production capacity, which have averaged approximately 0.7% per year since 1995, when refineries first started to run at or near maximum sustainable operating rates.

(vi) The growing import dependency is met primarily through foreign imports, with supplies from the US Gulf coast refineries stagnating because this capacity is fully utilized serving other US markets, while Jones Act shipping capacity is unavailable and faces significant further reductions as single hull product tankers are phased out.

(vii) Not only are foreign imports of gasoline and blending components indeed constrained by lack of tank capacity in marine terminals, but in addition significant commercial barriers exist because of lack of hedging opportunities which forces importers to incur significant risk in the volatile California markets.

(viii) Additional barriers to entry are also formed by the Unocal patents, which discourage traders or independent importers from attempting to bring finished products to the market, leaving only the California refiners capable of blending around the patent or absorbing the cost of licensing fees. The detrimental effects of the Unocal patents extend also to loss of production capacity, because refinery streams that might have been accretive to the gasoline pool are diverted to avoid patent infringement, while blending around the patent results in gasoline qualities that have sub-optimal emission performance.

(ix) The chronic shortage of gasoline in the California market is likely to worsen when the phase out of MTBE takes effect by year-end 2003, or earlier if refiners who make the switch to ethanol before that date on a voluntary basis, cannot timely solve supply issues. The prognosis is that a temporary shortfall of 5 to 10% will result, affecting primarily the Los Angeles Basin gasoline supplies. This level of supply reduction will cause prices in California to rise significantly over those of world markets. This in turn will attract other supplies, and prices are expected to level off at significant premiums over world markets.

(x) Under this scenario, the impact of temporary supply disruptions caused by refinery outages will be significantly more pronounced, since some of the initial price elasticity has already been absorbed.

(xi) The expectation is that the import dependency and chronic undersupply will cost gasoline consumers in California between $0.5 – 1.5 billion per year over what they would pay in a market where supplies are unrestrained. In addition, it is expected that on average, one major and several smaller supply disruptions will occur every year, resulting in a temporary price spikes that add at least another $0.5 billion to California's collective gasoline bill. It is estimated that for the largest part, the incremental revenues from gasoline sales will flow to energy companies outside the State.

Recommendations and Proposals

The recommendations formulated at this stage are:

(xii) The State of California is to provide a legislative framework that will enable the industry to better respond to market needs in terms of refining capacity and logistic infrastructure. Specific recommendations are:

a) To create a central authority to coordinate and expedite the permitting processes for projects related to energy infrastructure in general, similar to the one-stop shopping, fast-track permitting process created for projects related to California's electrical power supply.

b) To create a framework whereby refiners and other industry participants can expand production capacity and infrastructure capabilities without causing overall net additions to the State's emission inventories. Notably, a trade-off between reductions in mobile emissions through voluntary improvements in fuel quality beyond the minimum requirements can create room for refiners to offset stationary emission increases associated with capacity expansions. Currently, no framework exists within which emission reduction credits can be exchanged within stationary and mobile sources.

(xiii) The State of California is to issue a tender for the creation of 5 million barrel of versatile petroleum product storage under long-term lease agreements, 3 million of which would be in the LA basin and 2 million in the Bay Area. In both locations, this storage is to be provided with deepwater access and connections to the main product distribution pipeline systems. The tender is to be issued to qualified commercial terminal operators.

(xiv) At 5 million barrels, the capacity is twice the proposed volume of actual reserves and as part of the storage lease agreements, the State will require the contract operator of this tankage to sublease half of the new capacity to interested third party market participants, with the State only providing a minimal financial guarantee in case storage is not occupied for a certain amount of time. This guarantee will enable commercial terminal operators to obtain financing without the need for long term contracts, thus satisfying the need for short-term tank rentals serving the import market.

(xv) The State of California will purchase 2.5 million barrels of gasoline and gasoline blending components to form the basis for a Fuels Bank, from which qualified industry participants can withdraw volumes against a fee, with an obligation to re-supply the borrowed volumes within an agreed time span. Potentially, some of the State's obligations to purchase power can be exchanged for purchases of fuels using hedging and exchange mechanisms to offset corresponding intrinsic energy values. Equally, there may be opportunities to offset some of the purchase costs with a corresponding sale of crude oil from the Federal Strategic Petroleum Reserve under a provision in the Energy Policy and Conservation Act. The initial fill will have to be purchased during the winter blending season, preferably from offshore sources, and at a rate of purchase that will not create shortages or run-ups in prices.

(xvi) The fee for the temporary usage of the product is to be determined in periodic electronic auctions, whereby the qualified participants can bid for the privilege of the time value for prompt lifting of the product with repayment in kind within a pre-agreed time period, not exceeding 6 to 8 weeks. Minimum fees should be set such that the operational cost of maintaining the State's share of the inventories is largely covered. In times of shortage, i.e., when a refinery outage has been announced, these fees can be expected to be bid up sharply, but as a derivative, their overall impact on the cost of supply is expected to be considerably less than run ups in the price itself in times of shortage.

(xvii) In this way, not only is a reserve created that will suppress price excursions in a cost effective way, with savings to California gasoline consumer far outweighing the cost to the taxpayer, but a physical delivery point and hedging mechanism is created that will facilitate imports and significantly reduce the State's risk of import dependency for its transportation fuels.

(xviii) A descriptive example of how a Strategic Fuels Reserve for California may work in the context of global gasoline markets, when such a reserve is designed to allow time-swaps and enable forward trades, is given in Attachment B. However, because of the complex nature of the proposals, which go well beyond the simple building of tanks and holding of stagnant inventories contemplated in earlier proposals for a California Strategic Fuels Reserve, it is recommended that following this initial feasibility study, funds are allocated to conduct a definition phase study during which:

a) an inventory is made of problems associated with current permitting procedures, leading to detailed recommendations for a framework that will allow a faster and more efficient response by the industry to important market needs without compromising California's environmental safeguards;

b) bids are obtained from commercial service providers for the tankage, so that costs of operating the reserve can be defined with the level of accuracy and confidence necessary for budget decisions;

c) options for the initial fill can be worked out in detail, possible even to the extend whereby tenders are answered and cost are locked in or hedged;

d) detailed working principles are defined for the operation and oversight of the SFR as currently proposed in concept only, including an auction mechanism for the use of volumes from the reserve;

e) further rounds of feedback on the detailed proposals are obtained from industry participants and other stakeholders; and

f) detailed proposals are prepared to enable final decisions by the legislature.

1 CALIFORNIA FUELS MARKET

The California market for petroleum products is insular in nature, isolated from the main US continental markets by the Rocky Mountains to the East and from most other major fuels markets by the Pacific Ocean in the West. The geographical isolation is aggravated for gasoline and diesel by the unique fuel specifications that were mandated by the State in the past decade to protect its air quality, a process that is still continuing with the anticipated introduction of CARB Phase III reformulated gasoline specifications in the near future.

Even within the California market, a certain amount of insularity occurs. The Northern California market, with the Bay Area as it main center, and the Southern market structured around Los Angeles, are not linked by pipelines for petroleum products and behave in many ways semi-autonomously. A third production center around Bakersfield has only limited capacity for gasoline and distillates. Within the San Joaquin Valley, other insular niche markets exist such as the markets for diesel in agricultural centers. External and internal insularity are major factors when evaluating the effectiveness and optimal locations for an eventual Strategic Reserve.

In the past California exported small excess quantities of certain fuels. In recent years however, the State has become a net importer of all petroleum products including finished gasoline, blend stocks, diesel and jet fuel, and the State's shortfall is expected to increase significantly over the coming years[1]. The State receives limited supplies from refiners in nearby Washington, but California has to cover the bulk of its shortfall of petroleum products with imports from remote sources such as the US Gulf Coast, the Canadian East Coast, the Caribbean, Europe, Asia, and the Middle East. It is important to note that the shortfall is not only caused by demand for fuels within the State, but that the California refiners also supply markets in Nevada and parts of Arizona, including fast growing population centers such as Las Vegas and Phoenix.

The proposed phase out of MTBE, currently scheduled for year-end 2003, concurrent with the introduction of the more stringent CARB Phase III requirements, will cause a reduction in supplies by 5 to 10%. This shortfall will predominantly affect the LA Basin market and is as yet not covered. Even if available import sources were to be identified within the global refinery network, the State would lack the infrastructure to handle a diverse mixture of blending components. Under scenarios in which the State is chronically undersupplied, the volatility of fuel pricing can be expected to grow progressively worse. Below, supply and demand will be analyzed for several scenarios, in particular with regard to imbalances that will increase price volatility and hence, the value of an eventual SFR.

[1] *Energy Outlook 2020*, California Energy Commission Staff Report, Docket No. 00-CEO-Vol II, August 2000

1.1 Current Supply

Forecasting the supply of clean petroleum fuels into California requires an analysis of its refineries and their capability for expansion, and an evaluation of import opportunities in terms of sources, logistical infrastructure and economical feasibility.

1.1.1 Refining Capacity in California

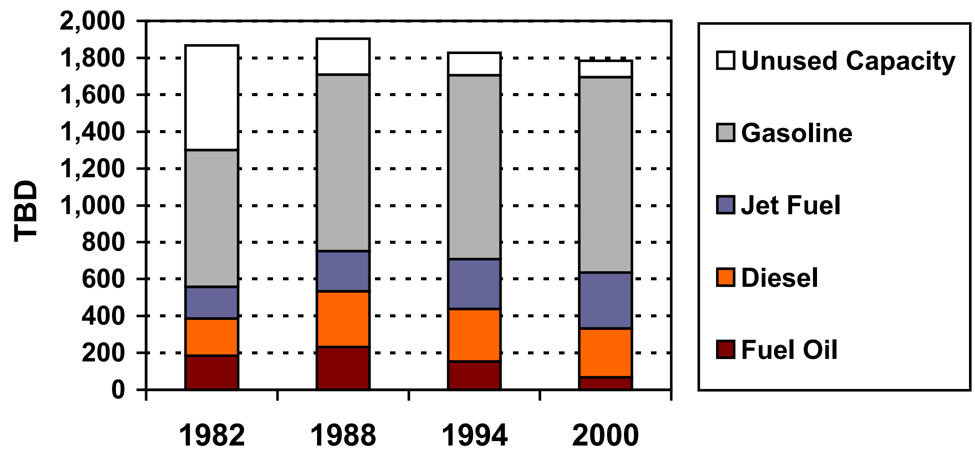
Historically, two factors have contributed to rationalization and concentration of refining capacity in California:

- The deregulation of the markets for petroleum products in 1981[2], which accelerated the closure of many uneconomic refineries nationwide.

- The requirements of the Clean Air Act Amendments (CAAA) of 1990, which for several refineries could not be achieved economically.

The concentration of production that took place from the mid 80-ies through the mid 90-ies has not only resulted in high utilization rates of remaining capacity, but the investment programs to meet the requirements of the CAA and subsequent amendments also led to a significant increase in gasoline production of lighter components at the expense of heavy fuel oil. As a result, the remaining gasoline-producing refineries in California are highly sophisticated full conversion facilities.

Figure 1.1 – CA Refinery Capacity Utilization[3]



[2] Executive Order 12287, Providing for the Decontrol of Crude Oil and Refined Petroleum Products, Jan 28, 1981.

[3] Source EIA and CEC data. Stream day capacities.

Figure 1.1 shows how since the mid 90-ies, unused refining capacity in California is less than 5%, indicating that all remaining refineries in California have essentially been running at the maximum practically feasible operating rate given the average age and the mechanical complexity of the installations. It also shows that the remaining refining capacity is predominantly geared towards production of gasoline at the detriment of fuel oil output, as a result of heavy investments into cracking and coking capacity in the late 80-ies and early 90-ies.

Out of the 15 refineries currently operating in California, only 12 facilities, owned by 7 companies, are capable of producing California specification gasoline and diesel. The capacities of these refineries are summarized below in Table 1.1 below.

Table 1.1 – California Fuels Production 1995-2001[4]

	TBD	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
NORTHERN CA								
CARB RFG		48.4	320.1	381.3	387.0	369.1	392.2	402.0
Oxygenated Gasoline		106.1	22.1	0.2	-	-	-	-
Other Finished Gaso		277.1	110.6	62.9	68.7	33.5	51.7	58.3
CARB Diesel		128.8	126.5	133.0	2.2	81.8	104.9	115.4
EPA Diesel		n/a	n/a	n/a	115.3	30.1	19.0	22.5
High S Diesel		19.2	15.1	4.3	2.4	7.7	8.1	5.2
Jet Fuel		97.0	111.6	111.5	102.0	84.5	94.5	101.4
SOUTHERN CA								
CARB RFG		405.1	464.4	493.2	399.0	584.9	548.6	552.3
Oxygenated Gasoline		3.6	-	0.8	n/a	3.9	5.5	3.1
Other Finished Gaso		126.3	71.6	61.5	65.9	52.9	52.5	40.2
CARB Diesel		122.7	125.1	127.3	1.7	56.8	69.4	74.1
EPA Diesel		n/a	n/a	n/a	139.6	102.4	76.8	81.4
High S Diesel		19.8	19.4	12.8	10.8	4.6	6.3	1.5
Jet Fuel		148.2	169.0	164.4	157.4	143.6	149.4	139.0
TOTAL CA								
CARB RFG		453.4	784.5	874.5	786.0	954.0	940.8	954.4
Oxygenated Gasoline		109.7	22.1	1.1	n/a	3.9	5.5	3.1
Other Finished Gaso		403.4	182.2	124.4	134.6	86.4	104.2	98.5
CARB Diesel		n/a	n/a	n/a	3.9	138.6	174.3	189.5
EPA Diesel		n/a	n/a	n/a	254.9	132.5	95.8	103.9
High S Diesel		39.1	34.4	17.0	13.3	12.3	14.4	6.8
Jet Fuel		245.2	280.6	275.9	259.3	228.1	243.9	240.4

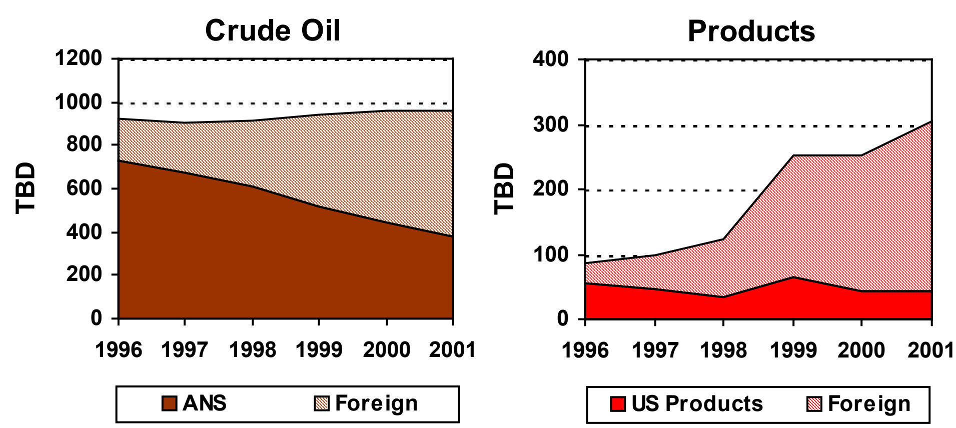
The production numbers for gasoline cited in Table 1.1 include blending components and unfinished gasoline blend stocks imported by the refineries. These imports play an increasingly important role in the refiner's abilities to meet California's fuels demand, and a detailed analysis of the imports of petroleum products will be provided below.

[4] Data from CEC weekly reported production numbers.

1.1.2 Imports of Petroleum Products

In the past, California was a net exporter of petroleum, either as crude oil or as refined distillates and partially refined feedstocks. In recent years however, internal demand has grown, and even though the refineries have become more sophisticated as California crude oil production has declined, the net effect is that imports of both crude oil and refined products have grown substantially, making the State a significant net importer of foreign crude and petroleum products, as shown in Figure 1.2 – CA Foreign and Domestic Petroleum Imports.

Figure 1.2 – CA Foreign and Domestic Petroleum Imports[5]



Over the past 5 years, imports of foreign crude oil and other refinery feedstocks into California have effectively tripled, from about 193 TBD in 1996 to 579 TBD in 2001. While refinery crude runs have been nearly constant, the increased foreign imports are replacing both Alaska North Slope crude (ANS), as well as California crude production. The impact of the increased imports of foreign crude is relevant for the need to create a Strategic Fuels Reserve because:

- Foreign crude is sourced increasingly from remote locations such as the Middle East, requiring Very Large Crude Carriers (VLCCs) to achieve economical freight rates. The logistics of receiving larger cargoes from more remote locations increases the risk of supply disruptions.

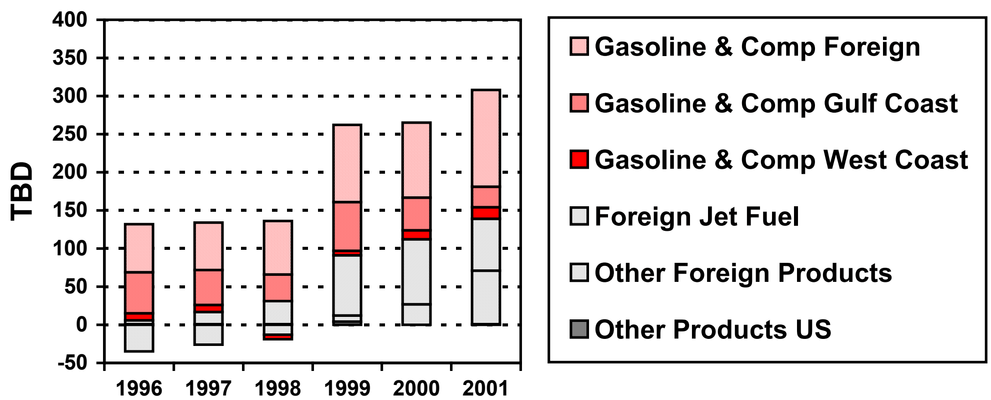
- At many terminals and refineries, crude and product receipts share common infrastructure such as docks, transfer lines and sometimes even tankage. The

[5] Data from EIA, CEC, Port Import Export Reporting Services/JOC Group, and US Army Corps of Engineers

additional maritime receipts of crude oil create an additional strain on product import capabilities.

Net product imports have grown from a small volume that resulted as the net sum of almost balancing imports and exports, to more than 300 TBD of net imports. Figure 1.3 shows the details of net imports by product category and origin.

Figure 1.3 – CA Imports of Petroleum Products [6]



*** Components include oxygenates such as MTBE, ETBE, etc**

As can be seen from Figure 1.3, the increase in imports is most significant in jet fuel and gasoline, but in all major fuel categories including diesel and miscellaneous other fuels (fuel oil, distillate blendstocks, lube stocks and additives), California has become import dependent, with gasoline and gasoline blending components forming the largest import category. Imports of petroleum products are a function of refinery performance and regional demand. The California refineries operated reliably in 1998, but significant refinery problems were encountered in 1999. The large increase in imports from 1998 to 1999 as seen in Figure 1.3 reflects this difference in refinery performance. The underlying trend is an annual increase in imports of petroleum products in California of 30 to 40 TBD per year, or approximately 1.6 to 2% per year of the total fuels capacity of the State's refineries. What is more significant, however, is the increase in waterborne imports itself: ***since 1996, the volumes of clean products handled through the State's marine receipt facilities have effectively tripled***. It is this sharp rise in import volumes coupled with a stagnating infrastructure, which is in large part responsible for the current supply difficulties.

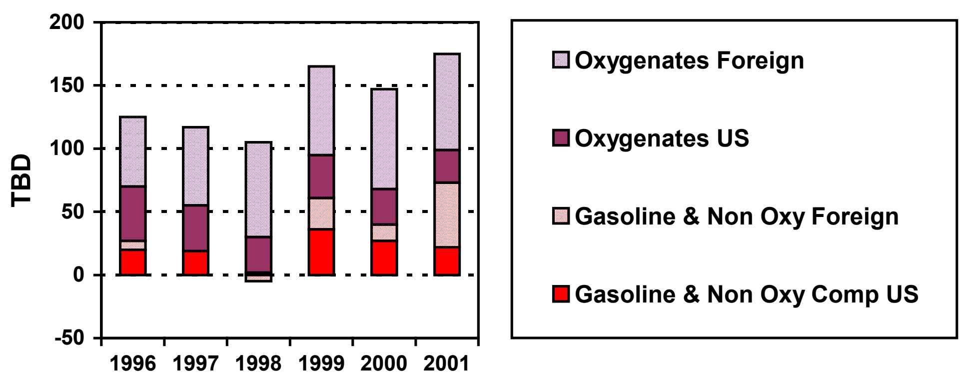
[6] Based on EIA data and Port Statistics collected by the US Army Corps of Engineers

Figure 1.3 also shows that, while in 1996 California still was a net exporter of distillates and miscellaneous refined products, it now has a net import requirement in all product categories. Moreover, while in 1996 foreign imports accounted for approximately 50% of California's imported shortfall of gasoline and blending components, by 2001 the share of foreign imports had grown to more than 80%.

The imports into the gasoline pool are a combination of finished gasoline, blending components and oxygenates. Components include alkylate, naphtha, reformate, raffinate, and natural gasoline. Oxygenates in the form of MTBE and ethanol make up the largest part of the imports of gasoline and blending components in California, with MTBE representing over 90% of the total volumes. Indigenous Californian production of MTBE, TAME and ethanol is less than 12 TBD, underscoring the import dependency of California for this fuel additive. Figure 1.4 shows gasoline imports by component.

As can be seen in Figure 1.4, foreign imports accounted for approximately 50% of California's imported shortfall of gasoline and blending components in 1996. By 2000, the share of foreign imports had grown to 70%, and it is important to note that in fact, the entire increase in California's imports of gasoline over the period has been met by foreign imports rather than imports from other US refining centers.

Figure 1.4 – CA Gasoline and Component Imports [7]



The increasing dependency on foreign imports represents significant exposure for the future capability to keep the State supplied with gasoline because only a limited number of foreign refineries is capable of producing CARB spec fuels, and this number will shrink even further as some of these refiners will not be able to produce CARB Phase III CARBOB. To the foreign refiners, exports to California are only an incidental

[7] Based on EIA data and Port Statistics collected by the US Army Corps of Engineers

occurrence with uncertain margins given the shipping delays, the volatility of the Californian market, and the lack of a futures market. Under these conditions, it is difficult for these refiners to justify investments in the necessary upgrades.

1.1.3 Interstate Product Movements

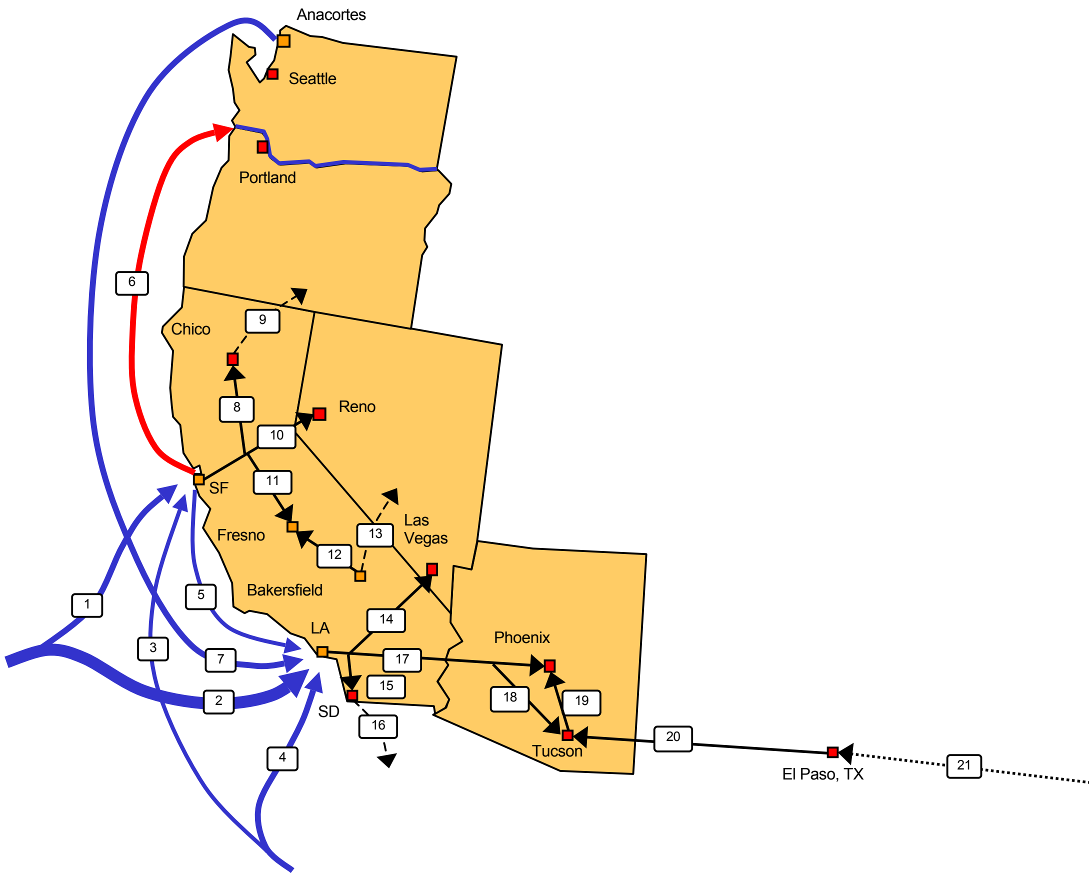
The import volumes shown in Figure 1.4 for the West Coast represent the balance of imports and exports to the Pacific Coast states, which have a considerable volume of petroleum movements between the various producing and consuming enclaves. Refineries in the Bay Area ship conventional gasoline to the Pacific Northwest, primarily to Portland, OR. The refineries on Puget Sound send somewhat larger volumes of reformulated gasoline or components down to San Francisco or Los Angeles by tanker or barge.

Besides maritime imports, pipeline and truck movements play an important role in the supply of California and the neighboring states for which California refineries provide a significant share of their fuels demand. There are two major pipeline systems, both owned and operated by Kinder Morgan Energy Partners LLC, one exporting products from the Bay Area refiners to Northern and Central California, as well as Northern Nevada, and the other taking products from the LA Basin refiners to Southern California, Southern Nevada and Arizona.

Kinder Morgan also owns a pipeline system that moves products produced in Texas and New Mexico from El Paso to Tucson and Phoenix. Capacity on this system is oversubscribed, and capacity for users of this line is prorated. Figure 1.5 gives an overview of movements on product pipelines and other means of transportation between California and its neighboring states. Numbers are for the year 2000 and are based on data obtained from EIA, CEC and the US Army Corps of Engineers.

Also shown in Figure 1.5 is the Longhorn Pipeline, a former crude oil pipeline system that was built to transport Alaskan Crude landed in Los Angeles by tankers to refineries on the US Gulf Coast. This pipeline system is currently in the process of starting up in clean product service to bring US Gulf Coast products to Western Texas and Arizona. However, until new pipeline capacity is added between Tucson and Phoenix, this new pipeline will not substantially contribute to California's requirements for clean fuels, nor will it significantly diminish the quantity of products supplied by LA Basin refiners into Southern Nevada and Arizona.

Figure 1.5 – CA 2000 CA Product Movements



Year 2000, TBD	Gasoline	Diesel	Jet
1 Foreign Imports into N-CA	29.8	0.6	13.0
2 Foreign Imports into S-CA	68.4	19.0	71.9
3 PADD III Imports into N-CA	6.8	n/a	n/a
4 PADD III Imports into S-CA	22.1	n/a	n/a
5 Ship/barge SF to LA	24.5	31.1	n/a
6 Ship/barge SF to Portland	28.0	2.7	n/a
7 Ship/Barge WA to LA	38.0	16.2	n/a
8 Kinder Morgan SF to Chico	17.6	n/a	n/a
9 Truck Chico into S-OR	0.4	0.5	n/a
10 Kinder Morgan SF to Reno	17.3	13.2	5.6
11 Kinder Morgan SF to Fresno	n/a	n/a	n/a
12 Kinder Morgan B'field to Fresno	n/a	n/a	n/a
13 Truck Bakersfield to W-NV	2.5	5.0	n/a
14 CALNEV LA to Las Vegas	45.9	32.3	32.7
15 Kinder Morgan LA to San Diego	n/a	n/a	n/a
16 Truck SD to Mexico	n/a	n/a	n/a
17 Kinder Morgan LA to Phoenix	60.9	28.4	29.5
18 Kinder Morgan LA - Tucson	4.1	2.6	0.5
19 Kinder Morgan El Paso - Phoenix	41.0	3.2	3.6
20 Kinder Morgan El Paso - Tucson	28.0	7.4	4.9
21 Longhorn	n/a	n/a	n/a

1.1.4 Supply Reliability Factors

When refiners state calendar day capacity (actual expected annual production divided by 365 days) and stream day capacity (highest operating rate sustainable on a single day), the difference for major refinery units such as distillation or cracking is typically around 5%. This means that refiners expect that on average, these installations will be out of service for 18 days per year for scheduled inspections, preventive maintenance, operational activities such as catalyst changes, and project work. Since 1995, the California refineries have been running at operating rates equal to 95% of published nameplate capacity, which means that effectively, they have been running as close to their maximum sustainable rates as can be expected, given the age and complexity of the installations. This operating record reflects favorably on the skill level and experience of operating personnel and refinery management.

Nevertheless, unplanned outages occur, sometimes for reasons that are completely outside the scope of control of the refinery management. An extensive study into the occurrence and impact of refinery disruptions, which was conducted by Dr A.J. Finizza in parallel to the SFR Study concluded that[8]:

- For all of California's refineries combined, evidence was found in publicly available information that between February 1996 and April 2001, a total of 49 refinery disruptions occurred with measurable effects.
- The average duration of these refinery outages was found to be 2.7 weeks, while the average net capacity loss was 20 TBD of gasoline production. The longest outage lasted 22 weeks, while the highest net capacity loss was 60 to 70 TBD.
- Given the frequency of occurrence and the duration of disruptions, there is a small but real chance of almost 8% that 2 of California's refineries are experiencing production outages at the same time.

With inventories on hand in the refineries that average only 10 days of supplies, and with long supply routes requiring lead times of 6 to 8 weeks for imports, the effect of supply disruptions is to cause temporary shortages that in turn result in market driven price spikes, with prices running up until demand will be reduced to a level that corresponds with the reduced supplies. Given the highly un-elastic price/demand behavior of gasoline, even small shortfalls in supply can cause very significant price swings. There is also ample evidence, as will be shown in

[8] Dr A.J. Finizza, *Economic Impact of Refinery Disruptions*, Study for the California Energy Commission, April 2002

Section 8 of this report, that even if incidents are confined to only one of the California refining centers, the entire California gasoline market moves up.

Supply reliability factors are not the only cause of price volatility. For instance, the lack of liquidity leaves the market vulnerable to sharp increases or decreases in posted prices on only a few reported deals. Yet in the majority of the cases, a real or imagined supply disruption is at the root of price volatility. In the most severe example, the refinery incidents in 1999 resulted in a capacity loss of 5 – 10%, and caused spot prices to double at their peaks, while retail market increased by 50% over prolonged periods.

In general, price volatility in the California gasoline market has significantly worsened in recent years, as the insularity of the market increased while the spare capacity available within the California refining system to make up for supply disruptions decreased.

Figure 1.6 – Gasoline Spot Price Differential LA – US Gulf Coast [9]

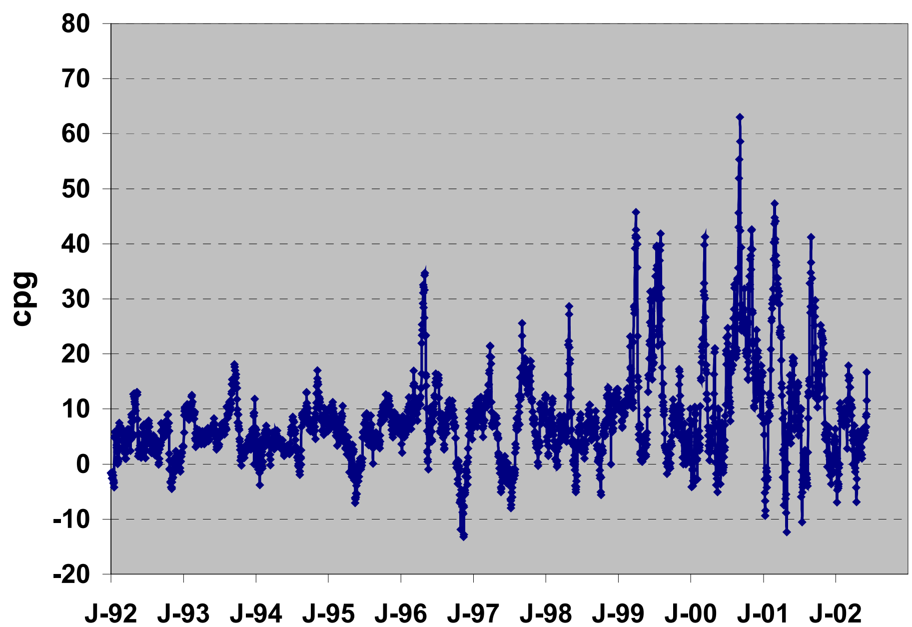
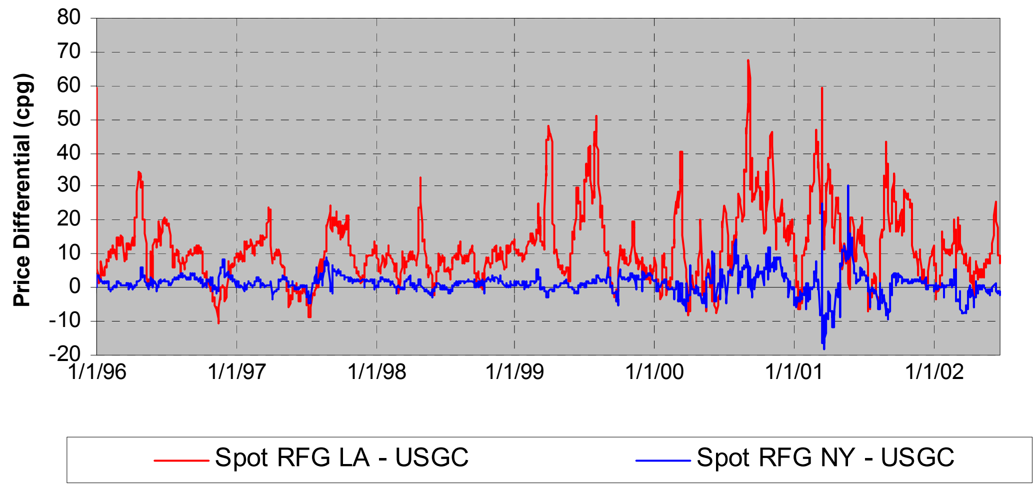


Figure 1.6 shows the premium of the LA conventional spot gasoline price over the spot price at the US Gulf Coast, the latter being a highly relevant marker price for gasoline worldwide. It is clear that the CA prices have gradually increased over world market levels, and that the volatility has significantly increased since 1995, when CARB Phase II was introduced.

[9] EIA Daily gasoline spot prices Los Angeles and US Gulf Coast.

The same conclusion is drawn when comparing prices for Reformulated Gasoline (RFG), as shown in Figure 1.7.

Figure 1.7 – Differential of LA Spot RFG over USGC RFG to NY RFG



It is clear that the volatility of the Los Angeles price differentials for regular spot RFG gasoline over the US Gulf Coast pricing is far more severe than that of the New York markets for RFG. Although from the data it would appear that the underlying tendency is for both markets to become more volatile, the California market volatility is an order of magnitude worse than that of New York.

Whereas an earlier price spike in 1996 led promptly to additional shipments from the US Gulf Coast to California at a rate equivalent to 50 TBD, more recent price spikes that far exceeded that of 1996 in amplitude and duration have failed to attract more than 10 to 15 TBD. Although the market still functions in so far that no actual shortages have occurred at the pump, it must be concluded from Figure 1.6 that currently, the California gasoline market is not efficiently supplied. In a well functioning market, supplies would be attracted at levels just above transportation and sourcing cost differentials, and prices would not have to run up until demand is reduced to match the insufficient offering.

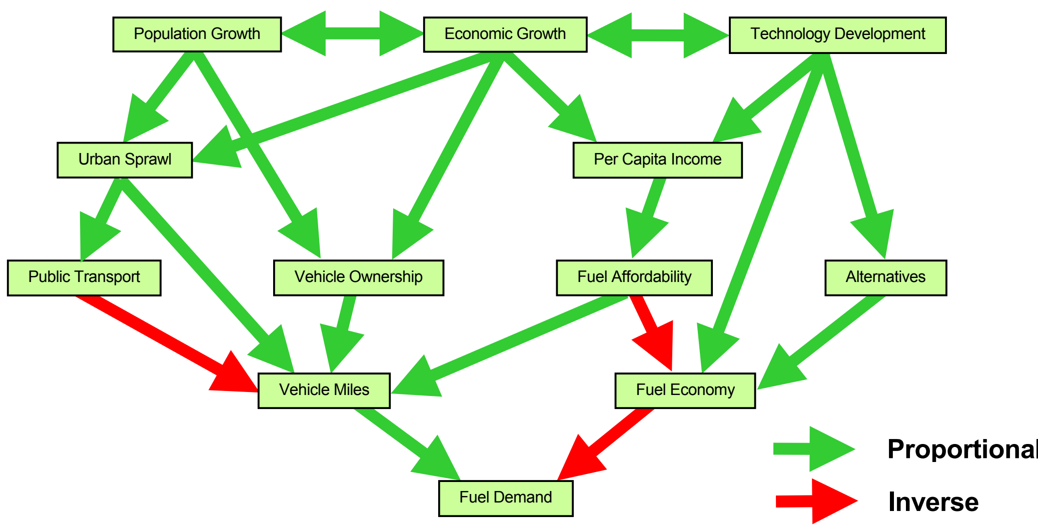
1.2 Demand

To estimate future demand for transportation fuels in California, this report will make extensive use of the results of a separate study launched by the CEC concurrently, with the specific purpose of forecasting energy demand in the State[10]. The main findings of this study are summarized below.

1.2.1 Growth Drivers

Demand for transportation fuels is the product of the total miles driven by all vehicles and the average fuel consumption per vehicle over the entire fleet. These two key factors, in turn are impacted by a complex set of interdependent factors as shown in Figure 1.8 below.

Figure 1.8 – Drivers for CA Gasoline Demand



For the key factors, the following historical and forecasted numbers were used:

- **Population Growth**. Over the past two decades, California's population grew by an average of 1.9% per year, a rate that is expected to slow to 1.4% per year over the next 20 years, resulting in a total population of 45 million people in the State by 2020.

- **Population Density**. Land development patterns in California are characterized by urban sprawl, leading to jobs and communities that are increasingly further apart. This trend is expected to continue.

- **Fuel Affordability**. Over the past 20 years, the average annual increase in per capita income in California was 3.1% per year, for an aggregate real increase

[10] Base Case Forecast of California Transportation Energy Demand, CEC Staff Report, December 2001

of 45% (1.9% per year). Over the same period, the real cost of gasoline in the State fell by 30%. Per capita income is forecasted to increase on average 1.5% per year, and primary energy cost to stay flat in constant dollar terms (the price of gasoline in CA may vary significantly depending on supply scenarios, but this effect is taken into account separately).

- **Vehicle Miles Traveled (VMT)**. The factors cited above contributed to an increase in total Vehicle Miles Traveled of 3.3% annually over the past 20 years. For the immediate future, the forecast is for an annual increase of 1.8%.

- **Substitution**. Public transportation and alternative fuel vehicles can substitute demand for conventional gasoline powered personal cars. However, the CEC estimates do not show a significant impact of alternative technologies in the near future.

1.2.2 Scenarios

For near term future gasoline demand scenarios, i.e., forecasts that extend up to five years out, the most leveraging differentiators are general economic climate and basic energy price levels, in particular the price of crude oil. Other factors, such as demographic changes of changes in fleet composition and average fuel efficiency, move too slowly to have a significant impact within a five-year time horizon.

Three scenarios were evaluated:

- A base case that assumes the current economic slowdown to level off, with a moderate recovery over the next two years and slower growth afterwards than seen over the past five years, resulting in an average increase in gasoline demand of 1.6% per year

- A high growth scenario that assumes rapid economic recovery to similar levels as seen over the past five years, averaging 2.1% per year.

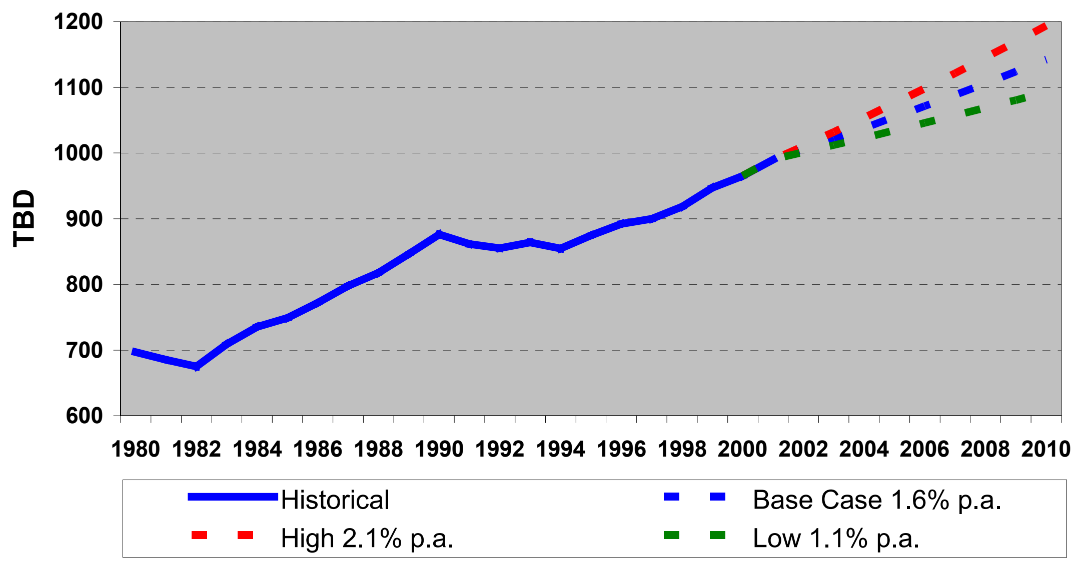
- A low case assuming a deepening and longer lasting recession, with gasoline demand growth slowing to 1.1% per year

All scenarios assume that crude oil prices will stay moderate, i.e., in a range of $20 per barrel, plus or minus $5. Because crude oil pricing is an almost straight direct cost pass through in gasoline prices, higher and lower crude prices will impact gasoline demand with essentially the same price elasticity as gasoline price excursions caused by local market supply imbalances. A high growth scenario could therefore also occur when economic recovery is delayed but crude prices revert to the low prices seen in the late nineties. It would take a combination of very high crude prices and a severe recession, similar to what was observed in the early eighties and early nineties, to cause gasoline demand to stay flat or show negative growth. The probability of this reoccurring is deemed extremely unlikely, especially in the light of statistics from the Board of Equalization (BOE) which show that demand in 2001 grew at nearly 3% over that of 2000, despite the economic downturn.

1.2.3 Demand Projections

Figure 1.9 shows the historical demand of gasoline in California, excluding the gasoline demand for those parts of Arizona and Nevada that are supplied out of California.

Figure 1.9 – California Gasoline Demand Forecast



The base case growth forecast is a close approximation of the long-term average annual increase over the entire period 1980 through 2000, while the upside and downside cases represent periods of rapid economic expansion and moderate recession respectively. Only a severe recession caused by or coinciding with crude oil prices in excess of $30/bbl have led in the past to scenarios in which gasoline demand in California stayed flat, or even showed modest decreases. This was the case in 1980 and in 1990 – 1993, but current signs of economic recovery as well as a stated policy by OPEC and non-cartel producing states to manage crude oil prices within ranges that do not harm world economies make a return of similar conditions unlikely in the immediate future. In fact, taxable sales in 2001 were up nearly 3% over those reported for 2000, and early indications for 2002 also show no signs of slackening demand.

1.2.4 *Arizona/Nevada Demand*

As shown in Section 1.1.3, California refiners supply fuels to Nevada and Arizona, which includes some of the fastest growing urban centers in the US. Table 1.2 shows the demand forecast for the California sourced demand in these states.

Table 1.2 – Arizona and Nevada Gasoline Demand

Growth Drivers	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Northern Nevada Growth (1)	2.9%	2.8%	2.7%	2.6%	2.5%	2.4%	2.3%	2.2%	2.1%	2.0%	1.9%
Southern Nevada Growth (2)	6.4%	5.2%	4.5%	3.9%	3.4%	3.0%	2.7%	2.4%	2.2%	2.1%	2.1%
Arizona Population Growth (4)	2.4%	2.4%	2.3%	2.3%	2.2%	2.2%	2.1%	2.1%	2.0%	2.0%	2.0%
Gasoline Demand (TBD)											
Nevada											
Northern NV (3)	21.0	21.6	22.2	22.7	23.3	23.9	24.4	25.0	25.5	26.0	26.5
Southern NV (3)	41.0	43.1	45.0	46.8	48.4	49.9	51.2	52.5	53.6	54.8	55.9
	62.0	64.7	67.2	69.5	71.7	73.8	75.6	77.4	79.1	80.8	82.4
Arizona											
West Line Sourced	87.0	89.1	91.1	93.2	95.3	97.4	99.4	101.5	103.5	105.6	107.7
East Line Demand	75.0	76.8	78.6	80.4	82.1	83.9	85.7	87.5	89.3	91.0	92.9
East Line Supply (5)	75.0	75.0	75.0	75.0	75.0	75.0	185.1	189.0	192.8	196.7	200.6
Total West Line Supply (6)	87.0	90.9	94.7	98.6	102.4	106.3	0.0	0.0	0.0	0.0	0.0
Total California Sourced Demand	149.0	155.6	161.9	168.2	174.2	180.1	75.6	77.4	79.1	80.8	82.4

1 Nevada State Energy Office estimate 2.8% in 2001 vs. 2.9% in 2000, a decline assumed to continue
2 As per Clark County Advanced Planning Division - "Clark County Demographics Summary"
3 Lynn Westfall, UDS presentation to CIOMA, April 2001
4 AZ Dept of Economic Security data - http://www.de.state.az.us/links/economic/webpage/page16.html
5 Assumes replacement of West Line supplies by Longhorn extension to Phoenix in 2006
6 Assumes all AZ pipeline growth until start up of Longhorn extension to be put on West line due to East Line proration

The main event that will impact the supply of California sourced gasoline to Arizona is the anticipated completion of a new parallel or “looped” pipeline from Tucson to Phoenix, which will allow US Gulf Coast refiners to substitute California supplied volumes. The assumption here is that the US gulf coast refiners, who currently operate at capacity, will be able to make these volumes available through refinery expansions, or by shifting products away from their current markets, which in turn would have to look for imports from foreign sources.

1.2.5 Total Demand

The total demand for gasoline to be supplied from California is shown in Table 1.3.

Table 1.3 – Total Demand for California Sourced Gasoline

TBD	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Base Case											
Northern California	372	378	384	390	396	403	409	416	422	429	436
Northern Nevada	17	18	18	19	19	20	20	21	22	22	23
Oregon	28	28	29	29	30	30	31	31	32	32	32
	417	424	431	438	445	453	460	468	476	483	491
Southern California	591	600	610	620	630	640	650	660	671	682	693
Southern Nevada	41	43	45	47	48	50	51	53	54	55	56
Western Arizona	87	91	95	99	102	106	0	0	0	0	0
	719	734	750	765	781	796	701	713	725	737	749
Total CA Base	**1136**	**1159**	**1181**	**1204**	**1226**	**1249**	**1161**	**1181**	**1201**	**1220**	**1240**
High Growth Case											
Northern California	372	380	388	396	404	413	421	430	439	449	458
Northern Nevada	17	18	18	19	19	20	20	21	22	22	23
Oregon	28	29	29	29	30	30	31	31	32	32	33
	417	427	435	445	453	463	472	483	493	503	514
Southern California	591	603	616	629	642	656	669	684	698	713	728
Southern Nevada	41	44	45	47	49	50	52	53	54	55	56
Western Arizona	87	92	96	100	103	107	0	0	0	0	0
	719	739	757	776	795	813	721	737	752	768	784
Total CA High	**1136**	**1165**	**1192**	**1220**	**1248**	**1277**	**1194**	**1219**	**1245**	**1271**	**1298**
Low Growth Case											
Northern California	372	376	380	384	389	393	397	402	406	410	415
Northern Nevada	17	18	18	19	19	20	20	21	22	22	23
Oregon	28	28	29	29	30	30	31	31	32	32	32
	417	422	427	432	437	443	448	453	459	464	470
Southern California	591	598	604	611	617	624	631	638	645	652	659
Southern Nevada	41	43	45	46	48	49	51	52	53	54	55
Western Arizona	87	90	94	98	101	105	0	0	0	0	0
	719	730	742	755	767	779	682	690	698	706	715
Total CA Low	**1136**	**1152**	**1169**	**1187**	**1204**	**1222**	**1129**	**1143**	**1157**	**1171**	**1185**

Since no official scenarios were developed for demand growth in Arizona and Nevada, it is assumed that high growth in these states would be 1% per year above base case growth, while a reasonable assumption for low growth is 1% below base case.

1.3 Forward Looking Supply/Demand Balance

Ignoring inventory effects, supply and demand will have to balance. The total demand shown in Table 1.3 above is the latent demand, i.e., the demand that will exist if sufficient product is available to meet the demand at prices that are not significantly different from historical numbers. The main event impacting the supply is the phase-out of MTBE.

1.3.1 Impact of MTBE Phase Out

Table 1.4 below shows the impact of the MTBE phase-out by region.

Table 1.4 – Impact of MTBE Phase Out[11]

TBD	N-CA	S-CA	Total CA
MTBE Balance			
RFG production	386	549	935
Ethanol Based CARB RFG	40	70	110
MTBE Based CARB RFG	346	479	825
MTBE Required @ 11%	38	53	91
MTBE imports foreign	24	51	75
MTBE imports US Gulf Coast	7	10	17
MTBE production	7	3	10
Total MTBE supply	38	64	102
Excess MTBE	0	11	11
Direct Impact			
Removal of MTBE	-38	-64	-102
Ethanol addition for oxygen requirement	21	34	55
Removal of butanes & pentanes	-17	-29	-46
Other Losses to meet distillation specs	-4	-6	-10
	-38	-65	-103
Capacity Compensation			
Major refinery capacity additions	22	0	22
Small CARB III mods, MTBE C4 to alky	3	2	5
Capacity Creep 2001 - 2002, 1%	4	6	10
Identified blendstock imports by refiners	0	10	10
	29	18	47
Net Shortfall	**-9**	**-47**	**-56**

The 11 TBD shown in Table 1.4 as excess MTBE is the sum of 3 TBD shipped down the Kinder Morgan pipeline to Phoenix, an unknown quantity that was used because of supply problems with ethanol for the current substitution of MTBE by some refiners, and a significant quantity, possibly as high as 6 or 7 TBD of MTBE used by LA refiners to make up for volume and quality problems by blending in more than 11%.

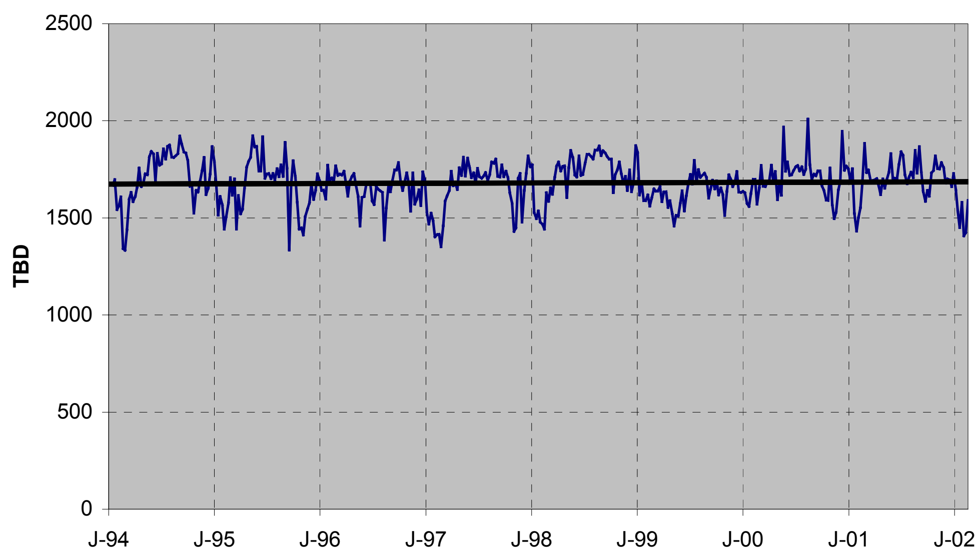
[11] Source of Data: CEC, CARB Phase III Compliance Plans as submitted by refiners Q4, 2001

The major addition in refinery capacity of 22 TBD shown in Table 1.4 above is not a net addition, but a partial conversion of conventional gasoline production into CARB Phase III grades [12]. It is clear from Table 1.4 that the southern California market will be impacted much more severely by the MTBE phase out than its northern counterpart. Moreover, the LA Basin is more constrained in terms of import capabilities than the Bay Area, making the south more vulnerable to supply shortages.

1.3.2 Capacity Creep

Capacity creep is the term used for the result of ongoing small plant improvements in refinery operations. Even though small, capacity creep is an important phenomenon because it can compensate for a significant portion of demand growth. In the absence of major expansion projects, capacity creep can be derived from production numbers over time. Figure 1.10 shows the weekly reported crude runs of California refineries.

Figure 1.10 – Reported Crude Runs by CA Refiners



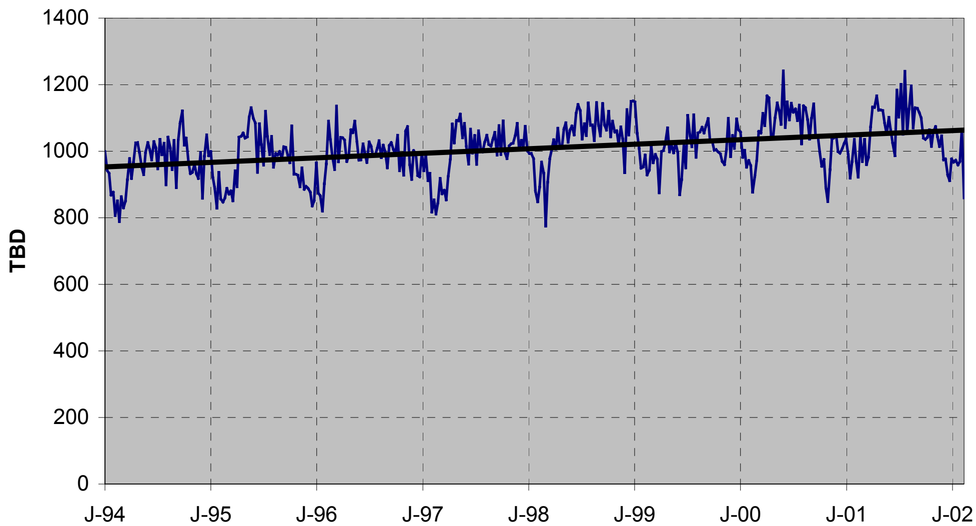
Although crude runs by California refiners have stayed virtually flat over the last 8 years, gasoline production has seen a small but significant increase in production, as shown in Figure 1.11 below.

Gasoline supplies by California refineries have grown on average by 1.3% per annum over the period 1994 through 2001, for an overall increase in average reported

[12] Information received during Stakeholder Meetings.

gasoline production of close to 100 TBD. Of this additional volume, approximately 40 TBD is due to increased receipts of imported blending components, which get reported as production after being blended off. The remainder, or 60 TBD, is the effect of the result of minor expansion projects and ongoing improvements in operations, which equates to approximately 0.6% per year. Although insignificant as fraction of total supply, capacity creep is important because it can represent up to half of the anticipated increase in demand.

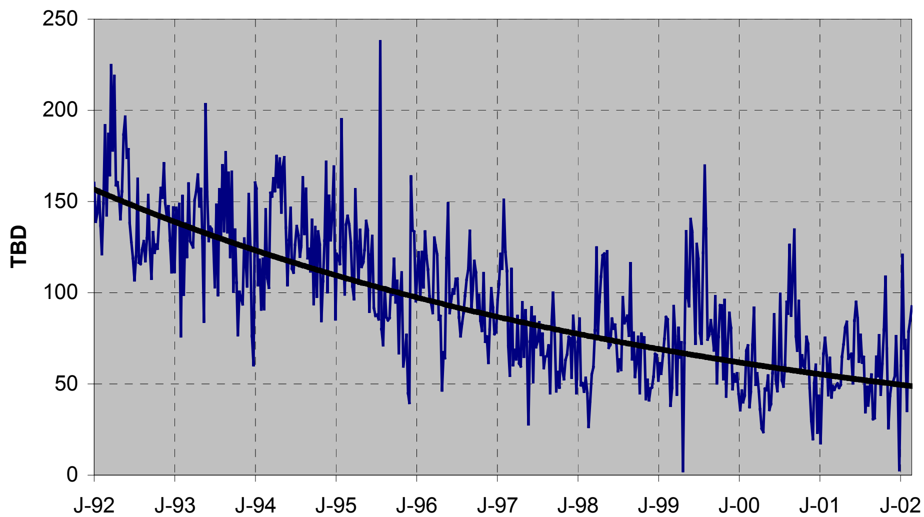
Figure 1.11 – CA Weekly Reported Gasoline Production



As can be seen in Figure 1.11 and Figure 1.12, the increase in gasoline production by California refiners by about 100 TBD was accompanied by a corresponding decrease in production of residual fuels, confirming that within the virtually flat crude conversion, refiners have been able to convert more of the heavy end of the barrel into gasoline. A small shift in distillate production can also be observed, but is not shown here. It is clear from Figure 1.12 that the capability to convert more heavy components into gasoline is reaching a point where further improvements are not physically possible.

In a market where supplies are tight, and where economic justification for small improvement projects can readily be found, capacity creep is likely to continue at historical rates. However, it is becoming increasingly difficult for refiners to expand capacity even by small increments because of restrictions imposed by their CAAA Title V operating permits, and the costs of additional emission credits in the absence of feasible offsets.

Figure 1.12 – CA Weekly Reported Production of Residual Fuels



For the base case projections, the annual increase of gasoline production is assumed to 1.0% per year. This rate of increase does not include known or expected discrete capacity additions through major debottleneck or expansion projects, nor does it account for the impact of specific programs such as the CARB Phase III compliance. This estimate is probably too optimistic in the light of the diminishing returns on further upgrading of the bottom of the barrel and the restrictive permitting climate for refinery projects in California.

1.3.3 Major Refinery Projects

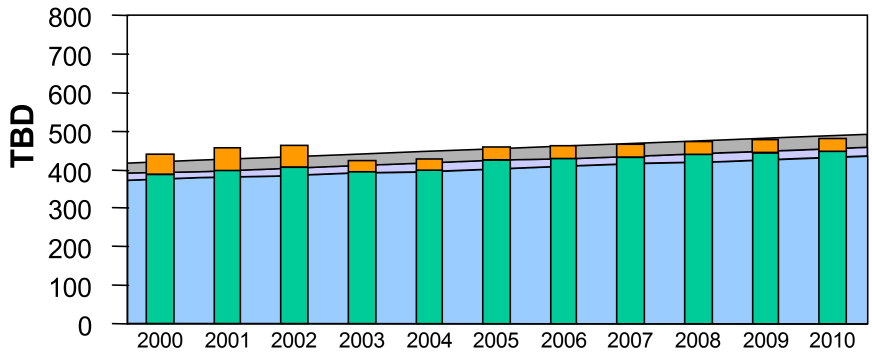
Other than the project to convert 22 TBD of conventional gasoline into CARB RFG in the Bay Area, there are few other major expansion projects that have been announced. It is estimated that a prolonged period of high price levels will provide a justification for other capital projects and may result in an additional 23 TBD of gasoline in the Bay to come on stream in 2005, which is the reason for the increased supplies shown in Figure 1.13 below for Northern California.

Other major projects, such as the expansion of a crude unit in LA and the restart of the idled Powerine refinery by CENCO, met with strong environmental opposition, which, in conjunction with marginal economics, has caused these projects to be abandoned.

1.3.4 Northern California Supply/Demand Balance

For the base case demand, Figure 1.13 and Figure 1.14 show the supply/demand balance for Northern and Southern California respectively.

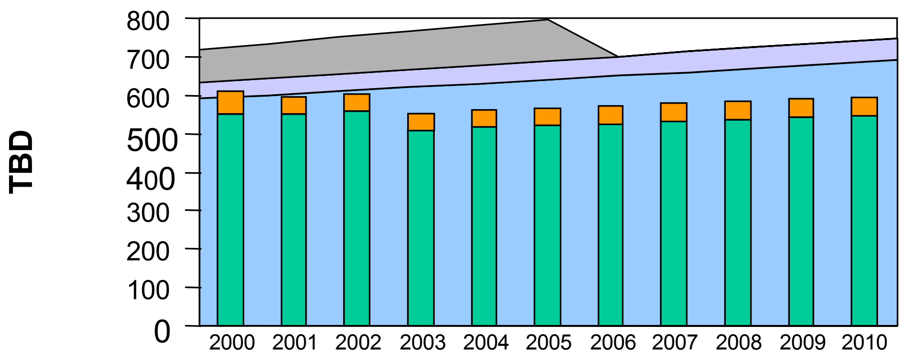
Figure 1.13 – Northern CA Gasoline Supply/Demand Balance



Demand	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OR	28	28	29	29	30	30	31	31	32	32	32
N-NV	17	18	18	19	19	20	20	21	22	22	23
N-CA	372	378	384	390	396	403	409	416	422	429	436

Supply	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
CONV	52	58	54	31	31	32	32	32	33	33	33
RFG	386	398	404	395	399	425	429	433	438	442	447

Figure 1.14 – Southern Gasoline CA Supply/Demand



Demand	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
AZ	87	91	95	99	102	106	0	0	0	0	0
S-NV	41	43	45	47	48	50	51	53	54	55	56
S-CA	591	600	610	620	630	640	650	660	671	682	693

Supply	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
CONV	58	43	44	44	45	46	47	47	48	49	50
RFG	549	552	558	511	516	521	526	532	537	542	548

From Figure 1.13 and Figure 1.14 it will be clear that whereas northern California is only minimally impacted by the MTBE phase out, southern California will see its import dependency – which is represented in the charts as the difference between the areas and the bars – approximately double. More importantly, the south currently depends for its shortfall in CARB RFG on barge imports from the Bay Area to the LA Basin by barge.

While the Bay area will be roughly balanced again once the all planned major refinery projects are completed, the south will still be significantly short even when the capacity of the East Line pipeline to Phoenix will be expanded. The shortfall will be even more acute when a rapid economic recovery will spur the demand to growth rates of 2% and more, as seen in 1996 – 2001.

1.3.5 Price and Volatility Effects of Shortfall

The effect of price on demand of gasoline, commonly referred to as the price elasticity of gasoline demand, is defined as the percentage change in the demand of gasoline divided by the percent change in price. Thus, a price elasticity of – 0.1 for example, suggests that a 20% increase in price would correspond to a 2% fall in demand.

The price elasticity for gasoline is not a constant number over a wide price range, but will be a function of other factors. For instance, the overall price level will play an important role: at low overall price levels, i.e., when crude oil and energy prices are low, a price increase by a certain percentage will not have the same impact on demand as the same percentage increase when prices are already high. Also, general economic conditions and substitution factors such as readily available public transportation will play a significant role. The latter may vary by region; for instance, in the Bay Area, where a well functioning public transportation alternative exists, short-term responsiveness will be different from the LA Basin, where public transportation options are more limited.

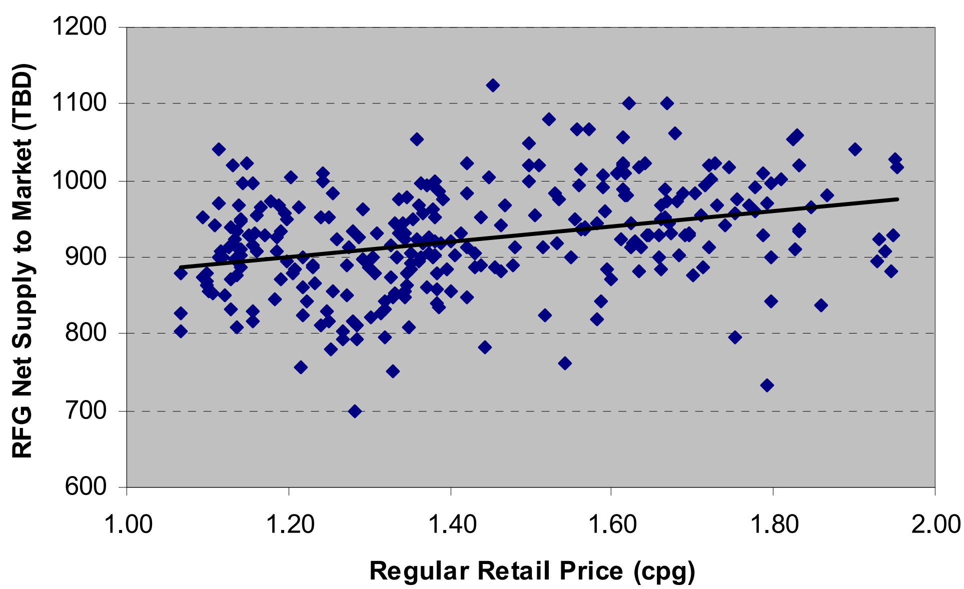
Moreover, there will be a significant difference between short-term responsiveness and long-term elasticity. Longer term, the effect of continued high pricing, such as that caused by fuel tax policies in many parts of the world, will have an impact on overall vehicle fleet fuel economies, use of alternatively powered cars, additions of public transportation infrastructure, and changes in demographic factors such as urban sprawl. Most of these factors take between 5 and 10 years to have a noticeable effect on consumer behavior. Short-term, the effect of these factors is negligible. Therefore it is not surprising that estimates given in Table 1.5 below have fairly wide ranges.

Table 1.5 – Gasoline Price Elasticity[13]

	Short-Term	Long-Term
FTC (2001) Midwest Gasoline Investigation	- 0.1 to - 0.4	Not reported
WSPA (2001) (PIRINC study)	- 0.05	Not reported
API (Porter) (1996)	- 0.19	- 0.71
Haughton & Sarkar (1996)	- 0.12 to - 0.17	- 0.23 to - 0.35
Espey (1996)	Not reported	- 0.53
Goel (1994)	- 0.12	Not reported
Goodwin (1992)	- 0.27	- 0.71 to - 0.84
Sterner (1992)	- 0.18	- 1.0
World Bank (1990)	- 0.04 to - 0.21	- 0.32 to - 1.37
Dahl (1986)	- 0.13 to - 0.29	-1.02

The combined sources of reported numbers as shown in Table 1.5 put short-term elasticity in the range of – 0.04 to – 0.40, and long-term elasticity in the range of – 0.23 to – 1.37. Below, an attempt will be made to derive more specific numbers for California.

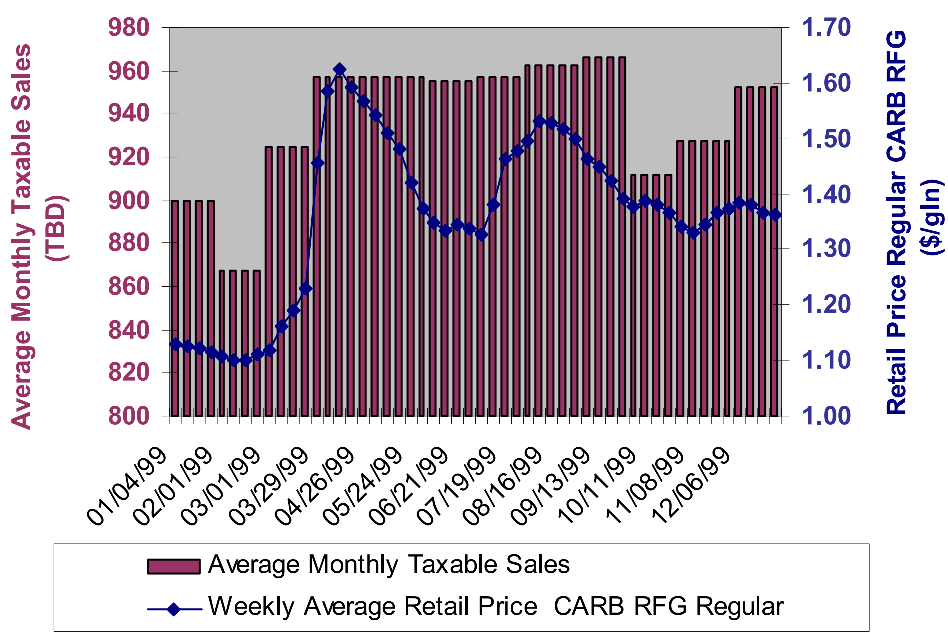
Figure 1.15 – Correlation CA Retail Price and Demand 1997 – 2001



[13] Table from Anthony J. Finizza Ph.D., *Economic Impact of Refinery Disruptions*, CEC Study, June 2002; full bibliography references are provided in this report.

Figure 1.15 shows the weekly average net supply of CARB RFG (weekly production plus refinery inventory change) versus the weekly average retail price of regular grade gasoline over the period 1997 through 2001. Since inventory effects in the distribution chain are relatively small, and with the short supply lines typical for the California gasoline market, the weekly supplies are a reasonable approximation for implied demand. What is interesting to note in Figure 1.15, is that it in fact would indicate positive price elasticity, i.e., prices are higher in periods when demand is high. This implies a supply driven pricing mechanism, whereby competitive pressures lead to lower prices in periods of reduced demand (i.e., the winter driving season), with complete consumer indifference to any effect of prices when competitive pressures lessen during the higher demand summer season. Another contributing factor is that of world crude oil prices, which increased over the period 1997 through 2001, but did not slow down the economic growth nor California gasoline demand.

Figure 1.16 – Short-Term Price and Demand Effects



California's gasoline consumption therefore appears to be relatively indifferent to medium term price effects. In the short term, the shock factor of sudden price spikes can be expected to affect demand somewhat. In 1999, a series of supply disruptions in the period March through August caused a 5 -10% shortfall in supply that was only partially made up from inventories and by imports. Price spikes in the spot market and at their peak reached values of more than double the prior levels (See Figure 1.16 above and also Figure 7.2 and Figure 8.2). Whereas the spot market can move sharply, retail prices generally follow more slowly, for reasons discussed in 7.2. As shown in Figure 1.16, the effect of the outages on retail prices was that Regular Grade CARB RFG Gasoline in California increased from a level of $1.10 per gallon to between $1.40 and $1.60 per gallon, an increase by 30 to 45%. The reaction of the market to these price spikes was not instantaneous, and in fact, taxable sales numbers do not show a significant drop. However, actual sales numbers do not take show how high sales might have been in the absence of a price spike. A better way to approach the issue may be to look at the price impact of the 1999 supply disruptions by comparing the average rate of taxable sales in the second and third quarter of 1998 with those over the same period of 1999, while estimating the growth in latent demand over the summer driving season to be at least equal to the total increase in gasoline usage over these years of 2.9%, which is likely to be a conservative approach.

Table 1.6 – Implied Demand Elasticity Comparison 1998/1999

	Q2/Q3 1998	Q2/Q3 1999
Average Retail Price Regular CARB RFG	$1.18/gln	$1.46/gln
Average Daily Taxable Sales	921 TBD	928 TBD
	Expected 1999 sales rate, 2.9% growth	948TBD
	Implied Demand Elasticity	- 0.09

In summary, the anecdotal evidence of the 1999 price spikes seems to confirm that the California market behaves in terms of price and demand elasticity well within the range of reported numbers from other sources. In his more rigorous quantitative analysis, Dr Tony Finizza[14] uses a range of – 0.10 to – 0.20 to evaluate the financial impact of supply disruptions on the California gasoline markets.

1.4 Alternatives to make up Shortfall

In the absence of any real possibilities to increase production within California over the capacity creep and discrete projects already taken into account in the base case supply, alternative supplies to make up the projected shortfall consists in the short term of increased imports from other US producing regions, or from foreign sources. Longer term, supplies can be anticipated from pipeline projects now under development and refinery expansions which are as yet unannounced..

[14] Dr A.J Finizza, *Economic Impact of Refinery Disruptions*, Study for the California Energy Commission, April 2002

1.4.1 Supplies from US Gulf Coast

The US Gulf Coast is the largest refining center in the US, and as such is a logical place to consider when looking for alternative supplies to meet California's shortfall. It has always been recognized that the CARB Phase III requirements would make sourcing finished product or CARBOB from the PADD III refineries difficult, but it is the availability of other blendstocks that needs to be evaluated, as well as the capabilities of the transportation system to move any available product to the West Coast.

Currently, several US Gulf Coast refineries are capable of producing gasolines that at or near CARBOB II specifications and most of these have made occasional shipments to California in the past. However, it is not economical for these refineries to invest in the necessary upgrades to be able to produce Phase III base blendstock, because of the limited overall production capability of the boutique quality material, the incidental nature of the export shipments, and the emergence of other premium markets for the these type of blendstocks such as the Chicago market, where high margins can be realized without the need for additional investments[15].

Not only is there no justification for Gulf Coast refiners to upgrade their capabilities to meet California specifications, there is also not much spare capacity in the PADD III system overall. Much like the refineries in California, the refining centers on the Gulf Coast are currently also operating at or near maximum sustainable operating rates. Refineries in the US as a whole and on the Gulf Coast in particular, have seen a steady increase in overall capacity utilization as expressed in total crude runs, from average levels of 85% in the early nineties to at or even above calendar day capacity during the seasonal peak demand periods in recent years[16]. Similarly, capacity utilization in the main gasoline-producing unit within most Gulf Coast refineries, the Fluidic Catalytic Cracker (FCC), has seen a steady increase and the total FCC capacity is fully utilized. In fact, demand now consistently exceeds capacity, and New York harbor depends on foreign imports to balance supply and demand. This means that any product shipped from the Gulf Coast to California will back out pipeline volumes to New York and will result in additional foreign imports into the Eastern states.

Besides finished gasoline or near finished blendstocks, a key gasoline component exported from the US Gulf Coast is alkylate. The choice blending component, which

[15] Information received during a Stakeholder Survey Meeting conducted for the CEC's Strategic Fuels Reserve Study.

[16] Source data: EIA

best fits the particular needs of the California refiners, is C7 alkylate, which is produced by combining propylene and butanes in a reaction that is catalyzed by sulfuric acid or hydrofluoric acid in a process that requires some of the most stringent safety and environmental precautions of any refinery installation.

Because alkylation units are inherently more hazardous than most other refinery operations, they have been more difficult to build and to expand because permitting is not always possible. Also, the uncertainties surrounding feedstock availability and alternative market values make investment decisions difficult. As a result, while the Gulf Coast refiners have been able to increase their capacity in FCCs and cokers, alkylate capacity has remained virtually flat. Moreover, alkylation units compete with many chemical industries for propylene, which usually commands much higher prices in chemical applications than its value in the automotive fuel pool.

The issues of competing uses for propylene (impacting the availability of C7 alkylate), and the difficulty of substituting C8 alkylate given current T50 restrictions, were extensively discussed by Cal Hodge[17] in the context of a CARB workshop held November, 2000. The conclusion drawn at the time still seems valid, in that alkylates may play some role in meeting California's projected shortfall, but their overall contribution is likely to be limited to small volumes, i.e. one cargo per month, at a significant premium.

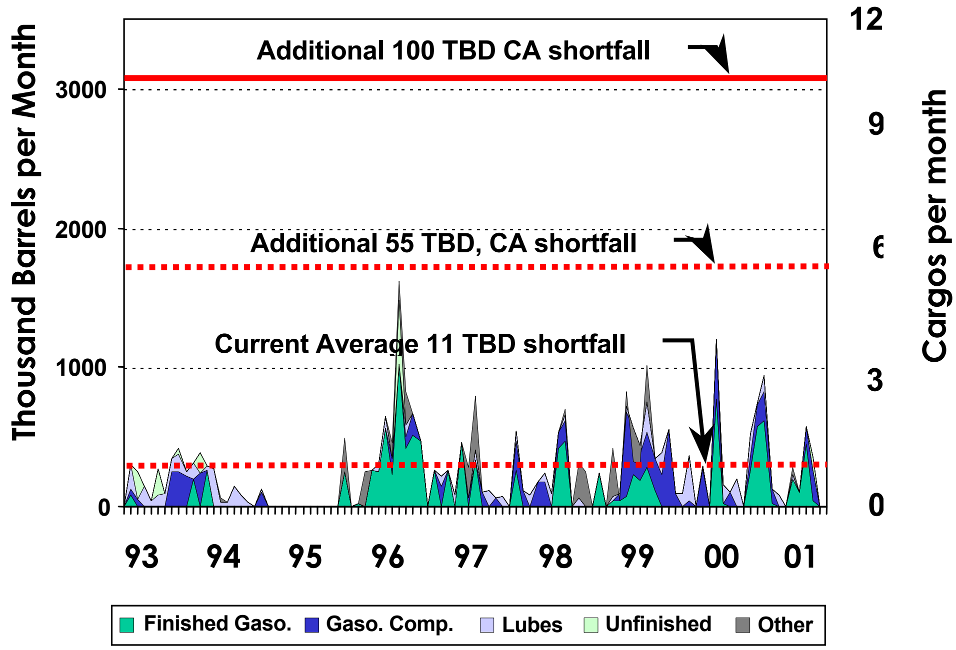
Finally, even if the US Gulf Coast were capable of producing additional gasoline blendstocks or components, there would not be sufficient Jones Act (prohibits the use of foreign flag vessels between US ports) product tankers available to transport quantities of 55 to 100 TBD, which is five to 10 times higher than the current volumes moved from the USGC to California. The impending phase out of single hull product tankers under OPA 90 severely reduces the availability vessels even further, making it necessary to rule out the US Gulf Coast as a short-term supply source.

It was shown earlier in Figure 1.6, that there is a rising trend with increasing volatility in the premium that California is paying over the Gulf Coast for its gasoline supplies. But while a price spike in 1996 was able to attract volumes from the US Gulf Coast at a rate corresponding to approximately 50 TBD, (see corresponding spike in shipping volumes in Figure 1.17 below), subsequent sustained and higher price differentials in recent years have triggered only moderate volumes to be shipped from the Gulf Coast.

[17] Letter by Cal Hodge, A2Opinion, to Alan C. Lloyd, Ph.D., Chairman of CARB, December 15, 2000

This confirms that increasingly, the US Gulf Coast and California have become disconnected markets, with quality requirements and lack of logistical means acting as barriers to supply.

Figure 1.17 – Maritime Movements of Petroleum Products USGC – CA



The conclusions that can be drawn from the analysis of US Gulf Coast supply options are that:

- Finished or near finished gasoline will not be available for CARB Phase III in any significant quantities.
- Components will be available at premiums that correspond to local blending value plus replacement imports costs.
- The choice blending component, C7 alkylate, is not available as a segregated stream and can only be sourced as a blend of mixed alkylates at premiums corresponding to alternate use of propylene as chemical feedstock.
- Even if blendstocks can be located, there will not be sufficient shipping capacity to move the products from the US Gulf Coast to California

The development of the gasoline price differential between California and the Gulf Coast over recent years supports these conclusions.

1.4.2 Supplies from Other West Coast States

The State of Washington has a major refining center on Puget Sound. In 2000, the Washington refineries shipped around 47 TBD of gasoline and blending components to California, while California exported 35 TBD to Oregon of conventional gasoline [18]. California refiners also own all major refineries in Washington, and often move products between Washington and California in order to optimize their material balances. Given prevailing market incentives, it appears that the current volumes represent the maximum feasible interstate exchanges, i.e. if significant spare capacity had existed, it would have been used. It is anticipated that a chronic shortage of fuels in California will lead to further optimization of these inter-refinery balances and that Washington refineries, after investments, may be able to increase their exports to California by up to 25 TBD.

1.4.3 Foreign Imports

Imports of foreign gasoline and blending components other than oxygenates have increased from erratic small net exports or imports in the early nineties to a level of 20 to 25 TBD in recent years. As with US Gulf Coast supplies, the availability and the logistics will have to be examined in order to establish what role foreign sources can play in alleviating a California supply shortfall.

Currently, several foreign refiners are capable of producing conforming CARB Phase II gasoline or “near-BOB”, base-stock gasoline that only needs the addition of MTBE to be on spec. Most of these have shipped occasional cargoes to California over recent years. A survey of these refiners completed as part of the Strategic Fuels Reserve Study currently underway revealed that only the Irving refinery in New Brunswick will be able to supply Phase III CARBOB, in quantities of up to two cargoes per month or the equivalent of 18 TBD. These supplies do not require Jones Act shipping and can therefore be delivered at competitive freight rates (8 cpg) and at relatively short notice (3.5 weeks transit). It is likely that most or all of this material will find its way to California if supply shortages will cause prices in California to depart substantially from East Coast levels, where the New Brunswick refinery currently sells most of its output.

Another potential source of Canadian material is Alberta’s Envirofuels, which is likely to convert its 18.5 TBD of MTBE production into an estimated 11 TBD of isooctane. This material is targeted for the California market, and the project is likely to be driven by the

[18] US Army Corps of Engineers Waterborne Commerce Statistics Center

need to move condensates from natural gas production rather than stand-alone economics, which would have forced Envirofuels to require significant premiums, given the conversion cost and the complicated logistics to move product from Edmonton, Alberta, to CA. Chevron, who is part owner in this venture, is likely to keep their share of the output within the Chevron system and use infrastructure released from MTBE service, while shareholder Neste may put their volume onto the open market.

In the Middle East, a new venture currently produces approximately 10 TBD of Phase II RFG, based on blends of isomerate and reformate. This facility has plans to increase production to 25 TBD, and make improvements to meet CARB Phase III specs. With current freight rates of 10 to 12 cpg, first supplies from this source have started moving into California in the fall of 2001.

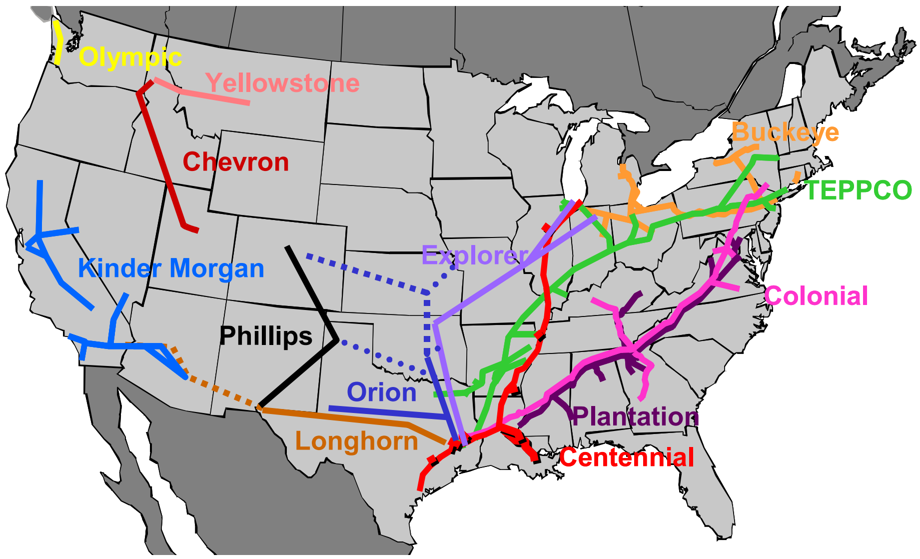
Other than the three specific foreign sources of CARB Phase III blendstocks, it can be safely assumed that the international majors such as ExxonMobil, BP and Shell, will be able to optimize the availability and usage of high quality blending components within their global refining systems, such that these materials will be routed to California when a price departure offers an opportunity to maximize corporate revenues on a global basis.

All in all, it would appear therefore that additional supplies up to 50 TBD could be mobilized at premiums over world market pricing that are not too different from price levels at which California currently buys its incremental barrel, although this volume does not appear to be committed to California at this time. Whether global availability of premium blendstocks will allow sourcing of 100 TBD seems a little more doubtful at this stage, but given sufficient incentive, i.e., if California's prices were to remain for a pronged period at levels of more than 50% over world markets, then it is likely that the State will attract every available conforming barrel that refiners around the world can segregate and ship. *The problem therefore becomes one of import logistics, and herein lies one of the key contributions a Strategic Fuels Reserve can make, provided it is designed to increase the State's capacity to imports fuels.*

1.4.4 Pipeline Supplies

One of the alternatives to supply California's shortfall is to transport products by pipeline from the US Gulf Coast. The issue here is not just that it requires pipelines that will move finished products from the refining center on the US Gulf Coast to the West Coast across 1500 miles of distance, but also that the availability of West Coast quality products on the US Gulf Coast is uncertain.

Figure 1.18 – Overview of US Long-Distance Product Pipelines



Once completed, the Longhorn pipeline will link the Eastern and Western gasoline supply systems in the USA, as shown by the dotted line in Figure 1.18. In principle, this would enable an arbitrage to be established between the two markets based on differentials in pipeline tariffs, fuel quality and transfer times[19]. However, the linkage is not effective until sufficient capacity is available at the connection point, which as explained below, may not happen in the foreseeable future.

Currently, the bulk of West Coast sourced demand in Arizona goes to Maricopa County (Phoenix and the surrounding cities). The stringent quality of gasoline for this area is very similar to California's gasoline quality. The issue is that demand for low sulfur gasoline will increase dramatically east of the Rockies (EOR) when the EPA reduces sulfur levels of all grades of gasoline in 2005. In the face of increasing local demand, supplies of low sulfur RFG will have to be bid away from local markets in order to move them to Arizona. This supply equation will be further complicated if Arizona decides to blend ethanol with gasoline in Maricopa County in the summer. An ultra low RVP blendstock, similar to CARBOB will be required.

The existing pipeline network for Southern California, Southern Nevada, and Arizona originates in Los Angeles. Product is moved by Kinder Morgan Energy Partner's pipeline from Los Angeles to San Diego, Las Vegas, and Phoenix. The LA to Phoenix

[19] Interliance, Pipeline Study for the CEC, March 2002, and Drew Laughlin, CEC Consultant Report , March 2002

system is known as the West Line. Some volume from Los Angeles also moves past Phoenix to Tucson.

Longhorn Pipeline is in the process of building a line from the refining center in Houston to El Paso. The company completed construction in June 2002, after the project has been significantly delayed by objections of the City of Austin, Texas. These issues now appear to have been resolved and the first products are expected be delivered into El Paso in the September 2002. The initial rate will be 75 TBD. The line's capacity can be expanded to 225 TBD with the construction of additional pump stations [20].

Because demand for the existing Kinder Morgan East Line from El Paso to Tucson and Phoenix exceeds its capacity, with flows for each customer being prorated, this line will have to be de-bottlenecked or a separate pipeline will have to be built to move the product that Longhorn can deliver to the Tucson and Phoenix markets. It is estimated that this separate line, or loop, in pipeline terms, could be completed at the soonest by late 2005 or early 2006, but industry feedback and Longhorn's dismal experience in obtaining pipeline permits and right-of-ways indicate that it would be optimistic to expect a fast track completion for such a project. However, if the pipeline were to be extended and if products are available from the Gulf Coast, they could displace all or part of the 93 TBD forecasted to be exported from California in 2006.

[20] Meeting with Longhorn Pipeline, CEC, CARB, Interliance, and Stillwater Associates, December 12, 2001, and subsequent contacts.

2 GENERAL REQUIREMENTS FOR A STRATEGIC RESERVE

The assignment contained in State Assembly Bill AB2076 is to evaluate the feasibility and costs of a reserve equal to two weeks of production of the largest refinery in California. Based on incidents occurring in recent years, a period of two weeks was considered to be a good order of magnitude fit with observed unplanned outages of refineries in California. For CARB gasoline, two week's worth of the largest individual production by a refinery in the State corresponds approximately to 2.3 million barrels. For CARB diesel and jet fuel, this number is 0.6 million and 0.9 million barrel respectively.

Because of unusable space in tanks (i.e., a tank will have a "heel", the minimum amount of liquid necessary to keep a floating roof from landing on the bottom, and a "freeboard" which is a minimum height to be left at the top), the nominal shell capacity of the tankage will be closer to 2.5 million barrels. Additional requirements for the reserve need to be formulated to ensure that the reserve is adequate to satisfy not just the letter of the Bill, but also the intention of the lawmakers, namely to ensure a certain degree of price stability at reasonable cost.

2.1 Requirements for Price Stability

A more detailed analysis of the effectiveness of a reserve based on two week's capacity of the largest California refinery will be provided in Section 8. However, some general operational requirements for a reserve can be formulated even when assuming that the two week's capacity requirement is a given. For instance, price spikes currently are almost instantaneous reactions in the spot market to supply disruptions that often last only days or weeks. If an unplanned refinery outage occurs at a time when industry inventories are already low, an intervention with volumes drawn from a reserve will have to be quick, i.e., within days rather than weeks, in order to have effect in stabilizing prices.

The need for reserve inventories to be immediately accessible translates into requirements not only for release procedures, but also for the logistics of moving product from the reserves into the markets. Even before conducting a detailed analysis of the reserves interaction with market mechanisms, it can be concluded that in order to bring price stability to a market where prices can move up by as much as 20 cpg on the same day that an announcement is made about a refinery outage, the reserve should have the capability, credible to the marketplace, to deliver product into the market within at the most one or two days at rates comparable to the lost capacity.

2.2 Fuel Quality Requirements

Typically, a California producer of gasoline may have to store and blend as many as 6 different qualities of gasoline during each of two separate seasons, a winter season which in most parts of California lasts from November into February, and a summer season which lasts the remainder of the year and is characterized by more stringent vapor pressure requirements. The diversity of gasoline grades, the seasonal changes, and other quality aspects such as the limited shelf life of gasoline in general, impose particular challenges for the eventual creation of a strategic reserve.

Moreover, given the likelihood of imports needed to replenish the reserve after a drawdown of stocks, and the fact that such imports will largely consist of blending components rather than finished products, the reserve will have to be designed in such a way that it offers flexibility in terms of storing various grades of unfinished products and blending components, and the ability to blend final products to customer specifications prior to delivery into the common carrier pipeline grid.

For this reason, it is recommended that tank sizes will be limited to 150,000 bbl, a size generally considered as not too big to store blending components cost effectively, and not too small so that at most two tanks are needed to receive waterborne shipments in full cargo loads. The tanks will have to be designed for multiple product use with drain-dry bottoms. Also, blending and circulation pumps will be highly desirable, as well as a Vapor Destruction Unit (VDU), that will enable collection and incineration of vapors displaced under a floating roof when it is refilled after the tank has been fully drained, with the roof landing on its supports. When considering those alternatives that involve newly built storage, the costs of the above facilities will be taken into account.

Even if the reserve is built as part of larger new storage terminals in which state-sponsored tankage is made available against commercial rates to qualified third parties, i.e., built 5 million barrels of capacity, keep 2.5 million for the reserve and lease the other half to commercial third parties to create a large commingled pool of gasoline and components, it is recommended to augment the number of tanks rather than the tank size. This will allow individual storage for all commonly used blendstocks and components, and will create the operational flexibility to maintain reserve inventories that can be blended to meet the specific requirements of a particular supply disruption.

2.3 Logistics Requirements and Site Selection

In determining the best location for the reserve, it is necessary to evaluate the logistics of delivery of fuels from the reserve into the market, as well as those of restocking the reserve after drawing down inventories. In order for the reserve to effectively compensate for an unplanned outage of a major refinery, it is important that fuels released from the reserve can reach the markets quickly, as concluded under 2.1 above. This translates into infrastructure requirements that will prevent the logistics involved of becoming a bottleneck in itself and still cause price spikes in the market.

Since California effectively consists of two separate markets served individually by the main refining centers in the LA Basin and in the Bay, a single location for the reserve would greatly reduce its effectiveness. In the absence of a pipeline link for products between the Northern and Southern refining centers, a single reserve would only be able to provide immediate relief to the market in which it is located, whereas a significant logistics effort would be required before product could be delivered to the other market. For instance, if a reserve were to be located in the Bay Area, and a supply disruption such as an unplanned outage of a major refinery occurred in the LA Basin, then at least 100 TBD of products would have to be transported over an average distance of approximately 400 miles, for a total transport requirement of 40 million barrel-miles per day.

Very little gasoline moves by rail in California and as a consequence the rail infrastructure in terms of tank cars and handling facilities is incapable of playing any role whatsoever in moving barrels from a reserve to market. Equally, the probability is low of finding and positioning a US flagged product tanker within days, the timeframe required to respond to a refinery outage before prices would be affected, also ruling out this transportation mode as an option. This leaves trucks and barges as the only remaining alternative, but here the issue is whether or not the transport system can mobilize sufficient additional capacity at short notice.

On average, delivery of gasoline to the retail stations involves an estimated 30 million barrel-miles per day of tank truck movements, while shipments of petroleum products and crude oil by coastal barge along the West Coast were 4.6 billion ton-miles[21] in 1999, or approximately 100 million barrel-miles per day. Clean product movements make up approximately one third of this volume. This means that to transport fuels from a reserve location in the Bay Area to LA or vice versa in case of a major refinery outage would require more than doubling daily truck and barge movements. It is not realistic to expect so much transport capacity to be available at short notice (i.e., as spare capacity, not otherwise utilized).

Given these logistical constraints it will be clear that if a reserve is to be created, it will have to consist of at least two separate storage centers, one for each main market. Other locations

[21] US Maritime Administration, *"Highlights Coastal Tank Barge Market",* Staff report, May 2001.

may be considered in addition, for instance at the existing staging terminals for the main long distance pipelines. However, if reserve volumes are located further downstream in the distribution system, they should not exceed the demand of the downstream market over the time period to be covered. If larger reserves were to be created further downstream in the distribution system, the volumes in excess of local demand would require reversal of normal distribution flows in order to be of any use, which in most cases is impractical if not impossible.

In general, given the high degree of utilization of the California infrastructure for fuel deliveries (terminals, gathering systems, long distance pipelines, truck, rail and barge fleets), it will vastly increase a reserve's effectiveness if it can be integrated into the refining centers in such a way that in order for the reserve volumes to reach the market, they will use the same logistical assets as the refinery volumes they replace.

Another important logistics consideration in determining suitable locations for a reserve is that of re-supply. Since California is overall short in production capacity for all its fuels, with refineries running at maximum capacity and achieving utilization rates of 95% or more, any lost production due to an outage of a major refinery must either be made up by imports or balanced by reduced demand caused by price increases. Since the latter is the undesired effect the reserve hopes to prevent, it follows that any volumes drawn from the reserve will have to be made up either directly or indirectly by imports, while additionally any short-notice delivery from the reserve must utilize existing infrastructure capabilities. Therefore the logistical requirements for an eventual reserve can be summarized as follows:

- The separate northern and southern California markets will each have to be served by its own reserve.
- The reserves will have to be integrated into the two refining centers in such a way that product from the reserve can be delivered to the market using the existing infrastructure, seamlessly replacing the lost volumes.
- The reserves will have to be provided with deepwater access so that they can be restocked directly with imported products.

The locations that meet these requirements are (i) in the North, the Eastern Bay area within the gathering system connecting the local refineries and commercial terminals with the Kinder Morgan pipeline head in Concord, and (ii) in the LA Basin, the Wilmington/Carson/Watson area with access to all major refineries, and tied into the feeder system for the Kinder Morgan pipelines at Colton. Further downstream, additional storage can be provided at Concord and Colton, or other pipeline hubs.

The problem that arises when locating separate reserves in each of the major refining centers is that of the distribution of the volume. If the requirement for two week's production of the largest refinery were applied to each of the centers, then the LA Basin reserve would have to be 2.2 MM bbl, and the Bay Area reserve 1.7 MM bbl. However, if a first reserve can provide immediate relief to the market in which it is located, volumes from the second reserve can be brought in over time across the distance separating the two markets within the restraints of the available logistical means. For the purpose of further evaluation, it will therefore be assumed that the total volume of all reserves will be kept at two week's capacity of the largest refinery, or 2.2 MM bbl, to be split into 1.3 MM bbl in the LA Basin and 0.9 MM bbl in the Bay Area, volumes that not only correspond to the ratio of gasoline consumption in the respective markets, but also to the ratio of the production capacity of the largest refinery in each center. These volumes would allow approximately one week's of autonomous coverage within each region, which provides adequate time to mobilize logistic resources to utilize reserves stocked in the other region if necessary.

2.4 Requirements for Extraordinary Events

Besides unplanned outages of California's refineries, there are other events that can cause even more severe supply disruptions and price spikes, i.e., earthquakes, acts of terrorism, crude oil supply disruptions resulting from environmental disasters (as was the case after the Exxon Valdez disaster), or geopolitical events such as embargoes and wars. In fact, as will be shown in Section 3 below, most countries that maintain a Strategic Fuel Reserve do so for reasons of national security rather than market stabilization. In such cases, the reserve volumes are much more substantial, i.e., in the range of several months of total consumption rather than two week's capacity of a single refinery.

While the creation of a reserve for reasons of national or State security is not included in the scope of this study, it is relevant to look at the potential value of a reserve in case of an earthquake. Whereas events such as wars and embargoes will have an impact on a national scale that requires very large reserves, the effects of an earthquake tend to be local and previous reserve studies were specifically commissioned to cover this event.

When evaluating the potential value in the event of an earthquake of a smaller reserve designed for commercial market stabilization, it becomes quickly apparent that the locations identified above for logistical reasons render the reserves vulnerable. The East Bay Area and the Watson/Wilmington/Carson area essentially share the same geologically unsound coastal structures as the major Californian refineries, and in that respect, they are not ideal because they too are likely to be affected to some extent by the same quake that might damage one of the refining centers.

Yet, to design a reserve capable of providing adequate coverage of fuel needs in the wake of a major earthquake is not practical and was evaluated in earlier studies as not cost effective. The reserve in that case would have to provide for many weeks of equivalent capacity to not one but likely several major refineries, for events that have a very low probability of happening during the technical and economical lifespan of the reserve.

For extraordinary events, for which the extent of the shortfall and the duration of the outage are likely to require a very large amount of fuels in reserve to mitigate the effects of the outage, but which have a very low probability of ever happening, a better approach than the creation of a reserve is a temporary relaxation of California fuel quality requirements, so that alternative supplies can be brought in from a wide array of supply options outside the State.

3 DESCRIPTION OF OTHER STRATEGIC FUEL RESERVES

National Petroleum Reserves became part of an overall emergency response plan orchestrated by the International Energy Agency (IEA) under the 1974 Agreement on an International Energy Program (EIP) of which the United States is a signatory. Every five years the IEA publishes an exhaustive report on its Member countries' preparations to respond to major oil supply disruptions. Most of the 28 countries maintain oil stocks well above the 90 days of net imports to which they are committed. IEA countries also have viable demand restraint programs and are monitored for weaknesses in their response systems. Those response mechanisms include: stock drawdown, demand restraint, fuels switching, extra oil production and the sharing of oil supplies.[22] Below, several of the domestic and international reserve initiatives will be evaluated in order to see whether experience gained with the creation and operation of these reserves has relevance for the situation in California.

3.1 General Aspects of Strategic Fuel Reserves

Some of the key aspects of strategic fuel reserves in general are the sizing, inventory management and release mechanisms

3.1.1 Sizing of Strategic Fuel Reserves

Almost all national SFR's are maintained by countries that are significant net importers of petroleum products, and the size of the inventories is designed to protect these countries from being held hostage by their supplying nations. Usually, such reserves are sized as a function of the total fuels demand of the nation as a whole, with typical quantities of fuels stored ranging from 90 to 120 days.

There are only a few instances where, as would be the case for California, a reserve is designed for price stability. Examples are the Northeast Heating Oil Reserve and the Massachusetts Heating Oil reserve, which were designed to protect their populations against price spikes as well as the physical dangers from running out of heating oil in abnormally cold winters.

There is no known example of a reserve specifically created to counteract supply disruptions caused by internal production problems, although the reserves created in other island economies such as Korea and Japan used to have, will have a somewhat dampening effect on prices, as will be discussed below.

[22] International Energy Agency website – http://www.iea.org

3.1.2 Inventory Management of Reserves

Many countries store petroleum products in addition to or instead of crude oil as part of their oil stockpiling programs. A broad range of stockholding mechanisms have been adopted by IEA and European Union (EU) members, none of which match the commercial or logistical features of California but are useful to consider as points of reference. There are three primary mechanisms:

- **Government Stocks**. These stocks are owned and controlled by member governments and account for 26 percent of stocks in IEA counties. Germany, Italy, Ireland, Japan and the United States hold government stocks.

- **Agency Stocks**. These stocks are held by agencies created by members for purposes of holding stocks and collaborating between government and industry. Agency stocks are much the same as government stocks, in that they fall under government procedures, are segregated, are of the same quality as government stocks, and are subject to government control. Agency stocks account for 5 percent of stocks in IEA countries.

- **Company Stocks**. These are privately held stocks, which count toward a member's IEA reserve commitment. In 1993, company stocks accounted for 69 percent of stocks in IEA countries. The only IEA member countries that do not impose compulsory stockholding requirements on companies are the two net oil exporters, Canada and Norway, and Australia, the United States and New Zealand. Under this approach, strategic stocks may be held by the oil industry on behalf of the government, usually as a legal requirement. Obligations are calculated and monitored by the government. Strategic stocks are part of or considered alongside operational stocks.[23]

The U.S. opted for a centralized government reserve, rather than the "industrialized petroleum reserve" or agency concept. Advantages of a government reserve are complete control over storage with release and use of stocks under central control with minimum disruption to the oil industry. Disadvantages are high initial set-up costs and administrative and technical burdens to the government. An amalgamated system provides flexibility but makes it difficult for the government to know how much oil is available in an emergency.

[23] Report to Congress on the Feasibility of Establishing a Heating Oil Component to the Strategic Petroleum Reserve, June 1998, Appendix F.

The U.S. differs from many other IEA countries in its means of financing the Reserve. In contrast to the United States, where the costs of the reserves are borne fully by the Government and financed out of general revenues, in countries such as Japan, Germany, and Italy, the costs are shared by the petroleum industry and the end-user.

Advantages of the agency approach to stockpiling are use of oil industry expertise for management, increased consideration of oil industry interests and flexibility in storage and distribution arrangements. Disadvantages are the high costs to set up such a program unless existing stocks and storage are already available, and the need for arbitration of various industry interests. In the case of a California SFR being adopted, this model had the strongest positive feedback among the stakeholders. Unanimously, the industry did not want to see the government operating a petroleum reserve. An Agency arrangement would be more responsive to California's unique supply, scheduling and pricing environments.

3.1.3 Trigger Mechanisms

One of the most critical components of any SFR is its trigger mechanism for release of inventory. For most national strategic fuel reserves, the authority to release inventories is vested at high levels in a country's executive branch, under conditions that meet a number of predefined criteria, which are usually so narrowly defined that the existence of the reserve is not really a factor in day-to-day market considerations.

For a reserve whose aim it is to prevent price spikes rather than to be there for national emergencies, a trigger mechanism needs to be broader defined. There is a widespread concern that if this vital element is mismanaged then price spikes could be prolonged rather than remedied. Uncertainty over when SFR inventories might be sold into a tight and rising market could actually inhibit out-of-state suppliers from sending cargoes to California. They would fear that after putting a California-bound cargo on the water, the SFR might dump product, driving down the price and undermining the value of their cargo position. Since there is no futures market in the State, an offshore supplier would be subject to this unintended risk.

The same concern was voiced by a number of participants in the Federal Petroleum Products Reserve (FPPR), during the feasibility assessment phase of the Heating Oil project. Even today, with the FPPR a well-defined and ongoing operation, a number of prominent companies believe that unfettered supply and demand forces are still the best antidotes to skyrocketing prices. They assert that when prices rise sharply, an immediate commercial incentive is created to deliver new supplies into that market from NW Europe, the Caribbean, from the US Gulf Coast and South America. Technical analysis of the efficacy of the Federal HO trigger mechanism still reveals flaws in the internal logic of that program.[24] *An eventual California reserve must be designed such that its use does not invoke an arbitrary, event driven trigger mechanism that caused importers to withhold shipments*.

3.2 Federal Strategic Petroleum Reserve

The Strategic Petroleum Reserve (SPR) was created in 1975 in the aftermath of the first oil crisis when President Ford signed the Energy Policy and Conservation Act [25] (EPCA42 U.S.C. §6231, et seq.). Several earlier attempts to create a national oil storage reserve during WWII and the Suez Crisis, and lastly by the Cabinet Task Force on Oil Import Control in 1970, all had failed. The SPR was commissioned in 1977 and it still is the largest emergency oil stockpile in the world, with a design capacity of up to 1 billion barrels. Together, the facilities and crude oil represent more than $20 billion in national investment. The emergency crude oil is stored in caverns created deep within the massive salt deposits that underlie most of the Texas and Louisiana coastline. The caverns offer the best security and are the most affordable means of storage, costing up to 10 times less than aboveground tanks.

The EPCA gives the Department of Energy (DOE) statutory authority to implement the Plan for a Strategic Petroleum Reserve, which is to acquire and operate the storage facilities. Equally, the DOE has the authority to acquire petroleum products for the SPR. The EPCA also authorizes the establishment of Regional Petroleum Reserves (RPR) as part of the SPR, and requires that the SPR Plan provide for the establishment of an RPR for each Federal Energy Administration region that relies on refined product imports for more than twenty percent of its demand.

Finally, the EPCA authorizes the Secretary of Energy to establish an Industrial Petroleum Reserve, which is defined as that part of the SPR consisting of petroleum products owned by importers or refiners (rather than owned by the Federal Government), and grants the Secretary discretionary authority to require refiners and importers of petroleum products to maintain readily available inventories equal to three percent of the previous years' throughput or imports.

The volumes of the SPR may only be used when the President determines that implementation of the Distribution Plan foreseen by the EPCA is required by a "severe energy supply interruption or by obligations of the U. S. under the international energy program", i.e., when

[24] PIRA report

[25] DOE Fossil Energy – Strategic Petroleum Reserve: Website – http://www.fe.doe.gov/spr/spr_facts.shtmal

the President determines that there is a significant reduction in supply, causing such a severe increase in the price of petroleum products that it is likely to cause a major adverse impact on the national economy.

Two exceptions permit sales from the SPR without a Presidential declaration under the emergency conditions, either as test sales in amounts not to exceed 5,000,000 barrels, or in amounts not to exceed 30 million barrels in total or for more than 60 days, both under narrowly defined conditions.

Relevance for California: The relevance of the EPCA for an eventual California Fuels Reserve lies in the federally mandated requirement for the creation of a Regional Strategic Petroleum Product Reserve for regions that are dependent on imports for more than 20% of their fuel requirements. California's foreign imports currently amount to approximately 25% of its crude and 15% of its petroleum products, percentages that are both expected to increase significantly. Thus, if the State were to constitute a region in its own right, it would have to create reserve for crude now and one for products in the not too distant future.

3.3 Northeast Heating Oil Reserve

The Northeast Heating Oil Reserve (NHOR) was created as a Regional Petroleum Product Reserve (RPPR) under EPCA, at the initiative in 1996 of several Members of Congress who were concerned that low inventory levels of heating oil might cause severe price spikes or outages in case of a severe winter[26].

The basic volume requirement for the reserve was set by estimated heating oil consumption in the Northeast during a severe winter, with a duration and with temperatures that can be expected to occur only once every 100 years, based on the statistic evidence of meteorological data collected for the region since the middle of the 19th century, which happened to correspond to conditions that prevailed in 1989. This calculation resulted in a volume requirement of 6 million barrels, but since only 2 million barrels could be placed in existing terminals in the Northeast itself, it was decided to limit the regional reserve to this volume, while provisions such as a waiver of the Jones Act would enable quick re-supplies from other inventories available in the SPR caverns in the Gulf Coast.

Three private companies were selected to store and manage the NHOR in leased storage at three terminals, located in New Haven, CT and Woodbridge, NJ. The reserve is commingled with commercial volumes in active tanks to avoid quality problems with aging inventories. Also,

[26] Department of Energy, *Heating Oil Component to the Strategic Fuel Reserve,* Report to Congress, June 1998

the commercial operators are occasionally allowed to dip into the reserve volumes with prior approval of the DOE.

The Northeast Heating Oil Reserve has special relevance for this study because it is one of the few examples of a reserve created specifically to provide price stability, rather than for reasons of national security. Moreover, the reserve was designed to meet certain criteria of cost effectiveness, and the methodology used in the study that justified its creation was based on sophisticated statistical evaluations.

During stakeholder survey meetings (see section 9), the issue was raised with companies that market fuel oil on the East Coast, and several meetings were dedicated specifically to this subject. The conclusion from these discussion is that, even though the reserve has not yet been put to the test of the once in a 100-year winter for which it was designed, the reserve is not expected to be effective in the opinion of the industry involved in the heating oil business in the region. The perceived shortfalls are:

- The 2 million barrels of reserves equate to only three days of average winter demand in the Northeast, less than two days in case of peak demand during a cold snap.
- The reserve occupies existing tankage that was well used by the industry and usually would be kept full at the onset of the winter heating season anyway (this argument was addressed in the heating oil study and was one of the reasons for only using up 2 million barrels of space).

Relevance for California: Because the Northeastern Heating Oil Reserve is one of the few reserves specifically designed to mitigate price volatility, and was executed within similar size tankage as would be the case for a California SFR, this reserve merits a more detailed comparison. In table 3.1 below, a comparison is made between the various factors that together constitute the framework for requirements and effectiveness for a Regional Petroleum Product Reserve.

From the comparison below, it will be clear that the requirements for an eventual California Strategic Fuels Reserve are far more complex but also more urgent than those of the Heating Oil Reserve in the Northeast. It would seem that if a reserve for heating oil in the Northeast could be justified on economic grounds, then a gasoline reserve in California could also be warranted by an economic justification. In this context it is interesting to note that the inventories for the Northeastern Heating Oil were in part funded at federal level by selling off equivalent quantities of crude oil from the Federal Reserve.

Table 3.1 – Northeast Heating Oil versus CA Gasoline Reserve

	Northeast HO*	CA Gasoline
Demand	0.7 MM BPD winter average	1.0 MM BPD year round
Available Inventory Range	20 to 60 MM bbl = 40 MM bbl	18 – 10 MM bbl = 8 MM bbl
Effective days inventory	70 days av. winter demand	8 days regular demand
Product Fungibility	Readily fungible	Unique to CA
Product Grades	One	Multiple Summer and Winter
Blending restrictions	None	Unocal Patent, CARB cert.
Market Liquidity	1000+ trades/day	<20 trades/day
Futures Market	Broad, up to 1 year deep	Narrow, next month only
Market participants	Large Community	Closed Market
Pricing	Transparent	Limited reporting
Demand	Seasonal Only	Year Round
Import options	100s of refineries worldwide	3 – 5 refineries
Shipping time	1 – 2 weeks	5 – 8 weeks
Import terminals	68 in 26 ports	16 in 2 ports (incl. refineries)
% of Population Affected	11% (54% in Maine)	>90%

* basis: 1996 DOE Study

3.4 Massachusetts

Shortly after the initiation of the Federal Heating Oil Reserve, the State of Massachusetts adopted a somewhat different program to ensure adequate supplies for the state through the winter of 2000, 2001.[27] Discussions with consultants involved in crafting the alternative plan, and review of the provisions of the actual program adopted, reveal a deliberate departure from the "hold, auction and sell" philosophy that underpins the two million barrel Federal Reserve described above. The view was that incentives could be offered to private sector companies to hold certain minimum target inventories through the potentially high-demand months of

[27] Commonwealth of Massachusetts Office of Consumer Affairs and Business Regulation – Heating Oil Inventory Program, A Report by the Division of Energy Resources, March 2001

December through March. The supply, demand and general market pricing factors that compelled the Governor of Massachusetts to urge the Legislature to fund an emergency inventory program were these:

- Heating oil inventories were at historic low levels and only about one-fourth the level at the start of the previous heating season.
- Crude oil prices were extremely high and there was uncertainty if they would increase or drop.
- In October, Massachusetts retail heating oil prices were 50% higher than the previous year.
- Increases in world crude oil production would not eliminate heating oil market vulnerability.
- The market was in 'backwardation' (a term used when prices in future markets are below the prompt market) and Massachusetts heating oil suppliers did not want to store heating oil if they might lose money.
- Cold to colder-than-normal temperatures would also lead to price spikes and increases in consumer heating bills.

Innovative Program: Rather than the State leasing storage and holding inventory, the program establishes a price insurance program for winning bidders that takes the backwardation out of the market for the key months. Essentially, the winning bidders were expected to purchase and store a minimum block, or 10,000 barrels of heating oil. The bidder could submit bids for one or more blocks, and had to specify a bid price and specific storage location for each block. Winning bidders were required to hold the oil until January 16, 2000. Thereafter, the winning bidders could release the oil for sale to Massachusetts's consumers. The decision to release oil before the program date was left to the winning bidders. If the market dictated a need for oil, and winning bidders decided to use the program oil, winning bidders could sell the oil before the program end date (early release). Notification of an early release had to be provided to DOER on the date of the early release. Because early release of program inventory was contrary to the goals of the program, an adjustment would be made to reduce the payment to a winning bidder that executed an early release. The payment adjustment provided an incentive to winning bidders to store the oil until the program end date.

A review of the success of the program after the winter showed:

- Heating oil inventory levels were higher than expected despite colder weather.
- Wholesale prices in Massachusetts were 2-3 cents lower than in surrounding states.
- Massachusetts' retail heating oil prices remained around $1.50 per gallon in December and January with no price spikes even though the weather was about 10% colder than normal.

The entire scope of the program is described in detail on the Massachusetts Energy Website[28].

Relevance for California: Storage for heating oil by winning bidders under the Massachusetts program is distributed in independent terminals around the State. In California, there is no such distributive storage in the hands of independents. As will be shown in Section 4 below, inventory capacity for fuels in California is extremely tight already. Consequently, an incentive program such as that adopted by the State of Massachusetts is not practical in California. It should be kept in mind however, that if the SFR initiative leads to new tankage being built, then a Massachusetts style incentive program might have to be revisited.

3.5 European Reserves

The fundamental purpose that underlies all European and IEA Strategic Reserves is that of national emergency and supply interruption preparedness, with systems designed and maintained for major events such as wars, sabotage, and natural disasters. The Reserves are part of a more comprehensive emergency civil response plan under which the EU requires its members to hold emergency stocks of oil products for three major categories (gasoline and related feedstocks, middle distillates, and heavy fuel oil) equivalent to 90 days domestic consumption of the previous year. The level of 90 days must be maintained for each category. Members may substitute crude oil for product stocks, but the crude oil and feedstocks are converted into finished product equivalents in the three categories for purposes of meeting the EU requirements.

The European systems range from distributive stocks held by the private sector but under government supervision in Italy, to complex mechanisms that have evolved over time in countries as diverse as France and the Netherlands. In Germany, Italy and Ireland, the government owns the Strategic Reserves. Denmark, France and the Netherlands hold agency stocks, with some agencies established under pressure from the industry rather than by government on its own accord.

[28] Massachusetts Department of Energy Website: http://www.state.ma.us

Relevance for California: Most European countries store their reserves in large volumes kept outside the normal distribution channels, in salt dome caverns (Germany, France) or in cavities excavated in granite and other hard rocks (Scandinavia), or in extensive aboveground tank farms (The Netherlands). Because for the most part, the European reserves are not operational, the inventories need to be periodically rotated to prevent product degradation. For many years, for example, straight run (non cracked) gasoline was held in tank without rotation in the Netherlands. After a change of specs was introduced and various streams of cracked hydrocarbons entered the gasoline pool, the reserves had to be commingled with industry stocks for rotation purposes. The turning of large volumes of old inventory created artificial price collapses and volatility, a lesson to be learned for California.

Because the release mechanisms for the European product reserves are designed for exceptional circumstances only, the presence of very large reserves does not affect normal market mechanisms in terms of supply and demand, with its associated volatility, other than the impact from the occasional stock rollovers for reasons of quality control.

3.6 Japan

Japan has a history of oil stockpiling going back to 1972 after the first oil shock, when the government introduced the “Petroleum Reserve Law” creating a 60 day reserve supply, which was increased to 90 days in 1976 and relaxed in April 1996 to 70 days. These requirements apply to all producers and importers, and to crude oil as well as to refined products, with quantities based on actual import levels for the preceding twelve months.

The change in 1996 was part of a deregulation effort when the country repealed a law that restricted imports. Since then, non-refiners are allowed to import gasoline, diesel and kerosene into Japan, so long as they maintain a rolling inventory that complies with the Law [29]. The idea behind this policy is that some level of reserves must be maintained for emergency situations, but in normal times the competition on the international petroleum markets should prevail, even in Japan.

Relevance for California: The parallel with California is that for petroleum products, both are de facto island economies. But while Japan is moving away from its self imposed isolation by opening its markets for imports while maintaining certain minimum reserve requirements, California has been moving the opposite way when it imposed unique fuel specifications and

[29] Petroleum Association of Japan: http://www.paj.gr.jp Annual Report “Overview of the Japanese Petroleum Industry”

lost import infrastructure assets in the ports. The market lessons from Japan will be discussed in more detail in Section 7.

3.7 Korea

In South Korea, the Minister of Commerce, Industry and Energy has wide ranging powers under the "Petroleum Business Act" [30], which grants rights to set the target amount for petroleum reserve not just for major events but also for price stabilization and control of the petroleum markets. It is important to note that Korea has some of the largest refineries in the world with capacities at LG Caltex, Yosu and Yukong (SK) in Ulsan, each in the range of 800 to 900 TBPD. Refinery capacity is overbuilt and geared toward export markets. Consequently the Korean Strategic Reserve has been set aside for crude oil rather than petroleum products.

Relevance for California: Because the markets for petroleum products in Korea is only just now starting a process of deregulation with import opportunities opening up and arbitrage pricing mechanisms linking these markets to world supply and demand, it is too early to tell whether or not the presence of the reserves and the way in which the reserves were managed, had any stabilizing effect on pricing, or caused imbalances between natural supply and demand.

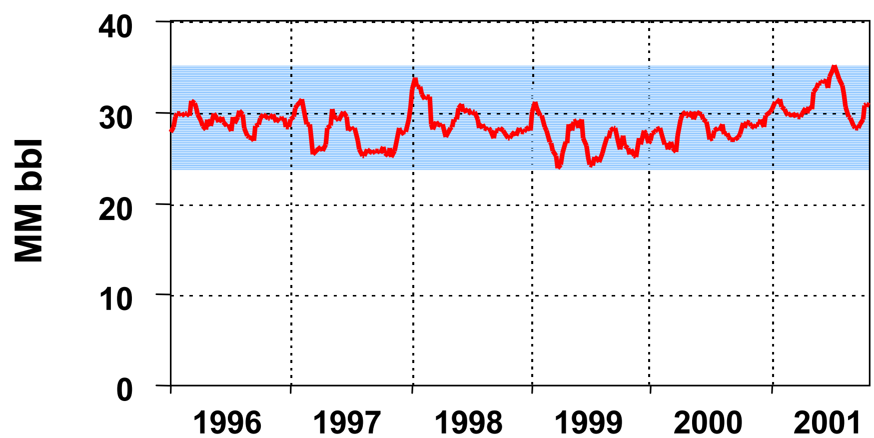
[30] Korea's Petroleum Business Act – Article 15; http://www.petronet.org/english/law/pact.htm

4 OVERVIEW OF INVENTORY CAPACITY AND USAGE

Besides the refiners, several traders and some of the larger buyers currently maintain their own inventories of fuels in California. The refiners also retain title to most of the products in the downstream distribution system, i.e., product in transit in pipelines and kept in distribution terminals.

The refiners and some of the terminals report their inventories on a weekly basis to the EIA and to the CEC. Unfortunately, most refiners consolidate their numbers for PADD V and do not separately report data by state.

Figure 4.1 – Weekly Reported Total Gasoline and Components PADD V



As can be seen in Figure 4.1, the total reported PADD V gasoline and blendstock inventories move in a fairly narrow band around 30 million barrels. When inventories fall below 27 million bbl, the market begins to anticipate shortages and product in general will be hard to find. When inventories start to climb over 30 million barrel, spot prices will start to fall, reducing the incentive to run crude or bring in imports. The 30 MM barrels of average stock represents approximately 18 days of supplies. This is lower than stocks elsewhere in the US, where inventories on average cover 30 to 35 days of supply.

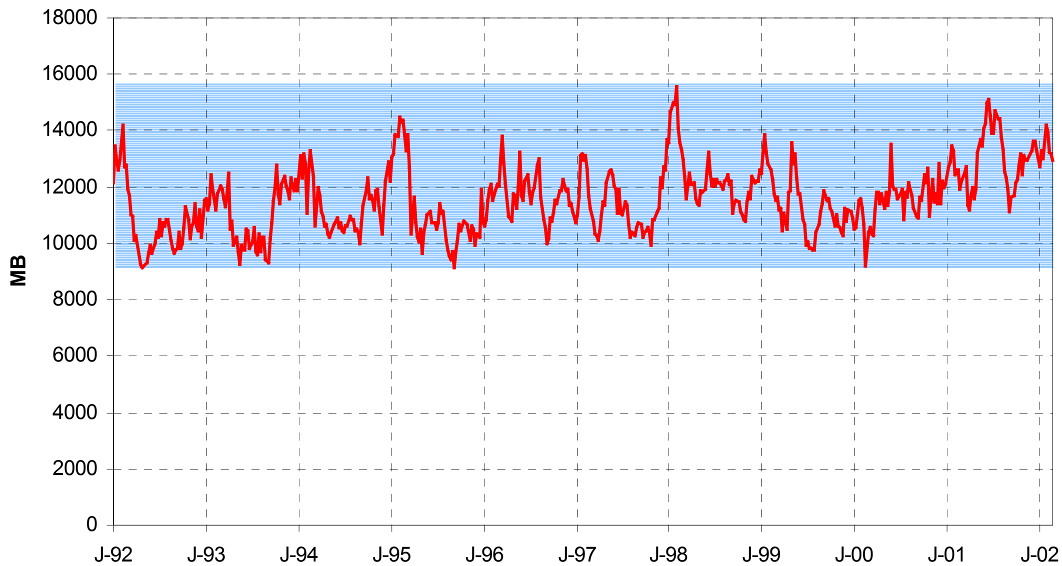
The industry attaches great importance to these inventory numbers as they are reported on a weekly basis, notably to determine whether the market is long or short, i.e., what the short-term trend in the supply/demand balance is. Yet it is generally not well understood how these inventories are distributed between the States within a PADD, or between the various parts of the distribution chain. Nor is it well understood what the total holding capacity is in the distinct northern and southern California markets, and how the industry manages inventory levels. Moreover, the current reporting system to the CEC does not capture all inventories held in the system. Yet to evaluate the effectiveness of a potential Strategic Fuels Reserve, the total current inventory capability in the State must be known, and current operational aspects must be understood. This Section addresses these questions.

Another interesting observation around Figure 4.1 is that of the narrowness of the range in proportion to the absolute inventory levels. The explanation is that the total number of tanks included in the PADD V inventory numbers is in excess of one thousand. Inventories in most of these tanks are driven by operational reasons, i.e., inventories in distribution tanks or tanks at refineries will cycle between full and empty on a regular periodic basis, sometimes as frequent as several times per week, with the time-weighted average equal to 50% of the workable range. The sum of a large number of such inventories will narrowly approach the average.

4.1 Refinery Inventory Capacity

California refinery inventory data are collected separately by the CEC. These inventories as reported also include certain inventories held at commercial terminals in the Bay area, but not in the LA Basin, and are shown in Figure 4.2.

Figure 4.2 – CA Refinery Inventories of Gasoline and Components [31]



As can be seen in Figure 4.2, gasoline and component inventories held at the California refineries move within a range of 8 to 16 million barrels. The total shell barrel capacity for tanks at the refineries dedicated to gasoline and gasoline components is approximately 13.3 million barrels for the Bay area refineries and 13.7 million barrels in the LA basin [32]. At their highest historical reported level, actual inventories represented therefore approximately 60% of the total available shell capacity, and at their lowest 30%. This percentage confirms that most

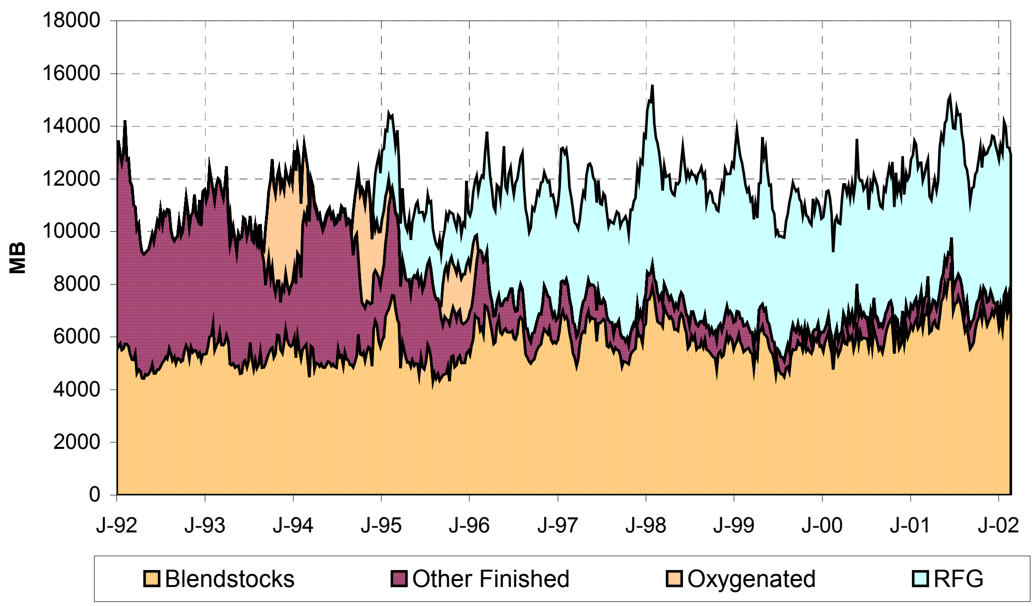
[31] CEC Weekly Reported Inventory Data

[32] Based on information received during the Survey Meetings conducted for this Study

refiners cannot use the tankage at their refineries as an internal reserve for strategic purpose or market tactics, but that operational considerations determine how tankage gets used, with most tanks cycling between full and empty as production is run down into tanks before a batch is pumped out on a pipeline.

For instance, in 1999 when prices were high at the time when major refinery outages occurred, refiners would have had every incentive to use available inventories to the maximum extent possible. That actual inventories never dipped below 8 million barrels confirms that this level represents a collective operational "heel", the minimum stock of blendstocks and finished products that is needed to maintain operations.

Figure 4.3 – Breakdown of CA Refinery Gasoline & Blendstock Inventories [33]



As can be seen in Figure 4.3, blendstock components, including oxygenates, make up over half of the total reported inventories at any point in time. Also noteworthy is that although Other Finished Gasoline constitutes only a small fraction of total inventories, supplying two distinct types of gasoline means that some tankage each in different octane grades, means an inherently less efficient use of tankage.

4.2 Inventory at Commercial Terminals

Most of the capacity in commercial bulk liquid petroleum terminals in California is concentrated in the Bay Area and in the Los Angeles Basin, where several commercial storage companies

[33] CEC Weekly Reported Refinery Inventories

operate facilities, most of which are tied in to deepwater berths as well as the refinery pipeline infrastructure. In addition to the commercial terminals, there are a few terminals owned by the refiners that provide commercial services to third parties if capacity allows.

Table 4.1 – LA Basin & Bay Area Commercial Petroleum Terminal Capacity [34]

MM bbl	Total Tank Capacity	Clean Product [1] Tanks	Gasoline & Components [2]
Bay Area			
Commercial Operator	8.5	5.7	3.8
Owned by Refiner	0.6	0.6	0.6
Total	**9.1**	**6.3**	**4.4**
LA Basin			
Commercial Operator	22.0	5.7	4.6
Owned by Refiner	7.7	7.2	6.8
Total	**29.7**	**12.9**	**11.4**
Total	**38.8**	**19.2**	**15.8**

1. Difference between total tank capacity and clean products is made up by crude oil and black oil tankage.
2. Difference between Clean Products and Gasoline is made up by diesel and jet fuel tankage.

Within clean product tankage, terminals cannot change service easily from gasoline to distillates unless the tanks are relatively new and designed as “drain/dry” tankage. On average, market information indicates that at any point in time, approximately 80% of tanks permitted for clean products at the major commercial terminals are in service for gasoline or blending components, including oxygenates.

It is important to note how in Southern California, refiners own the majority of the commercial storage for clean products. This is a legacy of two events, the closure of a refinery with tankage being retained as terminal, and the discontinuation of ANS pipeline exports, which freed up storage at the head of the pipeline. In both cases the refiners decided to monetize these assets by making them available to third parties in commercial service. Now that the LA storage market has grown very tight, while for these refiners internal demand for tankage has grown, this storage increasingly is only available to third parties when the refiner’s own operations allow. Moreover, most of the storage at the commercial terminals is leased out to refiners under long-term contracts, because commercial operators prefer the security of longer-term agreements with highly creditworthy customers to potentially higher rates from short-term agreements with trading companies or importers.

[34] Sources: OPIS Petroleum Terminal Handbook, ILTA Handbook, and Survey Meetings with Stakeholders

4.3 Distribution Terminals

Besides the inventories kept at the refineries and in the main commercial terminals, most integrated producers and marketers of gasoline maintain inventories of finished gasoline in the distribution system. Typically, these distribution terminals are connected to the main pipelines, and the facilities include loading racks to serve local distribution by tank truck to retail stations or large consumers. In addition, the pipeline operators maintain storage at strategic locations along the pipeline to serve their own operational requirements as well as customers' needs for distribution tankage.

Table 4.2 – CA Tank Capacity at Distribution Terminals [35]

MM bbl	Total Tank Capacity	Clean Product Tanks [1]	Gasoline & Components [2]
Northern California			
Commercial Operator	3.3	3.0	2.4
Owned by Refiner	3.5	3.2	2.6
Total	**6.8**	**6.2**	**5.0**
Central California			
Commercial Operator	0.6	0.6	0.5
Owned by Refiner	0.1	0.1	0.1
Total	**0.7**	**0.7**	**0.6**
Southern California			
Commercial Operator	2.2	2.2	1.8
Owned by Refiner	4.6	4.5	3.6
Total	**6.8**	**6.7**	**5.4**
Total	**14.3**	**13.6**	**11.0**

1. Difference between total tank capacity and clean products is made up by crude oil and black oil tankage.
2. Difference between Clean Products and Gasoline is made up by diesel and jet fuel tankage.

Again, within the total clean product tankage available, it is assumed that at any given point in time, approximately 80% is in gasoline service.

4.4 Pipeline Inventories

Long distance transportation pipelines for petroleum products will hold considerable volumes of distillates and gasoline that are in transit. For instance, a 300-mile long, 16" diameter pipeline will hold approximately 400,000 bbl of product, typically consisting of two or three sequential batches of diesel, jet fuel and gasoline.

Pipeline inventories are sometimes included in reported stocks, but overall, total gasoline hold-up at any given time is likely to be less than one million barrels. This volume cannot be readily

[35] Source: OPIS Petroleum Terminal Handbook, ILTA Handbook, and Survey Meetings with Stakeholders.

manipulated to play a role in working inventories in times of shortages and price spikes, although in theory, temporary substitution of batches of gasoline by other products might free up gasoline at the head of the pipeline. In practice however, given the limited storage for diesel and jet along the system in comparison with gasoline and the time, cost, and undesired operational consequences of changing tanks in service, pipeline inventories are not a factor in the total consideration of workable ranges for gasoline inventories in the State, and will not be taken into account here.

4.5 Reconciliation of Reported Inventories and Total Storage Capacity

The total storage capacity of tanks in service in California for gasoline and blendstocks appears to be around 53 million barrels, of which 26 are within the refineries, 16 million are at commercial terminals, and 11 million barrels are spread throughout the State at distribution terminals.

Reported actual inventories for PADD V on the other hand cycle between 25 and 35 million barrels. If inventories are assumed to be distributed in proportion to gasoline production and consumption, then California's share of these reported inventories would be around 70% of the total PADD V numbers, or between 18 and 25 million barrels. These numbers are low in comparison with the total shell capacity of 53 million barrels for all identified gasoline storage in California. However, a number of factors need to be taken into account when comparing reported actual inventories with total shell barrel capacity:

- Published industry tankage capacities are mostly based on nominal shell barrel capacity. Most tanks in gasoline service are of a floating roof design. To minimize the vapors that would be displaced by a rising liquid level under a fixed roof and thus cause hydrocarbon emissions, such tanks have a roof that floats on the surface of the liquid by means of pontoons, with specially designed seals between the shell and the roof edge that prevent the escaping vapors to cause emissions. The roofs have legs that will support it on the bottom when liquid levels drop to a minimum, in order to protect the pontoons and to keep the roof structure above other tank internals, such as suction lines or mixers. In normal operations however, the roof has to be kept afloat, which means that floating roof tanks cannot use the lower 5 to 10% of their shell height. On a statewide basis, this represents 3 to 5 million barrels of unusable capacity.

- Under applicable industry standards (API 653) tanks in gasoline service are required to be inspected on a 10-yearly cycle, although some operators will extend inspection intervals longer. Given the average duration of such inspection, which is often used to upgrade or modify tanks at the same time, as well as outages for operational reasons such as grade changes, up to 5% of the available storage can be expected to be out of service at any given point in time. This effectively removes 3 million barrels of listed capacity.

Most operational tankage in gasoline service sees heavy use and will cycle between full and empty on a continuous basis, with some of the tanks being turned over more than once a week. Other operational considerations also cause average inventories to be around half of the total available range:

- In the production process, enough empty tank space has to be available to allow continued rundown, even if a downstream process fails. Buffer tanks between processes that produce gasoline components and the final blending tanks cannot be kept full, but will typically be run between 40 and 60% of their capacity, to allow upside as well as downside swings.

- In the distribution chain, the same barrel passes through many tanks in a sequential process whereby each tank cycles between full and empty, with the average over a prolonged period being close to 50%. For instance, a blending tank in which a batch is prepared for pipeline dispatch will be empty, or only contain a minimum heel, before the batch is prepared. Once blended, the batch is pumped out to on a pipeline, where an empty tank must be awaiting it at the other end. To have all three tanks in the chain being full would result in an un-operable situation.

- Gasoline tankage is fragmented over as many as two-dozen components and blendstocks and for some refiners up to nine grades of final products. This fragmentation inherently causes tank space to be used less efficiently. For instance, a tank in service for a high octane blending component maybe almost empty, but will not help in storing rundown of treated naphtha.

Based on the above assumptions, it is now possible to reconcile the overall tank capacity for gasoline and blending components in California with the reported inventories for the State:

Nominal Tank Capacity California	53 MM bbl
Ullage, heels, non-operable capacity, 15%	- 8 MM bbl
Effective Total Capacity	45 MM bbl
Expected Average Inventory, 50%	22 MM bbl
Expected Average for CA as 70% of PADD V	21 MM bbl

Similarly, storage capacity and reported inventory numbers at California refineries can be reconciled:

Nominal Tank Capacity Refineries	26 MM bbl
Ullage, heels, non-operable capacity, 15%	- 4 MM bbl
Effective Total Capacity	22 MM bbl
Expected Average Inventory, 50%	11 MM bbl
Reported Average Inventory	12 MM bbl

Overall, despite apparent discrepancies, reported inventories can be reconciled with installed shell capacities. Some interesting conclusions now present themselves when looking at these inventory numbers:

- Inventories at refineries and in the distribution system are almost entirely determined by operational considerations, with tanks cycling continuously between their minimum and maximum practical inventory limits, averaging a little less than 50% of shell capacity.
- The only storage capacity that could be used to serve inventory strategies is that contained in commercial terminals, but total capacity is limited and is largely owned by or contracted out to the refiners.

4.6 The Market for Commercial Terminals in California

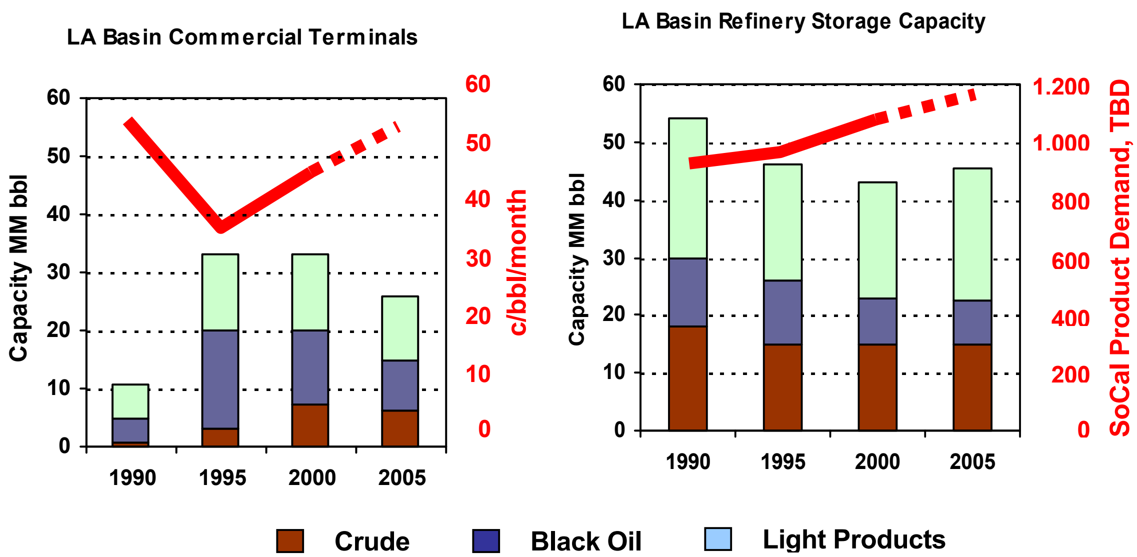
Commercial terminals in California are concentrated in the refining centers in the Bay Area and the LA Basin. In both areas, the commercial terminal industry has seen significant consolidation over the past decade as part of a nationwide trend whereby large companies that are structured as Master Limited Partnerships have a tax advantage over smaller independent operators.

Other factors that impacted the commercial storage market were refinery closures and the conversion of power generation from residual fuels to natural gas in the late eighties and early nineties. Both caused significant additions to terminal capacity, predominantly in storage for black oil. In the Bay Area, some 4 MM bbl of tank capacity were added, while in the LA Basin the commercially available tank capacity effectively tripled by additions by the LA department of Water and Power, Edison, Shell Carson and ARCO's tank capacity linked to inland pipeline transportation of Alaskan crude oil.

Even though most of the overcapacity was in tankage only suited for low vapor pressure products such as black oil and certain crudes, by the mid-nineties the glut of tank capacity caused rental rates, which historically had been in the range of $0.50 to 0.60 per shell barrel of tank capacity per month, to drop to rates as low as $0.30/bbl/month across the market.

Since then however, the market for commercial tankage in California has seen a remarkable recovery. This recovery is due in part to the industry consolidation referenced above, but mainly because of voluntary or forced capacity reduction, such as terminal closures forced by non-renewal of permits or leases. Also, conversion of tankage from black oil to crude oil or light products helped to restore prices. Moreover, demand for tankage continued to grow strongly as California became more import dependent. These phenomena particularly affected the LA Basin, as shown in Figure 4.4.

Figure 4.4 – Commercial Storage Market in the LA Basin



Currently, all spare capacity that was present in the LA Basin commercial terminal market has been used up. In the tightening market, the remaining tankage has essentially been signed up by the refiners under term contracts, and traders or incidental importers cannot find spot tankage capacity. As a consequence of the tightening market, rates have increased and are currently back up to historical highs of $0.50 to 0.60 per shell barrel per month. At these rates, commercial terminal operators have sufficient margins to justify new investments, and in a well functioning market new capacity additions can be expected.

Two factors however prevent a spate of new building so far. One is the extraordinary difficulty in obtaining permits for projects of any kind in the industrial areas of the LA Basin. The other is the fact that commercial tank farm operators need to have long-term bankable contracts with a creditworthy customer in order to justify building new tankage. With most of the existing storage under long-term contracts, the displaced demand and most of the increased demand is for short-term or spot rentals.

4.7 Inventory Planning

Inventory planning is different of each group of inventory holders, such as refiners, traders and large jobbers:

- The refiners balance financial, operational and commercial requirements. On the one hand, they would like to minimize inventories in order to reduce the costs of working capital, while on the other hand they have to resort to very costly measures when they are threatened running out of product. Operational flexibility demands that they leave themselves sufficient room to operate, both on the upside and the downside.

- Unlike refiners, traders usually do not own their tankage, but lease it from commercial service providers. The predominant operational requirement for most traders is that the size of the storage is determined by the cargo sizes of vessels. Traders sometimes want to hold on to inventory until market conditions are favorable to a sale. Often the costs of renting storage and the working capital costs are lesser considerations than the gain or loss on the cargo traded.

- The jobbers who maintain fuel inventories do so in order to reduce their vulnerability to market volatility. They have to offset the cost of working capital and rented storage against the advantage of being able to buy when prices are low, and to stay out of the market when supplies are tight.

Since the refiners control by far the largest inventories, and as producers and importers control the volume swings that are to a large extent the cause of market volatility, a more detailed analysis is provided below of factors that impact refinery inventory management.

4.7.1 Inventory Planning Processes

The planning processes can be thought of in three different time horizons. These are strategic, tactical, and operational. Strategic inventory planning is long range, one year or greater, and is normally done for the purpose of financial modeling by central corporate planning departments. At this level, turnaround planning is coordinated between a company's different refineries, and the basis is provided for long-term crude oil and feedstock supply contracts, tanker fleet charters, and other long-term commitments. At this stage, inventory targets are set as a function of overall working capital costs and as financial targets for management to achieve.

Tactical planning for inventory is usually the purview of middle management and generally covers the current month and out three to six months. It covers actual volume planning around turnarounds, crude runs, and expected market movements, such as those caused by seasonal specification changes. At this level, planning involves optimization using Linear Programming (LP) models of the refineries.

Operational inventory management is the responsibility of schedulers and occurs in the current timeframe, from right now to out six weeks or the duration of the scheduler's time horizon. It is the scheduler's job to keep product moving out of the refinery to the terminals to ensure that customer demand is met. At this stage, an actual forecast is made showing inventories for each tank, based on production and blending operations, ship and barge movements, pipeline cycles and demand forecasts.

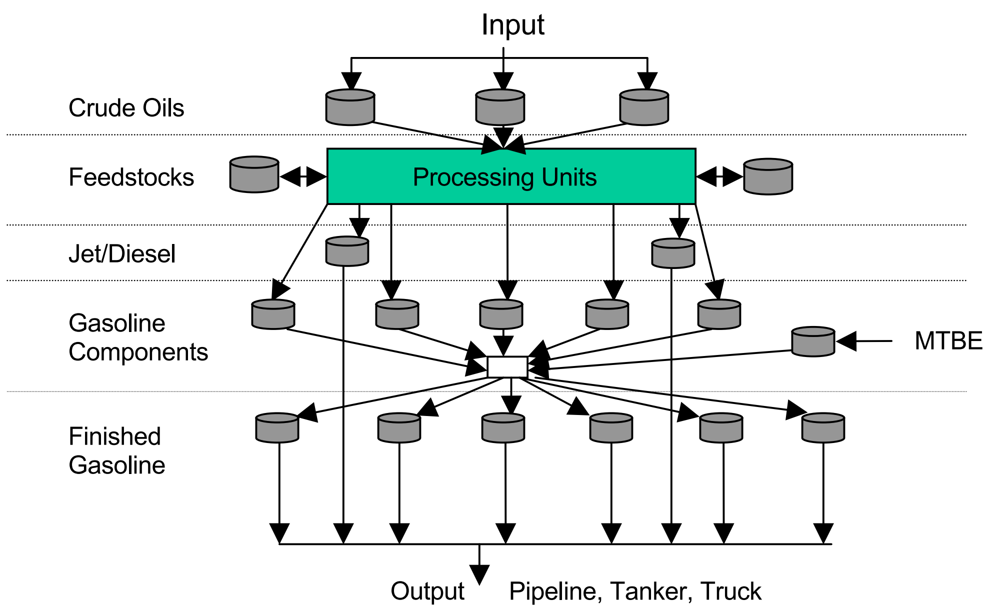
4.7.2 Refinery Inventory Management

The fuel distribution systems in California have not changed in some time and it is safe to assume that the refiners' inventory managers have determined their minimum operating inventory levels with a certain degree of precision. As seen above, minimum operating inventories are typically determined within a timeframe that spans from current to six weeks out. Any inventories carried above the minimum levels are termed "discretionary inventories" for the purpose of the following discussion.

Minimum operating inventory levels are set so that all requirements of the distribution system can be met without disruption or exceptional effort, without having excessive inventory volumes on hand. Gasoline components are available for blending to finished products, which are certified and pumped into the pipeline on schedule, and are delivered to the distribution terminal in time to be trucked to a gas station, plus some additional stocks to accommodate routine variances of supply and demand due to small refinery upsets, pipeline shipping delays or variances in actual retail demand versus forecast demand, for example.

As shown in Figure 4.5 below, refinery inventories consist of many different products in tankage that is usually dedicated to a specific service. For gasoline components and finished gasoline, a refiner may need to store between 20 to 30 different products and grades. Interchangeability is usually limited to tanks within a certain class, represented in Figure 4.5 as a horizontal band. Thus, it would be possible, although not necessarily easy, for a refiner to switch tanks between various components such as raffinate, alkylate, and isomerate, or change between finished product tanks for CARB RFG, conventional, and regular or premium grades. Switching service between different classes of service is usually not feasible because of physical location, connecting lines and permit restrictions.

Figure 4.5 – Various Types of Refinery Inventories



The large number of different and dedicated tanks in a refinery means that the minimum operating inventory works out to be a fairly large number, because each tank will have its own minimum service requirements. For instance, it does not help a refiner that there still is a fair amount of isomerate on hand when he needs alkylate to blend a finished gasoline. This analysis and historical data indicate that the minimum operating inventory for the California refining system is about fifteen to seventeen days of supply, or about 16 to 18 million barrels. The fact that even in periods of severe shortage and extremely high prices, inventories never dropped below these levels confirms the fact that these operating constraints form hard limits.

In Section 4.5, it was shown that normal California inventories of gasoline and blending components range from 18 to 22 million barrels. This implies discretionary inventories, those inventories held in excess of target operating ranges, amount to 0 to 4 million barrels, or 0 to 4 days of supply.

Discretionary inventories are held for a number of purposes and generally fall within the Tactical Inventory planning horizon, usually for one of the following reasons:

1. Uncertainties surrounding demand forecasts or refinery production.

2. For coverage of a turnaround.

3. To accumulate cargoes for ship movements or as a result of having received full cargo imports.

4. In anticipation of rising prices – speculative inventory.

Turnaround coverage is probably the single most important reason for holding discretionary inventories. In Figure 4.2 above, a distinct seasonal pattern can be observed whereby stocks are built up in late fall and winter and drawn down in early spring, when most refiners prefer to execute turnaround. The inventory drawdown during the planned outage corresponds to the need for low inventories when the switch to summer grade is made. The magnitude of this seasonal effect is 2 – 4 million barrels, confirming the analysis made above.

Other discretionary inventory is sometimes an unwanted effect of lower than anticipated demand or exceptionally strong production performance. Reasons for demand drop can be a spurious price increase, i.e., a price increase driven by rumor or market anticipation that is of sufficient duration and length to work its way from the spot market into retail. It is not always possible for refiners to adjust production rates quickly to a drop in demand because of commitments in crude oil shipments and limited crude oil storage. Equally, imports already headed for the California market often cannot be turned away at short notice. In such cases, inventories may run up above minimum operating levels. These and other non-seasonal effects are likely to be at the root of observed inventory fluctuations of up to 2 MM bbl.

Speculative stocks are likely to be held by refiners who did not have a major turnaround, or have had strong production runs and emerge from the winter season with ample stocks, or by traders who brought in imported material. Unlike the pre-turnaround season build-up, there is no clear indication of late-spring speculative stockpiling in the inventory data and the fact that such stockpiling is lost in the randomness of the numbers indicates that the speculative inventories at most add up to 1 million barrels even at the best of times.

In summary, it can be concluded that the industry in California currently manages inventories within the following ranges:

- Minimum Operating Inventories: 16 – 18 MM bbl
- Turnaround Preparation (Seasonal): 0 – 4 MM bbl
- Other Discretionary Inventories: 0 – 2 MM bbl
- Speculative Inventories: 0 – 1 MM bbl

For PADD V as a whole, these numbers are:

- Minimum Operating Inventories: 21 – 24 MM bbl
- Turnaround Preparation (Seasonal): 0 – 5 MM bbl
- Other Discretionary Inventories: 0 – 3 MM bbl
- Speculative Inventories: 0 – 1 MM bbl

Below, a further analysis will be provided of some of the inventory management aspects, and of the potential impact of a reserve on inventory management.

4.7.3 Inventory Management for Planned Outages

An oil refinery is made up of a number of processing units that require routine maintenance, such as inspection and repairs, catalyst replacement or regeneration, or upgrading for new technology and replacement of equipment that has reached the end of its service life. A process unit that is down for maintenance is said to be in turnaround. The turnaround cycle for each unit can vary from as little as three months to as long as four years depending on permitting requirements, severity of operating conditions, market conditions, unit performance, and the like.

Normally the maintenance on the units is grouped together such that a number of units are in turnaround simultaneously. A major turnaround typically occurs every three to four years when a refiner brings down its crude unit, catalytic cat cracker, hydrocracker, and/or coker. The duration of a major turnaround normally is 30 to 40 days, although the planning may have started eighteen months earlier.

The turnaround timing and duration are established well in advance. Refiners time their turnarounds so that they occur during the slack demand season. In California the major turnaround season occurs in the period January through March so that the refineries are back in operation for the summer's peak gasoline demand. A secondary turnaround season happens in October/November, after the peak demand.

Refiners do not coordinate the timing of turnarounds with one another, due to anti-trust concerns, but they do track one another's activities. Maintenance contractors frequently have to fulfill a role of go-between and coordinate the refiners' operations because their people and equipment will be at work in a number of refineries at the same time.

The impact of the turnaround on the refinery's fuel production is forecasted and managers responsible for supply and planning are charged with ensuring that sufficient fuel supplies are arranged to meet the refinery's demand forecasts, usually through pre-staging inventories through increased own production, purchases from other refiners or traders, or imports. Rented storage may be arranged when available, and external supplies are scheduled to be delivered through the refinery's own systems during the turnaround.

Generally, planned turnarounds do not create price spikes. The coverage for turnarounds is well planned and turnarounds are generally spaced out. A recent example was seen in the Los Angeles market during the spring of 2001 when a major refiner had an FCC turnaround. The Fluidic Catalytic Cracker (FCC) is the biggest producer of regular gasoline in most refineries. Industry publications reported that the refiner brought its FCC down suddenly, which normally means that the market will spike up as the refiner's traders scramble to cover the unplanned shortfall. In this case the market showed little reaction because the FCC went down on a planned turnaround, for which the refiner's Supply Department had planned adequate coverage, so that they did not have to go into the market at the last minute to cover demand [36].

Prices frequently will rise if the turnaround is extended past the scheduled completion date and the refiner's traders have to go into the spot market to cover the additional supply shortfall. One can observe, for example, that prices frequently rise in late March or early April as refineries are struggling to complete their maintenance.

[36] Information received during Stakeholder Meetings.

4.7.4 Reactions to Unplanned Supply Reductions

With most refiners, the Supply Department is not located in the refinery. Therefore, it may take the Supply Department some time to discover that their refinery has had an unplanned supply disruption. Supply disruptions could be as dramatic as a refinery explosion or as subtle as the loss of the pump that delivers product to the pipeline.

When a supply disruption occurs, the refiner's supply department will try to cover their requirements quickly and in such a way as to minimize the impact of the disruption on its own financial bottom line. This implies that if the disruption is not immediately apparent to the public, as is the case for most outages that do not involve a fire or explosion, the refiner will keep a tight lid on information related to its operational difficulties, and go into the market through parallel channels, either directly with its own traders approaching other refiners, or indirectly through multiple brokers and traders, in order to cover its shortfall before a market run-up occurs.

Eventually, the refiner's problems will become known in the market and, depending on the total inventory situation, this news will usually result in a price spike.

4.7.5 Impact of a Reserve on Industry Inventory Management

Some critics of government sponsored reserves have postulated that companies will reduce their inventories because of the availability of the government volume. Clearly, as seen above, refiners will manage inventories for reasons of operability and costs, and in how much the presence of a reserve will be factored into these equations will depend on the operational and commercial design of the reserve. An analysis is given below for each of the inventory components identified above: minimum operating inventories and discretionary inventories including speculative stocks.

- **Minimum Operating Inventories**. The presence of a reserve, even if tied in by pipeline to the refinery, will not reduce the inventories a refiner has to hold for to meet minimum operating requirements. Operating inventories have to be on immediate call and cannot be dependent on whatever release mechanism is designed for the reserve. The fact that currently, even at periods of major supply disruptions and record prices, refiners are physically unable to dig deeper into the operating stocks, makes it very unlikely that the presence of a reserve will enable a reduction of these inventories.
- **Turnaround Coverage**. Conceivably, a refiner may elect to use volumes from a reserve for turnaround coverage. However, a refinery turnaround is usually a

major project for which each detail will be meticulously planned. It is highly unlikely that a refiner will enter into a turnaround without having assured coverage, and leave it to up to the ad hoc ability to lift volumes from the reserve to cover his retail. What is likely however is that the presence of a reserve will enable a refiner to reduce the amount of contingency coverage for the eventuality that the turnaround will last longer than foreseen. In any case, turnarounds are usually planned outside the summer season, when the role of a reserve is less critical.

- **Speculative Stocks**. A reserve, if successful in suppressing price spikes, is likely to reduce the incentive for refiners or traders to stock product in anticipation of price increases. However, speculative stocks are rarely held deep into a price spike and most traders will prefer forward predictability rather than a blind gamble that a disruption will occur. The trade will create speculative inventories when the market is in contango, i.e., shows a small but predictable price increase. During such periods, the reserve would not be used by the trade to conduct prompt trades with forward redelivery, which is of value only in a backwardated market. Speculative stocks are therefore likely to remain a complimentary inventory component. In any case, as seen in Section 4.7.2 above, speculative stocks currently do not play a significant role in California's total inventories.

In summary, it can be concluded that industry inventories in California are almost exclusively serving the bare minimum operational requirements and are not drawn down between the habitual minimum levels even when it would be extremely lucrative for holders of such inventories to realize additional sales. It is therefore very unlikely that the presence of a reserve, limited to only 2.3 million barrels and designed with a release mechanism that creates forward liquidity, will have any significant impact on inventories currently held by the industry.

5 GOVERNMENT ISSUES

There are a number of current regulatory initiatives in the State of California that will negatively impact the supply capability of the petroleum industry in the State, either temporarily or permanently. This section will attempt to quantify the impact of each of these initiatives and their relevance for the creation of an eventual Strategic Fuels Reserve.

5.1 CARB Phase III and MTBE Phase Out

On February 19, 2002, a public workshop was held by the CEC to discuss the impact of the phase out of MTBE by year-end 2002, as mandated by the Governor's Executive Order of 1999. The conclusions of a separate study by Stillwater Associates were discussed at this workshop. The scope of this study was limited to the impact of the phase out on gasoline supplies and infrastructure, and the main conclusions of the report are no different than the points raised in the supply and demand section of the Strategic Reserve Study:

- Phase out by year-end 2002 will cause a 5 – 10% reduction in supply. The bulk of the supply shortfall occurs in the LA Basin. If left unfilled, such shortfall is likely to cause a 50 to 100% increase in prices.

- There are no suitable substitutes available from the US Gulf Coast, and even if there were, US flagged shipping would not be available in sufficient numbers.

- Sources for suitable blending components can be identified abroad, but given the currently already constrained import logistics, it is inevitable that the already severe pricing volatility will be aggravated.

- The economic impact of the initial price spike and the subsequent increased volatility were estimated to cost the California gasoline consumer between $1 and 3 billion per year.

- The recommendation was to delay phase out of MTBE by three years, until additional infrastructure for imports can be realized, and exports to Arizona can be kept within the State as pipeline supplies from the US Gulf Coast reach Phoenix.

As far as the actual scope of the study was concerned, comments during the workshop centered on the economic assumptions, projections of production capacity in the State, and impact of price spikes. Comments outside the scope mainly focused on the adequacy of ethanol supplies, and various environmental issues with viewpoints largely depending on the particular interest of the party.

The result of the various reports and briefings has been that the Governor issued Executive Order EO D-52-02 on March 15, 2002, delaying the phase out of MTBE by one year until December 31st, 2003. Subsequently two major refiners, BP and Shell, have announced that they will maintain a schedule that will result in an earlier, voluntary switch to ethanol. An important consideration in such decisions is likely to be the exposure of California refiners and MTBE suppliers to law suits brought by several parties claiming damages from MTBE leaked into ground and surface water. Under these circumstances, refiners have little to gain and a lot to lose by continuing to blend MTBE, while on the other hand, they stand to gain substantially from the price increases that are expected as a result of the volume loss when summer grade gasoline is oxygenated with ethanol rather than MTBE.

5.2 AQMD 1178

As part of a consent degree that resulted from the settlement of a lawsuit brought against the South Coast Air Quality Management District (SCAQMD) by several environmental organizations, the SCAQMD agreed to create new regulations that will result in further reductions in emissions of Volatile Organic Compounds (VOCs) in the Los Angeles basin by 8 short tons per year (8 TPY).

Of these target emission reductions, a total of 3 TPY are to be achieved in three consecutive phases through additional control measures in large-scale petroleum and petrochemical industrial installations. After an initial evaluation of the options, the SCAQMD decided that in the first phase, between 1 and 1.5 TPY of VOC reductions could be achieved by measures that will reduce evaporative emissions from bulk liquid storage tanks. The proposed measures included improving the tightness of roof fittings and constructing domed roof over open floating roof storage tanks containing high vapor pressure petroleum products. Subsequently, the SCAQMD instigated a workgroup with participants from the affected industries in order to discuss feasibility, cost effectiveness and implementation schedules for the proposed regulation.

The new regulation as proposed by the SCAQMD, Rule 1178, called for doming of all crude oil and product tanks at facilities with total VOC emissions greater than 20 TPY, under a program of which the first phase, comprising of the vast majority of all crude oil and product tanks at the LA refineries and at some of the main commercial terminals, was to have been completed by 2006. The cost effectiveness of the program was questionable for the larger tanks, in particular for those containing crude oil, and the 4-year implementation schedule was deemed unfeasible and considered a risk to supply security. Feedback from the affected parties, industry organizations and the CEC (assisted by Stillwater Associates), caused the SCAQMD to reconsider the scope and implementation schedule.

The regulation, as adopted by the District's Board in a public hearing on December 21, 2001, requires that 75% of the tanks for gasoline and gasoline components are to be domed by December 31st, 2006 and the remainder by December 31st, 2008. The rule no longer includes a requirement for doming of crude oil tanks because it is not cost effective. Even with this extended schedule, there is still cause to be concerned that supply reliability in the LA basin may be impacted by the number of crucial storage tanks that will be out of service at any given moment for project work. Under the applicable standard, API 653, aboveground atmospheric storage tanks are normally taken out of service for internal inspection and maintenance on a 20-year schedule, and the 7-year schedule with additional project work extending the down-time, means that on average during the next seven years, the amount of storage that is not available to accommodate demand swings or refinery problems is 3 to 5 times more than normal.

There is no doubt that the creation of a Strategic Reserve, or any other measure that will enable more storage to become available to the LA refiners within the extended timeframe of the new Rule, will help to alleviate the pressure on an already very tight market for bulk storage of petroleum products in the LA Basin and lessen the impact of Rule 1178 on the availability of storage.

The creation of Rule 1178 is illustrative of the tight regulatory framework within which the refiners in the LA Basin have to operate. In an environment in which upwards of $140 MM in investments are necessary to obtain a relatively insignificant reduction in VOC emissions, it is very difficult to justify projects to create incremental capacity, but have associated incremental emissions as well.

An idea developed by Stillwater Associates and currently presented to the industry is to allow refiners to take credit for voluntary improvement in fuels, which – using CARB's predictive model – can be translated in reductions in tailpipe emissions. Given California's unique market structure, in which the majority of the transportation fuels is consumed in the same confined geographical area in which the refineries are located, it would make a lot of sense to allow refiners a possibility to achieve the mandated reductions in the mobile source emissions caused by the fuels they produce, rather than by squeezing the last ounce out of sources within the refinery fence.

5.3 Ports of Los Angeles and Long Beach

Although joined by common waterways and infrastructure, the ports of Los Angeles and Long Beach are separate entities, each governed by a Board whose members are appointed by the elected officials of the two cities, with authority derived under a mandate from the State Lands

Commission. The management mandate for both Port Authorities resides within a Master Plan for land use and development that is approved by the State Lands Commission (CSLC). Even within the Master Plan, certain decisions concerning land use and development will be subject to review by the City Council of each port and the CSLC.

Current policies in both ports do not favor bulk liquid operations for petroleum products, and the closure of existing facilities and lack of development opportunities for new capacity could severely impact the capability of the State to meet future requirements for fuels through imports. Almost all terminals in both ports are built on leased land, and as the leases come up for renewal, the ports will reassess the land usage, with the result that over time, more terminals will have to make way for large scale container operations or other land uses with higher revenue than can be offered by bulk liquids.

5.3.1 Port of Los Angeles

The current long term Master Plan for the Port of Los Angeles (PoLA) provides for the creation of a common bulk liquid terminal for crude oil and petroleum products on the newly created landfill area of Pier 400. The plan assumed that some of the existing petroleum terminals that were located in areas for which the PoLA had other plans would be relocated to this new bulk liquid terminal area on Pier 400 when their current leases expired. This plan, which dates back over 10 years, never gained acceptance within the industry, mainly because the proposed site at Pier 400 is remote, requiring significant investments in pipelines in order to provide access into the existing refining infrastructure.

Given the lack of interest from the side of the industry, the PoLA has meanwhile granted most of the land of Pier 400 in leasehold to container terminal operators, with only a limited footprint remaining for bulk liquid facilities. The remaining area of 25 acres would allow building at the most three tanks of 0.5 million barrels each, which in combination with an 80-foot draft berth and a large capacity crude oil pipeline connection to the inland refineries will enable offloading of a fully loaded VLCC. The PoLA and several potential users are still evaluating the options for development of a crude oil terminal at Pier 400. In any event, it is very unlikely that any future development scenario for the site will include facilities for handling of clean products, and the net result will be that several clean products and black oil facilities will have been shut down in the PoLA without the anticipated replacement at Pier 400 being realized.

There are two other developments in the PoLA that could negatively impact the port's capability to handle imports of fuels. The first is formed by heightened community concerns about the safety of bulk petroleum storage as potential targets for terrorist attacks, which has led to a request by Council members to study the closure or relocation of three terminals in San Pedro and Wilmington. The second issue is that of Environmental Justice, a term used by NGOs protesting the disparity between the exposure to pollutants in the communities surrounding the Ports, with the poorer, largely minority populated communities bearing the brunt of the exposure.

Although understandable from a local perspective, these initiatives, if carried through, could lead to a further reduction in fuel receipt facilities in the PoLA and will make future expansion very difficult.

5.3.2 Port of Long Beach

The Port of Long Beach (PoLB) faces problems that are to a certain extent different from those in Los Angeles. Both ports face an increasing demand for container handling – in fact, the projections for the PoLB call for a doubling of containers from the current 5 million TEU (Twenty-foot Equivalent Units) to 10 million by 2010 and then to double again to 20 million by 2020. Much of this growth will be realized by creating mega-terminals, container facilities with at least 400 acres of storage yards and capable of handling the new 10,000 TEU container vessels.

However, Long Beach does not face the same pressure from individuals or action groups concerned about safety or environmental justice. Yet the need to create space for container terminals is so acute that it is still uncertain whether the PoLB will be able to accommodate two existing bulk liquid storage facilities in the plans it has for expansion of the Pier A container terminal.

As is the case for the PoLA with its Pier 400 project, the Port of Long Beach has plans for a new deepwater receipt facility for crude oil at Berth 123, adjacent to the current crude oil berth shared by three refiners. A request for proposals has been issued by the PoLB, with expressions of interest due July 17. The footprint for the new facility is limited to just 5 acres and will not allow for any storage at all. As for the LA Pier 400 plans, there are no plans for additional receipt facilities for petroleum products.

The lack of storage space set aside for this terminal and the accelerated schedule at which the Port wants to move forward make it unlikely that resulting operations will represent the best possible solution for California's energy supply security.

5.3.3 Summary of Port Issues

In Section 1.4.2 of this study, it was shown how California has become increasingly dependent on imports for its requirements of crude oil and petroleum products, and how the sources of these imports are shifting from domestic sources to remote foreign locations requiring larger scale receipt facilities. In Section 1.3 it was shown how predominantly, the shortfall occurs in the southern California market, which relies on the ports of LA and Long Beach for its imports.

The current trends and policies in the ports of Los Angeles and Long Beach are not favorable to bulk liquid storage facilities, and although plans exist in both ports to accommodate future requirements for crude oil imports, there are no established plans for increases in clean petroleum products such as gasoline and gasoline components.

5.4 Military fuels

Jet fuel was not part of original study, especially military jet fuel, but the terrorist attacks have changed this outlook. Defense Energy Supply personnel in California would like to meet with staff and contractors. Proposed work would examine quantities and locations of military jet that should be stored and will examine delivery infrastructure constraints.

5.5 MOTERP

After the 1994 Northridge earthquake, and other earthquakes in which marine terminal facilities were damaged, the California State Land's Commission initiated a project to create a set of uniform engineering standards that would ensure that marine oil terminals would be equally resistant to earthquakes as the refineries to which they are linked.

Currently the CSLC has a final draft in preparation of new regulations that will require the owners of a high-risk facility (risk of a spill of more than 1,200 bbl of petroleum products in a standardized accident scenario), to inspect their docks and shore facilities within 30 months after the regulations take effect. These inspections will follow a detailed protocol and an action plan must be developed to mitigate any findings. Lower risk facilities have 48 months in which to carry out the inspection program.

The CSLC will evaluate each plan on an individual basis, and in general, does not impose a hard time limit for completion to allow the concerned terminal operator to design a workable schedule, which minimizes impact on operations. In general, the CSLC believes that most facilities can be remediated within 6 to 8 years.

Given the scheduling flexibility, it is not expected that MOTERP implementation will lead to an immediate reduction in available import facilities, as is the case for SCAQMD Rule 1178. Nevertheless, there are likely to be facilities for which the cost of the upgrades cannot be justified by the operator, and which will therefore close down.

6 OPTIONS FOR A STRATEGIC FUEL RESERVE

A fundamental choice for creating a Strategic Fuels Reserve is whether to use existing inventory capacity or to build new tankage. As seen in the previous Section 4, by conventional logistic standards existing tankage is already inadequate for the volumes currently handled. Moreover, during the stakeholder meetings, the shortage of existing storage capacity was widely reported as one of the major problems the industry currently faces (see Section 8.1). This study will therefore focus on adding new storage capacity or converting existing tankage currently not in petroleum products service as the only viable way to create an eventual reserve in California.

This study does not attempt to develop any of the considered options to a level of detail where cost estimates can be prepared with the accuracy normally required for an investment decision. At this stage of early feasibility analysis, order of magnitude estimates are used, where possible based on factorial comparison with known costs for similar projects, or based on published information and industry practice.

6.1 New Tankage

For new tankage, the primary considerations is the selection of a location, in particular whether the storage needs to be built as a grassroots project requiring its own infrastructure development, or whether it can be built as an extension to existing facilities and share in already available infrastructure such as roads, docks, pipeline connections, and utilities. For the first option, reference will be made to existing studies, while for the latter two locations are examined in more detail.

6.1.1 Findings of 1993 Study

In 1993, an extensive study was carried out by Invictus Corporation of Wilton, CA, to determine the feasibility and cost for a single reserve of petroleum products, capable of holding an inventory of 5 million barrels [37]. The costs of the project, including acquisition of a 215 acre site and connections to the main product distribution pipelines, but excluding the cost of an initial fill of the reserve, were estimated at $131 to $143 million (1995 $). Operating cost for the facility were evaluated at $6.6 to $7.9 million per year, with the high end of the range representing a location in Stockton that included operating a dock. The other locations that were evaluated for the reserve besides Stockton were Fresno and Roseville. These three locations were retained after

[37] *Feasibility Study of a Regional Petroleum Product Reserve in California*, December 1993, Invictus Corporation, Wilton, CA, Resource Decisions, San Francisco, CA, and Capital Research, Chevy Chase, MD.

an initial survey that included a total of 15 sites, mainly inland and chosen for reasons of earthquake security rather than connectivity with existing petroleum infrastructure.

If escalated for inflation from 1995 to current [38], the construction cost for the Stockton option would amount to $154 million, or $31 per barrel of shell capacity, and operating cost of $0.16 per shell barrel per month. These numbers are similar to numbers quoted by major oil companies as fully loaded costs. In general, commercial terminal operators reported substantially lower numbers for new grassroots construction, claiming that they are able to build and operate terminals cheaper than the major oil companies or the State because of their specialized knowledge and lower overheads. If the project were to be realized as an expansion of an existing facility, with infrastructure already in place, costs could fall to half the numbers used by Invictus, based on information received from commercial terminal operators currently involved in expansion projects.

In addition to the construction and operating costs, Invictus evaluated the cost of filling the reserve at more than $150 million at then prevailing fuel prices. The conclusion of the Invictus study, using an economic model to predict the price moderation effect of the reserve in case of a major supply disruption, was that the costs of building, filling and operating the single 5 million barrel reserve was not warranted by the increase in security of supply.

The 1993 study did not address the logistics of moving product in and out of the reserve, other than the pumping costs for the initial fill, and as has been shown in section 2.1.3 above, the concept of the single, central reserve would have been flawed because of the inability of the existing transportation system to deliver products to the different markets in a timely manner. Also, the concept of tying the reserve into the distribution grid with a single 8” line would have proven impractical, since it would have taken almost two months to draw down or replenish the reserve. Yet the cost estimate is representative for grassroots investment, and will be used in the build-or-buy analysis below.

6.1.2 New Storage Built and Operated by the State

For new storage to be built and operated by the State, the following overall scope will be assumed to meet requirements for full integration into local refining centers and import capability:

[38] Bureau of Labor Statistics Data, *Producer Price Index All Industries*. 1995: 124.2; 2001(p): 133.5

- Bay Area: 6 x 150,000 bbl drain-dry open floating roof tanks, 15 acre site owned fee simple, dock 800 feet long, 35 feet draft, VDU, 5 mile 16" pipeline connection to main grid.

- LA Basin: 9 x 150,000 bbl drain-dry floating roof tanks with dome, 20 acre leased site, use of 3rd party dock, 2 mile 16" connection to main grid.

The differences in scope between the Bay Area storage and the LA Basin facility reflect a reasonable estimate of prevailing local conditions, i.e., leased versus owned land and SCAQMD requirements.

If the reserve is to be part of a larger project, i.e., if double the volume is deemed necessary, or if additional storage were to be built simultaneously for lease to third parties as part of a larger, commingled terminal in which both the State and private entities maintain inventories, then there will be certain economies of scale from which the State would benefit on a proportional basis. For the time being, as a conservative first approach, the costs for building the reserve will be calculated on an individual project basis.

Summary of construction and operating costs (for details see Attachment A):

Table 6.1 – Cost Summary of State Owned and Operated Reserve

	Bay Area	**LA Basin**	**Total**
Investment, $ MM	39	36	75
Fixed Costs, $ MM/year	8	9	17
Throughput Cost, $/bbl			
Pipeline In/Pipeline Out	0.34	0.34	
Pipeline In/Barge Out	0.25	0.44	
Vessel In/Pipeline Out	0.23	0.41	

The total investment costs of $75 MM for 2.2 MM bbl are consistent with the figure of $154 MM of escalated costs for the 5 MM bbl storage of the earlier Invictus study, in that it would imply an exponential scaling factor of 0.88, which is conservative when compared to the value of 0.7 to 0.8 generally used in the industry for this type of installation (a higher number means a more linear relationship between scale and costs, a lower number means that on a per unit basis, smaller installations are more expensive).

The throughput costs are the cost related to moving material in and out of the reserve, such as the fees for using the 3rd party owned pipeline gathering systems, port fees, dock fees paid to 3rd parties for options where the dock is not owned, and the cost of physical losses associated with the movement of the material, such as evaporative and trans-mix losses, which are estimated to average 0.1%.

6.1.3 New Storage Built and Operated by a Commercial Service Provider

Market information obtained during the survey meetings has confirmed that commercial terminal operators in the Bay Area and in the LA Basin are willing to build new storage capacity under a long-term, i.e., 10 year contract at currently prevailing market rates of $0.45 to $0.55 per barrel of shell capacity per month.

Table 6.2 – Cost Summary for Leased Reserve

	Bay Area	**LA Basin**	**Total**
Investment, $ MM	0	0	0
Fixed Costs, $ MM/year	5.4	7.2	12.6
Throughput Cost, $/bbl			
Pipeline In/Pipeline Out	0.33	0.33	
Pipeline In/Barge Out	0.25	0.44	
Vessel In/Pipeline Out	0.23	0.41	

The fixed costs are based on the minimum fixed tank rental of $0.50/bbl/month, which under the terms customary in the industry includes the right to store and withdraw the tank volume once per month (one “turn”). Any excess throughput in a given month incurs an additional throughput fee, usually in the order of $0.20/bbl. However, no excess throughput charges are included in the Through Put Costs as listed, since it is unlikely that a reserve could be utilized and replenished more than once during one month. The throughput cost for the leased tankage in terms of pipeline and port fees, and inherent product losses, are virtually equal to those for owned tankage. The slight reduction for the pipeline in/out option is due to the energy cost for pumping, which is included in the base cost for leased storage.

It will be clear from a comparison of Tables 6.1 and 6.2 that it will be difficult to justify building state-owned and operated tankage, given the very competitive prevailing market rates of commercial service providers. The disparity between commercial rates and fully loaded costs incurred by large corporations is further explained below and is consistent with market information received during the survey meetings with industry stakeholders as conducted for this Study (Section 10.1).

6.2 Incentives for Increased Inventories by Current Inventory Holders

An idea that was floated during the stakeholder survey meetings was that of an industry-held component to an eventual reserve, i.e., that by providing incentives to compensate for the cost of working capital associated with larger stocks, the current holders of inventories could be enticed to increase the amount of product held at any point in time, and would only dip into a certain portion of their inventories under pre-agreed conditions or when specifically authorized to do so. On reviewing inventory data and from feedback received during the stakeholder meetings, it became immediately clear however that there is little or no room to increase inventories within the California refining and distribution system.

The same arguments that apply to inventories at refineries also apply to those held at commercial terminals: space is tight and even when provided with incentives to compensate for working capital cost plus tank rental expense, owners of fuels would not be able to find more space.

This leaves the option to provide incentives to the industry that will result in more storage capacity being built. These incentives can take the form of providing financial aid, such as investment guarantees or subsidies, but can also include measures to remove the barriers that currently prevent normal free market mechanisms to cause supply to match demand,

6.2.1 Financial Incentives to Increase Storage Capacities

Currently the contract rental rates for petroleum product tankage are around $0.45 to $0.50 per bbl per month in the Bay Area, and $0.50 to $0.55 per bbl per month in the LA Basin. Spot contracts can be between 5 to 10 cents higher. At these rates, commercial terminal operators have reinvestment economics, but large refiners would need higher numbers to justify building new tankage for themselves under the criteria that most of these companies apply for internal rates of return.

There are several reasons why a large refiner’s costs are higher, and they are relevant when considering what incentives may be needed to promote infrastructure investments:

- A large refiner's project costs are generally substantially higher than those of smaller specialized firms because of allocated corporate overheads, more elaborate company standards, and higher cost of the owner's project management team.

- Required internal rates of return are higher in oil companies where projects generally carry significant risk and therefore need higher rewards, versus the service industry whose projects are usually backed by long term contracts with low risk and are therefore acceptable at utility level returns.

- Oil companies do not benefit from certain tax advantages available to most commercial terminal operators, who are often structured as Master Limited Partnerships (MLP).

- Capital resource allocation decisions in oil companies will favor investments in core businesses such as exploration, production and refining, rather than in infrastructure projects.

These factors have led to a proportional under-investment by refiners in storage, causing their inventory capacity to lag behind their increases in production capacity. In general, storage capacity will only be added at refineries when justified by operability issues rather than economic reasons.

Trading companies or large purchasers of fuels, who also maintain inventories, face similar obstacles to investment in wholly owned terminals and pipelines. In addition, these companies are generally not well equipped to run capital projects of this nature, have even higher internal hurdle rates for investment, and have a forward demand that is not always predictable.

The logical conclusion would be for refiners, traders, and large buyers to outsource their storage requirements to specialized third party service providers. For short-term requirements that can be met with existing capacity, this is indeed how the industry functions. However, this solution of choice becomes more complicated when the service provider has to invest in new facilities to meet the demand. For new investment, given their inherently lower utility level rates of return, the service companies need long-term commitments from the principals before they can invest, usually in the order of 5 to 15 years.

Unfortunately, it is almost as difficult for refiners, traders and buyers to commit to a long-term contract, as it is to obtain approvals to spend the capital internally. Long-term capital commitments are also referred to as pseudo-capital commitments, which have to be footnoted in financial statements and may impact a company's borrowing capability in a similar way as debt incurred to finance investments. Thus the problem becomes a vicious cycle, in which the holders of inventory are reluctant to invest in owned infrastructure, nor eager to commit to long-term contracts, and the service providers unable to invest without such commitments.

A measure available to the State to promote new infrastructure investment in the petroleum sector would be to offer guarantees for certain projects under well-defined conditions. For instance, rather than renting storage for 0.9 MM bbl of state-owned reserve in the Bay and 1.3 MM bbl in LA, the State could:

- Offer a tender for commercial storage operators to build the required volumes of tankage.
- The commercial storage operators rent out tankage at normal rates to refiners, traders and marketers under short-term agreements.
- If for some reason, tankage is not rented out for longer than a certain minimum delay period, the State would reimburse the operator for the fixed cost and capital recovery part of the monthly rental fee, but not the profits.
- Contracts for the guarantees would be awarded to those commercial terminal operators offering the lowest required monthly guarantee, after the longest delay, over the shortest overall number of years of validity of the guarantee.

The advantage of this option is that it is unlikely that it will ever require the State to spend any real money, but that it will allow the commercial operators to build tankage without long-term commitment from customers. This solution can be combined with other initiatives, whereby the State would rent part of newly built reserves itself and fill it with State owned reserves, while allowing the commercial terminal operator to rent out the remainder under the guarantee program in commingled tankage. The resulting combination is one of the solutions of which the economic effectiveness will be evaluated in Section 8.

6.2.2 Removal of Barriers to Infrastructure Projects

The main reason why normal laws of supply and demand do not function in the market for bulk liquid storage for petroleum products is the formidable efforts that must be undertaken to obtain the necessary permits. Even permits for a relatively modest expansion took over three years to obtain. This project was located in a heavily industrialized area, for tankage that was in fact a replacement of military fuel storage removed nearby, and was undertaken by one of the leading companies in the field [39].

Several factors complicate the permitting process:

- In the refinery centers in the Bay and the LA Basin, the areas where storage is most in demand, the permitting process for new tanks involves approval processes with multiple regulatory agencies. These processes are largely sequential and involve public review at several stages.

- Even when approved after all due regulatory review, projects can be held up indefinitely in court by Non Government Organizations (NGOs) representing interests of communities, even if projects are located in remote areas zoned for industry with no residential habitation in the direct vicinity.

- The NGOs that represent the local interest operate nationwide, are relatively well funded, and benefit from better central coordination and more favorable press relations than the industry.

- Permit applications for individual projects may require a lengthy procedure to update the Master Plan for land use in the ports as laid down in the State Land grants under which the Ports operate, while granting an exemption leaves the Port Authorities vulnerable to suits filed by opponents.

- The Port Authorities and other local regulatory agencies that have control over land use are not always aware of the greater interests at stake, and may have to give priority to interests of local electorate.

- The momentum in the Ports is building against bulk liquid terminals, with several terminals in the Bay and in the LA Basing closed down in recent years, and several more currently under scrutiny.

In summary, the current regulatory environment is such that it is easy and cheap to prevent infrastructure from being built, while filing project applications is uncertain and costly. Measures that the State could consider as options to ensure an adequate infrastructure for fuels, including a Strategic Fuels Reserve, are:

[39] Information received during Stakeholder Meetings.

- Centralizing the permitting process for bulk liquid storage and pipeline projects for fuels ("one stop shopping")

- Preparing blanket Environmental Impact Reports (EIR) for major changes, such as CARB Phase III implementation, whereby the overall macro-environmental impact factors are defined centrally, so that for individual projects, only local factors need to be considered.

- Introduction of a fast track procedure for fuels infrastructure projects that improve overall fuel supply reliability in the State.

These measures will enable normal market supply to meet the inherent demand without direct intervention or significant expenditure of taxpayer money. Similar measures were enacted for the power generation and transmission infrastructure, but only after 13 years had passed in which no new capacity was added, and a real crisis had sprung up. The challenge is to implement this type of program as a preventive measure rather than in a crisis environment, given the political hurdles at local level.

6.3 Recommissioning of Idle Tankage

Given the tightness of the bulk liquid storage market in California, there is no tankage that is currently left idle that does not have some significant problems associated with it that prevent its re-commissioning.

6.3.1 Idle Tankage linked to Refinery Infrastructure

A survey of the LA Basin and the Eastern Bay Area, the primary areas for location of an eventual strategic fuels reserve, revealed some terminals with decommissioned or otherwise idle storage with sufficient capacity to be considered for service as a Strategic Fuels Reserve. This tankage is mainly associated with power stations and closed-down refineries.

Table 6.3 – Summary of Idle or Decommissioned Tankage

	Bay Area	LA Basin	Total
Tankage at Closed Refineries	0.0	1.7	1.7
Fuel Oil Storage at Power Plants	4.0	3.5	7.5
Total	**4.0**	**5.2**	**9.2**

Several factors make it unlikely that the idle storage identified in Table 6.3 can be brought on-line again economically:

- For 1.0 MM bbl of refinery storage in the LA Basin, rates quoted by the owner for rental of the recommissioned tanks are 60 to 80% higher than the cost of new built tankage. This high cost is likely to be due to the factors quoted in Section 6.2.1 listing some of the reasons why large refiners incur substantially higher net project costs.

- The remaining 0.7 MM bbl of idle refinery tankage is associated with a refinery that may still be reactivated and its storage is not separately available.

- In total, 3.5 million barrels of idle power station fuel oil storage was identified in the LA Basin, and up to 4 million barrels in the Bay area. This idle tankage consists for the most part of older tanks that are neither suitable nor permitted for storage of high vapor pressure products. To make these tanks suitable will require significant investments, and the permitting process will be similar to that for new tankage. Moreover, the individual tanks are usually very large, i.e., in the range of 300,000 to 500,000 bbl per tank, which renders them less useful for product storage (see Section 2.2), while pipeline connections with the clean products distribution system would have to be created using whatever black oil lines are available.

Despite the obstacles, it seems likely that using existing tankage will result in some savings in time and project costs versus building new tanks for the reserve. Evaluating each of these options in sufficient detail to quantify cost savings versus new construction requires a level of engineering work not foreseen in the scope of this study. At this stage of early feasibility evaluation, it seems reasonable to assume that if a tender for the creation and operation of a reserve were issued to service industries operating in the LA Basin and in the Bay Area, and if those companies would be able to offer services at more competitive cost by using the idled power station tankage, then normal market forces would drive inclusion of these alternatives in the proposals to the State. For now, no significant cost reductions will be assumed.

6.3.2 Tankage Not Tied to the Distribution System

Only a few instances have been identified of idle tankage outside the refining centers, not connected to the main distribution system.

- In Ventura, 800,000 bbl of tank capacity associated with the former USA refinery. This tankage has been out of service for 15 years and would require major investment to be brought up to code. Moreover, dock facilities have been removed and substantial investment would be involved in converting an idled crude pipeline to products.

- In various coastal power stations, a total of 3 million barrels of former fuel oil tankage has not yet been removed. Most of these tanks are in poor shape, have no longer access to single point moorings or dock facilities, and are in locations where pipeline connections to the refining centers would require new pipelines through environmentally sensitive areas.

In total, the volume of such tanks that could in theory still be rehabilitated and made fit for service in light products may exceed the 2 million bbl required for the reserve. For all of the sites however, it makes no economic sense to attempt upgrade and connect the storage by pipeline to the refining centers, because even grassroots investment within the refining centers is bound to be more cost effective.

6.4 Conversion of Tanks Currently in Black Oil or Crude Oil Storage

In both the northern and southern refining centers, some tanks are currently used in black oil service (heavy fuel oil, VGO, bunkers, crude oil) that are capable of and permitted for storage of clean petroleum products. While surveys did not produce a complete inventory of all tanks with dual capability in California, with 1.5 MM bbl of identified tankage with commercial terminal operators in the LA Basin and at least 0.5 MM bbl in the Bay, it is estimated that total volume of such tankage exceeds the proposed volume of a Strategic Fuels reserve in each area.

However, using these tanks for a Strategic Reserve in light petroleum products is unlikely to bring an overall improvement of supply reliability in the State. Storage for black oil and crude is also very tight in both refining centers, and although commercial terminal rates for these products tend to be slightly below those of clean products in the current markets, the actual costs of the facilities that can handle the heavy products is higher. More often than not, black oil tanks and pipelines have to be heated and insulated, and pumps and other equipment have to be designed for highly viscous products.

If 2.3 MM bbl of tankage that has dual capability were to be removed from black oil and crude service to create a Strategic Reserve, this would represent less than 10% of available storage volumes for these products in the State. However, at less than 15 days of storage, crude oil inventory capability in California is already dangerously low by standards applied in most other parts of the world. Especially with the crude supply situation changing rapidly and the State becoming increasingly dependent for its crude oil supplies on foreign imports from remote locations requiring Very Large Crude Carriers (VLCC), it would not be prudent to recommend creating a Strategic Fuels Reserve for light products in current crude oil tankage with light product capability.

Black oil storage capacity, in contrast, seems more generous, with more than 20 MM bbl of tankage available in commercial terminals alone. However, black oil storage requirements are not determined to the same extent as gasoline or crude oil in terms of days of throughput, but rather by operational requirements for intermediate product storage allowing refinery units to function somewhat independently from each other, in particular to enable partial shutdowns and turnarounds of upstream units such as cokers and distillation units, and downstream upgrading sections. As it is, black oil storage available to refiners has declined by over 8 MM bbl over the past years, with aboveground tankage being scrapped or converted to crude oil, and the last of the large in-ground reservoirs has been decommissioned. It is therefore not recommended to attempt creating a Strategic Fuels Reserve in either black oil or crude oil storage capable of handling lighter products.

6.5 Floating Storage using Converted Tankers

Worldwide, many instances can be found where laid-up or obsolete tankers have been used to provide floating storage, usually as a floating dock and surrogate marine terminal, capable of receiving cargoes through a board-board transfer from a similarly sized or smaller vessel.

To evaluate this option as an alternative for a Strategic Fuel Reserve in California, a number of factors need to be considered, such as size and availability of vessels, the logistics of moving product in and out of the floating storage, and of course the approximate cost of maintaining tankers as storage.

Table 6.4 below compares a number of alternatives. From this table, it will be clear that it is not practical to assume that a reserve can be created using product tankers, simply because of the number of vessels that would be required and the cost involved. Even though availability is not the issue (it is estimated that in the next two years, 11 single hull US flagged product tankers will be retired [40]), the cost of maintaining the vessels at anchor and operating them as a floating terminal are likely to be prohibitive at an estimated $24,000 per tanker per day. Moreover, at least in LA, the space is simply not available to anchor 5 of these vessels.

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[40] MARAD, *OPA Schedule for retirement of Single Hull Product Tankers*, Jan 2001

Table 6.4 – Alternatives for Floating Storage

	VLCC	Product Carrier	Reserve Fleet
Provenance	Foreign, newly retired vessels	OPA single hull retirement	NDRF
Size (DWT)	250 – 300,000	35 – 40,000	18 – 35,000
Draft (feet)	50 - 60	35 - 40	30 - 35
Capacity (bbl)	1.5 – 2 MM	250 – 300,000	175 – 300,000
Vessels required, Bay / LA	1 / 1	3 / 5	3 / 5
Costs ($/bbl/month)	$0.75 - $1.00	$2 - $2.50	?
Cost product in/out ($/bbl)	>$0.75	>$1.00	?

While also expensive, the use of one retired VLCC in the Bay and one in the outer harbor of Los Angeles, both permanently moored and equipped with fenders and loading arms for board-board transfers, is at least doable from a practical point of view. The difficulty here will be to obtain a waiver for the Jones Act requirement, since no US flagged VLCCs were ever built, and to obtain permitting for a single hull vessel to be used as floating storage. All these factors, as well as the high cost, make this an option of last resort, since it has the advantage of being able to be implemented at short notice, i.e., in less than 4 to 6 months.

6.6 Incentives to Increase Fuel Production in California

The need for an SFR is borne out of a chronic supply shortage of gasoline in California, where refiners run close to or at maximum capacity with import options limited by commercial and physical barriers. In such a situation, each unplanned refinery outage immediately translates into a price spike. If somehow, production capacity could be increased so that a healthy margin of spare refining capacity existed, as was the case up to the mid-nineties (see Figure 1.1), other refiners would be able to take up the slack and compensate for the loss of production due to unplanned outages.

It is clearly not within the mandate of AB2076 to evaluate whether the State should enter into the refining business. However, there are measures the State could consider with regard to increasing refinery capacity that could achieve the same goal of suppressing price spikes at potentially comparable or lower cost than are likely to be incurred in the creation of an SFR. In particular, the State could contemplate measures to streamline and expedite the permitting process for projects that increase fuel production in California similar to the legislation introduced in order to accelerate capacity additions for power production.

Currently, the political climate in California is not conducive to the expansion of fuel production in the State. The consensus opinion amongst industry participants is that no new refineries will ever be built, although CEC forecasts of gasoline demand require the supply equivalent of an additional two refineries to be built between now and 2020, despite expected advances in fuel economies of cars [41].

Problems that refiners face when contemplating even small capacity additions are:

- Many refiners are up against hard constraints in their CAAA Title V Operating Permit. Even a small debottleneck of one unit may require applying for a new overall operating permit. In many cases, this renders the project uneconomical.

- Emission credits are expensive and offsets are hard to achieve, which again means that small projects are often not attractive.

- NGO's have proved to be adept at slowing or eliminating needed expansions. Part of the decision that CENCO Refining made to abandon plans to restart the Powerine refinery can be attributed to lawsuits brought by environmental groups. Unions have delayed the permitting of CARB Phase III projects in refineries in Northern California.

Government agencies have enforced their own agendas to the detriment of fuel production and logistics. The Port of Los Angeles has tabled the relocation of terminals in their port. The South Coast Air Quality Management District's Rule 1178 will put pressure on the distribution system, risking supply disruptions because of tankage that is taken out of service for doming. Permitting is a time consuming process. It took Kinder Morgan two years to get permits for the construction and operation of three new jet fuel tanks at their tank farm in Watson.

Government can create incentives to increasing fuel production by reducing the barriers that government has created. These include a coordinated permitting process, a new look at permitting requirements, and one-stop shopping for all energy related projects, not just electrical power.

[41] *Energy Outlook 2020*, California Energy Commission Staff Report, Docket No. 00-CEO-Vol II, August 2000

7 MARKET CONSIDERATIONS

The California markets for gasoline, diesel and jet fuel are each different in key aspects such as structure, liquidity, and forward trading opportunities. Of the three major liquid fuels, the gasoline market is not only the largest market by far, but also the most complex because of such factors as the uniqueness of the fuel specifications, the overall tightness of supplies and the relative inelasticity of demand. These and other factors underlie the severe volatility of the gasoline market and will be evaluated below, with the other markets, in particular the market for jet fuel, used only as a frame of reference.

7.1 General Description of the California Gasoline Markets

The California gasoline market has a layered structure, formed by four separate but interrelated markets:

- **Spot**. The spot market consists primarily of the trade at the refinery level. Traded gasoline volumes are typically 25 MB (approximately 1 million gallons, also referred to as a "piece") and are delivered into a pipeline at a place and time specified by the buyer. Most deals are "prompt", meaning the first open cycle on the pipeline, usually within one or two weeks. There are some twenty to thirty participants in the West Coast spot market, including refiners who buy and sell products between themselves to balance out volume requirements, trading houses, brokers, and the large independent marketers. The spot market moves with the perceived change in refinery supply and demand.

- **Rack**. The rack market consists of wholesale buyers such as independent retailers and bulk customers who operate their own truck fleet ("jobbers") and who take delivery of their product at a truck loading rack situated at a terminal, or sometimes directly at the refinery. Rack market participants may buy branded products destined for branded stations, or unbranded products destined for independent service stations or commercial/industrial accounts. In general, branded rack prices tend to move in relation to street prices. Unbranded rack prices tend to move with the spot market.

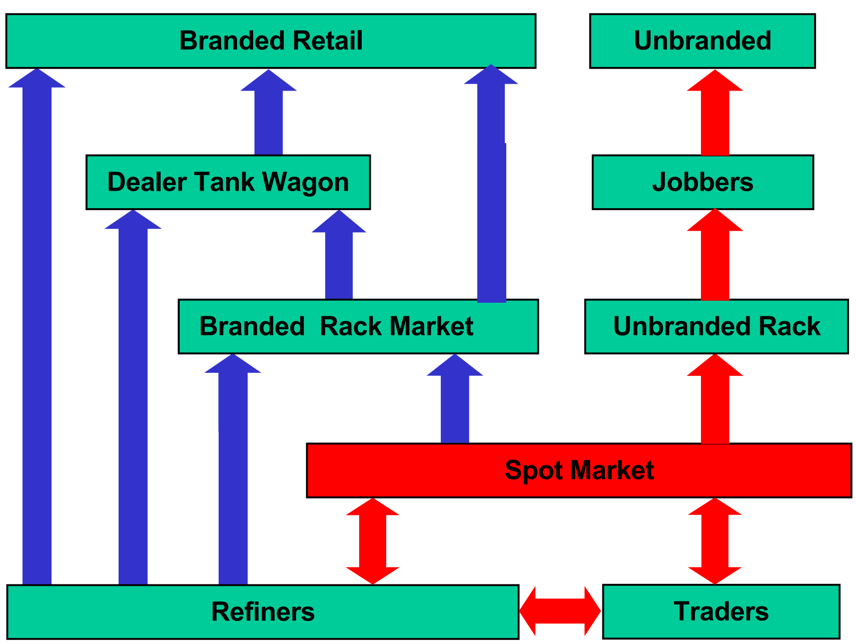
- **Dealer Tank Wagon**. The price of gasoline delivered to a branded retail site is termed Dealer Tank Wagon ("DTW"). In a stable market, DTW is set by review of competitive prices. In an unstable market, DTW tends to move with the change in spot prices, although the magnitude and duration of the changes can be different than those of the spot market.

- **Retail Market**. The retail market is where pump prices are posted. Street prices are normally set relative to prices of other local gasoline stations. Recently, a new force in retail is emerging in the form of High Volume Retailers ("HVR"), which are operated by large chain stores aim at large volumes at low margins. HVR's tend to price their gasoline on cost, rather than local competition.

7.2 Pricing Mechanisms

The spot market is essentially an over the counter market, with deals negotiated on an individual basis between participants. Reporting of deals and posting of pricing by reporting services such as OPIS or Platt's occurs when both buyer and seller confirm the deal. In the California spot market, which includes deals made for supplies into Nevada and Arizona, there are between 20 and 30 active participants, and a "liquid day" is a day that sees four or five deals being concluded. More typical are days with only one or two deals. Not all reported deals are physical deals: pieces can be bought and resold several times, and become physical only when delivery is due by the final seller in the chain at the scheduled slot in the pipeline cycle.

Figure 7.1 – CA Gasoline Market Structure



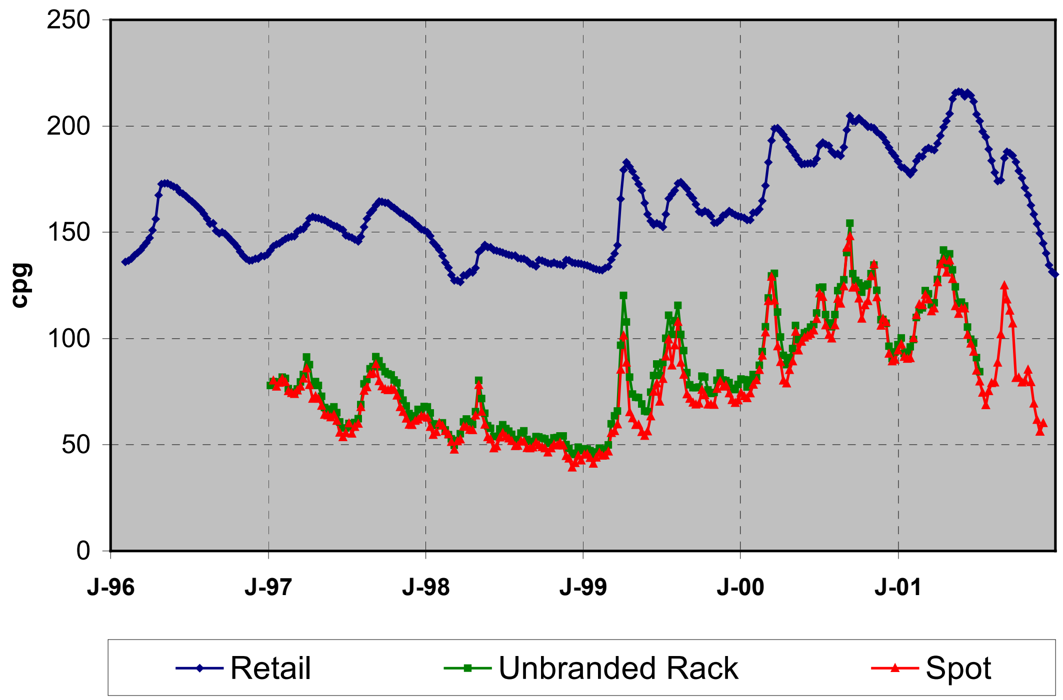
Daily spot prices are driven by prompt market imbalances in supply and demand that are brought to a head by the weekly pipeline schedule requiring prompt physical delivery. Every spot purchase by definition is a one-time event. The buyer and the seller incur no obligation for future transactions, although forward deals may be transacted as adjunct to, or independently from, the spot purchase. The cumulative effect of these transactions propels the price up when markets are tight, with several buyers chasing limited supply. In down markets, the price will descend in the absence of firm deals as sellers look for buyers at lower prices, while buyers back away. These imbalances can be as small as ten thousand barrels (10MB), with 25MB being the average 'piece'. If a refiner, marketer or trader is 'short' that amount of product and must 'cover', or purchase in the prompt spot market in order to meet physical delivery obligations, that transaction can push the spot price, as reported by OPIS up five to seven cents per gallon in a tight market. In other words, 25MB moves the deemed value of the entire gasoline inventory in the State because it represents, "the last deal done".

Rack pricing for gasoline is broken into two segments: Branded and Unbranded. Pricing of gasoline for these two classes of trade is complex, dynamic and interrelated. Branded gasoline wholesalers are subdivided into classifications of "jobbers" and DTW (Dealer Tank wagon) accounts. DTW prices represent the wholesale price paid by the dealer to a refiner for gasoline delivered in bulk to that dealer's retail outlets. Often the DTW price is higher than the unbranded rack, plus transportation. The branded dealer has, in effect, traded off the opportunity to take advantage of steep wholesale price declines during periods of oversupply, for a greater consideration of security of supply and an acceptable guaranteed margin over the long term. Imbedded in the DTW price is the deemed value of the supplying company's brand name.

Jobbers are those companies that service the market sector from the refiners' truck loading racks to end-user retail and consumer accounts. They establish credit lines with the refining companies sufficient to service their customer base and pick up their loads against pre-negotiated contracts. A jobber may service both branded and the unbranded accounts. They take title to the product as it passes the truck flange but may be restricted by contract to deliver certain loads only to branded customers in particular market zones. The refiners structure their contracts with the jobbers to prevent the delivery of 'unbranded rack' priced truckloads to 'branded dealers' when the unbranded and spot market prices are weaker. Conversely, they are not allowed to 'over-lift' branded gasoline during tight market and deliver those loads to the unbranded sector. Because of differences in zone pricing, even in the 'branded' sector the same jobber may pick up several loads from the same refiner on any given day and be charged a different price for each through a long-established value of TVA discounts (Temporary Voluntary Allowance).

Competition among the major brands in various metropolitan and even outlying areas rises and falls in intensity based on market-share strategies and promotions. Each market zone will be charged a price approximating what that particular market will bear, given its demographic position and a number of secondary factors such as traffic count, corner location and deemed price-elasticity, nearest competitor, etc. The integrated refiners also operate their own truck fleets dedicated to branded gas station deliveries under the DTW system. Surveys of the major refining & marketing companies in the state have found that most do not post a meaningful 'unbranded rack' price. They remain balanced to short with respect to their refining capacity and their branded dealer downstream demand. Through recent mergers, the number of refiners supplying the unbranded rack market in significant quantities has been reduced from two to one.

Figure 7.2 – CA Gasoline Spot and Retail Prices



It is clear from Figure 7.2 that the unbranded rack price closely tracks the spot price, and that retail pricing, which includes a significant mark-up from federal, state and local taxes, follows the movements of spot and rack not only with a slight delay, but also with movements that are somewhat dampened by the fact that the refiners will protect their branded retail to some extend on the upswing, while holding on to margins a little longer on the downward slope.

Another important element of pricing is that of the transfer pricing policies within the integrated refining and marketing companies. The integrated oil companies produce crude oil, refine it, and distribute the products through their branded retail locations. None of major oil companies operating in California are completely integrated, since all of them are somewhat dependent on other companies (or countries) for crude oil supply upstream of the refinery and product supply or offtake downstream of the refinery. In order to help measure their performance, the refiners have to have a benchmark for the crude oil and products markets. In general, they use the spot market for this gauge. They assume they are buying crude oil from their producing company at the spot, refining it, and selling the products to their retail organization at spot prices. The retail organization receives product at a spot price and sells it at retail. Their relative profitability can be described as DTW or Rack Price minus Spot Price minus expenses. This permits a company to quantify the relative profitability of each link in its supply chain.

7.3 Effect of Insularity

For petroleum products, California is an insular market, separated from world markets not just by geographical distance, but also by product quality aspects, commercial barriers and infrastructure limitations, all of which cause price differentials above mere transportation cost. There are many examples of markets that are insular in nature, sometimes because they literally are islands, such as is the case for Hawaii or Japan, sometimes because of protective tariffs, and sometimes, as is the case for California, because of a complex set of factors that prevent a free flow of goods when price differentials would dictate they do.

The relationship between price differentials between markets and the total cost to move goods between them, including transportation, duties, storage, time value of money, etc., is referred to as geographical arbitrage, or “arb”. The arb is said to be open when the differential is large enough to leave a profit to the importer, and the arb is closed when differentials do not justify movements.

In closed economies, local prices can be substantially above world market plus transportation costs because of restrictions on imports or duty barriers. Usually, high local prices then are indicative of inefficient production or limited competition, or a combination of the two.

In open economies, such as is the case for California, local prices should be at world market prices plus transport cost. However, sometimes for prolonged periods, California prices are substantially higher. Since California refineries are amongst the most sophisticated in the world, and since temporary situations of oversupply during winter months immediately result in severe price drops – as was the case as recently as December 2001 through January 2002 – it can be concluded that the insularity of the California market has not resulted in inefficiencies or uncompetitive practices. The only remaining explanation for the prolonged price excursions above world market plus arb is therefore that import options are indeed restrained by physical reasons (terminal capacity) and commercial factors (price volatility), It is important to note that because on average, California refineries are efficient and low-cost, and are engaged in open competition, imports are not necessarily going to lower the average price. Rather, the import dependency has caused an increase in the incremental cost of supply, which in turn raises the price of the entire market and increases refining margins. The effect of an eventual SFR maybe to lower the cost of imports and reduce price spikes, but it will not lower the price of gasoline to the incremental cost of production within the State itself.

7.4 California Fuels Forward and Futures Markets

A forward market is a market in which a buyer and seller agree to a physical transaction with a future delivery date, but for which prices and delivery terms are agreed at the time of the transaction. The advantage of a forward market is that it allows a buyer and seller to lock in margins over cost on a specific shipment. However, both buyer and seller take a risk that the market may shift and either party to the agreement stands to lose or gain substantially on the deal when compared to the market conditions that may prevail at the time of physical delivery. A forward transaction implies integrity on the part of both parties to honor the commitment despite market changes. The spot market in Los Angeles currently has only a very thinly traded forward market component, i.e. only one or two forward trades are typically conducted per week and rarely for more than one month into the future.

A futures market is a market in which non-physical trades are conducted using standardized contracts under which factors such as product specifications and delivery terms are defined. Futures are transacted between licensed traders in open auctions on a trading floor rather than directly between principals, with the exchange acting as the clearinghouse for all transactions. Futures markets, such as the NYMEX (New York Mercantile Exchange) in New York and the IPE (International Petroleum Exchange) in London are subject to government regulation. Since buyers and sellers do not deal directly with each other, but rather through the institution, or clearing house, a system of margin calls and allowable “open interest” (total number of contracts, long or short, in a given month for a given company) is strictly enforced to ensure the integrity of the Exchange. At the NYMEX, futures are traded for crude oil, gasoline, and heating oil. The advantage of a futures market is that it allows parties to a forward contract not just to lock in prices and margins over costs, but also to lock in prices relative to prevailing market conditions at some future point in time. Using standardized futures, a seller can hedge a physical forward sale by offsetting it with a non-physical forward buy of another commodity that generally moves in the market at a fixed differential to the commodity he wants to sell at some future date. The process of reducing future market risk by entering into offsetting selling and buying agreements is called hedging.

A thinly traded forward paper market does exist in California but with insufficient volume to provide a bridge to a traditional futures contract. In the absence of a forward or futures market, a trader or importer bringing products into California takes a significant gamble, given the volatility of the market. The importance of the existence, or rather lack thereof, of future or forward markets for the California fuels situation lies in the insularity of the California markets in general. A potential importer of a cargo of gasoline typically has to take a decision to produce and load a cargo 6 to 8 weeks before it will reach the market. Even though the spread between production costs plus shipping costs and the California market price may be very attractive at the moment a decision has to be taken, the situation may be reversed by the time the cargo finally reaches the market. Many importers would prefer to lock in a known margin of 1 or 2 cpg at the time of shipment, rather than take a gamble that a 20 cpg price spike in the California market will last until their cargo arrives [42]. A cargo of gasoline arriving on Friday could be valued at twenty cents per gallon lower than one arriving on Monday of the same week, a potential loss of millions of dollars.

Because the lack of forward price protection inhibits out-of-State suppliers from delivering cargoes to California, price spikes are exacerbated and become long plateaus of relative price elevation. A futures market would enable hedging and liquidity, which in turn will attract cargo re-supply when needed.

The question now becomes, what can be done to promote liquidity and create forward and futures markets for California gasoline. A survey of a broad range of market participants, including Futures Markets planners and administrators, confirmed that the prerequisites for a commodity futures contract to take root in any market are:

- **Market Liquidity**. There must be a minimum number of buyers and sellers in the market, each with different business orientations, who together form sufficient critical mass to conduct a minimum number of transactions daily.

- **Fungibility**. There needs to be an established transaction flow in a product with a common specification or with established price differentials to other commonly traded commodities. Heating oil, for example, has been a very successful NYMEX commodity because its specifications can cross over to a number of markets: Jet fuel, transportation diesel, home heating oil, kerosene, etc. Diversion from this basic commodity spec can be evaluated in the physical market between buyers and sellers. The NYMEX contract can still be used as a basis for exchange after factoring in such value differentials. California

[42] Information received from all traders and importers during the Survey meetings with industry Stakeholders.

gasoline and CARB diesel, on the other hand, are unique formulations that contribute to the isolation of the State and to price volatility. This is one of the major obstacles for establishing a liquid futures market in California.

- **Physical Delivery Point**. A futures contract buyer, also known as 'a holder of a long position' retains the legal right to demand physical delivery of the commodity upon expiration of that contract. Without a basis in guaranteed physical delivery, a commodity futures market would be merely an arena for speculating on price movement in the absence of underlying value. Given this necessity for physical delivery, California has never been seen as a fertile field for a traditional futures market, such as NYMEX to take root. There is no common storage available to non-California refiners or international traders. It has been noted that the Kinder Morgan (KM) pipeline gathering system could serve as such a delivery point, if it were to be linked to common storage accessible to various classes of trade. Existing refineries and most product terminals are already connected to the KM gathering system. A State sponsored SFR commingled with private sector inventories could provide the common storage that could form the physical delivery point for a standardized futures commodities contract.

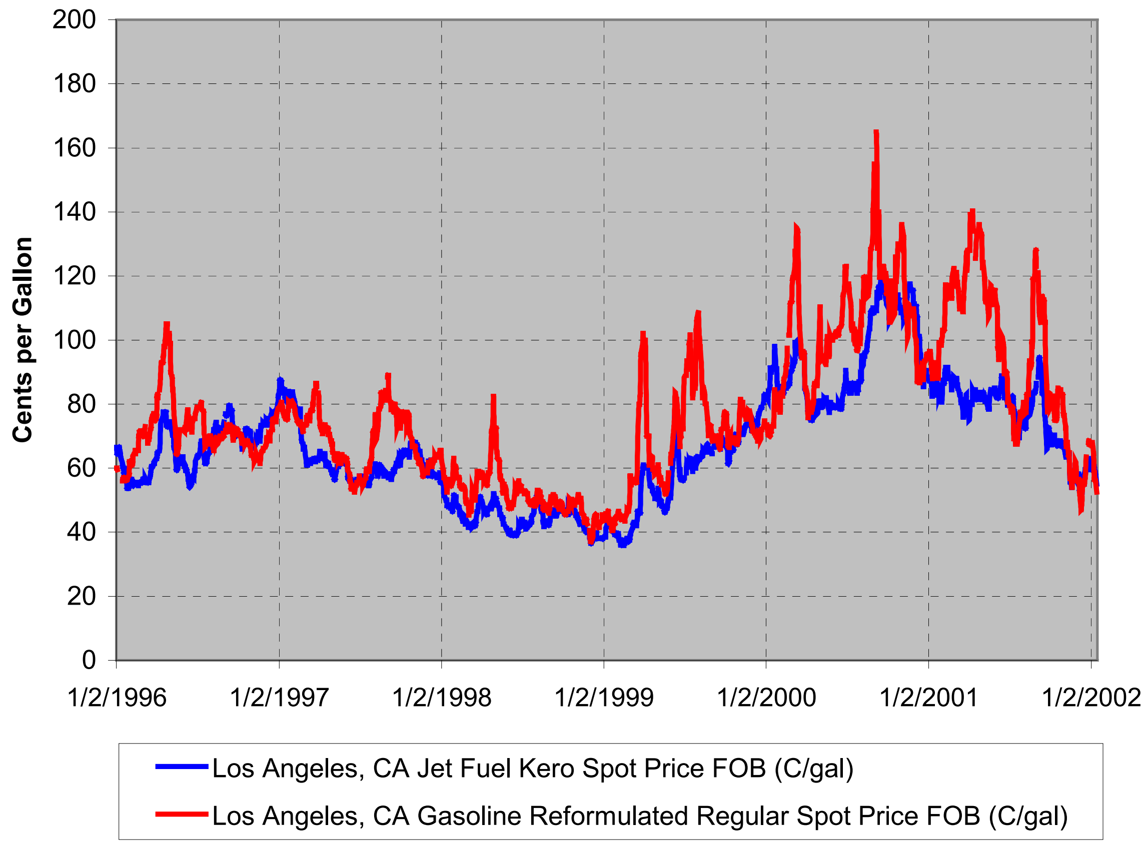
- **Multiple Supplies**. There should be a variety of supply points into the locus of the futures contract. NYH is easily accessible by vessel from such diverse points as Northwest Europe, South America, the US Gulf and Caribbean areas.

- **Diversity of participants**. Besides diversity of geographical supply points, the participants should also represent a diversity of interest in order to ensure market liquidity. For example, in New York Harbor (NYH), besides the refiners and global traders, there are over twenty-five local companies involved in shipping, blending, trading, marketing, etc. These spot-market oriented companies tend to depress price spikes by blending batches to meet local demand. Gasoline blending is not feasible in California outside the refining systems due to the lack of available storage, the Unocal Patent barrier and the severe penalties attached to off-test blends. The greatest part of a futures market's liquidity actually comes from non-integrated traders and energy companies. The integrated majors tend to regard their integrated supply chains (i.e., Crude ⇒ Refinery ⇒ Distribution System ⇒ End Customer), as a natural hedge against price aberrations that occur at any point in the value chain, such as local price spikes in gasoline or heating oil.

- **Day-to-Day Participation.** A commodity market is most effective when buyers and sellers enter the market every day. A stop and start system, as would be engendered in a boutique fuels market such as California gasoline, does not lend itself to a viable futures market.

One finds most of these prerequisites fulfilled in connection with the Los Angeles jet fuel market, but not in gasoline where there is no common specification, no common storage and no established transaction flow from alternate sources. Consequently, the price volatility for jet fuel is far lower than for gasoline as illustrated in Figure 7.3. While jet fuel tracks the same underlying trend as gasoline, which is mainly related to crude oil pricing, the jet prices do not show the spikiness and volatility of gasoline.

Figure 7.3 – LA Spot Prices for Jet Fuel and Gasoline[43]



It should be noted that futures trading has sometimes failed in other markets. The NYMEX U.S. Gulf Coast Heating Oil and Gasoline contracts, for example, could not generate enough liquidity (transaction volume) because the Gulf Coast is essentially a supply center rather than a consuming center. In theory the contract had a chance to work, in that Gulf Coast refiners might want to hedge their production locally. Instead, they preferred to continue using the

[43] Source: EIA daily spot prices

destination market of NYH on a net back basis (NY price minus a differential). Singapore crude oil was another failed experiment. A Brent vs. Dubai (European vs. Asian) crude contract was established in the mid nineties to capture more efficiently the international flow of cargoes and prices. The contract was ultimately under-subscribed, largely because of an Asian business culture that prefers negotiated deals to anonymous, electronic transactions. Basically, these experiments lacked one or more of the prerequisites indicated. Nonetheless, a California futures market for gasoline, diesel and perhaps blend stocks could emerge in the private sector through the operation of an SFR if the following strategic elements are incorporated into it:

- SFR inventories are commingled with private sector inventories.
- The tankage is connected to the Kinder Morgan gathering systems in the Los Angeles basin and in the Bay Area.
- Use of the SFR inventory is triggered by time-trades, or buy-sell agreements rather than outright sales.
- Access to the SFR inventories is open to various, pre-qualified classes of trade.
- The SFR has direct waterborne access for incoming cargoes and can serve as the physical delivery point for a futures market.

8 DESIGN AND EFFECTIVENESS OF THE RESERVE

Based on the above, the most effective design of a reserve will be that which will function not as a stagnant inventory set-aside program, but as highly liquid physical delivery point for imports, fully integrated into the refining infrastructure, marine terminals, and distribution pipeline systems, with its volume accessible to qualified participants as a “bank” from which supplies may be drawn against a fee, with repayment in kind within a specified time frame.

The very existence of such a bank will provide a center for discharging incoming products cargoes. By virtue of being located at the head of the distribution pipeline systems the SFR will provide a clearing center for price and transaction liquidity. By commingling any State-owned inventory with private sector supplies (similar to the Heating Oil Reserve in NYH), a double benefit can be gained. First, the commingled product will be constantly “turned over” in the normal flow and scheduling process. This will insure seasonal quality integrity and prevent quality degradation. Whether release of State-owned SFR inventories are to be triggered by pre-defined price formula, or unscheduled refinery events under one model, or by a regular withdrawal allowance system as an “oil bank” under an alternative model, the effect of such release will be to draw the island of California more rationally into regional price and logistic patterns (geographic arbitrage).

8.1 Tank Space

The rigorous quantitative analysis carried out by Dr Tony Finizza[44] indicated that a volume of 900,000 bbl is sufficient to cover all but 10% of refinery disruptions. However, several factors make that the originally planned net volume of 2.3 MM bbl (2.5 MM bbl gross), is still the right number:

- As shown in Section 2.3, logistic factors call for reserve volumes to be fully integrated with both the LA Basin and the Bay Area refining centers, forcing a split in total volume. At just over 1 MM bbl each, according to Dr Finizza’s analysis, these local reserves would be individually capable of dealing with a major disruption in their respective refining center.

- The use of the reserve as a forward market mechanism to facilitate imports will imply that at any given point in time, a significant portion of the reserve may be lent out and somewhere in transit on its way back.

[44] Anthony J. Finizza, Ph.D., *Economic Impact of Refinery Disruptions*, CEC Study, June 2002

- Although not specifically designed to deal with major emergencies, the value of the reserve to also act as a safeguard for California's gasoline supplies in case of a major disaster such as an earthquake or terrorist act, the value of a reserve for these purposes would be greatly diminished if reduced to a bare minimum.

- Dr Tony Finizza's analysis is based on historical numbers and the expectation is that California's gasoline supply situation will worsen considerable over the coming years, as shown in Section 1.4.

Based on the findings of Section 6 above, tank space will have to be newly created, and the most cost effective way of doing so is by issuing a tender for bids by qualified commercial storage operators for a long-term, i.e., 10-year contract for storage space. To suppress the cost of the State's share and to help create storage space for use by third parties not normally capable of entering into the long-term agreements tank operators need as financing prerequisites for new storage, the State could request double the amount of tankage to be built, but offering only minimal guarantees for the excess capacity, with would oblige the commercial operator to exercise best efforts to find lessors.

Assuming that the base 2.5 MM bbl can be leased for $0.50 per bbl per month for a cost of $15 million per year, and that the State's guarantee for the additional 2.5 MM bbl will be $0.35/bbl/month, and the guarantee on average will be evoked for 10% of the time, costing the State an additional $1 million per year, then the total cost for the storage will be $16 million per year.

With the tanks operated as a fuel bank, all additional operating costs identified in Section 6 above, such as volume losses and pipeline fees, will be absorbed by the parties drawing from the reserve and replacing it.

8.2 Fuel Quality

As discussed in 2.2, the reserve will have to be designed such that all requirements for gasoline quality will be met. The most cost effective way of ensuring that compliant gasoline can be delivered from the reserve as needed, is to store only summer grade CARBOB in the SFR tanks. The chances that a reserve would be called upon during the winter driving season is low, and even in the unlikely event that gasoline would have to be supplied from the reserve during the winter season, it would not be too difficult or onerous in terms of costs to increase vapor pressure by blending in lighter components to ensure usability of the fuel in colder regions of the State.

However, if only summer grade CARBOB is allowed in the reserve tankage, while most imports that will be brought in to backfill the SFR after usage are likely to consist of blendstocks or near-conforming gasoline blends, facilities must be created to enable receipt of other than finished gasoline imports, which can subsequently be blended off to produce conforming CARBOB. It is therefore proposed that in addition to the 2.5 MM barrel capacity of the SFR itself, measures are taken to facilitate the building of additional storage integrated with the SFR.

Figure 8.1 – SFR and Satellite Commercial Storage

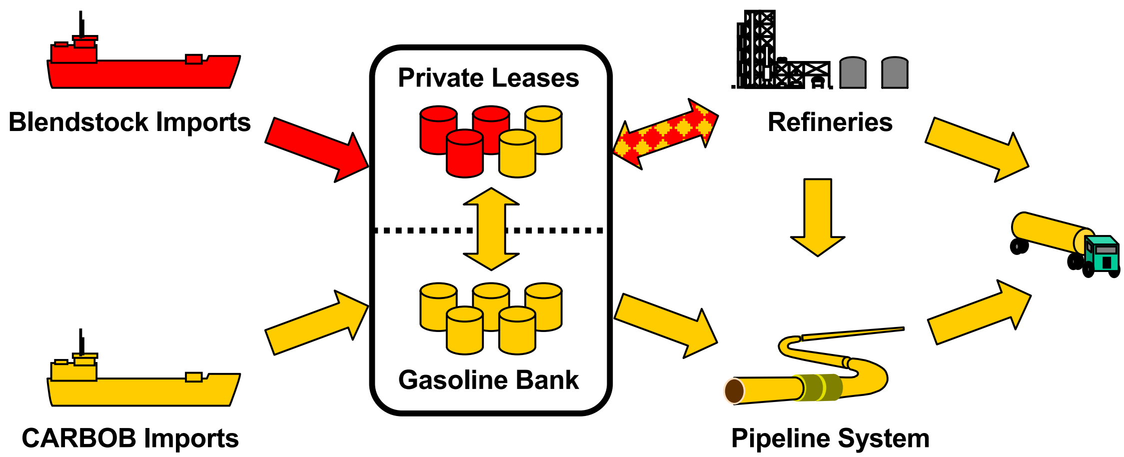


Figure 8.1 shows the concept whereby additional tankage is created for private leases next to the State owned inventories that form the gasoline bank. This will enable users of the SFR to bring in blendstocks and blend these off in cooperation with local refiners to conforming CARBOB for repayment of volumes borrowed from the SFR.

8.3 Initial Fill

Based on a recent-years historical range of gasoline prices from 50 to 130 cpg, the initial fill of 2.5 MM bbl can cost anywhere from $50 to $140 million. There are however several alternatives open for the State to minimize the upfront capital outlay for this purchase.

Firstly, a partial offset can be claimed against the Federal Petroleum Reserve, because volumes held in reserve as products in California need not be covered by a corresponding amount of crude oil in the Texas caverns. This mechanism was also used in part to fund the Eastern Heating Oil Reserve.

Secondly, the fuel will not be consumed, but will remain substantially in place as collateral, with guarantees in place from qualified participants for volume lent out at any point in time. It should therefore be possible to secure debt against the collateral, possibly subject to margin calls if the underlying risk of fuel price fluctuations cannot be entirely secured by forward rolling hedge mechanisms.

A reasonable estimate therefore seems to be that the costs of the initial fill can be reduced to the cost of the debt service on part of the purchase costs, possibly in the range of $5 to $10 million per year.

In order not to cause a market disruption, it will be important to purchase the initial fill quantity gradually, preferably during the winter season and from remote sources. Contrary to what has been suggested in AB2076, it is recommended to include local refiners in the parties allowed to bid on tenders for the initial fill. During the winter season, some spare capacity usually exists in the California refining system, and the local refiners would be able to use imported blendstocks to complement local capacity to produce CARBOB for storage in the SFR.

8.4 Participants

Access to the reserve volumes is one of the key questions that was raised during the Stakeholder Meetings. The options on this issue range from an entirely open forum, whereby even non Industry participants capable of posting financial guarantees would be invited to an SFR auction, to a highly selective core group of major oil companies. Each of these options is discussed in detail below.

- **Open Forum.** It can be argued that a truly democratic approach to operating the SFR would be to open the bidding for supply to all financially capable applicants. This approach was tried with the Federal Crude Oil Reserve with disastrous results. The winner of the initial purchase bid turned out to be a non-industry party who was not capable of performing under the terms of the contract upon winning the bid. This caused confusion, and became an embarrassing waste of time and money. Since the recommended solution for the California SFR is a “time swap” mechanism rather than an outright sale of product, (see “Operating Mechanism below), the system will require a high degree of familiarity with contractual and operational issues, such as scheduling pipelines and vessels, product quality details, etc. There will be an obligation incumbent upon any successful bidder to physically perform the contracts on both the inventory drawdown side and the product replacement side. Product will move into and out of the SFR on a contractually binding schedule. This will require a measure of professional expertise with the California supply and distribution system. Financial ability alone will not suffice to qualify an applicant to participate in the auction process.

- **Refiners Only**. Another theory advanced has been that only California refiners should be allowed to draw product from the reserve. Since price spikes are primarily caused by unscheduled events in a refinery, such as fires, explosions, unit downtime, etc. it could be argued that it is the refiners alone who should avail themselves of the product held in reserve by the State. If not limited to the particular refiner suffering the problem, then the field of auction participants should at least be narrowed down to the Refining class of trade. On the other side of this argument stands the widely acknowledged fact that a price spike caused by a supply interruption at a particular refinery impacts the statewide gasoline market, to some degree. The laws of 'force majeure' do not relieve a commodity supplier from delivery obligations under contract, so long as alternative supplies of that commodity are available, at some price, in the market. So too, a refinery suffering an unscheduled event that causes production curtailment and a price spike remains bound to cover his contract obligations so long as alternative supplies can be purchased or acquired through trade. That refiner, and the refining class of trade as a whole, should have the right to bid for product from the SFR, but it is not an exclusive right any more than California petroleum products are an exclusive market. Business Interruption Insurance is available to the manufacturing sector of any industry.

- **Qualified Stakeholders**. The balanced approach is to invite Industry professionals to participate, subject to predefined financial and performance criteria. Under this scheme all market sectors in California would be allowed to compete for product released from the SFR in volume increments consistent with their operational needs and credit limits. It may be necessary to install volume limits for individual companies in order to prevent too much of the SFR falling into too few hands, thereby creating a market control situation. A concerted effort must be made to ensure that qualified Independents have access to the SFR system.

8.5 Effect of Mobilizing Reserve Volumes

When the creation of the Northeast Heating Oil Reserve was being discussed, there was speculation that inventory managers would take the government's inventories into account when planning their inventories [45]. The theory was that creating a reserve could lead to lower inventories because the government would be there as a backstop. Similarly, during the

[45] Statement of Neal L. Wolkoff, Executive VP, NYMEX before the US House of Representatives Committee on Commerce, Subcommittee on Energy and Power, October 19, 2000

Stakeholder meetings, several companies suggested that a fuel reserve could reduce commercial inventories.

In the course of the Stakeholder Meetings conducted for this study, a number of companies who are participants in the Northeast Heating Oil Reserve were interviewed. None of them thought that the existence of the Reserve impacted commercial inventory planning practices. However, the Northeast Reserve has only been in existence since the fall of 2000 and seemed to be a non-factor in the heating oil market after it was filled.

The workable inventory range for gasoline at the refineries is between 8 and 16 million barrels (see Figure 4.2), which equates to a mere 8 days of production. Over half of this inventory consists of blendstocks and components. In Section 4.7 it was shown that the primary considerations for refiners in setting inventory targets are operational necessities. This was borne out by information received during the Stakeholder Meetings, during which refiners without exception reported that their operational considerations are paramount, with inventories resulting from fluctuations in demand and production that are largely unplanned.

The presence of a reserve can be a concern however to importers, who may be reluctant to commit to a cargo that would arrive 6 to 8 weeks after the onset of a price spike if volumes from a reserve are overhanging the market. To avoid these concerns, criteria can be formulated for release mechanisms:

- Release mechanisms must be clearly formulated and strictly applied.
- If an event driven trigger mechanism is chosen, the conditions for release should be set so high as to apply only to exceptional emergencies, as is the case for most large scale Strategic Reserve's. The presence of such reserves seems not to interfere with day-to-day market operations.
- Because the purpose of the California SFR is to mitigate price spikes, which are frequent events, it is by definition impossible to create sufficient distance between normal market levels and an event that would trigger release of reserve volumes. If an event driven trigger mechanism were chosen for the California SFR, it would likely have an adverse effect on marginal supplies. *Therefore, release mechanisms for the California SFR need to be designed for continuous use, whereby the primary goal of the reserve is to function as a mechanism for forward trades and facilitate rather than hamper marginal supplies*.
- Access to the reserve must be open to all classes of regular suppliers and distributors of gasoline and components, with an option to borrow and repay in kind (time swap).

Some “gaming” of the release rules can be expected and trading around the lifting rights or obligations to replenish are expected to create a satellite market which is likely to improve overall market liquidity in California. The potential for misuse of the reserve volumes can further be minimized by providing adequate oversight. Since the use of the reserve volumes involves prompt physical lifting with physical replacement of volumes borrowed, and involves only a limited number of participants, it is an easier process to oversee and regulate than many of the current commodity trading hubs.

8.6 Operating Mechanisms

Given the considerations above, the proposal is to operate the reserve volumes as a base volume for time-swaps. This trigger mechanism has distinct advantages over event driven triggers, which have the problem that hurdle levels can be set either too low (preventing normal market re-supply), or too high (requiring real economic damage to occur first). The time-swap operation also answers best to the requirements formulated in AB 2076:

> “The commission shall evaluate a mechanism to release fuel from the reserve that permits any customer to contract at any time for delivery of fuel from the reserve in exchange for an equal amount of fuel that meets California specification and is produced from a source outside California that the customer agrees to deliver back to the reserve within a time period to be established by the commission, but no longer than six weeks.” 46

At this stage of early feasibility study, the evaluation of the release mechanisms is limited to conceptual considerations. As appropriate for an early stage feasibility study, the means are currently not available to complete the detailed design necessary for final investment decision and commencement of operations. Four alternatives for the operation of the SFR are currently deemed viable, and will merit further evaluation:

- **Daily scheduled auctions.** Auctions for the use of the reserve’s volumes would be held daily, preferably in a fully transparent format, i.e., on an electronic exchange, whereby a pre-qualified participant can bid on a fee to pay for prompt lifting with redelivery within 6 weeks. To prevent an early stock-out, the quantities that can be auctioned off on a daily basis must be limited to a prorated portion of the reserve. For instance, a workable solution may be to limit the amount of gasoline and blending components to be auctioned

[46] California Assembly Bill 2076, Chapter 8.2, Section 25720, para (4) (c)

of for prompt lifting with redelivery 6 weeks later, to 50 TBD. Then, because there are 30 working days with auctions in the intervening period, on average 1.5 million barrels will always be on the water, with a remaining reserve of 1 million barrels in storage. A volume of 50 TBD daily is relevant to the shortfall that is predicted after the phase out of MTBE, and is also relevant to the production loss of 29 TBD, which is the average reported number for refinery disruptions. A limit of 50 TBD would not allow all California imports to be hedged through forward swaps using the reserve volumes. Moreover, a limit of 50 TBD will not allow an importer to cover a full cargo of up to 300,000 bbl in one transaction. However, not all imports need to be covered through forward transactions in order for the material to make its way to California. For instance, the major refiners currently bring significant volumes to the State from within their global refining systems, and will average out gains and losses over the long term.

- **Weekly scheduled auctions**. Weekly auctions would be similar to the daily model described above, with the quantity raised to 300,000 bbl. A weekly event would reduce overheads somewhat, and has the advantage of enabling to bid on a quantity that corresponds to a full cargo size. Moreover, the weekly auction could be timed to fit the weekly pipeline notification schedule.

- **On Call Auctions**. Auctions would be held within a pre-agreed format and venue, but only when called for by one of its accredited participants. This model will be better suited if the predominant use of the forward time-swapping mechanisms is mitigation of refinery disruptions rather than as a means to facilitate a forward pricing mechanism for regular imports.

- **Fixed Fee Usage**. Rather than having to bid for the time-value of the product within the backwardation of the market, users of the reserve for forward time-swaps could be charged a simple fixed fee. This will make it easier for importers to take decisions on available cargoes, in that they can commit to a sale before having to wait what the auction fee for the forward swap will be. On the other hand, the fixed fee doesn't allow market forces to place a value on the backwardation, but would effectively set the backwardation at whatever the fixed fee would be.

At this stage of early feasibility study and conceptual analysis, it is sufficient to say that each of these alternatives appears imminently viable, and that there do not appear to be any fundamental reasons why a forward time-swap mechanism utilizing volumes made available by the State cannot be made to work. Given the tremendous potential for consumer benefits as outlined in the remainder of this study and as confirmed by the analysis of Dr Tony Finizza, a next step that would involve a detailed design of operating mechanisms seems fully justified.

8.7 Fees

In the light of historical values of market backwardation is not unreasonable to assume an average fee of 2 cpg for eliminating a 6-week price risk. At this rate, and assuming 250 trading days with an average of 50 TBD in volumes, the gross revenues for the State from the reserve's operation as a bank for forwards time-swaps will be approximately $10 million per year.

8.8 Reserve Management and Oversight

There is currently no State agency that has the necessary experience or qualifications to perform the operational duties involved in managing a petroleum product terminal. In order to be cost effective, the function of managing the SFR will therefore have to be outsourced to private industry on a competitive bid basis. Operating the SFR means both managing its physical aspects, such as safety, quality assurance and scheduling, as well as managing the auctions, credit and collections of the State-owned inventory. For the latter, the best suited private industry entities are not the same as those who can run the terminals, and the best approach is likely to be for the State to issue separate tenders for each of the two functions.

Even when the State will outsource both the physical and commercial management of the reserve, the requirement will remain to create an oversight function within a suitable State Agency, that would be empowered to supervise the reserve's operations, with authority to issue the tenders for building or converting the required terminal capacity under long-term contracts, and for the purchase of the initial fuel inventory. This Agency will further need the authority to regulate the auction process for the forward time-swaps of fuels in the reserve, to qualify participants and to oversee the usage of the fuels by the participants, with the powers to revoke trading privileges in the event a participant is delinquent on timely redelivery of borrowed volumes, or is caught using the reserve volumes for speculative purposes.

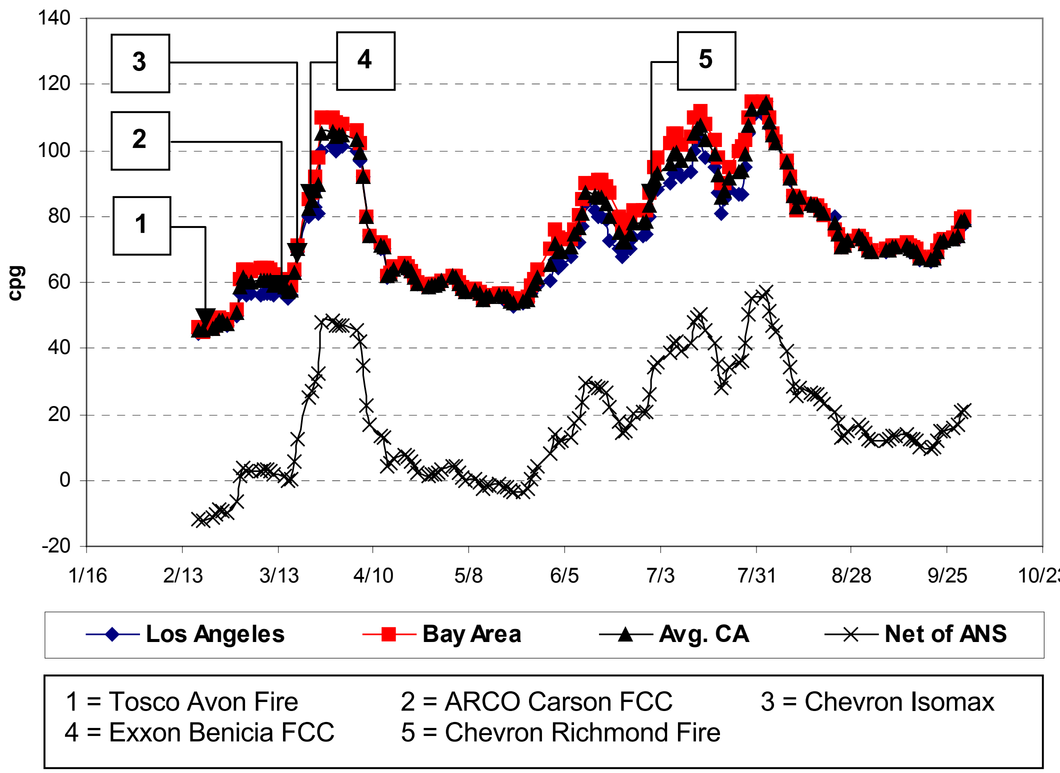
8.9 Effectiveness

At 2.5 million barrels, of which an estimated 2.3 million are effectively usable, the proposed reserve represents only little more than 2 days of the combined demand of gasoline supplied out of California. If the time-swap mechanism is adopted to create a forward market and stimulate imports, then the inventories at hand at any point in time may be as low as 1 million barrels only, with 1.5 million barrels on the water, on its way to California. Moreover, this volume will be divided between the two refining centers in the Bay area and the LA Basin. To evaluate the effectiveness of the reserve, it must be shown that such a relatively small volume can indeed mitigate the impact of refinery disruptions. Separately, in Section 9, it will be shown to what extend benefits of mitigating the price spikes outweigh the cost of the reserve.

A rigorous analysis of refinery disruptions and their effects on inventories and prices was carried out in parallel to this study, also on behalf of the CEC, by Dr Tony Finizza[47] who concluded that the mean expected value of the volume impacted by a refinery disruption (disrupted barrels = capacity loss x duration of the outage) is around 400,000 bbl. The 90th percentile (i.e., only exceeded by 10% of the disruptions) was just under 900,000 bbl. As outlined in Section 8.1 above, the proposed volumes for the reserve cover at least the 90th percentile refinery disruption for each of the refining centers and can therefore be considered effective.

In addition to Dr Finizza's detailed approach, an analysis is provided below of the California gasoline market equivalent of the 100-year storm for which the NE Heating Oil Reserve was designed. The events that marked the worst year in the recent history of refineries in California occurred in 1999, when a series of fires and operating problems at several refineries caused two significant price spikes.

Figure 8.2 – 1999 CA Refinery Outages and Price Spikes



[47] Anthony J. Finizza Ph.D., *Economic Impact of Refinery Disruptions*, CEC Study, June 2002

As can be seen in Figure 8.2, a series of refinery events, two fires and several minor outages, caused a rapid run-up in prices between February and April. Although prices had almost returned to normal by late May, they started moving upward under pressure of the summer driving season while supplies and inventories had not fully recovered from the earlier supply disruptions. When in July another major refinery fire occurred, the market reacted with a prolonged run-up in prices.

Figure 8.3 shows to what extend supplies and inventories were affected during these events.

Figure 8.3 – 1999 CA Gasoline Inventories and Weekly Production[48]

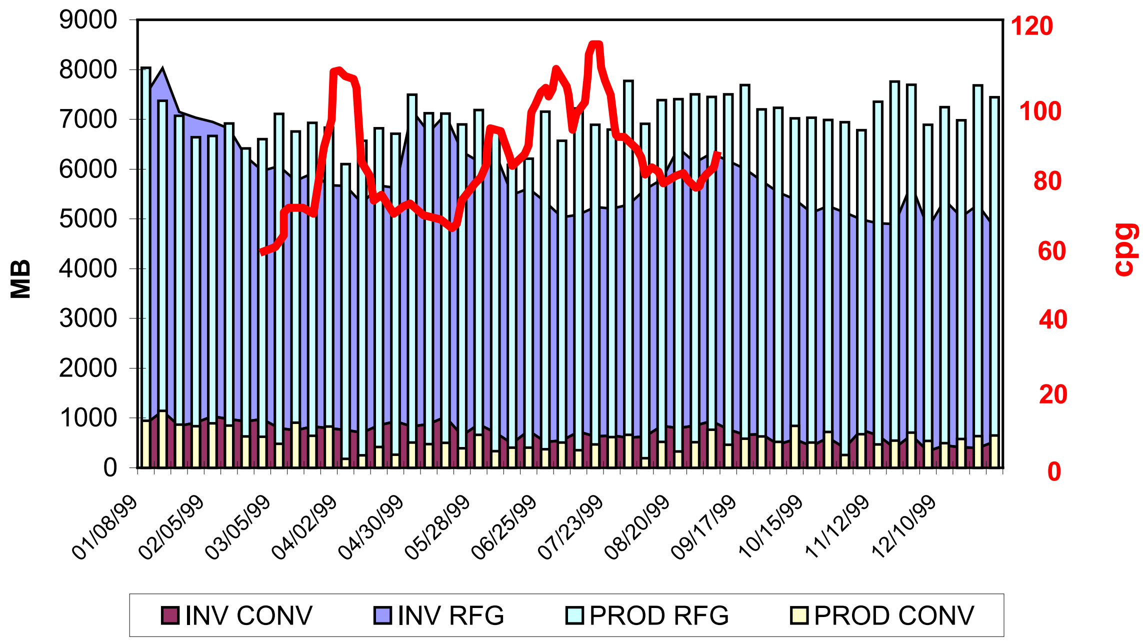


Figure 8.3 shows how the inventory of finished RFG and non-RFG gasoline during the 1999 price spikes dropped from an average of 7.5 to a low of 5 million bbl, while the variations in total weekly production of RFG and conventional gasoline were from a high of around 8 million barrels per week to a low of 6 million (1140 to 850 TBD). Equally important is that the average rate of decline in inventories during the first series of events was 125 MB/week, and in the second price spike 200 MB/week.

If a reserve of 2 million barrels had been available, it would have enabled an additional supply of 200 MB/week over a period of 10 weeks, well beyond the delay within which additional

[48] Source of Data: EIA, CEC, Weekly Fuels Watch

imports could have been mobilized. Moreover, with the forward time-swap mechanism offering price protection to importers, cargoes would have been launched earlier. By contrast, without forward protection, an importer who would have bought a cargo in mid March 1999, at the while a steep run-up was in progress, could have lost a substantial amount of money by the time his cargo arrived in late April.

The conclusion is that a modest reserve of 2 to 3 million barrels can be effective in mitigating the effects of even severe supply outages if it is deployed in such a way that it will facilitate imports. If a reserve were to be created as an offline pool that is not part of the normal flow of imports and trades, it is likely that its deployment during the first price spike would have prevented any imports from coming in. In the absence of imports, there would have been no way to replenish either the reserve or industry inventories before the second series of events, and at the height of the summer driving season, the result might well have been even more onerous for the California gasoline consumer than was the case in 1999.

8.10 Commercial Effectiveness: Convergence of Physical and Paper Markets

Certain stakeholders have suggested that a forward market could be stimulated by economic incentives, or by converting government contract purchases to forward contracts. An analysis is presented below that shows how California's unique requirements call for more than paper instruments and how the proposed SFR will be effective where mere stimulation would not.

8.10.1 Physical versus Paper Markets

In certain circles the proposed SFR is perceived as an unnecessary government intrusion, and that an SFR is not the proper tool to create a forward market. Admittedly, the two issues are not inextricably linked (SFR and Forward Markets). But it is the physical nature of the problem that is overlooked by paper market solutions. Dr Phillip Verleger illustrates this point in his work on physical and paper markets prepared for the California Energy Commission[49]. Dr Verleger's inductive conclusion that "*inventories tie markets together*" confirms the issues raised in this study about the physical barriers to entry caused by California's lack of infrastructure. However, his observation that, "*spreads between spot and forward or futures prices are correlated with the level of inventories*" must be modified when one focuses on California. This insight may be an axiom in integrated commodity markets, such as NYMEX Heating Oil. But the 'island effect' in California causes a significant lag factor to enter the

[49] The Status of Paper Markets for Energy, Philip K. Verleger, Jr. Senior Advisor to the Brattle Group and President, PKVerleger LLC, September 25, 1997

equation, which intensifies and prolongs price spikes. The problems are storage and liquidity.

The implementation of the California SFR, triggered by a time exchange auction, provides a unique solution for circumventing many of the market barriers described in this report. It does so by lessening the *uncertainty factor.* It creates a physical correlation between shipping and price arbitrage opportunities from remote supply points (The U.S. Gulf, Australia, Finland, The Caribbean, The Arabian Gulf, etc.) It introduces a new set of pricing dynamics, more in line with the Nash equilibrium than with island oligopoly.

Such an assertion draws attention to another of Dr. Verlerger's observations, "Markets are Linked by Arbitrage", wherein he borrows from the American Heritage Dictionary in defining the term: "*The purchase of securities on one market for immediate resale on another market in order to profit from price discrepancy."*[50] As amply illustrated throughout this report, the island of California is disconnected from such arbitrage opportunities because of a lack of third-party storage.

Dr. Verleger also points out by example that, "attempts to distinguish between markets (paper and physical) based on the method by which prices are established are meaningless. The way prices are set is simply a form of convenience to the parties, except in the case of organized futures markets."[51]

It can be argued, of course, that the mere existence of storage tanks will be sufficient for the California gasoline market to achieve rationalization against the global arbitrage through private market competition. That there is no need for the State to hold inventories, since the unseen hand of the market will always supply the demand if physical access is available. But tanks alone will not annihilate distance, as does the SFR. The private market will have no incentive to hold inventories and promote imports by creating forward time swaps in order to mitigate price spikes caused by refinery disruptions. The SFR time-swap mechanism proposed herein will serve several purposes which private industry is ill equipped to serve. It will provide the arbitrage linkage as described by Dr. Verleger. It will fulfill his accurate prescription that, "Inventories Tie Markets Together"[52] Finally, it will serve as the physical basis for more

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[50] Ibid Page 11

[51] Ibid Page 10

[52] Ibid – Section IV Heading, Page 12

robust forward and paper markets, thereby eliminating the “meaningless distinction” between them.

In some quarters these observations raise another set of questions with respect to the role of government in the process. The SFR swap mechanism will not put the state in the market in terms of price setting, but rather as a facilitator of trade. This is a far cry from the Hawaii legislative model of wholesale and retail price caps. Prices will continue to react to the laws of supply and demand, driven by private sector competitions. The difference from today’s captive market lies in the SFR’s capacity to bridge time and distance and to act as a fire extinguisher on price spikes driven by the flames of speculation and by spot market shortages. Such a buffer stock mechanism will be increasingly necessary for market stability with the phase out of MTBE and with the introduction of Ethanol. It has been illustrated in a separate Stillwater Report on MTBE Phase Out that that transition will result in an increased needs for imports of 5% to 10%, or up to 100,000 barrels per day.

8.10.2 Lessons of the Past

In Section 7.3 of this report, gasoline market aspects were analyzed of other island economies: Hawaii, Japan, Australia, and the U.K, where global arbitrage had been inhibited and island prices inflated by the lack of independent storage and distribution capability, which were corrected by the creation of storage and opening of cargo trade. There are other useful lessons of petroleum products history that should be brought to bear on our analysis, namely:

Jet Fuel Market Evolution. In Section 7.4 it was shown how jet fuel prices are far less volatile than gasoline and explained the underlying reasons: (1) Fungible Specification, (2) Ample storage in third party hands, (3) Forward Market liquidity, (4) End user participation, and (5) Global arbitrage accessibility.

This salient set of circumstances is not fortuitous. The Airlines were once *locked out* of access to airports from a fuel supply perspective. Jet Fuel storage facilities had been in the hands of major oil companies until the oil embargo of the mid seventies. In those days, the local price of aviation fuel was controlled by refiners who, in essence, also controlled the means of storing and delivering the product. The Carter Administration oil shock, with its resultant widespread shortages, sent every Airline Company into a global scramble in the cargo markets. But, in order to bring a cargo from, let us say, Singapore into LA and/or San Francisco Airports, the Airline Company would need to pass through the storage tanks owned and operated by the local refiners. This could not be done without changing the system. Storage and distribution facilities were "proprietary", while imports were presumably the province of the major oil companies. By pooling their demand and investing in storage tanks, the airlines transitioned from their weak position as captured customers, with open access to international supply but no access to local distribution, to the powerful, market-balancing role that they play today.

Gasoline, as a private party commuter fuel, is much more of a gallon-by-gallon market than jet fuel, which is bought and sold in bulk. In aggregate, however, it is a far greater and more integral part of the California energy equation. Because of the barriers to supply that have grown up around gasoline, it becomes incumbent upon the state to restore competitive balance through the SFR operation. There is no identifiable incentive in the private sector to do so. And whereas the Airline Companies were able to 'hedge' their inventories against the commoditized NYMEX Heating Oil contract, the SFR exchange will enable gasoline wholesale consumers to hedge more effectively because its forward value will be transparent.

NYMEX Evolution. The second lesson of history is NYMEX itself. Before its Heating Oil contract was launched in the early eighties, the New York Mercantile Exchange conducted extensive market research as to which market sectors were most likely to subscribe to it. The first order of business was to locate the storage facilities in and around NY Harbor that could serve as delivery points. Physical deliverability was seen as absolutely essential to the legal and commercial foundation of the contract. Initially there was great resistance, particularly among the refiners, to the idea that an instrument commonly associated with grain, coffee beans and pork bellies might be applied to the 'liquid gold' of petroleum. Over time, even the major oil companies began to subscribe to the NYMEX in order to hedge their own price risk and expand market liquidity. The California SFR will meet the same initial resistance. But it appears to be the best solution to the complex supply, price and logistics problems that are described in this report.

Summary. Both the evolution of the jet fuel consortium and of the NYMEX petroleum contracts illustrates the absolutely essential role that storage plays in the areas of both geographic and price arbitrage. These perceptions are borne out in theory and in fact by Dr. Verleger's work and by a common sense view of the situation. Terms such as: "extreme volatility", "geographic isolation", and "supply dislocations" belong to the vocabulary of captive markets. In the case of California, arguments will be heard that lay the blame wholly at the feet of the unique specifications for CARB gasoline. "Create a fungible spec and price spikes will disappear" is commonly voiced as a panacea. But there are many more sides to the problem as explained in the body of this report.

The SFR time swap moderates price spikes. It stimulates liquidity without sacrificing either the clean-air quality of CARB gasoline, or the State's position of leadership in this vital area. It is practical and relatively cheap. On these grounds, we recommend that CEC take the next step by entering the more detailed phase of the SFR feasibility analysis.

9 OVERALL COST/BENEFIT EVALUATION

For the purpose of this study, which is to establish the conceptual feasibility and does not yet incorporate engineering level cost estimates or firm offers for services, costs and benefits will only be evaluated at an order of magnitude level. A more detailed and more rigorous quantitative analysis of the benefits of the reserve, notably with regard to reducing market volatility caused by refinery disruptions, is provided by Dr Tony Finizza in a separate report[53]. Dr Finizza's conclusions are in good agreement with the overall numbers presented here.

9.1 Cost

The costs as calculated in Sections 6 and 8 can be summarized as follows:

- Lease of 1 MM bbl of new tank capacity in the Bay Area @ $0.50/bbl/month: $6.0 MM
- Lease of 1.5 MM bbl of new tank capacity in the LA Basin @ $0.55/bbl/month: $9.9 MM
- Call on loan guarantees on $40 MM for 10% of time, at 8% interest $0.3 MM
- Interest on bonds to finance initial fill, 2.3 MM bbl at $40/bbl, @ 6% $5.5 MM
- Cost of rolling hedge to protect value of reserve, insurance and fees $1.3 MM
- Cost of oversight, audits and surveying $2.0 MM

Total gross annual cost of reserve $25.0 MM

These costs will be offset in part by the fees charged for use of the reserve. With a 2 cpg minimum charge for prompt delivery and return in 6 weeks, while during periods of outages the backwardation may be worth as much as 5 cpg, and an average throughput of 50,000 bpd, the revenues from fees may be in the order of $5 to 10 MM per year. Moreover, if offsets from the sale of crude oil can be used to finance the purchase of the initial fill, a possibility provided for under the Energy Policy and Conservation Act, then cost would be reduced by a further $3 to 5 MM per year.

At this stage of early feasibility study, in the absence of firm bids for the operation of the reserve and given the lack of definition for certain cost elements of the reserve's trading

[53] Anthony J. Finizza Ph.D., *Economic Impact of Refinery Disruptions*, CEC Study, June 2002

mechanisms, a reasonable estimate for the net annual cost of the reserve seems to be $15 to $20 MM.

9.2 Benefits

The reserve, as currently envisaged, will not function as a stagnant inventory overhanging the market, but rather create a tool for forward trading and a physical delivery hub for imports, linking California's gasoline market to whatever suitable blendstocks and blending components are available in the worldwide refining system. As such, three separate benefits can be identified:

- Reduction of chronic shortages due to physical and commercial supply barriers.
- The prevention of smaller, often spurious price spikes.
- The mitigation of significant price spikes caused by major supply disruptions.

For each of these potential benefits, an order of magnitude analysis of cost savings to the California gasoline consumer will be provided below.

9.2.1 Prevention of Chronic Shortages

As seen in Section 1.3.1, the phase out of MTBE and the mandated usage of ethanol to replace it will cause a shortfall of 50 to 100 TBD in California's supplies of gasoline, mostly in Southern California. Amongst alternative solutions to prevent these shortages are measures such as additional refinery capacity, demand reduction programs, pipeline supplies from Texas into Arizona, and relaxation of fuel standards. While some or all of these alternatives may be realized to some extent, the most likely scenario, certainly in the short to medium long term, is that California will become increasingly import dependent.

Although foreign sources of conforming base gasoline blendstocks are limited, there are a number of refineries worldwide that can from time to time supply components or blendstocks to California if market conditions are right. As has been shown earlier in this report, potential importers face a number of problems:

- Physical barriers: lack of terminal space, particularly in the LA Basin.
- Commercial barriers: lack of liquidity in forward markets, no mechanism for hedging against volatility in the California market, only refiners are capable of blending final product, Unocal patents pose threat to blending by importer.

As is currently already the case, these barriers mean that prices have to rise well above the normal arbitrage level (the differential in market prices that will cover all transportation costs, duties, cost of hedging, etc.), before an independent importer will attempt to bring in a cargo. The use of the SFR volumes to conduct prompt trades on import cargoes that will arrive 6 to 8 weeks later will remove the major physical and commercial barriers to imports, and will limit California's pricing to world market prices plus quality premiums and import costs. The table below illustrates the difference the SFR will make on an importer's decision process.

Table 9.1 – Example: Import Decision Processes with and without SFR

Current Situation without SFR	**Future Situation with SFR in Place**
The California market is tight as the summer blending season starts and prices are steadily rising. When the spot price reaches 97 cpg, Refiner A in Country C starts talking to global Trader B. A has a cargo of suitable blendstocks that he could send to California if he tops off with alkylate to produce CARBOB. His added production costs are 5 cpg, and his shipping cost to CA are 8 cpg. A's alternative is to send the cargo to New York for a netback of 77 cpg FOB. On a prompt basis a sale to CA would create a 7 cpg profit, or $800k for the cargo, over the NY alternative. However, the LA forward market for next month delivery is backwardated by 5 cpg. This would still leave a 2 cpg margin, but trying to sell a full cargo in this thinly traded market would suppress the forward price by more than 2 cpg. Moreover, B can't find a tank to offload the cargo. The deal doesn't work. The CA price continues to rise, and reaches 105 cpg. Trader B can do some forward pieces at 97 cpg for one third of the cargo and	The California market is tight as the summer blending season starts and prices are steadily rising. When the spot price reaches 97 cpg, Refiner A in Country C starts talking to global Trader B. A has a cargo of suitable blendstocks that he could send to California if he tops off with alkylate to produce CARBOB. His added production costs are 5 cpg, and his shipping cost to CA are 8 cpg. A's alternative is to send the cargo to New York for a netback of 77 cpg FOB. Trader B buys the cargo from Refiner A at 84 cpg FOB and starts selling prompt pieces out of the SFR at 97 cpg, paying on average 5 cpg when bidding for the usage of the SFR volumes, equivalent to the backwardation of the market. He realizes an average prompt margin of 2 cpg. Refiner A and Trader B both realize $200k profit on the shipment. The cargo arrives 5 weeks later and is offloaded into the reserve without problems.

decides to take a gamble on the rest. He buys the cargo from Refiner A at 84 cpg FOB, for a 92 cpg landed cost 5 weeks later. B realizes a margin of 5 cpg on the forward trades, but incurs substantial demurrage cost on the vessel because he cannot find tankage. Trader B makes a small loss on the remainder of the cargo before he can sell it to a refiner.	

The example of Table 9.1 is based on observed price differentials, but is otherwise of course just an anecdotal illustration of decision processes such as they occur every day in the global gasoline trade. Moreover, it is the simplest case, where an offshore refiner, at incremental production cost, can actually produce a conforming grade of gasoline that can be offloaded directly into the SFR to backfill the volumes lifted into the prompt market.

In reality, use of the SFR as envisaged may involve complex deals, involving several parties. For instance, if the offshore refiner has high value blendstocks available but cannot produce a conforming CARBOB, the deal may involve offsetting trades around the backfill volumes, whereby the blendstocks get sold to a local refiner who in turn fulfills the obligation to backfill the SFR.

The underlying principle however does not change: currently, a certain class of offshore producers and traders will only sell into the California market if there is a premium to compensate for the risks that cannot be hedged. These risks are the volatility of the California market relative to markets that can be hedged, i.e., the NYMEX, and the risk of being unable to physically offload the cargo when its gets there.

Obviously, there are other classes of import trade that are not affected by the unsecured risks currently inherent when importing gasoline or blending components into California from remote sources. The global refiners are integrated from the foreign source all the way into the branded retail, and although they will still have to optimize returns on a global basis, any losses or gains on individual trades between operating entities are offset on a corporate level. Also, the refineries owned by global majors operating in California are more capable of handling the physical aspects of the imports, although some are better equipped than others in terms of terminals and tank capacity.

When taking into account the increasing import dependency of California however, especially after the phase out of MTBE, when import volumes may have to double over current rates, there will be periods when the incremental barrel that sets the price of the market will be imported from independent foreign sources who will have to build compensation for unsecured risk into their decision processes.

An order of magnitude cost impact for this phenomenon can be construed as follows:

- During 86% of the time, there are no refinery disruptions[54], but during the summer season, the market is still import dependent even when no disruptions occur. What happens during price spikes is the subject of separate analysis and will be excluded here.

- If import dependency is assumed during 75% of the 86% corresponding to the summer grade blending season, and if it is assumed that for only 20% of this time, the spot market is determined by imported barrels from independent, non-integrated sources, then such sources set the spot market price during 13% of the time overall.

- Based on observations and market feedback, a conservative assumption for the risk premium is 5 cpg for independent importers is at least 5 cpg. This premium affects primarily the spot market, but whereas price spikes are not passed on directly to the retail market, long term trends do (even spikes eventually get passed through, at lower levels but over longer periods).

- The total consumer benefit associated with removing forward market risk and physical restraints for independent importers of gasoline or blending components into the California gasoline market is therefore estimated at 13% of 15 billion gallons per year at 5 cpg, or approximately $100 MM/year, with a range of + or – 50%, or $50 to 150 million.

9.2.2 Prevention of Small Price Spikes

Given the vulnerability of California's gasoline infrastructure and the volatility of gasoline prices, the market currently overreacts from time to time to rumors of supply disruptions. The system is vulnerable to manipulation, and instances are known when the market moved over 10 cpg on a single day on relatively few reported deals, fueled

[54] Anthony J. Finizza, Ph.D., *Economic Impact of Refinery Disruptions*, CEC Study, June 2002

by unfounded rumors of refinery problems or in overreaction to real events that were quickly resolved and did not cause much actual production loss. Usually such market reactions occur in times when inventories are low and demand is anticipated to be high, i.e., during the summer blending season.

In a parallel study commissioned by the CEC, Dr. Anthony J. Finizza conducted an extensive statistical analysis[55] of supply disruptions that occurred over a five year period from 1996 through 2001. His analysis concluded that small, spurious price spikes occur on average 25 days per year, with an average value of price increase over the duration of the spike of 4.2 cpg. Most of these spikes are short lived, but effects in the retail market can persist over one or to two weeks. The longevity of retail price effects after spot prices have subsided was extensively analyzed by Dr Tony Finizza.

It is likely that the very presence of the SFR will suppress these spurious price spikes. If no real shortage occurs and the retail market is kept adequately supplied, retail prices will not move driven by price elasticity, and it will be difficult to move the market on rumor alone. An approximation for the benefits to the California gasoline consumer of eliminating the small price spikes is 25 days per year at an average of 4.2 cpg, or $40 million. If it is assumed that not all small spikes are preventable, or that in some cases costs of mobilizing reserve volumes will be passed on, then a reasonable range for these benefits would be $20 to $40 million.

9.2.3 Mitigation of Significant Price Spikes

Dr Tony Finizza's study (ibid) focused on the mitigation of significant disruptions. Through a statistical analysis of historical data of disruptions and subsequent modeling of market response to supply changes under several assumptions for price elasticity of demand, he produced a detailed analysis of consumer benefits as well as gains in total welfare associated with mitigation of the gasoline market volatility. As was done in Section 8.1 for analyzing the effectiveness of the proposed SFR in terms of capacity, a check will be performed below to match the results of Dr Finizza with results derived earlier using a more empirical approach.

For the purpose of this study, significant price spikes were defined as events that involve either a large net capacity loss, or last over prolonged periods. Table 9.2 shows

[55] Anthony J. Finizza, Ph.D., *Economic Impact of Refinery Disruptions*, CEC Study, April 2002

how, based on data from Dr Finizza's study, a total of 17 significant disruptions occurred over a 5-year time frame.

Table 9.2 – CA Refinery Disruptions 1996 - 2001

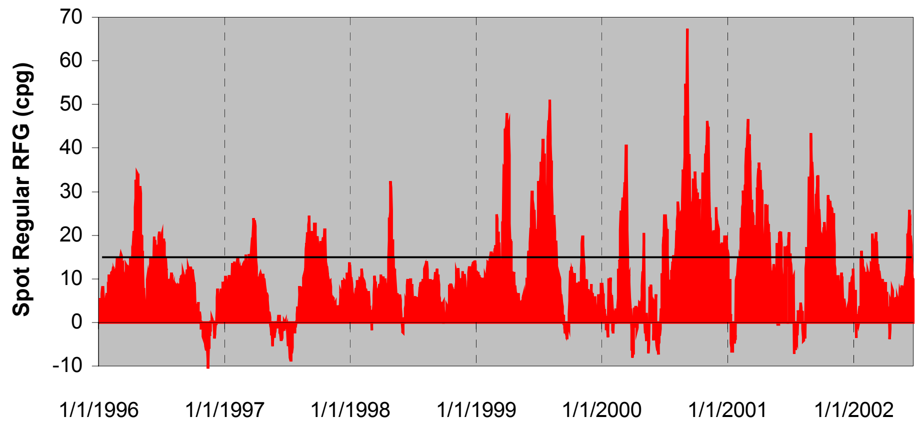
	Short 1 Week	Medium 2-3 Weeks	Long > 6 Weeks	**Total (Significant)**
Small < 10 TBD	13	1	**1**	**15 (1)**
Medium 10 - 30 TBD	18	**4**	**2**	**24 (6)**
Large > 30 TBD	**3**	**2**	**5**	**10 (10)**
Total (Significant)	**34 (3)**	**7 (6)**	**8 (8)**	**49 (17)**

Dr Finizza used detailed statistical analysis to show how only those disruptions that occurred during periods of normal or below normal inventories resulted in price spikes. His analysis also showed that, based on probabilities of events as derived from the 1996 through 2001 statistics, and assuming an average retail market price of $1.50/gln and a market elasticity of – 0.20, the potential direct consumer benefits of an SFR would be $465 million per year. With an elasticity of – 0.15, the benefits increase to $767 MM/yr while at the low end of the range of sensitivities studied, benefits could drop to the low $200 MM/yr range, still an order of magnitude higher than the predicted costs.

This analysis only takes credit for significant disruptions in periods of normal or below normal inventories, and furthermore assumes that the California shortage will translate in a price spike of 10 cpg in landed cost of replacement materials into the SFR because of the limited availability of suitable blendstocks worldwide. If materials can be brought in through the SFR at an incremental spot price of 5 cpg, the benefits increase to $631 MM/yr, while at 15 cpg incremental cost, savings are still $363 MM/yr.

A check against historical data is presented in Figure 9.1. The area in red represents the differential of LA Spot Regular RFG over US Gulf Coast RFG FOB Spot price plus a 15 cpg premium for transportation and quality premium. This area represents a value $2.8 BN or $430 MM/year. If the reserve is more effective and can attract import volumes and blendstocks at average premiums of only 10 cpg over US Gulf Coast and other world market prices, than the savings would have amounted to $4.6 BN, or $708 MM/yr. On the other hand, an assumption that it would take a premium of 20 cpg over world markets before products will move reduces the advantage to $1.6 BN, or $246 MM/yr.

Figure 9.1 – Margins of LA Spot RFG over US GC plus Transport



These numbers refer to spot markets and as was shown in Section 7.2, the retail market behaves different than the spot market in that price spikes are generally lower, but last over longer periods.

Figure 9.2 – CA Retail and Refining Margins

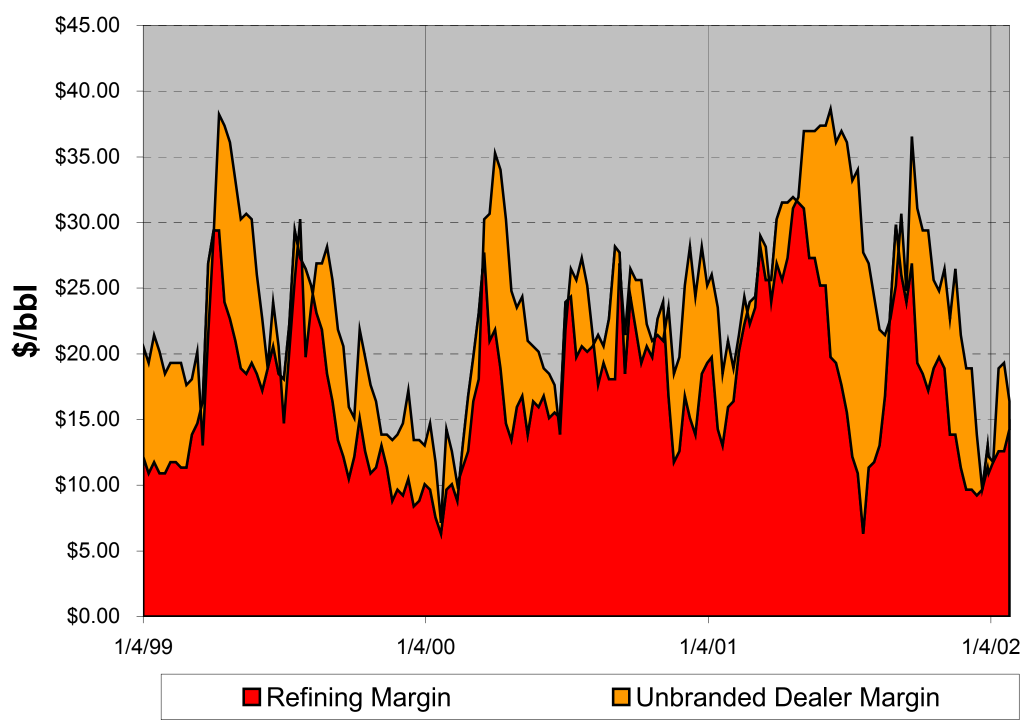


Figure 9.2 shows how during the price spikes of 1999 through 2002, refining margins after deducting all applicable taxes, dealer mark-ups and average crude oil cost, were in the range of $10 to $30/bbl. If it is again assumed that the SFR will be able to attract supplies from external sources at world market prices plus a 15 cpg ($6.30/bbl) premium, and that the refineries capable of producing suitable products or blendstocks are able to operate at crack spreads of $10/bbl, then savings to the consumer from reducing the peaks amount to $408 MM/yr.

These numbers are similar to those found by Dr Tony Finizza, who as described above, used a more rigorous quantitative analysis. Regardless of the details in these numbers, it will be clear that the costs of chronic undersupply and price spikes caused by supply disruptions is at least one order of magnitude higher than the costs of the proposed fuels reserve.

10 RESULTS OF MEETINGS AND WORKSHOPS

One of the primary considerations of the study was to fully involve the various stakeholders in the industry. In the early stage of the study, the objective was to collect opinions and ideas through a series of meetings with individual stakeholders, whereas at a later stage, feedback was solicited on concepts and alternatives through a workshop, open to all interested parties.

10.1 Survey Meetings with Industry Participants and Other Stakeholders

From late August through early October 2001, the CEC and its contractor, Stillwater Associates, met with representatives of:

- All eight gasoline-producing refiners in California. For some of these, separate meetings were held with individual operating entities, while for others, a single meeting was held with corporate staff and/or representatives of several facilities.
- Six refiners operating facilities outside California, but selling blendstocks or finished products into the California market.
- Ten major international traders who regularly import fuels and blendstocks into CA and who have representation in the State, and one major brokerage house.
- Five independent marketers of gasoline in CA.
- Four major logistic service providers, owning and operating terminal facilities and pipelines for clean petroleum products in California, two of which are subsidiaries of major oil companies.
- Stakeholders from miscellaneous backgrounds, including the State of Arizona, an industry association, two publications, and the Southern California Port Authorities.

A separate confidential report was prepared by the CEC and its consultant to document the individual discussions held with the selected stakeholders. Although supply and demand for diesel and jet fuel were discussed as well, the discussions heavily focused on the gasoline markets, and in particular jet fuel was often used in the discussions only by way of example of a well functioning, stable market. Moreover, the discussions were generally qualitative in nature, with most parties reluctant to share numbers or referring to data already available in the public domain through other reporting channels.

A summary of some of the main issues raised during the meetings by the various constituents is given below.

10.1.1 Strategic Reserve

The broad consensus opinion of industry participants is that the California market is not broken and does not need the fix of a Strategic Reserve. Virtually all supply-side market participants expressed a clear resentment of intrusion by the government into the private market, and thought that an intervention in the natural forces of supply and demand would be detrimental to the long-term development of new sources.

Despite this initial aversion, most survey participants freely contributed constructive ideas once it was clear that the study will evaluate a broad range of alternatives, including some that might improve market liquidity as a whole, or solutions whereby the government's role might be limited to that of a facilitator of private industry efforts. The most frequently heard contributions are summarized below.

- **Location**. Although a few participants favored locations downstream in the distribution system, the more commonly held view was that the Strategic Reserve, if it were to be created, should:

  a) Be in more than one location, with as a minimum separate coverage for the Northern and Southern California markets;

  b) Be directly tied into the refinery supply and distribution system, i.e., at the head of the Kinder Morgan pipeline networks; and

  c) Have access to deep water in order to be able to receive direct imports in order to be replenished from outside sources after a supply interruption, and to improve supply options in general.

  The locations that meet these criteria are Concord in the Bay Area, Watson and Carson in the LA Basin, and to a lesser extent (because it lacks direct deep water access), Colton at the head of the Southern and Eastern pipeline systems. The industry insights are born out by this Study's analysis of location options and logistics requirements in Section 2 above.

- **Tankage and Inventory Options**. All participants, without exception, reported a shortage of tank capacity. For operational reasons, most refiners would not be able to increase on-site inventories in existing tankage, even when compensated through special incentives for the higher costs of working capital and other operating and marketing costs associated with larger inventories. Traders and importers complained about their inability to find storage to land products. Given the shortage of tankage in the main distribution centers, the overwhelming consensus of the participants was that if an SR were to be created, it should not use existing tankage. This industry opinion confirms the results of Section 4 and 6 above.

- **Release Mechanisms**. None of the participants had a specific proposal for release mechanisms for eventual inventories held in the reserve. However, several stakeholders warned that whatever release mechanisms were chosen, they had to be “fair”, and “clear”. Concerns were voiced that if threshold price levels for release were set too low, the existence of a reserve would prevent the influx of additional supplies, and could cause an early stampede on the reserve by anybody with empty storage space who could then hoard the supplies until a delayed price spike occurred. Most participants stressed that a reserve should only be released to prevent real stock-outs at the pump, when prices had risen already sufficiently to ensure additional supplies from higher cost sources.

- **Quality Aspects**. With the different vapor pressure requirements for gasoline in summer and winter, and because of other quality and performance parameters for gasoline that are affected by the time over which it is stored, it will be necessary to turn over the reserve at least twice per year. This is one of the reasons why most participants favored locations within the current distribution system, so that the reserve effectively would be a bulge in the pipeline that could see continuous throughput if required.

10.1.2 Barriers to Entry into the California Gasoline Markets

With the exception of some of the major refiners and the refiner-owned logistic service providers, all industry participants complained about barriers that currently prevent the influx of products from outside the State. Since the Bay Area is currently a net exporter of products while the LA Basin is short, these problems are more relevant for the Southern California market than for the north. The major concerns can be summarized as follows.

- **Lack of CARB Spec Fuels outside CA**. The single most important difficulty mentioned by current or potential importers and out-of-state suppliers are the unique quality requirements for California gasoline and diesel. This problem is going to be aggravated by the introduction of CARB Phase III. Of the five out-of-state suppliers that were interviewed, only one claimed to be capable of producing CARBOB for Phase III. None of the others thought that the investments required to comply with Phase III would be justified given the incidental nature of export shipments to California, and the increasing opportunity to realize premium values for higher quality fuels in other markets. Moreover, few would be able to avoid contamination with MTBE above the *de minimis* requirements for MTBE post Phase III, given the nature of the storage and the costs of draining and cleaning tanks and ships for incidental shipments.

An additional complication when bringing in finished gasoline is that certain quality requirements, notably low sulfur levels, require analytical tools that are rarely available in surveyor's laboratories outside California. Material certified in a foreign port as in compliance with the specifications, may fail a retest on arrival resulting in significant financial risk to the importer.

- **Infrastructure**. All potential suppliers of out-of-state gasoline or blending components, as well as some of the major refiners with limited on-site tankage, mentioned lack of adequate infrastructure as a major obstacle to bringing in cargoes and efficiently distributing products to meet market shortages. The providers of commercial services in this area all complained of permitting barriers that prevent investment in facilities despite a viable demand. Common themes were:

  a) There is an acute shortage of bulk liquid storage space in the ports of Los Angeles and Long Beach, which is aggravated by current policies of the Port Authorities favoring other land uses such as container and car terminals over bulk liquid storage.

  b) Terminal facilities owned by refiners which in the past provided third party commercial services now have ceased to provide such services under the short term contracts that typically fit the needs of occasional importers.

  c) Commercial pipeline systems are approaching capacity, especially in the gathering systems.

  d) Projects to increase infrastructure capacity, such as additional storage or increasing pipeline capacity, meet with considerable delays in the permitting process. Increasingly, such delays are caused by well financed, nationally operating interest groups. Delays of up to three years were mentioned.

e) Several new legislative initiatives currently in development threaten to make this situation even worse. Of particular concern is the recently adopted Regulation 1178 of the South Coast Air Quality Management District, which will require installation of domed roofs over all open floating roof storage tanks, and the Marine Oil Terminal Environmental Review Process (MOTERP) proposed by the State Lands Commission. Both initiatives will result not only in very significant cost increases, but require key assets such as storage tanks and docks to be out of service for prolonged periods. These comments were the reason that this Study was expanded to include regulatory developments in Section 5.

The shortage in storage capacity, and the breakdown of normal supply and demand mechanisms in the storage market because of permitting delays for new projects were compared by several participants to the situation in the power industry, where years of lagging investments contributed to the power crisis.

- **Unocal Patent.** Most potential importers expressed a concern that even when finished CARB spec products were to be available outside California, they would be reluctant to attempt importing the finished product because of the risk of infringement of the Unocal patent and the associated punitive penalties. For occasional importers, licensing fees would add a prohibitive cost to an already risky trade.

  Also mentioned was that the Unocal patent puts a further strain on the already scarce tankage. Blending around the patent leaves only very narrow margins, and refiners typically now need more time to prepare an on-spec blend whereas previously, final blends were prepared just in time before scheduled pipeline dispatch. This requires more tank space, while off-spec or near-spec batches resulting from an incomplete blending operation might take a longer time to blend off.

  One participant mentioned that a patent recently awarded to Snamprogetti of Italy on blends of isooctanol and ethanol may add similar difficulties post CARB Phase III implementation, and aggravate the blending tankage situation even further.

- **Difficulties of Blending Finished Products**. With finished gasoline meeting CARB specs hard to find outside the state, importers resort to bringing in blending components. The possibility to do so is limited by a number of factors.

  a) As stated above, the Unocal patent presents a significant risk that only a refiner with alternative resources and multiple blending options can afford to take.

  b) Certification of the final blended product requires in-depth knowledge of complex administrative procedures.

  c) The lack of adequate infrastructure makes it difficult for occasional importers to find cost effective blending and storage facilities.

  As a result of these restrictions, traders bringing in blending components will sell such cargoes to the major refiners, who will produce the finished gasoline.

- **Lack of a liquid Futures Market**. All participants, without exception, reported the lack of liquidity in the forward market for gasoline as an impediment to imports. The inability to negotiate a price in advance for when imported product arrives, exposes the importer to considerable price risk. To produce a cargo of CARBOB, a producer typically requires two weeks lead time to schedule blending components and tankage within the refinery. Typically, this is also the time required to find shipping space. Sailing times from the closest out-of-state sources (Caribbean, US Gulf Coast and Eastern Canada Seashore) range between two and three weeks. An importer would therefore need a futures market with enough liquidity for next month or two months out in order to lock in a margin.

10.1.3 Market Mechanisms

The California gasoline market has a layered structure, formed by four separate but interrelated markets: Retail, DTW, Rack, and Spot, which are described in detail in Section 7.1.

The feedback received from participants in the various markets stresses the spot market as the primary source of volatility in the event of supply disruptions. This is the market where pricing is “made”, and as such would be where a reserve would have to intervene if it is to be successful in reducing volatility. Participants confirmed that the spot market can move as much as 5 cpg on one or two trades, and instances were quoted in which market shifts of 20 cents or more have occurred with no more than 40,000 bbl of product changing hands.

The prices in the spot market translate almost directly to the rack market, while the retail market is often sheltered against abrupt price spikes by the major refiners, who are afraid to lose market share if they increase pump prices ahead of competitors. When the retail price lags the spot price too much, rack and spot based DTW customers are sometimes caught in an “inversion”, when their purchase price exceeds the pump retail price. On the other hand, on the down slope of a temporary price spike, branded retailers often manage to hold on to margins for a while, with pump prices only coming down slowly over several weeks after the spot prices has already returned to pre-spike levels. In these periods, rack and DTW customers make up for losses incurred at the onset of the spike.

It is clear from this input that release mechanisms from an eventual reserve will have to be designed to fit the needs of the spot market.

10.1.4 Futures Market

One message that came across loud and clear from the participants is that the lack of liquidity in forward markets for California is a major impediment to imports, and a significant contributing factor to instability, since virtually all trades are done on a prompt basis.

Several participants pointed to the jet fuel market as an example of a well functioning futures market, with forward deals possible as far as 6 months or even one year into the future. In the opinion of most participants, the main reasons why the forward market for jet fuel works, whereas for gasoline it does not, are:

- **Fungibility**. Jet fuel is a readily fungible product, with only a few different specifications shared on a worldwide basis.
- **Liquidity**. Because of its fungibility and ample storage facilities, many traders and importers can participate in the jet fuel market.
- **Hedging**. Because of fixed differentials between jet fuel and heating oil based on alternative uses and transportation cost, forward trades of jet fuel can be pegged to fuel oil futures, which allows traders to hedge their risk.

- **Future Demand**. Airlines have a need to buy a certain quantity of fuel forward because they also sell a certain fraction of their capacity well into the future through advance bookings. Moreover, they like to work against fixed budgets whenever possible.

Given the fact that California gasoline is not a readily fungible product, that there are no suitable forward traded commodities against it can be hedged, and that the largest market sector, the retail market, is not well suited to forward commitment on price, creating mechanisms for a futures market will be a challenge.

Many participants however thought that if a reserve was to be created in which market participants were to be allowed to use the top half of the inventory to lift product prompt and replace it within a certain period, with a bidding process to establish a value for the use of the product over time, then this would not only establish liquidity, but also offer importers a mechanism to obtain fixed forward values for product before it is put on the water.

10.1.5 Inventory Planning Practices

Current inventory planning practices varied considerable between industry participants. For some refiners, operational considerations are the dominant factor, and those refiners generally prefer to run with relatively low inventories. Other refiners, especially those who sell a significant portion of their production into the merchant market rather than into their own branded retail, will set inventory targets according to their expectations of market trends. These refiners will run their tanks as full as operationally possible if they expect prices to go up. In any case, most refiners have very little room to play with and most dismissed the concept of creating a reserve by compensating refiners to hold more inventory as not feasible.

The way market participants interpret reported industry inventory numbers is currently undergoing some changes, according to feedback received. Whereas previously the market would begin to feel tight when PADD V inventory levels fell to 25 million barrels, currently supply begins to tighten at levels around just below 30 (these numbers include finished gasoline, as well as blendstocks and unfinished products). Since the highest reported inventories are in the range of 34 to 35 million barrels, this means that effects of blending around the Unocal patent and increases in production capacity without corresponding increases in storage, apparently do affect the buffering capability of inventory.

Most participants use public sales and inventory data as provided by API and EIA, the accuracy of which was sometimes questioned. Not all were aware that the CEC provides more detailed, State specific information.

10.2 Meetings with CEC Staff

To be completed after key presentations have been made.

10.3 Workshops

A preliminary workshop was held on March 13, 2002, to discuss the results of the various Contractor Studies with the public. Given the complexity of the issue and the relatively short time span that was available for the industry and other interested parties to review the studies, it was decided to schedule a second workshop later in the year.

10.3.1 CEC Workshop of March 13, 2002

At the Workshop held March 13, 2002, in the auditorium of the California Energy Commission in Sacramento, presentations were made by Stillwater Associates regarding the Strategic Fuel Reserve, by Drew Laughlin regarding supply options from the US Gulf Coast, while the results of the Interliance, Inc. study regarding the pipeline supply options were presented by Gordon Schremp of the CEC itself. Dr Tony Finizza presented his analysis of supply disruptions and a preliminary evaluation of the economic benefits of an SFR.

A detailed overview of comments on the Strategic Fuels Reserve presentation is provided in Attachment B. Comments made during the workshop itself were relatively few and mostly concerned clarification of issues. After the workshop, a more in depth discussion ensued between on the one hand members of the Western States Petroleum Association (WSPA) and consultants retained by WSPA, and on the other hand representatives of the CEC and their consultants. Key points of this discussion can be summarized as follows:

- There is no fundamental disagreement on the analysis of the supply situation, infrastructure problems and barriers to supply. The industry would welcome more streamlined permitting processes as a means to enable the refiners to meet current and anticipated demand.
- The industry is generally skeptical of the State’s ability to manage projects and processes that interact with market forces. A stagnant, classical reserve is

deemed to be counterproductive in improving supply reliability. The more complex proposal developed by Stillwater Associates involving time-swaps as a means to promote forward liquidity and create a physical entry point for imports was not fully understood by all members at the time of the workshop, and the consensus opinion of the industry was that the difficulty in realizing this novel concept would be in designing its operational framework ("the devil is in the details").

- The evaluation of benefits as presented in the first workshop included an example of refinery economics obtained from public information regarding a recently acquired California refinery. The example was not quoted in the right context and the economic evaluation of the benefits of a reserve has since been superceded by a more rigorous statistical analysis by Dr Finizza.

Subsequent to the workshop, feedback was received from various sides, including experts within the California Energy Commission. These comments were highly constructive and have been helpful in preparing the current version of the study. Where necessary, errata have been addressed, and a wider range of scenarios has been developed for evaluation of the benefits.

However, since the current study is conceptual in nature and since the funding provided by the CEC covers an initial feasibility study only, in line with the request by the legislature, it is at this time not appropriate to proceed with a detailed design of the reserve, which would include issuing a Request for Proposals from commercial service providers in the logistic industry, and designing a detailed framework for the operation and governance of the reserve.

10.3.2 Workshop Held _____

To be completed after the next workshop.

11 CONCLUSIONS AND RECOMMENDATIONS

Based on the findings of this study, both in qualitative and quantitative terms, a number of conclusions and recommendations are formulated below. In addition, a long-term outlook will be formulated for a scenario in which no pro-active measures are adopted, and compared with the expected long-term results of the proposed measures.

11.1 Conclusions

The major findings of the study are listed below in a sequence that is in part causal, whereby increasing shortfalls, market insularity and infrastructure deficiencies combine to produce partially dysfunctional and unstable markets, in particular for gasoline, which result in significant damage to the State's economy.

11.1.1 Increasing Shortfall

California's refineries have not been able to keep up with demand growth over recent years and California has become dependent on imports for all categories of petroleum products. Most of the growth in import requirements has been satisfied from foreign sources, because refining capacity and transportation options from within the US are also constrained. The outlook is that in-state capacity additions will be increasingly difficult to realize because of permitting restrictions. The chronic shortfall has led to market instability and increasing vulnerability to unplanned supply disruptions. The phase-out of MTBE as currently foreseen by year-end 2002 will increase the need for imports beyond the current infrastructure capabilities.

11.1.2 Market Insularity

The California gasoline market suffers from insularity caused by its unique specifications, a subsequent lack of liquidity and inability to lock in future pricing, and impediments to market entry by outside sources. These factors contribute significantly to price volatility, in addition to the supply interruptions identified as a cause of price spikes in the legislation that led to this study.

11.1.3 Inadequate Infrastructure

California's infrastructure for petroleum products, comprising of pipelines, terminals and dock facilities, is currently already constrained and has insufficient capacity to handle and anticipated incremental demand. Capacity additions are hampered by lengthy and costly permitting procedures, and by policies practiced by the ports that favor other land uses over bulk liquid storage. Import terminals are predominantly owned or leased under long-term contracts by the refiners, and access to markets has become increasingly difficult for traders and importers whose business interest are short-term in nature.

11.1.4 Restrictive Patents

The Unocal patents are a significant additional burden on California's ability to meet growing demands for transportation fuels while improving air quality. The licensing fees and punitive damages are such that incidental importers will not dare to attempt to blend finished gasoline, while refineries who blend outside the patent's envelope lose capacity by diverting products from the gasoline pool and in doing so actually increase evaporative emissions.

11.1.5 Limited Classes of Supply

There is no indication of unlawful market practices and competitive forces do still result in deep price cuts at times of temporary oversupply in the market. However, for gasoline in particular, supply of finished product is limited to the in-state refiners, and despite the fact that the market has become import dependent, with the incremental import barrel determining the price of the market as a whole, neither independent importers upstream of the refiners nor independent marketers of finished product downstream of the refiners currently have the means to bypass the refinery controlled infrastructure.

11.1.6 Economic Impact

The increasing import dependency of California requires incremental supplies from remote foreign sources that meet unique specifications and carry significant manufacturing and transportation cost. These supplies will set the market price, and the premium that California will have to pay for its import dependency is likely to be in the range of 20 to 30 cpg. This represents a value of $3 to $4.5 billion per year, but this is not a number that will be affected by the creation of a reserve. The economic impact of a price spike of 50 to 60 cpg over a period of 4 to 6 weeks is $0.6 to $1 billion. The effect of these incremental expenditures on the State's economy is somewhat similar to the legacy of the higher electricity prices caused by the power crisis: a significant portion of the gross impact will flow to out-of-state corporations or foreign entities at the expense of discretionary spending by California households and businesses.

11.2 Recommendations

The recommendations below are provisional, in that they represent the Contractor's viewpoint based on the analysis performed and feedback from the first Workshop held March.

11.2.1 Regulatory Processes

In order for the industry to be able to respond in a timely fashion to California's market needs in terms of production capacity and logistic infrastructure for transportation fuels it is recommended that:

- A complete inventory is made of current permitting and regulatory processes governing capacity additions in key areas of energy infrastructure, such as refineries, marine terminals, pipelines and distribution facilities.

- A detailed survey is conducted amongst stakeholders, such as industry participants, regulatory agencies, environmental interest groups and local communities, to identify bottlenecks and inefficiencies.

- A system is designed to accelerate and streamline the proceedings, while maintaining guarantees for due review. It seems likely at this stage that such a system would incorporate the creation of a single, central authority to coordinate and manage the permitting process.

- Novel avenues must be explored to reconcile the contradicting needs for the petroleum industry to keep up with market demand, and the need to safeguard the public from adverse affects associated with increased production and consumption of transportation fuels. One such avenue is a mechanism whereby refiners can receive and trade emission credits associated with voluntary improvements of fuel quality beyond regulatory limits, thus reducing mobile emissions, against stationary emissions associated with the refining process.

- It is strongly recommended that the regulatory review and the design of any measures outlined above shall be part of a concerted and integrated approach within a long-term visionary framework for use of transportation fuels in California, as a way to prevent over-building or capital wastage by the industry as well as chronic or acute shortages of essential commodities in the State.

11.2.2 Definition Phase Study for SFR

Given that there is overwhelming evidence that the consumer benefits associated with the creation of an SFR as a physical trading hub and mechanism for forward market liquidity is an order of magnitude larger than the cost to the consumer of the current price spikes, a next phase is warranted in the process to create and operate such a reserve. Given the complexity of the proposals, it is recommended to allocate sufficient funds to proceed with the following steps:

- Draft a Request for Proposals for the construction and operation of 5 MM bbl of versatile clean product storage, 2 MM of which are to be located in the Bay Area to be fully integrated within that region's refining infrastructure, and 3 MM bbl in the LA Basin to be similarly integrated into the local infrastructure, complete with deepwater access and linked to the Kinder Morgan distribution pipelines. The proposals from established service providers in the petroleum industry shall include provisions for renting out half of the new capacity to interested third parties under guarantees provided as part of the State's SFR contract.

- Evaluate the proposals. Award of contract considerations shall include duration of term, fixed and variable costs and other fees, extent of guarantees needed for the additional storage to be leased out to third parties, etc. The evaluation shall include a verification of physical capabilities for each proposal, such as the existence of bottlenecks in pipeline gathering systems, the connectivity and access to marine terminal facilities for each location and other factors that will impact the operability and effectiveness of proposed facilities.

- Developing rules for operation of the reserve including detailed procedures for the auction mechanism, if an auction is retained as tool for usage of reserve volumes by third parties. The design will include the physical aspects of the reserve such as they will be proposed by the service industry with their respective tenders. If warranted, proposals will be invited from qualified parties, i.e., operators of current auctions or trading platforms, to submit competing proposals for the operation of the forward swap market proposed for the SFR.

- Design a system for oversight of the reserve, including the assignment of proper authority to ensure that the SFR is operated in the best interest of the California gasoline consumer.

- Conduct a review of the proposed systems with all relevant stakeholders in the industry. Revise systems as necessary.

- Prepare a comprehensive report for the legislature, including investment level cost estimate for facilities and operations. Confirm the viability and perform a final cost benefit evaluation.

It is important to note that these recommendations do not represent a delay associated with more studies, but rather represent the normal steps by which projects of such magnitude and complexity usually proceed. The sequential nature of the various design and execution phases of a project (feasibility study, definition phase, preliminary engineering, detailed design, procurement and construction, and start-up), merely mean that at each juncture, a decision is called for to proceed with the next phase and allocate the funds required to complete them. It is estimated that the work outlined in the steps above can be completed for $0.5 MM to $1 MM.

Attachment A - Cost Estimate for Reserve

Capital Cost Estimate - Bay Area Reserve

	Item Cost	Unit	Qty	Cost	Subtotal	Total
Tanks						
Shell Material & Labor, 225,000 bbl @ $8/bbl	$ 1,800,000	ea	4	$ 7,200,000		
Foundation, paving and bund w alls	$ 120,000	ea	4	$ 480,000		
Floating Roof	$ 500,000	ea	4	$ 2,000,000		
Dome Roof	$ 700,000	ea	0	$ -		
					$ 9,680,000	
Process Equipment & Piping						
Pipeline Delivery Pumps, 4000 bbl/hr, 300 hp	$ 60,000	ea	2	$ 120,000		
Blending & Circulation Pumps, 6000 bbl/hr	$ 40,000	ea	2	$ 80,000		
Piping, 20% of tank shell cost	$ 360,000	ea	2	$ 720,000		
Plant Air System	$ 300,000	ea	1	$ 300,000		
					$ 1,220,000	
Safety & Environmental						
Firew ater & Foam Systems	$ 800,000	ea	1	$ 800,000		
Vapor Destruction Unit	$ 1,200,000	ea	2	$ 2,400,000		
API Separator	$ 200,000	ea	1	$ 200,000		
					$ 3,400,000	
Pipelines						
16" Underground, incl. ROWs	$ 800,000	mile	5	$ 4,000,000		
Metering, Cathodic Protection	$ 300,000	ea	1	$ 300,000		
Pig traps	$ 50,000	ea	2	$ 100,000		
Tie-in	$ 100,000	ea	1	$ 100,000		
					$ 4,500,000	
Dock						
Jetty, 800 ft long, 40 ft draft	$ 6,000,000	ea	1	$ 6,000,000		
Loading arm, 16"	$ 200,000	ea	2	$ 400,000		
Piping, 24"	$ 100,000	ea	1	$ 100,000		
					$ 6,500,000	
Electrical & Indstrumentation						
HV Transformer & Sw itchgear	$ 200,000	ea	1	$ 200,000		
Lighting, other electrical	$ 300,000	ea	1	$ 300,000		
Level Gages, Overfill Protection	$ 50,000	ea	4	$ 200,000		
SCADA, computers, radios, telcom	$ 200,000	ea	1	$ 200,000		
					$ 900,000	
Civil						
Land purchase	$ 100,000	acre	15	$ 1,500,000		
Site prep, grading, drainage	$ 10,000	acre	15	$ 150,000		
Control room, MCC	$ 40,000	ea	1	$ 40,000		
Fencing, gates, site security	$ 15,000	acre	15	$ 225,000		
Roads & Paving	$ 10,000	acre	15	$ 150,000		
					$ 2,065,000	
						$28,265,000
Project Overheads						
Preliminary Engineering and Permitting			2%	$ 565,000		
Detailed Design & Procurement			8%	$ 2,261,000		
Construction Supervision			5%	$ 1,413,000		
					$ 4,239,000	
Contingency			20%		**$ 6,501,000**	
Total Capital Cost						**$39,005,000**

Capital Cost Estimate - LA Basin Reserve

	Item Cost	Unit	Qty	Cost	Subtotal	Total
Tanks						
Shell Material & Labor, 225,000 bbl @ $8/bbl	$ 1,800,000	ea	6	$ 10,800,000		
Foundation, paving and bund w alls	$ 120,000	ea	6	$ 720,000		
Floating Roof	$ 500,000	ea	6	$ 3,000,000		
Dome Roof	$ 700,000	ea	6	$ 4,200,000		
					$ 18,720,000	
Process Equipment & Piping						
Pumps, 4000 bbl/hr pipeline, 300 hp	$ 60,000	ea	2	$ 120,000		
Piping, 20% of tank shell cost	$ 360,000	ea	2	$ 720,000		
Plant Air System	$ 300,000	ea	1	$ 300,000		
					$ 1,140,000	
Safety & Environmental						
Firew ater & Foam Systems	$ 800,000	ea	1	$ 800,000		
Vapor Destruction Unit	$ 1,200,000	ea	1	$ 1,200,000		
API Separator	$ 200,000	ea	1	$ 200,000		
					$ 2,200,000	
Pipelines						
16" Underground, incl. ROWs	$ 1,000,000	mile	2	$ 2,000,000		
Metering, Cathodic Protection	$ 300,000	ea	1	$ 300,000		
Pig traps	$ 50,000	ea	2	$ 100,000		
Tie-in	$ 100,000	ea	1	$ 100,000		
					$ 2,500,000	
Dock						
Jetty, 800 ft long, 40 ft draft	$ 4,000,000	ea	0	$ -		
Loading arm, 16"	$ 200,000	ea	0	$ -		
Piping, 16"	$ 100,000	ea	0	$ -		
					$ -	
Electrical & Indstrumentation						
HV Transformer & Sw itchgear	$ 200,000	ea	1	$ 200,000		
Lighting, other electrical	$ 300,000	ea	1	$ 300,000		
Level Gages, Overfill Protection	$ 50,000	ea	6	$ 300,000		
SCADA, computers, radios, telcom	$ 200,000	ea	1	$ 200,000		
					$ 1,000,000	
Civil						
Land purchase (leased land)	$ -	acre	20	$ -		
Site prep, grading, drainage	$ 10,000	acre	20	$ 200,000		
Control room, MCC	$ 40,000	ea	1	$ 40,000		
Fencing, gates, site security	$ 15,000	acre	20	$ 300,000		
Roads & Paving	$ 10,000	acre	20	$ 200,000		
					$ 740,000	
						$ 26,300,000
Project Overheads						
Preliminary Engineering and Permitting			2%	$ 526,000		
Detailed Design & Procurement			8%	$ 2,104,000		
Construction Supervision			5%	$ 1,315,000		
					$ 3,945,000	
Contingency			20%		**$ 6,049,000**	
Total Capital Cost						**$ 36,294,000**

The Strategic Fuel Reserve in its Local and Global Context

A majority of stakeholders reading this report may not be familiar with the working dynamics of either domestic or international cargo markets in an arbitrage context. Considering the overwhelming importance that those dynamics will play in connecting the island of California, through the SFR, to the rest of the global economy in gasoline, we will set out on a conceptual journey to see it in action. Our voyage will be an exposition of the obvious for some, for others – a tutorial. For many, it will provide enlightenment.

A narrative camera will guide us from one gasoline supply port to the next. Readers who have traded in the international petroleum markets will suffer the shock of recognition as we sit at the desks of traders from Long Beach, California, to Sydney Australia, to the Arabian Gulf. From each perspective we will wrestle with the invitation to bid into the California Strategic Fuels Reserve. The jolt of reality will be inescapable, for we are dealing with the fundamental building blocks of global petroleum markets: Specifications; Transportation costs; Storage fees; Scheduling; Logistics; Arbitrage, and Price. A chart on the Global Arbitrage Matrix has been inserted at the end of the scenarios to recapitulate the raw cost and revenue assumptions from each port that will be factored into the competition.

We have elected to invite upon our voyage the illustrious Dr. John Nash, the enigmatic hero of the film, “Beautiful Mind”. His presence, through the creative precision of his economic insights, will provide both a frame of reference and an antidote to ideological responses against any form of government intervention that might otherwise gloss over the benefits of this specific proposal.[56] Although the tone and tenor of this Addendum steps beyond the confines of standard government reports, we trust that readers will recognize the intrinsic merits of its arguments and illustrations.

Similarly, that segment of the academic community who may have long ago rejected the very notion of government-held “buffer stocks” as economically unfeasible will also find grounds to reassess that position when the time-swap auction, and the lack of a defined trigger point enters the equation. The obvious benefits of connecting the island of California to the rest of the world in gasoline will be

[56] “Nash mathematically clarified the distinction between cooperative and noncooperative games. – Because noncooperative games are common in the real world, the discovery revolutionized game theory. – He recognized that in noncooperative games there exist sets of optimal strategies (so-called Nash equilibria) used by the players such that no player can benefit by unilaterally changing his or her strategy if the strategies of the other players remain unchanged. The theory of games applies statistical logic to the choice of strategies.

seen through the prism of the Nash equilibrium and the robust competition of "non-cooperative games".[57]

SFR – THE LOCAL VIEW

California: In the following scenarios the SFR auction process will be viewed from a number of international supply ports. In California, the SFR Administrator will see only the bid differential submitted by each company. The differential represents the amount that each participant is willing to pay to the SFR for the right to lift prompt inventory. By understanding the *content* of each player's analysis, within the *context* of his regional market matrix, one can appreciate the immense complexity of trying to anticipate who the most competitive player will be in any particular SFR transaction. Each participant will assess an SFR tender from his own geographical position, against alternative marketing and shipping options. Published prices for key global supply points, (i.e. Singapore, NYH, Rotterdam), do not tell the whole story, as amply illustrated in the ensuing scenarios. They do not provide a road map, but rather a preliminary set of directional reference points. Another level of complexity will be introduced when unfinished gasoline and blendstocks come into the equation through "outer ring"[58] storage and hedging strategies. The SFR will sit at the center of these pro-active strategies. The consumer benefits from all of them. The Nash equilibrium helps explain the underlying economics involved in a consistent manner.

Despite the complexities described in the ensuing scenarios, despite the wide-flung non-cooperative games focused on the SFR, despite the joint ventures of convenience and the juggling of ship schedules, specifications and price trajectories, the functioning of the SFR itself remains clear and simple. It is the "black box" that acts as a magnet for competitively priced, high-quality gasoline. It is not disruptive. It serves a common good.

A central principle driving the conceptual design of the SFR has been that of non-government interference with market forces. The controlling idea, in fact, is that, unlike European, Asian and U.S. Federal Reserve systems, California SFR inventories will not be sold at all. Its gasoline will be "time-traded". A barrel out equals a barrel in. Contractual volumes will be loaned out on the next

[57] www.encyclopedia.com/html/g/games-th.asp

[58] "Outer Ring" refers to the private, third party storage that will surround the SFR, but will not be governed in any way by its regulations. "Surround" in this sense does not necessarily mean contiguous to, or encircling the SFR. The point is that the private storage, wherever it is located, will be connected to the SFR by pipeline.

pipeline cycle for replenishment within “x” number of weeks. The SFR will be a rolling inventory that provides a physical basis for greater forward liquidity in the private sector. In essence, competitors in the free market, by bidding for prompt SFR gasoline, will define price backwardation[59] in the market. It facilitates trade. It renders the forward market transparent. It stimulates competition. The island of California, through the SFR time swap, will be re-connected with the rest of the world’s sophisticated refineries, but not necessarily to the detriment of California refiners.

Steep ‘backwardation’ can be another way of describing a price spike, although price backwardation occurs naturally in commodity markets during times of economic downturn. (Commodity manufacturer’s reluctance to hold inventory creates a prompt scarcity.) By the same token, price backwardation is a normal market reaction to spot shortages, refinery disruptions, and to various specification and seasonal changes. The unique and disruptive elements of gasoline backwardation (price spikes) in California are dictated by the State’s island situation, as well as by its unusual specifications, as explained in the Study. Being at least four weeks away from re-supply, and without a robust forward market for hedging the price-risk of potential incoming cargoes, what would be temporary backwardation in more open markets, becomes a plateau of elevated prices that must ultimately be passed on to the California consumer.[60] And one must not overlook the fact that the means of access to this particular island, namely third-party tanks, are in the hands of local manufacturers who have a natural, institutional bias against imports, other than to service their own down-stream systems.

The SFR system recommended here will accomplish a number of useful purposes:

1. Create much-needed logistical infrastructure (tanks and pipeline connections) that will be built by the private sector, through government incentives.
2. The loan out of SFR gasoline supplies will serve to bridge the time gap to other markets. It is a cheaper and more globally effective alternative to constructing a USGC to California pipeline.
3. The “outer ring” of private tanks will interact with the SFR so that it becomes the ultimate balancing point of the non-cooperative games heretofore described. Through that

[59] Backwardation refers to those markets conditions wherein the future price of a given commodity is lower than the prompt price

[60] See CEC Study “Economics Impacts of Refinery Disruptions – Implications for a Strategic Reserve” April 2002 - by Anthony Finizza, Ph.D. (AJF Consulting)

competition for California business, high quality gasoline and blend stocks will be attracted to the State at competitive prices.

4. Independent marketers of gasoline will not only be able to stay in business, but will source their supply more creatively, thereby insuring a healthy mix of competition in the State.

NOTE: California refiners will also participate in the SFR time-swap process, thus ensuring equal access to the system.

One Alternative for the Operation of the SFR

As outlined in Section 8.6 of the SFR Study, there are a number of alternative to the operation of the Reserve. Below is another alternative:

The Request for Supply: Instead of a trigger mechanism based on price or event and subject to bureaucratic review, the SFR will respond to *Requests for Supply* from the private market. These may be submitted by any of the pre-qualified participants and will be subject to a minimum transaction rate. For the sake of example, let us assume that the transaction rate is a minimum of 2 cpg with a minimum volume of 25MB. Intrinsic to the *Request for Supply* will be a “firm offer” by the initiating party, obliging them to accept the contract at that minimum transaction rate if no other parties elect to participate. This feature will discourage companies from ‘toying with the system’. It also assumes that the initiator sees the market in backwardation by at least that amount, or that a privileged source of cheaper blend stocks or CARBOB supply is available to him within six weeks. Otherwise he would not be in the company’s economic interest to initiate the *Request*.

The Timing Element: Tenders may be structured to allow for different replacement schedules, say: four, five and six weeks within a “Not Later Than (NLT)” context. Or, a fixed return schedule may be decided upon. If a single, fixed time schedule is adopted, then pre-defined penalties will be incorporated into the contract for late delivery. This is a common feature of other government-run petroleum tender systems. Off-specification claims will be handled under prevailing legal remedies.

The Participants: In keeping with its Public Sector responsibilities the SFR, upon receipt of a *Request for Supply*, will be obliged to open an *Invitation to Bid* to all qualified companies. The ‘qualification process’ will require both financial and performance guarantees to be filed with the SFR Administration.

The Terms and Conditions: Attached is a simple frame contract that can be used as a reference when drawing up the formal documents under the detailed planning phase of the SFR project. This style of contract is familiar to petroleum traders around the world.

The Tender Format: A *Request for Supply* that has been received by the SFR Administrator will be converted into an *Invitation to Bid* upon review of the SFR's inventory balance and its operational schedules. After assuring that the *Request* can be accommodated by the SFR, and that its initiator is in good standing from a credit and performance point of view, the bid invitation will be sent out electronically to qualified classes of trade. (It has yet to be determined whether separate Classes of Trade should be defined in SFR procedures in order to insure access to small companies.) As for the methodology of the transactions, there are a number of proven e-commerce auction formats already in use in the Petroleum Industry. One of these may be adapted to the needs of the SFR. Alternatively, a new system may be designed, as was the case with the Federal Heating Oil Reserve in the Northeast. The question of whether a traditional auction format will be most appropriate is yet to be resolved. We are reminded that participants will not be bidding on price, but rather on the time-value of the prompt barrels in light of prevailing market backwardation, or offshore replacement costs. Consequently, it can be expected that bid increments may be in fractions of a cent.

For example, if market backwardation to the next month is deemed to be 10 cpg based on published reports, then that number will presumably set the ceiling as to the differential that any company might be expected to bid for the prompt barrel. Otherwise, they would be losing money. A traditional auction process (i.e. E-Bay) would incrementally approach that 10 cpg until the most competitive counter party reaches his optimum equilibrium bid and others dropped out. With this fractional reality in mind, it may be prudent to elect a single, blind bid system, as is common in government tenders in many petroleum markets.

The SFR Tender Screen: It follows that there are at least two possible formats for computer displays that the SFR Administrators may be working with:

1) An Auction Format that allows the Administrator to see all bids submitted and that informs him as to which company is submitting each bid. Competing companies, looking at their own screens, will see only the highest bid at the moment, the "number to beat", so to speak. They will not see who submitted that number or what strategies other non-cooperative game players have in mind.

2) A Single Blind Bid format might be adopted, either exclusively or in conjunction with an auction format. If there is to be an auction element, then the bidding will run to a certain strike price at which time all participants will be asked electronically to submit their fixed and final bid. Alternatively, a single bid without preliminary auction might become the format elected in order to simplify the process.

Note: The foregoing commentaries provide only a preliminary sketch of the SFR mechanism on a conceptual scale. The procedures and e-commerce platforms that will be ultimately adopted are subject to a considerable amount of additional analysis and work with the Industry.

General Comments on Geographic Arbitrage

Geographic arbitrage is the term used to define the margins for trading between geographically separated market, taking into account price differentials between these markets and transportation costs. In traders parlance “the arb is open” means that market differentials are sufficient to justify transport cost. Trades between different geographical regions over long distances involve lengthy transit times, which translate into working capital expense and risks from price volatility. Other risks include product quality, i.e., through transport contamination, currency risk, and many other factors, all of which will impact a decision on individual trades.

With regards to the SFR:

- From an arbitrage point of view, replacement of SFR inventory may be CARBOB as the most straightforward. Alternatively, gasoline components, i.e. alkylate, reformate, etc. might be shipped to California for their blending value.
- Unfinished gasoline and components would be delivered first to private storage, or to a refinery for blending to meet CARBOB specs. Only summer-grade gasoline (CARBOB) will be accepted into the SFR. No blending or substitution of quality will be allowed within the SFR. This rule will be strictly enforced.

- Based on standard practice, FOB value of gasoline, blend stocks, or components in Asia (Australia in this example) will be pegged to MOPS (Mean of Platt's Singapore) prices for Naphtha.

- SFR participants based in Pacific Rim countries (Japan, China, Korea, Taiwan, Singapore, Australia) will evaluate the difference between prompt prices of gasoline in LA or SF (SFR origin) to its replacement cost based on the FOB value of cargoes in the region, plus freight, insurance and cost of money.

In the following sections, a number of typical arbitrage scenarios are described for trading products through the SFR.

A View from Down Under

Australia: A Los Angeles based refiner or trading company, upon receiving notice of an SFR tender contacts his Sydney, Australia office to inquire as to the cost of delivery into the SFR (or into leased storage) within six weeks. Let us assume the SFR's tender is for 200MB. Under this scenario the Sydney/LA trading team is confronted with three alternatives:

1. CARBOB specifications delivered directly into the SFR on a full cargo basis (300MB). The LA office must decide how to dispose of the additional 100MB and at what price in order to offset the cost of dead freight. For example, freight on a one-to-one port basis from Sydney to LA might be quoted at lump sum $1,135,000. On a full cargo basis this works out to a transportation cost of 9 cents per gallon (cpg)[61]. If only 200MB is hauled, the cost per unit (gallon) becomes 13.5 cpg, an increase of 4.5 cpg on the whole cargo.[62] Under these transportation conditions the LA office will decide whether to take the risk on the additional cargo. Their evaluation will directly impact the team's decision on the differential they should bid to the SFR. On the sell-side they must also calculate the weighted average value they expect to realize for the prompt SFR barrels that will either be sold into the spot market, or used to cover pre-committed sales.

[61] $1,135,000 ÷ 300MB = $3.78/bbl ÷ 42 = 9 cpg

[62] $1,135,000 ÷ 200MB = 5.67/bbl ÷ 42 = 13.5 cpg

2. Alkylate (100MB) and other gasoline components (100MB) available in Australia can be delivered as part cargo into leased storage in LA, or taken directly into a refinery. In this case let us assume that the balance of the cargo is jet fuel that can be delivered into LAX Fuels at a break-even, thereby eliminating the 'dead-freight' element (4.5 cpg) The LA office must calculate the presumed value of this particular component and blend stock cargo against CARBOB replacement costs into the SFR. They will need to either exchange the cargo, while on the water, with a California refiner for CARBOB, or take the components into storage where it will be blended or exchanged at a later date. If the leased storage option is chosen, then the LA office must take the additional cost of approximately 2.0 cpg per month of terminalling and handling charges into account. At the same time, they will evaluate the presumed value of the prompt SFR barrels as the other side of the equation.

3. The Sydney office will also look at alternative disposition options to the SFR auction such as: Domestic spot market sales that will weaken local prices. Cargo sales into northeast Asia (Korea, China, etc.) involving different elements of risk. Sale to gasoline blenders in Singapore, and so forth.

Market Comments: To complete the picture, let us assume that the FOB Australia value of CARBOB is 80 cpg, calculated as a differential against MOPS Naphtha price. Singapore prices are weak, with the market in backwardation. Prompt shipping; however, is available at below market rates of 9 cpg due to a backhaul opportunity on an incoming chemical/products carrier. The LA office, meanwhile estimates that prompt SFR barrels can be sold at a weighted average price of 96.5 cpg, assuming the sale of 100MB on the next pipeline cycle at 98 cpg, followed by 50MB at 96 cpg and 50MB at 94 cpg in successive pipeline cycles.

Profile of the Trade

FOB Sydney:	80 cpg based on MOPS Naphtha differential – Singapore Market in backwardation reduces forward value of the cargo in the region.
Transportation:	9 cpg based on lump sum one-to-one spot charter at USD 1,135,000 for 300,000 barrels
Insurance & Cost:	1 cpg (includes cost of working capital)
Total landed cost:	90 cpg
LA-SFR Sales:	100MB @ 98 cpg, 50MB @ 96 cpg, 50MB @ 94 cpg
Average revenue:	96.5 cpg
Estimated margin:	**6.5 cpg**

SFR Bidders' Considerations: From the point of the view of the FOB Australia supplier, raw published numbers do not tell the whole story. Alternative dispositions of the cargo will be taken into his calculations, as well as the local market effect of exporting the cargo (firming local prices). Without the possibility of going to California, for example, his next optimum destination may be as blending stock in Singapore, where prices are weak and tank availability is tight. On the other hand, the next shipping position, after the prompt 'backhaul opportunity' posited in this example, may be at a much higher rate. In concert with his LA office he will also assess the SFR supply probabilities from other regions such as the Caribbean or the US Gulf Coast in order to anticipate what the competition might bid to the SFR. We draw attention to these influences because they are part of the matrix of options within which this particular cargo will be evaluated. The Australia bid will need to compete with a broad range of alternate supply possibilities made possible through the SFR auction process. We can see that in this case Australia shows a margin of 6.5 cpg on the CARBOB portion of the cargo, which translates to a profit of US$546,000[63]. In conjunction with his LA office, the company must decide exactly how much, if not all, of this deemed margin to sacrifice in order to win the business.

This complex, dynamic, but entirely realistic commercial situation fits the description of noncooperative games as defined mathematically in Dr. John Nash's Nobel Prize winning paper. Dr. Nash's observations offer a much more realistic way to describe and understand the principles

[63] 6.5 cpg x 42 gallons per bbl = $2.73/bbl x 200MB = $546,000

that will drive the California SFR than do the inert platitudes of traditional economics that preceded him ("supply, demand and the "unseen hand of the market").[64] More will be said about this game theory in subsequent stops on our global tour.

A View from South Korea

Korea: A Seoul-based refiner can supply 100MB of alkylate; another can supply 100MB of high octane, low sulfur reformate in the same time frame. Both become aware of the California SFR tender through traders and international oil companies with offices in Los Angeles. A 200MB cargo can be "topped off" with 100MB of conventional gasoline meeting Oregon specifications but not suitable for California. Based on a two-port load, two-port discharge voyage plan the trading arm of the international oil firm, Alpha Company calculates a total freight cost of 7.8 cpg.

The international trader from "Z" Company calculates the same cost since both are talking to the same ship owner, in case they win the business. The trader places the ship on subjects, with firm validity until close of the SFR tender. The international oil company, being a refiner in California, calculates the value of the high octane alkylate and reformate according to the internal economics provided by the Process Engineering section of his California refinery. He does not wish to take a position on the Oregon grade "top up" parcel of 100MB, but does so reluctantly in order to maintain competitive shipping economics. "Z" Company, on the contrary, considers the probabilities surrounding the value of these blend stocks in forward months, in the event that he should discharge the cargo into leased tanks and trade around that future value to secure replenishment CARBOB supplies for the SFR within six weeks.

Market Comments: Both Alpha and "Z" company offices in LA have estimated the prompt value of the SFR barrels, according to their matrix of options, in the same manner as the Australia oriented company in "A" above. At the same time, the two Korean refiners are calculating the alternative

[64] "Nash took a novel tack; he simply finessed the process. He visualized a deal as the outcome of either a process of negotiation or else independent strategizing by individuals each pursuing his own interest. Instead of defining a solution directly, he asked what reasonable conditions any division of gains from a bargain would have to satisfy. He then posited four conditions and, using an ingenious mathematical argument, showed that, if the axioms held, a unique solution existed that maximized the product of the participants' utilities. Essentially, he reasoned, how gains were divided and how much the deal is worth to each party and what other alternatives each has." Quoted from: "The Essential John Nash", Harold W. Huhn (Editor) Sylvia Nasar (Editor)

value of their respective part-cargoes by looking at export possibilities in the form of finished gasoline to Japan and/or China/Taiwan. They enter into FOB sales negotiations with both interested parties simultaneously. The California SFR tender will close the next day. Assuming, for the sake of this illustration, that the international oil company wins the SFR tender. "Z" Company must give up 'subjects' on the ship. Alpha Company puts it on charter and is looking at the following set of economics:

	Profile of the Trade
FOB Yosu & Onsan	82 cpg Based on MOPS Naphtha differential, adjusted for blending value to an equivalent gasoline price.
Transportation:	7.8 cpg Based on lump sum $885,000 (one-to-one for 300MB Plus $100,000 for one additional load and one additional discharge port, including 'reverse geographical rotation' ($885,000 + $100,000) / 300MB = $3.29/bbl ÷ 42 = 7.8 cpg
Insurance & Cost	1 cpg (including cost of working capital)
Total landed cost:	90.8 cpg
LA-SFR Sales	100MB @ 98 cpg, 50MB @ 96 cpg, 50MB @ 94 cpg
Average revenue:	$96 cpg
Estimated margin:	**5.7 cpg**

SFR Bidders Considerations: Similar to the Australia example ("A") the raw published numbers do not tell the whole story. In this example we have stated that Alpha Company, bidding on the Korea Alkylate and Reformate supply, was the winner of the SFR tender. This is entirely possible, despite the fact that his landed cost in LA is deemed to be slightly higher than the Australia competition, due primarily to the higher FOB equivalent price for the blend stocks. There are any number of reasons why Alpha Company would have bid more aggressively than "Z" Company who was also considering the Korea supply, or the Australia company who had slightly better economics "on paper". For example, it might have been unscheduled unit problems in his LA refinery that caused the price spike in LA. He may have not been looking for speculative profit, but rather to cover an "in house" shortage at break-even. Or his Trading Department might have wanted to establish a customer track record with the Korean suppliers, thereby causing them to bid higher for the FOB barrels than the trading company would consider. The whole scenario, of course, could have resulted in no supply at all coming out of Korea, if markets for premium gasoline into Japan and/or Taiwan looked stronger in the eyes of the Korean suppliers than did the FOB part-cargo sales under discussion.

The point of this value matrix description is to, once again, draw attention to the noncooperative gamesmanship involved. Each party, including the suppliers in Korea and the purchasers of prompt SFR barrels in Los Angeles would be working toward a point of maximum profitability with minimum downside risk exposure. The beneficiary of this intense and complex competition, fought out in different corners of the globe, is the California gasoline consumer. In effect, the California market has been able to successfully bridge its isolated island situation through the mechanism of the SFR time trade. At the same time, a momentum has been created in the forward market that can provide the physical base for the private sector to unleash its creativity, arbitrage and risk-management skills.

And let us not forget the Nash equilibrium in all this – Nash's Nobel-prize-winning idea- has become "*the analytical structure for studying all situations of conflict and cooperation."* His biographer, Sylvia Nasar summarizes his work this way:

> "Obviously, each participant in a negotiation expects to benefit more by cooperating than by acting alone. Equally obviously, the terms of the deal depend on the bargaining power or each. Beyond this, economists had little to add. – They too had come up empty."
>
> "It is easy to see why: real-life negotiators have an overwhelming number of potential strategies to choose from – what offers to make, when to make them, what information, threats, or promises to communicate, and so on."[65]

This paper is not intended as an academic study, but rather as a foundation document for an entirely new and unique method of managing gasoline inventories through global competition focused on the State of California. The purpose of introducing the Nash equilibrium is to place the focus of that equilibrium squarely in the State's Strategic Fuels Reserve. The SFR will act as a magnet and a catalyst, as the NYMEX has done for heating oil and gasoline in New York Harbor. But the high-stakes complexities described above will occur 'beyond the fence'. Managers of the SFR will not be required to participate in, or to even comprehend those complexities. The SFR will be the still center of a swirling world in gasoline and gasoline components. But its operation will be clear-cut and disarmingly simple.

[65] "The Essential John Nash" Harold W. Kuhn (Editor) Sylvia Nasar (Editor)

A View from the US Gulf Coast

Houston: The East-of-the-Rockies Supply Department of Beta Company, an integrated oil conglomerate with refining/marketing assets both in California and in the U.S. Gulf Cost (USGC), receives notice of a tender for 200MB to be lifted promptly from the SFR and replaced within six weeks. Currently, NYMEX (RFG) gasoline is priced at 80 cpg in the first contract month (futures market), but the price is in backwardation by 3 cpg for each of the second and third months. Premium gasoline commands a 6 cpg price spread over Regular grade, the commodity traded on the NYMEX. The Gulf Coast is trading at a 4 cpg discount off of NY Harbor, reflecting the downward trend of the forward months. In order to supply CARBOB to a vessel sailing for California, the USGC refinery must borrow high-octane components from its blend stock pool, thereby creating a shortfall in Premium gasoline production that must be made up by purchases in the spot USGC market. His calculated FOB Houston break-even price would be:

78 cpg	NYMEX 1st & 2d month split
(4)	USGC location differential to NYH
74	
+ 6	Octane and RVP premium to make CARBOB
80 cpg	**FOB value**

American Flag shipping is available at 12 cpg on a full ship basis (275MB). The refinery can 'top off' the cargo with 75MB of additional blending components to defray 'dead-space' costs. The LA office estimates that it can sell 100MB prompt SFR barrels at 98 cpg. They are less bullish on the second 100MB, estimating a second cycle value of 94 cpg. Consequently, their weighted average sales estimate is 96 cpg.

Profile of the Trade – Beta Company

FOB Houston	80 cpg
Transportation	12 cpg
Insurance & Costs	2 cpg (including Canal tolls, Cost of money, and demurrage)
Total Landed Cost	94 cpg
SFR Sale Revenue	96 cpg
Deemed Margin:	**2 cpg**

Meanwhile, an international trader, “Y” Company, holding leased storage in both the USGC and in LA, with connections to the SFR, evaluates the SFR tender from the perspective of stored Alkylate and Reformate inventories that have been hedged against the NYMEX, producing an attractive ‘book profit’. In order to realize that book profit, the trader pegs his blend stock cargo on a CARBOB-equivalent basis, at 78 cpg FOB the USGC. He is looking at the same shipping economics as confronts Beta Company, but his LA office is more bullish than the competition on the prompt value of SFR barrels, which they estimate can be sold at an average price of 97 cpg. For the sake of illustration, the trading company’s position would be scribbled on the back of an envelope like this:

Profile of the Trade – “Y” Company

FOB Houston	78 cpg based on value of blendstocks
Transportation	12 cpg
Insurance & Costs	2 cpg (including Canal tolls, Cost of money, and demurrage)
Total Landed Cost	92
SFR Sale Revenue	100 MB @ 96 cpg
	100 MB @ 96 cpg
Average Revenue	97 cpg
Deemed Margin:	5 cpg

SFR Bidders Considerations: In this scenario the “Y” Company trader holds the advantage of having stored alkylate and reformate in the USGC and hedged those products against the NYMEX at a time when octane value was lower than on the day of the SFR tender. He does; however, face a different kind of risk when bringing those blend stocks to California with the intent of bartering them for finished CARBOB in order to replenish the SFR. On one side (USGC) he translates embedded book value into a ‘wet transaction’. On the California side, he assumes an element of liquidity risk. On the basis of these variables he will seek the “Nash Equilibrium” by enhancing his position; that is, by moving the blend stocks closer to a higher value market. His acquisition and immediate sale of the prompt SFR barrels will ‘lock in’ that higher value. With this strategy in mind, his company will bid aggressively, bidding to the SFR more than 75% of the deemed point-to-point margin in the trade (Paying 3.75 cpg for the prompt barrel)

A View from the Caribbean

Caribbean: The Caribbean- based refiner, "H" Company looks at the California market from a unique perspective. Situated in a Free-Trade Zone in the Virgin Islands, he is allowed by Law to employ foreign-flag shipping. This provides him with a significant transportation-cost advantage over the USGC refiner who must use American Flag (Jones Act) shipping. The voyage cost can range from 50% to 100% higher on the American Flag ship. He is also in a position to regularly optimize his cargo sales into the highest netback market: New York Harbor (NYH), the USGC, Puerto Rico, Mexico, or California, opportunistically aiming at the random price spikes that occur in those markets. Actually, it is not known whether the Caribbean-based refiner will be capable of producing Phase III CARBOB after MTBE phaseout. But for the sake of illustration, let us assume that his refinery does invest in that capability. (Alternatively, unfinished gasoline components might be chosen as the barter commodity as described in the USGC example above.) Because he is only four sailing days away from NYH, the Caribbean refiner can realize first month NYMEX value, plus 5 cpg for the prompt physical supply of RFG quality. Ocean freight, Insurance and incidental costs are 3.5 cpg. He finds that the NY delivery option is more attractive than selling lower quality gasoline into Puerto Rico. This local market reality narrows his options to NYH and the California SFR. His value matrix appears as follows:

Destination Option Comparison

(1) NYH option:	80 cpg	NYMEX 1st month contract
	0,5 cpg +	Prompt cargo premium
Revenue	80.5 cpg	
Shipping cost	(3.5)cpg	
FOB netback	**77 cpg**	
(2) CA-SFR option	97 cpg	Per LA brokers assessment
Shipping cost	(8) cpg	Includes canal tolls + cost of money
FOB netback	**89 cpg**	
Estimated margin:	**12 cpg**	(based on the optimized economics)

Note: For the sake of simplicity we are assuming no premium component penalty for the Caribbean refiner, unlike the USGC refiner who must borrow Alkylate from his premium gasoline pool to produce CARBOB.

The differential of 12 cpg for the CA SFR over New York Harbor shows an overwhelming advantage to compete for the SFR outlet at this time. But a decision must be made as to how much of that margin should be offered to the SFR in order to win the tender.

As is often the case, an international trader from Random Company is also assessing that Caribbean refiner as a potential supply source for the SFR tender in question. The trading company has its own ship on long-term charter working the region. They anticipate additional profit opportunities on this particular voyage to California by way of first discharging the SFR cargo in LA, then sailing north to Washington, where their LA office informs them that a clear gasoline cargo will be available for backhaul delivery to Mexico. This shipping advantage and incremental trading advantage compels them to propose a joint venture approach to the Caribbean refiner. Both parties will share the total cost, risk and revenue of the voyage transaction. Let us assume that the added J/V revenue is 3 cpg. This would be added to the 12 cpg base case for a 15 cpg margin accruing to the joint venture.

We add this random 'arbitrage opportunity' element not only because it is a common strategy, but because it illustrates one more element of "the Nash equilibrium".

> *"Nash also introduced the concept of bargaining, in which two or more players collude to produce a situation where failure to collude would make each of them worse off."*[66]

The joint venture, of course, must still decide how much of the venture's deemed margin to sacrifice to the SFR in bidding the tender. They can only infer from reported gasoline prices and shipping rates in other regions what their competition might bid to the SFR. Before the advent of Nash, this element of competitive uncertainty had been a recognized part of "cooperative game theories" originally conceived and published in 1942 by the renowned mathematicians, Oskar Morgenstern and John Von Neumann, for describing game competitions where the ground rules were known and agreed upon by all the players:

> *"Whenever an optimizing agent expects a 'reaction' from other agents to his own actions, his payoff is determined by other player's actions as well, and he is playing a 'game'. Game theory provides general methods of dealing with interactive optimization problems; its methods and concepts, particularly the notion of strategy*

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[66] The Columbia Encyclopedia, Sixth Edition

> *and strategic equilibrium. – A game consists of a set of rules governing a competitive situation in which from two to 'n' individuals or groups of individuals choose strategies designed to maximize their own winnings or to minimize their opponent's winnings; the rules specify the possible actions for each player, the amount of information received by each as play progresses, and the amounts won or lost in various situations."*[67]

It is easy to see that Nash's models on "noncooperative games" are far more applicable to the California SFR operation than the earlier "cooperative game" theories when the SFR is seen in its dynamic context of international price arbitrage. Not only do the various players act in isolation from each other, and with imperfect knowledge of the various positions on the playing field, i.e. the international oil market on any given day, but the rules under which each player decides his own course of action are imperfectly drawn. The overwhelming advantage to the California consumer, as a passive agent in this complex and dynamic global game, is that the SFR acts as the ultimate point of "equilibrium" toward which all competitors are striving. Their competition, based on the rational self-interest of each party, brings harmony to the market. The SFR's time-exchange mechanism is the metronome that sets the cadence of that harmony and brings rational order out of the chaos of price spikes.

Views from Newfoundland and New Brunswick

North Atlantic: The refineries in New Brunswick and Newfoundland, Canada share a foreign-flag shipping advantage over the USGC, but are disadvantaged in comparison with the Caribbean by about four days sailing time and three to five cents per gallon additional shipping costs. Their primary export market for gasoline and heating oil is New York and Boston Harbors, where highly liquid cargo markets are linked to NYMEX prices. Almost without exception the value matrix that North Atlantic refiners will refer to when evaluating California SFR auctions will consist of four elements:

1. Prompt RFG cargo market values in Boston and New York

2. Shipping costs, through the Panama Canal to California

[67] See J.Von Neumann and O. Morgenstern, *Theory of Games and Economic Behavior* (3d Ed. 1953)

3. Cost of covering existing supply obligations in NY and New England through replacement cargo, or local purchases.

4. Value of prompt gasoline borrowed from the SFR

It is expected that one of these refiners will be capable of producing California Phase III CARBOB (after MTBE phase out). The other will be capable of producing "NEARBOB"[68] and high-octane blend stocks. These "outer ring" products will be an increasingly significant part of the trading currency in California gasoline over the next few years. They will form the basis of another sub-set of non-cooperative games that will benefit the California consumer.

Market Scenario: The trading headquarters of the Newfoundland refinery has taken a short position on 150,000 bbls in the California pipeline market, expecting that prices will soften in the near term. A local refinery incident causes wholesale prices to run up suddenly in Los Angeles. The company is looking at losses on this prompt position of 8 cpg or about a half million dollars[69] unless they are able to "cover" that short position in the prompt market. Winning the SFR tender (electronic auction) will provide them with that "cover". But in order to win that prompt supply, they must coordinate with the Newfoundland refinery. The company must calculate an overall cost/benefit analysis of the SFR transaction. They must look at their matrix of options and ask: "What is the value of alternative disposition of the cargo in New York Harbor?" If another party wins the SFR tender, will we be able to cover our position without being caught in a short-squeeze? If we do win the tender and decide to bring NEARBOB into our leased 'Outer Ring' storage tanks, what will it cost for terminalling, and for blending that product up to SFR specifications, or for swapping it for finished CARBOB in order to replenish the Reserve?"

While Newfoundland and Houston are engaged in these abstruse cogitations, the New Brunswick refinery looks at a much simpler equation. They can cover their RFG commitments in New England by purchasing an incoming European cargo at 1 cpg over the screen. (NYMEX first-month contract)Freight costs to LA will be 11 cpg, including insurance and deemed demurrage. Brokers in LA promise to arrange sales for the prompt 200MB of SFR gasoline at 96 cpg. The comparative economics of the SFR transaction as seen by the two neighboring refineries would look like this:

[68] "NEARBOB" is a California market term used to describe gasoline that comes close to meeting the CARBOB specification, but needs additional blending in order to actually meet that legally defined quality.

Profile of the Trade

FOB New Brunswick	78 cpg (81cpg NYH value, less 3 cpg freight & ins.)
Transportation to LA	10 cpg
Insurance & cost	1 cpg
Total Landed Cost	89 cpg
LA SFR Sales	200MB @ 96 cpg
Revenue	96 cpg
Estimated margin	**7 cpg**
FOB Newfoundland	76 cpg (81 cpg NYH value, less 2 cpg quality upgrade penalty to finished RFG and 3 cpg freight & Insurance)
Transportation to LA	10 cpg + 1 cpg for Insurance
Total Landed Cost	87 cpg
LA SFR Sales	100MB @ 97 cpg, 100MB @ 96 cpg
Revenue	96.5 cpg
Other costs/benefits	2 cpg (- 2 cpg terminal & blending, + 4 cpg short cover adv,)
Estimated margin:	10.5 cpg

Coopetition: Borrowing a term that came into vogue during "dot.com mania" in this country, one finds that despite their different reading of the SFR transaction value, netted back to their respective refinery gates, there is still room for both competition and cooperation between them. Neither company knows what the other will bid, while the dead freight element will be perceived by both as putting them at a disadvantage against other supply points. (The shared shipping dilemma echoes John Nash's view of the bargaining problem within the larger context of non-cooperative games.)

More specifically, the Newfoundland refiner, and his non-cooperative competitor across the water in New Brunswick are evaluating the SFR tender from different perspectives: One seeks to cover an existing short position, using non-conforming gasoline as trade currency. The other simply wishes to improve his netback economics, as compared to his normal outlets in NYH and New England, by delivering an 'on-spec' SFR cargo. But since they do share a common vulnerability on shipping, they may decide to strike a deal and split the proceeds on the SFR sale. There are a number of

[69] 8 cpg x 42gallons per bbl x 150MB = $504,000

ways for this freight and cargo joint venture to play out. For the sake of illustration, we need only to recognize that the possibility is a real one, and is a not uncommon part of everyday cargo markets. The point lies in the elegant convergence of theory and practice with respect to the Nash model for non-cooperative games. The application of this convergence to SFR time-swaps is obvious.

> "For two centuries after the publication of Adam Smith's The Wealth of Nations there were still no principles of economics that could tell one how the parties to a potential bargain would interact, or how they would split up the pie. ---Mathematical models captured the results of competition but the consequences of cooperation remained elusive."[70]

> "Obviously parties to a bargain were acting on the expectation that cooperation would yield more than acting alone. The striking feature of Nash's paper is not its difficulty, or its depth, or even its elegance or generality, but rather that it provides an answer to an important problem. – The notion that the bargain depended on a combination of the bargainers' back-up alternatives and the potential benefits of striking a deal."[71]

A VIEW FROM NW EUROPE

Finland & NW Europe: The Neste Refinery in Finland had been a consistent source for CARB gasoline until Arco purchased the Thrifty independent gas station chain in the mid nineties. Thrifty had been Neste's primary customer, while Neste, being the government owned refining company of Finland had been the first refinery in Europe to upgrade to clean burning fuels that could comply with CARB specifications. Terminal space had been available at the time and a price formula between the independent retailer and the offshore refiner was negotiated. This arrangement maintained strong price pressure on the California refiners.

During the intervening years the California gasoline market has been consolidating into fewer and stronger hands through: a) The merger of refining/marketing companies and b) the trend toward "branding up" among independent retailers, in other words, converting to major brands and becoming part of their downstream network. The commercial effect has been more centralized control of the distribution chain and downstream prices. At the same time, specifications in Europe and in New York Harbor have tightened.

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[70] *A Beautiful Mind: a biography of John Forbes Nash Jr.; winner of the Nobel Prize in economics, 1994/ Author: Silvia Nasar (Published by Simon & Shuster)*

[71] Ibid

The CARB spec remains a stumbling block that is compounded by the Unocal Patent in the eyes of European traders. Recently the multi-national oil companies have sourced cargoes of California gasoline from other refiners in Northwest Europe. For the sake of illustration the region will be treated as a single supply source regardless of which refiner might supply the gasoline or blendstocks in the future. Traders point out that it is not only the specification that has prevented European sourced gasoline cargoes from coming to California over the past few years.

The lack of tanks and the lack of a forward market are even more severe hurdles. Ample liquidity and the ability to "lock in a margin" in NY Harbor renders that destination far more attractive from a risk/reward standpoint. Shipping costs to California from NW Europe are about 4 cpg higher that the NYH destination. An SFR in California, available to European suppliers, would solve the problem for forward liquidity on the basis of the time-swap auction. Since tank space would also be available, the two major barriers to supply from the European point of view will have been remedied.

The SFR bid process from the European perspective would resemble that of the Canadian refiner and, in some respects, the Caribbean refiner. Each will be evaluating alternative dispositions for their cargoes when preparing bids to the SFR. The NYMEX will be their basis for comparison. The prompt selling price in California, the cost and availability of shipping and timing issues will enter their evaluation. In other words, regional supply & demand conditions will influence the decision of each bidder in a unique way. For example, the Caribbean refiner might find strong demand in Central America and Puerto Rico, while the Finland refiner confronts weak demand in NW Europe.

Recognizing these shifting realities one can readily observe that prices reported through Industry publications only show approximate value. With these facts in mind, let us assume that NW Trader receives an invitation to bid for 200MB from the SFR. He is looking at the same NYMEX screen as his noncooperative competitors in the Caribbean and in Canada, and he must make a similar evaluation.

The value of high octane blendstocks in NW Europe must be taken into account, as well as his ability to dispose of the balance 100MB of products that he will co-load with the SFR cargo in order to defray freight costs. His freight cost from Rotterdam to NYH is 4.5 cpg with an additional 4 cpg for the onward voyage to LA, including Panama Canal tolls. A broker in LA informs him that he will be able to sell the prompt SFR barrels at 96 cpg. His evaluation is relatively straightforward, in that there are no J/V, or ship optimization opportunities available to him at the moment. His economics look like the following:

Profile of the Trade	
FOB Rotterdam	76 cpg (0.80 NYMEX lst Month, less 4 cpg freight & insurance)
Transportation	95 cpg (including Canal tolls)
Ins. & finance	1 cpg
Uncertainty factor[1]	2 cpg
Total Landed Cost	87.5 cpg
LA SFR Sales	200MB @ 96 cpg
Revenue	96 cpg
Estimated margin	11.5 cpg

The European supplier is uncertain as to the marketability of the balance cargo that he will load on the ship (110MB). He has chosen to load Jet Fuel but does not have time to fix the selling price in LA. Consequently he assumes a 2 cpg loss on that portion of the cargo as a conservative accrual.

A VIEW FROM THE ARABIAN GULF

Arabian Gulf: Supplies of CARBOB and/or high octane blending components sourced from the AG through the multinational oil companies are treated as part of the "local view" section below. The multinationals will enjoy economies of scale, shipping and blending flexibilities within their California refineries that will not be apparent to non-integrated competitors in the spot market. Besides, SFR transactions are designed to capture the marginal barrel' of supply at the lowest cost, the growing segment of demand in California that has outgrown the state's production capacity.

Non-major suppliers also operate in the Arabian Gulf. Their primary marketing objective, in fact, is the US West Coast, often the highest price gasoline market on the planet. Under today's situation, any cargo sourced in the AG and bound for California will, by necessity, pass through the hands of one of the local refiners. The SFR auction system will open the market for different kinds of marketing alliances. Whereas the global scenarios sketched above indicate a set of complex regional alternative surrounding each SFR bidder, the AG supplier will, most likely, look for marketing alliances within California itself to dispose of cargo lots. His shipping alternatives are more one-dimensional. His marketing flexibility will be played out at the receiving end. Often this will occur through the 'outer-ring', or private sector tanks that surround the SFR. These assets are apt to be equipped with truck loading racks in order that incoming cargo lots can be sold incrementally to independent marketers.

The SFR's time-swap mechanism will provide the forward price protection to this "long haul" supply source. The ability to move product between the SFR and the 'outer ring' system will add the marketing flexibility at Jobber and Distributor level that will bring more robust competition to the street. For example, a delivery of 200MB of gasoline from the AG to the SFR may be sold through a combination of brokered pipeline batches and through truck deliveries over the course of a month at a pre-agreed price with a Super-Jobber. With these observations in mind one can see that the AG supply equation will usually evaluated against much less economically attractive markets, such as Europe and Asia. Consequently, the AG supplier will look at the NYMEX and the IPE in Europe as overall market indicators, rather than as strict indicators of cargo value as they are to the NW Europe, Caribbean and North Atlantic suppliers. The AG supplier might fill out the ship with high octane blend stocks that he calculates as a break even for the sake of his SFR bid.

Profile of the Trade

FOB Arabian Gulf	72 cpg (Next best alternative disposal less freight)
Transportation	13 cpg (including Canal tolls & cost of working capital)
Late Penalty[1]	2 cpg
Total Landed Cost	87 cpg
LA SFR Sales[2]	200MB @ 97 cpg
Revenue	97 cpg
Estimated margin:	**10 cpg**

The voyage time from the AG is thirty-three days. Another week is required to prepare the cargo and arrange the FOB vessel. The SFR Auction calls for delivery within six weeks. A late penalty of 2 cpg per week is imposed by the SFR for late delivery. The AG Supplier has taken this into account in his economics, although he expects to arrive within the six-week deadline.

The AG Supplier has arranged a marketing alliance with a Super Jobber in LA whereby a price of 97 cpg has been guaranteed.

Summary

At this point in our global voyage let us pause and take stock of the key principles involved as they apply to arbitrage competition into the California SFR:

1. Each potential supplier outside the state will evaluate his options within a matrix of alternative cargo dispositions, including that of selling the product in his own domestic market.
2. Each player's equilibrium point will be defined as that disposition which produces the maximum netback price with the minimum risk, or negative market impact.
3. "Risk", as defined in this context will include such elements as:
   a) Relative firmness of the selling price. (SFR vs. other alternatives)
   b) Relative probability of the profit margin.
   c) Relative reliability of the buyer in terms of credit and performance.
   d) Direct and indirect consequences of choosing alternative dispositions.
   e) Corporate "bottom line" consideration, such as: Covering an affiliate office's short position. Relieving downward price pressure on local markets, etc.
4. The matrix evaluation of one supplier, i.e. in Korea, will not be transparent to his competitors in another region, such as the U.S. Gulf Coast, the Caribbean, or Newfoundland. In this respect, each potential supplier will be participating in a non-cooperative game.
5. Each non-cooperative competitor may; however, forge and alliance, a joint venture, or some form of risk/reward sharing scheme with a competitor to strengthen his position and lessen his risks as compared with other competitors.
6. Each competitor will strive for equilibrium within the netback matrix of his own market
7. The California SFR will provide the ultimate equilibrium point through its electronic time-exchange auction process.
8. The California gasoline consumer will be the ultimate beneficiary of these non-cooperative games by virtue of:
   a) Lessening the "island effect" of California's gasoline supply, by providing a time-bridge through the SFR exchange process.

b) Increasing competition in the State for high quality gasoline and components by opening the market through the SFR.

c) Enabling independent marketers to service their customers on more equal footing with local refiners by virtue of the open-access features[72] of the SFR auction process.

The following chart shows the matrix of costs, selling prices and deemed margins extracted from the above scenarios that could form the basis of a typical SFR time-exchange auction:

Global Arbitrage Matrix – SFR Supply

Supply Source	FOB Value (cpg)	Trans & Insurance (cpg)	Delivered Cost (cpg)	Selling Price (cpg)	ETA (Days)	Deemed Margin (cpg)
Australia	80	10	90	96.5	20	6.5
Korea	82	8.8	90.8	96.5	16	5.7
USGC(a)	80	14	94	96	18	2
USGC(b)	78	14	92	97	18	5
Caribbean	77	8	85	97	14	12
Caribs-JV	77	8	85	97	14	15
Newfoundland	78	11	89	96	17	7
New Brunswick	76	11 + 2 quality diff	89	96.5	17	7.5
NW Europe	0.76	9.5+ 2 risk factor	87.5	96	23	11.5
Arab Gulf	0.72	13 + 2 Late penalty	87	97	33	10
Int'l Major Oil		Aussie	90	98	20	8
		Korea	89	98	16	9
		USGC	92	98	18	6
		Caribbean	90	98	14	10

[72] "Open Access" means, open to those companies who have demonstrated both the financial and operational capability to perform under the terms and conditions of SFR Exchange Contracts

Note: Bids to the SFR may be made on the basis of other considerations than the flat margins shown above. Each participating company will decide how much of its deemed margin to "give up" in order to win the SFR tender. Each will be blind to the economics being considered by their competitors. This set of "noncooperative games" will establish the equilibrium point for California gasoline on the basis of the prevailing international arbitrage for high quality octane components and CARBOB

LOCAL ADVANTAGE

Every petroleum market, regardless of its level of transparency or commoditization, provides certain niche advantages to local players. In New York Harbor heating oil and gasoline for example, where international and domestic prices converge, and where the full weight of billion dollar speculative "hedge funds" is played out in the futures market, there still exists an array of local traders who break bulk, who blend incoming cargoes; who swap prompt barge lots against forward contracts and who perform various downstream arbitrage functions.

The same level of local competition is found in other actively traded markets, such as Rotterdam and Singapore. California will be no exception after adoption of the SFR time-swap system. California refiners will still retain the very substantial advantages that their years of servicing and investing in the market have brought them. California jobbers and independent retailers will not surrender their local advantage. Imports into the SFR will be defined, in economic terms, as "the marginal barrel". In other words, the last increment of supply to enter the market after local refiners have exhausted their ability to cover prompt demand beyond their own downstream networks (unbranded sector).

The dramatic difference will be more open accessibility to alternative sources of supply from outside the state. Through the SFR an efficient, relatively low-cost system will exist to fill the supply gaps that contribute to price spikes and which cost consumers hundreds of millions of dollars per year.[73] The refiners themselves will share access to this innovative SFR system but, unlike today's situation, access to external supply will no longer be their exclusive domain.

Part of the so-called, "local advantage" will inhere in the SFR's basic operational requirements. In order for any pre-qualified company to win an SFR tender, that company must be able to dispose of

[73] See Dr. A. J. Finizza's related study for the California Energy Commission at: www.energy.ca.gov

the prompt SFR barrels in the California market. They will also need a certain level of local market and operational knowledge to execute their contractual obligations on the scheduling and re-supply sides. It is not unlikely that new alliances will be formed that will link California trader/marketers to external supplies in order to "complete the circle" with respect to both lifting and replacing SFR inventories. It should be emphasized that government will have no hand in these realignments. They will come about by virtue of the open-access feature of the SFR and by its time and distance bridging capabilities, as described in foregoing scenarios. The end result will be lower prices to California consumers by virtue of both the more diverse mix of market competitors, and by the reduction of price volatility and hedging capability.

CA SFR and Local versus offshore Players

Local Perspective: From the vantage point of its home base in Southern California we will now consider three competing scenarios. The first is the arbitrage view of an SFR auction as seen by the Trading Manager (TM) of an integrated multinational oil firm. Call it, "Alpha Company". This will be followed by the Independent Retailers' view ("Beta Company") and, finally by brief comments on the role of arbitrage-opportunity traders. ("Z Company")

Alpha Company

Alpha Company, having been invited to an SFR tender, is quickly in contact with all of its major supply centers in the world. The prompt SFR inventory can be readily sold through its downstream network, without disturbing current spot market prices of 0.98 cpg. Against this known revenue Alpha's TM collects the following SFR replacement options from his or her worldwide network.

a) Australia promises a NEARBOB cargo that can be delivered within five weeks for a landed price of $0.87 cpg. Alpha Company's refinery estimates they can blend the product up to SFR specifications (CARBOB) for $0.02 cpg. An additional $0.01 cpg must be accrued for pipeline, dock and other handling charges. Fully weighted replacement costs in five weeks, therefore is: $0.90 cpg

b) South Korea contacts Alpha Company's Singapore office to inform them that they can deliver a combined Alkylate and Reformate cargo within four weeks, for a delivered priced of $0.93 cpg. The refinery estimates the value of these high-octane blending components to be CARB gasoline, plus $0.04 cpg. Since this enhanced value must be equated with CARBOB, its landed cost, on a CARBOB equivalent basis, will be: $0.89 cpg.

c) Alpha Company's US Gulf Coast (USGC) refinery, through the Houston supply department, can deliver conforming CARBOB with three weeks at 0.92 cpg.

d) Houston also informs the TM that a Caribbean sourced cargo is available through brokers at a floating NYMEX related price that equates to 0.90 cpg for delivery within four weeks. It's floating price element will require the TM to decide when to 'lock in' the actual cost when submitting his SFR bid.

e) An Arabian Gulf supplier promises delivery of a complying CARBOB cargo at 0.88 cpg, but cannot guarantee delivery until eight weeks, rather than the six weeks required by the SFR. (The TM will, thereby be required to borrow inventory from his own system to repay the SFR, then back-fill with the AG cargo.)

In aggregate, Alpha Company has a range of options to choose from, some in strict conformity to the SFR tender, others needing adjustment in terms of timing or specifications. These adjustments are well within Alpha Company's capability. The TM's job is to select the most favorable offer and to bid accordingly. At this stage of its conceptual development it is not outside the SFR's operating parameters to consider multiple offers based on shipping distances and scheduling. For example:

Differential bid to SFR	Delivery Basis
4 cpg	Within three weeks
5 cpg	Within four weeks
6 cpg	Within five weeks
7 cpg	Within six weeks

Assuming that no such delivery schedule flexibility is built into the governing rules of the SFR, then Alpha Company's TM must make a market decision on the basis of a specific time frame. This decision must be made contemporaneously with all the non-cooperative game players who will participate in this tender and who's behavior the TM cannot fully anticipate.[74]

[74] "In noncooperative games, unlike cooperative ones, no outside authority assures that players stick to the same predetermined rules…."

Beta Company

Beta Company is a high-volume independent retailer. It may be a Gasoline marketing specialist with convenient stores, similar to the major branded systems. Or, it may be a “big box” hyper-marketer, where gasoline is sold at a discount at the pump island to attract customers into its primary store. In any event, the marketing company may bid on SFR supplies either through alliance with a California refiner, a local Jobber with trading company connections, an offshore refinery capable of delivering CARBOB to the SFR, an international trading company, or through the commercial relationships of its Gasoline Supply Manager who may call upon any combination of the above. Under these types of strategic relationships Beta Company provides the downstream liquidity for the SFR transaction.

The alliance partner, or partners may propose a range of profit and risk sharing options. These options could include the tank transfer of prompt SFR inventories into the “outer ring” (private storage) to be lifted ratably by Beta Company over the net “x” number of weeks, by which time the alliance partner will be obliged to replace the inventory according to the terms of the SFR tender.

Z Company

“Z” Company is a speculative, or opportunity trader. This style company assumes market risks that lie beyond the business scope of either Alpha or Beta Company. Its local office may be part of a regional, or worldwide network. Such companies enter the market in a long or short position, depending on their view of emerging price trends. They serve a useful function in many Energy markets by enhancing the level of liquidity through assumption of price risk, and by creating robust secondary (derivative) contracts and instruments. It is entirely possible that “Z” Company will bid aggressively on an SFR tender without lining up exactly to whom the prompt barrels will be sold, or from which source they will be replaced. But the SFR contract will be performed, even at a great loss if necessary, because this non-asset based class of trade cannot survive the legal or market stigma of non-performance. The consumer benefits by “Z Company’s” presence through the added liquidity and hedging tools that they offer, and by the added level of competition that it brings to bear upon the market.

WHAT THE SFR ADMINISTRATOR SEES

We have described scenarios by which the SFR transactions can be understood from a number of international and local perspectives. We have illustrated, by way of specific reference, how the economic dynamics involved reflect the kind of *search for equilibrium through non-cooperative games* that were modeled so creatively by Dr. John Nash in his Nobel Prize winning work. We have shown how the famous "Nash equilibrium" will find its ultimate focal point in the SFR through its convenient time-swap mechanism, and how the California consumer will become the beneficiary of that creative competition. We have asserted that the SFR operation itself is not complex at all. It simply compels the multitudinous markets surrounding it to perform their independent evaluation, each based on their own matrix of alternative options, - and to place a bid. SFR barrels are not for sale. The absolute price of gasoline will not be tampered with in any way by government action. The open access time-swap is a thoroughly unique approach to managing a strategic inventory. The usual objections that are raised in connection with other types of strategic reserves simply do not apply. i.e. government involvement in the market, unpredictable trigger mechanisms, stagnant inventories, etc. All competition will take place in the free market. California consumers will benefit. Capitalism trumps oligopoly.

However, after absorbing the rich complexities of international trade in gasoline and blending components as laid out in the forgoing scenarios, how can one feel confident that the SFR itself will not become entangled in the far-flung mesh of those non-cooperative games? The answer becomes self evident when one stands in the shoes of the SFR Administrator and see what he sees. The Administrator can be blind to the intricacies of the private sector maneuvers taking place 'beyond the fence' of the strategic reserve and still be effective. He only needs to care about swap differentials and contractual performance. The market will take care of itself.

Who bids what?

On the basis of the raw numbers shown in the matrix, one would expect that the J/V cargo from the Caribbean would walk away with the prize. Their deemed margin of 0.15 cpg places them well ahead of the competition from around the globe. But, just as the published prices for markets around the world cannot tell the whole story that drives the strategies of each player, so too, the deemed margin that each player calculates will not determine exactly what price he will bid to win the auction.

An element of guesswork enters the equation. A process of, once again, evaluating the alternatives enters the heated moment. The nature of this phase of decision-making is more intense than that of 'lining up the deal' on paper. As time draws near to 'pull the trigger' and to submit a firm offer to the SFR, each player will wrestle with the possible outcomes. "What if I bid too aggressively and leave too much money on the table? How will my boss react?" thinks the trader in Australia, blind as he is to the economics of his competition in the Caribbean, or the Arabian Gulf.

> "Game theory is a theory of rational behavior for interactive decision. Problems. In a *game*, several agents strive to maximize their (expected) utility index by choosing particular course of action, and each agent's final utility payoffs depend on the profile of course of action chosen by *all* agents. The interactive situation, specified by the set of participants, the possible courses of action of each agent, and the set of all possible utility payoffs, is called a *game*."[75]

It is also possible that the Caribbean J/V that produces such a robust profit margin (15 cpg) is a fragile one. It may fall apart before the final bids are placed, with each party deciding to 'go it alone.'

Meanwhile, the major oil company Supply Manager who is also considering a bid on the basis of a Caribbean sourced cargo might discover that he has been 'counting the same barrels'. That particular cargo could slip out of his hands if his Houston office cannot work a deal to bring it 'firm' before the bid deadline. This compels him to rely on his next best option out of Korea at 9 cpg.

> "In competitive markets (competitive market equilibrium), it is enough that each player optimizes regardless of the behavior of other traders. As soon as a *small* number of agents are involved in an economic transaction, however, the payoff's to each of them depend on the other agents' actions."[76]

But having shifted his strategy to the Korea source, he unknowingly enters a netback margin territory shared with non-cooperative players from NW Europe and the Arabian Gulf. Beside, he

[75] http://www.sfb504.uni-mannheim.de/glossary/game.htm

[76] Ibid

needs to keep part of the proceeds of the SFR deal for his own profit center and to share the balance with his counterpart in Seoul.

Often the players participating in a government tender will call each other, either directly or through brokers, to 'get a feel' of what the competition is thinking. But this process seldom yields real dividends. No player wants to reveal his strategy for fear that any leaked information will be used against him.

> "Although the word 'game' suggests peaceful and 'kind' behavior, most situations relevant in politics, psychology, biology, and economics involve rather strong conflicts of interest, competition, and cheating, apart from leaving room for cooperation or mutually beneficial actions."[77]

In the final analysis the winner of an SFR auction will not necessarily be the company with the greatest 'deemed margin' built into his economics, but rather that company who is willing to give up the greatest share of his deemed profit in order to secure the business. Or the winning bid might come from unsuspected quarters. In this case the trader for the company in the Arabian Gulf is looking at rather bleak alternatives if he loses the SFR opportunity. He is willing to give up half of his deemed margin to secure the business. He decided to bid 5 cpg to the SFR, thinking that his competitors will not match this level of margin sacrifice.

But the wild card in the competition turns out to be "Z Company", the international arbitrage trader who owns no refineries anywhere. Because he is not locked into any particular supply source, he is free buy from any and all of them on the strength of his company's credit and performance record. "Z Company" will assess the forward price trajectories of all global markets over the next six weeks and place its bid in the confidence that its traders will be able to 'cover the short position' at a profit. All, or part of that coverage may, in fact, come from the California spot market itself, if prices fall after the auction. In this instance, "Z Company's 'read' of the local and international price trends, lead is to bid 7 cpg to the SFR. This bid wins the auction. As a result, holders of cargoes in all of the aforementioned markets remain long. They must sell those parcels elsewhere, or to "Z Company", in another example of bargaining within the context of noncooperative games.

[77] http://www.sfb504.uni-mannheim.de/glossary/game.htm

Note: These hypothetical cases are not far-fetched. They are intended to illustrate the dynamic complexity of the SFR in action. California becomes the hub of global gasoline trading, as it should be. Local refiners retain their significant advantage, but a new level of competition stretches from Asia, Europe and the Arabian Gulf to the streets of San Francisco. It is only the California gasoline consumer who comes out a winner in every scenario.

SFR – ALTERNATIVE TO A FUTURES MARKET

The SFR as outlined above, both in its administrative profile and in the global scenarios described, resembles the workings of a Futures Market. But that is not the primary intent of this proposal. Forward liquidity, linked to the physical flow of prices and products, will be enabled by the time-swap auction, but there will be no "clearing house" function involved. Various stakeholders and active East Coast participants in the NYMEX[78] point out that California gasoline will never provide the enormous liquidity that is common to the NY Heating Oil, or WTI (West Texas Intermediate) Crude Oil Contracts.

Even with the common delivery point that an SFR would provide, there will still be boutique fuel and Unocal Patent issues to contend with. CARB gasoline will not become a fungible commodity like Jet Fuel. Some see the comparison with NYMEX as beside the point. They remind us that the NYMEX has grown accustomed to being the clearinghouse for thousands of petroleum contracts that are traded by non-petroleum interests, such as fund managers, cross-commodity technical traders and financial institutions.

European and South American traders, not to mention the entire U.S. Gulf Coast refining complex, use the NYMEX as a hedging mechanism for physical cargoes and pipeline shipments. Traders of weather derivatives, of natural gas, of electricity and other hydrocarbons find both a 'leading indicator' and a risk diversification tool in NYMEX futures contracts. But these diverse, big money interests have been drawn to the NYMEX commodity exchange over a course of twenty years.

The brief history sketched below reminds us of it halting beginnings in petroleum. California, on the other hand, has no history to fall back on. But it has tremendous potential. And new electronic systems exist that can, when used in conjunction with the SFR auction, provide. If an SFR is to be

[78] New York Mercantile Exchange

established in the state, then these tools should be used for control, for convenience and to provide market transparency.

- **NYMEX Model:** The size of the California gasoline market is small compared with products traded in New York Harbor. The Eastern Seaboard is a destination market for refining centers in the Gulf Coast, as well as for arbitrage cargoes from South America and Europe. But with adequate private sector storage, connected to the SFR, a physical delivery point for forward contracts would be established. It would link the State to the rest of world without incurring the expense of building a pipeline from the U.S. Gulf Coast. With such a system in place, one would expect liquidity in today's thinly traded forward markets to expand exponentially. Nonetheless, a traditional NYMEX floor-brokered system would not be justified in the foreseeable future.

- **E-Commerce Model:** The NYMEX and Europe's IPE models are based upon a guaranteed performance and margin call structure, whereby the clearinghouse stands between buyers and sellers, becoming a principle to every transaction. But an array of alternative trading methods have emerged across the Internet in the past few years. Such trading platforms as: Houstonstreet.com, Redmeteor.com, Inter Continental Exhange (ICE), and certain home grown models such as Energyswap.com [79] have been introduced with various degrees of success. Credit and performance parameters must be pre-approved between the counter-parties, as would be the case with the SFR. The electronic systems offer varying degrees of flexibility for defining specifications, delivery terms and conditions, etc. They are not pure commodity markets. The fact that these platforms already operate east of the Rockies, begs the question, "Why are they not used in California today? The answer lies in the lack of underlying liquidity, or transaction intensity described throughout this Study. The SFR bridges that gap.

Additional Scenarios:

[79] See websites: www.enrononline.com, www.houstonstreet.com, www.redmeteor.com, www.ice.com; www.energyswap.com;

Example 1 – Present Situation: A cat cracker in a major refinery goes down unexpectedly. The spot market gasoline price in California shoots up by fifteen cents per gallon, from say 85 cpg to $1.00 per gallon. The notional cost of CARB spec gasoline in the Caribbean, or in East Coast Canada is 80 cpg. Freight costs from either location are 10 cpg. Calculating the cost of money, insurance and storage fees in LA (total of 2 cpg) either cargo could land within three weeks for a cost of 92 cpg, an apparent margin of 8 cpg. On the face of it, this scenario would yield the offshore supplier a **profit** of **$1,008,000** (one million and eight thousand dollars) on a typical 300,000 BBL cargo. ($0.08x42=$3.36/BBL x 300,000BBLs = $1,008,000). But in many cases neither cargo will set sail for California.

In the mind of offshore refiners and traders, the price spike could evaporate as quickly as it appeared. Most cargo traders would rather "lock in" a margin of, say $0.02 cpg than take a chance on a million dollar windfall. Experience teaches that a windfall profit on paper can become a devastating loss in the course of a voyage. There is no "lock in" mechanism in California because there is no robust forward market. There is no forward market because there are no waterborne storage facilities available to international traders and offshore refiners. All waterborne storage is in the hands of integrated refining/marketing companies. There is a strong economic incentive for these companies to "keep the market tight". These are simply the facts.

Example 2 – SFR Release: Given the same scenario, a Request for Supply (RFS) would be submitted to the SFR by one or more market participant. Responding to that request the SFR would initiate a time-exchange auction as described above. The auction releases "prompt" barrels of gasoline, in exchange for replacement in four to six weeks. (To be explicitly defined.) The auction results in a bid by offshore supplier "x" to pay six cents per gallon to the SFR for the privilege of drawing prompt inventories that can be sold into the market at the current price. This cost is subtracted from his cargo economics from Example 1, leaving a "locked in margin" of $0.02 cpg, or a cargo **profit** of **$252,000** ($0.02 cpg x 42 = $0.84/BBL x 300,000BBLS = $252,000). Of course the value of 300,000BBLS being released into the spot market would moderate the price spike, and would be taken into account by all participants in the auction. In reality, there should be no requirement that replacement barrels come from outside the state. If the price spike solves itself through other means, then participants in the auction should be free to avail themselves of local supply to replenish the SFR inventory.

Example 3 – Private Sector Solution: The most probable result of the very existence of an SFR as herein described would be that more vigorous forward liquidity would be created in the private sector by virtue of new import storage being available. This will be even more likely if the SFR inventory is connected to such private sector storage (the “outer ring”), as is the case with the Federal Heating Oil Reserve on the East Coast. There are no incentives in the private sector; however, to provide this inventory bridge. The ‘rolling’ of the SFR inventory through the in-and-out transactions of the auction process, will define the ‘forward curve’, which is the perceived shape of the commodity’s value at various points in the future. It will also serve to keep the inventory fresh from a quality shelf-life perspective.

Other Examples: Much of California’s recent electricity crisis, particularly the collapse of the major Public Utilities, can be attributed to a failure to understand, or utilize available ‘forward curve’ pricing instruments for “locking in” costs or margins. The alternative faced by the Utilities was to remain perpetually naked to the intense pressures of the prompt (daily and hourly in electricity) market. In the absence of such a forward market, California gasoline is traded as electricity was traded during the most severe days of the crisis. Under the now defunct “PX” system in electricity, the last kilowatt traded in a particular session would set the price for the entire grid. All competitors in an auction to supply the “PX” would be paid the optimum price for that session. This market absurdity was eventually understood by government authorities and, billions of dollars later, the PX was laid to rest. In today’s California *gasoline* market; however, the last ‘deal done’ and in many cases the last ‘rumor of a deal done’ sets the price for the entire “unbranded rack” and spot pipeline price throughout the state (Adjusted for SF vs. LA differentials), very much like the now-defunct PX system. A spot transaction of 25,000bbls, or 2.5% of the state’s gasoline pool, is enough to accomplish this. Of course, price spikes occasionally do occur within a futures market, but they are symptomatic of a much larger supply & demand phenomenon, often global in scope, than the “hiccups” that become “convulsions” in California.

Postscript: We have called upon the work of Dr. John Nash throughout the global scenarios in order to illuminate the nature of the trading patterns that will emerge, and the particular dynamics that will be at play, with the advent of the California SFR. We have written to Dr. Nash at Princeton to ask for his comments on the aptness of our applications. The Nash references have not been meant as a "stamp of authority" from a figure so recently in the public eye. On the contrary, it is the logically disciplined, yet thoroughly original nature of his work that has helped us tie together global trading patterns that would otherwise be seen as an incomprehensible jumble of options. In the same spirit, the SFR time-exchange auction system proposed herein provides the State with a logically disciplined and thoroughly original solution to taming price spikes and connecting the State to the rest of the world.

CALIFORNIA
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ECONOMIC BENEFITS OF MITIGATING REFINERY DISRUPTIONS

A SUGGESTED FRAMEWORK AND ANALYSIS OF A STRATEGIC FUELS RESERVE

CONTRACTOR REPORT

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Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

Prepared By:
Anthony Finizza, Ph.D.
10 Monarch Bay Drive
Dana Point, CA 92629
Contract No. 500-00-002

Prepared For:
Sherry Stoner
Contract Manager

Gordon Schremp
Project Manager

Pat Perez
Manager
Transportation Fuel Supply & Demand Office

Nancy Deller
Deputy Director
Transportation Energy Division

Steve Larson,
Executive Director

ECONOMIC BENEFITS OF MITIGATING REFINERY DISRUPTIONS

A Suggested Framework and Analysis of a Strategic Fuels Reserve

Study Conducted By

Anthony Finizza, Ph.D.

AJF Consulting

For

The California Energy Commission

Pursuant to California State Assembly Bill AB 2076

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DISCLAIMER

Anthony Finizza, the sole proprietor of AJF Consulting, prepared this report at the request of and for the sole benefit of the California Energy Commission. Neither the whole report nor any part of the report shall be provided to third parties without the written consent of the author. Any third party in possession of the report may not rely on its conclusions without the written consent of the author. This report was prepared using reasonable care and skill in applying methods of analysis consistent with normal industry practice. All results are based on information available at the time of presentation.

The US Department of Energy's Energy Information Administration and staff members of the California Energy Commission provided data to the author. The author does not warrant the accuracy of their data. The analysis can be no more accurate than the accuracy of the underlying data. In preparing this report, the author did not have available any individual company data, nor did he meet or visit with any company personnel. He drew upon his general experience with the Atlantic Richfield Company, for which he served as Chief Economist, but did not use any specific information of that company.

Changes in factors upon which the report is based can affect the results. Forecasts are inherently uncertain because of events that cannot be foreseen, including the actions of governments, individuals, third parties, and various other market participants.

This report should be read in conjunction with the Stillwater Associates' Strategic Fuel Reserve report. Any ad hoc criticism of the assumptions or methodologies contained in this report should not be summarily applied to benefits of the SFR as described in the Stillwater Report. Nor should it be read in isolation of that report.

Finally, the study is intended as a high level overview of the issues. More detailed modeling with more resources could alter and/or refine the conclusions herein.

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GLOSSARY

ANS	Alaska North Slope, term used to designate crude oil of that region
API	American Petroleum Institute
CARB	California Air Resources Board
CBA	Cost-Benefit Analysis
CEC	California Energy Commission
cpg	Cents per Gallon
DOE	U.S. Department of Energy
DTW	Dealer Tank Wagon
EIA	Energy Information Agency
FCC	Fluidic Catalytic Cracker, primary gasoline producing unit in a refinery
FTC	Federal Trade Commission
H2	Hydrogen
HC	Hydro Cracker
HT	Hydro Treater
Jobber	Independent distributor of petroleum products
LA	Los Angeles
LAX	Los Angeles International Airport
mb	Thousand barrels
mbd	Thousand barrels per day
MM	Million
MTBE	Methyl Tertiary Butyl Ether
NY	New York
NYMEX	New York Mercantile Exchange
OMB	Office of Management and Budget
OPIS	Oil Price Information Service
PADD	Petroleum Administration for Defense District.

RFG	Reformulated Gasoline meeting the requirements of the CAAA
SF	San Francisco
SFR	Strategic Fuels Reserve
USGC	US Gulf Coast
VGO	Vacuum Gas Oil
WSPA	Western States Petroleum Association
WTI	West Texas Intermediate Crude Oil

CHARTER

In 1999, following a series of refinery outages that caused significant price spikes in the California fuels markets, the Attorney General's office created a taskforce to investigate causes and recommend solutions to prevent recurrence. The efforts of this taskforce resulted in Assembly Bill 2076, which called for the California Energy Commission:

> "..to examine the feasibility of operating a strategic fuel reserve and to examine and recommend an appropriate level of reserves. If the commission finds that it would be feasible to operate such a reserve, the bill would require the commission to report this finding to the Legislature and request specific statutory authority and funding for establishment of a reserve."

The bill also provided general directions for the work to be performed

> (a) By January 31, 2002, the commission shall examine the feasibility, including possible costs and benefits to consumers and impacts on fuel prices for the general public, of operating a strategic fuel reserve to insulate California consumers and businesses from substantial short-term price increases arising from refinery outages and other similar supply interruptions. In evaluating the potential operation of a strategic fuel reserve, the commission shall consult with other state agencies, including, but not limited to, the State Air Resources Board.
>
> (b) The commission shall examine and recommend an appropriate level of reserves of fuel, but in no event may the reserve be less than the amount of refined fuel that the commission estimates could be produced by the largest California refiner over a two week period. In making this examination and recommendation, the commission shall take into account all of the following:
>
> (1) Inventories of California-quality fuels or fuel components reasonably available to the California market.
>
> (2) Current and historic levels of inventory of fuels.
>
> (3) The availability and cost of storage of fuels.
>
> (4) The potential for future supply interruptions, price spikes, and the costs thereof to California consumers and businesses.
>
> (c) The commission shall evaluate a mechanism to release fuel from the reserve that permits any customer to contract at any time for the delivery of fuel from the reserve in exchange for an equal amount of fuel that meets California specifications and is produced from a source outside of California that the customer agrees to deliver back to the reserve within a time period to be established by the commission, but not longer than six weeks.
>
> (d) The commission shall evaluate reserve storage space from existing facilities.
>
> (e) The commission shall evaluate a reserve operated by an independent operator that specializes in purchasing and storing fuel, and is selected through competitive bidding.

This Study was performed within the specific framework of the Legislation, to answer as a minimum the questions asked, by the stated deadline. In addition, in cooperation with the consultant retained by the Commission for this study, Stillwater Associates of Irvine, CA, the Commission deemed it appropriate to evaluate other factors that contribute significantly to the volatility of California's fuel markets, such as breakdowns in market mechanisms for gasoline, and the inadequacy of the logistics infrastructure serving the fuels market.

INTRODUCTION

In 1999, following a series of refinery outages that caused significant price spikes in the California fuels markets, the Attorney General's office created a taskforce to investigate causes and recommend solutions to prevent recurrence. The efforts of this taskforce resulted in Assembly Bill 2078, which called for the California Energy Commission:

> "... to examine the feasibility of operating a strategic fuel reserve and to examine and recommend an appropriate level of reserves. If the commission finds that it would be feasible to operate such a reserve, the bill would require the commission to report this finding to the Legislature and request specific statutory authority and funding for establishment of a reserve."

The bill also provided general directions for the work to be performed that are pertinent to this report: (*italics are the author's*)

> The commission shall examine the feasibility, including *possible costs and benefits to consumers and impacts on fuel prices for the general public*, of operating a strategic fuel reserve to insulate California consumers and businesses from substantial short-term price increases arising from refinery outages and other similar supply interruptions.
>
> The commission shall examine and recommend an appropriate level of reserves of fuel, but in no event may the reserve be less than the amount of refined fuel that the commission estimates could be produced by the largest California refiner over a two-week period. In making this examination and recommendation, the commission shall take into account …*the potential for future supply interruptions, price spikes, and the costs thereof to California consumers and businesses.*

As part of that effort, the Energy Commission asked Dr. Anthony Finizza to conduct an economic study of the economic implications of refinery disruptions in California and develop a framework for evaluating other options. The framework is applied to the Stillwater Associates' study of the Strategic Fuel Reserve. The Commission also asked the author to review relevant other studies and determine if their conclusions were still supported by more recent information. Finally, the Commission asked the author to examine the likelihood, the size, and duration of future disruptions, to determine the potential benefit of instituting a fuel reserve, and an analysis of the optimal size of the Strategic Fuel Reserve.

EXECUTIVE SUMMARY

Gasoline prices in California are more volatile than in the rest of the country. Volatility has increased since the introduction of CARB Phase II gasoline and has remained at high levels since 1999. The factors that lead to this volatility, including the “island” aspect of California, the unique specifications of the fuel, and others, are not seen to be abating in the near future. Gasoline price volatility is significantly greater than for jet and diesel fuel. Gasoline price volatility costs California consumers hundreds of millions dollars per year on the average.

Refinery disruptions, along with inadequate infrastructure, unique CARB Phase II gasoline specifications, and geographical & price-arbitrage isolation of California that make it difficult to offset a disruption, are the main causes of this price volatility. Refinery disruptions, which have occurred roughly once per month since 1996, are generally short-lived and small, with a number of notable long and severe disruptions. Retail price spikes, however, linger for up to six to eight weeks after the onset of the disruption. Disruptions have an immediate impact on wholesale prices, which get transmitted to retail prices with a lag, following an asymmetric pattern whereby the rise is faster than the fall. Disruptions are particularly troublesome in the summer blending season, when alternative gasoline supplies are not as readily available.

Price spikes due to a refinery disruption in either Northern or Southern California are transmitted throughout all of California, but not to other refining centers like the U.S. Gulf Coast or New York harbor. These spikes are more pronounced when levels of inventories are below normal.

Although this study addresses the economic impact on the state caused by refinery disruptions, and examines how a Strategic Reserve might lessen those impacts, it must be viewed in the overall context of the Stillwater Associates report on the Strategic Fuels Reserve (SFR). The innovative solutions introduced in that report propose to “connect” the State of California to external supply sources through a time-swap mechanism. Since this is a thoroughly new concept for a Strategic Reserve in the author’s experience, the traditional tools of economic analysis can only approximate its benefits to the California consumer. If one accepts the proposition that California is, indeed an “island” in terms of gasoline supply and if the proposed SFR can “link” California to the rest of the world, then one is led to conclude that the economic benefits to consumers of the time-and-price bridging power of the proposed SFR is an *order of magnitude* above the cost estimates contained in this ancillary study.

The potential benefit of implementing the full SFR as proposed by the Stillwater report accrues from avoiding part of the massive addition to consumer costs that would occur if refinery disruptions behave according to the frequency, size, and severity as evident in the 1996 to 2001 time period.

The amount of additional storage required to offset the rare, large refinery disruption is, on average, significantly less than that suggested by the California Legislature. Given the significantly favorable benefit to cost that is projected for the Stillwater SFR proposal, however, the minor cost benefits from optimizing SFR inventory levels are secondary.

The calculations used to derive the optimum size for the SFR have been based on historical data. They do not take into account the possibility of significant increases in gasoline imports, or supply disruptions that may impact the California gasoline markets after phase out of MTBE. In any event, the unique SFR time-swap mechanism, and its private sector tank features as recommended by Stillwater Associates create a dynamic element not usually found in government sponsored Strategic Reserves. The optimum size of the SFR must, therefore be evaluated in conjunction with its function as an open-access gateway for lower cost gasoline supply to the state.

In summary, the benefit of the SFR to the California consumer of avoiding price spikes is projected to be about $400 million per year against an annualized cost of $20 million. The benefits can rise to $700 million or fall to below $200 under a range of reasonable assumptions. Even at the low value, the benefits are an order of magnitude above the projected costs of the SFR. In addition, the SFR will likely provide additional benefits in the form of lower average gasoline prices on the order of $150 - 350 million per year.

1 GASOLINE PRICE VOLATILITY

Commodity industries are inherently unstable. For most commodities, the intrinsic value of the product to the end consumer is much higher than its production cost, but competitive pressure keeps market prices near the cash cost of the leading producer except for brief periods of physical shortage when prices will soar to whatever level the market will bear. Gasoline pricing in California is no exception to this principle, and below, some of the factors contributing to price volatility will be analyzed in more detail.

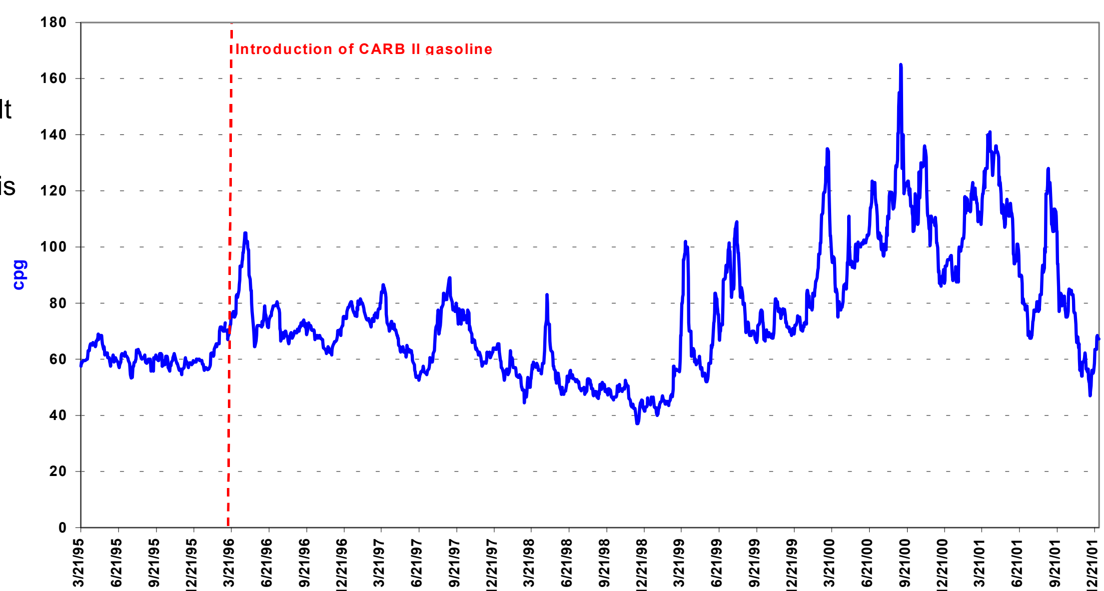
1.1 Current Supply

Gasoline prices in California are more volatile than in any other region of the United States. A cursory look at data for California suggests that the volatility of gasoline prices has increased over the last several years and most notably, since the introduction of CARB Phase II gasoline in March 1996. Figure 1-1 plots the daily spot price for RFG in Los Angeles since early 1995.

Figure 1-1 – LA Spot RFG Regular Gasoline Price[1]

It

is

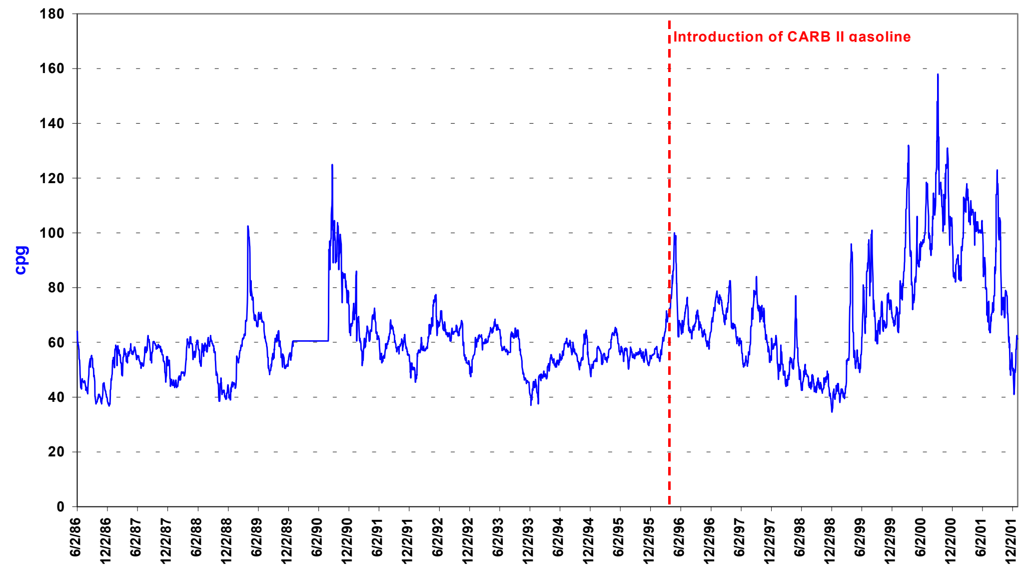


It is important to note that increased price volatility is a feature of the California landscape. The volatility has increased since 1986, as shown in Figure 1-2, which shows the trend in pricing for

[1] Source EIA and CEC data..

conventional gasoline, necessary to look back before 1995, when CARB specifications became effective.

Figure 1-2 – LA Spot Regular Conventional Gasoline



The report uses as a measure of volatility, the standard deviation of log changes in prices, $\log_e(p_t/p_{t-1})$. Table 1.1 presents the variance of returns and the appropriate F-values for the test of equality of the variances.

Table 1.1 – F-Values to Test Log Change Gasoline Prices

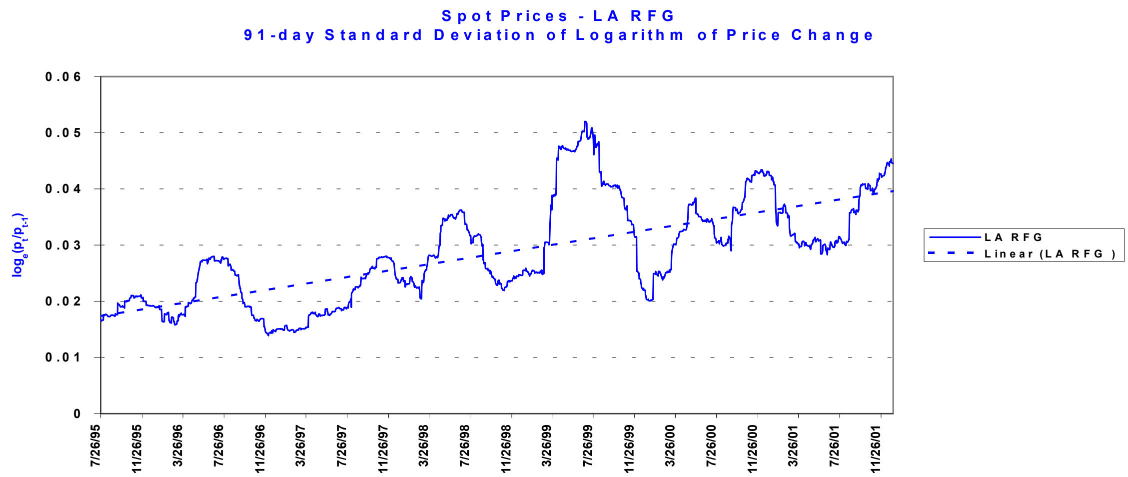
Year	Variance (x 1000)	$F=\sigma_1^2/\sigma_2^2$ (Year vs. Prior Year)	Difference in Variance Significant?
1995	3.14		
1996	4.50	1.43	Yes
1997	4.61	1.03	No
1998	8.41	1.82	Yes
1999	14.70	1.75	Yes
2000	13.20	1.11	No
2001	13.22	1.00	No

The statistical significance of the change in volatility, as measured by the variance (the square of the standard deviation) in log price changes over time, can be tested.[2] Notice in Table 1.1

[2] The test of significance for the difference between variances of two samples is the F-test. If the value of F calculated from the two years, $F=\sigma_1^2/\sigma_2^2 > F\varepsilon$ corresponding to n_1-1, n_2-1 degrees of freedom, then the hypotheses that the years are from the same population is rejected at the level ε. $\sigma_1^2=n_1s_1^2/(n_1-1)$ and

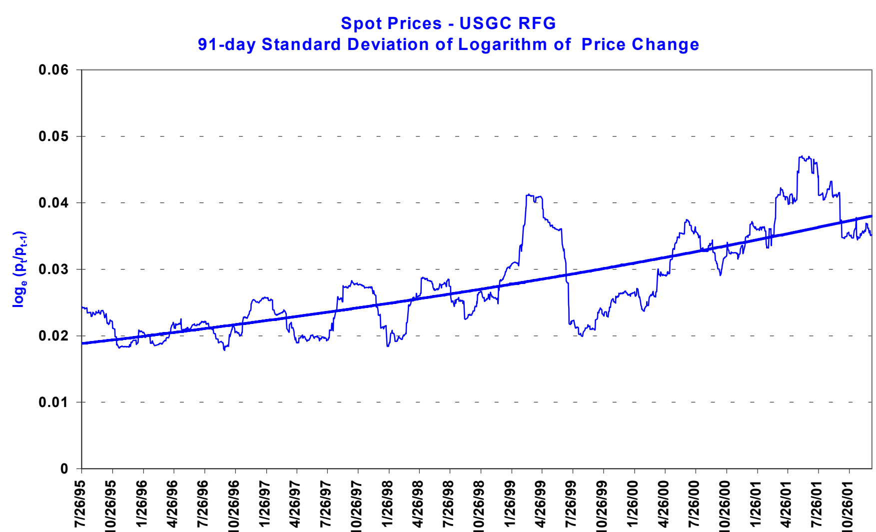
that the variance increases for 1996, 1998 and 1999. This Illustrates that one can reject the hypothesis that the variance in adjoining years is the same in 1997, 2000, and 2001[3]. Figure 1-3 show the steady increase in volatility for the Los Angeles reformulated gasoline market.

Figure 1-3 – Price Volatility of Los Angeles RFG



This increase in volatility is also evident in Gulf Coast prices, although not as significant as in California. (Figure 1-4)

Figure 1-4 – Price Volatility US Gulf Coast RFG



$\sigma_2^2 = n_2 s_2^2/(n_2-1)$ where s_1^2 and s_2^2 are the variances of the two years and n_1, n_2 are the number of observations in the two years. $F\varepsilon \sim 1.25$ for the .05 confidence level and the number of yearly observations.

California gasoline is also more volatile than New York RFG and is increasing relative to New York gasoline. (See Figure 1-5 and Table 1.2).

Figure 1-5 – Gas Price Volatility in California and New York

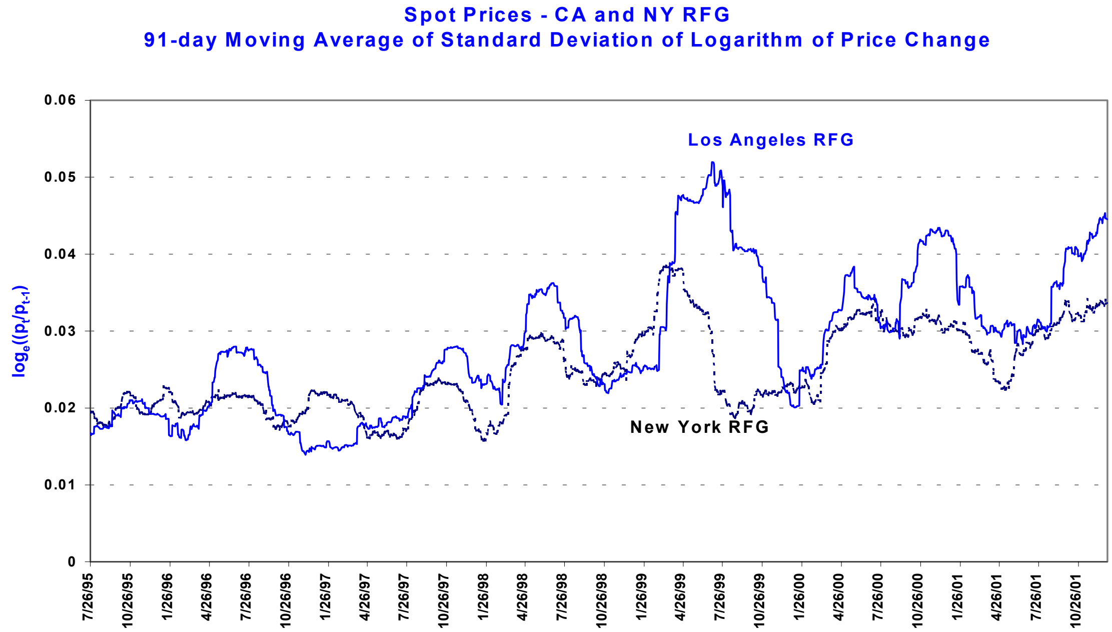


Table 1.2 - Comparison of Price Volatility: LA RFG vs. NY RFG

Year	LA RFG Variance (x 1000)	NY RFG Variance (x 1000)	LA Statistically Higher than NY?
1995	3.14	3.74	No
1996	4.50	4.35	No
1997	4.61	3.61	Yes
1998	8.41	7.25	No
1999	14.70	7.23	Yes
2000	13.20	9.43	Yes
2001	13.22	8.87	Yes

[3] The results do not change if one were to use as a measure of volatility, the standard deviation of prices.

Most of the volatility in gasoline prices is accounted for by the volatility in gasoline itself, and not its feedstock, crude oil. (See Figure 1-6 and Figure 1-7.)[4]

Figure 1-6 – RFG Less WTI

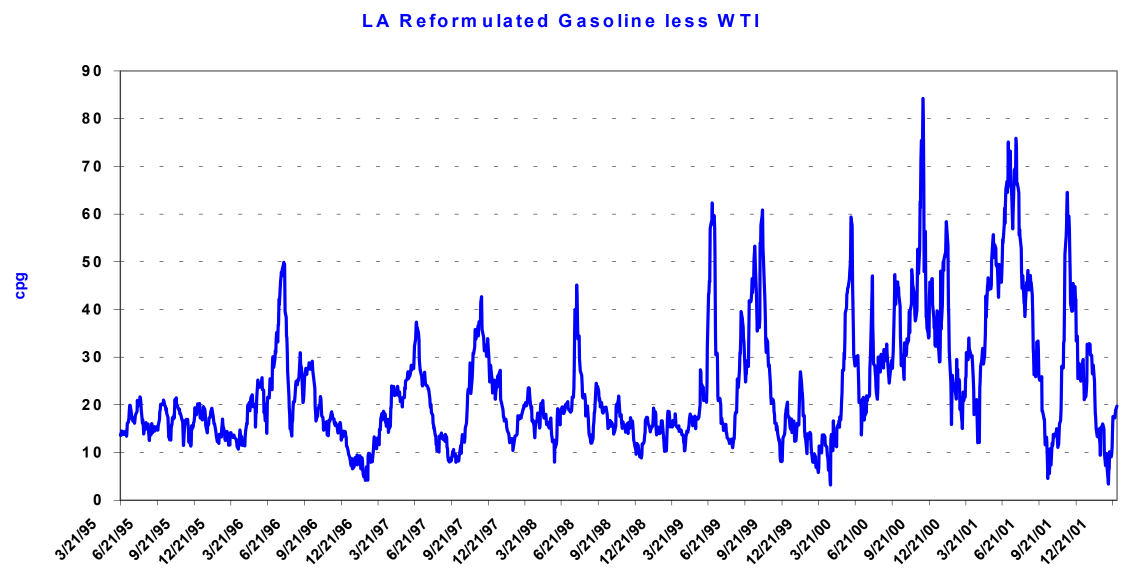
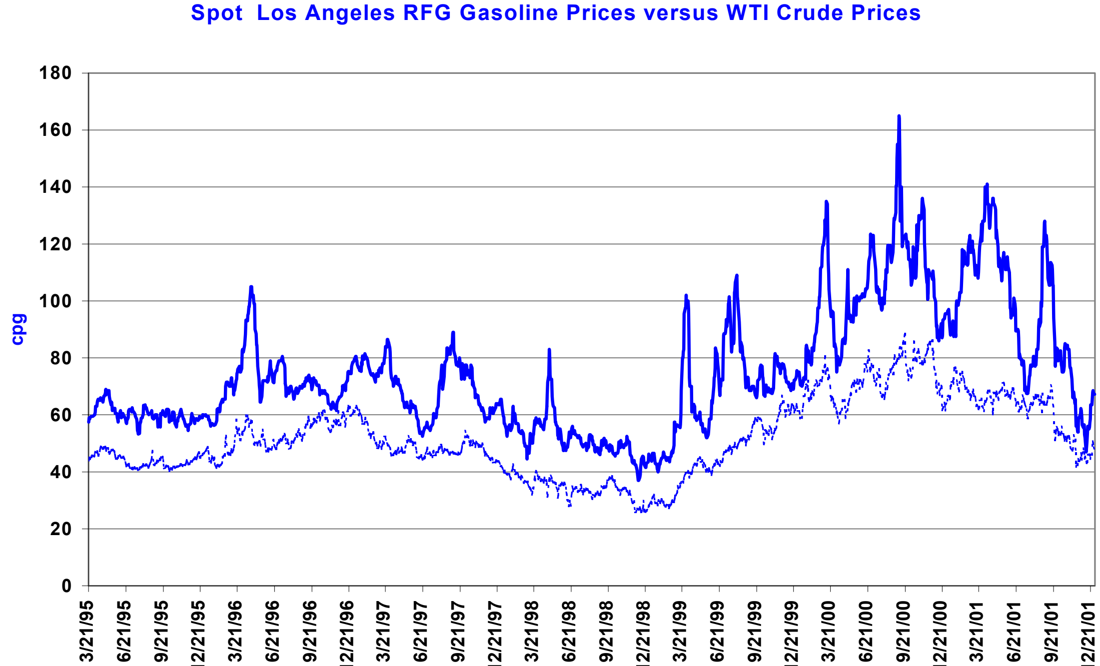


Figure 1-7 – Spot LA RFG versus WTI Crude



4 The conclusion does not change if ANS is used instead of WTI.

1.2 Price Volatility of Other Products

As shown in Table 1.3, diesel and jet fuel prices are less volatile than gasoline in California. Moreover, gasoline price volatility is greater than jet and diesel fuel in each and every year of the sample, although the volatility of RFG versus jet fuel is close in 1996 and 1997.

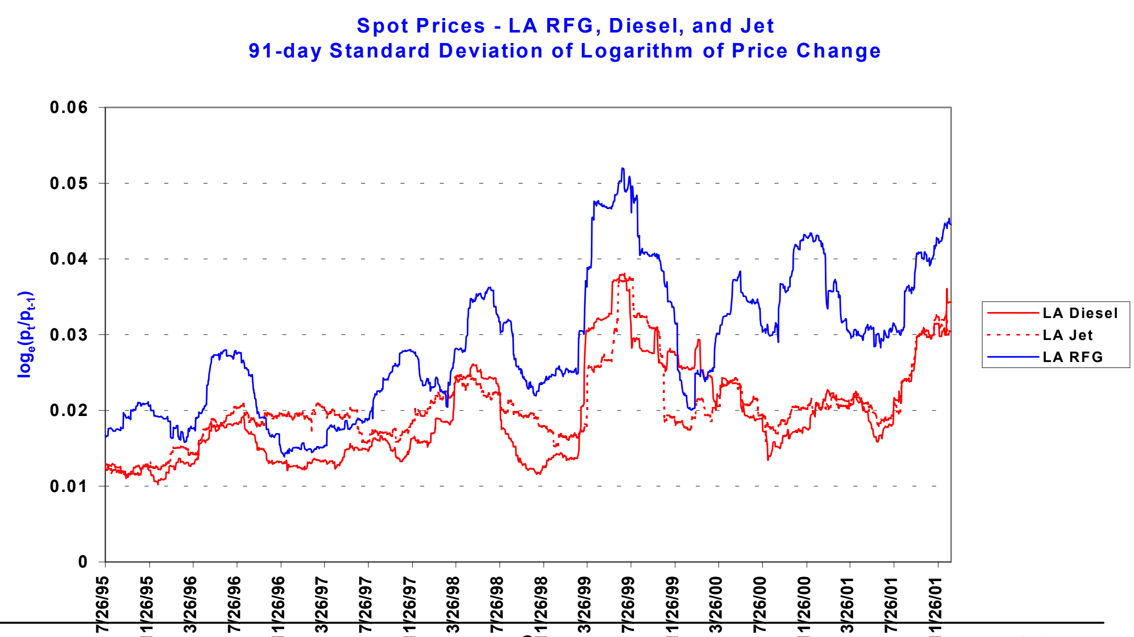
Table 1.3 – Variance in Log Change of RFG, Jet and Diesel Prices

	Variance (x 1000)			F-Value	
	RFG	Diesel	Jet	RFG vs. Diesel	RFG vs. Jet
1995	3.14	1.40	1.57	2.25*	2.00*
1996	4.50	2.41	3.45	1.87*	1.30*
1997	4.61	2.25	3.59	2.05*	1.29*
1998	8.41	3.57	4.09	2.36*	2.06*
1999	14.70	8.41	6.91	1.75*	2.13*
2000	13.20	4.19	4.45	3.15*	2.96*
2001	13.22	7.30	6.65	2.08*	2.00*
Total	**10.02**	**4.32**	**4.49**	**2.32***	**2.23***

*=Statistically significant.

Figure 1-8 shows the moving average of the standard deviation for daily spot prices for these products. RFG has a higher average standard deviation with more pronounced movements.

Figure 1-8 – Moving Average St. Dev. of RFG, Jet & Diesel Prices



The variance of all fuels has increased over time. In each year, gasoline is more volatile statistically than either diesel or jet. (See Table 1.3)

The lower volatility in jet fuel is due to a number of factors that are relevant to the issue of gasoline market isolation and lack of storage that have played a key role in the proposed SFR:

- Jet fuel is a readily fungible commodity, traded worldwide to the same specifications.
- There are no specific import barriers for jet fuel, i.e., there is no Unocal patent to be concerned about.
- There is a deep and liquid forward and futures market against which import shipments of jet fuel can be hedged.
- The airline consortium at LAX has ample storage to cushion disruptions.

In short, the jet fuel market in California has a de facto SFR due to the LAX consortium. It is sometimes argued that jet fuel is more elastic than gasoline. For Los Angeles, that may not be true. For one, Los Angeles is in chronic short supply. Also, although jet fuel is an international commodity, airlines have limited flexibility to “fill up” at other locations without altering flight patterns.

Diesel fuel volatility is less than gasoline for a number of reasons. Diesel fuel has more flexible specifications and is more fungible. Additionally, jet fuel and diesel are somewhat linked in the refinery system through substitute capacity: if increased diesel supply is needed, refiners can blend jet fuel into diesel.

1.3 Reasons for Increased Volatility

A number of authors have commented on the reasons for the increased price volatility in gasoline[5]. These reasons include:

- *Tight capacity utilization in California refineries.* One source of increased supply during a refinery disruption is increased output from underutilized local refineries to make up for the shortfall. Since California refiners have been running at over 95% of nameplate

[5]Borenstein (2000), Stillwater Associates (2002), and Verleger (2000), for example.

capacity, significant incremental gasoline supply is not available from increased output to moderate a price spike.

- *Low inventories in California versus the rest of the country*. Commodity prices such as gasoline are highly sensitive to inventories, so relatively low workable inventories, on the order of 5 days (finished gasoline at refineries) poses an extra burden on California gasoline producers.

- *Geographic isolation of California.* After drawing on inventories, California refineries would have to replenish disrupted supplies from imported finished gasoline or blending components. The time delay in obtaining these alternative sources, either from the Gulf Coast or foreign sources, exacerbates the price volatility.

- *Difficulty in making California grade gasoline.* California Phase II gasoline, introduced in March 1996, is more difficult to make and more costly than gasoline in other parts of the country[6] as well as gasoline in California prior to 1996. This difficulty reduces flexibility during disruptions.

- *Blending around the Unocal patent*. The Unocal patent requires additional fees for these refiners who chose to license with Unocal. Major refiners, so far, have chosen to blend around the patent, which causes additional constraints on making CARB II gasoline.

- *Inelastic gasoline demand.* In addition to an inelastic gasoline supply, as determined by many of the items listed above, the demand for gasoline is highly inelastic (non-responsive to price). Consumers are not able to quickly bring down a price spike by changing their usage of gasoline. In addition, the lagged pass-through effect does not allow the consumer to observe the price effect of disruptions immediately.

- Lack of Access and Import Infrastructure Constraints.

[6] Historically, there are only a limited number of refineries throughout the world that have made California Phase II gasoline and supplied it to this market.

Most observers believe that there are no signs that this volatility will decrease in the near future.

1.4 Conclusions about California's Price Volatility

The analysis of California's gasoline pricing yields the following conclusions. Gasoline price volatility:

- Is higher than in the rest of the country.
- Has increased since the introduction of CARB II
- Is usually higher than in the Gulf Coast and New York
- Has increased relative to the Gulf Coast and New York
- Has increased over time, but was relatively unchanged from 1999 to 2001.
- Has been higher than either jet and diesel fuel, which are approximately equal in volatility

2 CHARACTERIZATION OF REFINERY DISRUPTIONS

Refinery disruptions are unplanned events involving a complete or partial loss of production capacity. Of particular interest for this study are disruptions that affect the core gasoline producing units of a refinery such as distillation, coking and cracking.

2.1 Data

In a study of potential shocks to California's supply of transportation fuels that could result from the 2001 electricity crisis, the Department of Energy's Energy Information Administration (EIA) conducted a study of refinery disruptions during the period from early 1996 through early 2001[7]. The underlying data, derived from third party sources, were not independently corroborated with the refiners involved. Only a few of the incidents were reported in the general public press.

The EIA identified 65 disruptions from OPIS reports. Only 49 of these contained information as to size (in thousand of barrels per day gasoline impact) and duration (in weeks) of the disruptions. A cursory look at price data suggests an additional 15 periods of severe gasoline price volatility not identified with a refinery disruption occurred over the same period. Some of these may have been refinery turnarounds or related to crude oil movements. Only the 49 identified parametrically were used in this report.

The author has adjusted the EIA data for:

- Minor errors in the data
- Removal of refinery disruptions that were classified as 'rumor' but not borne out by the data[8]
- Improved alignment of dates to correspond to impacts,

A summary of the data is given in Attachment A.

According to the DOE data, refinery disruptions with measurable impact and duration occurred roughly monthly over the five-year sample period. The disruptions averaged 21 mbd and lasted

[7] Energy Information Administration (2001).

[8] This will be analyzed as a sensitivity in Section 6.

2.7 weeks on average. The total lost production to disruptions (referred to here as "disrupted barrels") averaged 393 mb.

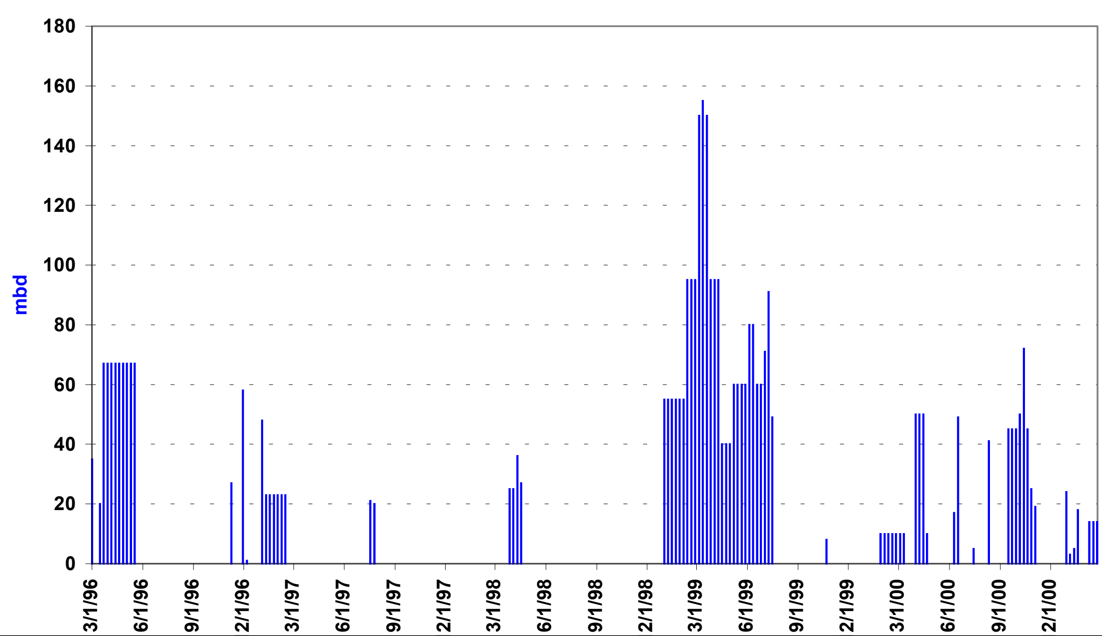
Table 2.1 – Summary Statistics of Refinery Disruptions

	Average	Median	Standard Deviation	Range
Weekly Size of Disruption (mbd)	21	19	15	1 - 67
Duration (weeks)	2.7	1.0	3.9	1 - 11
Number of Days Between Disruptions	38	7	64	0 - 259
Total Disrupted Barrels (mb)	393	144	1280	14 - 6160

2.2 Frequency of Refinery Disruptions

Each bar in Figure 2-1 represents disruptions on a weekly basis. If a disruption, for example, is 20 mbd for two weeks, it would appear as two side-by-side bars of 20 mbd each. If a disruption of 20 mbd in one refinery occurs during the same week as a 30 mbd disruption in another refinery, it would be shown as a bar of 50 mbd. Notice the concentration of disruptions in spring 1999 and to a lesser extent in late 2000.

Figure 2-1 – Weekly Refinery Disruptions

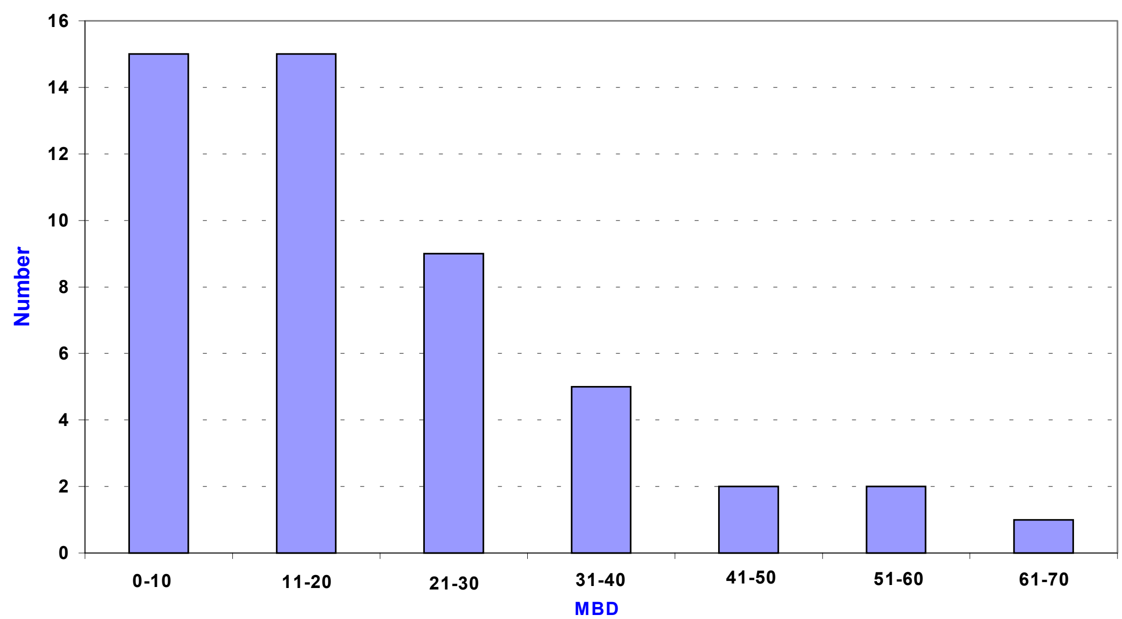


California refineries experienced eight disruptions in 1996 after the introduction of CARB Phase II gasoline. The frequency of occurrence abated in 1997 and 1998, falling by 60% over the 1996 rate. The frequency of disruptions intensified in 1999 and 2000 before falling again in 2001. The 1999 episodes were particularly painful due to the duration of an average disruption (5.7 weeks) more than twice the average (2.7 weeks) over the sample period.

2.3 Size of Disruptions

Refinery disruptions in California averaged 20.8 mbd with standard deviation 2.7 mbd. They ranged in size from 1 to 67 mbd. The size distribution given in Figure 2-2 is skewed to the right with thirty of the refinery disruptions below the average in size. Only five had more than a 30 mbd impact.

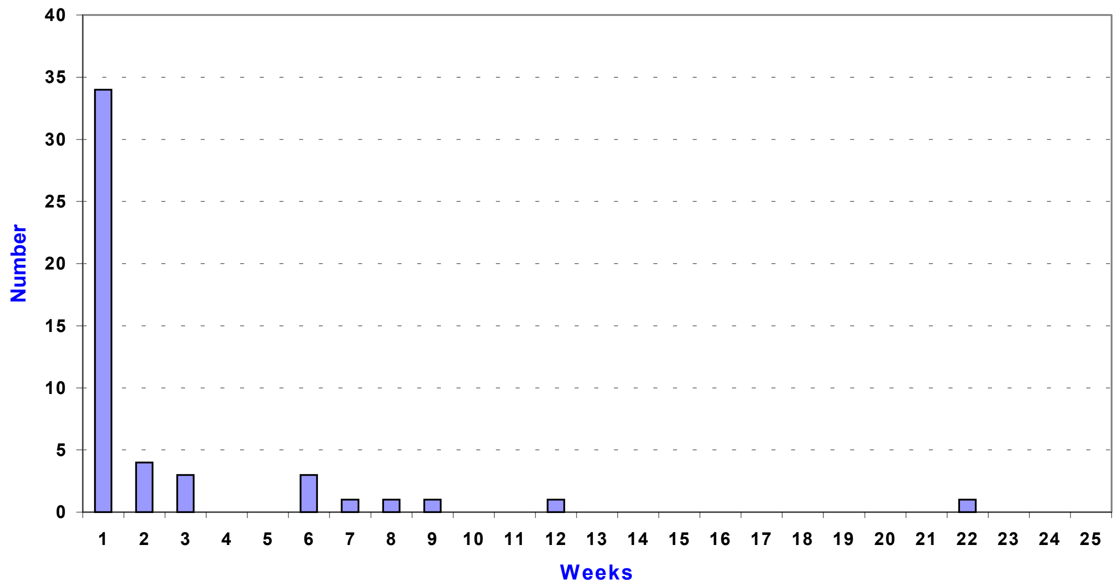
Figure 2-2 – Size Distribution of California Refinery Disruptions



2.4 Duration and Coincidence of Disruptions

The typical refinery disruption was short-lived. The average length of a refinery outage was 2.7 weeks with a standard deviation of 3.9. The modal and median value was 1 week, which represented 34 of the 49 disruptions. Figure 2-3 shows a cluster of disruption lengths from 1 to 3 weeks, another from 6 to 9 weeks, and finally two outliers at 12 and 22 weeks.

Figure 2-3 – Duration of California Refinery Disruptions



Another feature of the refinery disruptions is that they can occur simultaneously. During the 263-week sample, disruptions occurred at four refineries at the same time twice, three refineries at the same time seven times, and there were 221 weeks where there were two refinery outages simultaneously. The distribution of disruptions by the number of refineries that were disrupted during a given week is given in Figure 2-4 and Table 2.2.

Figure 2-4 – Number of Refineries Experiencing Disruptions

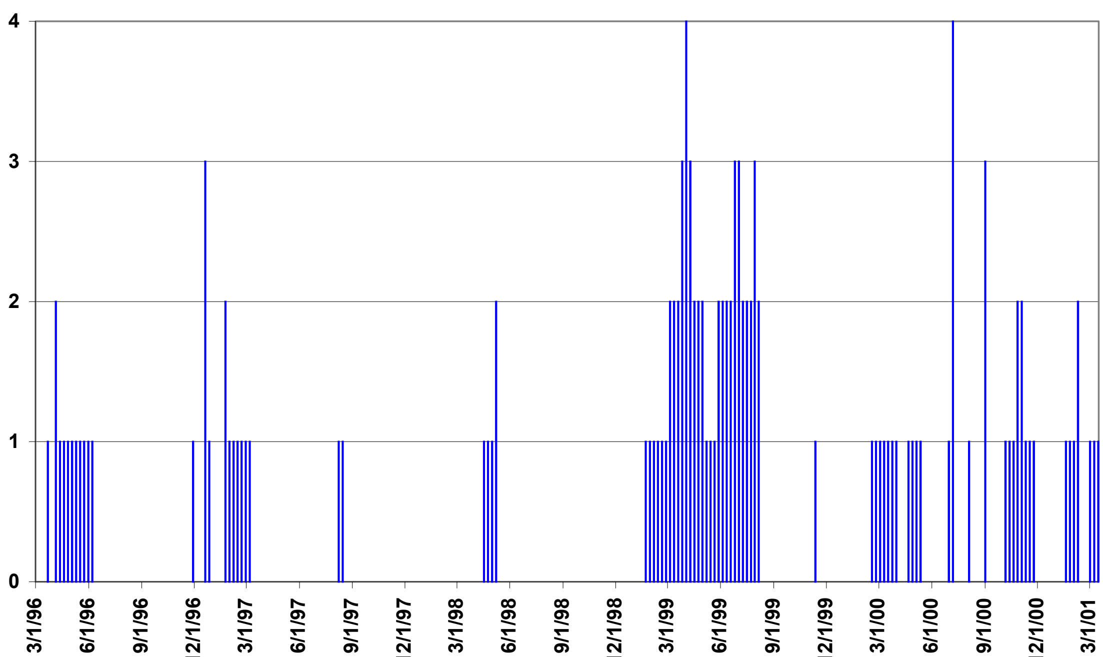


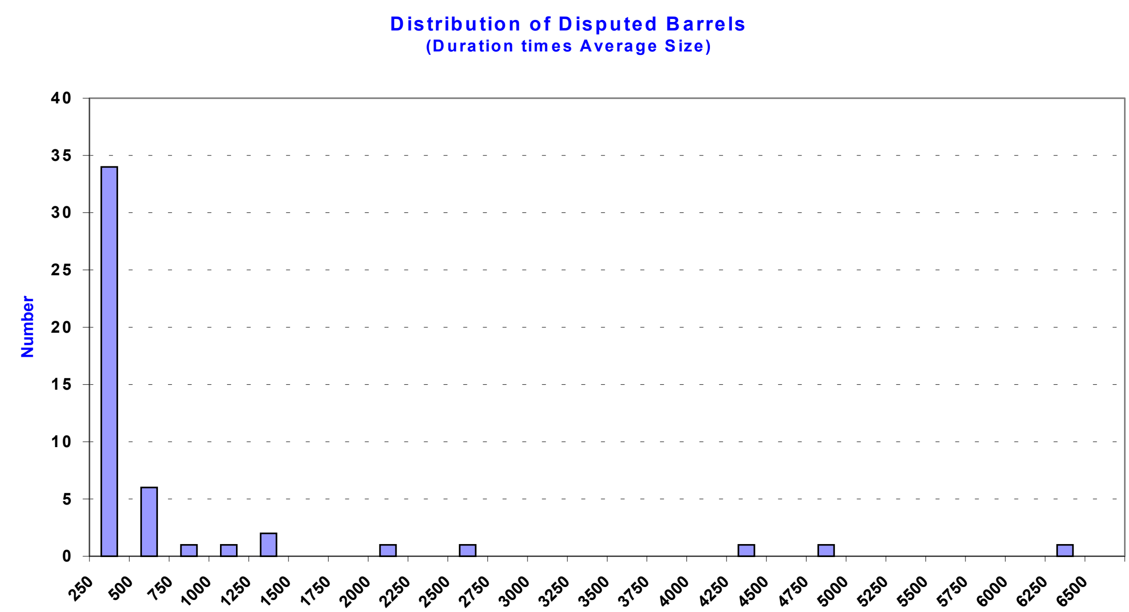
Table 2.2 – Number of Weeks with Disrupted Refineries

Number of Disrupted Refineries During a Week	Number of Weeks	%
0	176	66.9%
1	58	22.1%
2	20	7.6%
3	7	2.7%
4	2	0.8%
>4	0	0.0%
Total	**263**	**100.0%**

2.5 Size of Total Disruptions

The calculation of size times duration of disruptions yields total disrupted barrels. This distribution is given in Figure 2-5.

Figure 2-5 – Distribution of Size of Disruption times Duration



Notice the large number of disruptions that are 250 MB and under, a small cluster between 500 and 1500 MB, and then five outliers with total disrupted barrels in excess of 2 million barrels. Three of the five outliers exceed 4 million barrels.

2.6 Disruptions over Time

It is interesting to note that the frequency, size, and duration of disruptions vary considerably over the years. The highest frequency year, 2000, was mild in comparison to 1999, which had significantly greater average size and duration than 2000. The year 2001 (through March) had the lowest frequency, duration, and size of all the years. (Table 2.3).

Table 2.3 – Frequency, Size and Duration of Disruptions by Year

Year	Number of Weeks Considered	Frequency		Size	Duration
		Number of Disruptions	Frequency*	mbd	Weeks
1996	41	8	.018	25.9	2.1
1997	52	4	.007	22.3	2.3
1998	52	4	.007	22.0	1.3
1999	52	10	.017	27.2	5.7
2000	53	16	.027	17.9	1.9
2001	10	7	.063	10.0	1.3
Total	**260**	**49**	**.017**	**20.8**	**2.7**

*Note: There were 11 refineries in the survey, so the frequency is calculated as disruptions divided by refineries plus weeks.

Table 2.4 – Refinery Disruption Size and Length over Time

	Weekly Average Size		Disruption Length	
	Average	Standard Deviation	Average	Standard Deviation
1996 (partial)	26	2.1	21.4	2.8
1997	22	2.3	2.2	2.5
1998	22.0	1.3	12.4	0.5
1999	27.2	5.7	17.7	6.8
2000	18	2	13.1	1.9
2001 (partial)	10.2	1	7.7	0.8

The data do not support the hypothesis that large disruptions last for long periods. The average size and duration of refinery disruptions are not highly correlated (R^2=.28 in Figure 2-6). This suggests that the one can treat duration and size as being independent events. The duration and total size of disruption are, however, highly correlated (Figure 2-7).

Figure 2-6 – Refinery Disruptions: Impact vs. Duration

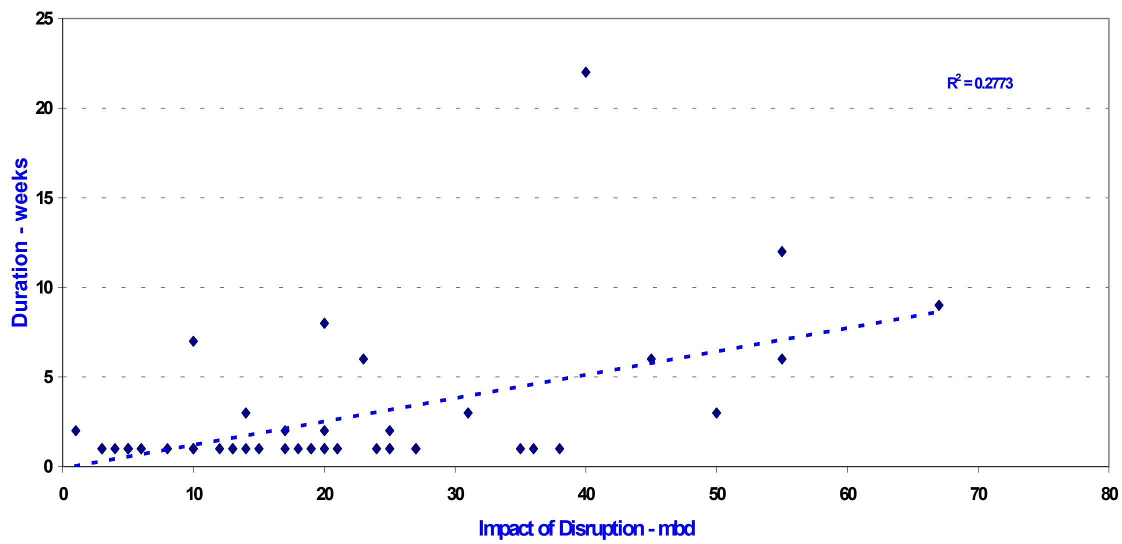
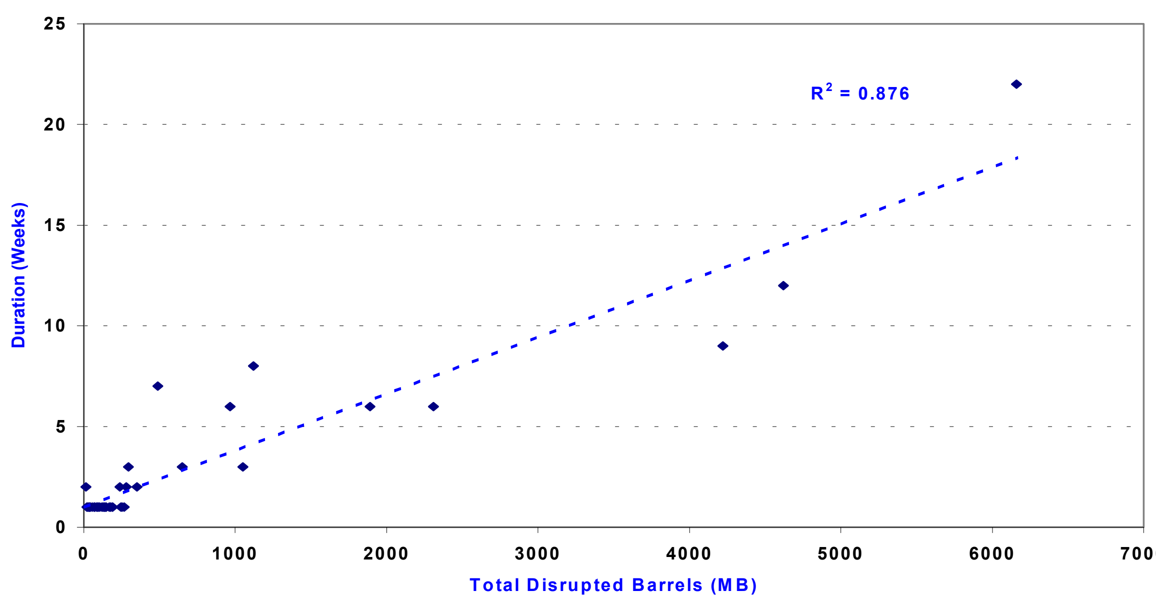


Figure 2-7 – Refinery Disruptions: Disrupted Barrels vs. Duration



2.7 Seasonal Timing of Refinery Disruptions

The summer gasoline-blending season extends approximately from mid-March to November 1 in Northern California and from the end of February to November 1 in Southern California, or about 65% of the year. The number of disruptions that occurred in the summer blending season was also 65% of the total. The total barrels disrupted, however, occurred disproportionately in the summer blending season (74% of the total). (See Figure 2-5)

Table 2.5 – Distribution of Disruptions by Blending Season

	Summer Blending	Winter Blending	Summer % of Total	Winter % of Total
Disruptions	32	17	65%	35%
Disrupted Barrels (impact times duration)	21,014 mb	7,413 mb	74%	26%
Length of Blending Season	North: 33 weeks South: 35 weeks	North: 19 weeks South: 17 weeks	65%	35%
Barrels Produced in Season			67%	33%

2.8 Classification of Refinery Disruptions

It is useful to categorize refinery disruptions by average size versus average length. Choosing rough breaks in the data, refinery disruptions are broken down by region, size, and duration in Table 2.6. The preponderance of disruptions is short-lived and small.

Table 2.6 – Classification of Refinery Disruptions by Region, Duration & Size

	Southern California			Northern California			All Refineries			
	Short	Medium	Long	Short	Medium	Long	Short	Medium	Long	Total
Large >30 mbd	2	1	2	1	1	3	3	2	5	10
Medium 10-30mbd	13	1	0	5	3	2	18	4	2	24
Small <10 mbd	9	1	1	4	0	0	13	1	1	15
Total	**24**	**3**	**3**	**10**	**4**	**5**	**34**	**7**	**8**	**49**

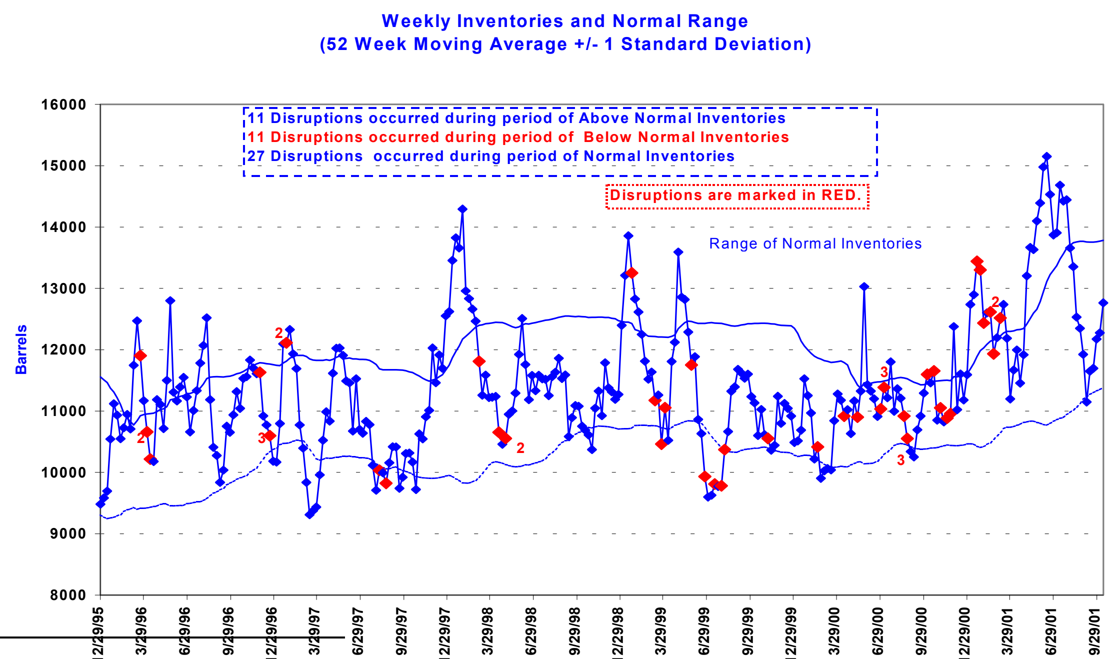
Short = 1 week or less; Medium = 2 to 3 weeks; Long > 3 weeks

2.9 The Role of Inventories

In petroleum markets, producers (as well as consumers and third parties) hold inventories to avoid stock depletions, minimize the costs of adjusting production over time, and optimize product delivery. Since inventories can reduce production and marketing costs as demand conditions change, they should reduce short-run price fluctuations. Since inventories cannot be prudently reduced below some minimal level, "… price volatility tends to be greatest during periods when inventories are low."[9]

The obvious relationship is widely used by itself to model price movements. The finance literature, however, specifies a different relationship. The spread between spot and futures prices and the level of inventories follow what is known as the "Working" curve, after Holbert Working who first derived the relationship[10]. If one were to view the spread as the extent of backwardation in product markets, then when inventories are relatively low, the spread is greatest (steepest backwardation). We are more likely to draw a close relationship of inventories and the spread between spot and futures prices, than we are with inventories and the level of prices. We are, however, able to perform a qualitative analysis of the relationship of spot prices with normal inventories. Normal inventories here are defined as the range plus and minus one standard deviation of a 52-week moving average of inventories.[11]

Figure 2-8 – Inventory Levels during Disruptions



[9] Pindyck (2001) p.4.

[10] See for example Williams (1986) and Verleger (1993).

[11] The conclusions in this section remain the same if seasonality in inventories is considered.

Figure 2-8 shows the level of refinery inventories (finished gasoline and blendstocks) on the normal range of inventories. It is not surprising that there is an equally likely chance to have a refinery outage (a disruption, but not necessarily a price spike) when inventories are below normal as above normal (11 disruptions occurred when inventories were below normal, 11 disruptions occurred during periods of above normal inventories, and 27 during periods of normal inventories.) What is different is that during period of below normal inventories, the price response is magnified since refineries cannot draw on "excess" inventories to ameliorate the outage.

Figure 2-9 – Spot Gasoline Prices with Indicated State of Inventories

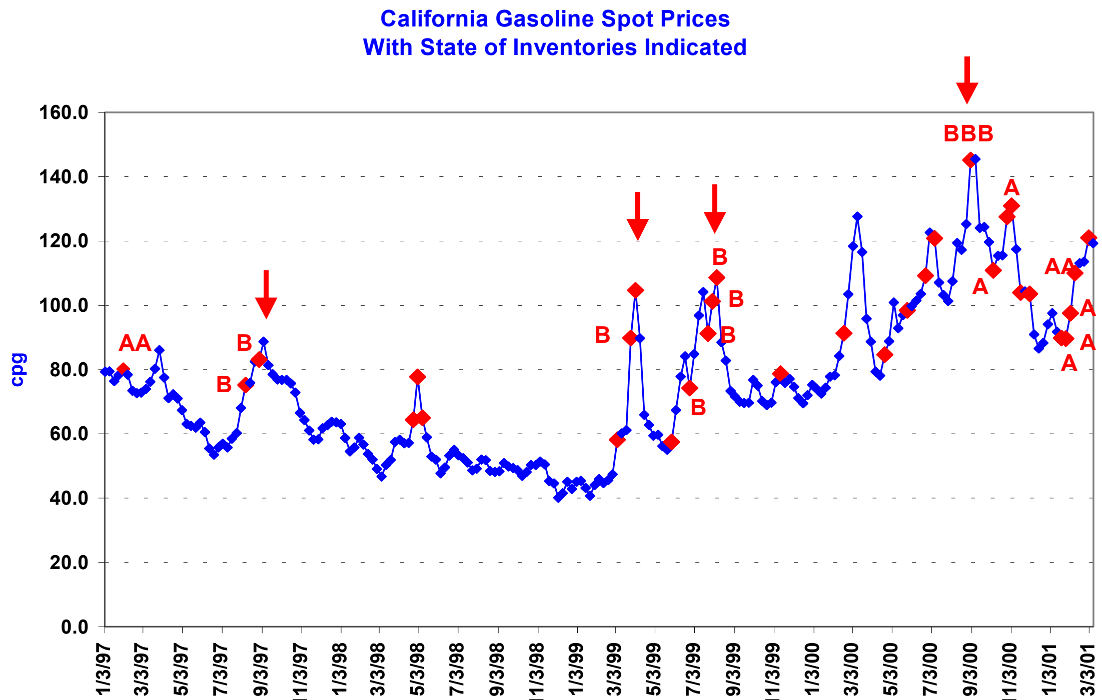


Figure 2-9 illustrates the pattern of California Spot Gasoline Prices with an indication of the state of inventories at the time of disruption. The red diamonds indicate refinery disruptions. An "A" indicates a period of above normal inventories, "B" below normal inventories, and no label indicates normal inventories. [Multiple letters indicate multiple disruptions.] The price spikes are more pronounced whenever inventories are below normal. It appears that when inventories are edging toward the low end of the range, and the market is uncertain about the length of the disruption, prices respond to the danger in inventories falling below the acceptable levels.

2.10 Conclusions: Characterization of Disruptions

In summary, refinery disruptions in California:

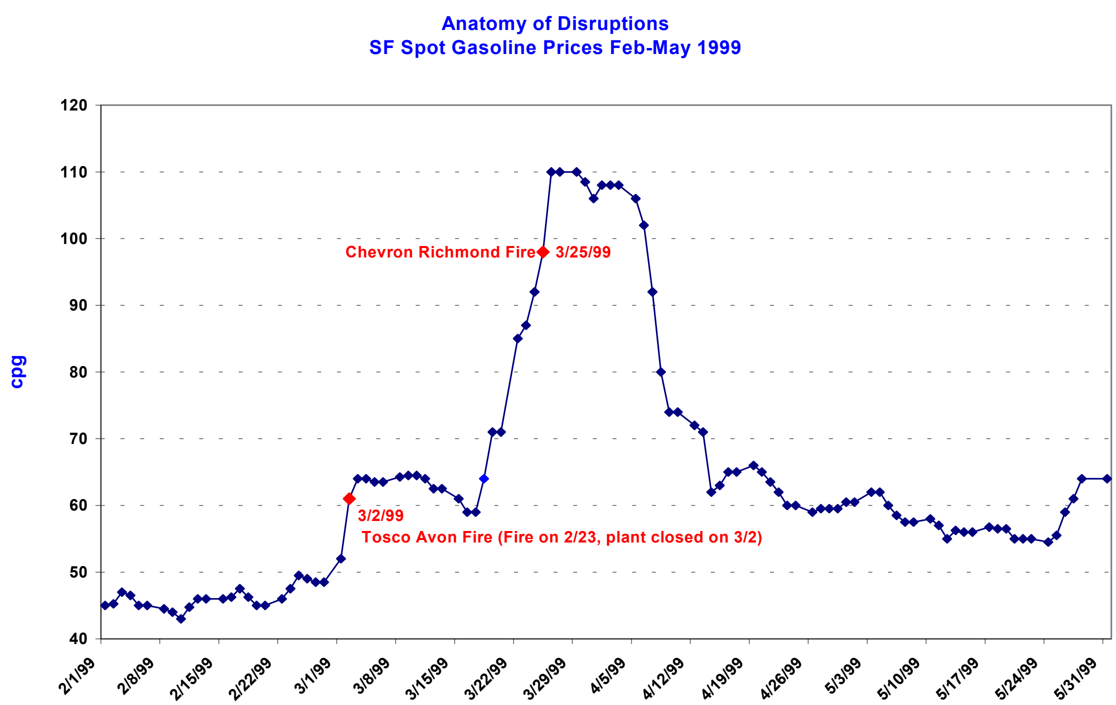
- Have occurred once a month on average since 1996
- Have caused average production loss per incidence of 21 mbd with several larger disruptions
- Are generally short-lived with an average duration of 2.7 weeks, although some can last 6 to 8 weeks
- The short-lived disruptions generally also tend to involve less loss of capacity, while long ones tend to be large
- Occur in both summer and winter blending seasons in proportion to the time, but have a more pronounced price effect during the summer blending season.

3 ANATOMY OF SPECIFIC REFINERY DISRUPTIONS

In order to illustrate the points made in Sections 1 and 2, a more detailed examination of specific refinery disruptions is instructive. (Refineries will be referred to by their name at the time of the disruption.) Refinery disruptions do not always have an immediate impact on prices. Figure 3-1 shows spot price movements in San Francisco in early-1999. This was a period of severe unplanned disruptions in the Bay Area refineries. The February 23, 1999 Tosco crude unit fire did not have an impact on price immediately, but on March 2, 1999 when it was announced that Contra Costa County would shut the refinery down for the longer term, the gasoline prices spiked up. A later disruption at Chevron's Richmond refinery caused spot prices to surge once again.

It is interesting to note the spot price behavior after the Tosco Avon fire. After an initial run up, spot prices fell off gradually, until it became clear that the refinery would be disrupted for a sustained period. The refinery was out for over five months.

Figure 3-1 – San Francisco Spot Price Movements in Early 1999



This price responsiveness is also seen later in 1999 (Figure 3-2). A non-refinery disruption, the Olympic, Washington Liquid Fuels Pipeline ruptured and caught fire on June 10, 1999. Spot prices responded immediately. In July, a Chevron Richmond refinery explosion and a mishap at Mobil's Torrance refinery caused two more spikes.

Figure 3-2 – San Francisco Spot Price Movements May – August 1999

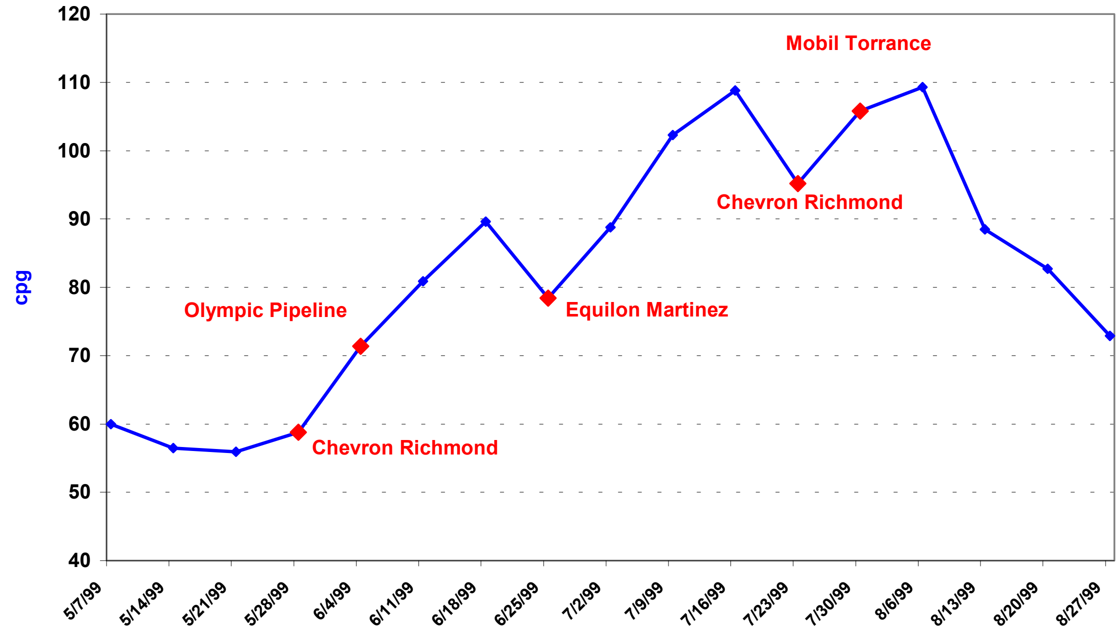
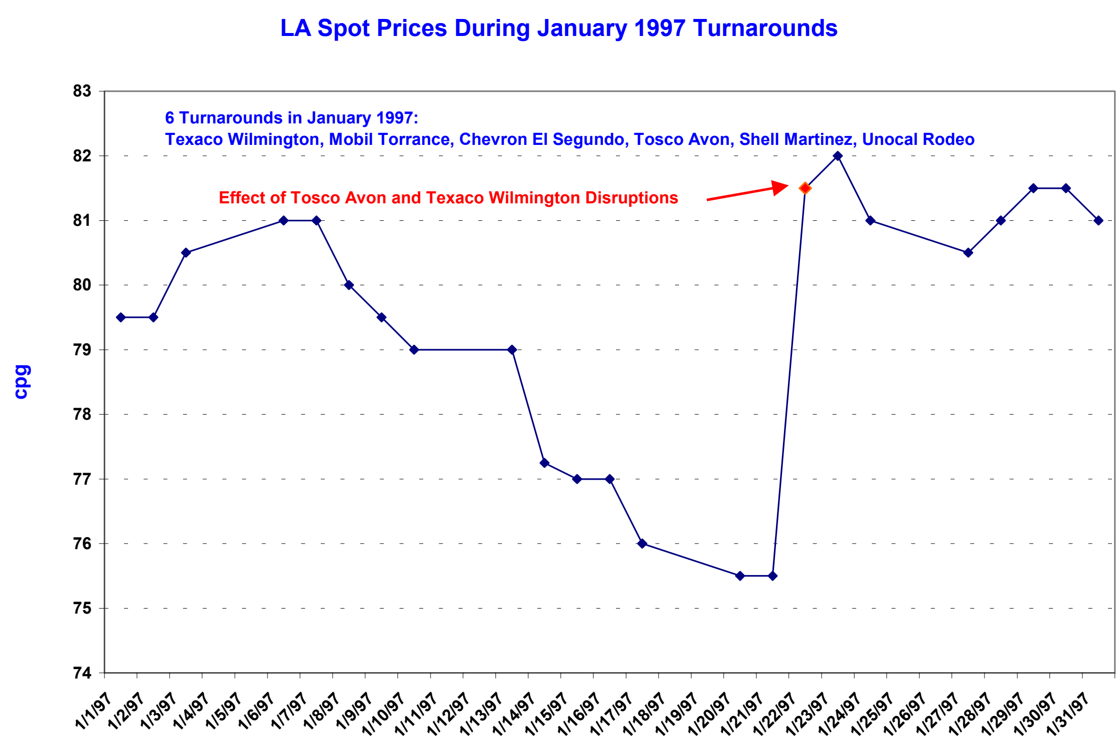


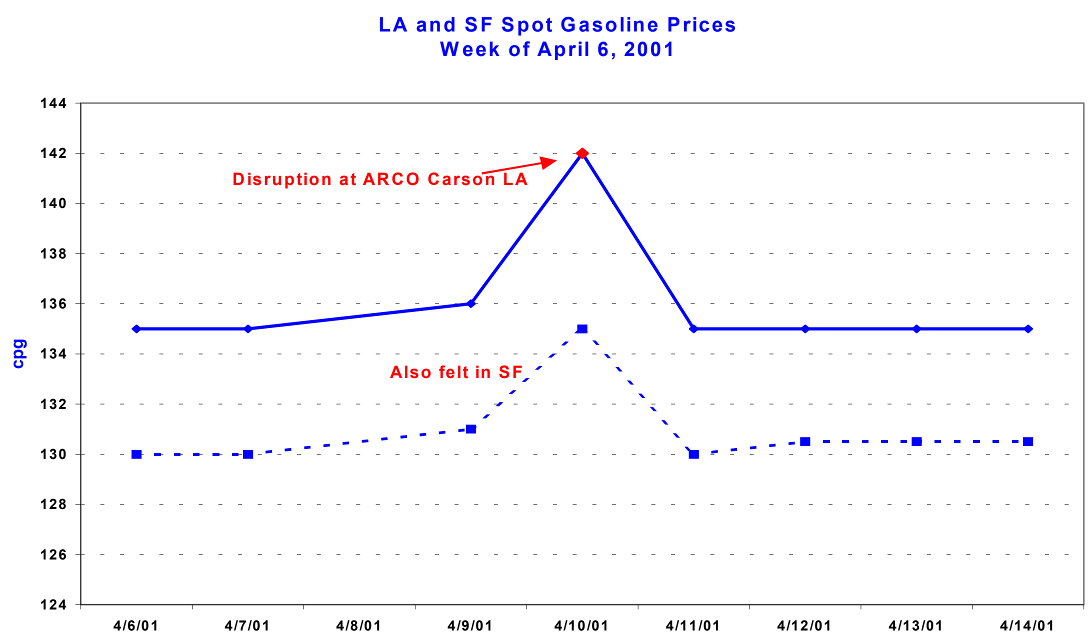
Figure 3-3 – Price Effect of Turnarounds and Disruptions



Planned turnarounds do not affect prices unless they happen to coincide with a disruption. Refiners plan their turnarounds in the "off season" and take precautions to have enough alternative sources of gasoline. There, of course, is still the chance that another refinery could have a disruption during a heavy turn-around season. This occurred in January 1997. Figure 3-3 shows Los Angeles Spot Gasoline prices. Texaco Wilmington. Mobil Torrance, and Chevron El Segundo planned turnarounds in the south, while Tosco Avon, Shell Martinez, and Unocal Rodeo scheduled turnarounds in the north. Prices actually fell through that period until both Texaco Wilmington and Tosco Avon had disruptions.

A disruption in either part of California can affect all of California. The California gasoline system, while disconnected to the rest of the US, is more linked between North and South. While there is no pipeline flow that moves gasoline between North and South, there is a large volume of gasoline that flows from the Bay Area to Los Angeles by barges and through inter-refinery exchanges. As such, a price impact in one part of the state will affect the other part of the state. This is clearly shown in Figure 3-4.

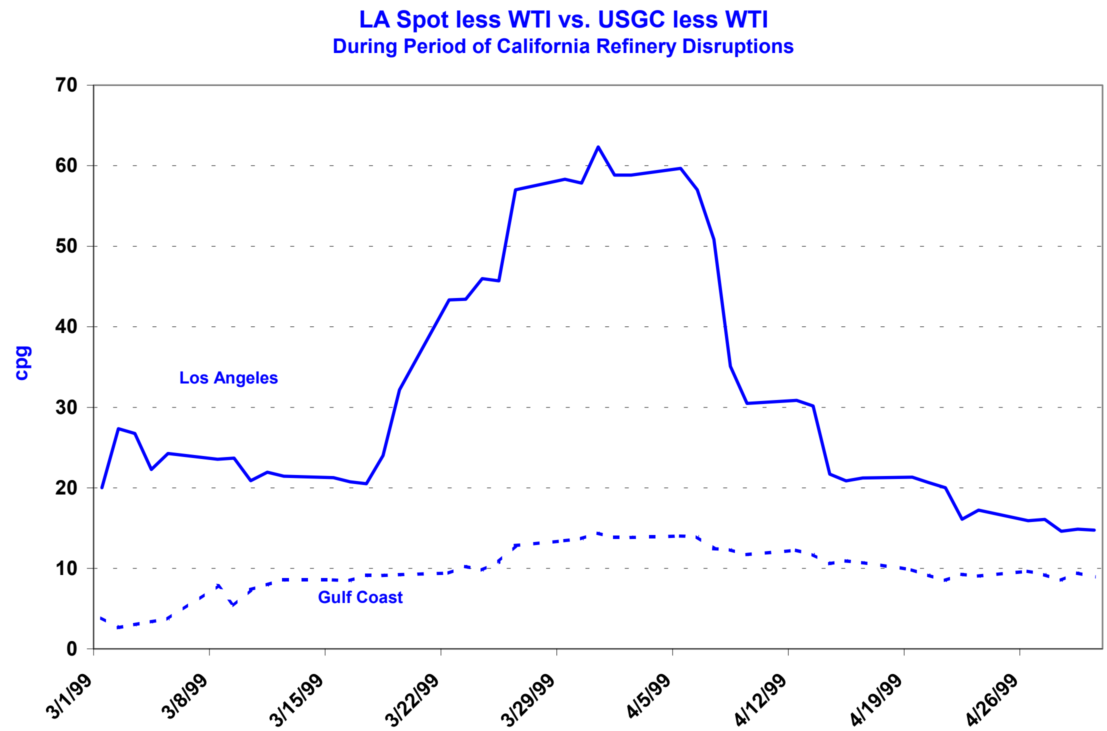
Figure 3-4 – Transmission of Price Spikes throughout California



While price spikes get transmitted throughout California, they do not get transmitted to the Gulf Coast[12], as shown in Figure 3-5. Both price curves have the effect of crude price movements excluded from them. During mid-1999, a number of refinery disruptions, primarily in Northern California, caused a sharp spike in gasoline spot prices. The impact on the Gulf Coast was minimal.

[12] It is possible, and likely, that price spikes get transmitted to neighboring states that rely on California refineries.

Figure 3-5 – Non-Transmission of Price Spikes Outside California



Finally, not all disruptions lead to price spikes. In early 1999 there were three refinery disruptions in Northern California, Exxon Benicia, Tosco Avon, and Chevron Richmond. Figure 3-6 shows price movements in early 1999 along with three horizontal bars that depict the duration of three refinery disruptions: Exxon Benicia, Tosco Avon, and Chevron Richmond. The figure indicates prices did not spike upward during the Exxon Benicia 12 week disruption until the Tosco Martinez refinery disruption occurred. This was largely due to the large amount of inventories on hand at the time. The price spike abated after the Exxon Benicia refinery resumed normal operations, only to spike again when the Chevron Richmond outage occurred. Price spikes in this period only occurred when there were two refineries went out at the same time.

While most spot price rises translate into retail prices increase with a lag, not all price spikes get automatically transmitted. Figure 3-7 shows price behavior during a disruption episode in early Fall 2000. Spot prices rose from $1.09 per gallon in early October to $1.35 a gallon by early November on the basis of outages at the Mobil Torrance and Arco Carson refineries. One of the disruptions occurred during planned maintenance. This period was at the tail end of the summer driving season and right before the winter blending season. Retail prices did not rise, but fell by approximately 3 cpg over the five-week period that spot prices were increasing.

Figure 3-6 – Three Disruptions in Early 1999

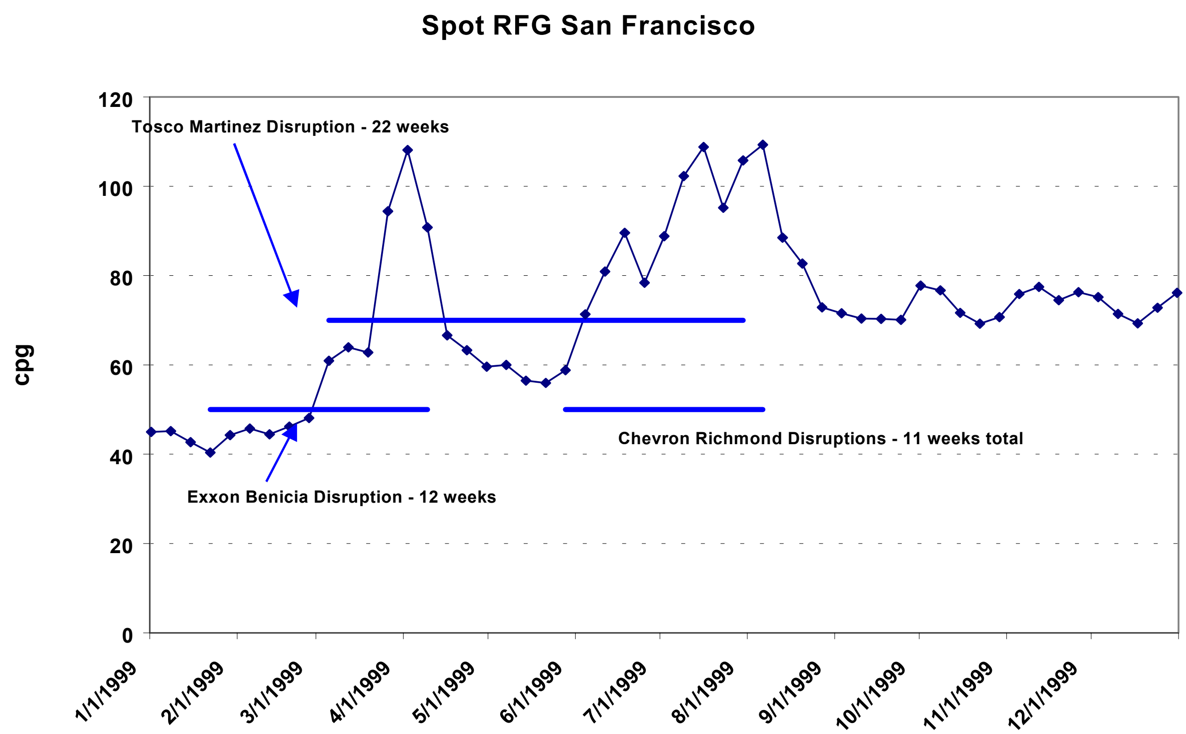
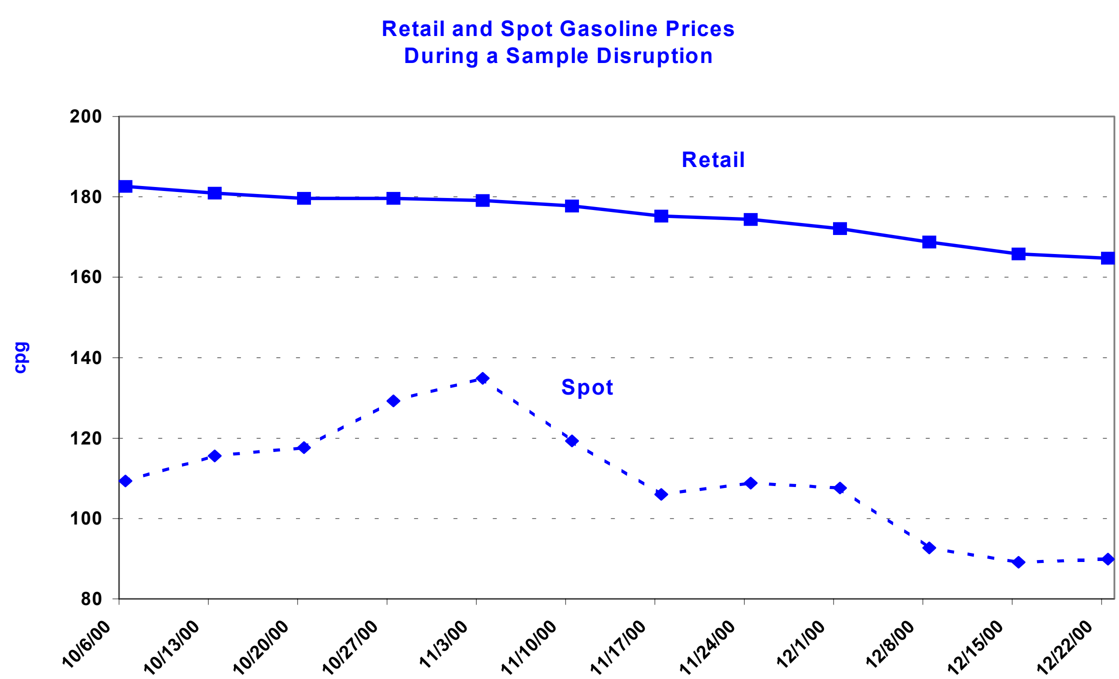
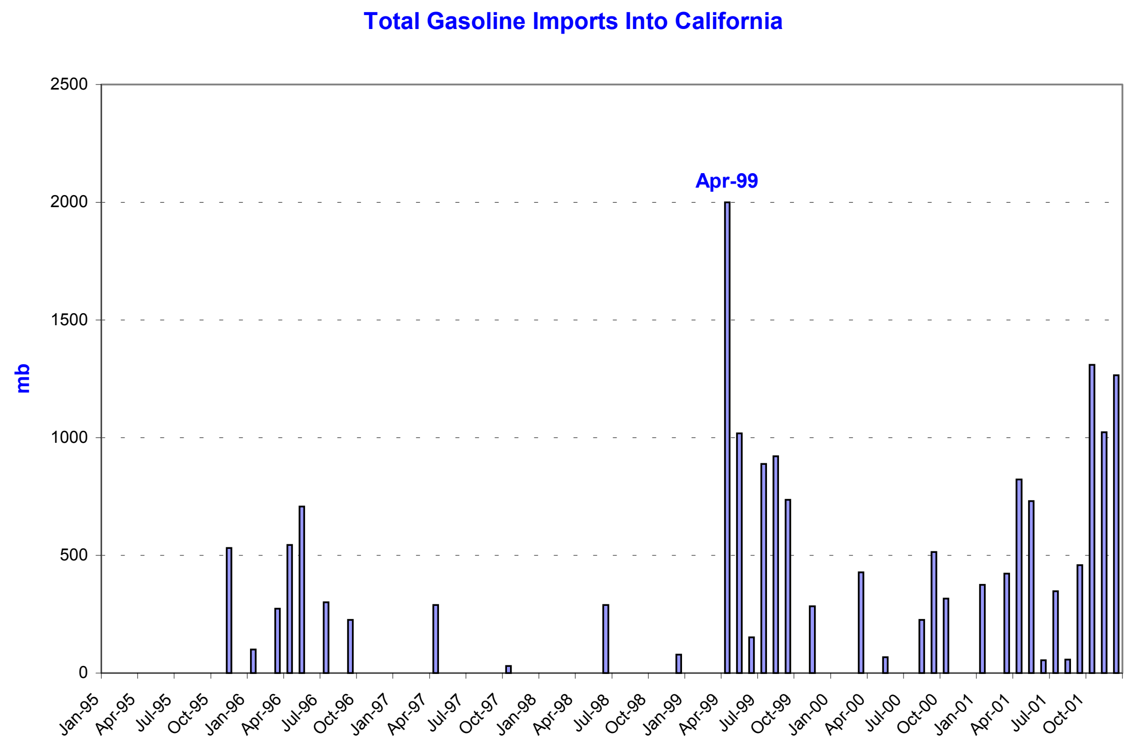


Figure 3-7 – Example of Spot Price Spike without Retail Price Effect



Refineries act immediately to source alternative gasoline supply during disruptions. Figure 3.8 shows the sharp increase in gasoline imports in the month of or following major disruptions. Of course, with the lag in delivery time, the disruption has already had its impact on spot prices.

Figure 3-8 – Gasoline Imports to California



In summary:

- Refinery disruptions normally have an immediate impact on spot prices, but in some instances the impact can be delayed
- Refinery disruptions normally cause a spot price spike and a companion retail price spike, except during some instances over the winter months
- Planned turnarounds do not affect prices unless coincident with a disruption
- A refinery disruption in either part of California affects all of California

- Price spikes are not transmitted to the Gulf Coast, but may be transmitted to neighboring states (not studied).
- Refiners respond immediately to try to offset disruptions by increased sourcing of gasoline from other areas.
- The time delay to ship these cargoes from distant refineries means that wholesale price rises can continue until the additional supplies arrive in California.

4 PRICE IMPACT OF DISRUPTIONS

As shown above for certain disruptions that were analyzed in detail, most but not all refinery disruptions create a price spike. In this section, a systematic analysis will be presented on how disruptions affect the California gasoline market.

4.1 General Description of the California Gasoline Markets[13]

The California gasoline market has a layered structure, formed by three separate but interrelated markets:

Spot. The spot market, primarily trades at the refinery level, is essentially an over the counter market, with deals negotiated on an individual basis between participants. Reporting of deals and posting of pricing by reporting services such as OPIS or Platt's occurs when both buyer and seller confirm the deal. In the California spot market, which includes deals made for supplies into Nevada and Arizona, there are between 20 and 30 active participants. Traded gasoline volumes are typically 25 MB (approximately 1 million gallons) and are delivered into a pipeline at a place and time specified by the buyer. The spot market moves with the perceived change in refinery product supply and demand.

Rack. The rack market consists of wholesale buyers such as independent retailers and bulk customers who operate their own truck fleet ("jobbers") and who take delivery of their product at a truck loading rack situated at a terminal, or sometimes directly at the refinery. Rack pricing for gasoline is broken into two segments: Branded and Unbranded. Pricing of gasoline for these two classes of trade is complex, dynamic and interrelated. Branded gasoline wholesalers are subdivided into classifications of "jobbers" and DTW (Dealer Tank Wagon) accounts. DTW prices represent the wholesale price paid by the dealer to a refiner for gasoline delivered in bulk to that dealer's retail outlets. Often the DTW price is higher than the unbranded rack, plus transportation. The branded dealer has, in effect, traded off the opportunity to take advantage of steep wholesale price declines during periods of oversupply, for a greater consideration of security of supply and an acceptable guaranteed margin over the long term. Imbedded in the DTW price is the deemed value of the use of a company's brand name.

Jobbers are those companies that service the market sector from the refiners' truck loading racks to end-user retail and bulk consumer accounts. They establish credit lines with the

[13] This section relies heavily on Stillwater (2002).

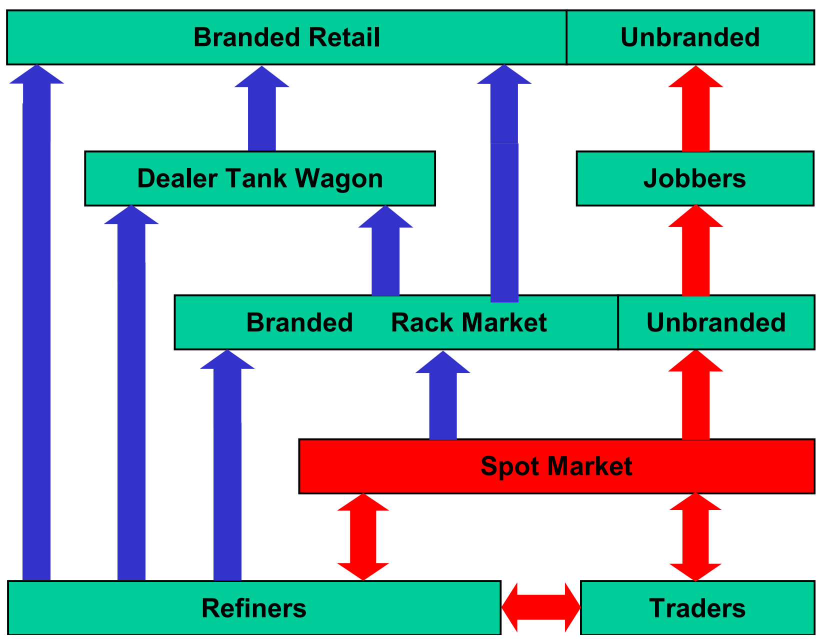
refining companies sufficient to service their customer base and pick up their loads against pre-negotiated contracts. A jobber may service both branded and the unbranded accounts.

Rack market participants may buy branded products destined for branded stations, or unbranded products destined for independent service stations or commercial/industrial accounts. In general, branded rack prices tend to move in relation to street prices. Unbranded rack prices tend to move with the spot market.

Retail. The retail market, where pump prices are posted, are normally set relative to prices of other local gasoline stations. They include Federal and State excise tax plus local sales taxes.

Figure 4-1 shows these relationships schematically.

Figure 4-1 – Structure of the California Gasoline Market



4.2 Price Movements

Figure 4-2 shows the behavior of prices during a typical disruption. The price response at the time of a disruption is almost immediate. Spot prices react first, followed by unbranded rack, and then by branded rack. After prices peak the price reaction is in the same order: spot prices lead the way down, followed by unbranded rack, then branded rack. The difference between the price run up and its trajectory back down is that branded rack prices tend to be sticky on the way down.

Figure 4-2 – Wholesale Price Movements during a Disruption

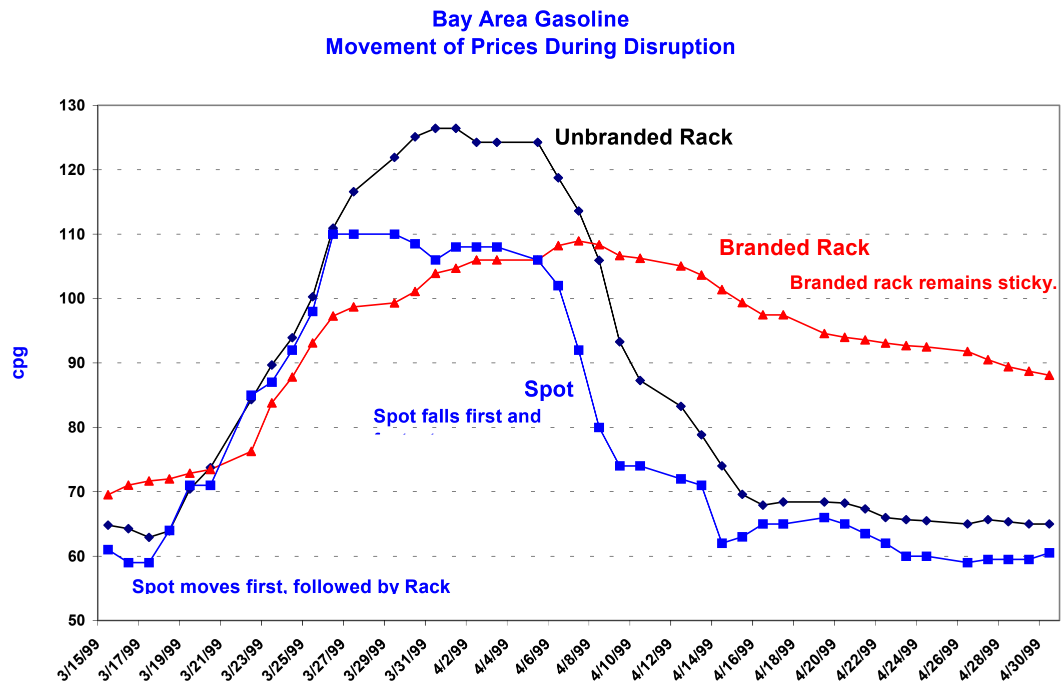
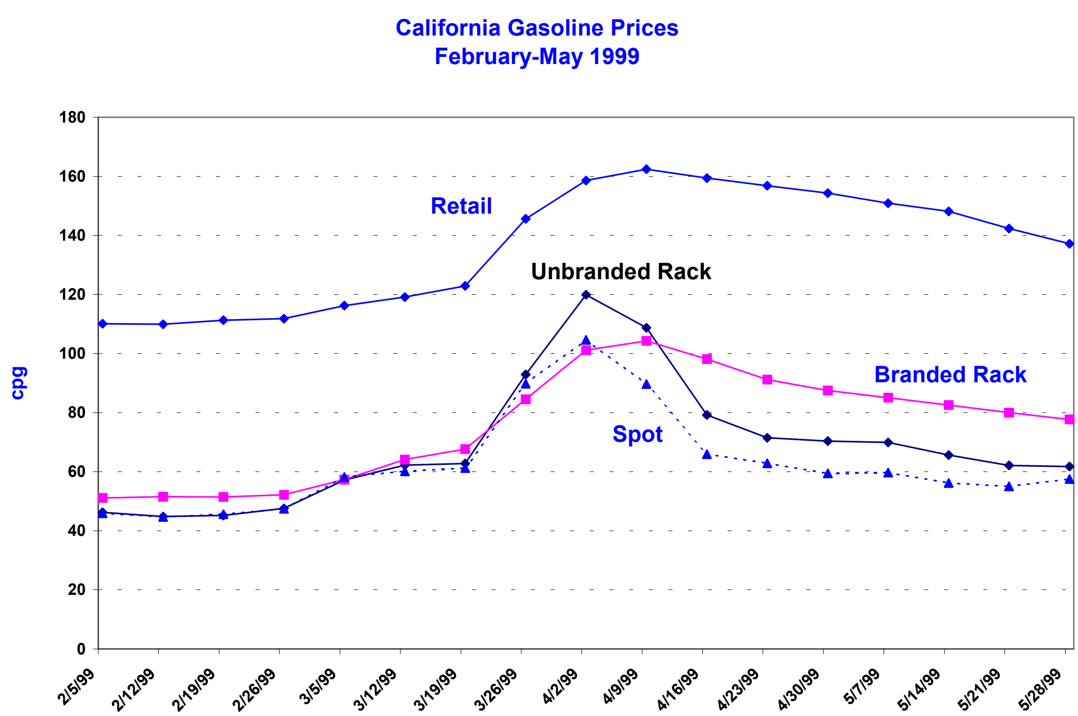


Figure 4-3 traces the movement of retail and wholesale prices. Here, retail price effects clearly linger longer than wholesale prices. They fall slower than they rise.

Figure 4-3 – Retail and Wholesale Movements during a Disruption



Prices at the various market stages are highly correlated, both on a level basis (Table 4.1) and change basis (Table 4.2). Considering changes in price movements in the latter table, the unbranded rack price tracks the spot price most closely. Retail pricing, which includes a significant mark-up from federal, state and local taxes, follows the movements of branded rack most closely.

Table 4.1 – Correlations of Prices for Various Stages of Gasoline Sales

Gasoline Price	Retail	Branded Rack	Unbranded	Spot
Retail	1.0	0.94	0.88	0.86
Branded Rack		1.0	0.97	0.96
Unbranded Rack			1.0	0.99
Spot				1.0

Note: A correlation of 1.0 indicates the variables move in exactly the same way.

Table 4.2 - Correlations of Changes in Prices For Stages of Gasoline Sales

Gasoline Price	Retail	Branded Rack	Unbranded	Spot
Retail	1.0	0.70	0.55	0.45
Branded Rack		1.0	0.77	0.63
Unbranded Rack			1.0	0.92
Spot				1.0

4.3 Asymmetry of Price Changes

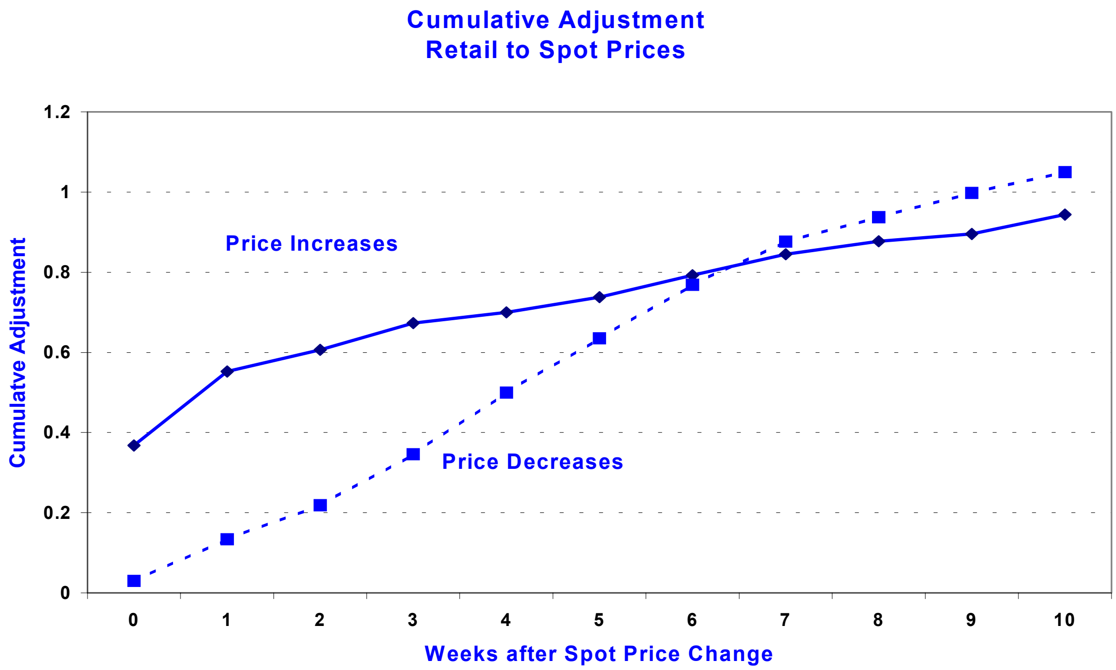
Studies have suggested that there is a statistically significant asymmetry between wholesale and retail prices. A number of studies have suggested that the wholesale to retail pass-through is virtually complete within four to eight weeks from onset of the disruption. The author has applied these models to the California data. Using a model developed by Borenstein, et. al.[14], the author calculated the price response function for spot price increases and decreases.

[14] Borenstein, Severin, Colin Cameron, and Richard Gilbert (1992). “Gasoline Prices Respond Asymmetrically To Crude Oil Price Changes?” National Bureau of Economic Research, Working paper No. 4138, August 1992

The response weights shown in Figure 4-4 suggest that by the sixth week, the price response is virtually complete. But, one will notice that the cumulative response of price increases in the second week is about .6 while the cumulative effect of price decreases in the two week period is only about .2. So, one infers that the cumulative adjustment of retail prices to changes in wholesale prices occurs faster than when wholesale prices decrease. The cumulative adjustment, however, equates by the sixth week.

The regression equation is given in Attachment D.

Figure 4-4 – Cumulative Adjustment of Retail Price to Wholesale Price Changes



The price impact of refinery disruptions can last 6 to 8 weeks. Figure 4-5 shows the price response to a number of refinery outages in Los Angeles refineries. Note that the spot price rises substantially at the occurrence of the disruption, then slowly falls off. The spot price crosses two measures of return to normalcy, the 91-day (three-month) moving average of prices and a new price minimum, between six and eight weeks after the initial disruption.

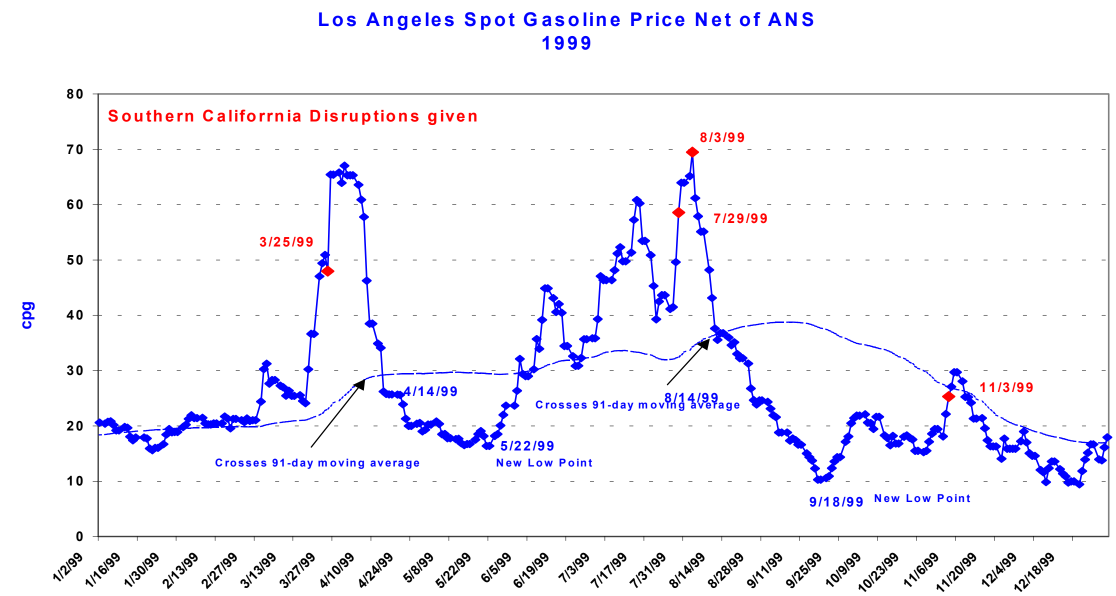
This asymmetry was also found by Duffy-Deno[15] in the Salt Lake City market. Various explanations have been offered for the asymmetry, including market power, search costs, consumer response, and refinery adjustment costs. The author's belief is that the phenomenon

[15] Duffy-Deno, Kevin (1996). "Retail price asymmetries in local gasoline markets," *Energy Economics*, 18, pp. 81-92

has a more benign explanation. Adopting the arguments of Balke, et. al.[16], if consumers accelerate their gasoline purchases to beat further expected increased in prices, they will increase inventories in their gasoline tank, hence accelerating the price rise. On the downside, consumers may fear running out of gasoline and do not slow their purchases to bring the inventories in their tank back to normal.

It should be noted that the EIA study[17] (1999) of prices changes in the Midwest gasoline market finds price asymmetry but concludes that it is largely a statistical artifact due to lagged adjustments.

Figure 4-5 – Disruption Duration during a Sample Disruption



4.4 Price Impacts – Conclusions

In summary:

- The rise and fall of prices caused by a disruption are asymmetric
- Retail price effects linger longer than other prices.
- Price spikes are more pronounced during periods of low inventories

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[16] Balke, Nathan, Stephen Brown, and Mine Yucal (1998). "Crude Oil and Gasoline Prices: An Asymmetric Relationship?," *Economic Review*, Federal Reserve Bank of Dallas, pp. 2-10, First Quarter 1998

[17] Energy Information Administration (1999). "Price Changes in the Gasoline Market: Are Midwestern Gasoline Prices Downward Sticky?" (DOE/EIA-0626), February 1999

- Prices at the various market stages are highly correlated.
- The wholesale to retail pass-through is virtually complete within 4-8 weeks

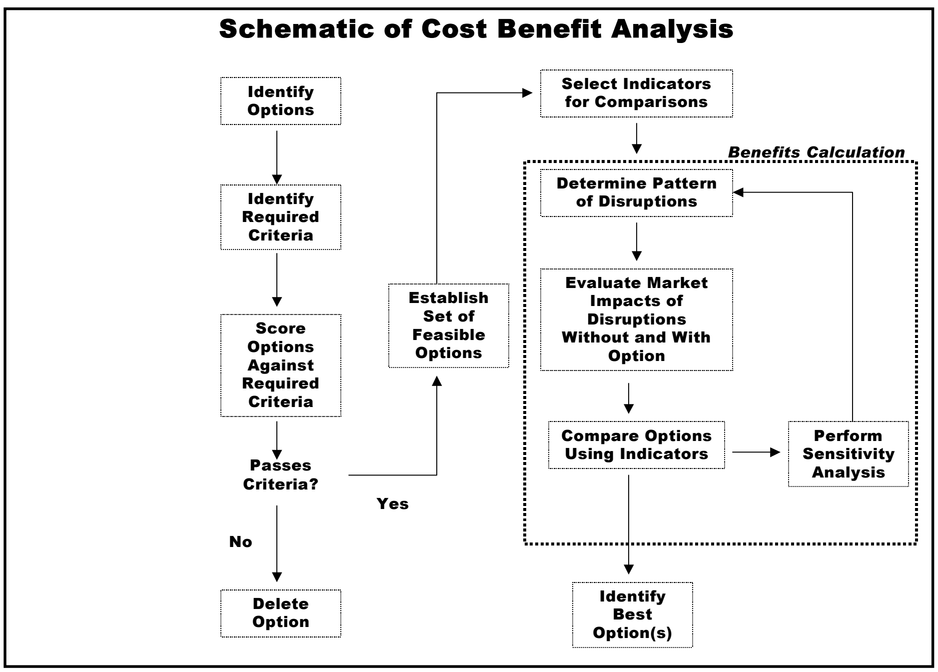
5 FRAMEWORK FOR ECONOMIC ANALYSIS

The State of California has a number of options available to it for the potential abatement of price spikes associated with unplanned refinery disruptions, including the option of doing nothing. These various options can be compared on the basis of generally accepted cost benefit analysis principles[18].

5.1 Cost – Benefit Analysis

Cost Benefit Analysis (CBA) is an organized framework to compare alternative policies on the basis of net benefits to society. The CBA process can be separated into the following steps: (Figure 5-1)

Figure 5-1 – Cost Benefit Analysis



1) Specify the set of feasible options

2) Identify the required criteria for consideration of an option and score the option on meeting the required criteria

3) Identify the set of benefits and costs to consider

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[18] See Boardman (2002), Gramlich (1997), and Layard (1994).

4) Identify the economic indicators to use for comparisons and evaluate the economic impacts **without** and **with** the option

5) Perform sensitivity analysis on leveraging assumptions of the options

6) Identify the best option(s) from the analysis.

5.2 Set of feasible Options

A number of options to mitigate the price spikes associated with unplanned refinery outages have been proposed. They include:

- Strategic Fuel Reserve
- Fast track authority to allow expedited siting of storage facilities
- Additional storage built by the State that would be available to private holders
- Subsidy to private holders of inventory
- Incentives for in-State independent refiners to expand their facilities to increase CARB Phase III gasoline production capacity
- Incentives for nearby out-of-state refineries, such as those in Washington State, to upgrade their facilities to increase CARB Phase III production capability
- Demand-reduction programs
- Conversion of proprietary systems to common carrier status
- Long-term procurement of gasoline by the State
- Importation of non-compliance gasoline with a 15 cpg waiver

There are, of course, additional options and it is possible that some of the preferred options may face political impediments. The Stillwater Report identified a potential market imperfection that the demand for additional storage by refiners may be thwarted by restrictive permitting requirements by local and state government or refiners' fear of shifting environmental rules. Some or all of the options cited above may, in fact, do more harm than good in resolving the perceived market imperfection. The first step in the analysis is to examine if the options have the ability to satisfy some necessary conditions to mitigate price spikes in a timely manner. In short, the analysis must address: Does the option effectively reduce or eliminate the perceived market imperfection?

The first step in the cost-benefit analysis is to narrow the options down to those that can solve the problem, that is, test the set of proposed options against a set of identified criteria.

Stillwater consultants and other market commentators have suggested a set of requirements that the options must satisfy[19]. They are:

- *Is the option capable of mitigating price spikes from disruptions in a timely manner?* That is, can the mechanism respond fast enough to prevent a rise in price that would be transmitted on to the consumer? This is the necessary, central feature of the option and must be satisfied for it to be further considered. As shown in Section 3, California refiners respond quickly to a disruption, but their option of sourcing imports or shipments from the Gulf Coast take too long to quickly mitigate the price spike.

- *If a price mechanism, such as an auction, is envisioned as part of the option, is it non-discriminatory and non-manipulative?* California consumers are all too familiar with problems associated with electricity deregulation. Much play has been made of the ineffectiveness of the auction scheme for incremental power. In a number of articles, Paul Klemperer[20] has warned about the problems with auction design. Citing the fact that the "devil is in the details," he notes that the two critical features of auctions that matter are attracting entry and preventing collusion. He notes that choosing an ascending auction, one in which the bids are raised until the highest bid wins the auction, can deter entry and could possibly lead to collusive activity. Conversely, he suggests that a sealed bid auction, one in which the bidder provides one and only one bid, can avoid signaling to eliminate collusion. He further notes that this may still lead to inefficient outcomes. In a number of cases, he has proposed

[19] There may be additional criteria to test against.

[20] Klemperer (2001).

a hybrid of these methods. The auctioning mechanism, if there is one, must be tested against relevant auction theory and practice.

- Will the proposed option provide a disincentive for the holding of private inventories, i.e. "crowd out" or offset private inventory holder's actions? Stated conversely, does the option provide an incentive for private storage at some point? Williams and others[21] have warned about the potential crowding out of private inventories by public inventories. In work examining the formation of the US Strategic Petroleum Reserve in the early 1980s, Williams and Wright[22] showed that one-third to two-thirds of incremental public storage was offset by compensating decreases in private inventory holdings. Since the options considered here have mechanisms that might have a public aspect to them, the option must be evaluated on its effectiveness and potential offsets.

- *Does the option promote forward liquidity in the gasoline market?* The Stillwater Report and Verleger[23] cite the need to promote forward liquidity to foster movements of imports and shipments from outside the region. Both believe this is a necessary condition for adequately mitigating excess price volatility. The Stillwater study illustrated the risk inherent in 2000 for refiners to bring cargoes to the West Coast. Gregg Haggquist[24] has codified five elements that are required for a physical basis for a forward market.

    1) Common delivery point
    2) Diversity of market participants
    3) Common or fungible specification
    4) Robust transaction flow
    5) Accessibility by a cross-section of suppliers

[21] Williams (1986), Verleger (2000), Williams and Wright (1991).

[22] Williams, Jeffrey and Brian Wright (1982). "The roles of public and private storage in managing oil import disruptions," *The Bell Journal of Economics*, 13, No.2, pp. 341-353

[23] Verleger, Philip (2002). Prepared statement before the Permanent Subcommittee on Investigations of the Senate Governmental Affairs Committee, May 2, 2002

[24] Haggquist, private communication (2002)

Each option should be examined against these requirements to ensure that it promotes improved forward liquidity.

5.3 Scoring the Options

The options should first be scored against conditions that will confirm the effectiveness of the proposed solutions, i.e., will they mitigate price spikes and promote security of supply of gasoline to California consumers.

If they pass this review, then the various alternatives can be evaluated on the basis of their net social benefits, where we ask: Do the societal benefits outweigh the costs?

Table 5.1 shows a proposed schematic to screen options that do not pass the litmus test provided by the necessary conditions.

Table 5.1 – Preliminary Economic Screening of Options

Option: / Criteria:	SFR	State Builds Storage Tanks	…	Non-Compliance Gasoline Waiver
	Option 1	*Option 2*	…	*Option N*
Timely mitigation of the price spike				
Non-discriminatory price mechanism				
Crowd out private inventories				
Provide forward liquidity				
… etc.				

5.4 The Cost-Benefit Paradigm

After satisfying the necessary conditions, the resultant feasible options are then compared on the basis of benefits versus costs, that is, net benefits (benefits less costs) with the option versus without the option.

On the cost side, one must include all incremental costs, including capital costs, operating costs, working capital (e.g. initial fill of the SFR), etc. on an annualized basis. If there is environmental degradation, such as the option of supplying non-compliance gasoline, they must be monetized[25] and included as a cost (or a negative benefit).

On the benefit side, one must identify all the economic benefits (including fees collected) that society receives with and without the option in place. Two principal impacts should be considered in the cost-benefit analysis:

1) Lower average spot prices, due to the reduction in volatility that the option produces, given that it can be triggered in a timely manner. (As stated earlier, the theory suggests that price volatility and spot prices will both be lower with increased storage.)

2) Reduction (chopping the spike) of price spikes from refinery disruptions. Not all disruption spikes can be mitigated without cost or with certainty. As one example, during large disruptions, market psychology may "take over," and run the spot price higher than expected or required. Also, the cost of using an option, such as an SFR, would require restocking that imposes an implied cost on it use and hence a higher spot price. Economic analysis should, as much as practicable, consider these effects.

5.5 Welfare Model Paradigm

The paradigm needed to calculate the economic impacts and benefits is a variant of the welfare model. This is depicted in the following stylized charts[26]. Figure 5-2 illustrates the supply and demand conditions in the gasoline market before and after a disruption. The shaded areas in Figure 5-3, Figure 5-4, and Figure 5-5 illustrate three measures of benefits to avoiding price spikes: (1) the loss in consumer surplus, (2) the loss in societal welfare, and (3) the increase in the consumer's gasoline bill from the disruption, respectively.

The concept of consumer surplus measures the extra value consumers derive from their consumption compared with the value measured at market prices. Similarly, producer surplus

[25] There are numerous studies that quantify environmental costs.

[26] More representative supply and demand curves for the California gasoline market are given in Section 6.

is the extra value received by producers above their marginal costs. Social welfare is the sum of consumer and producer surplus. The loss in social welfare is the change in the sum of consumer and producer surplus after change in a policy.

Figure 5-2 – Impact of a Disruption on Consumer and Producer Surplus

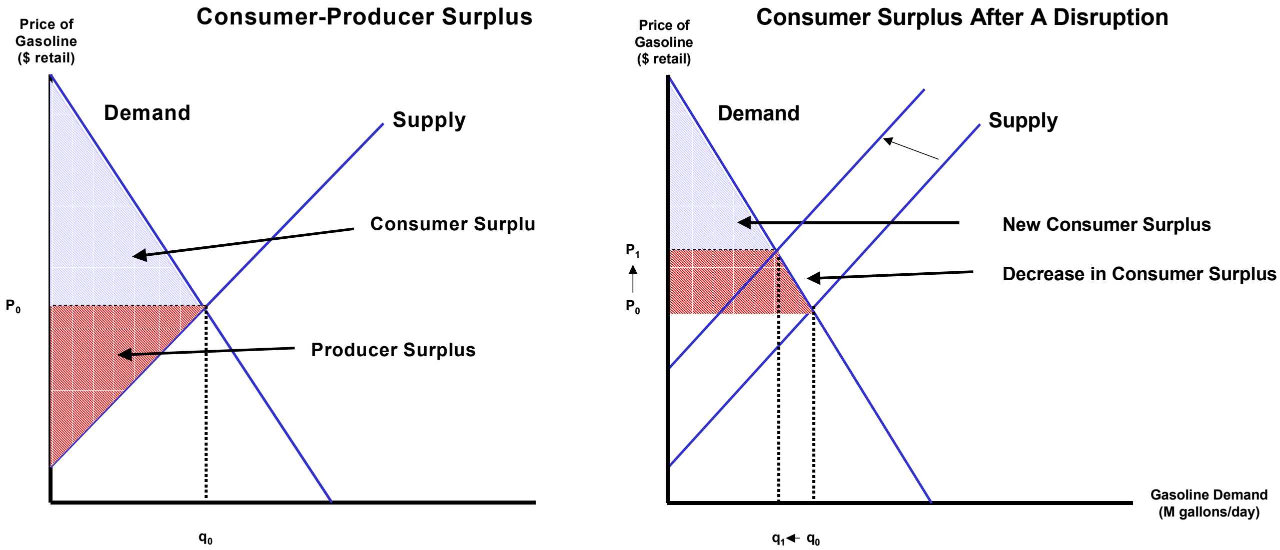


Figure 5-3 – Producer Surplus after a Disruption

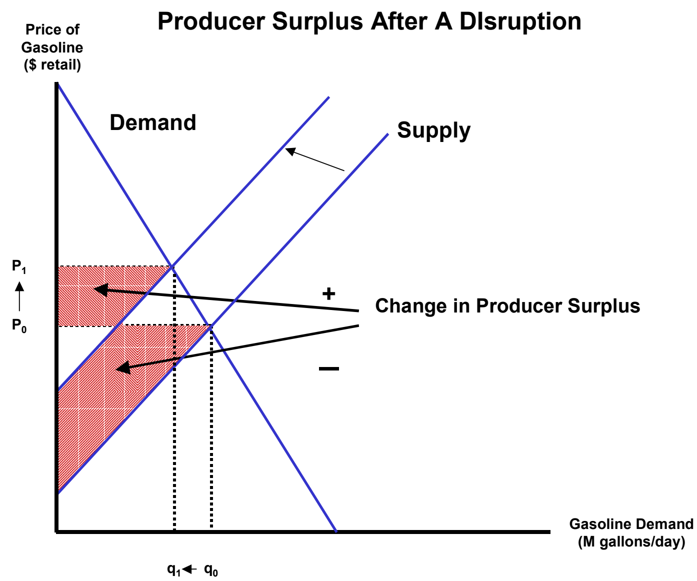
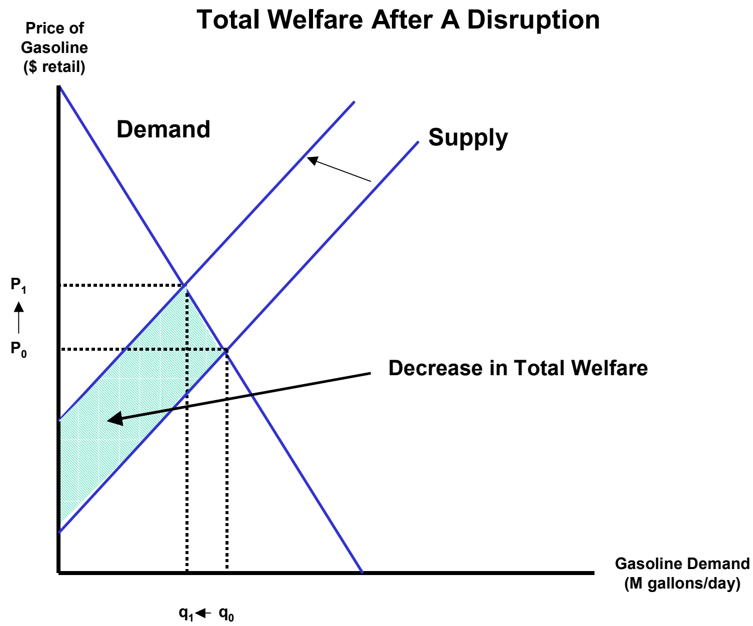
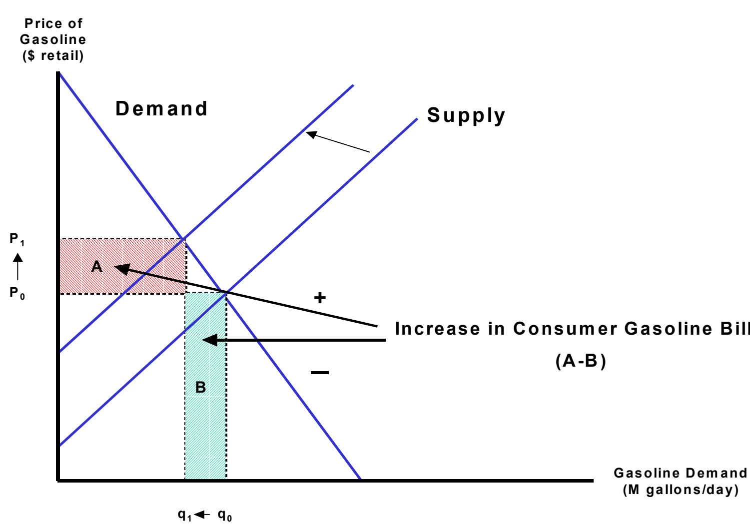


Figure 5-4 – Total Welfare after a Disruption



Most often, cost-benefit analysis uses net social welfare (shown in Figure 5-4), the sum of consumer and producer surplus changes, as the appropriate indicator of the benefit from a policy change. Here, however, the recommended measure is just the consumer benefit portion, the change in consumer surplus (the benefit is the avoidance of the loss in consumer surplus.) for two reasons: (1) The benefits accruing to producers will not largely stay in California, and (2) The California Legislature in AB 2076 specified the calculation of net consumer benefits.

Figure 5-5 – Change in the Consumer Gasoline Bill after a Disruption



Also, the federal government Office of Management and Budget states that "consumer surplus provides the best measure of the total benefit to society from a government program or project."[27]

The graphs presented in this section are for expository purposes. The analysis of feasible options will require quantification of the demand and supply elasticities and particular shape of the demand and supply curves. Since many commentators on the proposed options might use one of the other alternative indicators, it is advisable to carry along all three measures in subsequent analyses. It should be noted that in many instances, the net change in social welfare is often small, because of largely offsetting changes in consumer and producer surplus.

The implementation of these concepts for the SFR envisioned in the Stillwater Report is presented in Section 6. Each of the three indicators of benefits is calculated in that illustrative analysis.

5.6 Evaluation of Benefits under Uncertainty

A central feature of all the options to be considered is that they face a future environment of refinery disruptions. The economic analysis must consider plausible alternative refinery disruption environments in the cost benefit analysis.

The particular frequency, size, and duration of future refinery disruptions cannot, of course, be known in advance. Future disruptions may follow a similar pattern to the 1996-2001 period, become more frequent and severe due to even more stringent environmental regulations, or even abate due to improved refinery practices as a result of learning. These alternative patterns will change the size of potential benefits accruing to options employed. These alternatives can be explored through use of powerful statistical simulation techniques. The estimation of economic benefits can be done prospectively using assumptions about uncertainty by generally accepted Monte Carlo techniques. This approach allows for explorations around key assumptions, including supply and demand elasticities, and size, duration, and frequency of disruptions.

The approach can explicitly allow for:

- Different price spike impacts during high and low inventories.
- Multiple disruptions at one time as has happened in the past four years

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[27] OMB (1992), p.6

- A probability distribution over disruption durations
- A probability distribution over disruption sizes
- Alternative specification of disruption occurrences.
- Alternative specification of short-term supply and demand elasticities

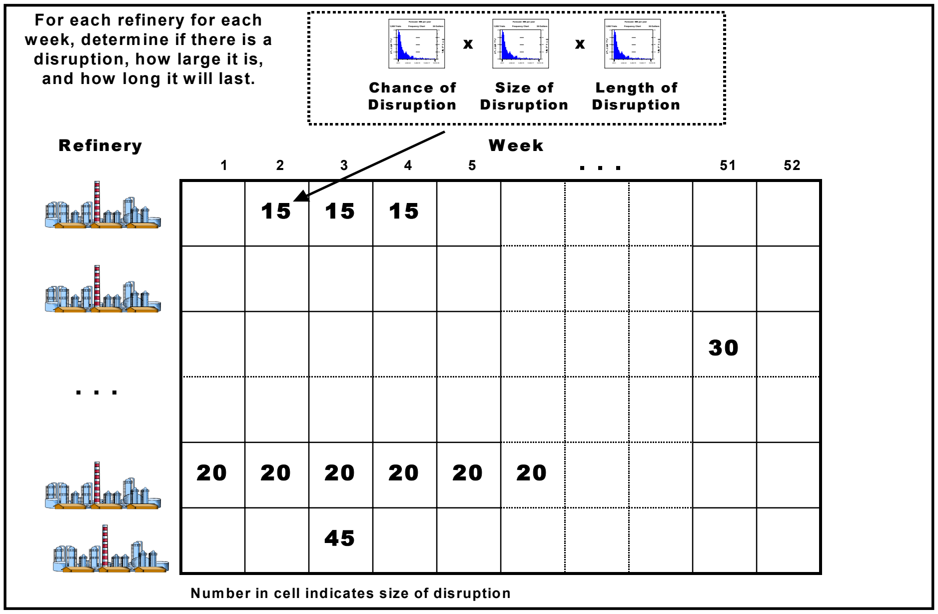
As a baseline, one can estimate the frequency, size, and duration of refinery disruptions from the database of California disruptions from early 1996 through early 2001.

The resultant output will include a distribution of economic benefits. From that, one can ascertain the expected value (central tendency) and the range of certainty around it. In addition, other useful cases can be run. For example, one might assert that 1999, a particularly bad year for disruptions, is an anomaly (a "10-year flood") and should be excluded. Or, one can assume that refiners will face 1998, a benign year, over and over again. These and other scenarios can be explored to see how robust the economic benefit estimates are.

In order to clearly account for low inventory conditions, winter and turnaround conditions, which have different elasticity or frequency parameters, and to ensure that we do not double count refinery disruptions, the benefits are simulated over a 52-week period for 11 representative refineries[28]. In this approach, each week, for each refinery, a random draw is taken from the disruption, size, and length statistical distributions to determine if a disruption has occurred, and, if so, what size and length. (The spreadsheet ensures that a refinery that is down for more than one week will not suffer another outage until the current outage is over.) The spreadsheet then calculates the total disrupted barrels, and then estimates the price response given the supply and demand elasticities. The model can distinguish between high and low inventory positions. (See the schematic in Figure 5-6.))

[28] This model was developed by Dr. Anthony Finizza. Please arrange for its use directly from the author: afinizza@aol.com or afinizza@uci.edu.

Figure 5-6 – Refinery Disruption Tableau



5.7 Consideration of the Economics of the Inventory Behavior

Since most of the options involve gasoline inventory issues, the economic analysis should consider results of the growing literature on inventory behavior.

In recent work on the dynamics of price, production, and inventories for commodities, Robert Pindyck[29] shows how prices, production, and inventories are determined in two interconnected markets: a cash market for spot product sales and a market for storage.

He shows that the cash market is in equilibrium when net demand for product equals net supply. His model depicts this equilibrium in terms of the inverse demand function:

$$P = f(\Delta N, z_d, z_s, \varepsilon)$$

where P is the spot price, ΔN is the change in inventories, z_d are demand-shifting variables, z_s are supply-shifting variables, and ε is the error term.

He describes the demand for storage function as an inverse demand function,

$$\psi = g(N, \sigma, z_d, \varepsilon)$$

[29] Pindyck (2001a), (2001b).

where ψ is the marginal convenience yield (price of storage), N is inventories, σ is the volatility of prices, z_d represents demand shifting variables (now including the spot price of gasoline), and ε is the error term.

The marginal convenience yield, the price of storage, equals the value of services from holding a marginal unit of inventory. Values of the marginal convenience yield can be directly measured whenever there are future prices through the arbitrage equation relating it to spot prices, and futures prices, the risk free rate, and the cost of physical storage.

The inference from his work and others is that:

- Price volatility is greater during periods of low inventory
- An increase in price volatility, such as might be caused by disruptions, should increase the need for inventories to buffer increases fluctuations in supply and demand, which increase the chance of outages.
- Increased price volatility raises spot prices and the cost of storage.

6 ECONOMIC EVALUATION OF THE SFR PROPOSED BY STILLWATER

The framework outlined in Section 5 can be applied to the SFR proposal suggested by Stillwater Associates.

6.1 Preliminary Scoring of SFR Option

Using Table 5.1 as a guide, the SFR proposal by Stillwater can be scored under the four necessary criteria described.

6.1.1 Timely mitigation of the price spike

The proposal is to divide the SFR into two separate operational entities, to be fully integrated with each of the refining centers in the Bay Area and the Los Angeles Basin respectively. The direct linkage of the SFR to the logistic system ensures that the use of its storage will produce a more timely response to outages than long haul shipments from the Gulf Coast or foreign locations.

6.1.2 Non-discriminatory price mechanism

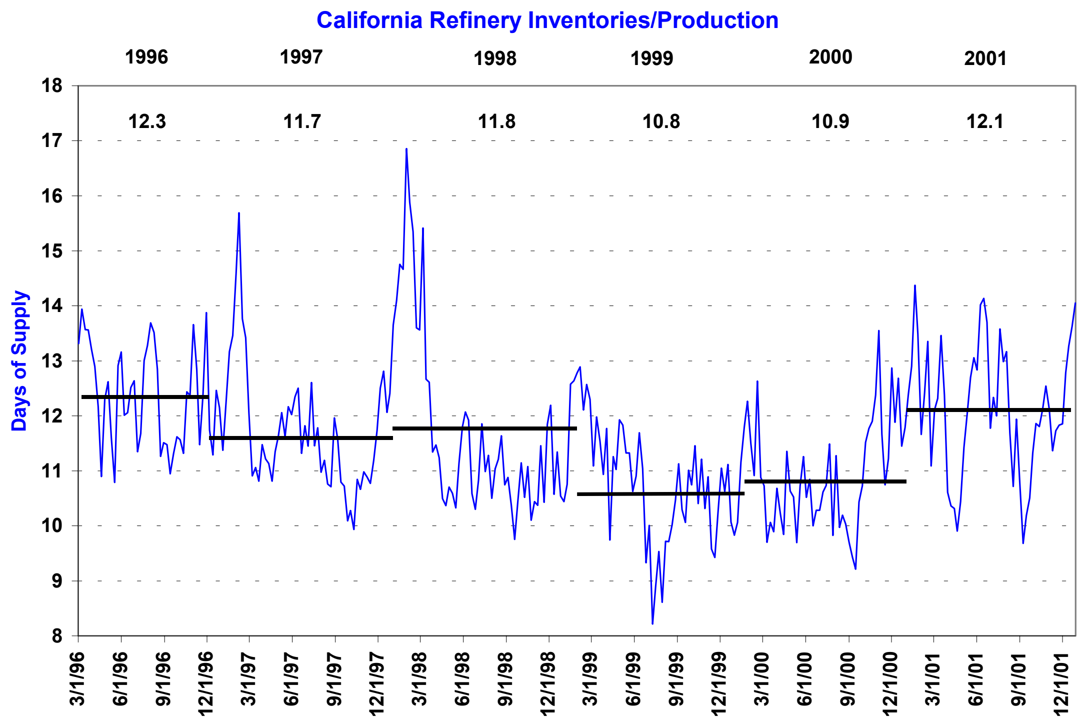
This feature is possible given a careful construction of the auction mechanism. This feature cannot be evaluated yet, since the details have yet to be described. Since the proposal is to not have arbitrary trigger mechanisms but to allow continuous access to the reserve in the form of time swaps for a fee, with open access for qualified parties, it seems likely that the pricing system will be non-discriminatory.

6.1.3 Crowd out private inventories

The Stillwater report suggests that the refinery industry does not hold much inventory above working levels. A cursory look at inventories in relation to production at California refineries (Figure 6-1) suggests that refiners held about 12 days of supply during periods of normal activity (e.g. 1996, 1997, and 2001, years of minimal disruptions) and drew down their inventories in response to severe disruptions in 1999 and 2000.

As stated earlier, the theory of inventory behavior suggests that refiners would hold increased precautionary inventories during periods of high price volatility. While refiners appeared to have added to inventories after the period of severe disruptions, they did not add to inventories beyond historical holdings on a day of supply basis. This seems to confirm the Stillwater perspective that there has not been an increase in precautionary inventories as price volatility increased. Still, it can be argued that the 12 days of supply contains some precautionary inventories and that some would be offset by inventories in the SFR. Under that view, precautionary inventories reductions should be expected to be minimal.

Figure 6-1 – California Refinery Inventories in Days' Production



Since the current proposal also includes facilitating the building of additional commercial tankage for use by private parties, it could well be that average industry inventories will increase rather than decrease as a result of the proposal.

6.1.4 Provide forward liquidity

The Stillwater report illustrates how the SFR will increase forward liquidity. The time swap mechanism proposed for accessing the reserve volumes for a fee effectively exposes the value of the backwardation and allows importers a physical means to lock in prices and costs for future deliveries, removing the risks imposed by market fluctuations.

6.2 Summary of Preliminary Screening

It appears that the SFR proposal passes the initial test of feasibility. It should be compared against scoring of the other alternatives. A summary is provided in Table 6.1.

Table 6.1 – Preliminary Scoring of the Stillwater SFR Option

Option: / Criteria:	Stillwater SFR	State Builds Storage Tanks	…	Non-Compliance Gasoline Waiver
	Option 1	*Option 2*	…	*Option N*
Timely mitigation of the price spike	Yes			
Non-discriminatory price mechanism	Likely, but will have to be confirmed in detailed design			
Crowd out private inventories	Minimal,			
Provide forward liquidity	Yes			
… etc.				

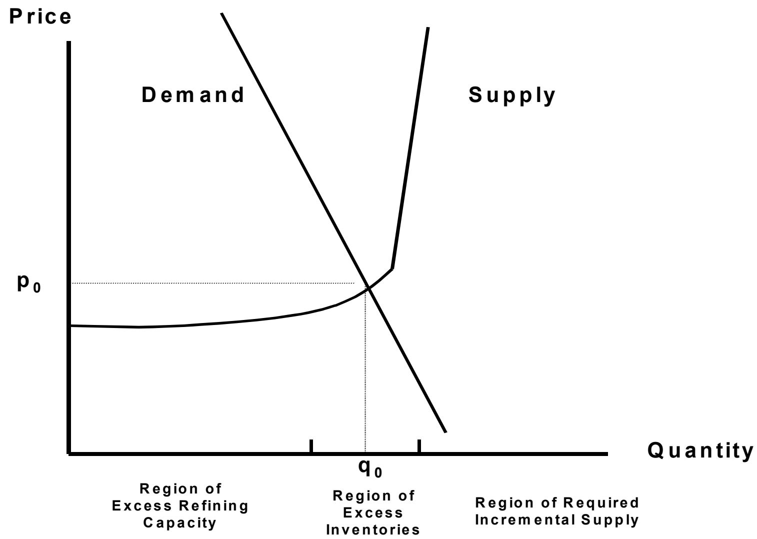
6.3 Supply-Demand Representation of the California Gasoline Market

In order to evaluate the potential economic benefits of the proposed SFR, the short-term supply and demand of gasoline in California needs to be examined.

6.3.1 Without the Proposed SFR

Figure 6-2 illustrates the short-term gasoline market in California. The demand curve is highly inelastic. The supply curve is flat (elastic) for production up a point close to full refinery capacity utilization. The current market is at capacity, so this region is not where the industry is operating. The next region of the supply curve, which is more inelastic, is the region where supply could be sourced out of precautionary inventories. The industry does not have excess inventories during most of the year but operates this way typically during winter and turnaround periods. Finally, the last region represents the inelastic part where supply would be sourced out of high cost imports.

Figure 6-2 – Short-Term Gasoline Supply and Demand without SFR



For this study, the above construct is approximated by that given in Figure 6-3. The supply curve is flat up to the point of full capacity and excess precautionary inventories, at which point it become highly inelastic to reflect the high costs of sourcing imported product. Note that there is no producer surplus in this approximation.

Figure 6-3 - Supply and Demand Curves Without SFR

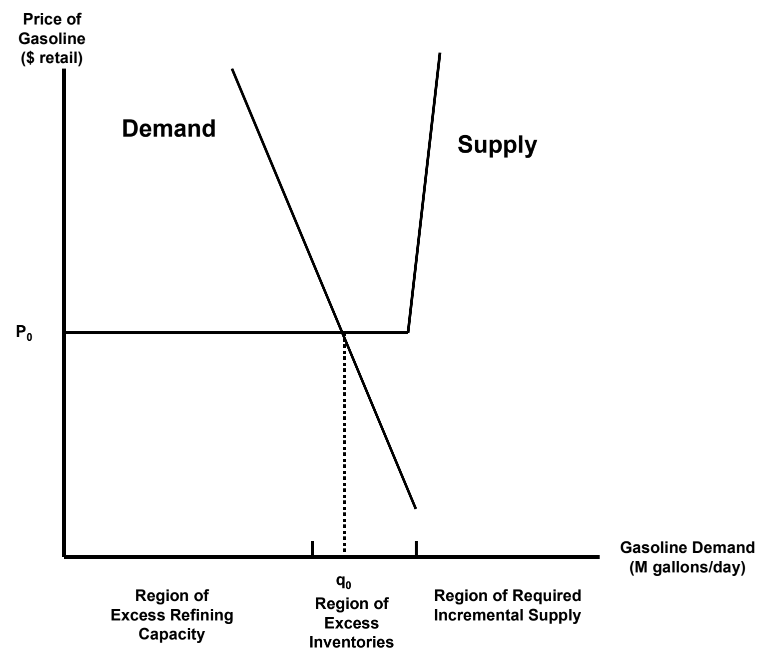


Figure 6-4 and Figure 6-5 illustrate the price impacts of two types of disruptions, the first large relative to the level of precautionary inventories and the second small relative to precautionary inventories.

Figure 6-4 - Price Impact Under a Large Disruption – Without SFR

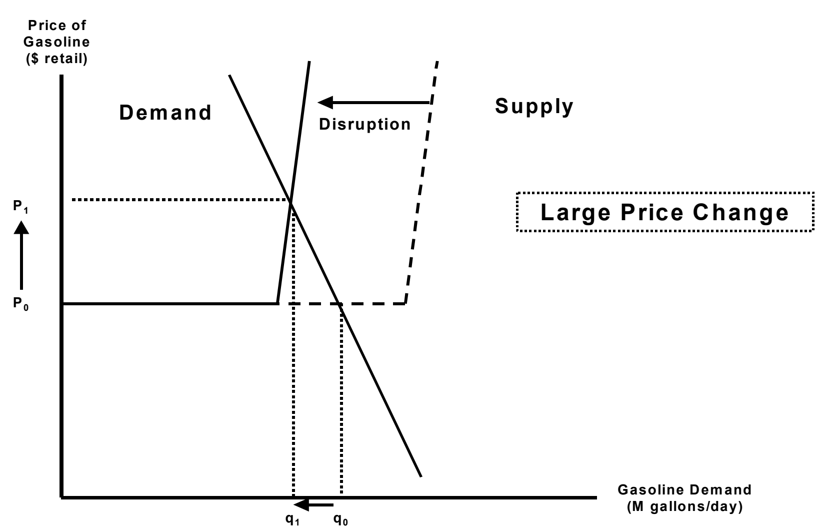


Figure 6-5 - Price Impact Under A Small Disruption – Without SFR

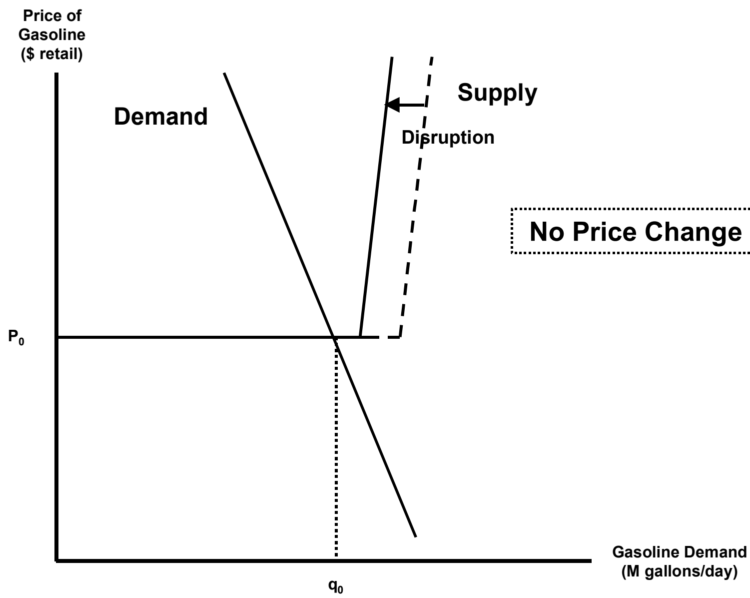


Figure 6-6 and Figure 6-7 show the increase in the consumer gasoline bill and the decrease in consumer surplus for a supply disruption **without** the SFR.

Figure 6-6 – Increase in Consumer Gasoline Bill Due to Disruption Without SFR

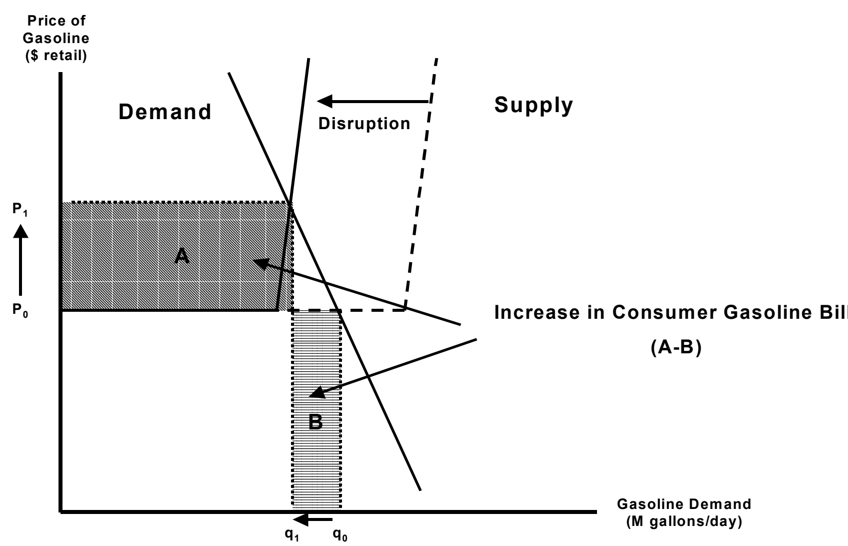
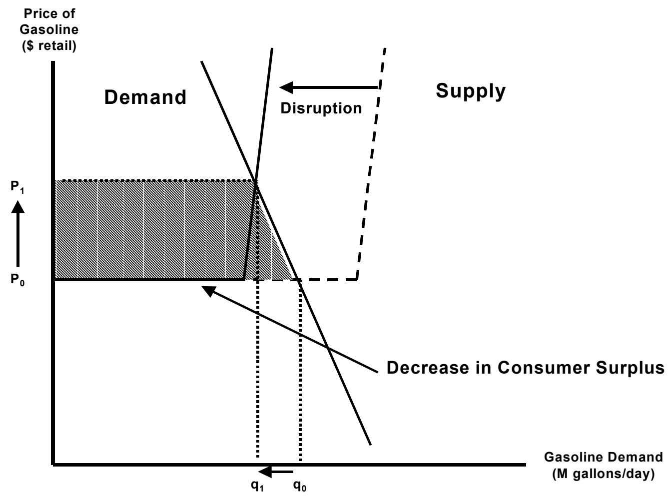


Figure 6-7 - Decrease in Consumer Surplus Due to Disruption Without SFR

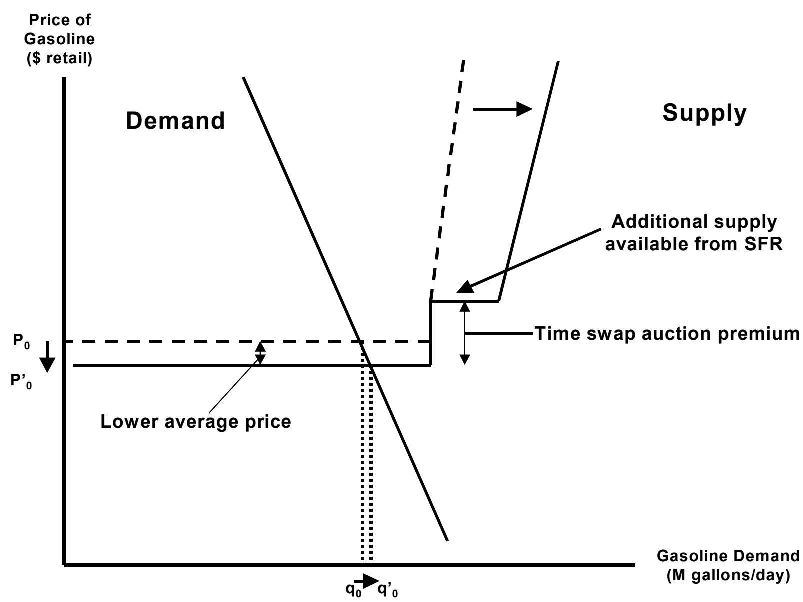


During a disruption, incremental supplies are sourced out of precautionary inventories and then from distant sources. Prices rise to clear the market in accordance with their elasticities. Prices return to normal, with a lag, after the disrupted barrels are replaced. In the interim, the consumer faces a lower consumer surplus and a higher gasoline bill (on all barrels sold during the disruption). A static calculation of these measures under representative demand and supply elasticities is given in Section 6.

6.3.2 Supply-Demand Response with the Proposed SFR

After the introduction of the SFR, the net total system precautionary inventories will be larger (SFR offset by small reductions, if any, in private inventories) and the supply responsiveness with respect to imports will be greater. So, the supply curve will shift by the net change in inventories plus become more elastic. The additional cost of accessing the SFR, labeled the time-swap auction premium, is discussed below. This is shown in Figure 6-8. This suggests that there is a net social benefit through lower "average" prices in the absence of a disruption. This should be included in the benefits.

Figure 6-8 – Short-Term Gasoline Supply and Demand with SFR



With the SFR and during a similar size disruption, the impacts on the measures of welfare loss are, of course, smaller, since the higher level of precautionary inventories will mitigate a price rise. (See Figure 6-9 – Price Impact of a Large Disruption With the SFR.) When comparing the net benefits of the SFR, the **without SFR** effects as shown in Figures 6.6-6.7 must be compared to the **with SFR** effects shown in Figures 6.10-6.11.

Consider the case of the impact of a disruption during a period of low or no precautionary inventories. The net benefit to the consumer is the avoidance of the price spike that would have occurred without the SFR less the amount of the spike that cannot be avoided with the SFR (e.g. the time swap auction premium that represents the cost of sourcing a replacement barrel via a time swap). For this, we need to compare the resulting price-quantity equilibriums under two cases, **without** and **with** the SFR. This is shown in a stylized description of the price effect in Figure 6-12 for a representative gasoline price change. The net benefits (which must be applied to all barrels consumed during the price spike) are shaded.

Figure 6-9 – Price Impact of a Large Disruption With the SFR

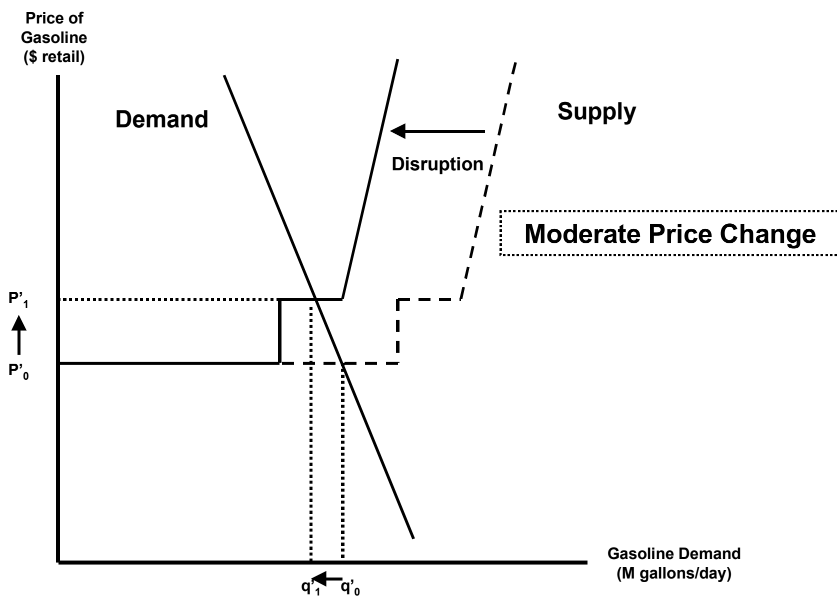


Figure 6-10 – Increase in Consumer Gasoline Bill with SFR

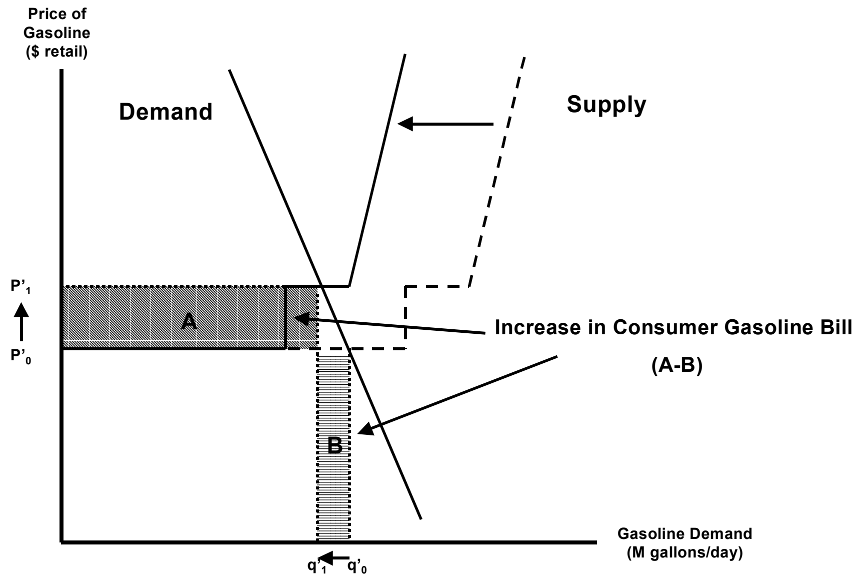
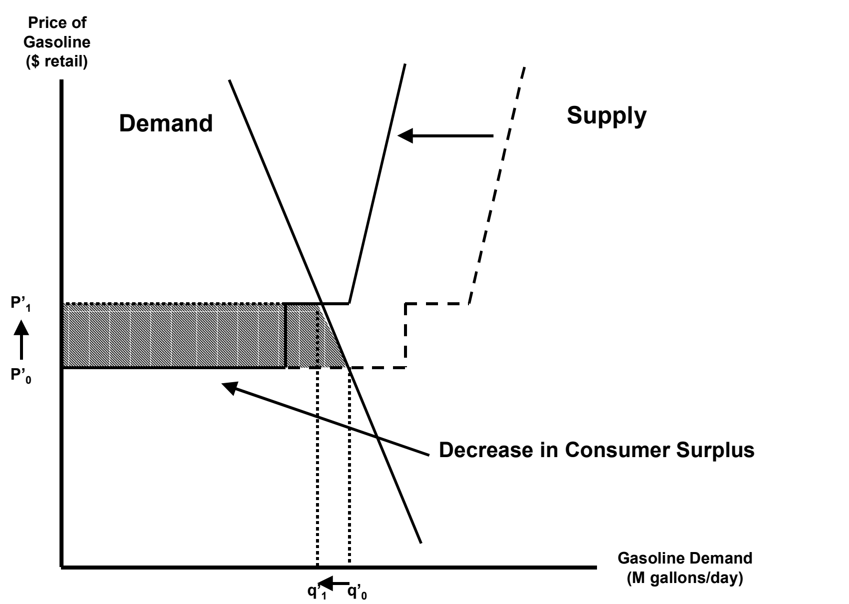
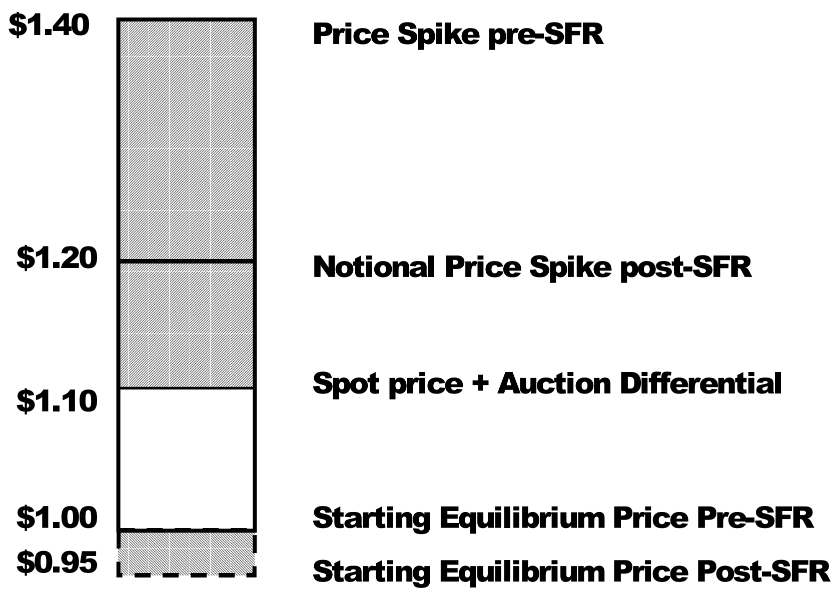


Figure 6-11 – Decrease in Consumer Surplus with SFR



- Even under the most benign combination of alternative assumptions, that disruptions have lower occurrence and that the SFR mechanism can only offset spikes in excess of 15 cpg, the economic benefits are over $ 140 million.

Figure 6-12 – Price Effect for a Representative Price Change



6.4 Demand and Supply Elasticities

In order to quantify the benefits that can accrue to the existence of an SFR, we are required to estimate the short-term gasoline demand and supply price elasticities in the current environment **without** the SFR and then **with** the SFR.

6.4.1 Use of Elasticities

The *price elasticity of demand* is the percentage change in quantity demanded divided by the percentage change in price. If the elasticity is less than 1 in absolute value, the demand for that commodity is inelastic. So, a demand price elasticity of – 0.1, for example, suggests that a 2% fall in demand would indicate a price increase of 20% [2%/(-0.1)=20%]. The larger the absolute value (price elasticity of demand is negative) of the price elasticity, the more sensitive demand is to given change in price. Demand is more sensitive the more there are close substitutes for a product. In the short run, demand is less elastic than in the long run, since there are more opportunities for substitution over time.

The price elasticity of supply is the percentage change in quantity supplied for a given percentage change in price. The value of the supply elasticity is positive, because an increase in price will stimulate additional supply. The elasticity of supply depends on the level inventories that can be supplied into the market and the amount of spare capacity in the refinery industry that can serve as a source of additional supply. Supply is likely to be more elastic the longer the time period, since the firm can adjust its production to new conditions.

6.4.2 Estimates of Demand Elasticity

Although there have been no published studies of the demand price elasticity for gasoline in California to the author's knowledge, there have been a number of empirical calculations of the price elasticity of demand for gasoline for US and international gasoline markets by various economists. (See the Bibliography for a useful list of papers.) The studies report a wide range of estimates, due to their choice of estimation procedure, data sample, and different time frames for analysis.

It is widely acknowledged that gasoline demand is highly inelastic. Thus, small changes in the availability of supply (e.g. a disruption) will have a large effect on gasoline prices. It also means, of course, that small errors in forecasting the elasticity will have large effect on the results.

Three complete surveys of elasticities are worth mentioning. Carol Dahl, in 1986 and 1995 and with T. Sterner in 1991, has examined most studies of demand elasticity for gasoline. In her most recent survey, she distinguished among short-term, intermediate-term, and long-term elasticities of demand. We are interested in the short-term elasticity. This author corrected a number of obvious errors to compile the results in Table 6.2. It is interesting to note that there are often outliers in the estimates that badly skew the results when using the mean of the sample. For example, (See Appendix C) in her 1995 study, Dahl reported one estimate of –2.13 by Franzen and an estimate of +. 03 by Gately. The inclusion of the Franzen estimate in the mean, in particular, skews the results.

The average of the 25 elasticity estimates is -.19, or -.116 if the two outliers are removed. As expected, this is virtually identical with the median of the 25 estimates.

The elasticity estimates do not change materially from her 1986 survey to her 1995 survey.

This author has added seven estimates made after 1995 to Table 6.2. The mean and median of those are in line with the Dahl results.[30]

Of particular interest is the elasticity estimate of -.05 provided by the Western States Petroleum Association on their website tutorial, *Gasoline 101*. This estimate is too low (in absolute value), although a comparison of data for the 1998 and 1999 summer driving season by Stillwater[31] also indicates the same highly inelastic behavior in a response to supply disruptions in 1999.

Table 6.2 – Estimates of Demand Elasticities in the Literature

Surveys of Studies	Mean	Median	Range
Dahl (1995)	-.19	-.10	+. 03 to –2.13
Dahl and Sterner (1991)	-.19	-.18	-.08 to -.41***
Dahl (1986) **	-.15*	-.125*	-.01 to -.52
Post-1995 Individual Studies	**Mean**	**Median**	**Range**
Verleger (2002) Senate Testimony	-.1		
FTC (2001) Midwest Gasoline Investigation	-.2		-.1 to -.4
Perry (2001)	-.05		
WSPA (2001) (PIRINC study)	-.05		
Borenstein (2000)	-.15		
Kayser (2000)	-.23		
API (Porter) (1996)	-.19		

[30] The author has noted a number of studies that use results of the Dahl and Dahl–Sterner work, and quote the range of elasticities that are provided by those authors. Examining the tables in those original works, however, it is clear that the linkage between conclusions and tables are in conflict. For example, Dahl and Sterner quote a mean of short-run estimates, which include inadvertently non-short-term data. Underlying data from their work are given in Appendix C.

[31] Stillwater SFR Report, June 2002

Haughton & Sarkar (1996)	-.15		-.12 to -.17
8 Individual Studies	-.14	-.15	
Std. Deviation of 8 Individual Studies	.07		

*Calculated by this author.
** Estimate is for monthly and quarterly models. Dahl cited -.29 for yearly models.
***Range of means.

Molly Espey (1996, 1998) provides two "meta-analyses" of elasticities. In her creative work, she explained the elasticity estimates (used as dependent variables) on the basis of characteristics of the study (independent variables). Examples of these explanatory variables include functional form, lagged structure, region, time interval, etc.

She concluded, in part, that:

- The short-term response of gasoline demand to price changes is quick, with virtually all the short-run response occurring within a month. (Our results suggest that at the end of four-weeks, over 75% of the price effect is passed-through, but that the full effect takes six weeks, and that the full episode is from 4-8 weeks.)
- Short-run gasoline demand price responsiveness seems to have declined over time.
- The price responsiveness in the United States is significantly different than other countries, usually Canada and European countries. (This study excludes non-US estimates.)
- Static models appear to overestimate short-term elasticities.

Her most important conclusion for our purposes is that "models that include some measure of vehicle ownership and fuel efficiency capture the 'shortest' short-run elasticities by effectively measuring the influence of price and income changes on driving only. Models that omit one or both of these variables would measure … an intermediate or long-run elasticity."[32] Examining the elasticity estimates in the studies in Table 6.2 indicates that those studies that conform to the statement by Espey have lower (in absolute value) demand elasticities. A prime example is the work by Gately. The mean of his elasticity estimates are -.096 and .10, respectively. For purposes of measuring the

[32] Espey (1998) p. 288. The author wishes to thank Sy Goldstone of the California Energy Commission for bringing this to his attention.

short-term impacts of supply outages, it seems appropriate to choose -.1 as the "best estimate" for the demand elasticity.

6.4.3 Estimates of California Gasoline Supply Elasticity

Gasoline supply in California is highly inelastic as well, because of the boutique fuel specifications, the very limited storage, and the long supply routes from alternative sources. During a disruption, alternative supply options in the short-run are primarily from inventory and increased production at other refineries. Given the tight capacity prevailing in California refineries, inventory changes are the primary alternative source.

There do not seem to be any credible estimates of gasoline supply elasticity. It is widely acknowledged, however, that gasoline supply is highly inelastic, and more inelastic than demand in the short-run. Many analysts assume supply is fully inelastic. For our purposes, we use .05.

6.4.4 Combined Supply-Demand Effect

The effect of a shock, such as that caused by a refinery disruption and the subsequent market reaction, is comprised of both demand and supply effects. Given the lack of estimates for the supply elasticity and given the belief that the supply effect is much smaller that the demand effect, the report uses a range of elasticities that captures the uncertainty around the demand and supply effect. Many analysts adopt the approach of assuming the supply curve is fully inelastic[33]. While this simplification should not have a material impact on the results, we choose to explicitly consider both supply and demand effects. Using the most likely value of the demand elasticity and the assumed supply elasticity, we get -.15 for the best estimate of the combined effect. In order to capture the uncertainty around both estimates, the analysis in later sections uses the range of -.10 to -.20 for the combined effects.[34]

6.4.5 Empirical Support for Demand and Supply Elasticity Estimates

In early 1999, due to two disruptions in Northern California, retail prices rose from 112.1 cpg to 162.4 cpg, a 45% rise. In that period, gasoline production fell from about 928 mbd to 844 mbd, a 9% fall, and inventories offset part of this reduction, being down

[33] See Borenstein (2000), Bulow (2001), Verleger (2002).

[34] For medium-term supply problems, such as the tightness envisioned due to problems of an MTBE phase-out, the analysis should use a value of about -.5.

20 mbd, for a total supply fall of 6.9%. This implies an elasticity of -.153, which is close to our estimate.

There are four clean periods for which we can observe price reactions to refinery outages. These periods have low or normal inventories, do not have crude price movements, and do not have any overlapping outages that confound the estimation. A table of these price impacts and the implied combined demand and supply price elasticities is given in Table 6.3. The mean value of -.143 conforms to our assumption.

Table 6.3 – Estimates of Combined Demand & Supply Price Elasticities

Outages	Size (mbd)	Inventory Character	Implied Elasticity
01/24/97	25	High (Winter)	-.200
08/08/1997	21	Low	-.108
04/17/1998	28	Normal	-.137
07/23/1999	31/51/49	Low	-.125
		Average	**-.143**

6.4.6 *Supply Elasticity with the Proposed SFR*

Supply should become more responsive after the introduction of the SFR. We can turn to the work by Pindyck to attempt to quantify this approach, using the demand for storage function introduced in Section 5,

$$\psi = g(N, \sigma, z, \varepsilon)$$

where ψ is the marginal convenience yield (price of storage), N is inventories, σ is the volatility of prices, z represents demand shifting variables (including the spot price of gasoline), and ε is the error term.

Values of the marginal convenience yield can be directly measured whenever there are future prices through the arbitrage equation relating it to spot prices, and futures prices, the risk free rate, and the cost of physical storage. We, however, do not have estimates of the futures price, so we will employ a proxy variable.

We take demand-shifting variables to include monthly dummy variables, the spot price of gasoline, and measure volatility as described before. Since this equation is part of joint equilibrium with the cash market, we need to estimate it by Two Stage Least Squares with appropriate instrumental variables. The resulting equation [35]suggests that an additional million barrels of storage would depress the spot price by about 3-5 cpg on average and increase the supply elasticity by .05. A 1 cpg reduction amounts to a $145 million dollar lower consumer gasoline bill per year.

A detailed model of the California market would be required for these empirical estimates to be more credible.

6.5 Economic Benefit of the Proposed Strategic Fuels Reserve

This section derives estimates of the economic benefit of an SFR through (1) lowering the average spot price (via reduced volatility and increased supply responsiveness) and (2) the ability to truncate the price spikes attributed to refinery disruptions.

Removing an entire spike by replacing disrupted barrels from storage, of course, is highly unlikely and, since it would have to be timed perfectly, not alter consumer perceptions, and not deplete inventories below minimal acceptable levels. The analysis will first illustrate the maximum potential benefit to give an idea of what is at stake and then calculate the likely offsets to this.

The Strategic Fuel Reserve outlined in the Stillwater Associates' report is a dynamic inventory where a fraction (assumed to be 50 mbd, but to be determined) is available to be auctioned off on a daily basis. The reserve may be idle on most days. The characterization of the benefit that can accrue to the California consumer depends on details that have yet to be determined. The key element affecting that benefit include:

- To what extent does the SFR open the California market to potential suppliers that might not normally wish to take the price risk during the long supply journey?
- How quickly the SFR can supply the market?
- How successful is the mere existence of the SFR in muting price spikes associated with rumor?

[35] See Appendix F for the econometric results.

A full analysis will not be possible until these questions have been answered.

6.5.1 Maximum Potential Benefit

Today, California consumers use about 14.5 billion gallons of gasoline a year or roughly 40 million gallons per day. At an average retail price of $1.50 per gallon, California consumers pay $60 million per day for gasoline. Each 1 cpg above the average retail price translates into an additional $400,000 per day. The associated consumer surplus approaches $200 million per day, that is, the surplus over the California consumer's willingness-to-pay.

As shown in Section 2, refinery disruptions have occurred on average about 10 times per year and last for three weeks and take 2% of the gasoline supply out, on average. The price spikes associated with the 2% outages, if not filled out of precautionary inventories, can increase retail prices by 10% and more.

6.5.2 Static Analysis of Benefit during an Average Disruption

The following is an illustrative example, with parameters that may have existed at the onset of the 1999 refinery disruptions. Assume a $1.50 retail price, consumption of 40 million gallons of gasoline per day (14.5 billion gallons per year), and a combined price elasticity of – 0.15. With an average size disruption (2%), the gasoline price increases to $1.70 in accordance with the assumed elasticity. The daily change in the consumer gasoline bill and in consumer surplus is given in Table 6.4. These values show how much is at stake if the disruptions can be mitigated.

Table 6.4 – Changes in Welfare after a Sample Disruption

Elasticity = - 0.15	Before Disruption $ MM/day	After Disruption $ MM/day	Change $ MM/day
Consumer Surplus			-7.92
Consumer Gasoline Bill	60	66.64	+6.64

Since the average disruption is 19 days (2.7 weeks) and there are about ten disruptions per year, the figures in Table 6.4 would have to be multiplied by 200 to express them on an annual basis.

So, even partial mitigation of some of the spikes can reap large economic benefits. The rest of the section turns toward applying the concepts introduced in Section 5 to quantify the economic benefits. For this we first need to determine the likelihood of future refinery disruptions.

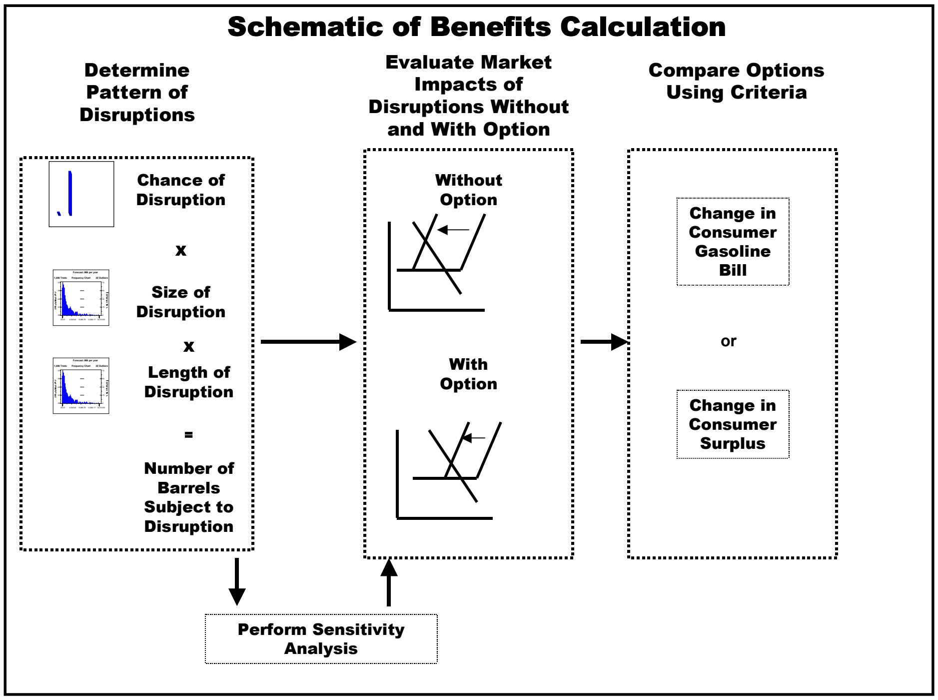
6.6 Monte Carlo Approach to Calculating Economic Benefits

6.6.1 Model

A rich approach to modeling the economic impact of refinery disruptions is through Monte Carlo analysis. This approach derives statistically the distribution of likely total disrupted barrels and then applies the price elasticity of gasoline supply shocks to measure the implied price effect. This analysis proceeds by combining statistically the chance of a refinery disruption, the likely size of a disruption, and the length of the disruption. This is all done assuming draws from relevant probability distributions[36]. (See Attachment E for details on the assumed distributions.)

Figure 6-13 depicts the Monte Carlo model for conducting benefits analysis. As indicated in Figure 5-6, for each week, a random draw is chosen to establish if a refinery suffers a disruption and, if so, how large and long will it last? The model then calculates the economic impact of the disruption without and with the SFR, using elasticities provided earlier. The “with the SFR” calculation allows the spot price to rise by the assumed auction premium, which is a variable in the model. The model then calculates the benefits measures, change in consumer gasoline bill and change in consumer surplus. The model is next used for sensitivity analysis by varying the key assumptions of the user’s choice. The particular set of alternatives is given in Section 6.6.4.

Figure 6-13 – Schematic of Benefits Calculation



The required inputs to the model are:

- Demand elasticity (short-term)
- Supply elasticity (short-term)
- Size of market
- Retail price of gasoline
- Chance of a disruption (per week)
- Probability distribution of size of disruptions (mbd)
- Probability distribution of length of the disruption (weeks)
- Auction differential (cpg)
- Frequency of high Inventories

[36] It is possible to calculate a closed form of the joint distribution, although that approach will not allow for ease of sensitivity analysis.

6.6.2 Statistical Parameters for Monte Carlo Analysis

Chance of a Disruption. Either a disruption can occur or not occur. The probability of a refinery having a measurable disruption during a week is .017, that is, the chance of a given refinery having a disruption in a given week is 1.7%. Since there are 11 refineries in the sample, the chance of a disruption is = 1- $(.983)^{11}$= .172 or a 17.2% chance of at least one disruption during a week.

Distribution of Disruption Sizes. Using the historical data presented in Section 2, the distribution of disruption sizes (mbd) is approximated by the Lognormal distribution.

Distribution of Disruption Duration. The distribution of duration of disruptions (in weeks) is approximated by the Lognormal distribution using historical data.

6.6.3 Base Case Assumptions

For the Base Case, the three key assumptions of disruptions are the historical values for 1996-2001. (See Table 6.6). The price elasticity assumptions of -.10 for demand and .05 for supply are taken from Section 6.3. In addition to these previous discussed inputs, there are four additional assumptions, the first two of which will be considered in the sensitivity analysis.

Retail price. We assume $1.50 per gallon.

Auction premium. When the SFR is operational during a refinery disruption, the auction differential will set the spot price of gasoline. Another way of looking at this is that the prevailing market cost of gasoline plus auction price paid to “borrow” the SFR barrels to be returned at a specified later date sets the marginal price of gasoline. Since the differential is not known with precision, we need to estimate this premium by examining market conditions for providing gasoline from non-California regions, PADD 3 and imports. It is the premium that establishes how much of the price spike the SFR can eliminate – the portion of the “notional” price spike above the auction premium. The base assumption is 10 cpg. A numerical example will help explain this. Consider the behavior of LA and USGC spot prices around a representative refinery disruption. (See Table 6.5 and Figure 6-14.)

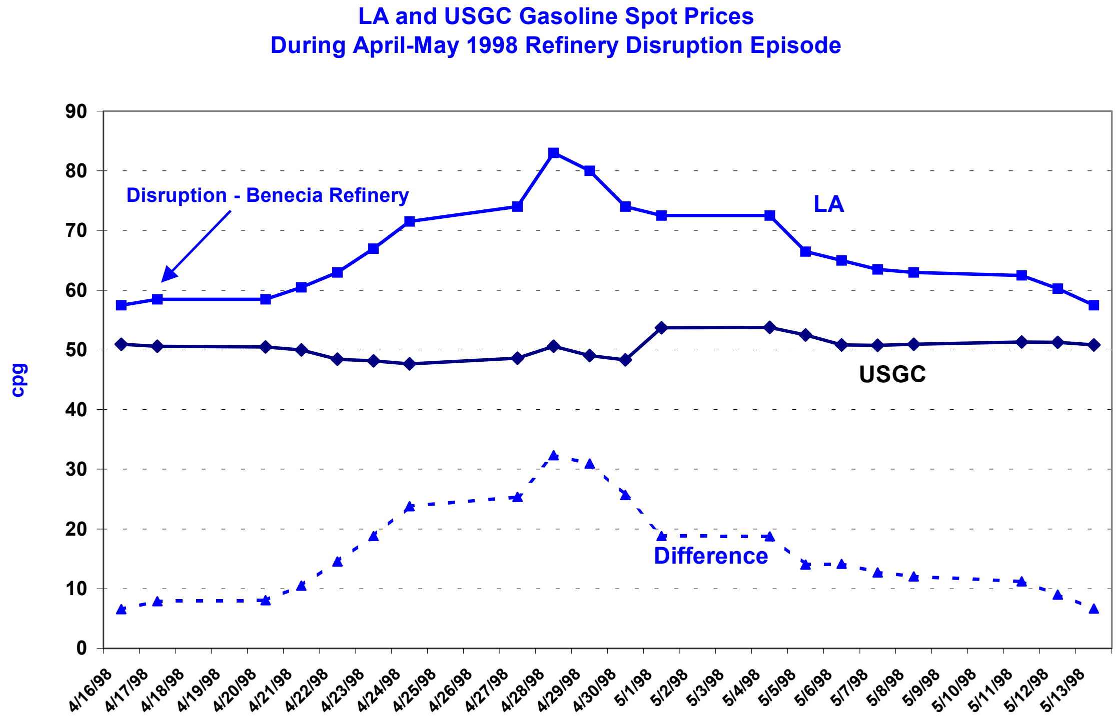
Table 6.5 – Gasoline Prices LA and USGC

	USGC Spot RFG Price	LA Spot RFG (CARB) Price	LA less USGC	Notional USGC CARB delivered to LA
4/16/98	50.93	57.50	6.57	65.93
4/17/98	50.60	58.50	7.90	65.60
4/20/98	50.48	58.50	8.02	65.48
4/21/98	50.00	60.50	10.50	65.00
4/22/98	48.45	63.00	14.55	63.45
4/23/98	48.18	67.00	18.82	63.18
4/24/98	47.68	71.50	23.82	62.68
4/27/98	48.63	74.00	25.37	63.63
4/28/98	50.63	83.00	32.37	65.63
4/29/98	49.03	80.00	30.97	64.03
4/30/98	48.33	74.00	25.67	63.33
5/1/98	53.70	72.50	18.80	68.70
5/4/98	53.75	72.50	18.75	68.75
5/5/98	52.48	66.50	14.02	67.48
5/6/98	50.83	65.00	14.17	65.83
5/7/98	50.78	63.50	12.72	65.78
5/8/98	50.95	63.00	12.05	65.95
5/11/98	51.30	62.50	11.20	66.30
5/12/98	51.25	60.25	9.00	66.25
5/13/98	50.85	57.50	6.65	65.85

On April 17, 1998, the Exxon Benicia refinery had a disruption. Spot prices in LA rose from 57.5 cpg to 83 cpg on 4/28/98 before falling back to 57.5 cpg on May 13, 1998, a month after the disruption. Spot prices in the USGC moved only a few pennies over this time. It appears that Exxon mitigated the disruption by bringing gasoline from the Gulf Coast that landed in late April and early May, about the time of the moderation in spot prices. At the time of the refinery disruption, the cost to transport product from the Gulf to the West coast was about 10 cpg and the cost to produce CARB was about 5 cpg over USGC gasoline. So, the notional cost of delivering CARB from the USGC was

15 cpg above the USGC RFG price. On or about April 22, 1998, LA and USGC CARB prices were in parity. Had the SFR been in place, a market participant could have bid 6 cpg for the immediate delivery of gasoline and back filled it with USGC gasoline without incurring a loss. The spot price spike would have been capped at about 64 cpg in this example. The economic benefit accruing to this scheme would have been the avoidance of running the spot price to 83 cpg, a difference of 19 cpg.

Figure 6-14 – USGC-LA Gasoline Price Differential during Disruption

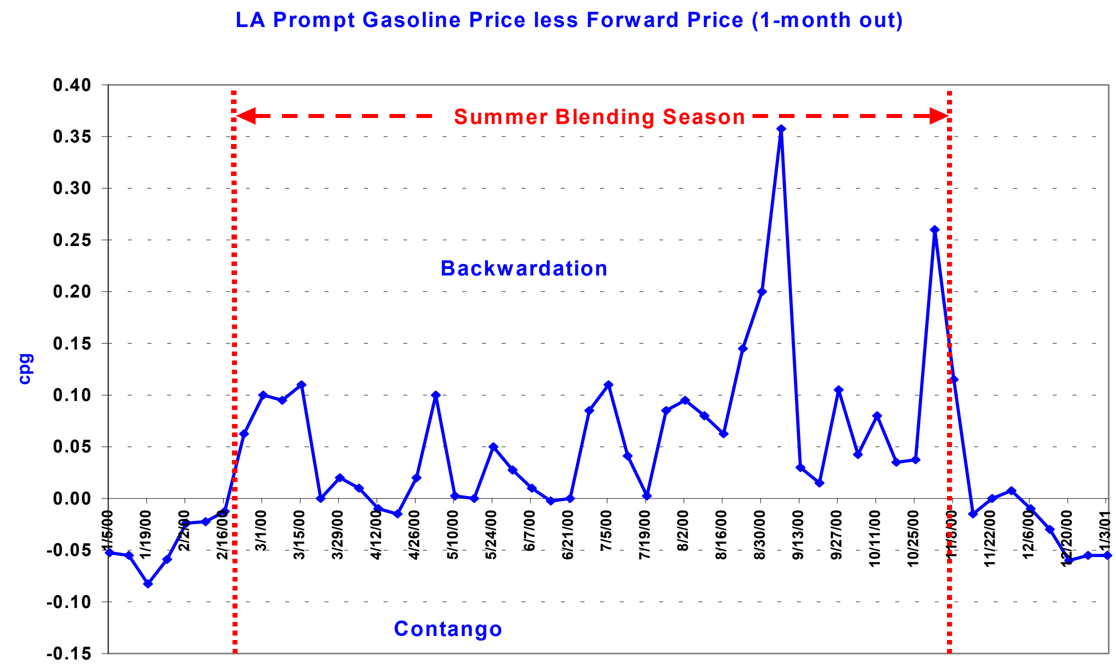


Instantaneous pass-through of the price effect. In Section 4 it was shown how spot price changes are not passed through to retail instantaneously or symmetrically. They pass through with a lag, rising faster than they fall. Since the model simulates a year's worth of disruptions, the lag is not critical to the calculations. The asymmetry, however, suggests that the economic benefits are slightly understated, perhaps as much as 10%.

Frequency of High Inventories. As shown in Section 4, price responses are muted whenever precautionary inventories are high relative to the size of the disruption. High inventories, occur usually, but not always in anticipation of a turn-around period or during the transition from winter to summer gasoline production which is roughly one-quarter of the time. The model explicitly accounts for this effect. According to the

Stillwater Associates plan, the SFR would only contain summer gasoline. Since the SFR will not likely be triggered during a period of high inventories, that is if there are available supply to ameliorate a disruption, an indication of the SFR non-use would be during contango[37] in the forward market. The gasoline market is most likely to be in contango during transition from winter to summer blending. A snapshot of 2000 in Figure 6-15 illustrates this effect. This effect is captured in the model.

Figure 6-15 – Seasonal Backwardation



6.6.4 *Sensitivity Analysis*

The analysis is performed for the following alternative scenarios:

1) *Alternative retail gasoline prices*. Base Assumptions, except that the average retail price is assumed to be $1.00 and $2.00.

2) *Alternative SFR auction differentials*. Base Assumptions, except that the SFR price differential is taken to be 5 cpg and 15 cpg. This explores the effect of not being able to truncate the price spikes at the 10 cpg level.

[37] Contango occurs when the forward price (one-month out) is higher than the prompt price.

3) *Exclusion of severe disruptions*. Base Assumptions, except the disruptions occur at the historical frequency, size, and duration excluding the year 1999. This explores the critique that analysts have raised that 1999 was a analogous to a "100 year flood" [38] and should be excluded from the analysis.

4) *Inclusion of "rumors*." Base Assumptions, except the disruptions identified as "rumors" are included at 1-week duration but no price impact. This explores the notion that the data sample excluded small, actual disruptions because they were not measurable.

A summary of the disruption input assumptions is given in Table 6.6.

Table 6.6 – Input Assumptions for Monte Carlo Analysis

Lognormal Distribution	Chance of Occurrence	Average Size MBD		Average Length Weeks	
Case	Probability	Mean	Std. Dev	Mean	Std. Dev
Base Assumptions Disruptions occur at historical frequency, size, duration	.017	21	15	2.7	3.9
Disruptions occur at historical frequency, size, duration excluding the year 1999	.014	19	14	1.8	1.9
Disruptions include rumored disruptions at 0 mbd impact and 1-week duration	.023	15	15	2.2	3.3

The SFR is not likely to be triggered for small disruptions (less than 10 mbd) of short duration (one week). The model handles this implicitly by not generating large enough price spikes to be ameliorated by the SFR. Thus, small disruptions such as those occurring in winter months are not counted in the economic benefits, since they do not produce a spike above the implied "refill" from the Gulf Coast.

[38] A "10 year flood" would be a more apt analogy. The base case includes 1999 data, in line with this being an "insurance policy."

6.7 Results

6.7.1 Economic Benefits of Reducing Price Spikes.

The Base Case and alternatives were analyzed using Crystal Ball, a Monte Carlo estimator add-in to Excel. Summary results are given in Table 6.7 and Table 6.8. Under repeated conditions that existed in the 1996 to 2001 time frame, the analysis suggests that additional consumer costs would be on the order of $400 million for base case conditions. The change in consumer surplus is close in size to the change in the consumer gasoline bill. The benefits can be reduced by over half this amount if the market does not experience refinery disruptions like those in 1999. In the Base Case, 4 of the 10 estimated refinery disruptions cause price spikes large enough to be truncated by use of the SFR. In all the sensitivities run, the consumer benefits, as measured by the reduction in the consumer gasoline bill or the net increase in consumer surplus with the SFR, would be an order of magnitude above the costs calculated by Stillwater Associates.

Table 6.7 – Net Economic Benefits – Lower Consumer Gasoline Bill

Lower Consumer Gasoline Bill with SFR versus Without SFR			
Assumed Combined Elasticity:	- 0.10	- 0.15 (Best Estimate)	- 0.20
Base Case Assumptions Historical disruption frequency, size, duration $1.50 retail price before disruptions 10 cpg incremental spot price to replenish SFR No price rise during period of high inventories	$687 MM/yr	$398 MM/yr	$261 MM/yr
Sensitivities - Base Case Assumptions Except:			
$1.00 retail price		$220 MM/yr	
$2.00 retail price		$607 MM/yr	
15 cpg incremental spot price		$339 MM/yr	
5 cpg incremental spot price		$498 MM/yr	
Disruptions excluding the year 1999		$169 MM/yr	
Rumored disruptions included		$255 MM/yr	

Even under the most conservative combination of alternative assumptions, for example, that disruptions have a lower chance of occurrence (excluding 1999) and that the SFR mechanism can only offset spikes in excess of 15 cpg, the economic benefits still exceed $ 140 million.

Note that the economic benefits are not symmetric with respect to elasticities, retail gasoline prices, and auction differentials. Using a different analytical approach, Stillwater Associates (2002) estimate that an SFR could have saved the consumer $.5 billion in a ninety-day period in 1999 and $4.7 billion over the 1999-2001 timeframe. These estimates are consistent with the ones provided here. The Stillwater study concludes that the SFR would cost $20 million annually. The benefits calculated in this report exceed the costs by an order of magnitude.

Table 6.8 – Net Economic Benefits – Consumer Surplus

Increase in Consumer Surplus with SFR versus Without SFR			
Assumed Elasticity:	- 0.10	- 0.15 (Best Estimate)	- 0.20
Base Case Assumptions Historical disruption frequency, size, duration $1.50 retail price before disruptions 10 cpg incremental spot price to replenish SFR No price rise during period of high inventories	$745 MM/yr	$401 MM/yr	$269 MM/yr
Sensitivities - Base Case Assumptions Except:			
$1.00 retail price		$200 MM/yr	
$2.00 retail price		$632 MM/yr	
15 cpg incremental spot price		$310 MM/yr	
5 cpg incremental spot price		$535 MM/yr	
Disruptions excluding the year 1999		$166 MM/yr	
Rumored disruptions included		$250 MM/yr	

6.7.2 Economic Benefits of Lowering the Average Gasoline Price.

One consequence of instituting the SFR is that gasoline prices will be on average lower than before the SFR. The estimated equation introduced suggests that prices will be lower by 3-5 cpg on average, translating into the consumer savings in Table 6.9.

Table 6.9 – Lower Average Gasoline Prices.

Days Applicable	3 cpg Lower Average	5 cpg Lower Average
175 Non-disruption days	$210 MM/yr	$350 MM/yr
125 Non-disruption days during the Summer Blending Season	$150 MM/yr	$250 MM/yr

7 OPTIMAL SIZE OF THE STRATEGIC FUEL RESERVE

A number of proposals have been made as to the "optimal" size of the SFR. A sample is given in Table 7.1. The legislative proposal for a reserve equal to two weeks' capacity of the largest refinery translates into 2.3 millions barrels.[39] An SFR sized to cover the average refinery disruption over the sample is 380 mb. To cover the maximum disruption in 1999 without imports contributing to the shortfall would require 6.3 million barrels.

Table 7.1 – Alternative Size Assumptions for the SFR

	MB
Legislative Prescription	2300
Cover average disruption: one refinery suffering a 20 mbd disruption for 2.7 weeks (19 days)	380
Cover Maximum Disruption in 1999	6300

We can use the same analytical approach as used in Section 6 to address the "optimal" size of the SFR (without reference to any offsets). Here, the desired size of a reserve would be one that would be sufficient to offset a disruption given that it occurs. Since the reserve would be replenished in a prescribed manner after the disruption, we need only have sufficient reserves to handle a typical disruption. Since the intent of the legislative inquiry is clearly to have a sufficient supply available, this can be interpreted to mean a sufficient supply to handle, say, the rare disruption. This can be translated statistically to mean the disruption that occurs in the, say, 90th percentile.

Using average parameters for 1996-2001, the Monte Carlo results indicate that the expected size of a disruption is 405 mb with the relevant distribution of results given in Table 7.2. Attachment E shows the full distribution of the size of a typical disruption.

[39] See Stillwater (2002).

Table 7.2 – Distribution of Disruptions under Average Parameter Assumptions

Percentile	Total Disrupted Barrels During a Typical Disruption
Mean (Expected Value)	405
80th	529
90th	865

Alternatively, the estimate of the required size was examined in another manner. A random six-week period, roughly the time of re-supply from imports or the Gulf, was simulated using the model. The resulting distribution of “disrupted barrels” approximates the distribution above.

Table 7.3 – Distribution of Disrupted Barrels during a 6-Week Period

Percentile	Total Disrupted Barrels During a Six-Week Period
Mean (Expected Value)	406
80th	700
90th	1,114

The implication of this analysis is that the size prescribed by the Legislature is significantly more than is necessary to offset a disruption of the type we have experienced in the 1996-2001 period. In order to have sufficient gasoline available to offset the 90th percentile of disruptions (a one-in-ten chance of occurring), the size of the SFR would need to be about 900 mb. Since Northern California and Southern California are not fully connected, one might need to have this available this amount allocated to two locations, one in the North and one in the South[40]. The split would need to be determined by a study of transportation logistics.

Since the SFR is sized for the large disruption episodes, the possible non-usage during the winter does not materially alter the conclusions about the optimal size.

[40] There may be the claim that we need this amount in both locations because of the lack of North-South connection. Since there is waterborne movement of gasoline from North to South, the shifting of barrels might be optimized, so that we do not need to “double” the size of the SFR. Even so, perhaps an amount of additional storage would be needed in addition to the amount calculated herein.

8 CONCLUSIONS

The conclusions from this study are that in California:

- Gasoline prices are higher and more volatile than in the rest of the country (including the Gulf Coast, an important petroleum refining center, and New York, site of the NYMEX).
- Gasoline price volatility has increased since the introduction of CARB II.
- Gasoline price volatility, while increasing generally over time, has been relatively unchanged since 1999.
- Gasoline price volatility is significantly higher than for jet fuel and diesel fuel, which are approximately equal in volatility.
- Refinery disruptions have occurred once a month on average since 1996.
- Production losses due to refinery disruptions average 21 MBD with several larger disruptions.
- Disruption effect is generally short-lived; average 2.7 weeks, but some last 6-8 weeks.
- In most cases, refinery disruptions have an immediate impact on spot prices.
- Planned turnarounds do not affect prices unless coinciding with a disruption.
- A refinery disruption in Northern or Southern California affects prices in the whole State.
- Price spikes are not transmitted to the Gulf Coast, but may be transmitted to neighboring states.
- Refinery disruptions occur in both summer and winter blending seasons in rough proportion to the time in those seasons, but have a more pronounced effect during the summer blending period.
- Refiners respond immediately to try to offset disruptions by drawing down inventories and increased sourcing of gasoline from other areas.The rise and fall of prices during a disruption is asymmetric.
- Retail price effects linger longer than other prices.
- Price spikes are more pronounced during periods of below normal inventories.

- Prices at the various market stages are highly correlated.
- The wholesale to retail pass-through, which is also asymmetric, is virtually complete within 4-8 weeks.
- For measuring short-term price impacts, a reasonable range of price elasticities (combining both demand and supply effects) is – 0.10 to – 0.20 with the best estimate at – 0.15.
- The potential economic benefit of the SFR reducing price spikes, if measured by the avoidance of increased consumer costs or increased consumer surplus, is about an average of $400 million per year under average disruption conditions. The benefits range from $200 to $700 million under various alternative assumptions considered. Benefits could be greater if future refinery disruptions are larger and the duration significantly longer than specified in this analysis.
- The additional potential economic benefit of the SFR in lowering the average price of gasoline (including spurious price spikes) is in the range of $150 – 350 million per year.
- The economic benefits are an order of magnitude larger than the costs determined in the Stillwater report.
- The “optimal” size of the SFR, given the average disruption conditions that existing in the 1996-2001 period, is significantly less that that prescribed by the Legislature.

9 RECOMMENDATIONS

1. Analyze alternatives to the SFR envisioned by Stillwater on a common Cost-Benefit framework similar to that outlined in Section 5. All economic comparisons should be done with the same rigorous analysis.

2. Since the economic benefits of the SFR proposal envisioned by Stillwater Associates appears to offer benefits of an order of magnitude above the estimated costs, the California Energy Commission should proceed to go beyond the scooping study and:

Design the detailed operational features of the SFR,

Examine the auction design to ensure that the mechanism is non-collusive and does not deter entry,

Simulate the SFR under “real” world conditions,

Perform an intense analysis of private versus public storage to ascertain the possibility of “crowding out,”

and

Examine the issues related to development of a forward market for gasoline in more detail.

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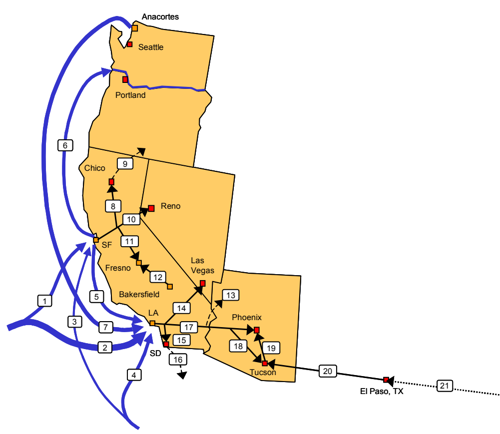


"California is an Island",

Gregg Haggquist, Stillwater Associates, 2002

Attachment A – DOE Data on California Refinery Disruptions

				Gasoline Impact	
	Week Ending Friday	Facility	Brief Description	Amount of Decrease	Maximum Duration
				mbd	weeks
1	3/22/1996	Mobil-Torrance	alky unit & coker	35	1
2	4/5/1996	Arco-Carson	HC & H2 plant at reduced rates	17	1
3	4/5/1996	Chev-Richmond	H2 plant reduced rates	3	1
4	4/12/1996	Shell Martinez	explosion	67	9
5	11/29/1996	Mobil Torrance		27	1
6	12/20/1996	Unocal Wilmington	FCC	1	2
7	12/20/1996	Chevron- Richmond	problems w/ FCC	38	1
8	12/20/1996	Ultramar Wilmington	unplanned prod losses	19	1
9	1/24/1997	Tosco Avon	HC fire	23	6
10	1/24/1997	Texaco-Wilmington	fire alky unit	25	1
11	8/8/1997	Chevron-Richmond	reformer down	21	1
12	8/15/1997	Exxon Benecia	HC & HT problems	20	1
13	4/17/1998	Exxon Benecia	reformer	25	2
14	5/1/1998	Ultramar Wilmington	shut down during outage	36	1
15	5/8/1998	Texaco-Wilmington	shut down during outage	21	1
16	5/8/1998	Tosco Wilmington	shut down during outage	6	1
17	1/22/1999	Exxon Benecia	FCC down for another month	55	12
18	3/5/1999	Tosco Avon	fire in crude unit	40	22
19	3/26/1999	Arco Carson	FCC	55	6
20	4/2/1999	Chevron Richmond	explosion	5	1
21	5/28/1999	Chevron Richmond	HC down	20	8
22	6/25/1999	Equilon Martinez	elec problems w/ FCC	20	2
23	7/23/1999	Chevron Richmond	FCC & alky unit unplanned maint	31	3
24	7/30/1999	Mobil Torrance	fire in H2 plant	20	1
25	8/6/1999	Arco Carson	unspecified	18	1
26	11/2/1999	Tosco Wilmington		8	1
27	2/18/2000	Mobil Torrance	alky problem	10	7
28	4/21/2000	Arco Carson	reformer	50	3
29	5/12/2000	Chevron El Segundo		10	1
30	6/30/2000	Chevron El Segundo	H2 plant problems	17	2
31	7/7/2000	Chevron Richmond	HC problem	10	1
32	7/7/2000	Equiva LA	coker down	12	1
33	7/7/2000	Tosco SF	coker at reduced rates	10	1
34	8/4/2000	Arco Carson	coker down	5	1
35	9/1/2000	Arco Carson	HC & coker down	13	1
36	9/1/2000	Equiva LA	reformer down	13	1
37	9/1/2000	Tosco SF	HC down for unplanned maint	15	1
38	10/6/2000	Mobil Torrance	planned maintenance	45	6
39	10/27/2000	Arco Carson	blending problem	5	1
40	11/3/2000	Arco Carson	HT down	27	1
41	11/17/2000	Mobil Torrance	problems restarting	25	1
42	11/24/2000	Chevron Richmond	crude unit maint	19	1
43	1/19/2001	Arco Carson	VGO HT in planned turnaround	24	1
44	1/26/2001	Valero Benecia	power outages	3	1
45	2/2/2001	Texaco	cut runs due to power costs	5	1
46	2/9/2001	Tosco LA	FCC problem	4	1
47	2/9/2001	Valero Benecia	HC due to restart	14	1
48	2/16/2001	Equilon LA	trouble coming back from turnaround	6	1
49	3/2/2001	Valero Benicia		14	3

DOE defined Refinery Disruptions excluded from sample.

				Gasoline Impact			Reason For Exclusion		
	Monday After Incident	Facility	Brief Description	Amount of Decrease	Maximum Duration	No Impact Given	No Duration Given	Event Had No Impact	Unproved Rumor
				mbd	weeks				
1	4/1/1996	Texaco-Wilmington	HC down			X	X		
2	4/1/1996	Unocal- Wilmington	HC & reformer down			X	X		
3	4/22/1996	Tosco Avon	FCC			X	X		
4	5/17/1996	Unocal Rodeo	fire			X	X		
5	11/18/1996	Texaco-Wilmington	fire levelled a cat feed HT		4	X			
6	3/17/1997	Chevron-Richmond	problems with isomax unit	0			X		
7	4/27/1998	Arco Carson	FCC unplanned maint	170	2				X
8	7/19/1999	Exxon-Benecia	HC running at reduced rate	20			X		
9	7/27/1999	Arco Carson			1	X			
10	2/18/2000	Exxon Benecia	FCC down	0	2			X	
11	6/26/2000	Equilon Wilmington	coker	0				X	
12	7/24/2000	Equiva SF	coker down			X	X		
13	8/7/2000	Equiva SF	HT problem			X	X		
14	10/11/2000	Equilon Martinez	HC	0				X	
15	10/11/2000	Chevron Richmond	crude & HC & cat	0	6			X	
16	11/13/2000	Valero Benecia	H2 plant problems	0				X	
17	4/2/2001	Chevron El Segundo	crude unit sched maint	27			X		

Attachment B – Alternative Volatility Analysis

As an alternative measure of volatility, some analysts use the moving average of the standard deviation of price movements, a useful measure of volatility[41]. It is also expressed in the same units of measure, e.g. cpg, as the underlying data. Figure B.1 displays the 90-day moving average of the standard deviation of prices and a trend line fitted to the data. The standard deviation (volatility) shows an upward trend since 1995. This increase in volatility is also evident in Gulf Coast prices, although not as pronounced. (Figure B.2.)

Figure B.1. LA Spot RFG Gasoline Price

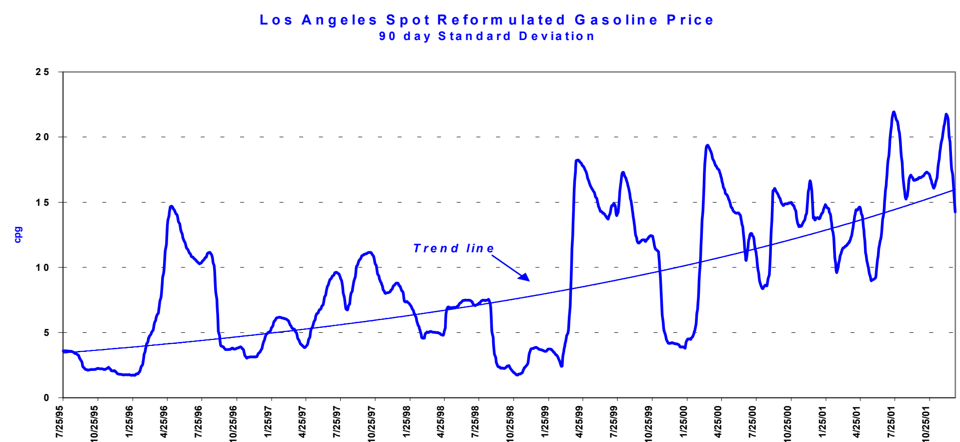
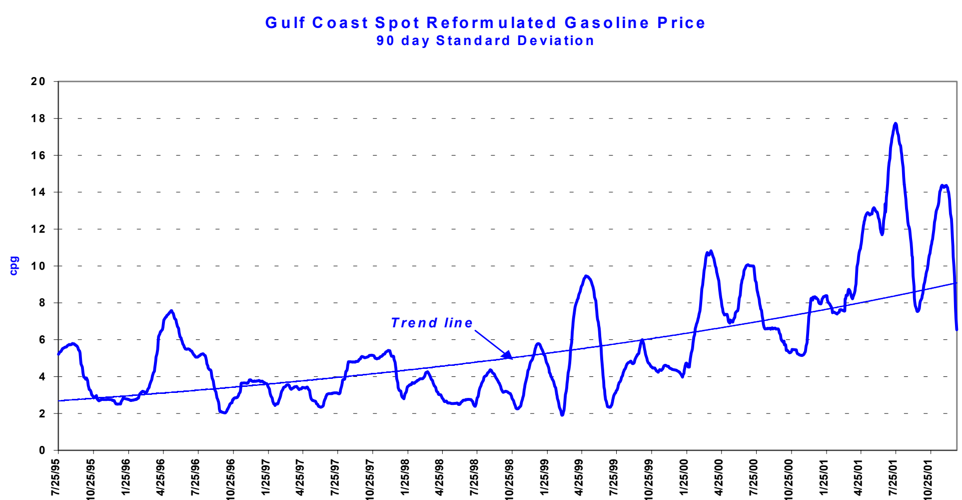


Figure B.2 Gulf Coast Spot RFG Gasoline Price



[41] Many analysts use the standard deviation of adjusted daily log changes in prices as the measure of volatility. See the main text for details.

We can test the statistical significance of the change in volatility as measured by the variance (the square of the standard deviation) in prices over time. The test of significance for the difference between variances of two samples is the F-test, as discussed in the main text. Notice in Table B.1 that the variance increases each year except for the move from 1996 to 1997. As Table B.1 Illustrates, one can reject the hypothesis that the variance in adjoining years is the same in all but the change from 1996 to 1997.

Table B.1. F-values To Test Difference Between Variance In Gasoline Prices Over Time.

Year	Variance	$F=\sigma_1^2/\sigma_2^2$ (Year vs. Prior Year)	Difference in Variance Significant?
1995	9.76		
1996	89.18	9.76	Yes
1997	81.33	1.10	No
1998	44.48	1.83	Yes
1999	248.69	5.59	Yes
2000	336.45	1.35	Yes
2001	547.50	1.63	Yes

Note: F is always calculated with the larger number of the pair in the numerator.

We conclude that gasoline price volatility:

- Has generally increased over time
- Has not changed since 1999

Attachment C – Empirical Results from Selected Elasticity Studies

Table C.1. Short-term Gasoline Price Elasticity Estimates From Dahl (1995)

Study (Year) **	Short-term Elasticity	Short-term Elasticity Chosen*
Hsing (1990)	-.20	-.20
Koshal (1991)	-.17	-.17
Sterner (1990)	-.13/-.29	-.19
	-.19	
Franzen (1991)	-2.13	-2.13
Gately (1992b)	-.10	-.095
	-.13	
	-.06	
	-.09	
Gately (1991)	-.00	-.00
	+.03	
	-.07	
Rao (1993)	-.14	-.14
Uri (1989)	-.31/-.36	-.335
Gately (1988)	-.10/-.15	-.125
Hogan (1989)	-.14	-.14
Gately (1992a)	-.01	-.01
	-.00	
	.00	
	-.02	
	-.00	
	-.01	
Mean	-.191	-.32
Standard Deviation	.42	.61
Median	-.10	-.155
Mean, excluding High and Low	-.116	-.156

* If the study had more than one estimate, this author took the median of the estimates. (For even number of entries, by convention, the median was chosen as the mean of the two middle entries.)

** These are citations in Dahl (1995) and do not correspond to this report's bibliography.

Table C.2. Short-term Gasoline Price Elasticity Estimates From Dahl & Sterner (1991)

Equation Category Cited	Short-term Elasticity	Number of Estimates
C3	-.24	38
C4	-.13	17
C5	-.14	10
C6	-.20	4
C7	-.19	5
C14	-.12	8
C15	-.17	4
C16	-.08	4
C17	-.22	13
C18	-.41	9
Mean	-.19*	
Mean (weighted by estimates)	-.20*	
Median of Estimates	-.18	
Mean with High/Low Categories Deleted	-.18	

Attachment D – Estimate of Retail to Wholesale Price Effects

Figure D.1. Regression Results for Borenstein Model.

Dependent Variable: CR
Method: Least Squares
Date: 03/08/02 Time: 07:55
Sample(adjusted): 4/02/1997 1/23/2002
Included observations: 252 after adjusting endpoints

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.929517	0.352372	2.637885	0.0089
CS1P	0.289667	0.043108	6.719546	0.0000
CS1M	0.137204	0.049766	2.757003	0.0063
CS2P	-0.025771	0.044611	-0.577679	0.5641
CS2MM	0.126943	0.049360	2.571793	0.0108
CS3P	0.089213	0.048706	1.831670	0.0683
CS3M	0.127520	0.049008	2.602009	0.0099
CS4P	0.065058	0.049665	1.309927	0.1916
CS4M	0.107355	0.048497	2.213633	0.0279
CS5P	0.016918	0.050114	0.337583	0.7360
CS5M	0.163118	0.048052	3.394636	0.0008
CS6P	0.043919	0.050567	0.868539	0.3860
CS6M	0.078970	0.047105	1.676447	0.0950
CS7P	0.065538	0.050872	1.288291	0.1990
CS7M	0.042266	0.046723	0.904616	0.3666
CS8P	0.084853	0.050981	1.664403	0.0974
CS8M	0.027038	0.046436	0.582275	0.5610
CS9P	-0.017664	0.051449	-0.343321	0.7317
CS9M	0.027211	0.046346	0.587120	0.5577
CS10P	-0.012268	0.051163	-0.239783	0.8107
CS10M	0.067694	0.045566	1.485635	0.1388
CS11P	-0.053295	0.051452	-1.035821	0.3014
CS11M	0.059142	0.040684	1.453702	0.1474
CS12P	0.029284	0.050693	0.577665	0.5641
CS12M	-0.012748	0.040460	-0.315070	0.7530
RESIDESTLAG	-0.029007	0.018655	-1.554895	0.1214

R-squared	0.536736	Mean dependent var	-0.050397
Adjusted R-squared	0.485490	S.D. dependent var	3.297850
S.E. of regression	2.365528	Akaike info criterion	4.657334
Sum squared resid	1264.633	Schwarz criterion	5.021482
Log likelihood	-560.8241	F-statistic	10.47369
Durbin-Watson stat	1.457423	Prob(F-statistic)	0.000000

Where:

CSxy = Change in Spot Price with lag x

Y=P if positive, M if negative

Table D.1 Weights For Borenstein Asymmetry Model.

Weekly lag	Positive Price Changes	Negative Price Changes
0	.37	.03
1	.55	.13
2	.61	.22
3	.67	.35
4	.70	.50
5	.74	.64
6	.79	.77
7	.85	.88
8	.88	.94
9	.90	1.00
10	.94	1.05

Attachment E – Monte Carlo Results

Figure E.1. Change in Consumer Bill – Base Case Assumptions.

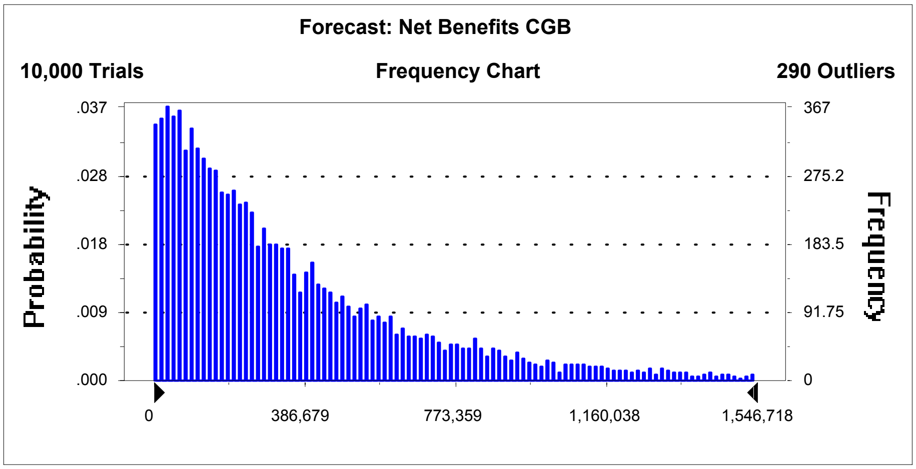


Figure E.2. Change in Consumer Surplus – Base Case Assumptions

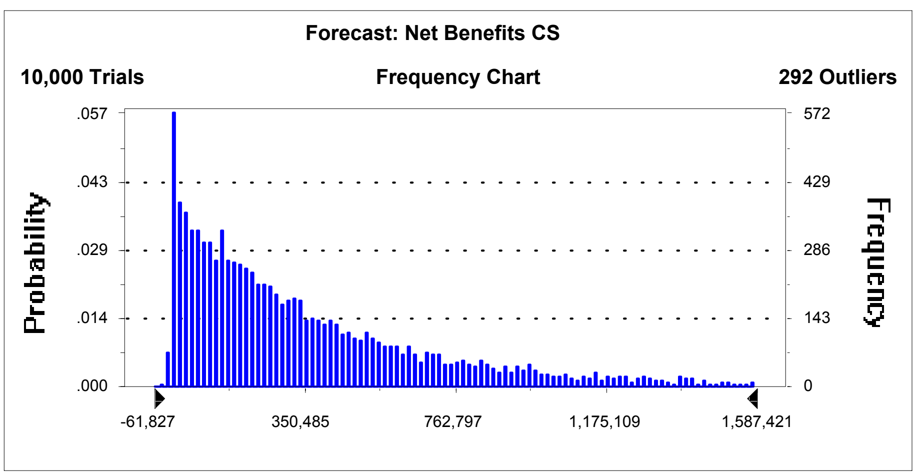


Figure E.3. Distribution of Total Disrupted Barrels Per Year – Base Case Assumptions.

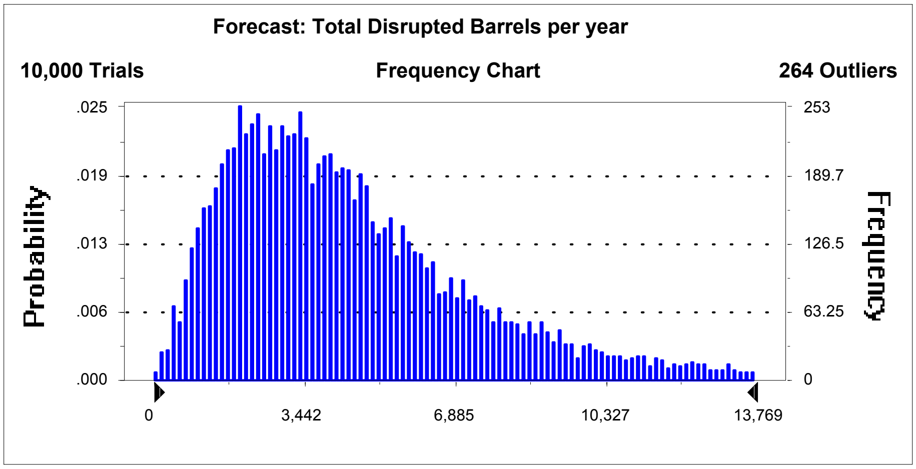
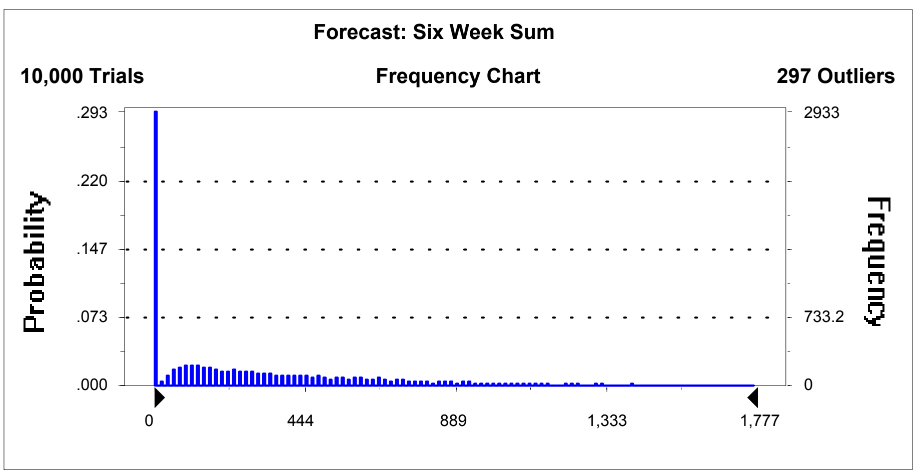


Figure E.5. Total Disrupted Barrels during a 6 Week Period – Base Case Assumptions



Attachment F – Economic Results of Supply Equation

Dependent Variable: SPOT_PRICE01
Method: Two-Stage Least Squares
Date: 05/30/02 Time: 10:09
Sample(adjusted): 1996:03 2001:12
Included observations: 70 after adjusting endpoints
Convergence achieved after 11 iterations
Instrument list: C JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV TIME C_SA_PD01 SIG TB3M TB3M(-1) TB3M(-2)
Lagged dependent variable & regressors added to instrument list

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	92.63351	39.78789	2.328184	0.0238
JAN	-3.231172	4.143809	-0.779759	0.4390
FEB	9.235601	5.583530	1.654079	0.1040
MAR	8.432972	6.092859	1.384075	0.1721
APR	10.88239	6.429755	1.692504	0.0964
MAY	6.478727	6.538065	0.990924	0.3262
JUN	8.179420	6.517032	1.255084	0.2150
JUL	2.230689	6.516596	0.342309	0.7335
AUG	4.115427	6.411578	0.641874	0.5237
SEP	-2.572314	6.343493	-0.405504	0.6867
OCT	-7.418770	5.784844	-1.282449	0.2053
NOV	-8.431357	4.397338	-1.917377	0.0606
ANS_PRICE01	2.054524	0.369190	5.564951	0.0000
CA_INV01(-1)	-0.008364	0.002782	-3.006465	0.0040
SIG	13.46495	7.438943	1.810062	0.0760
TB3M	-6.186311	3.807908	-1.624596	0.1102
AR(1)	0.778636	0.103374	7.532248	0.0000

R-squared	0.884893	Mean dependent var	77.72928
Adjusted R-squared	0.850143	S.D. dependent var	22.54294
S.E. of regression	8.726670	Sum squared resid	4036.203
F-statistic	28.13518	Durbin-Watson stat	2.172229
Prob(F-statistic)	0.000000		

Inverted AR Roots .78

Where:

Jan – Nov are monthly dummy variables (seasonal effects)

ANS_PRICE01 is the price of Alaskan oil (main raw material for gasoline in California)

CA_INV01(-1) is the level of inventories

SIG is a measure of volatility

TB3M is the Three-month T-bill (measures opportunity cost of holding gasoline inventories)

AR (1) First-order autoregressive correction term

STATE OF CALIFORNIA - THE RESOURCES AGENCY
Gray Davis, Governor
CALIFORNIA ENERGY COMMISSION
1516 Ninth Street
Sacramento CA 95814
website:www.energy.ca.gov

Preliminary Agenda for Committee Workshop on Strategic Fuel Reserve and Alternatives to Dampen Price Volatility

Thursday, April 24, 2003
Contractor Presentations and Public Comments

9:00-9:15	Welcoming Remarks (James D. Boyd, Commissioner)
9:15-10:15	Government Use of the California Gasoline Forward Market (Jeffrey Williams, Greg Haggquist)
10:15-10:45	Follow-up Questions and Discussion
10:45-11:45	Permit Streamlining for Petroleum Product Storage (ICF Consulting)
11:45-12:00	Follow-up Questions and Discussion
12:00-1:00	Lunch
1:00-2:00	California Marine Petroleum Infrastructure (Stillwater Associates)
2:00-2:30	Follow-up Questions and Discussion
2:30-3:30	California Strategic Fuels Reserve (Stillwater, Tony Finizza)
3:30-4:00	Follow-up Questions and Discussion
4:00-4:30	Public Comments

Friday, April 25, 2003
Alternative Views on SFR and Public Comments

9:00-10:00	Presentation on Selected Issues Related to Storage (Jeffrey Williams)
10:00-10:30	Follow-up Questions and Discussion
10:30-12:00	Presentations by Panel Members (Verleger, Pervin & Gertz, Hoff/ST Services)
12:00-1:30	Lunch
1:30-4:00	Panel Discussion on Critical Issues Related to the SFR (Verleger, Williams, Pervin & Gertz, Stillwater, Finniza, Haggquist, Hoff)

4:00-5:00 Public Comments

Page Updated: April 18, 2003

CALIFORNIA
ENERGY
COMMISSION

Permit Streamlining for Petroleum Product Storage

DRAFT CONSULTANT REPORT

APRIL 2003
P600-03-006D

CALIFORNIA ENERGY COMMISSION

Prepared By:
ICF Consulting
9300 Lee Highway
Fairfax, VA 22031
Contract No. 500-00-002

Prepared For:
Sherry Stoner
Contract Manager

Daryl Metz
Project Manager

Pat Perez
Manager
Transportation Fuel Supply
& Demand Office

Scott W. Matthews
Deputy Director
Transportation Energy Division

Robert L. Therkelsen
Executive Director

DISCLAIMER

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EXECUTIVE SUMMARY

Background

Historically California has been reasonably self-sufficient in both crude oil and products. In addition to the crude oil produced domestically, California's supply has been supplemented by crude oil from Alaska, and a certain amount of specialty crude oils from the Pacific, and occasionally from the Middle East. Product imports were always minimal. This supply picture began to change during the past few years, and California now finds itself at a point where a confluence of trends and events may have a deleterious impact on the state.

Changes in the market center around a number of factors, many of which California has no control over. California does, however, have control over some market influences. Converging trends include:

- Both federal and state officials are forecasting a steady increase in petroleum consumption during the next two decades, largely in transportation fuels.
- California faces growing dependence on imported petroleum.
- The specifications of California's transportation fuels are such that few refineries outside the state can currently manufacture these fuels.
- Changes in shipping and storage management have introduced efficiencies that have reduced the volume of inventory normally carried by both refiners and terminals, resulting in fewer tanks.
- Increasingly stringent environmental and safety regulations for petroleum product storage facilities have put further pressure on the implementation of optimal inventory management, and has led to the abandonment of older storage facilities.
- All sectors of the petroleum industry have been subject to mergers and acquisitions, reducing the number of firms whose aim is then to optimize and often reduce their assets to recoup their investment costs. This trend results in reductions to "redundant" storage capacity.
- Although California is slated to become more import-dependent the state is just at the cusp of the change. As a result, the current volume of imports fluctuates erratically, creating problems with tank availability.

The growth of demand and the need to import supplies has focused the attention of the California Energy Commission (Energy Commission) on the process of permit acquisition for tanks, this being one of the factors in the equation that they do, indeed, have control over. Anecdotes, complaints, and some information have raised concerns about the complexity of the permit process, a concern that other states are facing as well. The possible concerns range from overly complex regulations, to open-ended time frames, to overlapping jurisdictions, and to barriers raised by citizens (known as NIMBY). All of this translates into additional costs that ultimately get passed on to the consumer.

In a recent California Energy Commission analysis of options for a strategic fuel reserve, the permitting process for petroleum storage tanks was identified as potentially contributing to a shortage of storage capacity for petroleum product.[1] This study, *Permit Streamlining Petroleum Product Storage* was initiated to examine the permitting process for the construction, expansion, or acquisition of petroleum product storage facilities and identify potential areas for improvements and streamlining. This study is an attempt to actually quantify whether or not the complaints are correct and to identify where in the process the problems may lay. If the Energy Commission can identify a true barrier and quantify it, then the basis for streamlining options can be established.

Overview

The analysis was conducted in three phases. Under Phase I, interviews were conducted with permit applicants and representatives of permitting agencies involved in the permitting process for the construction or modification of refinery and storage tanks related to methyl tertiary butyl ether (MTBE) phase out as a gasoline additive. The Executive Order mandated the phase out to be completed by January 2003. This deadline has been extended to January 2004 due to the fact that companies do not have the infrastructure to accommodate the reformulated gasoline.. One factor contributing to this delay was attributed to the lengthy and complicated permitting process. Regulatory research was conducted under Phase II to identify current regulatory processes that hold the greatest potential for improvement. This final report, prepared under Phase III, includes the results of the analyses conducted under Phase I and II and recommendations as ways the State might facilitate and improve the permitting process to reduce the time, expense, and uncertainties incurred by permit applicants.

Findings

Construction of new petroleum storage facility will typically require the following permits: land use permit, building permits, authority to construct permit, hazardous waste generation permit, industrial waste discharge permit, national pollutant discharge elimination system permit, transportation permit, etc., from federal, state, regional and/or local agencies or entities. In almost all cases, construction of new petroleum storage tanks, or expansion of existing facilities will trigger an environmental impact review under the California Environmental quality Act (CEQA).

The three type of permits identified by permit applicants to be the principal cause of permit delays are: conditional use permits,[2] building permits, and air permits. City Planning and Building Commissions approve conditional use permits and building permits. The Regional Air Pollution Control District (APCD) or Air Quality Management District (AQMD) approves air permits or the Authority to Construct. There is no standardized procedure or rule of thumb to let the permit applicants know which permit

[1] California Strategic Fuel Reserve Report. Energy Commission Contractor Report P600-02-017D. July 2002.
[2] Conditional use permits are needed if the proposed project site for a new petroleum product storage facility is not zoned for industrial use. Conditional use permits allow the proposed project to proceed, without requiring a zoning change. Conditional use permits are increasingly required where light industrial development has encroached upon areas formerly zoned for heavy industrial use.

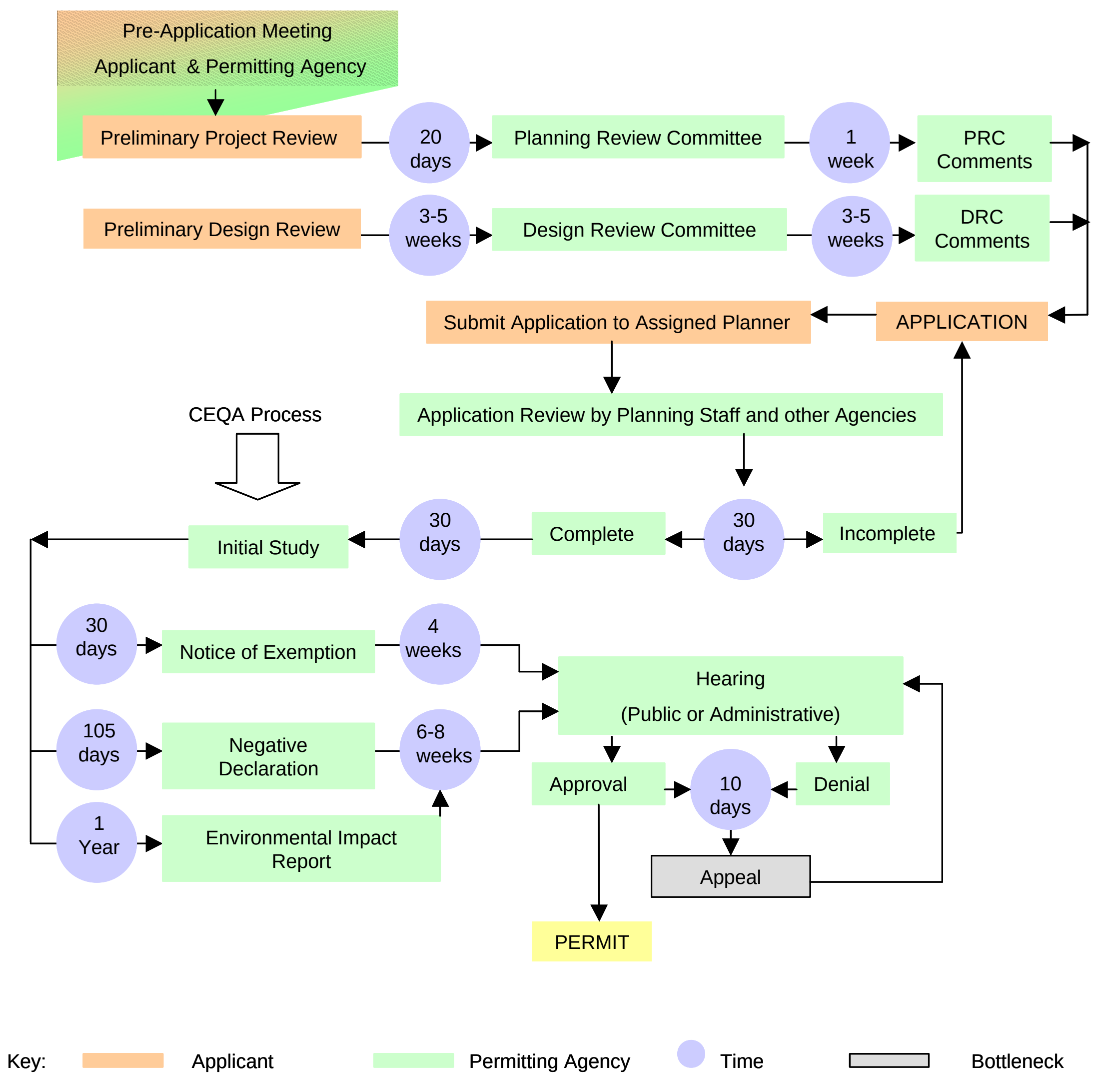
to apply for first. Permit applicants can apply for all the permits at the same time or apply for the permits consecutively. Depending on the location of the project and the permitting jurisdictions involved, Authority to Construct from the Air District may be approved only if the land use permit for was previously approved, or vice versa. Therefore, the strategy for applying for permits is an important consideration in project development. One respondent commented that applicants should concentrate on fulfilling CEQA requirements first.

For construction of new petroleum product storage facilities where a conditional use permit is necessary, the local Planning Commission normally serves as a lead agency under CEQA to coordinate its environmental review with other agencies. For upgrades, renovation, or construction of storage tanks, where conditional use permit is not required and an air permit is, the Air District normally assumes the lead agency role under CEQA. The lead agency must evaluate the proposed project to determine if it has potential to have any significant adverse effects on the environment. The lead agency is required to prepare either a Notice of Exemption (NOE) when it decides that a project is exempt from CEQA and grants approval of the project; a Negative Declaration (ND) indicating that the project will have no significant effect; or an Environmental Impact Report (EIR), which describes the potential negative impacts of the proposal and mitigation measures. After the Negative Declaration or the Environmental Impact Report have been completed, they are subject to public hearings and appeals. Permit applicants indicated that an environmental determination under CEQA could be appealed indefinitely. It appears that multiple appeals have been used as a delaying tactic by groups opposed to specific projects. Exhibit 1 shows a flowchart of a typical permitting process.

Permit applicants and permitting agencies indicated that a conditional use permit could be one of the most difficult and time consuming permits to obtain because of the NIMBY factor (not-in-my-backyard). Neighboring residential communities often oppose new construction or expansion of petroleum storage facilities. Air permits may be also time-consuming to obtain because regional Air Districts have more stringent New Source Review (NSR) requirements than Federal NSR. State-level NSR reviews may require Best Available Control Technology (BACT) control equipment and/or emission offsetting for Volatile Organic Compounds (VOCs). Permit applicants indicated that Air Districts NSR rules may have no clear de-minimus trigger for emission offsetting and BACT requirements are unclear.

Local building departments issue building permits for petroleum storage facilities if the permit application package is complete, the project complies with all applicable building codes, and the project has received all other approvals (e.g., conditional land use permits, air permits). Building permits can be a significant source of delay in the permitting process because often involve complex negotiations between permit applicants and building department personnel over the interpretation of building, zoning, fire safety and other codes and regulations. Almost eighty percent of permit applicant's indicated that more staff and training was needed at the city council level and there was an almost universal desire for training on refining products. The lack of knowledge of the petroleum industry contributed to a significant extension of permitting timeline.

Exhibit 1. Typical Permitting Process



The 1977 California Permit Streamlining Act (PSA) is intended to speed the processing by public agencies of permits for development projects. In general, the PSA specifies that once a permit application is deemed complete the permit application is to be processed through the decision hearing (not including any appeals) in sixty days if the project is exempt from environmental review under the California Environmental Quality Act (CEQA); four months if the project requires an Negative Declaration under CEQA, and one year if the project requires an Environmental Impact Review under CEQA. This study found that time limits set by the Permit Streamlining Act frequently exceeded during the permitting process for petroleum product storage facilities.

Recommendations to Streamline the Permitting Process

The permitting process in California is in general detailed and complex. The permitting process for petroleum product storage facilities is particularly challenging for permit applicants and permit writers. The potential benefits of streamlining the permitting process for petroleum product storage facilities include an increase in petroleum storage capacity, which would improve fuel supply reliability throughout the State.

Interviews with permit applicants for new petroleum product storage facilities indicated that the most difficult permits to obtain, and the ones holding up the entire permitting process, are one or more of the following permits: air quality permits; land-use approvals, such as conditional use permits; and building permits.

Based on survey responses the study team provides the following recommendations:

- Provide training and technical assistance services to city and county building department staff to facilitate permits reviews and field inspections of new petroleum product storage facilities.

- Provide training to local planning and building officials, when needed, in performing California Environmental Quality Act environmental reviews for issuing permits for construction of petroleum product storage facilities.

- Expansion of “hourly rate” approach to permit fees will promote hiring and training of staff. Also, applicants could directly fund consultants to assist permitting agencies in reviewing permit applications.

- Applicants should request preapplication conferences or “scoping” meetings with the permitting agencies to discuss how agencies’ specific rules will apply to their proposed projects. The California Permit Streamlining Act requires all state and local agencies to list the information needed from permit applicants and the criteria they will use in evaluating a project application.

- Establish a system where permitting agencies at the state, district, and municipal level set up, at the inception of the permitting process, a schedule and milestones for the permit review process and establish systems and procedures for the transfer of information among the permitting agencies. Municipalities should work together with the State-level and regional-level agencies with respect to review of the permit applications submitted at the city level. If the local authorities coordinate with the regional and state-level staff reviewing various permit applications, the transfer of information could speed up the permitting process.

- Expand participation in Certified Unified Program Agencies and the Unified Program to the Air Districts, Water Districts, local building and zoning, etc.

- Provide statewide authority for implementing and enforcing the Permit Streamlining Act.

- The agency responsible for implementing the PSA should establish a timeline and milestones for each permitting project, and the agency should track whether the timeline and milestones are being met, and provide for corrective action in the event that they are not being met.

- Update General Plans and zoning ordinances indicating where petroleum product storage facilities are either allowed, require permits or zoning changes, or are prohibited. Clarify when there is a need for a conditional use permit.

- Reduce discretionary decisions by individual permit writers, especially at the local level. Permitting agencies should make their decisions based on specific written guidelines and standardized information requirements. If two developers apply for permits for the same type of facility in the same jurisdiction at different times, they should be subject to a similar permitting process and similar permit requirements, and should be required to submit the same general level of detailed information to

- Provide an independent review of the practice whereby two environmental review studies are prepared at the same time, for the same project, both funded ultimately by the project applicant. Evaluate ways to eliminate this duplication of effort and cost, while avoiding conflicts of interest.

- Involve the Community. Neighbors want to have a voice in the development decision-making for their communities. Permit applicants and agencies should involve the community earlier in the planning process to explain them the benefits and environmental safeguards that the proposed project will have.

- Create a Permit Ombudsman. The ombudsman would assist applicants through the local review process by serving as primary contact throughout the process, responsible for tracking review progress, spurring things along where needed, and reporting status or additional information needs back to the applicant.

- Promote a Unified Program for Permit Review. Currently, the various permit applications required for permitting of new and expanded facilities are reviewed by separate agencies at separate times using separate processes. Municipal agencies, in particular, may not have ready access to information prepared by the applicant or by other permitting agencies for other permit applications. One way to remedy the situation would be to establish a “unified program” under which the various agencies have access to the same information and are in direct communication throughout the permitting process.

1. INTRODUCTION

1.1. Project Objectives

This report, *Permit Streamlining Petroleum Product Storage* was initiated by the California Energy Commission (Energy Commission) to examine the process by which the petroleum industry must engage with permitting agencies and with the public to obtain permits required for the construction, expansion or acquisition of petroleum product storage facilities. The objectives of this study are the following:

- To identify bottlenecks, redundancies, or other unnecessarily burdensome regulatory processes that add undue cost and delays to the permitting process, and
- To develop recommendations to reduce the time, cost, and uncertainties associated with permitting of new and expanded petroleum product storage facilities.

The potential benefits of streamlining the permitting process include increased petroleum storage capacity in the state of California, which could reduce short-term price increases associated with refinery outages and other similar supply disruptions, and improve fuel supply reliability throughout the State. It should be emphasized that the intent of this analysis is not to recommend changes to any existing regulatory standards for public safety or environmental quality. This analysis is only concerned with improving the administrative processes by which permit applicants obtain permits that comply with all existing regulations and standards.

Section 2 of this report provides an overview of the permitting and approval process for refined petroleum product storage tanks, incorporating relevant information about permitting time and permitting cost issues identified by interviewees. Section 3 presents survey results. Section 4 includes a discussion of areas for potential improvement based on analysis of the survey results and regulatory research. Section 5 provides conclusions and recommendations with respect to specific methodologies for streamlining the permitting process and improving permitting time and cost. Six appendices are provided. Appendices A and B contain a list of companies and agencies interviewed and the sample survey respectively; Appendices C and D provide additional information on the California Environmental Quality Act and its environmental checklist form respectively. Appendix E provides information on the California Permit Streamlining Act, a comparison of permit processes in other states is provided in Appendix E.

Based on the results of the surveys conducted under Phase I and supporting information obtained from regulatory research conducted under Phase II, specific recommendations were developed for permitting issues that have the greatest potential for modification and streamlining. The recommendations include steps that the State can implement to improve the permit process to accommodate cost effective and more timely construction and expansion of necessary storage facilities throughout the State. A graphical summary of the steps that are currently required for construction and permitting of a typical petroleum product storage tank was developed and is shown in Exhibit 1.

1.2. Overview of Study Methodologies

The analysis was conducted in three phases. Under Phase I, interviews were conducted with permit applicants and representatives of permitting agencies involved in permitting petroleum product storage facilities. Interviewees were identified based on a preliminary list of industry contacts provided by the California Energy Commission. Additional contacts were identified by selecting companies that had increased total storage capacity of refined products in recent years. This information is available from the OPIS/STALSBY *Petroleum Terminal Encyclopedia*.

The interviews focused on identifying the necessary permit approvals needed prior to construction or expansion of petroleum product storage facilities; whether permitting obstacles exist that are contributing to increased permitting time and cost; and to what extent any such obstacles can be addressed. A permitting timeframe table represented in Exhibit 9 identifies the permits attributed as potential bottlenecks or causes for delays in the permitting process for petroleum product storage facilities.

Regulatory research was conducted under Phase II to identify current regulatory permitting processes that may be characterized by bottlenecks and that hold the greatest potential for improvement. The California Environmental Quality Act, the California Permit Streamlining Act, regional and local land use and building codes and regulations, Air Quality Districts regulations, and related reports were reviewed to identify potential actions for streamlining the permitting process for petroleum product storage facilities.

This final report, prepared under Phase III, includes the results of the analyses conducted under Phases I and II and specific recommendations of ways the State could facilitate and improve the permitting process to reduce the time, expense, and uncertainties incurred by permit applicants.

1.3. Description of Survey Process

Interviewees included representatives of commercial storage providers, refiners, and other operators of petroleum product storage facilities who have successfully applied for permit approval for new or expanded storage facilities, recently entered the permitting process, or have determined that permitting barriers preclude the expansion of existing storage facilities. Interviews were also conducted with representatives of state and local permitting agencies. Appendix A lists companies and permitting agencies contacted.

The study team conducted interviews from November 2002 through January 2003. More than fifteen companies were contacted; only ten companies completed the survey. In many cases, more than one permitting manager within a company was interviewed due to their involvement with different permitting agencies. The first contact with permit applicants was done by phone, follow up e-mails with the sample survey as an attachment were sent to respondents to obtain additional information not readily available at the time of the phone interview. Most of the respondents (eighty percent) requested that their surveys responses remain anonymous. Appendix B provides a sample of the survey used to gather information from permit applicants. Information collected during the interviews included:

- Costs associated with the permitting process relative to the total project cost;
- Timing of costs incurred (i.e. are costs incurred up front, or later in the permitting process);
- Total time required for the permitting process;
- Permitting bottlenecks, or which steps of the permitting process are on a critical path;
- Identification of historical trends in the permitting process;
- Comparison with permitting processes outside California; and
- Specific problems of applicant.

Interviews with representatives of permitting agencies or municipalities were conducted by phone and via electronic mail. The study team found different levels of cooperation among different agencies. Vast majority of the agency representatives interviewed were very helpful; a small minority directed the interviewer to find more information on their web page or provided incomplete information. Information requested of permitting agency representatives included:

- Type of permits needed prior to constructing petroleum product storage facilities;
- The permitting process and timeline;
- Fees and costs associated with the permit;
- Factors that influence the duration and outcome of the permitting process;
- Complaints received by permitting applicants about the time it takes to process the permit;
- Do they believe that their office is understaffed?; and
- What can be done to streamline the permitting process?

2. PERMIT APPLICATION AND APPROVAL PROCESS

2.1. Overview of Permitting Process

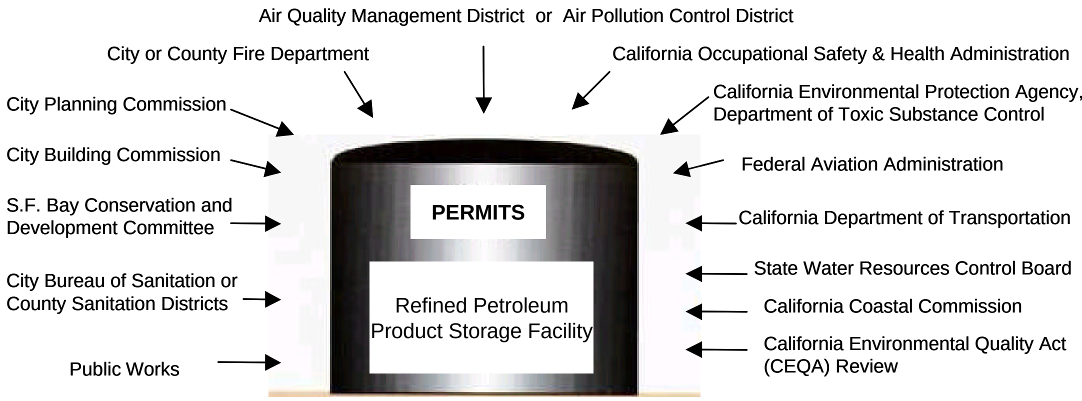
The permitting process for refined petroleum product storage facilities was identified as a significant problem with respect to the permitting process for the construction or modification of refinery and refined petroleum product storage tanks related to the methyl tertiary butyl ether (MTBE) phase out as a gasoline additive, the phase out was required by an Executive Order issued by Governor Davis related to producing CARB Phase III reformulated gasoline. The Executive Order mandated the phase out to be completed by January 2003. This deadline has been extended to January 2004 due to the fact that companies do not have the infrastructure ready to accommodate the reformulated gasoline. One factor contributing to this delay was attributed to the lengthy and complicated permitting process for storage facilities.

A list of typical permitting entities associated with construction or expansion of a petroleum product storage facility is illustrated in Exhibit 2. The involvement of the different permitting agencies and specific permits required is directly determined by the location of the proposed project and the affected resources. The specific geographic location of the project may trigger different federal, state, and/or local regulations; resources affected could be air, water, endangered species habitat, wetlands, etc. The procedure for issuing each particular development permit is governed by the particular law which establishes the permit authority, and by the California Permit Streamlining Act.

Exhibit 2 lists common permits required for a typical new or modified/expanded storage facility. Respondents including applicants and permitting agencies agreed that regulations and the permitting process differ from city to city, and that each project is unique. The permitting process for petroleum product storage facilities in the state of California differs from city to city. There are approximately 468 separate incorporated municipal jurisdictions in California. Each city in the state has its own set of planning and development rules. Land use approvals and building permits must be obtained from local municipalities. Applicants proposing to construct, modify, or operate a facility or equipment that may emit pollutants from a stationary source into the atmosphere must first obtain an Authority to Construct from the Regional Air District. California has thirty-five Air Pollution Control and Air Quality Management Districts, each with a different set of rules and regulations to control emissions. Respondents confirmed that there is no standard procedure regarding which permit to file first, however, one respondent commented that applicants should concentrate on fulfilling CEQA requirements first. There is no standardized procedure or rule of thumb to let the permit applicants know which permit to apply for first. They can apply for all the permits at the same time or apply for the permits consecutively. However, depending on the location of the project and the permitting jurisdictions involved, the air quality permit for a project may be approved only if the land use permit for the project is previously approved, or vice versa. Therefore, the strategy for applying for permits is an important consideration in project development.

The three types of permits identified by permit applicants to be the main causes of permit delays are conditional use permits,[3] building permits, and air permits. City Planning and Building Commissions approve conditional use and building permits; the regional Air Pollution Control District (APCD) or Air Quality Management District (AQMD) approves air permits or the Authority to Construct.

Exhibit 2. Sample of Permitting Entities for Petroleum Product Storage Facilities



2.1.1. The California Environmental Quality Act Process

The State of California enacted the California Environmental Quality Act (CEQA) in 1970, to ensure that state and local agencies consider the environmental impact of their decisions prior of approving a public or private project development. Every development project that is not exempt from CEQA must be analyzed by the lead agency[4] to determine the potential environmental effects of the project. It must be completed within specified time periods, which are concurrent with the time line during which an agency is required to approve or deny the project.

For construction of new storage facilities, the local Planning Commission normally serves as a lead agency under CEQA to coordinate its environmental review with other agencies. For upgrades or expansions of existing storage facilities, where a land use permit is not required and an air permit is required, the Air District assumes the lead agency role under CEQA. Once the lead agency is identified, all other involved agencies, whether state or local, become responsible[5] or trustee[6] agencies. Responsible

[3] Conditional use permits or zoning changes are not needed if the proposed project site for a new petroleum product storage facility is already zoned for industrial use, or if the construction of additional petroleum product storage tanks at an existing facility is deemed an “accessory use” at the site.

[4] The Lead Agency is the public agency which has the principal responsibility for carrying out or approving a project. The Lead Agency decides whether an Environmental Impact Report or Negative Declaration is required for a project, and causes the appropriate document to be prepared.

[5] A Responsible Agency is a public agency which proposes to carry out or approve a project, for which a Lead Agency is preparing or has prepared an EIR or Negative Declaration. For the purposes of CEQA, the term Responsible Agency includes all public agencies other than the Lead Agency which have discretionary approval power over the project.

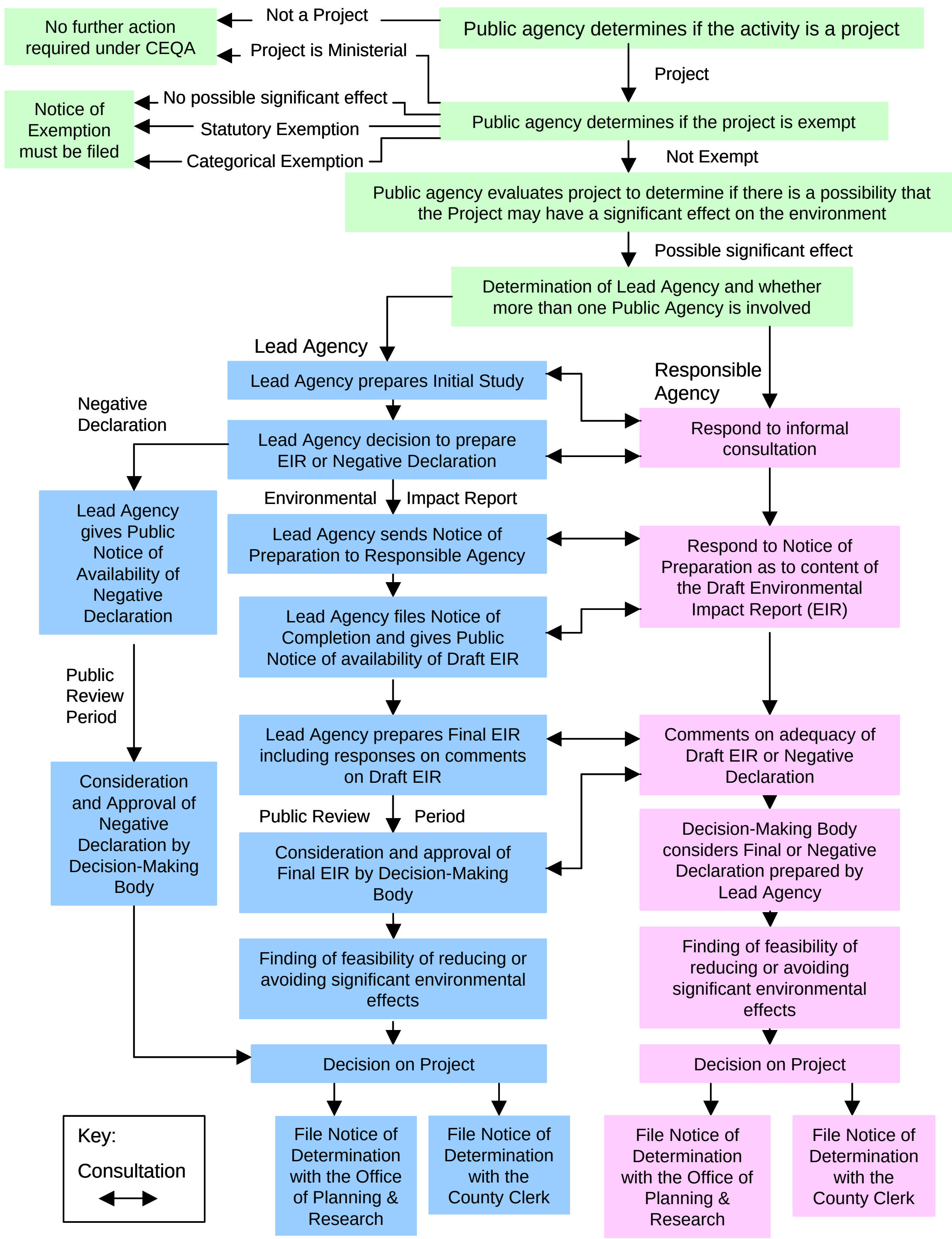
and trustee agencies *must* consider the environmental document prepared by the lead agency and *do not*, except in rare instances, prepare their own environmental documents. Refer to Appendix C for detailed information on the CEQA process. Exhibit 4 shows the CEQA Process flowchart

Exhibit 3. Common Permits Required for a Typical Facility

Agency	Permit
Federal	
Federal Aviation Administration (FAA)	Proposed Construction or Alteration of Objects that May Affect Navigable Airspace
State	
California Environmental protection Agency, Department of Toxic substance control	On-site Hazardous Waste Generation
State Water Resources Control Board (SWRCB)	National Pollutant Discharge Elimination System (NPDES) Permit/ Wastewater Discharge
California Department of Transportation	Transportation Permit
California Occupational Safety & Health Administration	Construction-related permits
California Coastal Commission	Development Permit
Regional or Local	
Air Quality Management District	Authority to Construct Permit
	Permit to Operate
CEQA Lead agency	California Environmental Quality Act (CEQA) Review
Regional Water Quality Control Board (RWQCB)	National Pollutant Discharge Elimination System (NPDES) Permit/Waste Discharge requirement.
Municipal Government	Land Use Permit . (i.e., conditional Use Permit)
	Building Permit
	Grading Permit
	Plumbing and Electrical Permits
County or Municipal Fire Department	Hazmat Permit/ Hazardous Materials Business Plan
	Above Ground Storage of Hazardous/Flammable Materials
County or City Bureau of Sanitation	Industrial Wastewater Discharge Permit

[6] A Trustee Agency has jurisdiction over certain resources held in trust for the people of California. The State Department of Fish and Game is one of four trustee agencies. The others include the State Lands Commission, the Department of Parks and Recreation, and the University of California. Trustee agencies are generally required to be notified of CEQA documents relevant to their jurisdiction, whether or not these agencies have actual permitting authority or approval power over aspects of the underlying project.

Exhibit 4. CEQA Process Flowchart



2.1.2. Local Permitting Process

Many development projects may require more than one type of local or municipal permit. When more than one type of permit is required, the Planning Commission encourages the developer to submit all the applications as one package, which will be processed concurrently. The following discussion summarizes a typical process for review and approval of development projects at the local level. Exhibit 5 illustrates an example of a typical permitting process at the local level, in this case for Martinez City.

Pre-Application Meeting. The applicant schedules a meeting with a staff planner and engineer to describe the proposal and to obtain the general plan policies, zoning requirements, engineering standards and any other applicable city policies or regulations. The staff explains procedures for processing development applications and should indicate all items required for submittal for preliminary review by the Planning Review Committee (PRC).

Planning Review Committee (PRC). Projects are scheduled for PRC review within twenty days of the submittal. Prior to the PRC meeting, staff will review the plans; visit the proposed site and review City policies and regulations pertaining to the proposal. Applicants are strongly encouraged to submit preliminary proposals for project review early in the process of designing the project. The PRC is composed of staff from the Community Development Department (planning, building, engineering and water), police and consolidated fire.

PRC Comments. The applicant will be notified of PRC comments within ten days. PRC comments typically include staff concerns with the project, project conformance with City policies and regulations, recommendations for revisions to the project, required applications and fees, submittal and notification requirements, approximate processing time and recommended conditions of approval. PRC comments should be included in the Preliminary Design Review if applicable.

Preliminary Design Review. Plans and maps should be submitted for Preliminary Design Review early in the process so that revisions to the plans to incorporate the Committee's suggestions can be made prior to formal submittal. The Design Review Committee (DRC) consists of architects, landscape architects and other members, appointed by the City Council, to review the design aspects of proposals and make recommendations to the Planning Commission. The Design Review Committee usually meets twice a month. Projects are scheduled for Design Review within three to five weeks following the submittal.

Application Submittal Applicants revise plans in response to staff (PRC) and Design Review comments and submit completed application forms and findings, plans, fees, notification requirements, environmental assessments and studies, soils reports, etc. to the Project Planner.

Plan Distribution Upon receipt of the application, the planner distributes the plans to the engineering division, fire district, and responsible agencies for review. Within 30 days from receipt of the application, staff should provide a written notification indicating the status of the application. If the application is deemed not complete, a list of information needed to complete the application should be provided to the applicant. Each submittal of new information follows the same procedure for review and notification of completeness within 30 days. No further processing will occur until the application is deemed complete.[7]

Complete Application. When the application is deemed complete, staff reviews the environmental checklist to determine if additional information is needed for the environmental determination. The notice of complete application indicates if additional information is needed. Appendix D shows the CEQA environmental checklist form.

Environmental Review. The City completes the environmental review process required by CEQA. The most basic steps of the environmental review process are to determine if the activity is a project to CEQA; determine if the project is exempt[8] from CEQA; and perform an Initial Study[9] to identify the environmental impacts of the project and determine whether the identified impacts are significant. Typically, a consultant retained by the City at the applicant's expense does the Initial Study. In order to assist in this review the consultant can use any background information submitted by the applicant. The Initial Study must be made within thirty days after the application is deemed complete.

The construction of petroleum product storage facilities is subject to CEQA requirements. CEQA requires the potential environment impact of projects to be evaluated prior to approval. A Negative Declaration is required for projects which have been determined to have no significant impacts. A Mitigated Negative Declaration is required for projects which could have a significant impact but have mitigation measures incorporated into the project to mitigate potential impacts. An Environmental Impact Report (EIR) is required for projects, with significant impacts or impacts that cannot be mitigated.

Time Limits. CEQA requires preparation of a notice of exemption within thirty days of a completed application, adoption of a Negative Declaration within 105 days of a completed application and adoption of an EIR within one year of a completed application. The Planning Commission is required to consider the project within fifty days of approval of the environmental document. In order to shorten processing times,

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[7] According to the Permit Streamlining Act an application may become complete or be deemed complete at any of the following four stages: a) The City or Permitting Agency (Agency) receives a permit application for the first time: The Agency must determine in writing and within 30 days if the application is complete or, if no written determination is made within the 30 days, the application is deemed complete. b) The Agency receives a resubmitted application: The Agency must determine in writing and within 30 days if the application is complete or, if no written determination is made within the 30 days, the application is deemed complete c) The Agency receives a second resubmitted application: The Agency must determine in writing and within 30 days if the application is complete or, if no written determination is made within the 30 days, the application is deemed complete or d) The Agency receives a written appeal of the Agency's determination that the second resubmitted application was incomplete: A decision on the Applicant's written appeal must be made by the Agency within 60 days of receipt of the Applicant's appeal or the application is deemed complete.

[8] A project could be Statutory or Categorical Exempt. Statutory exemptions are descriptions of types of projects for which the California Legislature has provided a blanket exemption from CEQA procedures and policies. Categorical exemptions are descriptions of types of projects which the Secretary of the Resources Agency has determined do not have a significant effect on the environment.

[9] Initial Study means a preliminary analysis prepared by the Lead Agency to determine whether an EIR or a Negative Declaration must be prepared or to identify the significant environmental effects to be analyzed in an EIR.

approval of the environmental document and consideration of the project are generally scheduled for the Planning Commission at the same meeting.

<u>Public Hearing.</u> Upon completion of the environmental review, the project should be scheduled for a Planning Commission hearing. The hearing is scheduled based on the required public notification. There is a minimum ten-day notification for all public hearings. There is a minimum twenty-day notification for all Negative Declarations (thirty days if a State agency is involved) and a thirty-day notification for draft Environmental Impact Reports. Typically projects are scheduled for the Planning Commission hearing within four weeks after the project is deemed complete for projects exempt from CEQA, and within six to eight weeks from completion of a Negative Declaration or EIR.

<u>Planning Commission Agendas & Reports.</u> Municipal government staff prepares a report, which describes the project and discusses how the project complies with City policies and plans. When the staff recommends approval of a project, a set of recommended conditions for approval are prepared and attached to the report. These conditions are required prior to the issuance of permits for the project or upon completion of the project. These reports and conditions are typically completed about the time the public hearing notice is sent out, ten days prior to the hearing. A meeting is scheduled with the applicant to review the draft staff report and proposed conditions of approval.

<u>Planning Commission Meeting.</u> At the Planning Commission meeting, the Chairperson introduces the item and the staff gives a report and recommendation. The Commissioners may ask for clarification. The applicant makes a brief presentation and acknowledges concurrence with the recommendation or concerns with specific conditions. The public hearing is opened by the Chairperson to hear testimony either for or against the project. Before closing the hearing, the applicant is given the opportunity to respond to questions or comments. The Chairperson closes the public hearing, the Commission discusses the project, a motion is made to approve with conditions, deny or continue the project. If the Commission requires additional information to make a decision the proposal is continued, to a future date.

<u>Approval Letter.</u> Within the week following the meeting, the applicant is sent a letter confirming the Planning Commission's decision. For approved projects, the final conditions of approval are attached.

<u>Appeals.</u> There is a ten-day appeal period from the date of the Planning Commission decision. Appeals can be made by anyone who is not satisfied with the Commission's decision. All timely appeals are scheduled for a City Council hearing.

<u>Permits.</u> No permits are issued until the end of the appeal period or until an action on the appeal is final. There is no limit on the number of appeals.

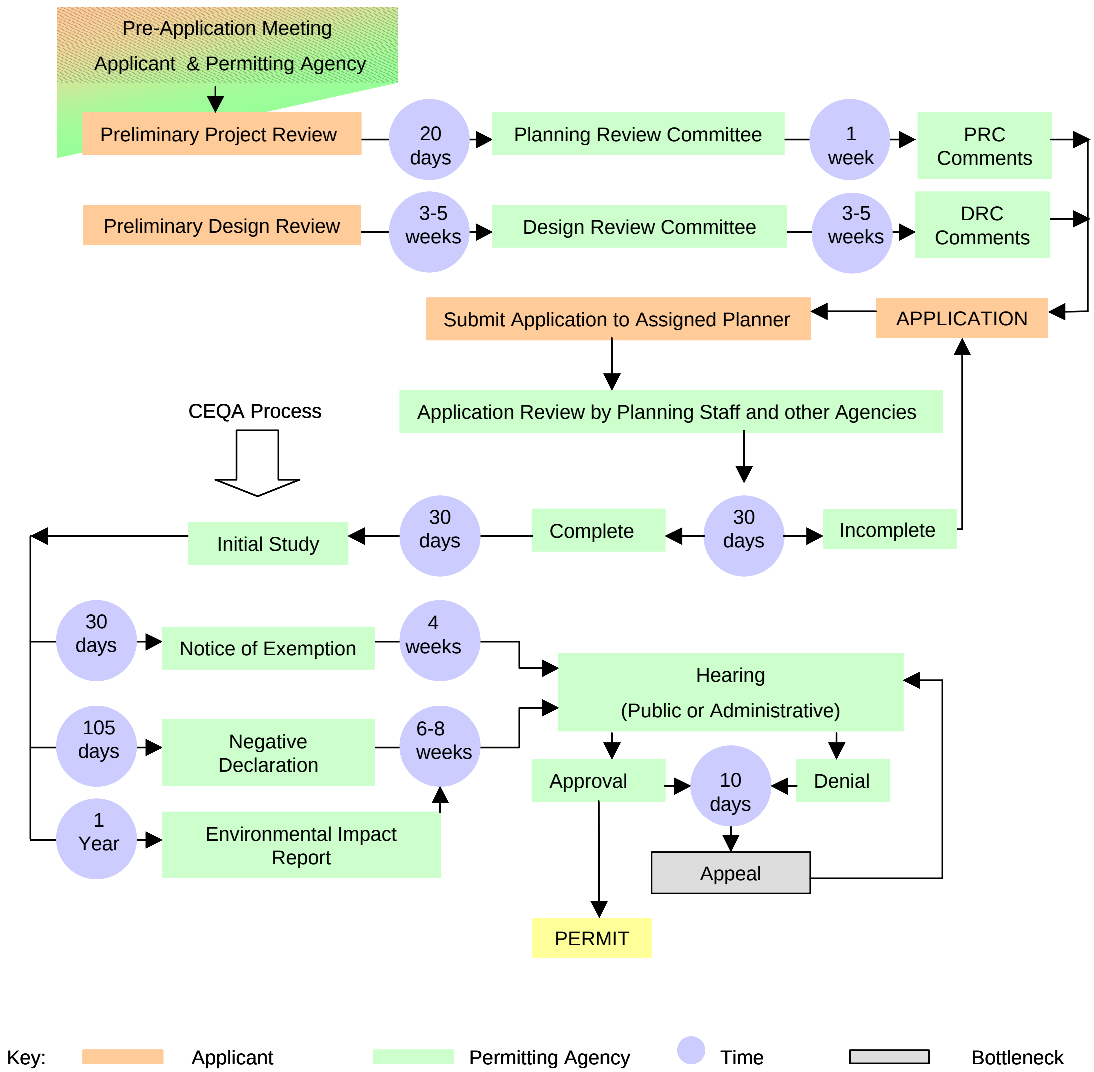
Permitting agencies that offer pre-meetings as part of their permitting process affirmed that the service is not fully utilized by applicants. This practice contributes to serious delays in the permitting process because incomplete applications are submitted for review, which must be returned to the developer for completion.

The public may appeal the issuance of a Negative Declaration or an incomplete EIR, etc. In many cases, concerned citizens appealed the environmental determination by requesting additional studies or information for projects assumed to have environmental and health risks. The applicant can appeal the initial study decision if the recommended action is to develop a complete EIR and they have basis to believe the proposed project won't have significant effects on the environment.

The drawback in the appeal process is that a Planning Commission determination could be appealed indefinitely. As an example, a Planning Commission decision to issue a Negative Declaration to grant the conditional use permit for the construction of an ethanol storage tank at a refinery was appealed by an environmental group several times for different reasons. It appears that such multiple appeals can be used as a delaying tactic by groups opposed to the project. In this case, it took the company more than one year to obtain a Conditional Use Permit.

Exhibit 5 represents an overview of the permitting process at the city level. It is important to highlight that not all permitting agencies offer the opportunity to meet with applicants' prior to submission of the application. The purpose of the pre-meetings or preliminary project reviews is to provide applicants an approximate processing time, related fees, and recommended conditions to facilitate permit approval. Agencies offering pre-meetings commented that that service is not fully used by applicants.

Exhibit 5. The Permitting Process



2.2. Permitting Approval Timeline

This section discusses the overall timeline for permitting new and modified petroleum product storage facilities. The permitting process timeline for new petroleum product storage facility projects based on survey results ranges from eighteen to thirty-two months, depending upon various factors. The primary contributors to the permitting timeline are the CEQA procedures involved in land-use and air quality permitting processes. Under most circumstances other types of permits required for new and expanded petroleum product storage facilities do not contribute significantly to the overall permitting timeline. The most important factors with respect to permitting timeline include the location of the project; the necessity to obtain a conditional use permit; and the necessity to prepare an Environmental Impact Report (EIR) under CEQA.

<u>The Permit Streamlining Act.</u> In 1977, the California Legislature passed the California Permit Streamlining Act (PSA) and established the Office of Permit Assistance (OPA).[10] The PSA was enacted to speed the processing by public agencies of permits for development projects. The Permit Streamlining Act places lead agencies on strict timelines in which to issue all necessary permits. The California Permit Streamlining Act (PSA) sets time limits for government action for permits and approvals for some types of projects. In general, the PSA specifies that once a permit application is deemed "complete" the permit application is to be processed through the decision hearing (not including any appeals) in sixty days if the project is exempt from environmental review under the California Environmental Quality Act (CEQA); four months if the project requires an Negative Declaration under CEQA, and one year if the project requires an Environmental Impact Review under CEQA. Exhibit 6 illustrates the time limits to process CEQA documents for permit applications under the PSA.

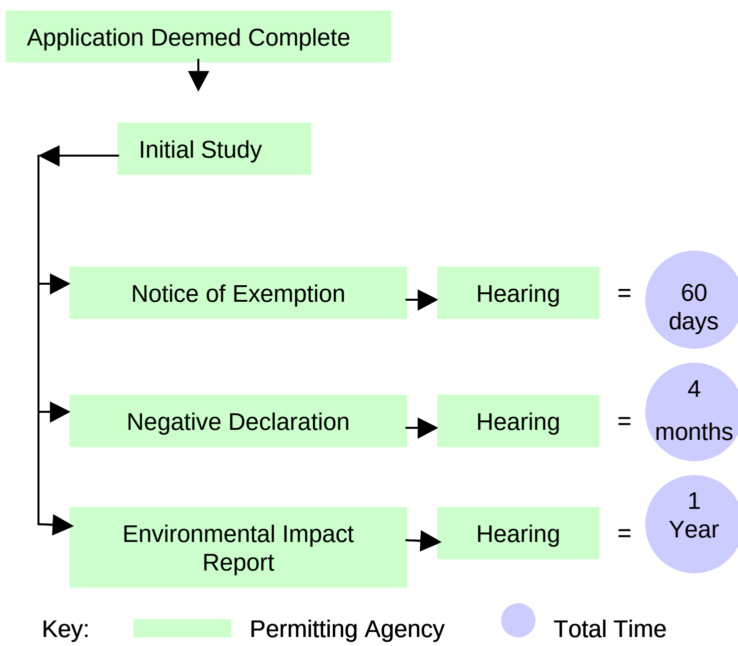
Types of land use permit and building permit applications that are covered by the PSA include: variances, conditional use permits, tentative subdivision plans, and building permits where city discretion is involved (permit is subject to discretionary review hearing). Items that are not covered by the PSA include: certificate of compliance, lot line adjustment, general plan amendments, zoning ordinances, and building permits where no city discretion is involved (permit is not subject to discretionary review hearing). The Permit Streamlining Act does not apply to administrative appeals within a state or local agency. Therefore, if a permit issuance is appealed to a higher body there is no strict time frame within which the appeal must be heard.

The time required to render a permit application “complete” in the view of the permitting agency represents one uncertainty with respect to permitting time. About forty percent of permitting agencies interviewed expressed that the major cause of permitting delays is that applicants do not present the complete set of documentation, studies, or maps when applying for a permit. On the other hand, thirty percent of applicants interviewed point out that they have experienced situations in which agency accepts the application as complete and then calls back after a couple of months requesting additional or missing

[10] The Office of Permit Assistance (OPA) was statutorily charged with enforcing the Act. OPA had fourteen Permit Assistance Centers in California. However, due to state budget cuts the Permit Assistance Centers are in the process of closing

information. The permit application review time may vary depending on project complexity, neighborhood controversy, and the degree to which the project mitigates environmental impacts and conforms to existing regulations and standards. Interviewees indicated that the time limits established in the PSA are not always met.

Exhibit 6. PSA Timeline



2.3. Critical Path Permits

This section discusses three type of permits identified by permit applicants to be the main cause of permit delays.

2.3.1. Land Use Permits

Land use permits include a variety of land use change or development requests, such as zoning changes and subdivisions. Conditional use permits or zoning changes are not needed if the proposed project site for a new petroleum product storage facility is already zoned for industrial use, or if the construction of additional petroleum product storage tanks at an existing facility is deemed an “accessory use” at the site. Whether conditional use permits are required in these two cases depends on the current local zoning ordinances governing the existing or proposed project site. Permit applicants disclosed that the conditional use permit is needed because growth has encroached on petroleum storage facility sites. Land that was once zoned for heavy industrial use in city development plans, now is zoned differently, frequently for light industrial use.

The approval of a conditional use permit is an administrative, quasi-judicial act. It is not a change of zone, but rather a project-specific change in the uses allowed on a specific property. Issuance of a conditional use permit does not involve the establishment of any new codes, regulations, or policies. Instead, a conditional use permit applies the provisions of the zoning ordinance and its standards to the specific set of circumstances that characterize the proposed land use.[11]

Cities and counties have the authority to establish either a board of zoning adjustment or a zoning administrator to hear and decide applications for conditional uses. Local ordinances can establish specific procedures under which a delegated board of appeals will hear and determine appeals from the decisions of the board of zoning adjustment or zoning administrator. In order to encourage concurrent processing for the purpose of expediting zone changes and general plan amendments, Section 65862 of the California Code provides that planning agencies may simultaneously process a consolidated application that may include a use permit, rezoning, and general plan amendment if all three applications encompass the same property.

<u>The California Environmental Quality Act</u>. The issuance of a conditional use permit is an action that is subject to the California Environmental Quality Act. Prior to the public hearing on the proposed conditional use permit, the city or county must evaluate the proposal to determine whether or not it may have any significant adverse effects on the environment. If the proposal is not exempt from environmental review, the city or county is required to prepare either a Negative Declaration, indicating that the conditional use permit will have no significant effect, or an Environmental Impact Report (EIR), which describes the potential negative impacts of the proposal and the means to avoid or lessen those impacts.

The PSA establishes time limits within which the review and approval or denial of a conditional use permit proposal must occur. For example, if an EIR is certified for a conditional use permit, the application for the conditional use permit must be acted upon within 180 days from the date of certification. A proposal for which a Negative Declaration is adopted or a CEQA exemption is issued must be acted upon within sixty days of that action. The PSA provides that failure to meet its deadlines will result in automatic approval of the conditional use permit. However, the permit can only be deemed approved if public notice and an opportunity to be heard have been provided either by the agency or by the applicant. Exhibit 7 represents the PSA timeline for a conditional use permit. The PSA is described further in Appendix E.

<u>Public Hearings</u>. The California Code of Regulations requires a public hearing to be held on an application for a conditional use permit. As a quasi-judicial act, the approval of a conditional use permit requires the board or administrator to adopt written findings to support their action. Whether the proposal has been approved or denied, the decision can be appealed to a higher body, usually the Board of Appeals, the Planning Commission, or City Council, in accordance with the city or county zoning ordinance. The appeals body may reverse or affirm, wholly or partly, or may modify the decision.

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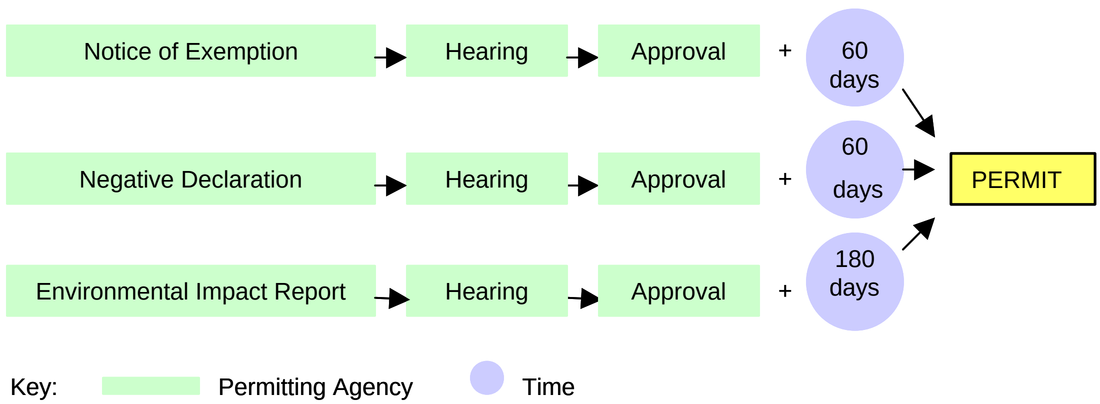
[11] *The Planner's Trainer Series: The Conditional Use Permit.* Governor's Office of Planning and Research (OPR). http://ceres.ca.gov/planning/cup/condition.htm

Permit applicants and permitting agencies indicated that in their opinion, one of the most difficult permits to obtain is a conditional use permit, because of the NIMBY factor. Neighbors often oppose construction of additional refined petroleum product storage facilities in their communities. Conditional use permits often require the project to comply with ordinances pertaining to aesthetics, noise, and traffic. For example, two permit applicants in the Bay Area emphasized the complexity to comply with city ordinances regarding site landscaping and visual impacts. “Proposed projects should not affect a scenic vista or highway. No new equipment should be visible from residential areas; any new equipment that might be visible is expected to blend with the existing site to an extent where the changes would not be noticeable.” One project was modified to comply with the fifteen percent landscaped site mandate buy the city. The second project was cancelled.

Exhibit 7. PSA Conditional Use Permit Timeline



2.3.2. Building Permits

Municipal Planning Departments are charged with the enforcement of the Uniform Building Code, the National Electric Code, the Uniform Plumbing Code, the Uniform Mechanical Code and other applicable codes as adopted by the city, county and the State of California. Building permits are required for construction or modification of petroleum product storage facilities. City or county building departments issue building permits if the permit application package is complete, the project complies with all applicable building codes, and the project has received all other approvals (e.g., conditional land use permits, air permits, etc). The building permit process is not subject to CEQA review or to the time limits imposed by the Permit Streamlining Act.

A typical design review takes approximately six to eight weeks for approval from the time a complete application is submitted. The length of time it takes for approval of the building permit application depends on the complexity of the proposed project (which will affect the duration of the design review), the schedule for Planning Commission and/or City Council meeting(s), how quickly and completely the applicant can respond to requests for information, and whether permit applications from other applicants are submitted to the permitting authority at the same time. Several sets of maps, drawings, and reports need to be submitted with the application form to be distributed to the different offices within the Planning Commission, such as plumbing, electrical, civil engineering, fire department, etc. Thirty percent of interviewees commented on delays in building permits due to the fact that the documentation submitted to the city was either misplaced or lost in the distribution process and had to be resubmitted.

Almost eighty percent of permit applicants indicated that more staff and training was needed at the municipal level and there was an almost universal desire for training on refined products. The lack of knowledge of the petroleum industry contributed to a significant extension of permitting timeline if staff does not have adequate background knowledge to evaluate the permit applications.

All aboveground storage tanks (AST) containing hazardous materials must be permitted by the local fire department under the Uniform Fire Code. A petroleum product storage facility is required to complete a Spill Prevention Control and Countermeasure (SPCC) Plan. The local fire departments are responsible for issuing permits for approving Risk Management Plans. Local fire departments are also responsible for assuring that the City fire codes are implemented. Every city has different fire codes, and the requirements of some local codes exceed the requirements of the State Fire Code Regulations. Modifications and construction of storage tanks are required to implement technologies imposed by the city, and in some cases city governments have requested that applicants install fire protection systems that go beyond the requirements of the existing State Fire Code and/or existing city fire codes. A negotiation process between the applicants and the fire department may be needed, which can delay the permitting process. For example, one permit applicant reported that the fire protection system proposed for the facility was a fully automated system, however, the local fire department requested a different system exceeding current code.

2.3.3. Air Permits: Permit to Construct and Permit to Operate

The principal air emissions from petroleum product storage facilities are volatile organic compounds (VOCs). In the presence of sunlight and heat, VOCs react with nitrogen oxides in the air to form ground-level ozone, the main ingredient in smog. Ground level ozone causes health problems by damaging lung tissue and sensitizing the lungs to other irritants. Local and regional Air Pollution Control Districts (APCD) or Air Quality Management Districts (AQMD) have the authority to issue permits for stationary sources of air emissions. Types of permits include:

- Authority to Construct. The ATC permit allows construction of a new facility or the installation or the modification of equipment at an existing facility.
- Inspection & Temporary Operation. Following construction, installation, or modification, Air District staff inspects the facility to ensure proper installation of all equipment. A temporary operating period is allowed for testing, calibration, and demonstration of compliance with conditions of the ATC.
- Permit to Operate (P/O). The P/O allows continued operation in accordance with all permit conditions and local, state, and federal air pollution requirements.

- Operating Permit. The P/O is re-evaluated every year and is updated as necessary to ensure compliance and to reflect any changes to local, state, or federal requirements.

In non-attainment areas, California's emission permit programs for new and modified stationary sources are referred to as New Source Review (NSR) programs. NSR requirements govern the building and expansion of stationary air emission sources such as petroleum product storage facilities. Under the NSR program, Air Districts evaluate the potential emission increases from new and modified stationary sources. If emission increases are above specified levels, the Air District requires the source to apply best available control technology (BACT) to control emissions. After BACT is applied, the project's remaining air emission levels are then compared to another specified level called the offset threshold. Offsets are required to mitigate any emission increases remaining after BACT has been applied. These offset requirements are usually at a ratio greater than one to one (e.g., a 100 pound per day emissions increase may have to be offset by 110 pounds per day of emission reductions). Offsets are emission reductions at the project location or at a nearby location, which compensate for the expected increase in emissions from the project. If a source reduces its emissions beyond what is required under NSR, it can receive emission reduction credits (or ERCs), which can be sold at a future date or used by the facility to offset future projects.

Each California APCD or AQMD has adopted its own set of regulations. Regulations differ primarily because of an Air District's status in meeting the federal or state ambient air quality standards. Air Districts not meeting the ambient air quality standards will have more stringent emission standards and potentially more complex permitting requirements. Each Air District has adopted specific procedures for evaluating permit applications for Authority to Construct (ATC). The following paragraphs give a general overview of the air permitting process.

Procedures. The local Air District staff first reviews the application to determine whether it contains complete and accurate information. If not, the staff returns it to the applicant specifying what additional information must be provided. When the Air District accepts the application as complete, the staff evaluates it for conformance with the New Source Review Rule, Air District, state and national emissions limitations, and national and state ambient air quality standards. The Air District requires applicants to calculate maximum expected quarterly emissions from the new source. In addition to evaluating criteria pollutant emissions from the proposed source, the Air District will also evaluate the emissions of relevant non-criteria pollutants or toxic air pollutants from the proposed facility.

After completing the evaluation, the air pollution control officer (APCO) decides whether to approve, conditionally approve, or disapprove an Authority to Construct. The APCO writes a preliminary decision and publishes a notice providing thirty days for the CARB (California Air Resources Board), the U.S. EPA, and the public to submit written comments about the preliminary decision. The APCO must consider all written comments and make a final decision within 180 days after accepting an application as complete. The Air District may take about four to six months to review an application for an Authority to Construct.

Construction of petroleum product storage facilities requires CEQA review. The APCO shall issue or deny the Authority to Construct within 180 days of the date on which the

CEQA lead agency approves the project. If the Air Pollution Control District is the lead agency in a project that requires CEQA review, the Air District shall prepare and act on CEQA requirements and permit processing. Once the APCD/AQMD approves the project by certifying the EIR, air quality permits (Authority to Construct) can be issued.

Appeals. If the APCO denies an Authority to Construct, the applicant may appeal the decision within 10 days of the denial notice to the district's Hearing Board. The Hearing Board conducts a public hearing at which the applicant, Air District staff, and the general public may present testimony. The Hearing Board must reach a decision within thirty days of receipt of the appeal, unless the applicant and the Air District agree to additional time.[12] Once the APCO issues a permit, the public participants in the permit proceedings, which include all those who filed comments, may file a petition to the Hearing Board to appeal the issuance of the permit. That petition needs to be filed within thirty days of the decision being rendered.

2.3.4. Other Permits

Construction of storage facilities require additional permits not discussed in detail in this study. Based on information received from respondents to this study these permits do not usually represent a significant hurdle or critical path in the permitting process. Construction-related permits may be required from the California Occupational Safety and Health Administration (CalOSHA) for demolition, construction, excavation, and erection of towers and cranes. For transportation of heavy construction equipment requiring the use of oversized transport vehicles on state highways, applicants must have a Caltrans transportation permit. Modifications to existing facilities may require revisions to the facility National Pollutant Discharge Elimination System (NPDES) permit issued by the Regional Water Quality Control Board (e.g., permits for storm water runoff.) Applicant can apply for these permits concurrently. These permits generally take no longer than sixty days to obtain or revise, and generally do not represent significant bottlenecks with respect to the overall permitting timeline.

Exhibit 8 shows the steps of a typical permitting process by any Air Quality District in California. The permits are individual Authorities to Construct for each emission unit associated for the proposed project.

[12] California Air Resources Board. www.arb.ca.gov

Exhibit 8. Generalized Authority to Construct Process for Stationary Sources

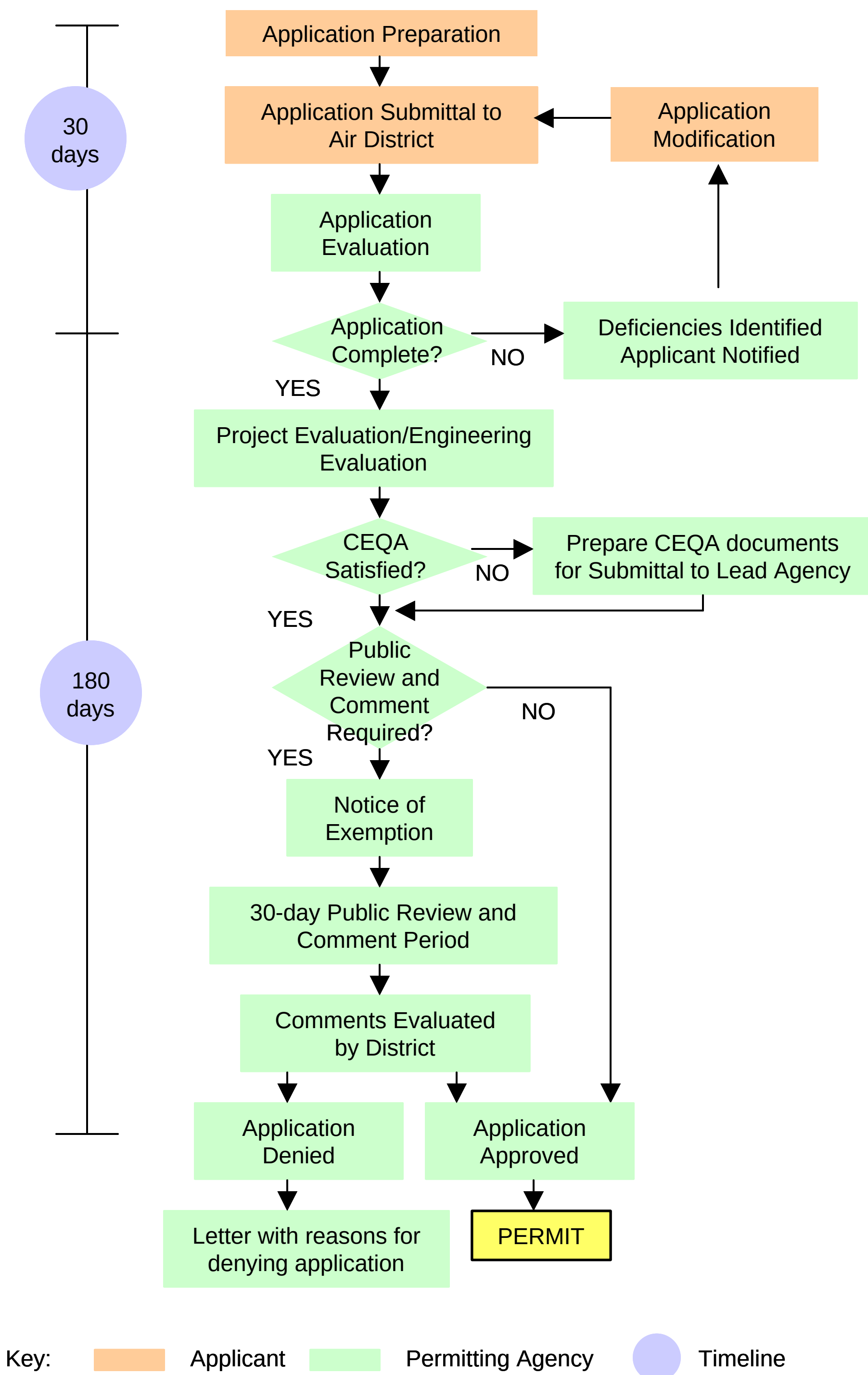


Exhibit 9 captures information provided by project respondents regarding the time normally required to obtain permit approval from the different agencies and local municipalities prior to the construction of petroleum product storage tanks in the state of California. The objective of Exhibit 9 is to identify the permits that have created delays or bottlenecks in the overall permitting process.

Exhibit 9. Permits Timeframe

Agency	Requirement	Delays	Time
State			
State Water Resources Control Board (SWRCB)	National Pollutant Discharge Elimination System (NPDES) Permit/ Wastewater Discharge		3 to 6 weeks
Caltrans	Transportation Permit		6 to 8 weeks
CalOSHA	Construction-related permits		4 weeks
California Coastal Commission	Development Permit		2 to 6 months
Regional or Local			
CEQA lead agency	California Environmental Quality Act (CEQA) Review	Yes	18 to 32 months
	Building, Grading, Plumbing and Electrical Permits		4 weeks to 6 months
City	Land Use Permit (if conditional use permit if needed)	Yes	4 weeks to 24 Months
	Building Permit		2 to 3 months
Fire Department	Hazmat Permit		2 to 6 months
Air District	Permits to Construct	Yes	3 to 6 months
	Title V: Permits to Operate		3 to 6 months

Source: Conversations with permit applicants and permitting agencies

2.4. Permitting Cost

This section discusses the overall cost for permitting petroleum product storage facilities. Project respondents indicated that permitting costs vary from city to city and no two permitting processes are identical. Responses regarding permit process costs ranged from one percent to twenty-five percent of total project capital cost, depending upon factors such as feasibility and CEQA-related studies consulting fees and legal fees. About half of the respondents indicated that these permitting costs were less than ten percent of the total cost of the project. The total cost of a project is considered to be confidential information. To provide an order of magnitude understanding of potential project capital costs, Exhibit 10 shows estimated construction costs for a generic 2.5 MMB (million barrel) petroleum product storage facility in the northeastern United States. Permitting costs are captured under Engineering, Design, and Inspections (ED&I). Respondents indicated that engineering and design costs are always higher than permitting and inspection costs. From this exhibit it can be assumed that permitting costs can fall below the ten percent range.

Exhibit 10. Estimate Construction Cost of Generic 2.5 MMB Tank

Item	Estimated Cost $ Millions
Land	Excluded
Site Work	$5.3
Concrete	$3.6
Metals	$0.8
Finishes	$1.1
Storage Tanks	$4.1
Mechanical	$5.9
Electrical	$3.1
Subtotal	$33.8
ED&I @ 25%	$8.5
Subtotal	$42.3
Contingency @ 25%	$10.6
Total	$52.9

Source: Report to Congress on The Feasibility of Establishing Heating Oil Component to the Strategic Petroleum Reserve. U.S. Department of Energy .1997

2.4.1. Permitting Costs Overview

The principal components of permitting costs for petroleum product storage facilities include the cost to prepare permit applications and other relevant documents, (in-house or contractor labor hours), permitting fees, as well as the important but difficult to quantify cost of delayed project construction. Participants emphasized the need for a faster, more responsive permitting process with firm deadlines for agency and public review, comment, and public participation to reduce those costs.

Industry respondents indicated that permit fees are small and do not contribute significantly to the total permitting costs. Agency respondents indicated that permit fees do not cover the cost to the agencies. Environmental and planning consulting fees can be significant, as can be the cost of uncertainties, delays and changing market conditions. Forty percent of the respondents complained that California New Source Review rules are poorly written with no clear *de minimus* trigger for emission offsetting. One respondent complained; “unanticipated costs were introduced after our application was submitted due to regulators imposing BACT or ERCs.” This is an important issue with respect to “uncertainty cost.” Applicants should be able to identify the regulatory requirement at the inception of their project. If additional studies such as traffic study, health risk assessment, or an environmental impact statement are required, costs could be much greater than anticipated. Sometimes the proposed project requires changes in design to accommodate comments received in the thirty-day review process by the general public or responsible agencies. This results in additional costs to produce supplemental or subsequent EIRs, not to mention the cost of changing the project design itself.

2.4.2. Permit Fees

<u>Land Use and Building Permits</u>. Agencies are allowed to charge applicants directly for permit processing. (i.e., in the form of an hourly rate or in the form of a flat fee). These fees are not established by state law but by municipal ordinances, and will vary greatly between cities. In some cities, filing fees paid up front are credited toward the evaluation fee. Exhibit 11 shows a sample of permitting fees charged to applicants. Information on permitting fees was gathered from applicants and permitting agencies.

<u>Air Permits.</u> Each Air District sets its own filing, evaluation, and emission fees. These fees cover the costs of reviewing applications, issuing permits, and ensuring compliance. Permit fees may range from $100 to $5,000 in major metropolitan areas. As represented in Exhibit 11, these permitting fees can be flat fees or hourly rates charged by the agency for permit processing. For example, the South Coast Air Quality Management District charges a flat fee to review permit applications while the San Diego Air Pollution Control District charges an hourly fee.

2.4.3. Consulting Fees

Due to staffing levels of local agencies, the number of projects, and previous commitments agencies may not be able to process the application in a timely matter. The agency could contract a planning consulting firm that specializes in providing contract support staff to assist governmental agencies. If the applicant wants to receive faster service they may choose to use the planning consulting services. The planning consulting firm assigns a planner to assist the agency in the processing of the project. The planner works under the agency’s direction in accordance with city procedures and policies, coordinating all aspects of the project including the environmental review, correspondence and staff reports. This service is provided at cost, typically at a rate of $90 per hour. To assist in the review, the consultant, as appropriate, may use background information submitted by the applicant. In some cities, a minimum deposit of $10,000 is required to retain these services. Any deposit remaining when the process is completed is refunded. If the cost of service exceeds the deposit, additional funds are requested.

Twenty percent of respondents indicated that a common practice among permit applicants, to accelerate the permitting process, is to contract the services of their own consulting firm to develop their own environmental studies. This means, in some cases, that two separate sets of environmental reports are being prepared for the same project by two different applicant-funded consultants. Sometimes the studies prepared under the direction of the applicant may be shared with the consultants under the direction of the permitting agency. In other cases, the studies prepared under the direction of the applicant also serve as a tool to revise the studies provided by the agency. This practice duplicates the costs of environmental reviews. Depending on the project location and the complexity of the project, consulting fees to prepare an EIR can range between $50,000 to $250,000.

Exhibit 11. Examples of Permitting Fees

Permit	Fee Ranges
Land Use Permit	
Site Plan Review	$500
Conditional Use Permit	$409 to $4,450
Special Use Permits	$13,751
Site Development Permit	$2,000 to $11,430
Tentative Map Review	$1,507 Plus $35 per lot
Commission Review and Approval Process	$3,850
Design reviews	$80 per hour (minimum 4 Hours)
Appeals to Planning Commission and City Council	$175
Building permit	
Grading permit application fee	$150
Engineering Review	$1,250 up to $4,392
Building Permit & Site Plan Review Fee	$75 per hour
Building/Electrical/Fire	$2,300 up to $4,385
Landscape Deign Review	$125 to $500
Air Permits	
AQMD Authority to Construct Filing Fee	$67
Time and Materials Labor Rate/hour	$73 to $110
Stationary Container [Gallons]	
40,000 to 399,999	$2,304 to $4,222
400,000 or greater	$2,876 to $5,278
Permit Fee based on Pollutants emission Nitrogen Oxides (NOx) Volatile Organic Compounds (VOC) Sulfur Oxides (Sox) Total Suspended Particulate (TSP)	Fee/Ton Pollutant $37 $28 to $37 $37 $37
ERC application filling fee	$120 up to $146
Applications to transfer ERCs	$730
Title V Permit.	$100 to $5,000
CEQA related fees	
CEQA “Lead Agency” for analyzing, processing and distributing environmental documents.	$300 to $5,000
Notice of Exemption (upon applicant request)	$180
Initial Studies	$200 up to actual cost plus 25%
Consultant Administration/Negative Declaration	$1,284 up to actual cost plus 25%
Mitigated Negative Declaration	$2,702 up to actual cost plus 25%
Environmental Impact Report	$2,400 up to actual cost plus 25%

Permit	Fee Ranges
Supplemental or Subsequent EIR	$3,605 up to actual cost plus 25%
Addendum to EIR	$2,702 up to actual cost plus 25%
CA Dept. of Fish & Game: Review of NDs	$1,250 by law
CA Dept. of Fish & Game: Review of EIRs	$850 by law
Consultants	
Environmental Impact Report	$50,000 to $250,000
Lawyers fees for CEQA Process	Up to $400 per hour

Source: Conversations with applicants, permitting agencies, and information published on Agency Internet sites

3. SURVEY RESULTS

This Section presents the results from interviews conducted with permit applicants, agencies, and local jurisdictions involved in the permitting process for petroleum product storage facilities across the state of California. The objective of the survey was to understand the existing permitting process and the constraints on permit approvals that have prohibited or delayed the construction of storage facilities. Appendix A lists the companies and agencies contacted contains a sample survey and Appendix B. Eighty percent of permit applicants requested to remain anonymous. The study team has categorized the responses in three categories: land use permits, building permits, and air permits. The following section provides examples of some of the responses.

3.1. Land Use Permit

Applicant comments:

- Inexperienced staff on industry issues. Staff expertise mostly in residential planning. Slow work by city planning staff when reviewing permit applications.
- Planning Commission assumes that all petroleum storage facilities need an Environmental Impact Report up front before granting the conditional use permit.
- Applicants have to contract the services of their own consulting firm to revise the studies provided by the agency's contactor, duplicating the cost for consulting fees.
- Several appeals by environmental groups and labor union to the Planning Commission to invalidate the Environmental Assessment Panel decision to issue Negative Declarations or Mitigated Negative Declarations, resulted in additional legal fees. The appeal process took more than a year to obtain the Conditional Use permit. One company abandoned a proposed project to construct storage tanks facilities for this reason.
- Catering too much to citizen appellant's schedules. Hearing was delayed a couple of months because neighbor went on vacation.
- Local agencies don't have any appreciation for state mandate, they don't feel the urgency to comply with CARB III, and applications can sit on their desks forever.
- Landscape and architectural review can be a big hurdle. In some cases the requirement is that at least fifteen percent of the constructed area be landscaped. Depending on the size of the site this ordinance could prohibit the construction of a storage tank facility.
- We were forced to change our scope of work based on ongoing jurisdictional conflicts and delays due to these conflicts. This set applicant back so far into the review timeline that a drastic scope change was the only option and the project cost several thousand dollars more to construct as a result.

- The arduous permitting process in California involving numerous stakeholders takes twice as long as other U.S. locations.

Agency Comments:

- Applicants do not submit complete applications. It is the applicant's responsibility to present a complete application, the failure to do so results in delays in the permitting process.

- The construction of a new storage tank facility will need a complete Environmental Impact Report depending on the area in which it is being built.

3.2. Building Permits

Applicant Comments:

- Ministerial permits, such as building permits, often involve complex negotiations over the interpretation of building, zoning, fire safety and other codes and regulations, including appeals. City/County staff reviewing applications are not familiar with how the Building Codes or Municipal Codes should apply.

- The Design Review Committee is supposed to encompass all departments to perform a preliminary review of the project scope. After the application package was submitted, it again went to the same departments and took just as long as if it had never been reviewed before.

- A very basic scope is submitted and the amount of time it may take the Building Department to review and approve the package can be exorbitant.

- Final Design is expected with application including engineering details, plumbing, electric, and civil engineering designs. Changing the engineering design is not a trivial operation.

- Fire protection requested by certain fire departments exceeds current code. Fire protection proposed in the tank farm was fully automated, but they wanted more.

- If an application is submitted for a small addition to the facility, the entire facility would be reviewed.

- Permit applicant submitted an application to build new storage tanks at the Long Beach Port. The application was never commented on, the applicant requested two meetings to find out the reason for the delay. They never got a response. The project was cancelled.

- Building and Planning Commissions give an estimated turnaround time at the time of the application submittal and some even have policies about the time to process the plans. More often than not, the city does not adhere to their own established timeline and have no reason to offer as to why the review has gone well past said timeline.

- Building Commission should offer step-by-step checklists of things to do in order to get a permit.

- Local agencies only meet twice a month for hearings, they have different agendas such as politics and reelections.

Agency Comments:

- The Commission role is to enforce city rules and ordinances. Applicants should contact the agency prior to start the permitting process to avoid surprises along the way.

3.3. Air Permits

Applicant Comments:

- Agencies do not have enough staff to review permits. Experienced work force is retiring. Air Districts send permit applications out to be reviewed by contractors. Contractor's comments are beyond the scope of project. New issues came up four months after application was submitted.

- California has stricter New Source Review (NSR) regulations than the Federal NSR regulations in the local Air Districts. State-level NSR reviews may require Best Available Control Technology (BACT) control equipment and/or emission offsetting for Volatile Organic Compounds (VOCs) that would not be required if the project were not in California.

- Air District NSR rule is written poorly with no clear de-minimus trigger for emission offsetting.

- NSR reviews may require BACT control equipment and/or emission offsetting for VOCs. Agency imposes BACT or ERCs. Agency was not able to produce supporting documentation to back up their BACT requirements.

- Company incurred in legal fees because their BACT were not approved at the beginning.

- Tank was empty for one month before it was inspected. Company needed to train agency inspectors to inspect work completion. Delays were attributable to staff inexperience, changing policies, and changing rules.

- California does not have a large community bank for ERCs. Additionally, recent power construction projects in the area have tied up existing ERCs.

- Although all applicants had problems within the permitting process, applicants from the Bay area indicated that not all agencies or local governments work the same way. As an example they indicated how easy it was to obtain an air permit from the Bay Area and the Yolo/Solano Air Quality Management Districts.

- Respondents also indicated that they have experienced delays at the city level in the Bay Area and delays based on more stringent air requirements in the Los Angeles area.

Agency Comments:

- No funding to increase staff. Trained and experienced staff leaves to better jobs.
- The South Coast Air Quality Management District has implemented a permit Streamlining Task Force in 1999 to add efficiency to its permitting process.
- For an easier and faster permitting process build the facility in a non-populated area, zoned as industrial with better air quality.

4. RECOMMENDATIONS AND METHODOLOGIES FOR POTENTIAL IMPROVEMENT

The permitting and environmental review processes in California are complicated in general. The permitting processes for petroleum product storage facilities are even more complicated than for other types of facilities. There are several agencies and many stakeholders involved in both the permit and environmental review processes. Hundreds of federal, state, and local laws and rules may apply to a particular project.

4.1. Recommendations

One of the principal bottlenecks with respect to permitting of petroleum product storage facilities is related to land use and zoning. Cities and counties regulate land use by way of planning, zoning, and subdivision controls. There are currently fifty-eight counties and approximately 468 incorporated cities in California, each with substantially the same authority for land use regulation.

Interviews with permit applicants for new product storage facilities indicated that the most difficult permits to obtain, and the ones holding up the entire permitting process, are one or more of the following permits: air quality permits; land-use approvals, such as conditional use permits; and building permits.

Based on responses from permit applicants and permitting agencies the study team provides the following recommendations:

- Provide training and technical assistance services to city and county building department staff to facilitate permits reviews and field inspections of new petroleum product storage facilities.

- Provide training to local planning and building officials, when needed, in performing CEQA reviews for issuing permits for petroleum product storage facilities.

- Provide an independent review of the practice whereby two environmental review studies are prepared at the same time, for the same project, both funded ultimately by the project applicant. Evaluate ways to eliminate this duplication of effort and cost, while avoiding conflicts of interest.

- Applicants should request preapplication conferences or “scoping” meetings with the permitting agencies to discuss how agencies’ specific rules will apply to their proposed projects. The PSA requires all state and local agencies to list the information and the criteria they will use in evaluating a project application.

- Establish a system where permitting agencies at the state, district, and municipal level set up, at the inception of the permitting process, a schedule and milestones for the permit review process and establish systems and procedures for the transfer of information among the permitting agencies. Municipalities should work together with the State-level and regional-level agencies with respect to review of the permit applications submitted at the city level. If the local authorities coordinate with the regional and state-level staff reviewing various permit applications, the transfer of information could speed up the permitting process.

- Expand participation in Certified Unified Program Agencies and the Unified Program to the Air Districts, Water Districts, local building and zoning, etc.

- Provide statewide authority for implementing and enforcing the Permit Streamlining Act.

- The agency responsible for implementing the PSA should establish a timeline and milestones for each permitting project, and the agency should track whether the timeline and milestones are being met, and provide for corrective action in the event that they are not being met.

- Update General Plans and zoning ordinances indicating where petroleum product storage facilities are either allowed, require permits or zoning changes, or are prohibited. Clarify when there is a need for a conditional use permit.

- Reduce discretionary decisions by individual permit writers, especially at the local level. Permitting agencies should make their decisions based on specific written guidelines and standardized information requirements. If two developers apply for permits for the same type of facility in the same jurisdiction at different times, they should be subject to a similar permitting process and similar permit requirements, and should be required to submit the same general level of detailed information to the agency.

- Promote standardization of regional building and fire codes.

4.2. Methodologies for Potential Improvements

This section identifies specific actions that the State might implement to improve the permit process to accommodate cost effective and timely construction of needed refined petroleum storage facilities.

4.2.1. Permitting Time

Coordination of Permit Review Processes

Permitting time for petroleum product storage facilities might be reduced significantly if permit applicants, planners, and permitting agencies staff meet earlier in the permitting process to explain the proposed project and to obtain complete information on permit requirements such as general plan policies, zoning requirements, engineering standards, city policies, permits fees and timing. This means also that the permitting agencies should not change the requirements or introduce substantial new requirements during the permit process, as some respondents have reported.

<u>Agencies Can Integrate Reviews.</u> CEQA provides a unique opportunity for streamlining efforts to share information and planning responsibilities with other affected agencies early on, so the environmental review process takes less time. Uncoordinated processes, on the other hand, put agencies and the public in adversarial positions

delaying actions that are important to local and regional economies, as well as actions that are intended to improve the environment. While an efficient CEQA process requires that all interested agencies become involved in proposals early on and remain involved until solutions are found, many agencies have failed to use CEQA in this way.

Applicants suggested the following recommendations to streamline the permitting process:

- Combine similar reviews and eliminate unnecessary procedures.
- Establish coordination among agencies— how well agencies share information and integrate planning responsibilities with other agencies early in the process.
- Schedule review steps to run concurrently.
- Provide a definite time period for completion of reviews.
- Decrease uncertainty in the review process by reducing the number of discretionary decisions.[13]

Although many individuals and agencies may be involved in the local development review process, designating a single agency for permit coordination will reduce the number of agencies and departments the applicant must deal with during the process. The applicant should be able to make a single visit to the permitting agency to gather all information and forms relevant to the construction or upgrade storage facilities. Municipal governments should work together with the State-level and regional-level agencies on the review of permit applications submitted at the municipal government level to ensure better coordination.

Creation of development review ombudsman*.* The ombudsman's role is to assist applicants through the local review process by serving as primary contact throughout the process, responsible for tracking review progress, spurring things along where needed, and reporting status or additional information needs back to the applicant. The ombudsman is typically selected from among the local review staff and must be intimately familiar with local development, refined petroleum storage tanks regulations, and all aspects of the review process.

Standardization of Permit Review Processes

An approach for standardizing the permitting process of petroleum product storage facilities would be to establish a “unified program” for permitting such facilities. Currently, the various permit applications required for permitting of new and expanded facilities are reviewed by separate agencies at separate times using separate processes. Municipal agencies, in particular, may not have ready access to information prepared by

[13] Discretionary decisions require that the local review official rely heavily on his or her own judgment when making a development approval decision, since specific evaluation criteria are not included in the relevant local development regulations. The regulations may only include general guidelines for decision making, such as "appropriate landscaping should be provided" or "design of new construction should be compatible with pre-existing development in the area." Non-discretionary decisions are instead based on specific criteria that are made explicit prior to project review. These criteria are specific enough to eliminate the need for judgment calls by the review official. For example: "10-foot wide landscaped buffers shall be provided; these shall include trees selected from Table B, planted at even intervals of between 20 and 25 feet down the center of the buffer area." The development approval is typically awarded immediately after the developer demonstrates compliance with all applicable evaluation criteria.

the applicant or by other permitting agencies for other permit applications. One way to remedy the situation would be to establish a “unified program” under which the various agencies have access to the same information and are in direct communication throughout the permitting process.

An excellent example at the state level is the California Environmental Protection Agency’s Unified Program.[14] The Unified Program (UP) was created by Senate Bill 1082 (1993) to consolidate, coordinate, and make consistent the administrative requirements, permits, inspections, and enforcement activities for the following environmental and emergency management programs:

- Hazardous Materials Release Response Plans and Inventories (Business Plans)
- California Accidental Release Prevention (CalARP) Program
- Underground Storage Tank Program
- Aboveground Petroleum Storage Act Requirements for Spill Prevention, Control and Countermeasure (SPCC) Plans
- Hazardous Waste Generator and Onsite Hazardous Waste Treatment (tiered permitting) Programs
- California Uniform Fire Code: Hazardous Material Management Plans and Hazardous Material Inventory Statements

The Unified Program is intended to provide relief to businesses complying with the overlapping and sometimes conflicting requirements of formerly independently managed programs. The Unified Program is implemented at the local government level by Certified Unified Program Agencies (CUPAs). Most CUPAs have been established as a function of a local environmental health or fire department. Some CUPAs have contractual agreements with another local agency, a “participating agency” (PA) that implements one or more program elements in coordination with the CUPA. The success of the Unified Program depends on the effective working partnerships of local, state and federal agencies. Local agencies (CUPAs, and PAs) have created a partnership and formed the California CUPA Forum.

The following state agencies are involved with the Unified Program:

- California Environmental Protection Agency (Cal/EPA)
- Department of Toxic Substances Control (DTSC)
- Governor’s Office of Emergency Services (OES)
- Office of the State Fire Marshal (OSFM)
- State Water Resources Control Board (SWRCB)

[14] http://www.calepa.ca.gov/CUPA

4.2.2. Permitting Costs

Survey responses indicate that some permitting agencies may not have enough trained staff to manage their workload of permit applications in a timely manner. Some permitting agencies, mostly at the local level, charge permit applicants a flat permit fee to review each permit application submitted, while other permitting agencies, mostly Air Districts, charge permit applicants an hourly rate for the time spent reviewing the permit application.

Expansion of Permit Fees. Changing the permitting agency fee structure from a flat fee structure to an hourly rate structure may allow agencies to recover more of the actual cost to evaluate applications. Generally, flat fees are relatively modest and do not cover all of the permit review costs. Permit driven agencies or departments within an agency should be able to sustain themselves with the fees charged to the developer to cover the actual operating costs to process and review the permit application. Expansion of the "hourly fee" approach to include both permit review and overhead costs would allow permitting agencies to hire additional staff.

Eliminate Duplication of EIR Preparation Costs. As previously described, a common practice among project developers is to contract the services of a consulting firm to prepare an EIR, in addition to the EIR being prepared by a consulting firm contracted by the agency. This means that for some projects two EIRs are being prepared for the same project at the same time by two different consultants, both funded by the applicant. The effects of this practice and methods to eliminate the need for duplicate EIRs should be studied further. One potential approach to eliminate duplicate EIRs is for the applicant to participate directly and on a day-to-day basis in the development of the EIR prepared by the consultant under contract to the agency. The applicant would provide funding to the consultant through the agency, and the agency would be responsible for reviewing, approving, and issuing the EIR, and would be responsible contractually for the consultant. However, the applicant and permitting agency would coordinate with the consultant to establish a schedule, scope of work, and milestones for preparation of the EIR. Developers, permitting agencies and contractors would work together throughout the process in the preparation of the EIR.

4.2.3. Streamlining Statutes

Following are examples of statutes that are applicable to and might be useful for improving the permitting process for petroleum product storage facilities in California.

California Permit Streamlining Act. The California Permit Streamlining Act (PSA) sets time limits for permitting actions. This act is little known among stakeholders involved in the permitting process, and therefore little effort is made to comply with the PSA. There is no agency within California specifically tasked with implementing the PSA. This is a fundamental problem. If the requirements of the Act are not promoted by a single agency responsible for its implementation, neither applicants nor permitting agencies will become familiar with the Act and with the importance of compliance with the Act. Also, in the absence of an implementing agency, the only way to enforce the PSA is for the applicant to sue the permitting agency for noncompliance with the provisions of the Act, which most applicants are unwilling to do.

Environmental Permit Streamlining Act (ESB 6188) (TPEAC).[15] The Washington State Environmental Permit Streamlining Act (RCW 47.06) is an example of a permit streamlining mechanism whose purpose is to coordinate streamlining the environmental permitting process for transportation projects. This statute creates an interagency Transportation Permit Efficiency and Accountability Committee (TPEAC), which is responsible for creating a sustained focus on achieving both the transportation and environment goals of the state. Transportation Permit Efficiency and Accountability Committee (TPEAC) includes senators and representatives from the state legislature, state agencies, local government, and business, trade and environmental organizations. Federal and tribal agencies are also invited to participate. Public involvement is an essential part of the streamlining process through public outreach activities, performance reports, and public attendance at TPEAC meetings. California could adopt a similar interagency committee to streamline the permitting process to construct or modify petroleum product storage facilities.

[15] Washington State Department of Transportation. Environmental Permit Streamlining Act (ESB 6188) (TPEAC) http://www.wsdot.wa.gov/environment/streamlineact/default.htm

APPENDIX A – COMPANIES AND AGENCIES INTERVIEWED

Exhibit 12. Companies Contacted

Company Name	Location
BP	Carson, Long Beach, Richmond, San Diego, Signal Hills, South Gate, Stockton, West Sacramento
Cenco Refining company	Santa Fe Springs
Chevron	Eureka, Huntington Beach, Martinez, Montebello, Richmond, Sacramento, San Diego, San Jose, Tracy, Van Nuys,
Coast Energy Group	Bakersfield
Equilon/Shell	Long Beach, San Diego, San Jose, South San Francisco, Stockton, West Sacramento, and Wilmington
Exxon Mobil	Anaheim, San Diego, and Vernon
Getty Terminals Corporation	Bronx in New York
IMTT	Richmond
Kinder Morgan	Brisbane, Chico, Fresno, Imperial, Long Beach, Milpitas, Niland, Orange, Rancho Cordova, San Bernardino, San Diego, San Pedro, and Stockton
Kern Oil & Refining Company	Bakersfield
Oiltanking Houston Terminal	Houston, Texas
ST Services/Shore Terminals LLC	Crockett, Martinez, Richmond, Stockton and Wilmington
Valero (Ultramar)	Bakersfield, Carson, Benicia, and Wilmington
Tesoro Refining and Marketing Company	Vancouver and Anacortes in Washington
VOPACK	Wilmington

Exhibit 13. Agencies and Organizations Contacted

Bay Area Air Quality Management District
California Air Resources Board
California Department of Fish & Game
California Office of Permit Assistance
City of Martinez
City of Richmond City
Independent Liquid Terminals Association
Port of Long Beach
Port of Los Angeles
San Diego Air Pollution Control District
South Coast Air Quality Management District
Texas Commission on Environmental Quality
York Engineering LLC

APPENDIX B – SAMPLE SURVEY

The purpose of this survey is to understand the necessary efforts that must be undertaken to obtain permits for the construction, or expansion of refined products storage facilities in the State of California. The outcome of this project may serve as basis to make recommendations to permitting agencies to streamline the permitting process.

Your response would be kept confidential if you desire to do so.

Confidential ____Yes ____ No

1. Permitting Process for:
   - Facility Name
   - Facility Type: ____ Refinery _____Terminal
   - Facility Location:
   - Proposed Project description:
   - Fuel type/Tank Capacity:
   - Other?
2. Please list the permits and the issuing Agencies (City/local, County, Regional, State, and Federal,) that your storage facility required prior to construction and before the start of operations. Please include as many rows as necessary.
3. How long did it take you to obtain each permit? If you don't have exact dates, please estimate the time it took you to obtain each permit or provide us a timeline of your permitting process experience.
4. Would you please estimate the cost incurred on each permit.

Agency	Permit Name	Application Submitted	Permit Approval Date	Estimated Cost
City Planning or Building Commission				
Fire Department				
Police Department				
AQMD/APCD				
Water District				
Environmental Health Department				
Others				

5. What, according to you, were the biggest hurdles for obtaining these permit? Which Agency or permits took longer? Why?

6. Please describe any bottlenecks, redundancies, or other unnecessarily burdensome regulatory processes that added undue cost and delays to your permitting process. Please explain.

Permit Name/Agency	Comments

7. Did the scope of your project change after it was reviewed by the permitting agencies? If yes, please explain.

8. What, according to you, needs to be changed so that the permitting process could be accelerated? Please provide recommendations on how to streamline the process.

9. How would the proposed changes impact your company?

10. How would you compare the costs, associated with the permitting process, relative to the total project cost? If known. What percentage of the total project cost were they? When were these costs incurred; at the beginning of the permitting process or towards the end?

11. In the past (if relevant), did you feel like you spent more or less time obtaining a similar set of permits? How long ago was that?

12. If you have to go through the same process again what would you do differently?

13. Do you have experience on storage tanks permits procedures in other states (TX, LA, NY, NJ, or WA)? How do they differ from the permit process in California?

14. Would you like to include information not requested in this survey that might be useful in the development of this project?

Thank you for your participation!

APPENDIX C – CEQA OVERVIEW

The California Environmental Quality Act (CEQA) was enacted in 1970 as a system of checks and balances for land-use development and management decisions in California. [16]

Environmental review is characterized by an Environmental Impact Report (EIR). The EIR records the scope of the applicant's proposal and analyzes all its known environmental effects. Project information is used by state and local permitting agencies in their evaluation of the proposed project.

Once the lead agency is identified, all other involved agencies, whether state or local, become responsible or trustee agencies. Responsible and trustee agencies *must* consider the environmental document prepared by the lead agency and *do not*, except in rare instances, prepare their own environmental documents. The procedure for issuing each particular development permit is governed by the particular law which establishes the permit authority and by the California Permit Streamlining Act.

There are three major phases in the development process as provided by CEQA and the PSA: The Pre-Application Phase, The Application Phase, and The Review Phase.

<u>I. Pre-Application Phase:</u>

The Pre-Application Phase begins when the developer-applicant has completed the conceptual and preliminary design work for a project and is ready to prepare a project proposal. At this point, enough information should be available to describe project activities and to identify the project's proposed location. The primary objective of this phase is to identify the appropriate permitting agencies and to collect as much relevant background information possible.

Many proposals (projects) will require special studies either before or during the formal processing of the application. All state and local agencies are required to list the type of information and the criteria they will use in evaluating a project application. Developer-Applicants may request preapplication conferences or "scoping" meetings with the permitting agencies to discuss how agencies' specific rules will apply to their proposed projects. By the end of the pre-application phase, the developer-applicant should have a good understanding of the detailed project information required, a list of probable permitting agencies, and an indication of the degree of environmental analysis required by the agencies. The agency with the greatest authority over the project will usually assume the lead agency role, all other involved agencies, whether state or local, become responsible or trustee agencies.

<u>II. The Application Phase:</u>

The Application Phase begins with the filing of the necessary permit application forms along with a detailed project description. Supporting documents must also be filed, where CEQA requires, with responsible agencies. Unless otherwise specified, the

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[16] Governor's Office of Planning and Research: Overview of the California Environmental Review and Permit Approval Process. Online at http://ceres.ca.gov/topic/env_law/ceqa/guidelines/intro.html

sequence of filing applications is left up to the applicant. It must be noted, however, that the failure of some agencies to accept an application until certain other permit approvals have been granted does not in any way impact the time limits under which the agency must act.

During this phase, each receiving agency must review the submitted application to determine if the individual filing is complete. The lead agency must make its determination in writing within thirty days. Should the agency fail to make its determination within thirty days, the application will be deemed accepted as complete by operation of law. If the application is determined to be incomplete, the agency *must* specify the deficiencies and the manner in which the deficiencies may be corrected. The developer-applicant may then refile the corrected application. Upon refiling, the agency has another thirty days to review for completeness. If the application is again determined to be incomplete, the agency must provide a process for an appeal of the determination and reach a decision within sixty days. Further dispute may be adjudicated. This step is critical to the process. A permit may not be denied for failure to provide information not requested.

Once an application is accepted as complete, the lead agency has six months to approve or disapprove a project for which an Environmental Impact Report (EIR) has been certified. The time limit in all other cases is three months after a Negative Declaration is adopted or an exemption issued.

<u>III. Review Phase:</u>

The Review Process begins immediately with the completion of the specific application. In recognition of §65941 of Chapter 4.5 of the Permit Streamlining Act, the lead agency will simultaneously review the project under the applicable permit rules and conduct the necessary environmental analysis. Permit rules vary depending on the particular permit authority in question, but the process generally involves comparing the proposed project with existing statutes. The procedure usually results in a public hearing followed by a written decision by the agency or its designated officer. Typically, a project may be approved, denied, or approved subject to specified conditions.

The CEQA procedure involves a number of steps which produce an environmental document examining the lead agency's as well as the responsible and/or trustee agencies' permit decisions. The first step in the CEQA process is to determine whether the proposed project is subject to CEQA. There are a number of statutory and categorical exemptions. If the proposal is not covered by CEQA, the lead agency may file a *Notice of Exemption*. If the project is covered by CEQA, the lead agency must prepare an *Initial Study* to determine whether the project may have a significant adverse impact on the environment. The Initial Study must be completed within thirty days after an application is accepted as complete.

If the Initial Study shows that the project will not have a significant effect on the environment, the lead agency must prepare and circulate a *Negative Declaration.* Where potential significant effects are shown, but the project is modified such that the effects are rendered insignificant, the lead agency must prepare and circulate a mitigated Negative Declaration. In either case, the Negative Declaration must be circulated for review for thirty days and must be ready for adoption by the lead agency within 105 days after a completed application is accepted. If, on the other hand, the Initial Study shows that the project may have one or more significant effects, the lead agency must circulate a *Notice of Preparation (NOP)* in anticipation of preparing an Environmental Impact Report (EIR) and must consult with responsible and trustee agencies as to the content of the environmental analysis. Responsible agencies must respond to the NOP within thirty days. If a responsible or trustee agency fails to respond, the lead agency may assume that the responsible agency has no response to make. Further, if a responsible agency fails to respond or responds incompletely, the responsible agency may not subsequently raise issues or objections regarding the adequacy of the environmental review.

At the close of this period, the lead agency must prepare and circulate a *Draft Environmental Impact Report (DEIR)*. All concerned agencies and the public may review the DEIR. All comments on the DEIR must be made within the forty-five day review period. At the close of the review and comment period, the lead agency must respond to the comments received. Comments from responsible or trustee agencies shall be limited to those project activities which are within the agency's area of expertise, are required to be carried out or approved by the agency, or will be subject to the exercise of powers by the agency. The lead agency prepares and certifies a *Final Environmental Impact Report (FEIR)*. If the lead agency approves the project, it must find that each significant impact will be mitigated below the level of significance where feasible, and that overriding social or economic concerns merit the approval of the project in the face of unavoidable effects. With the CEQA and permit review process completed, the lead agency must approve or deny the permit within six months of certifying the EIR or within three months of adopting the Negative Declaration and file a *Notice of Determination (NOD)*. Responsible agencies must then act within six months after the lead agency's action or, if the developer-applicant has not already filed an application with a responsible agency, within six months from the time the application is filed.

Environmental documents for projects involving one or more state agencies or involving issues of area wide or statewide significance must be sent to the State Clearinghouse for distribution to interested state agencies. The State Clearinghouse will link the lead agency with the responsible state agencies.

Special Concerns in the CEQA/Permit Process

There are several key points that agencies, developer-applicants and the public must be aware of in order to avoid misunderstandings and delays:

- The time limits for completing the requirements of CEQA and acting on a permit are concurrent and not consecutive. The Permit Streamlining Act discourages a government agency from requiring a completed EIR before accepting a permit application.
- CEQA can help resolve public policy disputes relating to development projects. Technical issues that find their way into policy disputes, no matter how dependent on scientific considerations, are inherently value-laden. CEQA specifically addresses the potential for conflicting expert discussions and mandates that all sides of an issue are considered.
- Under the Permit Streamlining Act, if a public agency does not approve or deny a project within the statutory time limit, the project may be deemed approved. The proponent must give notice to invoke the Permit Streamlining Act.

- The Permit Streamlining Act time limits are not applicable to all permit applications. Time limits only apply to development projects as defined in the PSA. The Streamlining Act specifically excludes ministerial permits such as certain building permits. The time limits do not apply to legislative actions such as the adoption or amendment of zoning ordinances. The time limits do not operate where a federal law specifies a longer or shorter period for action and, *with* the consent of the developer-applicant, the lead agency may waive the time limit if a joint environmental document is being prepared with a federal permitting agency.
- Where a public agency (or series of agencies) will issue more than one permit for a project, the agency(ies) makes each approval separately, but must still act upon the entire project within the statutory time limit.
- All Permit Streamlining Act time limits are maximum. Public agencies should act in a shorter time whenever possible.
- Members of the public may challenge, in court, a wide variety of public agency action and inaction, but only if they first present those challenges to the agency itself within thirty to 180 days after the occurrence of the challenged action, depending upon whether an Notice of Declaration was filed or not by the agency.

CEQA Glossary

<u>Comment Letters</u>. Letters written by the AQMD commenting on the air quality analysis to ensure impacts from the proposed projects were accurately identified and mitigation was applied to lessen the impact.

<u>Environmental Impact Report (EIR).</u> A detailed statement prepared under CEQA describing and analyzing the significant environmental effects of a project and discussing ways to mitigate or avoid the effects.

<u>Initial Study</u>. A preliminary analysis prepared by the Lead Agency to determine whether an EIR or a Negative Declaration must be prepared or to identify the significant environmental effects to be analyzed in an EIR.

<u>Lead Agency</u>. The public agency with the principal responsibility for carrying out or approving a project. The Lead Agency decides whether an EIR or Negative Declaration is required for a project, and causes the appropriate document to be prepared.

<u>Mitigated Negative Declaration</u>. A Negative Declaration that incorporates mitigation measures into the design of the project or establishes measures as conditions of project approval to avoid significant effects.

<u>Mitigation Monitoring Program.</u> When a lead agency adopts a mitigated Negative Declaration or an EIR, it must adopt a program of monitoring or reporting which will ensure that mitigation measures are implemented.

<u>Negative Declaration</u>. A written statement prepared by the Lead Agency that briefly describes the reasons that a project, not exempt from CEQA, will not have a significant effect on the environment and therefore does not require the preparation of an EIR.

Notice of Determination (NOD). A brief notice filed with the State Clearinghouse to document project approval. The filing of the NOD starts the statute of limitations period

Notice of Preparation (NOP). A brief notice sent by the lead agency to notify the responsible agencies, trustee agencies, and involved federal agencies that the lead agency plans to prepare an EIR, or Environmental Assessment with significant impacts for the project. The purpose of the notice is to solicit guidance from those agencies as to the scope and content of the environmental information to be included in the EIR or EA with significant impacts. An Initial Study, or preliminary analysis, is prepared and traditionally accompanies the NOP.

Responsible Agencies. Under CEQA, responsible agencies are all public agencies other than the Lead Agency that have discretionary approval power over the project.

Scoping meeting. An optional meeting under CEQA in which the lead agency meets with members of the public or agency representatives after the Notice of Preparation has been issued to discuss environmental issues related to a project. Scoping sessions provide the opportunity to discuss environmental issues, project alternatives and potential mitigation measures that may warrant in-depth analysis in the environmental review process

Trustee Agencies. Have jurisdiction over certain resources held in trust for the people of California. The State Department of Fish and Game is one of four trustee agencies. The others include the State Lands Commission, the Department of Parks and Recreation, and the University of California. Trustee agencies are generally required to be notified of CEQA documents relevant to their jurisdiction, whether or not these agencies have actual permitting authority or approval power over aspects of the underlying project..

Exhibit 14. CEQA Timeline

Trigger Event/ Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Project Definition																					
Application received.																					
As soon as the application is deemed complete for CEQA review purposes		->																			
After receiving a consultation request from a Lead Agency.																					
After scoping meeting is requested.																					
After receiving a NOP from a Lead Agency.																					
Conducting an Initial Study.																					
Negative Declaration																					
After application is deemed complete.																					
Hiring a consultant after environmental determination																					
After completing a ND or MND.																					
Provide public notice of public review period.									-->												
Provide public notices.																					
Receive comments from a public agency.										----->											
After project approval.																					
After project approval.											------>										
NOD filed.																					
EIR																					
After application is deemed complete																					
Hiring a consultant after environmental determination.																					
After completing a Draft EIR.										---->											
After completing a Draft EIR.																					
Provide public notice of public review period.													--->								
Provide public notices.																					
Receive comments from a public agency.																					
After project approval.																					
After project approval.																				---->	
NOD filed.																					

Key: ----> Event starts   Timeline mandated by CEQA   Permitted extensions

APPENDIX D – ENVIRONMENTAL CHECKLIST FORM

1.	Project title:		
2.	Lead agency name and address:		
3.	Contact person and phone number:		
4.	Project location:		
5.	Project sponsor's name and address:		
6.	General plan designation:	7.	Zoning:
8.	Description of project: (Describe the whole action involved, including but not limited to later phases of the project, and any secondary, support, or off-site features necessary for its implementation. Attach additional sheets if necessary.)		
9.	Surrounding land uses and setting: Briefly describe the project's surroundings:		
10.	Other public agencies whose approval is required (e.g., permits, financing approval, or participation agreement.)		

Environmental Factors Potentially Affected:

The environmental factors checked below would be potentially affected by this project, involving at least one impact that is a "Potentially Significant Impact" as indicated by the checklist on the following pages.

?	Aesthetics	?	Agriculture Resources	?	Air Quality
?	Biological Resources	?	Cultural Resources	?	Geology /Soils
?	Hazards & Hazardous Materials	?	Hydrology / Water Quality	?	Land Use / Planning
?	Mineral Resources	?	Noise	?	Population / Housing
?	Public Services	?	Recreation	?	Transportation/Traffic
?	Utilities / Service Systems	?	Mandatory Findings of Significance		

Determination: (To be completed by the Lead Agency)

On the basis of this initial evaluation:

?	I find that the proposed project COULD NOT have a significant effect on the environment, and a NEGATIVE DECLARATION will be prepared.
?	I find that although the proposed project could have a significant effect on the environment, there will not be a significant effect in this case because revisions in the project have been made by or agreed to by the project proponent. A MITIGATED NEGATIVE DECLARATION will be prepared.
?	I find that the proposed project MAY have a significant effect on the environment, and an ENVIRONMENTAL IMPACT REPORT is required.
?	I find that the proposed project MAY have a "potentially significant impact" or "potentially significant unless mitigated" impact on the environment, but at least one effect 1) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and 2) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. An ENVIRONMENTAL IMPACT REPORT is required, but it must analyze only the effects that remain to be addressed.
?	I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects (a) have been analyzed adequately in an earlier EIR or NEGATIVE DECLARATION pursuant to applicable standards, and (b) have been avoided or mitigated pursuant to that earlier EIR or NEGATIVE DECLARATION, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Signature Date

Signature Date

Evaluation of Environmental Impacts:

1) A brief explanation is required for all answers except "No Impact" answers that are adequately supported by the information sources a lead agency cites in the parentheses following each question. A "No Impact" answer is adequately supported if the referenced information sources show that the impact simply does not apply to projects like the one involved (e.g., the project falls outside a fault rupture zone). A "No Impact" answer should be explained where it is based on project-specific factors as well as general standards (e.g., the project will not expose sensitive receptors to pollutants, based on a project-specific screening analysis).

2) All answers must take account of the whole action involved, including off-site as well as on-site, cumulative as well as project-level, indirect as well as direct, and construction as well as operational impacts.

3) Once the lead agency has determined that a particular physical impact may occur, then the checklist answers must indicate whether the impact is potentially

significant, less than significant with mitigation, or less than significant. "Potentially Significant Impact" is appropriate if there is substantial evidence that an effect may be significant. If there are one or more "Potentially Significant Impact" entries when the determination is made, an EIR is required.

4) "Negative Declaration: Less Than Significant With Mitigation Incorporated" applies where the incorporation of mitigation measures has reduced an effect from "Potentially Significant Impact" to a "Less Than Significant Impact." The lead agency must describe the mitigation measures, and briefly explain how they reduce the effect to a less than significant level (mitigation measures from Section XVII, "Earlier Analyses," may be cross-referenced).

5) Earlier analyses may be used where, pursuant to the tiering, program EIR, or other CEQA process, an effect has been adequately analyzed in an earlier EIR or negative declaration. Section 15063(c)(3)(D). In this case, a brief discussion should identify the following:

   a) Earlier Analysis Used. Identify and state where they are available for review.
   b) Impacts Adequately Addressed. Identify which effects from the above checklist were within the scope of and adequately analyzed in an earlier document pursuant to applicable legal standards, and state whether such effects were addressed by mitigation measures based on the earlier analysis.
   c) Mitigation Measures. For effects that are "Less than Significant with Mitigation Measures Incorporated," describe the mitigation measures which were incorporated or refined from the earlier document and the extent to which they address site-specific conditions for the project.

6) Lead agencies are encouraged to incorporate into the checklist references to information sources for potential impacts (e.g., general plans, zoning ordinances). Reference to a previously prepared or outside document should, where appropriate, include a reference to the page or pages where the statement is substantiated.

7) Supporting Information Sources: A source list should be attached, and other sources used or individuals contacted should be cited in the discussion.

8) This is only a suggested form, and lead agencies are free to use different formats; however, lead agencies should normally address the questions from this checklist that are relevant to a project's environmental effects in whatever format is selected.

9) The explanation of each issue should identify:
   a) the significance criteria or threshold, if any, used to evaluate each question; and
   b) the mitigation measure identified, if any, to reduce the impact to less than significance

SAMPLE QUESTION

Issues:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporation	Less Than Significant Impact	No Impact
I. AESTHETICS -- Would the project:				
a) Have a substantial adverse effect on a scenic vista?	?	?	?	?
b) Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?	?	?	?	?
c) Substantially degrade the existing visual character or quality of the site and its surroundings?	?	?	?	?
d) Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?	?	?	?	?
II. AGRICULTURE RESOURCES -- In determining whether impacts to agricultural resources are significant environmental effects, lead agencies may refer to the California Agricultural Land Evaluation and Site Assessment Model (1997) prepared by the California Dept. of Conservation as an optional model to use in assessing impacts on agriculture and farmland. Would the project:				
a) Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to non-agricultural use?	?	?	?	?
b) Conflict with existing zoning for agricultural use, or a Williamson Act contract?	?	?	?	?
c) Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland, to non-agricultural use?	?	?	?	?

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporation	Less Than Significant Impact	No Impact
III. AIR QUALITY -- Where available, the significance criteria established by the applicable air quality management or air pollution control district may be relied upon to make the following determinations. Would the project:				
a) Conflict with or obstruct implementation of the applicable air quality plan?	?	?	?	?
b) Violate any air quality standard or contribute substantially to an existing or projected air quality violation?	?	?	?	?
c) Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard (including releasing emissions which exceed quantitative thresholds for ozone precursors)?	?	?	?	?
d) Expose sensitive receptors to substantial pollutant concentrations?	?	?	?	?
e) Create objectionable odors affecting a substantial number of people?	?	?	?	?
IV. BIOLOGICAL RESOURCES -- Would the project:				
a) Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	?	?	?	?
b) Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, regulations or by the California Department of Fish and Game or US Fish and Wildlife Service?	?	?	?	?
c) Have a substantial adverse effect on federally protected wetlands as defined by Section 404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means?	?	?	?	?
d) Interfere substantially with the movement of any native resident or migratory fish or	?	?	?	?

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporation	Less Than Significant Impact	No Impact
wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites?				
e) Conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?	?	?	?	?
f) Conflict with the provisions of an adopted Habitat Conservation Plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan?	?	?	?	?
V. CULTURAL RESOURCES -- Would the project:				
a) Cause a substantial adverse change in the significance of a historical resource as defined in '15064.5?	?	?	?	?
b) Cause a substantial adverse change in the significance of an archaeological resource pursuant to '15064.5?	?	?	?	?
c) Directly or indirectly destroy a unique paleontological resource or site or unique geologic feature?	?	?	?	?
d) Disturb any human remains, including those interred outside of formal cemeteries?	?	?	?	?
VI. GEOLOGY AND SOILS -- Would the project:				
a) Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving	?	?	?	?
i) Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault? Refer to Division of Mines and Geology	?	?	?	?

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporation	Less Than Significant Impact	No Impact
Special Publication 42.				
ii) Strong seismic ground shaking?	?	?	?	?
iii) Seismic-related ground failure, including liquefaction?	?	?	?	?
iv) Landslides?	?	?	?	?
b) Result in substantial soil erosion or the loss of topsoil?	?	?	?	?
c) Be located on a geologic unit or soil that is unstable, or that would become unstable as a result of the project, and potentially result in on- or off-site landslide, lateral spreading, subsidence, liquefaction or collapse?	?	?	?	?
d) Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property?	?	?	?	?
e) Have soils incapable of adequately supporting the use of septic tanks or alternative waste water disposal systems where sewers are not available for the disposal of waste water?	?	?	?	?
VII. HAZARDS AND HAZARDOUS MATERIALS -- Would the project:				
a) Create a significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials?	?	?	?	?
b) Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment?	?	?	?	?
c) Emit hazardous emissions or handle hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school?	?	?	?	?
d) Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code Section 65962.5 and, as a result, would it create a	?	?	?	?

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporation	Less Than Significant Impact	No Impact
significant hazard to the public or the environment?				
e) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project result in a safety hazard for people residing or working in the project area?	?	?	?	?
f) For a project within the vicinity of a private airstrip, would the project result in a safety hazard for people residing or working in the project area?	?	?	?	?
g) Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan?	?	?	?	?
h) Expose people or structures to a significant risk of loss, injury or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands?	?	?	?	?
VIII. HYDROLOGY AND WATER QUALITY -- Would the project:				
a) Violate any water quality standards or waste discharge requirements?	?	?	?	?
b) Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g., the production rate of pre-existing nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted)?	?	?	?	?
c) Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, in a manner which would result in substantial erosion or siltation on- or off-site?	?	?	?	?
d) Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner which would result in flooding on- or off-site?	?	?	?	?
e) Create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of	?	?	?	?

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporation	Less Than Significant Impact	No Impact
polluted runoff?				
f) Otherwise substantially degrade water quality?	?	?	?	?
g) Place housing within a 100-year flood hazard area as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood hazard delineation map?	?	?	?	?
h) Place within a 100-year flood hazard area structures which would impede or redirect flood flows?	?	?	?	?
i) Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam?	?	?	?	?
j) Inundation by seiche, tsunami, or mudflow?	?	?	?	?
IX. LAND USE AND PLANNING -- Would the project:				
a) Physically divide an established community?	?	?	?	?
b) Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program, or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect?	?	?	?	?
c) Conflict with any applicable habitat conservation plan or natural community conservation plan?	?	?	?	?
X. MINERAL RESOURCES -- Would the project:				
a) Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state?	?	?	?	?
b) Result in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan?	?	?	?	?

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporation	Less Than Significant Impact	No Impact
XI. NOISE -- Would the project result in:				
a) Exposure of persons to or generation of noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?	?	?	?	?
b) Exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels?	?	?	?	?
c) A substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project?	?	?	?	?
d) A substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project?	?	?	?	?
e) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project expose people residing or working in the project area to excessive noise levels?	?	?	?	?
f) For a project within the vicinity of a private airstrip, would the project expose people residing or working in the project area to excessive noise levels?	?	?	?	?
XII. POPULATION AND HOUSING -- Would the project:				
a) Induce substantial population growth in an area, either directly (for example, by proposing new homes and businesses) or indirectly (for example, through extension of roads or other infrastructure)?	?	?	?	?
b) Displace substantial numbers of existing housing, necessitating the construction of replacement housing elsewhere?	?	?	?	?
c) Displace substantial numbers of people, necessitating the construction of replacement housing elsewhere?	?	?	?	?

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporation	Less Than Significant Impact	No Impact
XIII. PUBLIC SERVICES				
a) Would the project result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, need for new or physically altered governmental facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times or other performance objectives for any of the public services:				
Fire protection?	?	?	?	?
Police protection?	?	?	?	?
Schools?	?	?	?	?
Parks?	?	?	?	?
Other public facilities?	?	?	?	?
XIV. RECREATION				
a) Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?	?	?	?	?
b) Does the project include recreational facilities or require the construction or expansion of recreational facilities which might have an adverse physical effect on the environment?	?	?	?	?
XV. TRANSPORTATION/TRAFFIC -- Would the project:				
a) Cause an increase in traffic which is substantial in relation to the existing traffic load and capacity of the street system (i.e., result in a substantial increase in either the number of vehicle trips, the volume to capacity ratio on roads, or congestion at intersections)?	?	?	?	?

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporation	Less Than Significant Impact	No Impact
b) Exceed, either individually or cumulatively, a level of service standard established by the county congestion management agency for designated roads or highways?	?	?	?	?
c) Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks?	?	?	?	?
d) Substantially increase hazards due to a design feature (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment)?	?	?	?	?
e) Result in inadequate emergency access?	?	?	?	?
f) Result in inadequate parking capacity?	?	?	?	?
g) Conflict with adopted policies, plans, or programs supporting alternative transportation (e.g., bus turnouts, bicycle racks)?	?	?	?	?
XVI. UTILITIES AND SERVICE SYSTEMS -- Would the project:				
a) Exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board?	?	?	?	?
b) Require or result in the construction of new water or wastewater treatment facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?	?	?	?	?
c) Require or result in the construction of new storm water drainage facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?	?	?	?	?
d) Have sufficient water supplies available to serve the project from existing entitlements and resources, or are new or expanded entitlements needed?	?	?	?	?

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporation	Less Than Significant Impact	No Impact
e) Result in a determination by the wastewater treatment provider which serves or may serve the project that it has adequate capacity to serve the project=s projected demand in addition to the provider=s existing commitments?	?	?	?	?
f) Be served by a landfill with sufficient permitted capacity to accommodate the project=s solid waste disposal needs?	?	?	?	?
g) Comply with federal, state, and local statutes and regulations related to solid waste?	?	?	?	?
XVII. MANDATORY FINDINGS OF SIGNIFICANCE				
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal or eliminate important examples of the major periods of California history or prehistory?	?	?	?	?
b) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects)?	?	?	?	?
c) Does the project have environmental effects which will cause substantial adverse effects on human beings, either directly or indirectly?	?	?	?	?

APPENDIX E – PERMIT STREAMLINING ACT

The California Permit Streamlining Act mandates specific timeframes local and state governments must comply with when processing permits. The intent is to provide clarity and consistency to the permit process. The PSA sets forth various time limits within which public agencies must either approve or disapprove a permit. If a public agency does not approve or disapprove a permit within those time limits, the permit "may" be deemed approved under PSA.[17]

Article 3. Applications for Development Permits

65940. Each state and local agency shall compile one or more lists, which shall specify in detail the information that will be required from any applicant for a development project.

65941(b) If a public agency is a lead or responsible agency for purposes of CEQA, that criteria shall not require the applicant to submit the information equivalent of an EIR as part of a complete application, or otherwise require proof of compliance with that act as a prerequisite to a permit application being deemed complete.

65944(a) After a public agency accepts an application as complete, the agency shall not subsequently request of an applicant any new or additional information which was not specified in the list prepared pursuant to Section 65940.

Procedural Requirements:

All public agencies must establish one or more lists specifying, in detail, the information required from applicants for a development project (§65940). Upon receipt of a project application containing a statement identifying the application as being for a "development permit," an agency has thirty calendar days to notify the applicant, in writing, of whether or not the project application is complete enough for processing. When rejected as incomplete, the agency must identify where deficiencies exist and how they can be remedied. The resubmittal of the application begins a new thirty-day review period. If the agency fails to notify the applicant of completeness within either of the thirty-day periods, the application is deemed to be complete (§65943; Orsi v. City Council (1990) 219 Cal. App. 3d 1576). If rejected as incomplete a second time, the applicant may appeal the decision to jurisdiction's hearing body who must make a final written determination within sixty calendar days. Again, failure to meet this time period constitutes acceptance of the application as complete.

Once complete and accepted, the agency then proceeds with the CEQA process, and the approval or denial of the project.

The Permit Streamlining Act includes time limit provisions for taking action on a project after the environmental determination is made. When an EIR is certified for a project, the public agency shall approve or deny the project within 180 days from the date of certification. When a project is found to be exempt from CEQA or a Negative Declaration

[17] The California Permit Handbook 1996/97 published by the Office of Permit Assistance of the California Trade and Commerce Agency.

is adopted for a project, the public agency shall approve or deny the project within sixty days from the date of the determination or adoption (§65950 and Public Resources Code §21151.5). If no action is taken within the allotted time, the project may be deemed approved by action of the Act. An application can only be deemed approved as a result of failure to act if the requirements for public notice and review have been satisfied (§65965).

Two options are available to an applicant to ensure that these requirements are met (§65956(a) and §65956(b)): (a) the applicant may file an action pursuant to Section 1085 of the Code of Civil Procedure (civil mandamus) to force the agency to provide notice or hold a hearing, or both; (b) if the applicant has provided seven days advance notice to the permitting agency of intent to provide public notice, an applicant may provide public notice using the distribution information provided pursuant to §65941.5 no earlier than sixty days from the expiration of the time limits. The notice must include the required contents as provided for by §65956(b) and a statement that the project will be deemed approved if the permitting agency has not acted within sixty days. Notice by the applicant extends the time limit for action by the permitting agency to sixty days after the public notice is sent out.

APPENDIX F – COMPARISON WITH OTHER STATE PERMIT PROCESSES

The approach used to compare the California permitting process with other states was to identify new facilities or facilities that recently expanded petroleum storage capacity in New York, Washington, Texas, and North Carolina in the past two years. The 2000 and 2002 editions of the *OPIS/STALSBY Petroleum Terminal Encyclopedia* were used to identify these facilities.

Similar to the California Environmental Quality Act, eighteen other states have their own state-level NEPA statute or environmental review processes resembling NEPA. States with state-level environmental review requirements or state-level NEPA statues require state and local agencies to perform environmental impact analyses when granting permits. Exhibit 15 shows a list of states with environmental review requirements. The New York State Environmental Quality Review Act, the North Carolina Environmental Policy Act, and the Washington State Environmental Policy Act will be discussed briefly after the exhibit.

Exhibit 15. States with Environmental Review Requirements

State	Environmental Review Requirements
California	California Environmental Quality Act
Connecticut	Connecticut Environmental Protection Act of 1973
Dist. of Columbia	District of Columbia Environmental Policy Act of 1989
Florida	Environmental Protection Act of 1971
Georgia	Georgia Environmental Policy Act
Hawaii	Hawaii Environmental Policy Act
Indiana	Indiana Environmental Policy Act
Maryland	Maryland Environmental Policy Act of 1973
Massachusetts	Massachusetts Environmental Policy Act
Michigan	Thomas J. Anderson Act
Minnesota	Minnesota Environmental Policy Act of 1973
Montana	Montana Environmental Policy Act
New York	New York State Environmental Quality Review Act
North Carolina	North Carolina Environmental Policy Act of 1971
Puerto Rico	Public Policy Environmental Act
South Dakota	South Dakota Environmental Policy Act
Virginia	Virginia Environmental Quality Act
Washington	Washington State Environmental Policy Act of 1971
Wisconsin	Wisconsin Environmental Policy Act of 1971

Source: Public Law Research Institute. University of California, Hastings College of the Law.

New York

The New York's State Environmental Quality Review Act (SEQRA or SEQR) came into effect in 1978. "The basic purpose of SEQR is to incorporate the consideration of environmental factors into the existing planning, review and decision-making processes of state, regional and local government agencies at the earliest possible time. To accomplish this goal, SEQR requires that all agencies determine whether the actions they directly undertake, fund or approve may have a significant impact on the environment, and, if it is determined that the action may have a significant adverse impact, prepare or request an environmental impact statement." SEQR applies to public and private projects, the definition of projects is similar to CEQA's and it applies whenever an agency is making a discretionary decision on an action that may affect the environment as Type I, Type II or Unlisted.

Type I actions require careful examination since they are more likely to have a significant impact. If more than one agency is involved in the review of a Type I action, a coordinated review is required and a lead agency must be established. A full Environmental Assessment Form (EAF) must be completed. Example of Type I actions include:[18]

- Non-residential projects physically altering ten or more acres of land;
- Zoning changes affecting twenty-five or more acres of land;
- Adopting land use plans (e.g., comprehensive plan).

Type II actions are actions that Department of Environmental Conservation (DEC) has determined will not have a significant adverse impact on the environment. Therefore, no further SEQR review is required. Example of Type II actions include:[19]

- Constructing or expanding a primary, non-residential structure with less than 4,000 sq. ft. of gross floor area;
- Non-discretionary approvals, such as building permits.

Unlisted actions are those actions not included in any statewide or individual agency lists of Type I or Type II actions. Unlisted actions require a SEQR review since they range from minor zoning variances to complex construction activities that fall just below the threshold for Type I actions. At minimum, a short EAF must be completed. If more than one agency is involved in the review, a coordinated review is optional.

Important Steps in the SEQR Process:

<u>Determining Significance.</u> The agency conducting the SEQR review must determine if a proposed action may or will not have significant adverse impacts on the environment. Impacts must be evaluated for both severity and importance. During this evaluation, an agency must consider all components or phases of the proposed action (the “whole action”). Determinations of significance must be based on information provided by the project sponsor in an EAF, other supporting documents and comments from any involved agencies and the public. Determinations can be:

- A Negative Declaration (Neg Dec) when an agency determines that a proposed action will not result in significant adverse environmental impacts. An agency’s Neg Dec must show, in writing, the reasons why the identified environmental impacts will not be significant. Therefore, an Environmental Impact Statement (EIS) is not required.

- A Conditioned Negative Declaration (CND) is a type of Neg Dec that can be issued for certain “Unlisted’ actions. A CND allows an agency to impose specific conditions, outside of its routine jurisdiction, to minimize identified impacts. For example, a Planning Board could impose a condition requiring an additional

[18] For a full list of Type I actions see SEQR regulations, 6NYRR Part 617.4.
[19] For a full list of Type II actions see SEQR regulations, 6NYRR Part 617.5.

turning lane to improve traffic flow. A CND is subject to a thirty-day public comment period.

- A Positive Declaration (Pos Dec) when the lead agency determines that there may be one or more significant adverse environmental impacts from a proposed action. An EIS must be prepared.

Scoping.[20] Is a not a requirement of SEQR. However, In New York, scoping is being used to identify the topics that should be covered by the EIS, including significant adverse environmental impacts of a proposed project and alternatives that could avoid or minimize these impacts. If an agency decides to scope, it must involve community members. The cooping process starts when the project sponsor files a draft scope with the lead agency. The lead agency circulates the draft scope and solicits public involvement. An agency can also decide to hold a public scoping meeting. A final written scope of issues must be completed within 60 calendar days of receiving the draft scope.

Preparing an Environmental Impact Statement (EIS). In New York, the developer is required to prepare all the reports at their expense. The draft EIS is a primary source of environmental information related to a proposed action. The EIS also serves as a means for public review and comment on the potential impacts of the action. After a draft EIS is submitted, the lead agency must determine that it is complete and adequate for public review. Once the draft EIS is deemed complete, a minimum of 30 days is required for public review and comment. A final EIS should be prepared within 45 days of any hearings or 60 days after filing the draft EIS. The final EIS must include: the draft EIS and any revisions/ supplements; a summary of substantive comments received; and the lead agency's responses to the comments.

Holding Public Hearings. Under SEQR is optional. Hearings are part of the review process for draft EISs and cannot be held before the draft EIS and related documents are available for public review. SEQR hearings should be combined with hearings mandated by laws governing the particular action being proposed. If a SEQR hearing is held, the hearing record or summary becomes part of the final EIS.

When the SEQR process begins, the total time required for preparation, public review and finalization of an EIS varies widely, although SEQR sets time periods for some phases. If a draft EIS is sufficient for public review on its first submission and the agency elects to have a minimum comment period with no public hearing, the process could take a little less than six months following submission of the draft EIS. If the agency chooses to provide a more extensive public comment and hearing opportunities, or if the draft EIS requires substantial revisions before being released for public comment, the total time required would be extended. For a proposal covering as broad an area a longer comment period including some public forum should be anticipated, and the SEQR process could then run closer to a year from submission of the draft EIS.

Under New York has zoning laws, construction of new petroleum product storage facilities must be in industrial zones. The New York Uniform Land Use Review Procedure (ULURP) takes five months.

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[20] Scoping is a process in which a Lead agency, consultant or applicant formally requests preliminary comments on a proposed project from responsible agencies and/or the public.

Washington

Washington's State Environmental Policy Act (SEPA) was enacted shortly after NEPA. SEPA, however, took a markedly different approach to environmental protection than CEQA. Rather than rely on procedural protections, such as public and agency comments on EIRs and judicial review, SEPA charges agencies with the task of mitigating environmental effects. SEPA applies, like NEPA, only to legislation and major actions having a significant effect. However, unlike NEPA, it does apply to private projects which require a permit or entitlement. The Act also follows NEPA by requiring impact reports only in cases where the effect on the environment is more concrete than speculative. Though it is clear that the scope of SEPA is considerably narrower than CEQA, there are still grounds for third party litigation and judicial review. Washington addresses this through expansive substantive requirements in SEPA.[21]

The SEPA review is intended to be integrated throughout an agency's permit review process, rather than a separate step. Most agencies make sincere efforts to process permit applications as efficiently as possible, while still addressing regulatory and environmental concerns.[22] The time needed to review a proposal will depend on the permits needed, the complexity of the project, the amount of information already available, and the need to complete additional analysis or studies. In many cases, project review may be completed in two or three months. On the other hand, completing project review for some complex projects may take years.

North Carolina

The North Carolina (State) Environmental Policy Act (SEPA) was adopted by the General Assembly into law in 1971 (G.S. 113A, Article 1). The purpose of the law, also referred to as SEPA, is to: 1) encourage the wise, productive and beneficial use of the natural environment; 2) preserve the natural beauty of the state; 3) create a public awareness of our environment; and 4) require state agencies to consider and report on environmental aspects and consequences of their actions involving the expenditure of public money or use of public land.

SEPA is a planning and decision-making tool meant to provide a thoughtful, analytical evaluation of a project's potential for impacting the quality of the environment. The evaluation is documented in the form of an Environmental Assessment (EA) or Environmental Impact Statement (EIS), depending on the impacts of the project. These documents are meant to disclose the direct, indirect, cumulative, long-range, and short-term impacts of the project. The disclosure includes the potential effects on surface and ground water resources, floodplains, wetlands, air quality, land use, wildlife resources, agricultural land, scenic and recreational areas, noise, shellfish and finfish, forestland, toxic substances (if applicable) and cultural and historical resources.

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[21] *A Primer on the California Environmental Quality Act (CEQA).* Pacific Research Institute. November 2001. Available online at http://www.pacificresearch.org/pub/sab/enviro/ceqa.html
[22] *SEPA Guide for Project Applicants.* Washington Sate Department of Ecology Environmental Coordination Section. June 2002. Available online at http://www.ecy.wa.gov

The North Carolina Department of Environment and Natural Resources (DENR) Rules for Minimum Criteria (15A NCAC 01C .0500) are used to distinguish activities with a high potential for environmental effects (major) from those with only a minimum potential (non-major). Minimum criteria for non-major activities (15A NCAC 01C .0504) have been established as thresholds at and below which environmental documentation under SEPA is not generally required.

An Environmental Assessment should be prepared if the project is not anticipated to produce significant adverse environmental impacts, if the impacts can be mitigated to a non-significant level or if the magnitude of impacts is uncertain. However, if an EA concludes that the impacts will be significant and cannot be fully mitigated, or if this is known initially, then an EIS should be prepared. A determination that an EIS is required may be made at any time during the EA review process. The North Carolina SEPA process is expected to take between 5 to 12 months if an Environmental Assessment is needed and between 12 to 24 months if an Environmental Impact Statement is necessary. County planning departments in North Carolina issue land use permits within three months of submittal of the application.

Texas

Although Texas does not have the equivalent of CEQA, Texas does have informal requirements for environmental review, and was included in the analysis because of its importance in the petroleum product terminal industry. Two terminal operators and the Texas Commission on Environmental Quality (TCEQ) were contacted during this study for information about the permitting process.

When a petroleum terminal must to be expanded, the owners must apply for air, fire, and building permits. An air permit application is filed with the TCEQ as a part of the New Source Review (NSR) process. In the case of a Houston area terminal, the terminal had accumulated enough offset emission credits for VOCs through the period 1991-1996 that it did not have to pay the fee gathered by TCEQ as a part of the permitting process. For the same reason, the air permit was issued within two weeks. Without substantial offset credits, as the average processing time for an air permit in Texas is about six months.

When in the past the same terminal had applied for “flexible” air permits (for tanks used for storing interchangeable products) the permitting process lasted considerably longer – up to two years instead of the regular six months. The respondent attributed the prolonged duration of the permitting process in this case to the fact that the agency officers were extremely busy at the time. On the other hand, several of the terminal’s tanks received the permit-by-rule Standard Exemption #86[23] for construction of fixed or floating roof storage tanks that meet certain criteria, as they claimed the standard exemption for tanks that emit less than five tons per year of VOCs. The permit approval process in those cases lasted again from two to three weeks. In cases in which the tanks

[23] Standard Exemption #86 allows for a quick construction or change of service of a storage tank without the delay of getting a permit or permit amendment. It is used generally to authorize larger tanks and not smaller tanks. It allows for the construction of any fixed roof or floating roof storage tank. It also allows for the change of service for these tanks for a given compound.

had the potential to emit over five tons per year of VOCs, a vapor recovery unit (VRU) was required and the permitting process lasted again about six months.

The fire and building permits were filed with the City of Houston (The Fire Marshall's office and the Building Services Department respectively). The plan review took about twenty-two days. Overall, the whole permitting process for the latest expansion took about six months (all the permit applications were filed concurrently) and the procedure was clear. No zoning or land use permits were needed. In some parts of Texas (e.g., Houston) there are no zoning or land use laws. No environmental review was required as per CEQA. When asked to compare the process in Texas to that in California, the respondent stated, (based on his personal information) "in Texas that process is much smoother and takes less time."

A phone conversation with TCEQ staff provided the agency's perspective on the permitting process. In addition to applying for the permits, each petroleum product storage facility owner has to register their aboveground storage tanks (ASTs) with the Commission.

Permitting Time

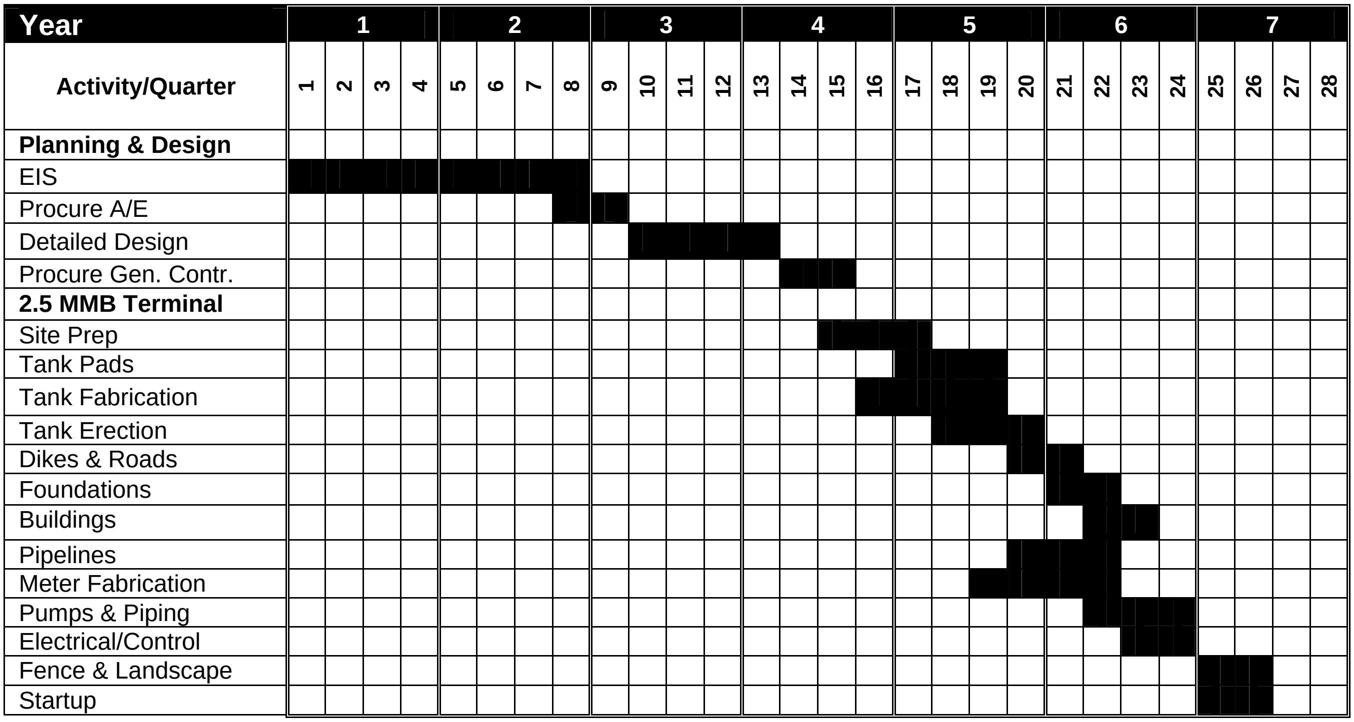
Permitting time always increases when an environmental review is conducted. Exhibit 16 compares permitting processing time by states. "As a rule of thumb, if a project needs to have an environmental review, set aside at least two years for the permitting process, if the project is located in California include an extra year for public participation." This statement by one of the survey respondents was confirmed when revising the Implementation schedule for the Heating Oil Reserve in the Northeast.[24] The schedule in Exhibit 17 includes an allowance of twenty-four months for EIS activities and presumes that all permitting can be accomplished within the time frames allotted for EIS and engineering activities.

Exhibit 16. Permit Timeline Comparison
(Months)

Permit /Time Range	California	New York	Washington	North Carolina	Texas
Environmental Process	12 - 32	6 - 24	12 - 24	5 - 24	n/a
Land Use	3 - 12	5	4	3	1
Building Permits	2 - 6	3	2 - 4	3	1
Air Permit	6 -12	3 - 9	6	4-6	1-24

Exhibit 17. Federal Storage Facility Implementation Schedule

[24] Report to Congress on the Feasibility of Establishing A Heating Oil Component to the Strategic Petroleum Reserve. Volume II: Appendix E. Second Revision: U.s. Department of Energy. June 27, 1997.



Source: Report to Congress on The Feasibility of Establishing A Heating Oil Component to the Strategic Petroleum Reserve. Volume II: Appendix E. Second Revision: U.S. Department of Energy. June 27, 1997.

Permitting Cost

Agencies or municipalities' permitting costs vary among states and localities. A contributor to cost variability are the different procedures and administrative activities involved with permitting processing, such as engineering analyses, record keeping, monitoring, training, etc.

A respondent with permitting process experience in both Texas and in North Carolina indicated that the main difference with the California's permitting process is that at the city Planning Commission level in California, a final design with engineering details is necessary when applying for a construction permit. The cost of preparing detailed engineering is high, and once detailed engineering is prepared, the developer cannot generally change "just one thing." Any design change suggested by the regulators would generally precipitate a raft of other changes, leading again to "uncertainty cost" and "schedule uncertainty." Other states do not require detailed engineering prior to issuing permits. Another respondent indicated that in the Northeast if the project requires an EIS the permitting process could be as much as $500,000. Another respondent indicated that the Missouri Department of Natural Resources is required by statue to refund permit fees associated with an application if a permit has not been addressed within the statutory timeline.

CALIFORNIA
ENERGY
COMMISSION

GOVERNMENT USE OF THE CALIFORNIA GASOLINE FORWARD MARKET

DRAFT CONSULTANT REPORT

APRIL 2003
P600-03-007D

Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

Prepared By:
Dr. Jeffrey Williams,
Professor
Department of Agricultural and Resource Economics
University of California
Davis, California 95616

Gregg Haggquist,
President
Monterey Global Energy (MGE)
584 Pine Street
Monterey, California 93940

Contract No. 600-01-100

Prepared For:
Brian Covi,
Contract Manager

Pat Perez,
Manager
Transportation Fuel Supply & Demand Office

Scott W. Matthews,
Deputy Director
Transportation Energy Division

Robert L. Therkelsen,
Executive Director

DISCLAIMER

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Executive Summary

The purpose of this project was to investigate the forward market within California for gasoline and the feasibility of state agencies buying bulk gasoline in that forward market.

Efficient and liquid forward markets provide an important relief mechanism during occasional periods of price volatility, which are typically due to refinery disruptions. Importers use forward markets to hedge the price risk associated with importing petroleum products over long distances, or more straightforwardly, to arbitrage across space and time. If California's forward markets do not provide a sufficient level of liquidity – itself the key question of this project – the ability of forward markets to provide a hedging and arbitrage mechanism to importers is impaired. If shipments would not be made, the result would be higher and longer lasting gasoline price spikes during refinery outages than would otherwise have been the case.

Previously, staff identified a likely contributing factor to California's relatively illiquid forward market is a lack of buyers relative to the number of possible sellers of forward contracts.[1] Staff has also identified that a variety of state agencies purchase gasoline in bulk, through procurement contracts with distributors tied to prices reported in wholesale markets. If these agencies were to purchase their fuel in the forward market as opposed to the spot market, the state would enhance the volume of buying in the forward market. If the forward market were lacking liquidity, the additional volume for the state might be sufficient to provide the critical level of liquidity required to facilitate forward sales by gasoline importers.

Summary of Findings

To learn about the forward market for gasoline, and to investigate the feasibility of government agencies executing their purchases in the forward market, the research team conducted a series of some twenty-stakeholder meetings with a cross section of California's petroleum industry. The following are the most significant findings:

- The forward market, which involves the two main pipeline routes, appears to be more active in southern than in northern California.
- The trading that occurs in California's forward market typically has a maturity of one month and occasionally two months. Given the logistics of California's petroleum industry, the lack of three-month or longer maturities is not surprising.
- Typical daily volume is in the range of three to five trades.

[1] See the California Energy Commission report contract #300-96-014, *The Status of Paper Markets for Energy*, by Philip K. Verleger, September 25, 1997.

- There does not appear to be a systematic imbalance between the number of potential sellers and buyers, despite earlier impressions.

- Market participants have surprisingly diverse views on how liquid is the forward market in California, but no one says the prices are not plausible or that deals cannot be done.

- The one-month forward price is often substantially below the spot price, a price pattern known as backwardation. These backwardations often occur at the time of the so-called spikes in the spot price of gasoline, which is a correlation consistent with behavior in other commodity markets.

- Delivery terms, credit checks, pipeline congestion, and other details of the forward market are not themselves impeding trading.

- The standard quantity in these forward markets – 25,000 barrels – inhibits smaller traders, but this large quantity comes primarily from logistics.

- No other barriers to entry are apparent.

- Collectively, the state agencies purchase gasoline equivalent to one standard pipeline lot per week.

- State agencies, needing smaller quantities at many locations, would have no direct need for a standard pipeline lot; private distributors would necessarily be involved.

In conclusion, it is not at all obvious that illiquidity in the forward market impairs importers. If anything, there is sufficient liquidity for importers. In any case, it is not clear that the state's active participation would make much difference in the operation of the forward market. Whether state agencies would be advised for their own sakes to base procurement contracts on the forward market is yet another question.

I. Introduction

Compared to other areas of the United States (U.S.), California seems to have more variability in the spot price of gasoline even as it has a relatively inactive forward market for gasoline. It is natural to wonder whether a more active forward market would itself dampen variability in the spot price of gasoline. This study first of all aimed to learn about the existing forward market in California, as a step to recommending how it might be improved.[2]

Ideally, forward prices serve as the signal guiding the accumulation or release of inventories and as the signal attracting imports of gasoline, since imports take time to arrive and storage by its nature allows adjustment between current and future conditions. Forward prices can serve as signals for a particular firm even if it does not trade in the forward market, provided the trades of others are reported. For those who do trade, the forward market converts highly risky ventures, such as a cargo sent across the Pacific with the hope that the spot price in California will still be high when the tanker arrives, into nearly certain, arbitrage-like operations.

Despite their advantages, forward markets are delicate institutions, easily disrupted by disputes over the performance of contracts after months have passed and conditions have changed. For a prospective importer of gasoline, the difficulty of finding counterparties who reliably perform their side of contracts acts much like a transaction cost such as a brokerage fee. Similarly, for a prospective importer of gasoline, the need to discount price to place the large volume of a typical tanker acts much like a transaction fee. Such costs broadly categorized as illiquidity are comparable to a tariff applied to imports, perhaps a tariff sufficiently high to preclude those imports.

Or to put that impediment due to illiquidity more hopefully: Reform of some small aspect of a forward market, such as minor adjustments to the prevailing terms of delivery, the reduction of credit risk through “netting” of trades, or the more consistent use of the market by some subset of traders, can attract additional volume. That increase in volume can attract yet more trading, and so increase liquidity as to eliminate the “tariff” on imports, thereby inviting the imports that would reduce price spikes. Perhaps the State of California, by redirecting its agencies’ bulk purchases of gasoline to the forward market, could set in motion this virtuous cycle. This study also aimed to determine whether the State of California had sufficient volume and flexibility to make this approach the recommended means for improving the forward market.

This proposition – that the State of California, by redirecting public purchases of gasoline to the forward market, would make the forward market more liquid and that liquidity in turn would make possible private traders’ imports – presupposes that three conditions hold. It is advisable to make the logical sequence of these three conditions as clear as possible. Indeed, this report will be organized around the three conditions.

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[2] A glossary of the many terms related to forward markets and to gasoline follows the main text of this report.

The first required condition, which may be so obvious as to be invisible, is that California would likely import gasoline during local disruptions. If the time involved is too great compared to a refinery outage or the freight rate always too high, any “tariff from illiquidity” in the forward market would not matter, since the absence of imports cannot be further discouraged. Second, the existing forward market needs to be poor by objective measures, either in terms of its price signals or its liquidity. Should the “tariff from illiquidity,” however large it is compared to the most active forward markets, not be very high relative to other influences on California gasoline, the existing forward market is unlikely to be a significant impediment to imports. Third, the state agencies need to purchase a sufficient quantity that its redirection to the forward market would matter to the normal volume in the forward market. In short, the issue of the state’s bulk purchases in the forward market is important should those forward trades put importers over the cusp of sending gasoline to California.

It is also advisable to make clear that “forward market” encompasses many markets, just as the category “gasoline” encompasses many commodities. An active forward market, such as the Brent crude forward market, involves a number of months into the future, namely one-month-ahead, two-months-ahead, three-months-ahead, and so on. For that matter, the divisions could be finer than a month; sometimes first-half and second-half are traded separately. Among these possibilities, the six-month-ahead market might trade irregularly while the two-month-ahead market could be so active as to serve as a benchmark for other regional markets. From this perspective of a constellation of delivery dates, the “spot market” is simply one with a very short horizon, and not necessarily the most important in the set.

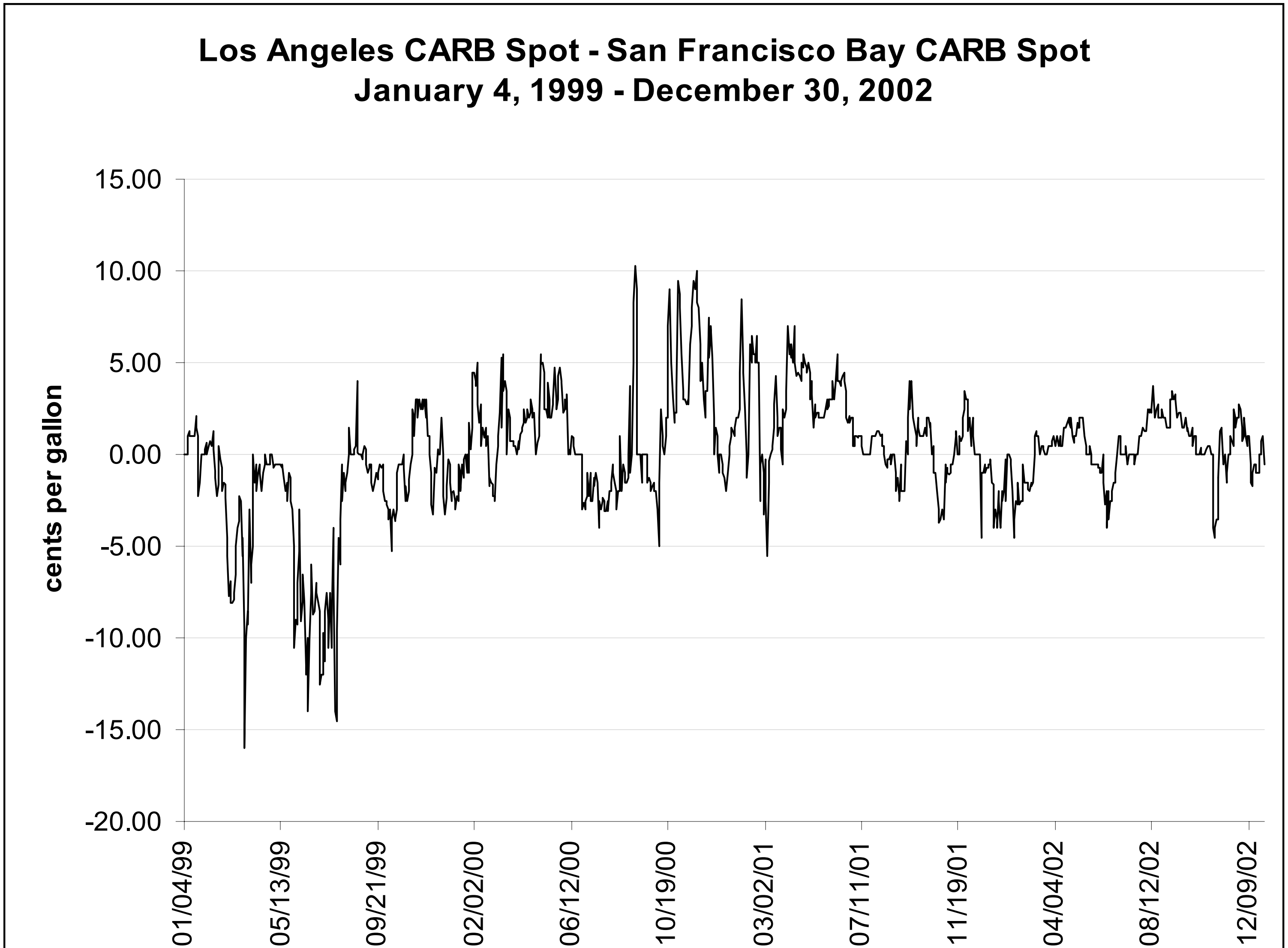
II. California As A Price Island In Gasoline

Increasingly popular is the metaphor of California as an island, where separated by distance and the specifications mandated by the California Air Resources Board (CARB), gasoline prices move somewhat independently of prices in other regions. Many of the stakeholders interviewed invoked the island metaphor at some point, especially regarding the effects of the California-specific specifications. This island metaphor is indeed useful for understanding the price effects of a local disruption. If gasoline were homogeneous everywhere and if all regions were interconnected (or equivalently, if transport costs and time were trivial), any local shock would be dissipated throughout the system. The metaphor of an island succinctly represents California's circumstances arising from the state's geographical separateness from refinery centers, especially those few now able to produce gasoline to California specifications.

The metaphor of California as a price island in gasoline needs some elaboration, nevertheless. First, because of the proliferation of boutique fuels across the U.S., California is no longer the only island market for gasoline in the country.[3] Each local environmental authority specifying a slightly different gasoline or slightly different rules for seasonal changes in specification adds to the U.S. Archipelago. Presumably, the local price spikes in other islands when they have local disruptions ripple through to California to some extent. No island is disconnected entirely, not least because crude itself can be redirected. Second, California is better thought of as two close islands, namely San Francisco Bay plus nearby and Los Angeles plus nearby. As Figure 1 shows, prices differ in the two locations within California, although not nearly as much as either California location sometimes differ from those elsewhere in the U.S. Third, the island metaphor includes the dimension of time as well as space. If specific specifications preclude that gasoline could come from Seattle but must come from farther away, perhaps as far away as Singapore, the increase in distance alone implies that California gasoline prices must rise more than previously to attract imports. But that increased distance also implies that California must rely on local production longer, since shipments from Singapore take longer to arrive than shipments from Seattle. Fourth, it matters to the metaphor that California the island is not routinely importing.

[3] See the EPA report, *Study of Unique Gasoline Fuel Blends ("Boutique Fuels") Effects on fuel Supply and distribution and Potential Improvements*, http://www.epa.gov/otaq/regs/fuels/p01004.PDF

Figure 1



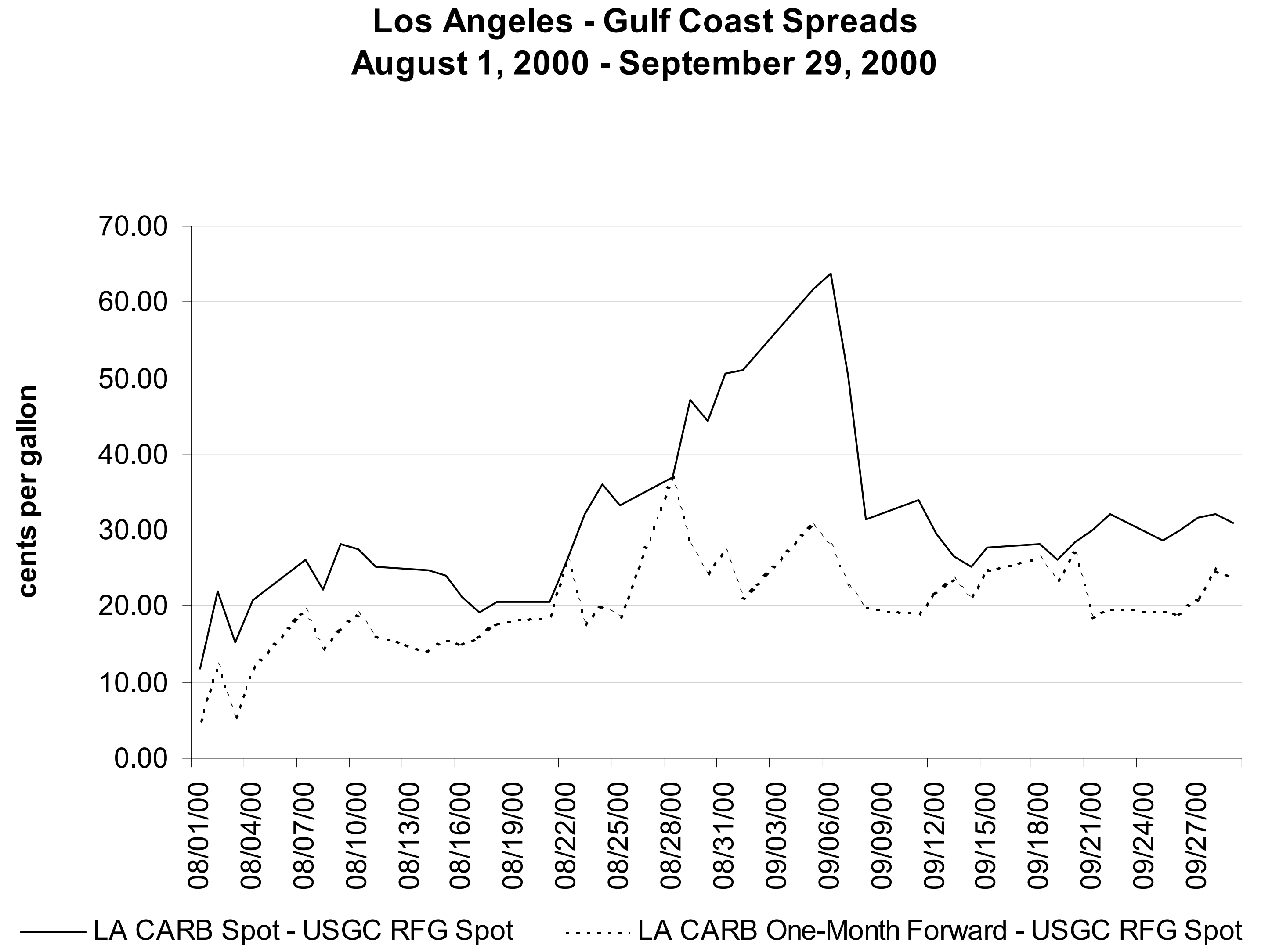
Source: Oil Price Information Service daily West Coast reports.

If the U.S. Gulf Coast, say, were always sending gasoline to California, at some fairly constant tanker rate, prices would move up and down nearly in parallel – the amount shipped, not regional price differentials, would be the mechanism absorbing the shocks within California.

Consider the sensible responses within an archipelago when one large island on the outer reaches has a major refinery outage. Although some islands are only one week away, those who could make the same specification are one month away. Only if the disruption on the large island were known to last more than one month would the rest of the archipelago be able to help the large island with the disruption. (One stakeholder made this very point about California.) Otherwise, decreased local consumption and whatever increased production is possible at other refineries on the large island must make up for the disruption. That is to say, the spot price and forward prices out to three weeks will spike considerably. If the disruption looks likely to last a month or more, the price for delivery in one month would rise, probably sufficiently to induce shipments from elsewhere in the archipelago. Only if the local response involves some tradeoff between the first month and the second month would the relief from imports have an effect on prices in the first month. (Such a connection between the two months could occur, say, through the pattern in the drawdown of inventories or through the delay of maintenance on refineries, which would allow increased production temporarily.) Because a shipment arriving in one month is sent immediately, the large island's disruption has an effect on the spot price of the exporting island, and perhaps on others who would otherwise routinely trade with that exporting island. In short, the pass through of shocks onto prices is quite complicated when both space and time are involved.

As regards California's price spikes, the relevant comparison of spatial prices should allow for the time required for the shipment. The comparison of spot prices in two locations, say California and the U.S. Gulf Coast as in Figure 2, are irrelevant for judging arbitrage possibilities, the existence of which would otherwise seem to be suggested by prices in California 60 cents higher than in the U.S. Gulf. During late August and early September of 2000, this spot spatial spread was sustained well over the estimated import parity, largely due to disruptions in California refining and to California pipeline shipments, those disruptions in turn due to local blackouts in electricity. An outside estimate of tanker costs and specification differences might be as much as 30 cents per gallon, much less than the 60 cent differential.

Figure 2



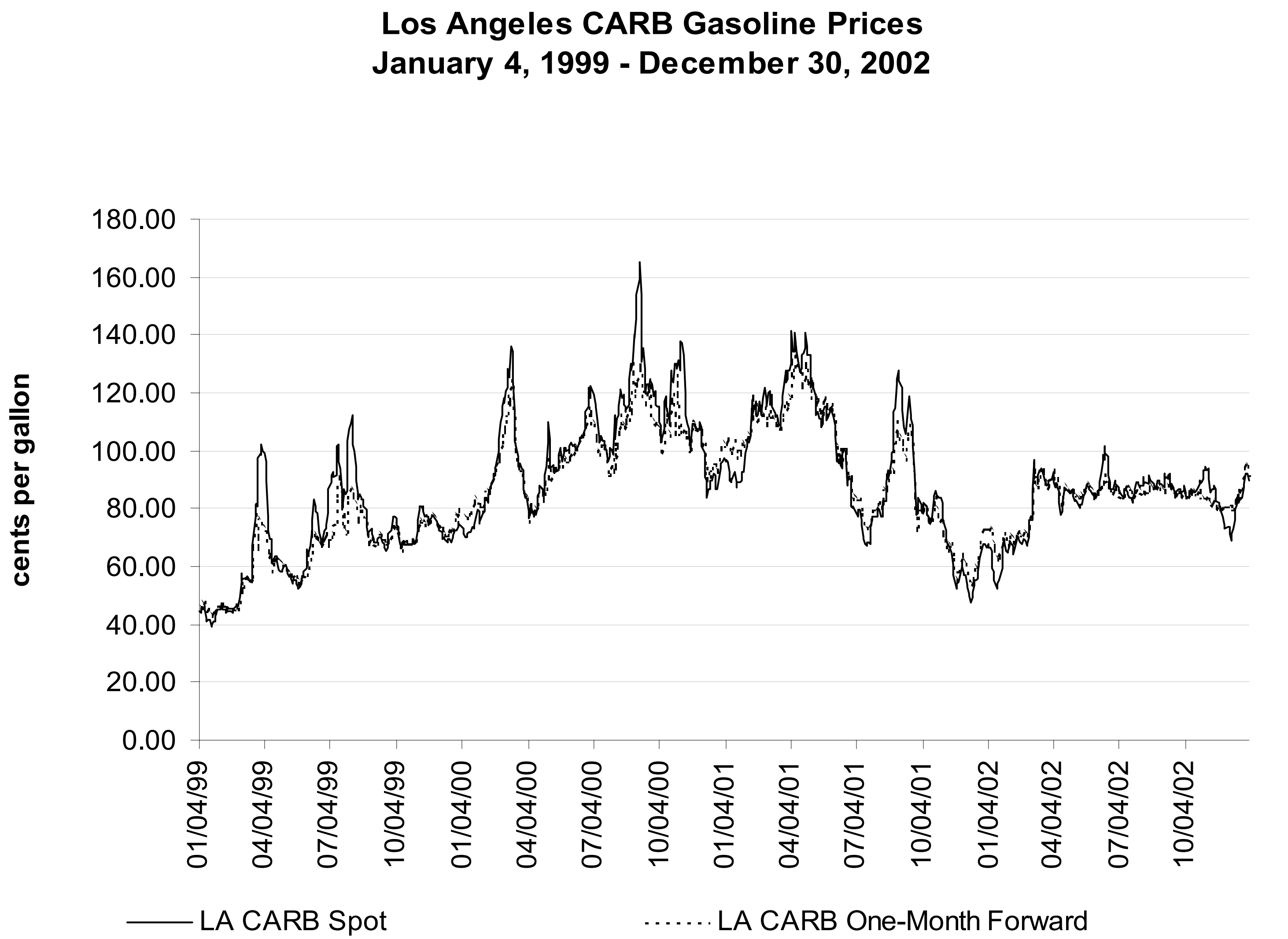
Source: Oil Price Information Service daily West Coast reports and Energy Information Administration spot price database.

For the spot spatial spread to reflect import incentives, however, gasoline must be transported from the U.S. Gulf Coast within one day. No one can move gasoline on that route within one day. It takes at least two or three weeks. The relevant comparison is thus between the spot price on the U.S. Gulf Coast (or better yet, a location where California specification gasoline is produced) and the price relevant for the time taken in transit, namely the one-month-forward price in Los Angeles. Over those days in August and September 2000 with a noticeable price spike, the Los Angeles forward price minus the U.S. Gulf Coast spot price was within the range of 30 cents (or less) on all but one day, and just barely over 30 cents on that one day. According to Figure 2, any arbitrage opportunities were fleeting and were acted upon, since the differential closely approximated shipping costs. Indeed, a number of cargoes were sent to California during that period. Similarly, during other price spikes, the one-month forward price is almost always within 30 cents of the U.S. Gulf Coast price, whatever the relationship between the two regions' spot prices. And during those periods, exports were sent on their way to California.

As Figures 3 and 4 illustrate, most often when a spike occurs in the spot price of gasoline, the one-month-ahead forward price (given for Los Angeles delivery in Figures 3 and 4) is substantially below the spot price. This discount, of ten, twenty, even thirty cents per gallon, does not measure the illiquidity in the forward market, namely the price a seller (or buyer) must offer to entice an offer. The discount reflects the pressure for immediate delivery of gasoline, which can be relieved in one month. This premium for immediate delivery – equivalently, a discount for later delivery – is known as a "backwardation" in the terminology of other commodity markets, where it is common even in the most active forward markets. (Indeed, the need to reflect backwardations as a price signal may be the major reason those markets are so active.) That is to say, the gasoline forward market as it does exist in California looks to display intertemporal price relationships much as do other forward markets, whether for gasoline or for other commodities.

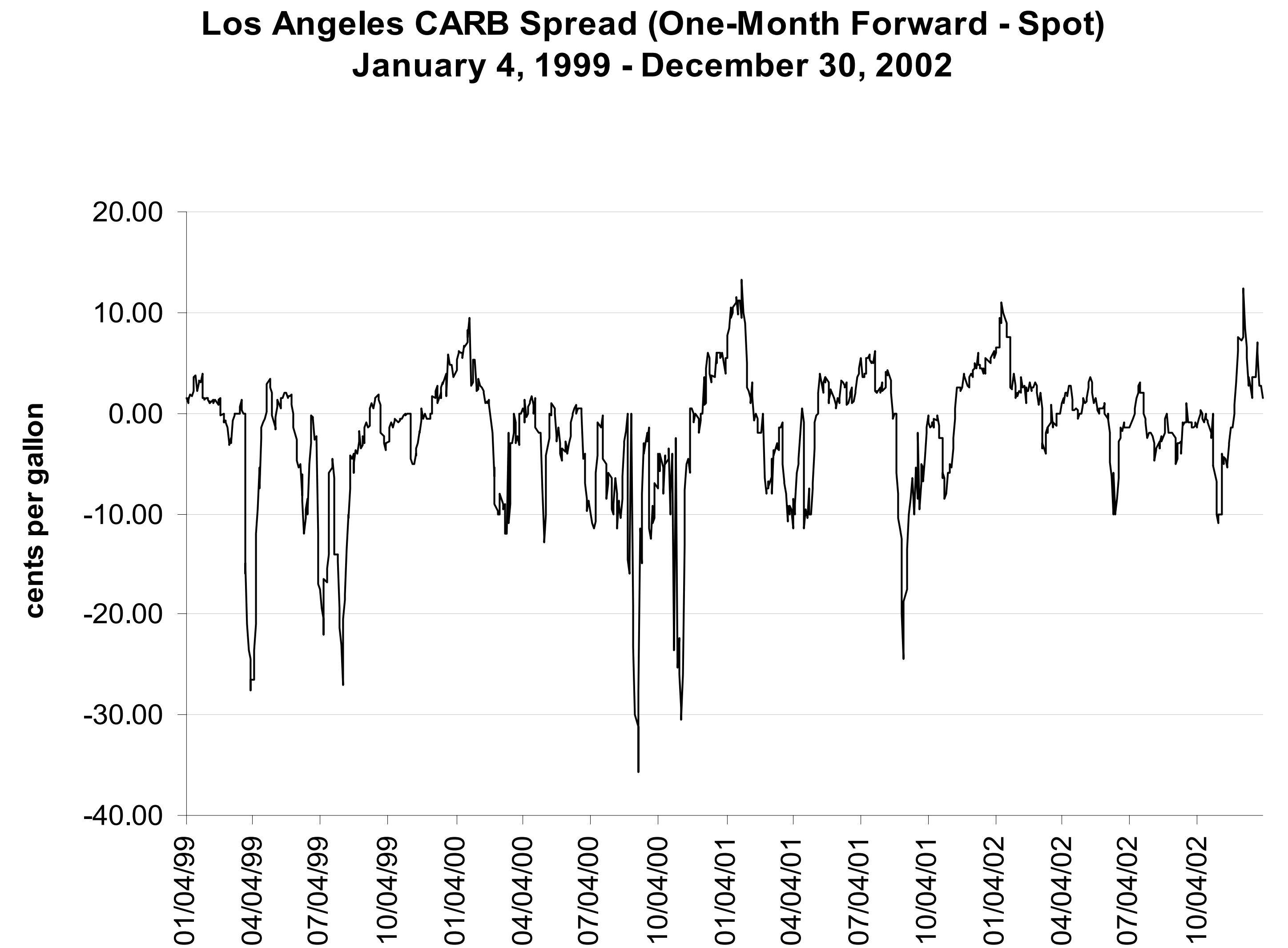
In sum, it appears that the first condition holds for California, namely that California is likely to import gasoline during local disruptions (and principally during those disruptions). Even so, that evidence is like a two-edged sword. Those imports appear to be a response to the relationship between the one-month-forward market in Los Angeles and spot exporting markets, which accords with the typical time of shipments. That fact itself suggests that the forward market in California is already performing its principal role as a signal for imports, quite apart from any additional liquidity provided by state agencies' trading.

Figure 3



Source: Oil Price Information Service daily West Coast reports.

Figure 4



Source: Oil Price Information Service daily West Coast reports.

III. Forward Gasoline Markets In California

With an ever-increasing gasoline demand of roughly one million barrels per day in California, one might expect comparable volume in a forward market. Northwest Europe, Singapore, New York Harbor (including NYMEX), the U.S. Gulf Coast, and Tokyo Harbor (including TOCOM) have developed forward markets with such volume. According to all stakeholders interviewed, the forward market for gasoline in California does not approach close to a volume of one million barrels per day. Many would estimate the volume to be on the order of 100,000 barrels per day, with the majority involving gasoline in Los Angeles.

The range around this mean estimate is surprisingly wide, and with it the perceived "depth" of the forward market. Some stakeholders thought it unlikely that they could sell as many as 100,000 barrels without a detrimental effect of the price while a few thoughts that the market could absorb 300,000 at prevailing prices. Most stakeholders agree that a transaction for twenty-five thousand barrels, or 2.5 percent of the daily California gasoline flow, can influence the price for unbranded gasoline, whether prompt or forward barrels. In that sense, the forward market is no more nor less liquid that the spot and prompt markets. Many stakeholders perceive that the liquidity of the forward market has been increasing in recent years. Perhaps the discrepancy in their estimates of the depth relates to the period they are remembering.

According to stakeholders, concerns about the creditworthiness of counterparties are not pronounced in the forward market. It is not that no credit risks exist. Rather they are so prevalent – even a tanker truck filling at a rack takes away gasoline worth some $10,000 – that the industry has put in place considerable checks and controls, which apply part and parcel to forward transactions. Stakeholders do remember one default and bankruptcy several years ago, but the memory does not impede trading today.[4] When asked about peculiar delivery rules, lot sizes no longer sensible, or trading customs giving too much advantage to one side of a bargain, stakeholders could think of no such problems discouraging forward trading. Nor did they mention a structural imbalance, such as too many offers to sell forward compared to offers to buy forward. Perhaps this balance has changed from six years ago.

The forward trading that does occur in California extends one month ahead, sometimes two months ahead, and almost never any farther. Sometimes individual weeks are distinguished, as in the example in Figure 5, which demonstrates the each weekly cycle in September traded at a different price as of early September. The forward trading concerns the scheduled pipeline flows, principally in the major pipeline coming out of Los Angeles and to a lesser extent on the pipeline from San Francisco east towards Sacramento. Pipeline batches, usually in a "piece" of 25,000 barrels, are bought and sold between all market participants on a daily basis. Prices for "prompt" shipment during the next week-long cycle on the pipeline are what OPIS and Platts report as the

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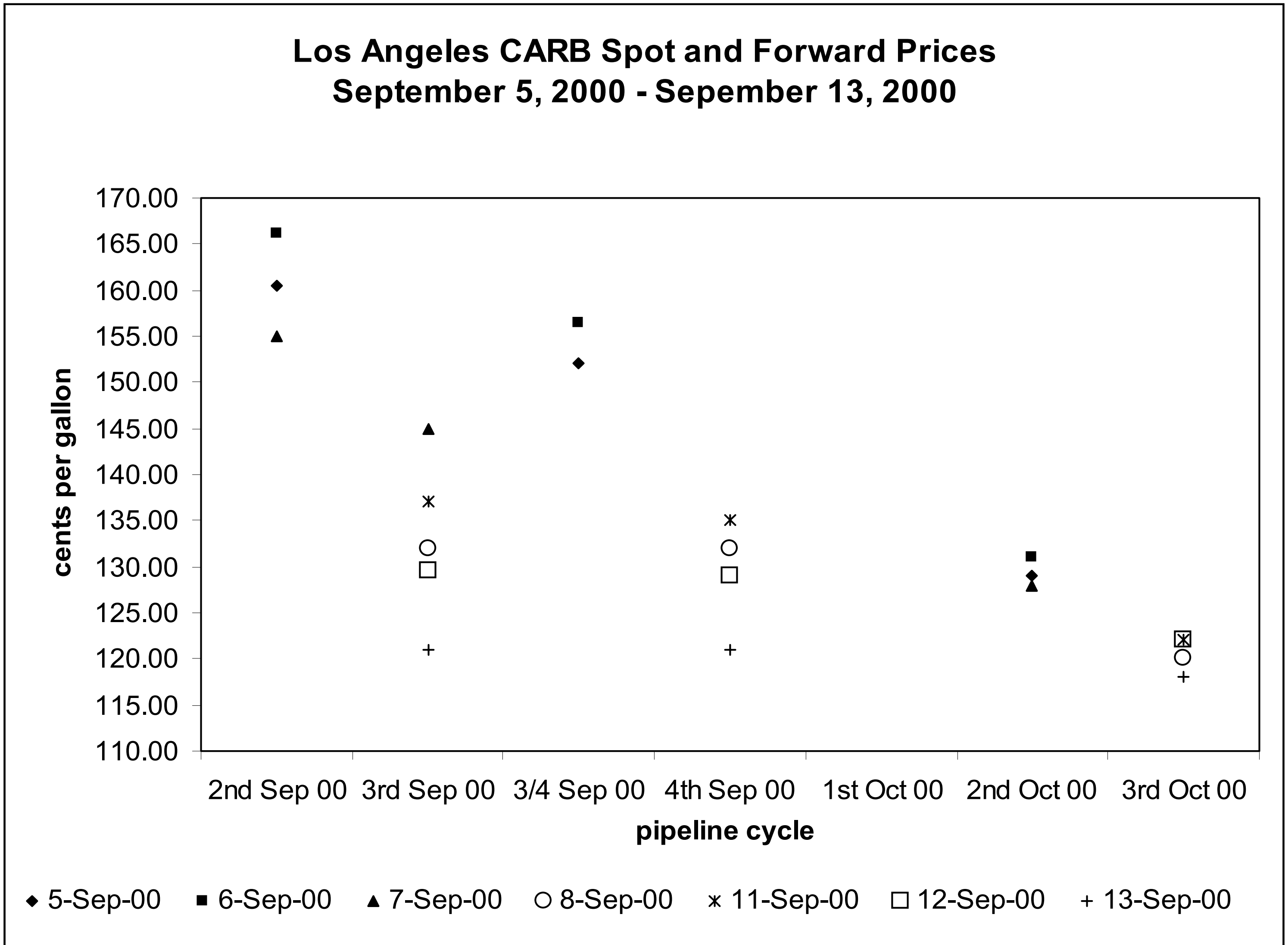
[4] The Oil Daily, "Trader's bankruptcy raises warning flags," March 18, 1998.

”spot market price” of the day; those for more distant cycles are the reported forward prices. The estimated daily volume in the forward market of 100,000 barrels thus corresponds to four trades per day.

The nature of the forward market is heavily influenced by the logistics within California. Major gasoline movements occur on pipelines originating in the refining centers to San Francisco and Los Angeles. Were California regularly and significantly dependent on gasoline imports, the principal pricing point, prompt or forward, would probably be C.I.F. San Francisco Bay or Long Beach. Were the two northern and southern pipeline routes interconnected, probably one origin would serve solely as the forward market. Were the pipelines frequently congested, which stakeholders say infrequently happens, additional pricing points might emerge. As a pipeline operator, Kinder Morgan is flexible about the nomination process, allowing rescheduling of when a shipment leaves and substitutions of the recipient until one week before a cycle begins, at which moment the arrangements “freeze”. That flexibility up to one week ahead allows those who bought gasoline but never truly wanted the “wet” barrels to sell the piece later to someone else or to “roll” the shipment to a later cycle. Such activity goes by the name “paper” trading. According to various stakeholders, some trades in the California forward market are indeed paper trades, but by no means a majority, let alone a great majority as in some forward markets. Many stakeholders emphasized the “wet” barrel as the common trading philosophy.

Figure 5



Source: Oil Price Information Service daily West Coast reports.

Among the cross-section of stakeholders interviewed, from major oil companies to independent dealers, there is consensus that a more liquid forward market would be a positive element of California gasoline. Such a consensus is not surprising, for it is difficult to imagine anyone damaged by a more liquid forward market in California specifically. (Whether stakeholders would like more paper trading and the greater presence of speculators that comes with paper trading was not a question asked.) Notwithstanding the desire for a more liquid forward market, only relatively few types of traders trade in the forward market. Even those who do not trade routinely are aware of prevailing prices. Several made mention of adjusting their inventories to the signals in the spread between spot and forward prices. Only a few kept sizeable inventories, however, although that situation appears to be changing as more storage space seems to be coming available.

Specifically, major oil companies, the so-called integrated majors, communicate an attitude of self-sufficiency with respect to the ability to supply the market, and hence do not focus on the forward market. They perceive that forward market liquidity could be greater, and that that development would be desirable, but that government agencies will not be able to provide more liquidity. Some of the majors are offering fixed forward pricing, or formulas linked to OPIS or NYMEX. Some indicate a willingness to sell to reliable, credit-worthy end users on a forward pricing basis over an extended period. But few customers seemingly are willing to take advantage of these offerings. And some customers dispute the willingness of the majors to offer long-term deals fixing a refining mark-up. At this stage, these types of transactions, which are familiar to the aviation industry with regard to jet fuel, have not been successful in gasoline.

From the larger independent refiners, who service the unbranded sector of the downstream market, one hears that more forward price liquidity would be a good thing. They look for forward fixed-price deals, and will sell forward into the pipeline if the transaction looks worthwhile. There also seems to be a willingness to sell directly to a refiner suffering an outage.

Both in northern and southern California, the class of trader encompassing distributors and jobbers aggregates the demand of independent gas station owners, industrial and commercial accounts, and state agencies. These traders negotiate bulk supply deals with refiners on an “unbranded pricing” basis. Because they stand between the physical supplier and the end user, and because they have price risk exposure on any unsold, or undelivered volumes, they mainly maintain a back-to-back balance between purchases and sales. At times, however, when they have a strong feeling about the direction of prices, they try to time their purchases and adjust their inventories. In any case, their operations require an intensive management effort in dispatching, notification about price changes, and monitoring inventories at various terminals. Kinder Morgan, which controls the marketing terminals out of which they operate, does not allow storage of incremental inventory beyond two weeks (if that). Kinder Morgan schedules a tight, top-to-bottom flow through the tanks against weekly pipeline shipments. In other words, inventory games cannot be played beyond a few days quantity of sales, to take advantage of a spot-forward spread in contango (a signal to build inventory), or in backwardation (a signal to reduce inventory as much as possible). These traders pay attention to the intertemporal price signals, and the related ones in the NYMEX futures markets.

Pipeline traders, along with the cargo traders (often a combined role), appear to be the primary bridge for price formation between prompt and forward markets in California gasoline. Pipeline traders would strongly support more liquidity in the forward market. They would, in fact, create that liquidity if there was a reliable means to tie such forward prices to a common index, such as NYMEX or MOPS Singapore. The international cargo traders propose that California needs both more marine storage and a forward market. They express great confidence that California grade gasoline and components can be found from both the Pacific Rim and East of Panama. In a normally functioning market those supplies would keep a healthy pressure on California prices. But they are disadvantaged by the lack of marine storage (particularly in Los Angeles) and by the lack of forward pricing mechanisms, or so they perceive. "There is no way to hedge [sell forward] a whole cargo," they say. And a drop of five cents per gallon in price, while the ship is on the water, works out to a loss of around $700,000, which is not an acceptable risk. They offered no specific examples of a cargo that was almost but ultimately not sent, however. And partial cargoes can be sent, as when gasoline is sent along with diesel or jet fuel, either of which can be hedged on NYMEX.

Until very recently, no electronic trading platform for petroleum products in California existed. Instead, a number of local telephone brokers canvass the market daily, linking buyers and sellers in prompt transactions, and in the few forward trades that do get reported. Generally, the brokers would like to see more transactions in the forward market. Liquidity is a sign of healthy competition, not to mention a sign of more deals that need brokers. Compared to the types of deals done elsewhere in the U.S., those in California are not very complicated – uncommon are trades such as collars tied to a strip of NYMEX contracts at a set basis differential. As it happens, the NYMEX has recently launched an electronic trading platform on which CARB gasoline can be traded on a differential against the NYMEX contract. Brokers will watch that development closely, since it could cut into their business. So far, no trades have been done in this format. Perhaps California-based traders are not sophisticated, perhaps other forward instruments serve the function nearly as well, perhaps the NYMEX contract has itself insufficient liquidity to set in motion the virtuous cycle of trading volume.

In sum, although the forward market in California cannot be said to function poorly – the second condition in the logical sequence for government attention – neither can the forward market be said to flourish. A number of participants and prospective participants perceive the market as relatively illiquid, especially for the larger quantities associated with a tanker, some 350,000 barrels. If that illiquidity were converted to a cost, perhaps it would be between one and two cents per gallon. Although a higher transaction cost by an order of magnitude compared to active forward markets, one to two cents per gallon does not seem the principal impediment to shipments to California, compared to freight rates on the order of 20 cents from plausible export points or the extra cost of producing CARB gasoline, some 5 to 7 cents. The forward market in California extends one month or so, which is the time necessary for most shipments to arrive in California. Perhaps an impediment to imports is the translation of a tanker shipment into the pipeline segments that are traded in the forward market, but that complication too seems a minor issue to the functioning of the forward market in California.

IV. State Agencies' Purchases

According to several current suppliers, purchasers in several state agencies, and the Department of Government Services (DGS), which oversees those purchasers, the best estimate of the state agencies' purchases is less than 5,000 barrels per day or 0.5 percent of the entire demand for gasoline within California. Were all state agencies' purchases aggregated, they would amount to the order of magnitude of one pipeline piece per week, that is, to one trade in the forward market per week. One or two trades per day might make a substantive difference to the forward market, but it seems unlikely that one trade per week would make a substantive change in its liquidity. Thus, the third condition in the logical sequence does not seem to hold.

Moreover, it is far from straightforward how the state agencies' purchases would be aggregated to a single weekly trade in the forward market. No central supply point, such as a single pipeline, services state government contracts. Demand is spread from urban center police departments, such as the Los Angeles Police Department (LAPD), to remote mountainous areas under the jurisdiction of the Department of Forestry and Fire Protection (CDF). Each government agency has its own methods for soliciting bids and administering the business. The great majority of state agencies' gasoline is supplied by jobbers who specialize in this geographically dispersed, non-uniform-lot class of trading. Other than Valero and Petro-Diamond, none of the refining companies or large trading companies has chosen to pursue this line of business. The smaller trading companies themselves are unlikely to deal in the minimum quantities prevailing in the forward market.

Since virtually all state gasoline demand is delivered by truck, the job of managing different truck routes and the gasoline specifications required in different parts of the state, including non-concurrent seasonal changeovers in those specifications, finds expression in the contract price itself. Most state agencies' contracts specify a differential (over which the bidding occurs) to a reference price, which is usually OPIS's "unbranded" rack price for the day of the truck delivery prevailing in some part of California. For example, a full truck and trailer load of gasoline delivered to a central LAPD location has a smaller differential than a bobtail truck (small-unit) delivery to Lake Arrowhead up in the mountains. A number of agencies are holders of Card Lock System Cards, which enable their vehicle fleets to pick up gasoline at designated locations on a floating price linked to OPIS's quotations for unbranded rack prices. Nothing in the style of these contracting arrangements precludes the use of another index, such as OPIS's quotation for the prompt cycle on the pipeline or its quotation for one-month forward on the pipeline. For that matter, the contracts could specify differentials (they would surely be different from those employing the current indices) to the price of gasoline in New York harbor. A different index, especially the forward pipeline price, might induce these smaller suppliers themselves to use the California forward market, but the advantages of this displacement are not obvious. The state agencies will continue buying gasoline day to day as they need it, regardless of price and regardless of the intertemporal pricing signal in the spot-forward spread. The state agencies' suppliers can see even now the intertemporal signals for their own procurement of gasoline.

The state government as a whole could look beyond individual contracts and undertake an aggregate hedging operation operated by the State Treasurer. (After all, state agencies do not routinely issue their own debt individually.) Such a hedging program, which could involve both NYMEX and California pipeline forwards, and rolls between them, might be sensible for the state out of concern for budget planning, quite apart from any benefit to the liquidity of the gasoline forward market. If a state hedging program is deemed to be feasible an immediate and obvious question will be, "How does the state account for the gains and losses?" Do the individual agencies' budgets adjust with the month-to-month outcome of the hedging? The aggregate demand of all deliveries throughout the state could be hedged against, say, the forward pipeline prices for Los Angeles and San Francisco as posted by Platts and OPIS. The differential between the daily and particular rack price and the forward market price would represent the gain or loss that could be booked to the particular agency's hedge account, at the State Treasurer's level. A full consideration of such strategies was beyond the scope of this study. The relevant point is that such a hedging program could direct more volume to the California forward market. But that volume would have to be paper trading, since the state would acquire the "wet" gasoline through its regular contracts. That is, the forward market would already need to allow sufficient paper trading for the state to add further liquidity.

V. Conclusions

From the argument that forward markets are delicate institutions, it does not follow that the absence of a forward market is necessarily indicative of some problem. Rather, the absence of the forward market may indicate that it is not needed because of features of the logistical and distribution system. Just as it makes little sense to have retail stations sell twenty-five different octane levels of gasoline – three seems to suffice – it makes little sense to expect active forward markets in all conceivable regions of the U.S. For several markets to be active, the differences in pricing situations need to be substantive. And those differences need to be sustained and variable. Should a pipeline serving as a city's principal source of gasoline have an accident, causing the spot price of gasoline in that city to spike relative to other locations, the price there for delivery three months later would not likely move from its normal spatial relations. Provided the pipeline could be repaired or supplies diverted within those three months; that three-month forward market in that city is unlikely to be active, for there is no price difference to reflect. In short, one would not expect active forward markets for gasoline in California beyond the time of plausible logistical constraints isolating California from other regions, given that those other regions have active forward markets for gasoline, not to mention that other regions have active forward markets for crude oil.

Logistical constraints within California are on the order of one month. Schedules on the two principal pipeline routes, one from Los Angeles, the other from San Francisco Bay, are settled within a month (namely, within four weekly cycles). Those pipelines are rarely, if ever congested, for more than a few days. Those two pipeline systems do not interconnect except indirectly. No pipelines from other regions reach into California. Extra gasoline must move by ocean tanker, if at all, to California, or by barge between Northern and Southern California. The longest of such tanker trips can be six weeks; one within California a week at most. Meanwhile, the trading that occurs in the forward market within California has a maturity typically of one month, occasionally two months. Given the logistical situation, the lack of two-month and higher maturity in California forward markets is neither surprising nor troublesome.

The one-month-ahead forward market appears to be more active in southern than northern California, and compared to other markets, not all that active even in southern California. Of course, it would be better if these markets were more active and the prices in them more transparent. Even so, traders pay attention to those price signals, especially in regards to making inventory decisions.

Impediments to forward trading are not obvious. Anyone in the wholesale gasoline business – not all that many firms, to be sure – can trade in the forward market. (Put differently, any constraints on trading style are also felt in the spot market.) There does not seem to be a systematic imbalance, meaning, say, far more willing sellers than willing buyers. (Put differently, the reported forward prices seem to be in line with those observed in other regions.) Although one default occurred several years ago, the market has not been plagued by the fear of defaults and bankruptcy. Through the credit checking necessary for wholesale spot markets, prospective counterparties have a good idea of default risk. There are few or none of the disputes over grade, quantities, and delivery timing that plague other commodity markets. In some forward markets – Brent crude is a good example – some originally minor clause of the contract has become a game of advantage, sometimes to the buyer, sometimes to the seller, and always an impediment to trading. The forward market for gasoline in California does not seem to have such problems. As a result, there is much less scope for the strong leadership of, say, the State of California to insist on customs sensible for the market as a whole, to apply to standards of credit analysis, to balance buyers and sellers, or to go out of its way to include excluded traders.

State agencies weekly buy a quantity of gasoline (i.e., about one million gallons) on the order of one lot in the forward market. An increase in volume of one lot per week would make some difference to the functioning of the forward market, since the daily volume is only a few lots at most, but the state's trading would be unlikely to transform the market. In any case, because the state agencies need gasoline at many locations (and in small amounts), the state itself could not disperse one pipeline lot. It would require gasoline distributors to serve that function, and part and parcel, to handle its trading in the forward market. Its effect on the forward market would need to be indirect. Substantial indirect effects are possible, but not likely. All the state's procedures for procurement and inventory control exemplify the rigidity opposite to the flexibility needed for sophisticated trading in forward markets.

Glossary of Terms

Backwardation: Describes the market condition where the price for nearby delivery exceeds the simultaneously quoted price for later delivery.

Barrel: A unit of measurement equivalent to 42 gallons, abbreviated bbl.

Basis: The basis is a differential to a benchmark price (typically the price of a futures contract traded in high volume) that determines the price of a commodity of a particular grade or at a particular location – the local price is "based on" the benchmark. This differential is not fixed, and the uncertainty created by the fluctuation in the basis is known as "basis risk."

Blendstocks: Blendstocks are components used in the production of finished motor gasoline. These components include various hydrocarbons as well as reformulated gasoline blendstock for oxygenate bending (RBOB), but exclude oxygenates and butane.

Boutique Fuel: State or local cleaner-burning motor gasoline specifications that are unique to that region of the U.S..

Branded Gasoline: Gasoline purchased from wholesale terminals or sold at retail outlets that are identified by a refiner trademark.

CARB: The California Air Resources Board. It is common to refer to the reformulated gasoline that meets the standards of the California Air Resources Board as "CARB gasoline."

CARBOB: RBOB that meets the standards of the CARB.

Carrying Charges: The cost of carrying a commodity forward in time, including warehousing fees, insurance premiums, and capital expenses. When the difference between the price for a nearby delivery date and the simultaneously quoted price for a more distant delivery date exactly covers the total cost of holding the commodity for that time, the price difference, or *spread*, is said to be at full carrying charges.

C.I.F.: C.I.F. stands for cost, insurance, and freight paid, paid by an exporter that is, and so represents the price of the good on board a vessel in the importer's harbor. Should the exporter be responsible only through the loading of the vessel and the importer responsible for the freight charges, the price is F.O.B., namely free on board in the exporter's harbor. Thus, a price quoted C.I.F. should always be higher than a price for the good quoted F.O.B.

Collar: A collar specifies the minimum and maximum price a buyer must pay for a contracted commodity.

Contango: Describes the market condition where the price for nearby delivery is below the simultaneously quoted price for later delivery.

Crack Spread: The simultaneous purchase or sale of crude futures and the sale or purchase of refined petroleum product futures. This *spread,* which represents the *refining margin*, can be “simple,” that is, a position in one refined product and an equal but opposite position in crude oil, or “diversified,” in which positions are held in more than one refined product with an equal but opposite position in crude oil.

Credit Risk: The uncertainty surrounding the possibility that someone will fail to fulfill a contract. For example, someone with a *long* position will *default* on their obligation to pay for and take delivery in a timely manner.

Dealer Tank Wagon price: The delivered price of wholesale gasoline charged by refiners to refinery owned retail outlets, often abbreviated DTW.

Default: Failure to make required payments, accept delivery, make delivery, or to comply with other conditions of an obligation or agreement on a timely basis.

Exchange Agreement: A contract between two refiners to trade gasoline. The trade is typically geographic, with each company giving to the other in a different region (e.g., refiner A gives to refiner B in San Francisco Bay and refiner B gives to refiner A in Los Angeles). The trade may also involve different grades or different products. It is a type of *swap*.

Exchange for Physicals: An exchange for physicals, often abbreviated EFP, is a double transaction, one part in futures contracts conducted away from the trading floor of the futures market, the other part involving the physical commodity, typically not in the contract grade or at the delivery points.

Forward Contract: In its most general sense, a forward contract is any agreement calling for the execution of some act in the future, including, but not limited to, futures contracts. Usually, the term is used not to refer to standardized futures contracts but to those contracts containing conditions tailored to the particular needs of the contracting parties and which, should either party’s needs change, must be renegotiated privately rather than offset. Other times, forward contract refers to relatively standardized instruments but with trading

Futures Contract: Futures contract abbreviates the phrase “contract for future delivery.” It usually refers to one of the standardized contracts traded in high volume on an organized exchange, with procedures for a clearinghouse and margin to ensure performance of the contracts. In effect, futures contracts become traded in their own right. In active futures markets, several delivery months trade simultaneously.

Hedge: A position taken in *forward* or *futures* contracts by a firm dealing in that or related products to reduce risk in the *physical position*.

Independent: “Independent” generally refers to a company that is not vertically integrated from crude oil to retail outlets. An independent refiner does not own crude oil assets, and may not own retail outlets. Independent *jobbers* belong to companies that do not have refining assets, and may not have retail outlets. An independent retailer is an individual or chain of retail outlets that are not owned by a refiner. Independent jobbers and retailers may sell *branded* or *unbranded* gasoline.

Inversion: In gasoline wholesale markets, an inversion describes the market condition where the branded rack price is below the unbranded rack price. To confuse matters, the more general use of inversion is as a synonym for *backwardation*.

Jobber: A jobber is an individual distributor who buys *loads* or less of branded or unbranded gasoline at wholesale terminals and resells the product to retail outlets and large end-users, such as government agencies.

Liquidity: Liquidity is a term that generally represents the trading activity in a market. Liquid markets tend to have higher volume and less price sensitivity to large trades than illiquid markets.

Load: A load is the standard quantity purchased by a jobber over the rack. One load is one truck compartment, or 8,000 gallons.

Long: Long describes the market position of someone who has bought something, whether the physical commodity or a futures contract. When making the trade, the person is said to “go long.” Long also refers to the net position of someone who has contracted to buy more than they have contracted to sell. Long has also come to indicate the person who holds the position.

Major: A “major” is a refiner that is vertically integrated, owning assets in crude oil acquisition, refining, product distribution, and retail outlets. Currently, there are six majors operating in California. Contrast with *independent*.

Marketing Margin: Also known as the “dealer margin,” the marketing margin represents the contemporaneous conditions in the wholesale and retail markets. Specifically, it is the difference between the simultaneously quoted retail product price, including all relevant taxes, and the wholesale price of that product.

MOPS: Mean of Platts Singapore (Platts is the dominant industry pricing publication in the region).

Nomination: Before someone can use the transportation services of a pipeline or cargo system, the service must be requested, or “nominated.” The nomination includes the physical infrastructure, origin, destination, supplier, and purchaser. Transportation companies have their own procedures for accepting nominations and scheduling shipments.

NYMEX: New York Mercantile Exchange. Also known as “The Merc.”

OPIS: Oil Price Information Service.

Paper Market: The paper market is often used synonymously with *forward* and *futures markets*, and generally refers to positions entered into these markets with intent to trade out, rather than accept physical delivery. Contrast with *physical market*.

Physical Market: In the physical market, the product changes hands upon completion of a transaction. This market is distinct from paper markets, where contracts change hands, possibly many times, without delivery being made. The physical market need not be simply *spot* trades.

Physical Position: Someone holding a product, or a commitment to make or take delivery of a product, is said to have a position in the *physical market*.

Piece: A piece is the standard lot size of transactions in the pipeline or cargo markets. A pipeline piece is 25,000 barrels, and a cargo piece is 250,000 barrels.

Pipeline Batch: The amount of a product injected into a pipeline for delivery to a terminal is called a batch. Pipeline carriers often specify minimum batch sizes, which are typically between 5,000 and 25,000 barrels, to preserve product flow through the pipeline system.

Prompt Market: Products that are available for delivery soon are traded on the prompt market. The product does not change hands immediately, and so the transaction is not a *spot* transaction, nor does it take place appreciably in the future, and so is not a *forward* transaction. Though different from a spot market, it is common in petroleum markets to use the words prompt and spot interchangeably.

Rack: A rack is a truck loading facility at a wholesale distribution terminal. There are typically several racks at a terminal, where *jobbers* purchase gasoline and other products for distribution to end-users.

Refining Margin: The refining margin is a *spread* that represents the contemporaneous conditions of the crude oil and *spot* or wholesale product markets. Usually represented in dollars per *barrel*, is the difference between the simultaneously quoted spot or wholesale product price and the spot price of crude oil. Compare to *crack spread*.

Reformulated Gasoline: Finished motor gasoline meeting the minimum requirements of the Environmental Protection Agency (EPA) established under the Clean Air Act.

Roll: The transfer of a position from one futures period to another involving the purchase (sale) of the nearby month and simultaneous sale (purchase) of a further-forward month. A roll postpones an obligation to either take or make delivery on a futures contract. The existing position is liquidated and simultaneously reinstated in another delivery month, and a payment is made (or received, as the case may be) equal to the difference between the price for the two delivery dates. In this most common sense, roll implies the special class of a “roll forward,” namely rolling a nearby futures contract into a more distant contract. “Roll back,” contrary to natural usage, means to roll a futures contract for distant delivery into a nearer month. A “transfer” is a roll when the contract is just about to expire; that is, the delivery month has arrived.

Short: Short describes the market position of someone who has sold something, usually a futures contract. If the sale called for immediate delivery, the position could not be kept open; hence, a short position usually has some degree of future commitment about it. Short also refers to the net position of someone who has contracted to sell more than he has contracted to buy. Short has also come to indicate the person who holds the position.

Spot: The term "spot" refers to a good that is right at hand, and so is available for immediate delivery. The price paid for a good to be delivered immediately is said to be the "spot price." In petroleum markets, *unbranded rack* sales are said to be "spot wholesale" sales.

Spread: A spread is the difference between the prices of a commodity for two different dates of delivery or at two different locations (the prices quoted simultaneously). The term is also used to describe the trades necessary to achieve such an implicit position in the market, for example, by the purchase of a nearby futures contract along with the sale of a futures contract with a more distant delivery date. The difference in price between later delivery and earlier delivery is the *carrying charge* for that time period.

Strip: A series of simultaneously entered consecutive *forward* positions covering a given time period. For example, someone in January may buy a strip of Los Angeles gasoline by entering a *long* position in the February and March forwards, paying a price equal to the average of the February and March forward prices.

Swap: A swap can be an informal agreement to exchange gasoline available today, say in Los Angeles, for gasoline next month, say in San Francisco. A swap can also be much more forward, with a price attached, paid by the party whose gasoline is more valuable by time or space. A swap can also be more routine and more standardized. In many commodities they have developed into markets. In these cases, they take on many features of a *forward contract*.

Tariffs: A regulated schedule of rates and general terms and conditions under which a pipeline carrier will transport refined products.

Throughput Tanks: Storage tanks at common carrier wholesale terminals are used exclusively for temporary storage, with inventories held just long enough to keep the terminals supplied between pipeline cycles. Since these storage facilities are used together with the pipelines to maintain product flow throughout the system, these tanks are referred to as "throughput" tanks.

TOCOM: Tokyo Commodities Exchange, an organized futures exchange principally trading precious metals and petroleum.

Unbranded Gasoline: Gasoline sold at wholesale terminals or retail outlets that are not identified by a refiner trademark.

CALIFORNIA
ENERGY
COMMISSION

CALIFORNIA MARINE PETROLEUM INFRASTRUCTURE

DRAFT CONSULTANT REPORT

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CALIFORNIA ENERGY COMMISSION

Prepared By:
Thomas E. Gieskes,
David J. Hackett,
Stillwater Associates, Inc.
3 Rainstar
Irvine, CA 92614
Contract No. 500-00-002

Prepared For:
Sherry Stoner,
Contract Manager

Ramesh Ganeriwal,
Project Manager

Pat Perez,
Manager
TRANSPORTATION FUEL SUPPLY AND DEMAND OFFICE

Scott W. Matthews,
Deputy Director
TRANSPORTATION ENERGY DIVISION

Robert L. Therkelsen
Executive Director

DISCLAIMER

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Overview

California's downstream petroleum infrastructure consists of 11 major refineries, 8 small refineries, 32 major terminals of which 27 are marine facilities, 156 distribution terminals, and 4520 end-user owned storage facilities, including 34 military depots. Thousands of miles of pipelines connect the refineries to each other, to the marine docks and tanks, and to the inland distribution terminals.

This study limits itself to three major elements of the marine infrastructure. The first are waterfront refineries and/or terminals with tankage directly connected to docks capable of receiving petroleum tankers and barges ("marine oil terminals"). Second are terminals and refinery tankage that are located some distance inland but are connected to a marine dock by pipelines. The third element is the pipeline connections ("gathering systems") to the common carrier pipeline network. This analysis models the flow of waterborne products off of tankers into tankage at the dock (or pipelines connecting to tankage inland) and then into the pipeline network to distribute the product further.

California has two distinct refining centers, the Los Angeles Basin (LA Basin) and the Bay Area, and each of these refining centers has its own separate pipeline distribution network operated by Kinder Morgan. The two pipeline systems are not interlinked. Yet in many ways, the California market behaves as one and a fair amount of feedstocks and products are interchanged between the two refining centers, primarily by means of coastal barges, adding to the marine infrastructure requirements. For each of the main refining centers, an analysis of the available infrastructure is presented below.

Bay Area

The marine petroleum infrastructure in the San Francisco Bay area is concentrated in the northeastern parts of the Bay, in Richmond, the San Pablo Bay and the Carquinez Strait, and consists of five major refineries, one smaller refinery, and eight marine terminals. Three separate clusters exist, separated from each other by approximately 10 miles:

a) The ChevronTexaco refinery in Richmond and five terminals on the Richmond inner harbor operated by ARCO Terminal Services Co., IMTT, ST Services, Kinder Morgan, and Phillips (Tosco). A sixth marine terminal in Richmond, operated by Paktank and located on the Bay, could not renew its license and was shut down in 2000.

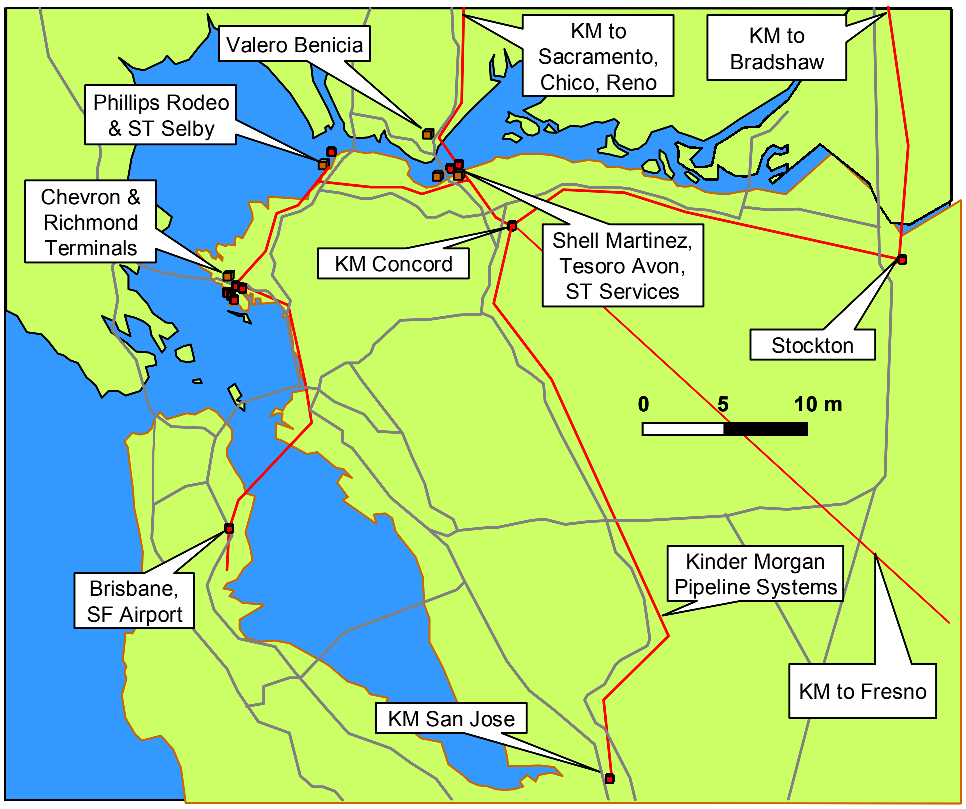
b) The ConocoPhillips Refinery in Rodeo, with the marine terminal of ST Services in Selby, near Crockett.

c) The Valero refinery (ex Exxon) on the north side of the Carquinez Strait, and the Shell refinery in Martinez on the south side, with the marine terminals of ST Services in Martinez and the Tesoro refinery and Amorco terminal in Avon.

These facilities are connected to the head of the Kinder Morgan Pipeline system at Concord. Products are distributed to the Bay Area, Northern California, Fresno, and Reno from Concord.

An overview of the Bay Area petroleum infrastructure is given in Figure 1.1 below.

Figure 1.1 - Bay Area Petroleum Infrastructure



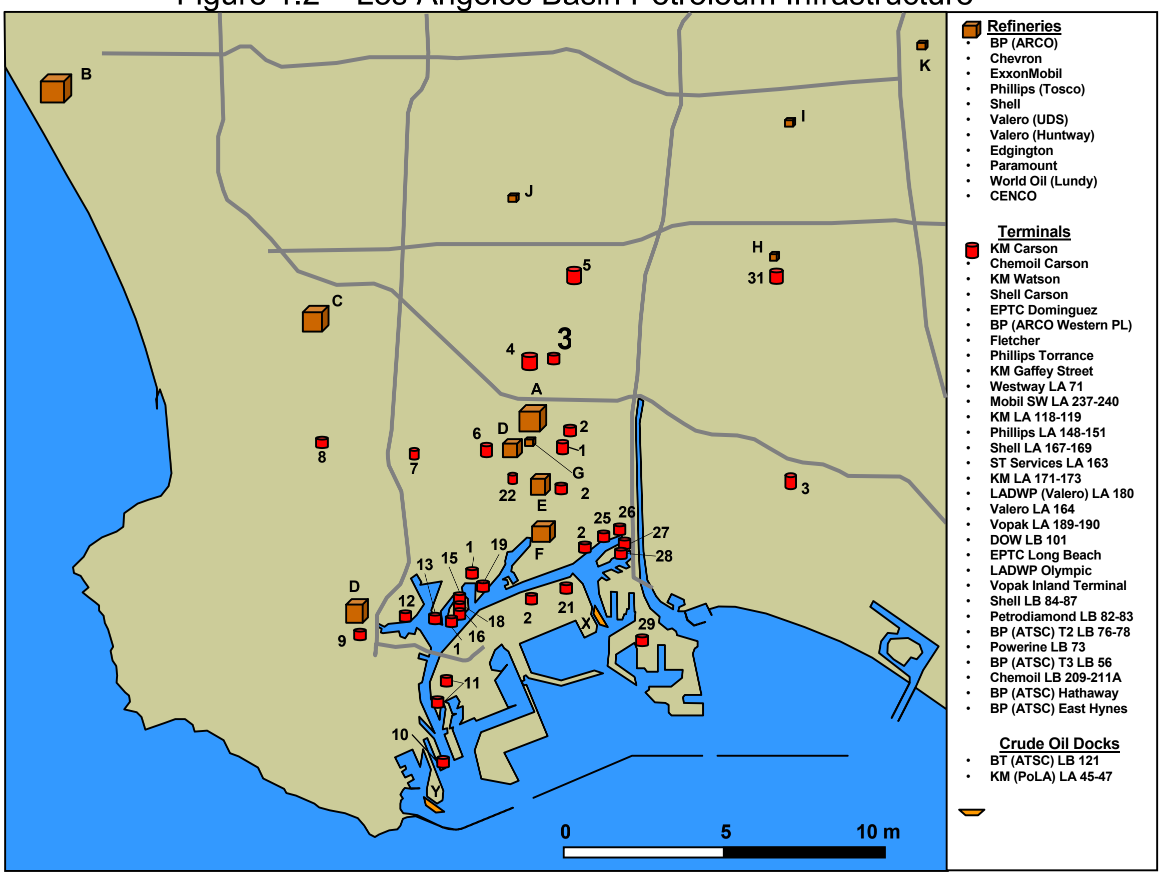
The Bay Area refiners and terminals are connected to each other by proprietary systems for clean products and black oil owned by refiners and ST Services, in addition to the Kinder Morgan pipeline systems that take products to Chico in the north, Reno in the east and Fresno to the south.

One of the key features of the marine terminals in the Bay Area is that for most sites, the draft of vessels is limited to 35 to 40 feet, with no single refinery or terminal capable of receiving a fully laden Very Large Crude Carrier (VLCC). Recently, the passage at Pinole Shoals has silted in to the point where draft is restricted to only 31.5 feet, restricting normal commerce up to Benicia, Martinez, Avon, Stockton, and Sacramento.

Los Angeles Basin

The marine petroleum infrastructure in the LA Basin is distinctly different from that in the Bay Area. Even though the Ports of Los Angeles and Long Beach are amongst the largest manmade harbors in the world, they are small in comparison to the natural harbor found in the San Francisco Bay. As a result, industrial waterfront property, which is already at a premium in the Bay Area, is even more valuable in Los Angeles. Many refineries and terminals that are part of the marine petroleum infrastructure in the LA Basin are actually located sometimes up to ten miles or more inland and connected to the dock by pipelines with sufficient capacity to achieve reasonable unloading rates.

Figure 1.2 – Los Angeles Basin Petroleum Infrastructure



Pipelines interconnections are not shown due to their complexity at this scale

All the refineries and most of the major terminals are connected to the Kinder Morgan pipeline system. The head of the Southern California pipeline system is at Watson, shown as terminal number 3. The pipeline delivers gasoline, jet fuel and diesel to San Diego, Colton, Barstow, Las Vegas, Imperial, Phoenix, and Tucson.

The trend in the Ports of Los Angeles and Long Beach over recent years has been to favor shorefront land use for containers and car imports, at the expense of bulk liquid terminals. The need to create mega-terminals for container handling, with footprints in excess of 500 acres, has forced the ports to rethink the land use. As a consequence, several marine petroleum terminals have lost tankage or have been closed altogether. The increasing trend to have the tankage separated from the docks by 5 to 10 miles of pipelines poses a set of constraints on the handling capabilities of the marine petroleum infrastructure in the LA Basin that is unique.

As can be seen in Figure 1.2, the Los Angeles refining industry is concentrated north of the port, some 2 to 5 miles inland. Exceptions are ChevronTexaco El Segundo, whose refinery is located on the Santa Monica Bay and ExxonMobil with its refinery in Torrance. Except for some large distribution facilities, most terminals are located in the port, with notable concentrations on Mormon Island in the Port of Los Angeles and the eastern end of the Cerritos Channel in Long Beach.

Approach

The approach taken by Stillwater and the California Energy Commission (Energy Commission) for this study was to:

a) Define marine petroleum infrastructure and focus on the two key refining centers in the Bay Area and the Los Angeles Basin.

b) Use available data from the State Lands Commission to compile a complete inventory of available marine petroleum infrastructure and product movements.

c) Integrate the data from the State Lands Commission with other public and private information obtained through stakeholder interviews and review of publicly available information, for instance, data regarding capacities for pipelines linking inland terminals to marine docks.

d) Evaluate the handling capacity of California's infrastructure based on industry practices and generally accepted engineering criteria, such as allowable jetty occupancy, number of turnovers of tanks and practical pipeline velocities.

e) Assess the current and future demand for marine petroleum infrastructure by analyzing import and export trends for petroleum products. The basis for this analysis will be the recently completed studies by Stillwater Associates for the Energy Commission, notably the Strategic Fuels Reserve Study, amended where necessary when more recent or more detailed information has become available since the original study was completed last year.

f) Obtain information from the Port Authorities and other involved parties related to existing plans to augment capacity through new projects, or conversely, what existing capacity may be lost in the near future.

g) Evaluate the adequacy of the existing and anticipated capacity as compared to current and future demand.

h) Recommend measures to alleviate eventual shortfalls in infrastructure capability, including next steps and implementation plans, and identify potential barriers to implementation, such as delays in permitting processes.

i) Collect feedback from the industry in an open forum workshop, and adjust where necessary the recommended alternatives.

j) Present the final conclusions and recommendations to the legislature.

Findings

The capacity of logistical infrastructure to handle petroleum products is determined by hard limits as well as softer constraints. Examples of hard limits are maximum throughput of pipelines, draft and tonnage restrictions for berths, and maximum storage capacities of tanks. Examples of soft limits are berth occupancy, volumes handled through tanks, and flexibility of assets for changes in product service. While the hard limits are difficult to overcome and often require major capital investments and long lead times when more capacity is needed, the softer limits translate into gradually increasing scheduling problems and higher operating costs.

In addition to physical constraints, there are a number of commercial developments that restrict access to infrastructure for independent importers of petroleum products, while other commercial factors in the petroleum terminal industry create hurdles for new capital investment. New capacity additions are also hindered by lengthy permitting procedures and land-use policy decisions in the ports.

After a review of hard limits, soft limits and commercial barriers, it was found that the marine petroleum infrastructure in California's main refining centers, the San Francisco Bay Area and the Los Angeles Basin, is significantly constrained in certain key areas and that under current commercial and public policy conditions, it is likely that future demand on the infrastructure will outstrip capacity. In particular, of concern are:

Docks, Berths and Moorings

Marine dock capacity for petroleum products in California is generally adequate. However, several operational constraints, that is, soft constraints that contribute to scheduling problems and higher operational cost, apply to the usage of marine berths for petroleum products:

a) In the LA Basin, approximately one fifth of tanker receipts and shipments of petroleum products are handled at berths that see very high monthly occupancy, at the level where scheduling conflicts become a concern. Pipeline capacity to move product away from these docks constrains further growth in imports. About half of all maritime petroleum volumes in LA are handled at berths that average at a level that is well within the normal operating range and still leaves some room for growth as long as pipeline capacity is adequate. The remaining 30 percent of dock capacity is operated in a proprietary manner and has additional, unused capacity.

b) In the Bay Area, more than 75 percent of the volumes handled by the refiners pass over docks that are occupied on average between 40 and 50 percent of the time, still within the normal operating range.

c) Capacity in the Bay is constrained because draft restrictions at Pinole Shoals require tankers to be lightly loaded. Shippers have to increase the number of vessels calling at those ports to make up for the lost shipping capacity. Stakeholders are very concerned about the ability of the various government agencies to solve the necessary problems in order to dredge the channels in the Bay to their proper depth.

Pipelines and Tankage

Storage capacity for petroleum products in California is generally tight. In particular tankage that is part of the marine infrastructure, with good access to deepwater docks, is highly utilized.

a) Two of the three large gasoline importing facilities in the LA Basin are constrained by their ability to move product away from their dock, according to Stakeholder input and consultant calculations.

b) In the LA Basin, tankage on average cycles between full and empty (one “tank turn”) once every 15 to 20 days, which is at the high end of normal operating usage. However, it is not uncommon for key tankage to cycle every 3 to 4 days, or up to one hundred tank turns per year. At this level of usage, the tank becomes a physical and operational bottleneck. Refiners reported to the South Coast Air Quality Management District that they are hampered by the lack of tankage in the LA Basin.

c) In the Bay Area, tank usage overall is also at the high end of the normal operating range. Detailed information as to turns of individual tankage was not available for the Bay.

d) Although not quite keeping up with demand, several projects to build new tankage are currently underway, mostly consisting of upgrading and recommissioning existing tankage, or under pre-existing permits.

    1. In the LA Basin, one large terminal operator has refurbished some 600-700 MB of tankage capacity by utilizing existing permits. This capacity has been taken by its refiner parent or by current customers. A small terminal operator, also with existing permits, added two 100 MB drain dry tanks. Another small terminal operator has obtained permission from the Port of Long Beach to build a 50 MB tank. A different large terminal operator, after agreeing to a contract with an independent oil company, has decided to go

ahead and start the permitting process for new tankage capacity at Carson. They expect that the project will take three years to complete.

2. In the San Francisco Bay, a large terminal operator has started construction on three tanks that had existing permits.
3. Market participants report that tankage is adequate in the Bay, but tankage remains very tight in Los Angeles.

Pipeline Gathering Systems

The following physical constraints were identified for the pipeline gathering systems from the terminals and refineries to the head of the common carrier pipeline:

a) The clean products pipeline gathering system in the Bay Area is operating at maximum achievable flow rates in almost all branch and loop lines connecting the refineries and terminals to the main pump stations for delivery into the Kinder Morgan long distance pipelines. This forces market participants to truck products around the bottleneck at Concord, raising the distribution costs of future demand growth.

b) Although less so than in the Bay Area, many of the proprietary line systems that constitute the gathering systems in the LA Basin are constrained in capacity, with only two terminals (and no refineries) capable of supplying into the Kinder Morgan pipeline at the rate required to avoid slow pumping fees.

Commercial Barriers

Significant commercial barriers exist that restrict the usage of existing storage and the construction of new tankage despite strong demand.

a) In the major import center for California, the LA Basin, most tankage is owned or controlled by the local refiners. This is a legacy of the market's traditional role as an exporter of oil. The region has only become a net importer of products since 1999. For gasoline and blendstocks, it is estimated less than 3 percent of available storage capacity is accessible to independent importers. As a consequence, competition is limited because very little gasoline is brought in outside of the refiners' distribution systems.

b) Two refiners do offer commercial storage in the LA Basin. The capacity of one is generally full with term customers. Stakeholders reported that the other has some limited spot capacity, but for fungible products only, no blending components.

c) Both areas have only one independent gasoline importing terminal of commercial significance, ST Services in the Bay and Kinder Morgan in LA.

d) Although current commercial rates for storage offer reinvestment economics to the terminal operators, new capacity additions have not kept up with increased demand. A number of commercial, financial, and permitting factors have been identified that contribute to the lack of new building. Terminal operators maintain that it takes three years to create new storage capacity – two years to permit and a year to construct.

e) Because supply and demand forecasts can change due to political decisions or due to economic conditions, the lengthy permitting and construction period creates an element of risk that is unacceptable to a number of logistics service providers and their customers.

Forecast Demand for Petroleum Infrastructure

The outlook for the short to medium term, i.e., to 2010, is that demand for marine infrastructure in terms of additional import volumes is likely to outstrip capacity. The primary areas of concern are crude oil and gasoline:

a) For crude oil, a continuing decline of Alaska production at approximately 8 percent per year and the anticipated decline of in-state production at 4 percent per year will call for more imports, primarily from the Middle East. Proposed projects in the LA Basin will improve the infrastructure to effectively meet the increased demand for marine infrastructure capability, while the Bay Area will see increasing cost and risk from offshore transfers from VLCC to smaller vessels. The overall storage capacity for crude oil in California will remain low relative to the potential need to effectively deal with major supply disruptions due to natural disasters or geopolitical events.

b) Imports of gasoline and blending components are expected to double from a level of 150 TBD in 2001 to 300 TBD in 2010. This increase, which primarily affects the LA Basin, will double the number of vessel movements, outstripping the handling capabilities of the current docks and marine terminals, especially when combined with a continued growth in import volumes of diesel and jet fuel. Overall, if the California fuel markets continue to grow at 2 to 3 percent per year while refining capacity only grows at 0.5 to 1 percent per year, between 0.5 million and 1 million barrels of new tank capacity would have to be added every year to maintain the current levels of capacity utilization. Despite some recent new capacity brought on line, conversion or new building is not keeping up with demand.

In summary, the logistics capacity in the Ports of Los Angeles and Long Beach to import products is constrained, primarily by the capacity of pipelines to move product away from highly utilized docks and the availability of inland tankage. Facilities in the Bay are constrained by the lack of dredging of the Pinole Shoals and by pipeline capacity between the refineries and import facilities and the head of the common carrier pipeline. Competition is limited because each complex is served by only one significant independent logistics service provider.

All these point to an urgent need for a coordinated approach between the industry and the state government to address the various constraints that will make California's petroleum supplies vulnerable to higher costs and to supply disruptions in the coming years.

STATE OF CALIFORNIA - THE RESOURCES AGENCY
Gray Davis, Governor
CALIFORNIA ENERGY COMMISSION
1516 Ninth Street
Sacramento CA 95814
website:www.energy.ca.gov

Discussion Questions for Workshop Panel On Critical Issues Related to the SFR

Commission staff has identified three key questions that need to be addressed to make an informed decision regarding the effectiveness of a strategic fuel reserve (SFR) in dampening California gasoline price volatility. These three questions are presented in bold below. The related discussion questions, also presented below, are intended to gain information to assist the Energy Commission in addressing the key questions.

What impact, if any, will the creation of an SFR have on liquidity in the California Reformulated Gasoline (CaRFG) forward market?

Forward markets provide gasoline importers the opportunity to "lock in" a selling price for their gasoline cargos as they are being purchased, even though their cargos may not arrive to California for several weeks. By selling forward, importers can reduce the price risk associated with importing cargos over long distances.

Related discussion questions include:

1. To what extent do current participants in the California petroleum market use the CaRFG forward market or the NYMEX?

2. To what extent does the CaRFG forward market provide a mechanism for current market participants to "hedge" during supply disruptions?

3. Looking to the future, is the trend in the CaRFG forward market towards more liquidity, or less?

What impact will an SFR have on existing discretionary inventories?

Discretionary inventories are those inventories that are held above and beyond the minimum required for normal operation of the distribution system (pipelines, terminal, etc.). Discretionary inventory levels respond to price signals in the marketplace, and reduce the severity of price spikes induced by refinery disruptions.

Related discussion questions include:

1. Is the existing level of discretionary inventories for gasoline/blendstocks in California sufficient?

2. Will the SFR crowd out existing discretionary inventories?

3. What will be the impact of the SFR on discretionary inventories over the long term?

What impact will an SFR have on competition in California's petroleum product market?

Some have claimed that an SFR could serve to ease access to independent importers into California's gasoline market which might lead to less volatile gasoline prices. Alternatively, it can be argued that price volatility itself provides an incentive for independents to enter the market. By competing with and reducing the incentives for independents to hold discretionary storage, an SFR may leave the market more concentrated, and may result in higher average prices. Some argue further that an SFR could lead to even higher gasoline price volatility in California.

Related discussion questions include:

1. To what extent is the California petroleum industry, inclusive of production, imports, and distribution, a competitive market, especially as compared to other regional petroleum markets in the U.S.?
2. To what extent is the California market for petroleum product storage a competitive market, especially as compared to other regional storage markets?
3. Do significant entry barriers exist which prohibit the participation of independent importers of gasoline or gasoline blendstocks?