FINAL REPORT

REFINING ECONOMICS OF PROPOSED AMENDMENTS TO THE CALIFORNIA PREDICTIVE MODEL

Prepared for

California Energy Commission

By

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1. Introduction and Summary

The California Energy Commission (CEC) retained MathPro Inc. to assess the effects on the California refining sector of the proposed 2007 Amendments to the Phase 3 California Reformulated Gasoline regulations (CaRFG). The California Air Resources Board (CARB) developed the Amendments primarily to account for the increase in vehicle emissions of volatile organic compounds (VOC) due to the permeation effects of blending ethanol in CaRFG. Ethanol's permeation effects, along with changes in the profile of the California vehicle fleet's emission control technologies, are reflected in the Amended California Phase 3 Predictive Model (Amended PM-3), which will be used by refineries to certify that gasoline complies with CaRFG emission standards.

In general, CARBOB[1] currently produced by California refineries and certified under PM-3 does not comply with emission standards under the Amended PM-3, because ethanol permeation (whose emission effects are incorporated in the Amended PM-3) increases VOC emissions. Hence, California refineries will have to change the formulation of CARBOB to offset ethanol's permeation effect. To do so, they will have to invest in new process capacity, modify refining operations, and most likely blend more ethanol in CaRFG.

We assessed the refining economics of the proposed Amendments using an updated version of an aggregate model of the California refining sector that we have employed in previous studies of the California refining sector. Updates to the model were based on a survey conducted by CEC of California refinery operations for the summer of 2006.

We analyzed two scenarios, denoting different compliance schedules for the Amendments: a *near-term* scenario in which California refining capacity remains unchanged from its 2006 level and a *long-term* scenario in which refineries make "optimal" investments in process capacity. Within each scenario we assessed four levels of ethanol blending: 0, 5.7 vol%, 7.7 vol%, and 10 vol% (corresponding to zero, 2.0 wt%, 2.7 wt%, and 3.5 wt% oxygen). Finally, we conducted a sensitivity analysis for each scenario and level of ethanol blending, in which we assumed that *all* gasoline produced by California refineries under Amended PM-3 would be CaRFG, i.e., that all gasoline exported to out-of-state markets (e.g., Arizona and Nevada) would comply with emission standards under Amended PM-3.

Our findings are as follows:

- Compliance with the Amended PM-3 in the near term (with no new process capacity brought on line) probably would force California refineries to curtail CaRFG production, sell high sulfur blendstocks in distant markets (the U.S. Gulf Coast or foreign markets), and sell or seasonally store larger volumes of high-RVP C5 blendstocks.

  Refineries could moderate gasoline volume loss by purchasing certain high-value gasoline blendstocks, if available, (e.g., alkylate and C6 isomerate) or by blending higher volumes of

[1] CARBOB refers to the gasoline produced by refineries for blending with an oxygenate, in this case ethanol. The acronym stands for <u>Ca</u>lifornia <u>R</u>FG <u>b</u>lendstock for <u>o</u>xygenate <u>b</u>lending.

ethanol in CaRFG. Our refinery modeling suggests that California refineries could maintain (energy-adjusted) CaRFG out-turns by blending ethanol at 10 vol%. However, this result is misleading because the aggregate refinery model reflects the average sulfur level of CaRFG. It does not explicitly represent the subset of refineries that currently produce CaRFG with sulfur content greater than 13 ppm; these refineries would have substantial difficultly producing a compliant, high-ethanol-content CaRFG under Amended PM-3. Such refineries account for about 25% of CaRFG production.

The effect of near-term compliance with Amended PM-3, in terms of curtailing gasoline production and increasing the volume of "excessed" material, would be greater if refineries produced only CaRFG (for both in-state use and for export) under the new CARB standards.

- The refining cost of complying with the Amended PM-3 in the long-term (when optimal investments in new process capacity could be made) decreases with higher levels of ethanol blending (at the assumed delivered, net-of-subsidy price of ethanol – set equal to the marginal refining cost of CARBOB), as does refinery investment in new process capacity. We estimate refining costs to be about 7½ ¢, 4¢, 1½ ¢, and 1¢/gal of finished CaRFG with ethanol blending, respectively, at 0, 5.7, 7.7, and 10 vol%. Corresponding estimated investment in refinery process capacity is about 2, 1, ½, and ½ $ billion.

- A higher delivered price of ethanol would raise the refining cost of complying with the Amended PM-3. If ethanol were priced $10/bbl higher than the marginal refining cost of CARBOB (about 25¢/gal higher than the estimated cost of CARBOB), refining costs would be about 1½, 2, and 2½¢/gal higher than shown above at ethanol blending levels of 5.7, 7.7, and 10 vol%, respectively. If ethanol were priced $10/bbl lower, refining costs would be correspondingly lower.

- The refining and investment costs of complying with Amended PM-3 would increase, both in absolute and per-gallon terms, if California refineries produced CaRFG under the new CARB standards not only for in-state use, but also for export (primarily to Arizona and Nevada). We estimate refining costs would be about 9, 7½, 4½, and 3¢/gal of finished CaRFG with ethanol blending, respectively, at 0, 5.7, 7.7, and 10 vol%. The corresponding estimated investments in refinery process capacity would be about 2½, 1½, ¾, and ½ $ billion.

- Blending more ethanol in CaRFG than the current 5.7 vol% would lower the energy content and fuel economy of finished CaRFG. Refineries would have to produce somewhat more CaRFG to offset the mileage loss associated with increased ethanol blending. We estimate the production cost of the mileage loss (that is, the additional refining cost of producing the additional CaRFG) to be about 1¢/gal for ethanol blending at 7.7vol% and about 2¢/gal for ethanol blending at 10 vol%. (The cost to motorists would be still higher because our estimated production cost does not include the additional federal and state taxes and distribution costs associated with the additional gasoline volume.)

The results of our analysis suggest that adoption of Amended PM-3 would cause California refineries to increase ethanol blending to at least 7.7 vol% (2.7 wt% oxygen) and most likely to 10 vol% (3.5 wt% oxygen). At these ethanol concentrations, the long-term cost of compliance, including both refining cost and the cost of mileage loss, would be in the range of about 2½ to

3¢/gal, if ethanol were priced close to the marginal refining cost of CARBOB. Investment in new refining process capacity would be on the order of $ ½ billion.

The balance of this report describes the analysis and discusses results and findings. Section 2 discusses the Amended PM-3. Section 3 provides information on the configuration and operations of the California refining sector developed primarily from the CEC survey. Section 4 discusses the refinery modeling and results. Section 5 describes the results of the sensitivity analyses. The report is written for an audience familiar with gasoline production, the California refining sector, and the CARB gasoline program.

Appended at the back of this report (after the appendices) is a presentation of the design and initial results of the study that we prepared for the CARB hearing held on June 14, 2007.

2. THE AMENDED PHASE 3 PREDICTIVE MODEL

CARB amended the PM-3 to incorporate the permeation effect of ethanol on VOC emissions and to account for the makeup of the current vehicle fleet and associated emission control systems.

2.1 Effects of Modifications to PM-3

The PM-3 as issued in the year 2000 (1) did not account for the permeation effects of ethanol on VOC emissions; (2) could be operated in flat limits mode or averaging mode, and with or without the use of the evaporative emission component; and (3) was estimated to represent the emissions profile of the vehicle fleet and emission control systems at that time. Our understanding is that most, if not all, of California refineries found it advantageous to use the PM-3 in the flat limits mode with the evaporative emission component turned off to demonstrate compliance with emission standards

The Amended PM-3 differs from its predecessor in that it (1) includes the permeation effect of ethanol on VOC emissions; (2) has been issued only in the flat limits mode and with the evaporative emissions component turned on; and (3) was estimated to represent an updated profile of the current vehicle fleet and emission control system.

The effects of these changes are illustrated in **Table 1**, below.

- *CARBOB Properties* represent the weighted average in-use properties of CARBOB for all California refineries in the summer of 2006.

- *Compliance Margins* indicate our estimate of the minimum differences between measured CARBOB properties and the flat limits properties reported by refineries to CARB for compliance purposes. (The exception is for olefins – refineries that have "room" with respect to NOx emissions often report high olefin levels to CARB to facilitate compliance with the VOC emission standard.)

- *CaRFG Compliance Properties* represent the weighted average, flat limits properties of finished CaRFG, after accounting for the effects of blending ethanol at 2 wt% oxygen.

- *% Change in Emissions* indicates the emissions performance of the finished CaRFG relative to baseline CaRFG. (The "% change in emissions" for each type of emission must be less than or equal to 0.05% for compliance under PM-3 or Amended PM-3.)

Table 1: Comparison of Emission Reductions under PM-3 and Amended PM-3

Property	CARBOB Properties	Compliance Margin	CaRFG Compliance Properties	Type of Emission	% Change in Emissions PM-3	% Change in Emissions Amended PM-3
RVP (psi)	5.60	0.12	6.94	VOCs (Total THC & CO)	-0.73	1.10
Oxygen (wt%)	2.0	0.00	2.0	NOx	-0.71	-2.46
Aromatics (vol%)	24.6	1.00	24.3	Potency Wtg Toxics	-1.87	-2.05
Benzene (vol%)	0.58	0.11	0.65			
Olefins (vol%)	5.9	2.60	8.1	Compliance Status	Passes	Fails
Sulfur (ppm)	10	2.00	12			
T50 (°F)	215	1.00	212			
T90 (°F)	311	3.00	312			
Ethanol (vol %)			5.6			

Table 1 indicates that the "average" CARBOB produced in summer 2006 complied with CARB standards under PM-3,[2] but that it would not comply under Amended PM-3 because of significant non-compliance for VOCs. For VOCs, the difference in the "% Change in Emissions" between PM-3 and Amended PM-3 – about 1.8 percent points – reflects the effect of ethanol permeation. Hence, the Amended PM-3 calls for additional refinery processing to achieve compliance.

Another major change is that Amended PM-3 is more "friendly" than is PM-3 regarding the effect of ethanol blending on NOx emission reductions. For example, under PM-3, producing CaRFG blended with ethanol at 7.7 vol% that is NOx-compliant (with a change in emissions of about -0.3%), requires CARBOB to have about the following properties: aromatics – 20 vol%, olefins – 5 vol%, sulfur – 10 ppm, T50 – 214 °F, and T90 – 310 °F. With these properties, Amended PM-3 returns a substantially larger change in NOx emissions, about -2.4% (with VOC and toxics emissions still in compliance); and NOx-compliant CARBOB could have up to about 16 ppm sulfur (holding the other properties constant). At 10 vol% ethanol blending, producing NOx-compliant CARBOB under PM-3 would be infeasible for virtually all California refineries (olefins and sulfur content would have to be close to zero – < 1 vol% for olefins and < 5 ppm for sulfur). But under Amended PM-3, California refineries could produce NOx-compliant CARBOB by holding olefins at about 5 vol% or less, sulfur at about 8 ppm or less, and reporting T50 (consistent with meeting required VOC emission reductions) of about 220 °F or more.

The changes incorporated in Amended PM-3 will lead the California refining sector to prefer blending ethanol at or in excess of 7.7 vol% (2.7 wt% oxygen), and most probably at 10 vol% (3.5 wt% oxygen), unless the cost of ethanol to refineries substantially exceeds the marginal cost of producing CARBOB.

[2] For purposes of this comparison, we represented use of PM-3 in flat limits mode with the evaporative emissions component turned off.

2.2 Incorporating Amended PM-3 in the Refinery Model

We developed and introduced into the refinery model four reduced-form approximations of the Amended PM-3, representing four ethanol blending levels expressed in terms of oxygen content: 0, 2.0 wt%, 2.7 wt%, and 3.5 wt%. To derive these reduced-form estimates, we used essentially the same estimating procedure as in previous studies that dealt with PM-3. For each alternative ethanol blending level we:

- Established a "property space" of allowable PM properties for finished gasoline;
- Generated 2000 "unique finished gasolines" (i.e., sets of randomly generated PM properties) and the associated emission reductions under Amended PM-3;
- Used regression analysis to estimate reduced-form approximations of the Amended PM-3 – the equations include linear and quadratic terms for PM properties;
- Converted the estimated equations so they are specified in terms of E_{200} and E_{300}, rather than in terms of T_{50} and T_{90} (Amended PM-3 is specified in terms of T_{50} and T_{90}, but our refinery model is specified in terms of E values)[3]; and
- Incorporated the converted equations in ARMS as a non-linear, but piecewise-linear approximation.

As with PM-3, the Amended PM-3 is both non-linear (quadratic in some PM properties) and non-separable (i.e., has terms representing the product of two PM properties, i.e., T50 x Aromatics). We dealt with the first aspect by including both linear and quadratic terms in the regression equations and with the second aspect by narrowing the property spaces over which the Amended PM-3 was estimated to minimize the impact of the non-separable components of Amended PM-3. The property spaces over which we estimated Amended PM-3, along with the estimated equations (specified in T50 and T90), are shown in **Exhibits A-1a and A-1b**.

Amended PM-3 has been issued only in flat limits mode. In this mode, refiners report to CARB a set of limits on properties (flat limits) that each designated batch of gasoline (CARBOB) must meet (and that yield at least the required emission reductions). The difference between a refinery's average "in-use" properties of gasoline (CARBOB) and the flat limits reported to CARB are "property compliance margins." They indicate, on average, how much margin refiners have designed into their operations to ensure regulatory compliance and to deal with measurement error.

We represent the flat limits mode in the refinery model by specifying a set of minimum, flat limit property deltas that are added to the computed average in-use gasoline properties for determining compliance with Amended PM-3. For example, if the aromatics level in finished CaRFG is 20

[3] Translations of T to E values are based on the following equations:

$T_{50} = 300.83 + 2.017*E_{200}$ and $T_{90} = 663.56 + 4.050*E_{300}$.

vol%, the flat limit property used in our representation of Amended PM-3 is 21 vol% – the "actual" level of 20 vol% plus the minimum flat limit property delta of 1 vol%. The minimum property deltas specified in the refinery model are shown below, along with "apparent compliance margins" found by CARB for 2005 and 2006 that represent the average difference between the properties measured by CARB for sampled batches of CaRFG and the flat limits reported by refineries to CARB for those same batches. Our minimum property deltas generally are smaller than the apparent compliance margins – refineries do not necessarily base the flat limit properties reported to CARB on the minimum values necessary to account for measurement error.

Gasoline Property	Minimum Property Deltas	Apparent Compliance Margins
RVP	0.12	0.12
Oxygen (wt%)		
Aromatics (vol%)	1.0	1.4
Benzene (vol%)	0.11	0.12
Olefins (vol%)	1.2	2.6
Sulfur (ppm)	2	3
T50 (°F)	1	1
T90 (°F)	3	5

In most instances, the refinery model will use the minimum property delta when "sending" flat limit properties to the Amended PM-3. However, because increases in olefins both enhance VOC emission reductions and degrade NOx emission reductions, some of the refiners that have "headroom" with regard to NOx emissions may report high olefin limits to help meet required VOC emission reductions. (This probably would not occur at higher levels of ethanol blending because the NOx constraint would become binding.) This phenomenon also may occur for T_{90} in Amended PM-3 when ethanol is blended at high levels. The refinery model accommodates this by allowing the property deltas to take values greater than the specified minimum (subject to maximum constraints on PM flat limit properties).

We represent the Amended PM-3 in terms of flat limit finished gasoline properties, rather than in terms of flat limit CARBOB properties. For most gasoline properties, this presents no additional concerns, because the effect of ethanol blending simply reflects dilution. However, ethanol's effect on the T_{50} and T_{90} of finished gasoline changes depending on the starting T_{50} and T_{90} of the CARBOB. We deal with this in the refinery modeling through an iterative process in which we calculate the implicit E_{200}/E_{300} (and T_{50}/T_{90}) of ethanol consistent with the finished gasoline properties yielded by ARMS. We then set ethanol's E_{200}/E_{300} equal to the calculated implicit E_{200}/E_{300} and rerun the refinery model. Usually only one iteration is required for approximate convergence of calculated implicit E_{200}/E_{300} values and those specified in the refinery model.

3. Configuration and Operations of the California Refining Sector

To support this study, CEC conducted a survey of the California refining sector to develop information on its configuration and operations in the summer of 2006. CEC collected data from each individual refinery and then aggregated the data to represent the entire refining sector. The data covered refining process capacity, refinery process feeds, refinery inputs and outputs, prices of crude oil and refined products, gasoline and distillate properties, types of crude oil processed, sales and storage of refinery streams, and gasoline blendstock volumes and properties.

We used the CEC survey data and other information, shown **Exhibits A-2 through A-9,** to update and calibrate an aggregate California refinery model that we have used in previous studies of the California refining sector.

- **Exhibit A-2a** shows California refining process capacity and actual throughput (or product out-turns for some processes), and **Exhibit A-2b** shows the distribution of feeds to key refining processes.

- **Exhibit A-3** shows out-turns of major refined products for Summer 2006, as well as projected out-turns for 2007 to 2012 for the California refining sector. Projected product out-turns are calculated as product out-turn in 2006 times growth in U.S. refinery out-turns projected in *AEO 2007's* Reference case. Projected average U.S. prices for crude oil, natural gas, and electricity are shown at the bottom of the exhibit.

- **Exhibit A-4** shows the volume, properties, octane, and prices of California RFG, Arizona CBG, other finished gasoline, and the entire gasoline pool derived from the CEC data.

- **Exhibit A-5** shows the volume, properties, "cetane detail", and prices for various refined distillate products.

- **Exhibit A-6a, A-6b, and A-6c** provide information on crude oil use, imports, and properties, along with the representation of the composite crude oil used in the refinery modeling. The volumes and properties of imported crudes were developed from DOE refinery-level import data for 2006. The California composite crude oil was developed using information from both CEC and DOE, in conjunction with crude oil assays.

- **Exhibit A-7** shows the volume and average properties of blendstock categories used in gasoline (CaRFG, Arizona CBG, and other) produced by California refineries in the summer of 2006. Most blendstocks were produced internally, but some were purchased (e.g., iso-octane and natural gasoline). The distillation curves for the various blendstock categories were derived by: (1) converting distillation curves specified in terms of T values to their E value equivalents for each constituent blendstock within a blendstock category (e.g., within the reformate category CEC provided data for full range reformate, light reformate, heavy reformate, etc.); (2) calculating a weighted average distillation curve in terms of E values for the blendstock category; and (3) translating the calculated distillation curve from E values to corresponding T values. Other properties were calculated as weighted averages of the reported average properties for constituent blendstocks.

- **Exhibit A-8** shows the volumes of refinery streams sold or stored during the summer of 2006. (These volumes are minor compared to aggregate out-turns of refined products.)

- **Exhibit A-9** shows the investment costs and per-barrel capital charges and fixed costs for refining processes that we used in the California refining model. The last two columns in the exhibit indicate whether the investment economics for specific processes reflected grassroots or expansion economics and whether any constraints were imposed on the addition of new capacity for specific processes.

CEC also provided information, shown in **Exhibits A-10a through A-10e**, on the distribution of selected PM properties in CARBOB. The points in the charts reflect the average properties of CARBOB produced by individual refineries, ordered from low to high, and the cumulative share of the volume of CARBOB accounted for by refineries with properties at or below the specified levels. For example, Exhibit A-10a shows six refineries produced CARBOB with aromatics content that averaged about 23½ vol% or less, and these refineries accounted for about 60% of all CARBOB production. In general, these data indicate that California refineries do *not* produce a uniform CARBOB; instead, individual properties vary considerably (subject to the over-arching emission reduction constraints imposed by the Predictive Model), consistent with refinery-to-refinery differences in crude slate and in the configuration and capability of refining process capacity.

Exhibits A-11a and A-11b provide another indication of variation in CARBOB properties across refineries. These charts show for each refinery's CARBOB the joint distribution of average olefins and sulfur, the two properties that most significantly affect NOx emission reductions, and of average T50 and T90, properties that significantly affect both VOC and NOx emission reductions, along with the CARBOB pool-weighted averages. Rather than being closely clustered around the pool averages, the points are well-dispersed, another indication of significant variation in CARBOB properties across refineries. As discussed later, the presence of such variation across refineries may lead aggregate refinery modeling to understate the difficulty the California refining sector could have in meeting new regulatory standards, particularly in the near-term when refining process capacity and operations cannot be modified significantly.

4. California Refinery Operations with Amended PM-3

The CEC asked us to analyze two scenarios with regard to the compliance schedule for the Amendments to the Phase 3 CaRFG Regulations.

- The first requires compliance in the near-term and does not allow adequate time for refineries to bring new process capacity on line; i.e., refining process capacity is limited to current capacity. For this scenario, we configured the California refining model to represent aggregate refinery process capacity and operations as of the summer of 2006 and then assessed how the refining sector could comply with Amended PM-3 without making new investments in process capacity.

- The second delays compliance so that refineries have sufficient time to make "optimal" investments in process capacity. For this scenario, we configured the California refining model to produce a refined product slate projected for Summer 2012, a time period consistent with the longer lead time needed for complying with Amended PM-3. New process capacity, if needed, could be added by the refining model to produce the additional volumes of refined products projected for 2012. We then assessed how the refining sector would produce the same product slate and comply with Amended PM-3, making any necessary "optimal" investments in process capacity.

Within each of these two scenarios, we assessed four "Study Cases" representing compliance with Amended PM-3 at four levels of ethanol blending: 0, 5.7, 7.7 and 10 vol%, corresponding to 0, 2.0, 2.7, and 3.5 wt% oxygen. We also conducted corresponding sensitivity analyses for these Study Cases in which all gasoline produced by California refineries is CaRFG, i.e., all gasoline exported to out-of-state markets, such as Arizona and Nevada, also complies with emission standards under Amended PM-3.

Refinery Modeling Cases

Scenario	Calibration/ Reference Case with PM-3	Study Cases with Amended PM-3 (by vol% ethanol blending)			
		0%	5.7%	7.7%	10%
Near-term Compliance					
Only CaRFG	x	x	x	x	x
All Gasoline		x	x	x	x
Long-term Compliance					
Only CaRFG	x	x	x	x	x
All Gasoline		x	x	x	x

4.1 Calibration Case

The first step in the refinery modeling was to reconfigure and calibrate our California refining model so that it reasonably represented refining operations in the summer of 2006.

Calibration of a refinery model involves adjusting technical data elements in the model such that the model yields solution values that match with sufficient precision certain key measures of refinery operations in the calibration period. In this study, we focused on matching (1) process unit throughput, (2) gasoline blendstock volumes, (3) shadow values of major refined products with reported spot price, (4) out-turns of major refined products, and (5) CaRFG properties and emission reductions. Exhibits **B-1 to B-4** compare the results of the refinery model calibration with data from the CEC survey.

Exhibit B-1 indicates that computed process throughput in the Calibration Case is in reasonably close agreement with reported throughput for most major processes. However, there are some discrepancies.

For example, crude throughput in the Calibration Case is about 5% higher than reported throughput. This reflects larger-than-reported out-turns of distillate material in the Calibration Case (see Exhibit B-3), but also could result from unreported use of unfinished oils rather than crude oil as process inputs, or from key processes employed by the California refining sector having somewhat better product yields than those embodied in the refinery model. The small difference in process throughput for alkylation results from our use of a "capacity use factor" greater than one for certain alkylation feeds. The difference between reported and calibration throughput for butane isomerization probably results from either over-optimization or slight differences in yields of normal butane versus iso-butane from crude oil or from various conversion processes. The largest differences between reported and calibration throughput occur for hydrotreating.

Fortunately, many of these processes have little influence on the results of subsequent analysis, either because they do not deal with gasoline blendstocks or the differences in through-put simply carry through across subsequent Study Cases. However, three of these processes – benzene saturation, FCC naphtha hydrotreating, and FCC feed hydrotreating do significantly influence gasoline properties.

With regard to benzene saturation, information collected by CEC on gasoline blendstocks indicates that less than half (perhaps only about a third) of reported throughput is in the general boiling range of benzene. We represent benzene saturation by treating a benzene-rich "heart cut," which leads to lower benzene saturation throughput in the refinery model than is reported by CEC. Additionally, benzene and toxics control are not important factors in the subsequent Study Cases. With regard to FCC naphtha hydrotreating, there is a discrepancy between the volume of throughput and the volume of post-treated FCC naphtha blendstock reported by refineries. Exhibit A-7 shows that refiners reported producing about 86 K b/d of post-treated FCC naphtha. This number is much closer to the calibration throughput of 66 K b/d for FCC naphtha hydrotreating than is the 118 K b/d of throughput reported by refiners. Further, a significant portion of the reported, post-treated FCC naphtha is low-boiling-range material that we exclude from post-treatment in non-selective FCC naphtha hydrotreaters, because it generally has low sulfur content and suffers significant octane loss during hydrotreating. Finally, the volume of FCC feed hydrotreating in the Calibration Case is higher than reported throughput because we constrained all FCC feed to be hydrotreated. This assumption carries through across all subsequent Study Cases.

Exhibit B-2 compares gasoline blendstock use reported in the CEC survey with gasoline blendstocks comprising all gasoline "produced" by the refinery model. There is fairly good agreement in blendstock volumes, although the Calibration Case shows somewhat higher volume for naphthas and correspondingly lower volumes for hydrocrackate, alkylate, and iso-octane (primarily a purchased blendstock).

Exhibit B-3 shows two types of comparisons: (1) for gasoline and EPA diesel, reported spot prices and computed shadow values at specified output volumes; and (2) for jet fuel and CARB diesel, reported volumes and "optimized" volumes at specified prices. This reflects how we set up the Calibration Case. We set product out-turns equal to reported product volumes for gasoline and EPA (and other) diesel, whereas we specified product prices equal to reported spot prices (with no constraints on volume) for jet fuel and CARB diesel.

The refinery model yields low shadow values for jet fuel and CARB diesel when out-turns for those products are fixed at reported volumes. The precise reason for this is unclear. It could result from our representation of the composite crude oil or because the model's process yields for distillate products are higher than actually is the case. It also might result from the model's cut points for naphthas and heavy distillate differing from those used in the refineries.

We thought it more appropriate to start with a Calibration Case that was better balanced in terms of the marginal cost of refined products, but with somewhat higher distillate out-turns, than to have significant discrepancies in distillate shadow values, particularly because the results for the near-term Study Cases are "price-sensitive." Hence, we allowed the volumes of "produced" jet fuel and CARB diesel to be optimized, subject to the specified prices.

The Calibration Case has a shadow value for CARBOB higher than the reported average refinery-gate spot price; however, because relatively small reductions in CARBOB volume (actually finished CaRFG volume) substantially reduce its shadow value, we elected to maintain specified out-turns equal to reported out-turns. On the other hand, the shadow values for Arizona CBG and other gasoline are lower than reported spot prices. This results from over-optimization – the refinery model is able to move into those gasoline pools, in ways individual refiners cannot, blendstocks that are unattractive to blend in CaRFG and that, therefore, have relatively low value.

Exhibit B-4 compares reported CARBOB properties, compliance margins, and CaRFG compliance properties and emission reductions (calculated using PM-3) with those estimated in the Calibration Case. There are moderate differences in CARBOB properties for aromatics, olefins, and T90. But, in general, calibration and reported CARBOB properties are reasonably close (as are emission reductions) and certainly the calibration CARBOB properties are well within the property ranges reported by refineries, as indicated in Exhibits A-10a through A-10e.

The Calibration Case could be refined through further iteration, but in our opinion, it is sufficiently "close" to reported refining operations to be used as a reference case for the "near-term" modeling and as the starting point for subsequent "long-term" modeling pertaining to 2012. Results for the Calibration Case are reported in more detail in **Exhibits C-1 through C-5**.

4.2 Reference Case for 2012

The Reference Case for 2012 is based on the Calibration Case with the following changes:

- Major refined product out-turns are specified at projected volumes for 2012 (Exhibit A-3);

- Prices for crude oil, purchased natural gas and electricity, and other refinery inputs are based on prices projected for 2012 in AEO2007 (Exhibit A-3); and

- Optimal addition of new refining process capacity is allowed (Exhibit A-9).

We assumed the California refining sector would continue to process the same composite crude, to blend ethanol at 5.7 vol% (2.0 wt% oxygen), and to use PM-3 in the flat limit, non-evaporative emission mode to certify CaRFG.

The refinery modeling results for the 2012 Reference Case are shown in **Exhibits C-1 through C-5**. Subsequent "long-term" Study Cases are based on the Reference Case.

4.3 Study Cases

We developed two sets of Study Cases representing compliance with Amended PM- 3 in the near-term and long-term. In the near-term, refineries would not have adequate time to make investments in new process capacity and refineries would have to comply by modifying operations and out-turns of refined products; in the long-term, refineries could make investments in new process capacity to facilitate compliance.

4.3.1 Near Term Scenario: Investment Constrained

The *Investment Constrained* cases were designed to assess the extent to which near-term compliance with Amended PM-3 would reduce gasoline out-turns of the California refining sector. We developed four individual cases, each representing a different level of ethanol blending: 0, 5.7, 7.7, and 10 vol% (corresponding to 0, 2.0, 2.7, and 3.5 wt% oxygen). The modeling for each case was conducted as follows.

- The Calibration/Reference Case was the starting point for each Study Case.

- PM-3 was replaced by Amended PM-3 and emission reduction targets were set as in the Calibration/Reference Case.

- No investment in new refining capacity (except for certain processes that represent purchases from merchant plants or changes in refining operations) was allowed.

- Purchased gasoline blendstocks and unfinished oils were maintained at Calibration/Reference Case volumes.

- Out-turns of Arizona CBG and other gasolines were held constant at Calibration/Reference Case volumes.

- Jet fuel and CARB diesel were priced as in the Calibration/Reference Case and upper limits on out-turns were set at Calibration/Reference Case production volumes plus reported imports, i.e., refinery production could increase up to the point at which all imports were displaced.

- Out-turns of CaRFG were successively increased (from an initial low volume) until shadow values for CaRFG were about 10 to 20% higher than in the Calibration/Reference Case. This established an estimate of the "maximum feasible" volume of CaRFG production, subject to an upper limit established by CaRFG production in the summer of 2006.

- Ethanol's E200 and E300 values were modified according to calculations using a CARBOB version of Amended PM-3, using the properties of finished CaRFG from the final "property iteration," as discussed in Section 2.2. The refinery model was then re-run with the revised E200 and E300 properties for ethanol.

The results of the refinery modeling are shown in **Exhibits C-1 through C-5**, under the heading "Investment Constrained." In general, compliance with the Amended PM-3 in the near term probably would force California refineries to curtail CaRFG production, sell high sulfur blendstocks in distant markets (the U.S. Gulf Coast or foreign markets), and sell or store larger volumes of high-RVP C5 blendstocks. (Such changes were so extensive with zero ethanol blending that we refrained from reporting results.) Refineries could moderate gasoline volume loss by:

- Blending higher volumes of ethanol in CaRFG – up to 10 vol% (3.5 wt% oxygen); or

- Purchasing certain high-value gasoline blendstocks (for example, alkylate and C6 isomerate, which have very high shadow values when ethanol is blended at or less than 7.7 vol% (2.7 wt% oxygen)). We did not allow such purchases because of uncertainty regarding the availability these blendstocks in the near term.

Exhibit C-1 shows that refinery process utilization is similar across the Study Cases for most processes. However, reformer charge rates decline in two of the cases and reformer severity declines across all cases. This causes increased purchases of hydrogen from merchant producers (represented in the refinery model as new refinery hydrogen capacity); we assumed additional hydrogen would be available. The refining model also depentanizes more FCC naphtha and straight-run naphtha (represented in the refinery model as new depentanization capacity). Other changes include modifying hydrocracker operations to produce more jet and distillate material and less naphtha, and moving more heavy FCC naphtha into the distillate pool.

Exhibit C-2 shows refinery inputs and outputs for the Study Cases. In the 2.0 and 2.7 wt% oxygen cases, out-turns of CaRFG are lower than in the Calibration/Reference Case, but the combined volume of jet fuel and diesel fuel increases. The refinery model finds it attractive to move higher boiling range material from the gasoline pool to the distillate pool. Greater volumes of C5s are "excessed" (to control RVP), along with FCC naphtha (to control sulfur, T50, and

T90). In the 3.5 wt% case, CaRFG out-turn is larger in strictly volume terms than in the Calibration/Reference Case; but it is equivalent in energy-adjusted terms. CaRFG produced in this case has lower energy content than CaRFG in the Calibration/Reference Case because it contains more low-energy-content ethanol. (Combined jet and diesel fuel out-turns decline somewhat in this case.)

These results seem to suggest that, even in the near term, California refineries could maintain energy-adjusted CaRFG volume by blending ethanol at 10 vol%. However, our aggregate refinery model reflects the average mix of blendstocks available for producing an "average sulfur content" CaRFG. It does not explicitly represent the subset of refineries currently producing CaRFG with sulfur content greater than 13 ppm and that would have substantial difficulty producing a compliant, high-ethanol-content CaRFG in the near term under Amended PM-3 (because of NOx emissions). Exhibit A-10c shows that there are three such refineries and that they account for about 25% of CaRFG production. Further, Exhibit A-11a shows that six refineries now produce CaRFG with combinations of olefins and sulfur that suggest they would have difficultly complying with the NOx emission standard under Amended PM-3 when blending ethanol at 10 vol% (3.5 wt% oxygen). Such refineries probably would have to "excess" FCC naphtha (to reduce olefins and sulfur) as part of their response to complying with Amended PM-3. Thus, it is highly likely that requiring near-term compliance with Amended PM-3 would cause a reduction in energy-adjusted CaRFG out-turns at all levels of ethanol blending.

Exhibits C-3, C-4, and C-5 provide modeling results regarding CARBOB properties, compliance properties, finished CaRFG properties, and the composition of finished gasoline.

4.3.2 Long Term: Investment Unconstrained

The *Investment Unconstrained* cases were designed to assess the long-term refining cost and investment associated with complying with Amended PM-3. We again developed four individual cases, each representing a different level of ethanol blending: 0, 5.7, 7.7, and 10 vol% (corresponding to 0, 2.0, 2.7, and 3.5 wt% oxygen). The modeling for each case was conducted as follows.

- The 2012 Reference Case was the starting point for each Study Case.

- PM-3 was replaced by Amended PM-3 and emission reduction targets were set as in the 2012 Reference Case.

- All medium and heavy FCC naphtha was required to be post-treated to comport with information provided by refiners to CEC regarding strategies for complying with Amended PM-3.[4]

- Investments in new refining process capacity were allowed as indicated in Exhibit A-9. Investments made in the 2012 Reference Case were *not* incorporated into "existing" capacity;

[4] Refiners would not necessarily increase FCC naphtha post-treatment when blending ethanol at 0 or 2.0 wt% oxygen. Removing the constraint to treat all medium and heavy FCC naphtha in those two cases would reduce estimated refining costs by about 1½¢/g of CaRFG.

rather, we assumed that refiners would have sufficient time to optimize their investments to comply with Amended PM-3.

- Purchased gasoline blendstocks and unfinished oils were maintained at 2012 Reference case volumes.

- The delivered price of ethanol, net of subsidy, was set at the marginal refining cost of producing CARBOB.

- Out-turns of all major refined products – CaRFG, Arizona CBG, other gasolines, jet fuel, CARB diesel, other diesel fuel, and residual fuel – were held constant at 2012 Reference Case volumes. (To facilitate cost calculations CaRFG out-turns were held constant in volumetric terms, even though energy-adjusted out-turns decline as ethanol blending levels increase.)

- Ethanol's E_{200} and E_{300} were modified according to calculations using a CARBOB version of Amended PM-3, using the properties of finished CaRFG from the final "property iteration," as discussed in Section 2.2. The refinery model was then re-run with the revised E_{200} and E_{300} values for ethanol.

The results of the refinery modeling are shown in **Exhibits C-1 through C-6** under the heading "Investment Unconstrained." In general, the refining cost of complying with the Amended PM-3 in the long-term decreases with higher levels of ethanol blending, as does refinery investment in new process capacity. As shown in **Exhibit C-6**, we estimate refining costs to be about 7½, 4, 1½, and 1¢/gal of finished CaRFG with ethanol blending, respectively, at 0, 5.7, 7.7, and 10 vol%. Corresponding estimated investment in refinery process capacity is about 2, 1, ½, and ½ $ billion.

Exhibit C-1 shows the refining process capacity added in each of the Study Cases in response to both projected increases in refinery out-turns (to meet increased demands for refined products) and imposition of Amended PM-3. The most significant differences in capacity additions between the Reference and Study Cases are for atmospheric distillation, hydrocracking, alkylation, FCC naphtha hydrotreating, and FCC gas processing.

Less distillation capacity is added in the Study Cases because of increases in iso-butane purchases (priced at about $10/bbl higher than composite crude oil), reductions in butane sales in the 0 and 2.0 wt% oxygen cases, and increases in ethanol use in the 2.7 and 3.5 wt% oxygen cases. Less hydrocrackate capacity is added in Study Cases with 2.7 wt% oxygen or less in favor of increased alkylation. FCC naphtha post-treatment expands to cover all medium and heavy FCC naphtha, and FCC gas processing expands to handle additional gases produced because of catalyst changes made to increase C3 and C4 olefin make to support additional alkylation. FCC conversion is higher in the Study Cases with ethanol blended up to 2.7 wt% oxygen, and then declines substantially at 3.5 wt% oxygen. Reformer charge rates are lower in all Study Cases.

Modeling results regarding product out-turns, CARBOB properties, compliance properties, finished CaRFG properties, and the composition of finished gasoline are shown in **Exhibits C-2 through C-5**.

Estimated refining costs depend on the assumed price of ethanol. **Exhibit C-6** shows how delivered ethanol prices $10/bbl lower or higher than the marginal refining cost of CARBOB (about 25¢/gal lower or higher than the estimated cost of CARBOB of about $1.50/gal) affect estimated refining costs.

Exhibit C-6 also shows the estimated cost of the mileage loss associated with blending more ethanol in CaRFG than the current 5.7 vol%. Blending more ethanol lowers the energy content and fuel economy of finished CaRFG. We estimate the cost of the mileage loss (the refining cost of producing more CaRFG to offset the mileage loss) at about 1¢/gal for ethanol blending at 7.7 vol% and about 2¢/gal for ethanol blending at 10 vol%. (The cost to motorists would be still higher because our estimate does not include the additional federal and state taxes and distribution costs associated with the additional CaRFG volume.)

5. California Refinery Operations with Amended PM-3: Sensitivity Analysis

We conducted a sensitivity analysis for each of the near-term and long-term Study Cases. The sensitivity analysis incorporated the assumption that all gasoline produced by California refineries under the new CARB standards would be CaRFG; i.e., that all gasoline exported to out-of-state markets (primarily Arizona and Nevada) would comply with California emission standards under Amended PM-3.

The results of the analysis are shown in **Exhibits D-1 through D-6**.

Our analysis indicates that the impact of near-term compliance with Amended PM-3, in terms of reduced gasoline production and increased volume of "excessed" material, would be greater if refineries produced only CaRFG (for both in-state use and for export) under Amended PM-3. **Exhibit D-2** indicates that (1) refinery out-turns of gasoline would be lower, relative to the original Study Cases (Exhibit C-2), by about 40 to 120 K b/d, depending on the level of ethanol blending and (2) the volume of "excessed" material stored or sold in distant markets would be greater, relative to the Study Cases, by about 70 to 100 K b/d.

The refining and investment costs of complying with Amended PM-3 would increase, both in absolute and per-gallon terms, if California refineries produced CaRFG for both in-state use and for export under the new CARB standards. As shown in **Exhibit D-6**, estimated refining costs in the long-term would be about 9, 7½, 4½, and 3¢/gal of finished CaRFG with ethanol blending, respectively, at 0, 5.7, 7.7, and 10 vol%.

Estimated refining costs are about 1½ to 3¢/gal higher with California refiners exclusively producing CaRFG, rather than continuing to produce a mix of CaRFG, Arizona CBG, and conventional gasoline. Estimated investment in refinery process capacity are about 2½, 1½, ¾, and ½ $ billion at the corresponding ethanol blending levels, and are about 0.1 to ½ $ billion higher than in the original Study Cases.

Exhibit A-1a: Flat Limit Property Ranges for Estimating Reduced-Form of Amended PM-3, by Oxygen Content

	Zero Oxygen			2.0 wt % Oxygen			2.7 wt % Oxygen			3.5 wt % Oxygen		
Property	**Lower**	**Upper**	**Delta**	**Lower**	**Upper**	**Delta**	**Lower**	**Upper**	**Delta**	**Lower**	**Upper**	**Delta**
RVP (psi):	6.6	7.00	0.40	6.60	7.00	0.40	6.60	7.00	0.40	6.60	7.00	0.40
Oxygen (wt%)	0.0	0.0	0.0	2.0	2.0	0.0	2.7	2.7	0.0	3.5	3.5	0.0
Aromatics (%):	16.0	22.0	6.0	16.0	22.0	6.0	15.0	22.0	7.0	14.0	22.0	8.0
Benzene (%):	0.50	0.80	0.30	0.50	0.80	0.30	0.50	0.80	0.30	0.50	0.80	0.30
Olefins (%):	6.0	10.0	4.0	2.0	10.0	8.0	2.0	8.0	6.0	2.0	6.0	4.0
Sulfur (ppm):	5.0	25.0	20.0	5.0	25.0	20.0	5.0	25.0	20.0	5.0	20.0	15.0
T50	205	220	15.0	205	220	15.0	200	220	20.0	190	220	30.0
T90	300	330	30.0	300	330	30.0	300	330	30.0	300	330	30.0

Exhibit A-1b: Estimated Coefficients for Reduced-Form of Amended PM-3, by Oxygen Content

Emissions	Constant	RVP	Arom	Arom^2	Benz	Olef	Sulf	T50	T50^2	T90	T90^2	R^2	Std. Err.
Oxygen = 0 wt%													
VOCs	220.563	3.614	0.563	-0.009		-0.116	0.061	-1.135	0.003	-0.877	0.001	0.992	0.074
NOx	10.908		0.202			0.371	0.410	-0.287	0.001	0.011		0.998	0.120
Toxics	-158.162	1.887	0.158	0.010	26.182	0.935	0.023	0.211		0.209		0.998	0.143
Oxygen = 2.0 wt%													
VOCs	209.084	3.590	0.629	-0.009		-0.114	0.059	-0.979	0.003	-0.992	0.002	0.993	0.084
NOx	-182.804		0.202			0.370	0.392	1.584	-0.004	0.011		0.998	0.120
Toxics	-153.148	1.815	0.272	0.008	25.965	0.845	0.023	0.203		0.194		0.998	0.175
Oxygen = 2.7 wt%													
VOCs	211.007	3.562	0.635	-0.009		-0.111	0.058	-1.089	0.003	-0.955	0.002	0.992	0.109
NOx	-178.824		0.206			0.376	0.392	1.590	-0.004	0.011		0.997	0.119
Toxics	-149.422	1.891	0.144	0.011	25.713	0.806	0.024	0.197		0.187		0.998	0.152
Oxygen = 3.5 wt%													
VOCs	206.776	3.546	0.564	-0.007		-0.106	0.056	-1.057	0.003	-0.972	0.002	0.988	0.167
NOx	-142.732		0.208			0.384	0.403	1.306	-0.003	0.012		0.995	0.131
Toxics	-146.724	1.867	0.245	0.008	25.562	0.761	0.022	0.192		0.180		0.998	0.141

Exhibit A-2a: California Petroleum Refining Process Capacity Summer 2006

Type of Process	Process	Capacity in Terms of	Planning Throughput (K b/sd)	Reported Throughput (K b/cd)
Crude Distillation	Atmospheric	Feed	1,838	1,750
	Vacuum	Feed	1,000	899
Conversion	Coking			
	Delayed	Feed	387	362
	Fluid	Feed	72	72
	Flexi	Feed	22	13
	Fluid Cat Cracking	Feed	696	644
	Hydrocracking	Feed	394	385
Upgrading	Alkylation	Product	175	165
	Pen/Hex Isomerization	Feed	94	82
	Reforming	Feed	404	366
	Polymerization	Product	2	3
	Dimersol	Product	5	5
	Iso-Octane	Product	1.4	0.585
Hydrotreating	Light Naphtha Feed	Feed	155	144
	Reformer Feed	Feed	263	229
	Benzene Saturation	Feed	142	124
	FCC Naphtha	Feed	129	118
	Kerosene & Distillate	Feed	378	328
	Distillate/Aromatics Sat.	Feed	136	130
	FCC Feed/Heavy Gas Oil	Feed	647	569
	Resid	Feed	37	38
	Other	Feed	57	52
Hydrogen	Production (MM scf/d)[1]	Product	1284	1170
	Recovery (MM scf/d)	Feed	38	34
Other	Butane Isomerization	Feed	39	29
	Lube Oil	Product	16	16
	Solvent Deasphalting	Feed	*59*	
	Coke (K t/d)		*21*	
	Sulfur Recovery (K Sh t/d)		*4*	
	Asphalt		*42*	

1 Includes refinery-owned and captive, 3rd party capacity.

Sources: CEC 2007 California Refinery Survey; and "2006 Worldwide Refinery Survey," *Oil & Gas Journal* , Dec. 18, 2006.

Exhibit A-2b: Distribution of Feeds to Key Refinery Process Units

Process Unit	Summer Planning Rates[2] (K b/sd)	Actual Throughput (K b/cd)	Type of Feed and Share of Feed Input (%)						
Coking	**458**	**434**	Vac Tower Bottoms 97.0%	Heavy Slop Oils 1.1%	FCC HCO 0.7%	Crude 1.2%			
FCC	**696**	**644**	Hydro-treated Gas Oils 50.3%	VGO 30.3%	Purchased VGO 2.0%	FCC Pretreat Bottoms 6.1%	LS Resid 5.5%	Coker Gas Oil 5.7%	
Hydrocracking	**394**	**385**	Straight Run Diesel 3.7%	Coker Gas Oil 19.2%	Straight Run Gas Oil 57.9%	FCC LCO 19.1%			
Alkylation	**175**	**165**	C3 Propylene 11.3%	C4 Butylene 57.7%	C5 Pentene 12.5%	Mixed 18.5%			
Reforming	**404**	**366**	Hydro-treated Naphtha 41.9%	Hydro-crackate 33.2%	Straight Run Naphtha 19.1%	Coker Naphtha 6.0%			
Isomerization	**94**	**82**	LSR Naphtha 22.3%	Light Coker Naphtha 7.0%	Light Naphtha 8.3%	Naphtha Splitter 31.7%	Light Reformate 15.6%	Hydro-treated C5/C6 9.3%	HCU Naptha 5.9%
Hydrogen (MM scf/d)	**1,160**	**1,066**	Purchased Natural Gas 50%	Refinery Gas 49%	C4/C5 1%				

Source: Derived from CEC 2007 Survey of California Refineries.

Exhibit A-3: Reported and Projected Production of Major Petroleum Products by California Refineries and Average U.S. Prices for Crude Oil, Natural Gas, and Electricity Summer 2006 - 2012 (K b/d)

	2006	2007	2008	2009	2010	2011	2012
Volume	**1,807**	**1,844**	**1,864**	**1,894**	**1,927**	**1,955**	**1,982**
Gasoline	**1,127**	**1,136**	**1,142**	**1,155**	**1,166**	**1,180**	**1,195**
California RFG[1]	937	944	949	960	969	980	993
Arizona CBG	54	54	54	55	56	56	57
All other	137	138	139	140	141	143	145
Jet Fuel	**247**	**256**	**266**	**278**	**294**	**300**	**305**
Diesel Fuel	**382**	**400**	**403**	**408**	**413**	**421**	**427**
CARB ULSD	270	283	285	288	292	297	302
EPA ULSD	75	78	79	80	81	82	83
All Other	38	39	40	40	41	41	42
Residual Fuel	**50**	**52**	**52**	**53**	**54**	**54**	**55**
Projected Growth[2]		**2.1%**	**3.1%**	**4.8%**	**6.7%**	**8.2%**	**9.7%**
Gasoline		0.8%	1.3%	2.5%	3.5%	4.7%	6.0%
Jet Fuel		3.6%	7.5%	12.5%	18.8%	21.3%	23.1%
Diesel Fuel		4.8%	5.6%	6.8%	8.3%	10.1%	12.0%
Residual Fuel		2.9%	4.2%	5.3%	7.3%	8.0%	10.1%
Average U.S Price							
Composite Crude Oil ($/b)	64.59	62.22	59.86	56.70	53.55	50.71	48.34
Natural Gas ($/mcf)[3]	8.24	8.14	8.06	7.46	7.11	6.66	6.49
Electricity (¢/kwh)[3]	10.4	10.7	10.7	10.5	10.3	9.8	9.6

1 Assumed to be blended with ethanol at 5.6 vol%.
2 Projected growth for U.S. relative to 2006 baseline.
3 Prices to industrial customers.
Source: 2006: CEC 2007 California Refinery Survey.
2007-2012: Derived using projected U.S. growth in liquid fuel consumption calculated from Table 11, "Year-by-Year Tables," *Annual Energy Outlook 2007*, EIA/DOE.

Exhibit A-4: Gasoline Production by California Refineries -- Volume, Average Properties, and Spot Price Summer 2006[1]

	California RFG		Arizona	All	Total	
	CARBOB	Finished[2]	CBG	Other	CARBOB + Other	Finished
Volume (b/d)	884,164	936,614	53,739	136,711	1,074,614	1,127,064
Properties						
RVP (psi)	5.61	6.83	6.7	8.0	6.0	7.0
Oxygen (wt%)	0.0	2.0	0.0	0.0		
Aromatics (vol%)	24.6	23.3	25.7	30.8	25.5	24.3
Benzene (vol%)	0.58	0.55	0.71	0.60	0.59	0.56
Olefins (vol%)	5.9	5.6	11.0	6.8	6.3	6.0
Sulfur (ppm)	10	9	22	23	12	12
T50	215	211	217	223	216	212
T90	311	309	321	330	314	312
E200 (%)[3]	41.9		42.4	42.4	42.0	
E300 (%)[3]	87.2		85.5	80.0	86.2	
API Gravity	59.5	58.8	59.0	57.5	59.2	58.6
Specific Gravity	0.741	0.744	0.743	0.749	0.742	0.744
Distillation (°F)						
IBP	106		100	93	91	
T10	149		142	133	146	
T30	181		174	160	179	
T50	215		217	224	216	
T70	251		255	275	256	
T90	311		321	328	315	
FBP	382		400	399	404	
Octane						
MON	82.5	84.2	83.0	83.5	82.6	84.0
RON	89.5	90.8	91.4	92.2	89.9	91.0
CON	86.0	87.5	87.2	87.8	86.3	87.5
Spot Price ($/b)	94.0		94.4	90.4		

1 June 1 through September 30, 2006 (122 calendar days).
2 Calculated using CARBOB version of PM-3.
3 Interpolated from distillation curves.
Source: Derived from CEC 2007 Survey of California Refineries.

Exhibit A-5: Jet, Diesel, and Residual Fuel Production by California Refineries -- Average Properties and Spot Prices

Summer 2006[1]

Volume & Property	Jet Fuel	Diesel Fuel				Residual Fuel
		CARB ULSD	EPA ULSD	Other Diesel	Pool	
Volume (bbl/d)	247,495	269,737	74,505	37,555	381,797	50,267
Properties						
API Gravity	42.1	38.5	36.8	33.9	37.7	7.0
Specific Gravity	0.815	0.832	0.841	0.855	0.836	1.022
Sulfur (ppm)	654	4	5	235	27	22,502
Cetane number (detail below)						
Clear[2]		49.1	44.0	43.9	47.6	
Including additized		51.3	45.9	44.0	49.5	
Aromatics (vol%)	20.1	17.6	30.9	31.5	21.6	
Polynuclear Aromatics (vol%)	NA	2.2	2.4	NA		
Naphthalenes (vol%)	1.2					
Nitrogen (ppm)		56.6	25.6	NA		
Freeze Point (°F)	-60.3					
Smoke Point (mm)	20.2					
Pour Point (°F unadditized)		0.9	-5.3	-14.9		
Pour Point Depressant (ppm)		None	None	None		
Distillation						
T Values (°F)						
IBP	320	342	356	405	342	
T10	350	391	397	454	387	
T30	382	427	432	488	436	
T50	402	479	476	515	483	
T70	432	524	521	544	533	
T90	465	606	597	590	604	
FBP	504	659	658	630	659	
E Values (% off)						
350	10.3	1.7	0.0	0.0	1.2	
400	48.0	15.2	11.6	0.0	13.0	
440	74.9	35.0	33.5	7.1	32.0	
465	89.9	44.6	44.9	16.5	41.9	
510	100.0	63.7	65.2	46.6	62.3	
560		78.8	80.3	76.9	78.9	
610		90.8	92.1	95.0	91.5	
Cetane Detail						
Diesel Without Cetane Improver						
Volume (bbl/d)		127,745	28,973	33,755	190,473	
Cetane Number (clear)		50.4	46.7	44.4	48.7	
Diesel With Cetane Improver						
Volume (bbl/d)		141,992	45,532	3,800	191,324	
Cetane Number (clear)		48.0	42.3	39.2	46.5	
Cetane Improver (ppm)		1,033	461	300	882	
Cetane Number (additized)		52.2	45.3	40.5	50.3	
Spot Price ($/b)	90.56	93.0	91.9			

1. Summer refers to the period June 1 through September 30, 2006 (122 calendar days).

2 Includes clear cetane of additized distillate products.

Source: Derived from CEC 2007 Survey of California Refineries.

Exhibit A-6a: Crude Oil Processed by California Refineries -- Volume, Properties, and Prices Summer 2006[1]

Crude Oil		Volume	Share	Gravity		Sulfur	West Coast Spot Price
Source	Crude	(b/d)	(%)	API	Specific	(wt%)	($/b)
Alaskan	**North Slope**	**251,353**	**14.1%**	**32.2**	**0.865**	**0.91%**	**69.17**
California	**Composite**	**658,876**	**36.9%**	**19.1**	**0.940**	**1.50%**	**61.1**
	Elk Hills	30,136	1.7%	29.8	0.877	0.61%	65.20
	San Joaquin Light	103,599	5.8%	29.4	0.879	0.82%	65.08
	Ventura	6,800	0.4%	27.8	0.888	1.34%	64.28
	Outer Continental Shelf	32,427	1.8%	19.8	0.935	4.56%	56.22
	Wilmington	29,654	1.7%	17.6	0.949	1.61%	59.37
	San Joaquin Heavy	269,022	15.1%	13.6	0.975	1.38%	59.12
	Kern River	56,500	3.2%	13.0	0.979	1.30%	59.12
	San Ardo	4,900	0.3%	11.7	0.988	2.15%	56.13
	Other	125,838	7.1%	24.1	0.910	1.79%	63.53
Imports	**Composite**	**874,566**	**49.0%**	**28.3**	**0.885**	**1.82%**	**65.91**
	Middle East	460,766	25.8%	32.2	0.864	2.26%	
	Canada	4,374	0.2%	20.7	0.929	3.37%	
	Latin America	340,841	19.1%	23.2	0.915	1.52%	
	Africa	64,535	3.6%	28.8	0.883	0.41%	
	Asia	4,050	0.2%	40.6	0.822	0.09%	
All Sources	**Composite**	**1,784,795**		**25.3**	**0.902**	**1.58%**	**64.59**

1 June 1 through September 30 (122 calendar days).

Source: Derived from 2007 CEC Refinery Survey.

Exhibit A-6b: Imports of Crude Oil by California Refineries, by Country of Origin 2006

Country of Origin	Volume K b/y	Volume K b/d	Volume Share	% Sulfur	API Gravity	Specific Gravity	Assigned Assay
Middle East	**151,612**	**415**	**50.8%**	**1.98**	**32.3**	**0.864**	
IRAQ	56,163	154	18.8%	2.44	30.6	0.873	Basrah Medium
OMAN	6,326	17	2.1%	0.85	33.6	0.857	Oman Export
SAUDI ARABIA	40,576	111	13.6%	2.40	30.8	0.872	Saudi Medium
SAUDI ARABIA	5,439	15	1.8%	1.90	33.4	0.858	Saudi Light
SAUDI ARABIA	20,218	55	6.8%	1.20	33.4	0.858	Saudi Light Low Sulfur
SAUDI ARABIA	20,743	57	6.9%	1.14	38.3	0.833	Saudi Berri
YEMEN	2,147	6	0.7%	0.60	30.7	0.873	Saudi Medium
Latin America	**122,523**	**336**	**41.0%**	**1.38**	**23.2**	**0.915**	
ARGENTINA	3,484	10	1.2%	0.20	24.0	0.910	Escalante
BOLIVIA	299	1	0.1%	0.02	58.5	0.745	Algerian Condensate
BRAZIL	17,938	49	6.0%	0.62	20.4	0.932	Marlim
COLOMBIA	9,362	26	3.1%	0.65	28.6	0.884	Cano Limon
ECUADOR	29,705	81	9.9%	1.73	19.4	0.938	Venezuela Bachequero 17 & Venezuela BCF24
ECUADOR	33,870	93	11.3%	1.24	23.6	0.912	Venezuela La Rosa
ECUADOR	7,660	21	2.6%	1.00	29.2	0.881	Oriente
MEXICO	13,013	36	4.4%	3.25	22.1	0.921	Maya
MEXICO	2,460	7	0.8%	1.55	32.3	0.864	Isthmus
PERU	962	3	0.3%	0.54	27.0	0.893	Brazil Cabiunas
VENEZUELA	3,770	10	1.3%	0.78	33.8	0.856	Tia Juana Light
Africa	**18,377**	**50**	**6.2%**	**0.53**	**28.6**	**0.884**	
ANGOLA	14,979	41	5.0%	0.58	29.1	0.881	Brazil Marlim
CAMEROON	337	1	0.1%	0.39	20.2	0.933	Indonesia Duri
CHAD	1,285	4	0.4%	0.16	21.2	0.927	Indonesia Duri
EQUATORIAL GUINEA	1,040	3	0.3%	0.53	30.0	0.876	Brazil Marlim
NIGERIA	736	2	0.2%	0.24	35.5	0.848	Escravos
Other	**6,163**	**17**	**2.1%**	**1.23**	**32.4**	**0.863**	
CANADA	2,450	7	0.8%	2.59	22.9	0.917	Fosterton
CHINA, PEOPLES REP	210	1	0.1%	0.29	21.8	0.923	Indonesian Duri
MALAYSIA	1,123	3	0.4%	0.04	45.3	0.800	Tapis
NORWAY	497	1	0.2%	0.20	32.5	0.863	Oseberg
VIETNAM	1,883	5	0.6%	0.34	40.0	0.825	Indonesian Minas
TOTAL	**298,675**	**147**	**18.0%**	**1.62**	**28.2**	**0.886**	

Source: Derived from DOE Company-Level Import Data (adjusted), 2006.

Exhibit A-6c: California 2006 Composite Crude Oils -- Fractions, Properties, and Distillation Curves

Fractions & Properties	Alaskan 14.1%	Domestic 36.9%	Foreign 49.0%	Calif. Composite
CRUDE FRACTIONS				
LPGs:				
Ethane	0.000	0.000	0.001	0.001
Propane	0.001	0.001	0.003	0.002
Isobutane	0.009	0.001	0.003	0.003
Butane	0.024	0.004	0.008	0.009
Naphthas:				
Very Light (C5-160)	0.043	0.014	0.040	0.031
Light (160-250)	0.084	0.036	0.059	0.054
Medium (250-325)	0.069	0.034	0.058	0.051
Heavy (325-375)	0.029	0.025	0.043	0.034
Middle Distillates:				
Kerosene (375-500)	0.101	0.090	0.114	0.104
Distillate (500-620)	0.120	0.115	0.114	0.115
Atmospheric Resid:				
Light gas oil (620-800)	0.160	0.188	0.163	0.172
Heavy gas oil (800-1050)	0.190	0.226	0.190	0.203
Resid (1050+)	0.170	0.231	0.077	0.147
Asphalt (1050+)	0.000	0.035	0.126	0.075
Total:	1.000	1.000	1.000	1.000
PROPERTIES (in ARMS)				
Sulfur (wt%)				
Kerosene (375-500)	0.14%	0.31%	0.29%	0.28%
Distillate (500-620)	0.28%	0.71%	0.98%	0.78%
Gas Oils (620-1050)	1.11%	1.42%	1.91%	1.60%
Resid (1050+)	2.20%	2.03%	1.66%	1.96%
Asphalt (1050+)		5.49%	5.21%	5.26%
API Gravity	30.7	23.2	28.9	27.0
Sulfur (wt %)	0.90%	1.44%	1.78%	1.53%
PROPERTIES (from Assays)				
API Gravity	29.5	19.2	27.7	24.7
Sulfur (wt %)	0.91%	1.49%	1.80%	1.56%

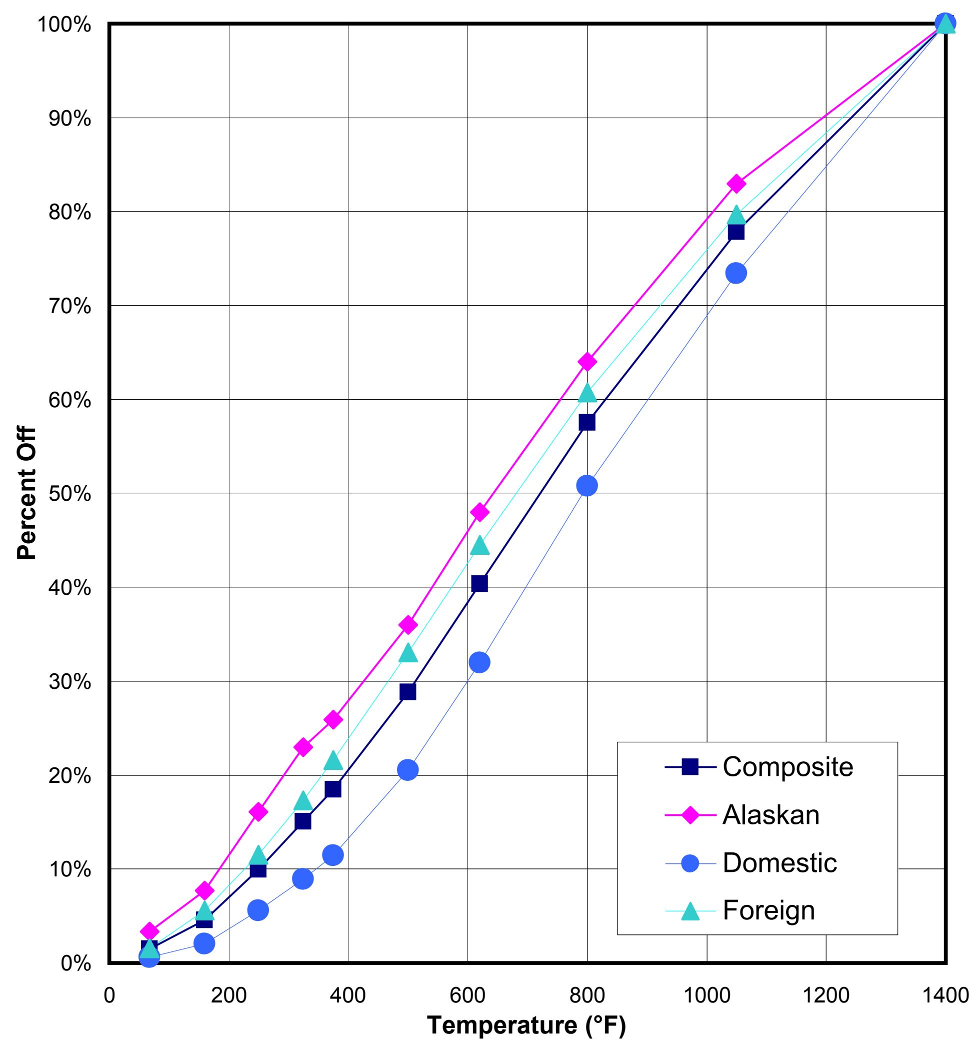


Exhibit A-7: Volume and Properties of Gasoline Blendstocks Produced and Used by California Refineries, Summer 2006

Blendstock	Volume	Octane		API	RVP	Aromatics	Benzene	Olefins	Sulfur	Distillation (°F)						
Category	(K b/d)	MON	RON	Gravity	(psi)	(vol %)	(vol %)	(vol %)	(ppm)	IBP	T10	T30	T50	T70	T90	FBP
N-Butane	6	89.6	93.6	111.0	53.1	0.0	0.00	0.2	2	36	49	-	59	-	69	71
Pentanes	31	83.9	86.4	97.4	21.4	0.0	0.00	0.5	13	48	83	87	91	93	101	109
Naphthas	39	67.6	70.7	72.7	10.0	3.0	1.48	0.3	22	98	131	146	160	178	208	248
Natural Gasoline	2	69.2	76.3	82.3	12.6	1.2	0.59	0.3	12	93	108	115	124	142	183	229
Isomerate (C5/C6)	83	78.7	81.0	79.9	10.2	0.8	0.14	0.0	1	72	119	128	134	147	164	221
Dimate	5	86.0	96.1	72.3	6.9	0.0	0.00	89.6	0	114	148	152	158	170	271	352
Polymerate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrocrackate	82	73.5	75.8	67.1	6.5	8.1	1.06	0.4	2	95	126	155	178	223	280	376
Alkylate (mixed)	173	90.5	91.8	69.0	4.2	0.7	0.01	0.4	4	110	172	203	221	239	291	404
Iso-Octane	8	98.3	100.3	69.8	2.4	2.4	0.01	1.3	2	187	203	208	211	213	228	321
FCC Naphtha	320	79.6	88.1	-	5.4	25.4	1.22	18.2	33	95	137	175	222	273	321	418
Not post-treated	235	81.1	90.5	-	6.2	23.0	0.84	23.4	42							
Post-treated	86	75.3	81.4	-	3.0	31.8	2.26	3.9	6							
Reformate	309	86.1	96.2	41.5	2.3	59.7	0.78	0.3	1	100	210	235	261	285	325	398
Other	9	83.9	86.7	82.0	15.5	2.5	0.06	2.8	10	-	-	-	-	-	-	-
Total	1,067	82.6	88.9	-	5.7	25.9	0.74	6.2	12	-	-	-	-	-	-	-

Note: Does not include purchased ethanol.
Source: Derived from 2007 CEC Refinery Survey.

Exhibit A-8: Refinery Streams Sold or Stored by California Refineries Summer 2006[1]

Refinery Stream	Volume (K b/cd)	Boiling Range (°F)	API Gravity	Sulfur (ppm)	Inventory Build[2] (bbl/cd)
Propane	5	NA	1		
Mixed Butanes	22	11 - 85	112	7	3,532
Iso-butane	0	NA	NA	NA	
Pentanes	2	49 - 380	82	75	500
Naphtha	1	86 - 385	53	106	
Alkylate	3	98 - 413	70	3	
Isomerate	1	100 - 225	82	0	
Hydrocrackate					
Reformate	6	210 - 385	38	1	
FCC Gasoline	3	120 - 450	50	63	-200
HS Diesel	2	475 - 625	32	50	-400
No. 6 Fuel Oil	3	530 - 1104	13	22,466	
LCO	3	290 - 730	18	1,844	100
FCC Feed	30	450 - 1100	17	12,950	700
HSVGO	4	600 - 1000	18	12,500	
Clarified Slurry Oil	3	650 - 900	2	1,500	600
Vacuum Resid	1	496 - 1134	18	10,000	

Source: Derived from 2007 CEC Refinery Survey.

Exhibit A-9: California Refining Model -- Process Investment and Per Barrel Costs, $2006

Type of Process	Process	Investment Cost ($K/(Bbl/d)) Grassroots	Investment Cost ($K/(Bbl/d)) Expansion	Per Barrel Cost ($/Bbl)[1] Grassroots	Per Barrel Cost ($/Bbl)[1] Expansion	Assumptions in ARMS: Investment Economics	Assumptions in ARMS: New Capacity
Crude Distillation	Atmospheric & Vacuum	4.350	1.608	3.296	1.265	expansion	open
Conversion	Coking						
	Delayed	13.952	6.064	11.005	4.770	expansion	open
	Fluid	18.025	7.884	14.208	6.201	expansion	not allowed
	Flexi	23.320	10.249	18.373	8.061	expansion	not allowed
	Fluid Cat Cracking	11.535	5.252	9.018	4.130	expansion	open
	Hydrocracking	15.778	6.631	12.287	5.215	expansion	open
Upgrading	Alkylation	14.953	6.734	11.774	5.296	expansion	open
	Pen/Hex Isomerization	8.001	3.391	6.241	2.667	grassroots	open
	Reforming	10.553	4.442	8.222	3.494	expansion	open
Hydrotreating	Light Naphtha Feed	2.310	1.106	1.839	0.869	expansion	open
	Reformer Feed	2.320	1.106	1.845	0.869	expansion	open
	Benzene Saturation	4.887	2.111	3.814	1.660	grassroots	open
	FCC Naphtha	4.137	1.960	3.268	1.541	grassroots	open
	Kerosene & Distillate	3.655	1.628	2.917	1.281	expansion	open
	Distillate/Aromatics Sat.	7.102	3.357	5.618	2.640	expansion	open
	FCC Feed/Heavy Gas Oil						
	Conventional	8.611	4.111	6.802	3.233	expansion	open
	Deep	10.131	4.838	7.997	3.805	expansion	open
	Resid	12.296	5.350	9.674	4.208	grassroots	not allowed
Fractionation	Debutanization	4.688	2.513	4.023	1.976	expansion	open
	Depentanization	0.563	0.302	0.442	0.237	expansion	open
	FCC Gasoline Fractionation	0.563	0.302	0.476	0.237	expansion	open
	Naphtha Splitters	0.693	0.371	0.567	0.292	expansion	open
	Heavy Nap/Ref. Splitter	1.050	0.563	0.848	0.443	expansion	open
Hydrogen	Production (MM scf/d)[1]	55.173	26.130	43.547	20.552	grassroots	open
Other	Butane Isomerization	11.034	5.025	8.907	3.952	grassroots	open
	Light ends processing[2]	1.208	0.578	0.972	0.455	grassroots	open
	Lube/Wax Plant	127.950	53.265	101.492	41.893	expansion	open
	Solvent Deasphalting	7.293	3.306	5.725	2.600	expansion	not allowed
	Sulfur Recovery (K Sh t/d)	420.000	201.000	342.961	158.089	expansion	open
	Steam (lbs/h)	0.139	0.066	0.113	0.052	expansion	open

1 Includes capital charges, fixed cost recovery, and labor costs for grassroots units;
includes capital charges and fixed cost recovery for expansions (i.e., no additional labor costs).

Note: California ISBL cost be 150% times U.S. Gulf Coast ISBL cost.

Exhibit A-10a: Aromatics Content of CARBOB

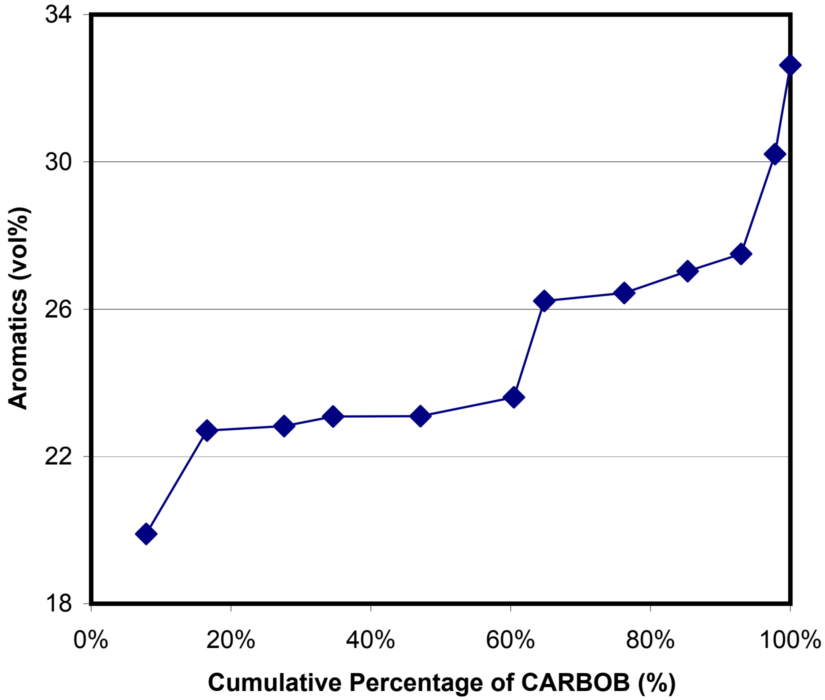
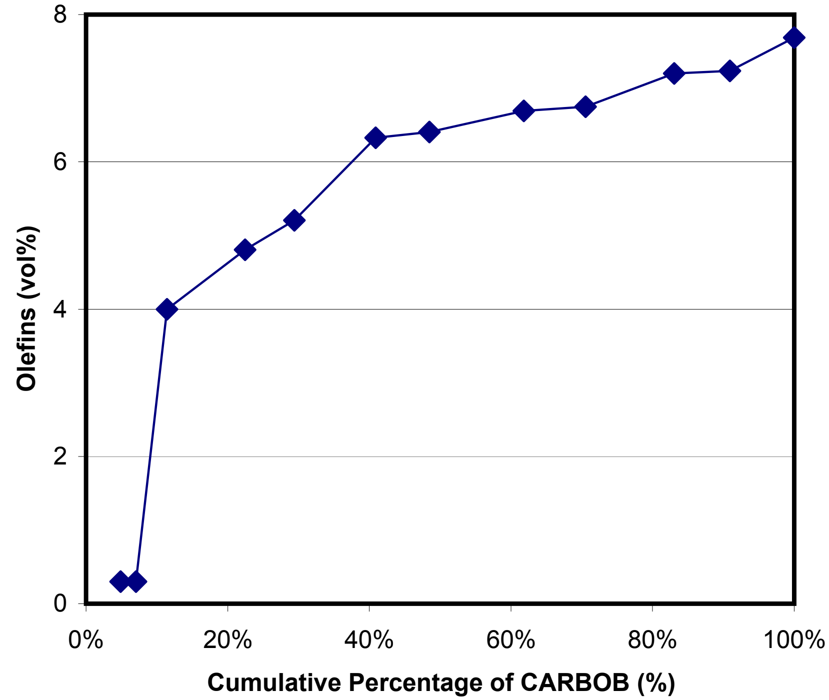


Exhibit A-10b: Olefins Content of CARBOB



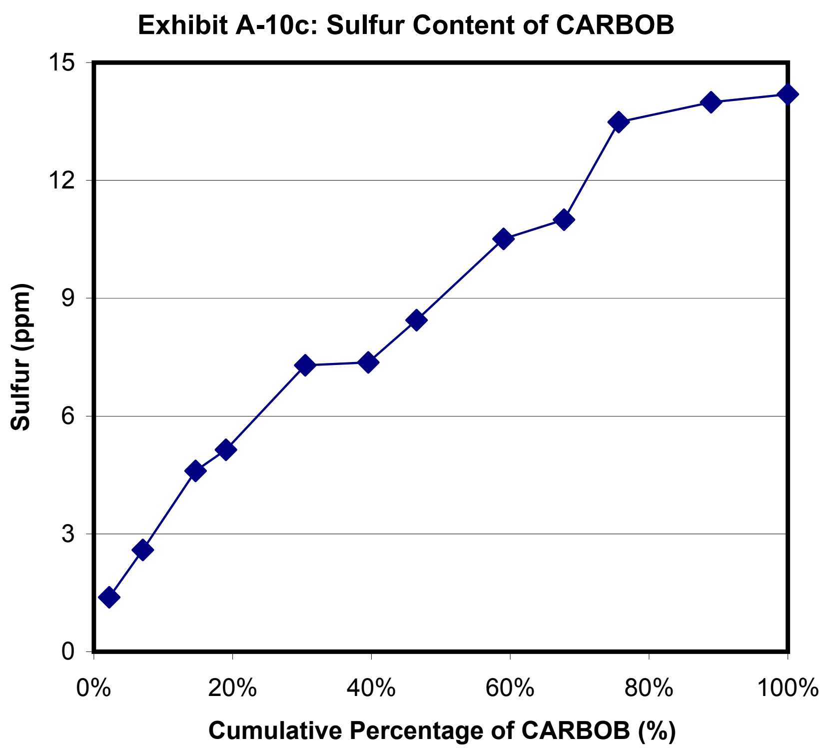


Exhibit A-10c: Sulfur Content of CARBOB
15
12
9
6
3
0
Sulfur (ppm)
0%
20%
40%
60%
80%
100%
Cumulative Percentage of CARBOB (%)

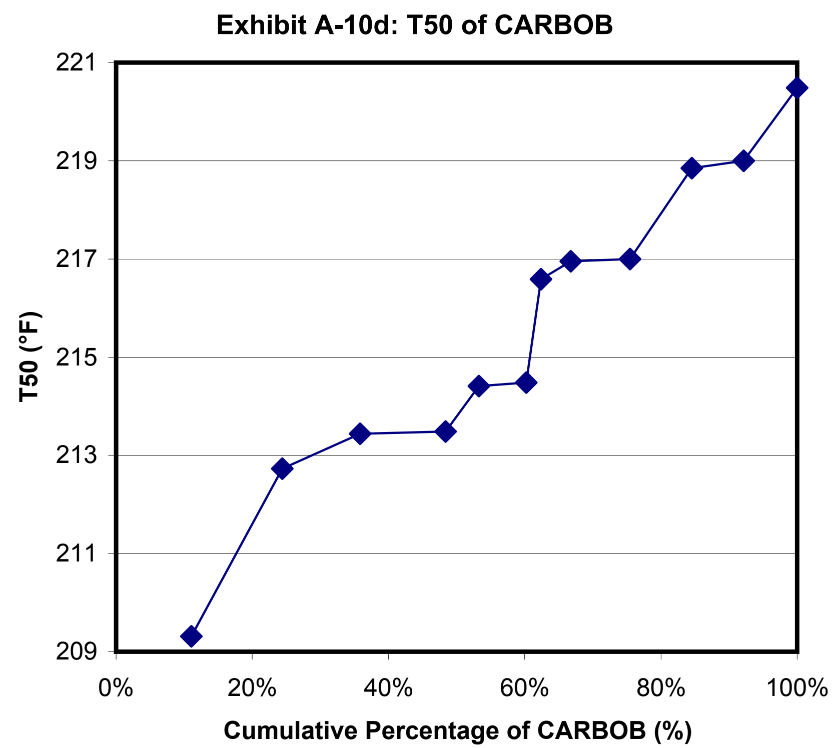


Exhibit A-10d: T50 of CARBOB
221
219
217
215
213
211
209
T50 (°F)
0%
20%
40%
60%
80%
100%
Cumulative Percentage of CARBOB (%)

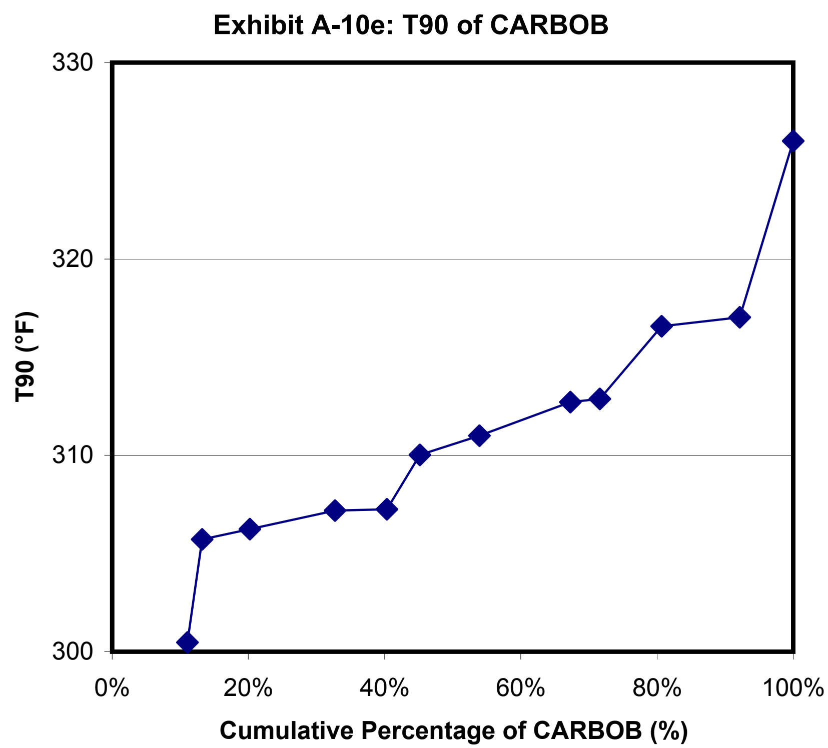


Exhibit A-10e: T90 of CARBOB
330
320
310
300
T90 (°F)
0%
20%
40%
60%
80%
100%
Cumulative Percentage of CARBOB (%)

Exhibit A-11a: CARBOB Average Sulfur & Olefin Levels

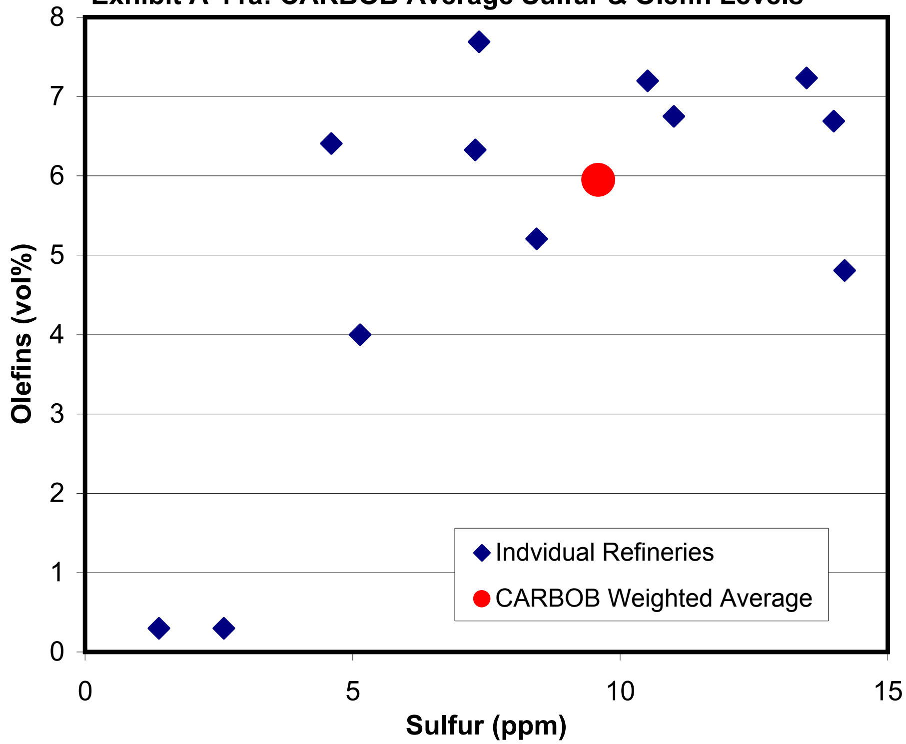


Exhibit A-11b: CARBOB AverageT50 & T90

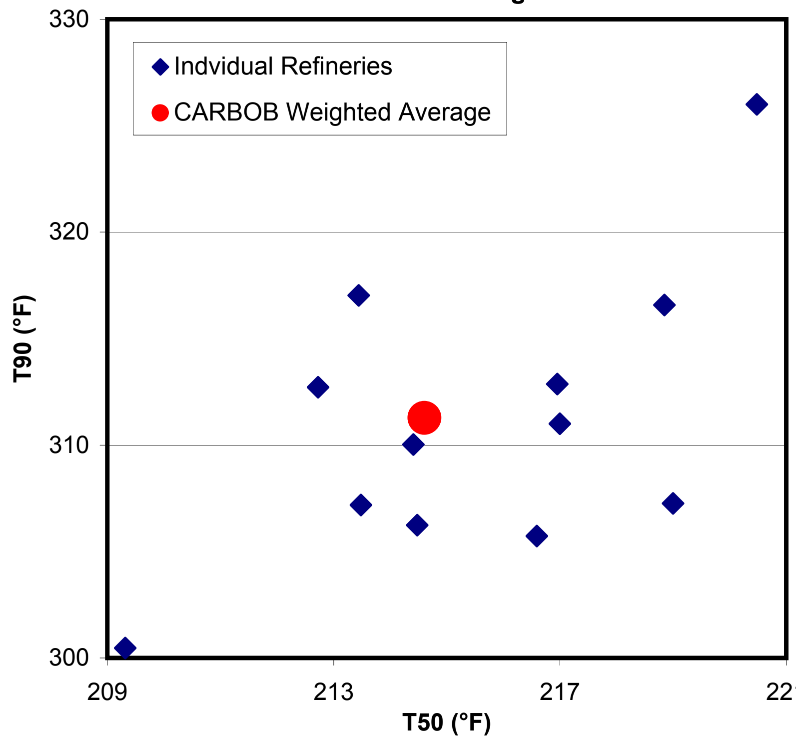


Exhibit B-1: Comparison of Refining Process Throughput: Reported and Calibration, Summer 2006

Type of Process	Process	Capacity in Terms of	Reported Throughput (K b/cd)	Calibration Throughput (K b/cd)
Crude Distillation	Atmospheric	Feed	1,750	1,832
	Vacuum	Feed	899	
Conversion	Coking	Feed	447	447
	Fluid Cat Cracking	Feed	644	644
	Hydrocracking	Feed	385	383
Upgrading	Alkylation	Product	165	160
	Pen/Hex Isomerization	Feed	82	82
	Reforming	Feed	366	370
	Polymerization	Product	3	1
	Dimersol	Product	5	5
	Iso-Octane	Product	1	1
Hydrotreating	Naphthas	Feed	373	311
	Benzene Saturation	Feed	124	26
	FCC Naphtha	Feed	118	66
	Kerosene & Distillate	Feed	328	340
	Distillate/Aromatics Sat.	Feed	130	194
	FCC Feed/Heavy Gas Oil	Feed	569	638
	Resid	Feed	38	
	Other	Feed	52	
Hydrogen (MM scf/d)	Production & Recovery[1]		1,203	1,289
Other	Butane Isomerization	Feed	29	4
	Lube Oil	Product	16	23

1 Includes refinery-owned and captive, 3rd party capacity.
Source: Exhibits A-2a & C-1.

Exhibit B-2: Comparison of Gasoline Blendstock Use: Reported and Calibration, Summer 2006 (K b/d)

Blendstock	Reported	Calibration
N-Butane	6	6
Pentanes	31	33
Naphthas	39	72
Natural Gasoline	2	2
Isomerate	83	81
Dimate	5	
Polymerate		6
Hydrocrackate	82	75
Alkylate (mixed)	173	160
Iso-Octane	8	1
FCC Naphtha	320	322
Reformate	309	309
Other	9	
Total	**1,067**	**1,068**

Source: Exhibits A-7 & C-5.

Exhibit B-3: Comparison of Prices/Shadow Values and Volumes for Major Refined Products: Reported and Calibration, Summer 2006

Major Refined Products	Price/Shadow Value ($/b): Reported Spot Price ($/b)	Price/Shadow Value ($/b): Calibration Specified Price ($/b)	Price/Shadow Value ($/b): Calibration Shadow Value ($/b)	Volume (K b/d): Reported (K b/d)	Volume (K b/d): Calibration Specified (K b/d)	Volume (K b/d): Calibration Optimized (K b/d)
Gasoline						
California CARBOB	94.0		101.4	884	930	
Arizona CBG	94.4		92.8	54	53	
All Other	90.4		83.0	137	137	
Jet Fuel	90.6	91.0		247		280
Diesel Fuel						
CARB Diesel	93.0	93.0		270		275
EPA Diesel	91.9		89.3	75	75	
Other			86.6	38	38	
Residual Oil			48.0	50	50	

Sources: Exhibits A-3, A-4, A-5, & C-2 and Refinery Modeling Results.

Exhibit B-4: Comparison of Properties and Emission Reductions for CARBOB and Compliance CaRFG: Reported and Calibration, Summer 2006

	Reported			Calibration		
	CARBOB	Compliance Margins	Compliance CaRFG	CARBOB	Compliance Margins	Compliance CaRFG
Properties						
RVP (psi)	5.60	0.12	6.94	5.58	0.12	6.92
Oxygen (wt%)			2.0			2.0
Aromatics (vol%)	24.6	1.0	24.3	25.9	1.0	25.5
Benzene (vol%)	0.58	0.11	0.65	0.58	0.11	0.65
Olefins (vol%)	5.9	2.6	8.0	6.7	1.2	7.5
Sulfur (ppm)	10	2	12	10	2	12
T50	215	1	212	215	1	212
T90	311	3	312	308	3	309
E200 (vol% off)	42.6	-0.5	44.2	42.4	-0.5	43.9
E300 (vol% off)	87.2	-0.7	87.0	88.0	-0.7	87.8
% Change in Emissions						
Total THC & CO			-0.73			-0.92
NOx			-0.71			-0.70
Potency Weighted Toxics			-1.87			-2.12

Note: Properties of Compliance CaRFG reflect the specified Compliance Margins and the effects of blending ethanol at 2.0 wt% oxygen (5.7 vol%) according to the CARBOB version of PM-3. % Changes in Emissions are calculated using PM-3.

Source: Exhibit C3.

Exhibit C-1: Refinery Modeling Results -- Refinery Operations and New Capacity

(K b/d, except as noted)

Type		2006	Investment Constrained				Investment Unconstrained				
of	Process	Calibration		Study Cases			Reference	Study Cases			
Process	Wt% Oxygen -->	2.0%	0.0%	2.0%	2.7%	3.5%	2.0%	0.0%	2.0%	2.7%	3.5%
USE OF IN-PLACE CAPACITY											
Crude Distillation	Atmospheric	1,832		1,824	1,833	1,816	1,920	1,920	1,920	1,920	1,908
Conversion	Fluid Cat Cracker	644		644	644	644	696	696	696	696	689
	Hydrocracking	383		383	383	383	385	385	385	385	385
	Coking	447		440	447	447	456	402	449	443	405
Upgrading	Alkylation*	165		165	165	165	175	175	175	175	169
	Iso-octene/octane	1		1	1	1	1	1	1	1	1
	Catalytic Polymerization*	1		2	2	1		2			
	Dimersol*	5		5	5	5	2	5			4
	Pen/Hex Isomerization	82		82	82	82	82	82	82	82	67
	Reforming	360		322	324	361	370	341	336	339	356
Hydrotreating	Naphtha Desulf.	311		299	301	310	323	309	319	317	302
	FCC Naphtha Desulfurization	66		41	51	72	55	65	62	68	70
	Benzene Saturation	26		21	14	10	15	15	14	4	
	Distillate Desulfurization	340		378	378	378	361	355	355	357	351
	Distillate Dearomatization	194		195	195	194	163	194	194	180	169
	FCC Feed Desulfurization	638		638	638	635	647	647	647	647	647
Hydrogen	Hydrogen* (MM scf/d)	1,289		1,289	1,289	1,289	1,289	1,289	1,289	1,289	1,289
Fractionation	Debutanization	200		197	197	201	202	202	202	202	197
	Depentanization	174		200	200	200	200	28	200	200	191
	Lt. Naphtha Spl. (Benz. Prec.)	190		168	167	132	159	161	147	146	122
	Med. Naphtha Spl.	18		18	18	15	18	18	18	18	18
	Hvy. Reformate Spl.	12				12	12			9	12
	FCC Naphtha Splitting	346		329	332	327	346	346	346	346	343
	Heavy FCC/Lt Cycle Oil Splitting	64		70	70	70	70	70	70	70	61
Other	Benzene Saturation	26		21	14	10	15	15	14	4	
	Butane Isomerization	4		6	7	2	17	39	39	24	6
	Lubes & Waxes*	23		23	23	23	24	24	24	24	24
	Sulfur Recovery* (K s tons/d)	7		7	7	7	7	7	7	7	7
	Steam Generation (K lb/hr)	10,845		10,776	10,743	10,903	11,791	12,454	11,918	11,561	11,333

Exhibit C-1: Refinery Modeling Results -- Refinery Operations and New Capacity
(K b/d, except as noted)

Type of Process	Process	2006 Calibration	Investment Constrained				Investment Unconstrained				
			Study Cases				Reference	Study Cases			
	Wt% Oxygen -->	2.0%	0.0%	2.0%	2.7%	3.5%	2.0%	0.0%	2.0%	2.7%	3.5%
NEW CAPACITY											
Crude Distillation	Atmospheric						60	6	17	20	
Conversion	Fluid Cat Cracker						5	38			
	Hydrocracker						65	3	16	38	97
	Coker										
Upgrading	Alkylation*						23	174	93	31	
	Pen/Hex Isomerization							10			
	Reforming										
Hydrotreating	FCC Naphtha Desulfurization							140	153	157	145
	Benzene Saturation										
	Distillate Desulfurization										
	FCC Feed Desulfurization						52	85	47	47	40
Hydrogen	Hydrogen Plant* (MM scf/d)	108		77	94	121	199	156	179	187	226
Fractionation	Debutanization						13	3	18	11	
	Depentanization			235	137	187					
	Medium Naphtha Spl.							110	117	109	58
	Hvy. Reformate Spl.										
	Heavy FCC/Lt Cycle Oil Splitting			26	6		2	46	43	37	
Other	FCC Gas Processing							588	172	2	
	Lube Oil Production						1	1	1	1	1
OPERATIONS											
Fluid Cat Cracker	Charge Rate	644		644	644	644	700	730	696	696	689
	Conversion (Vol %)	73.1		74.4	73.2	72.9	72.5	75.0	75.0	73.2	65.9
	Olefin Max Cat. (%)				2.9		4.7	77.0	27.0	5.0	
Hydrocracker	Charge Rate: Gas Oils	128		128	128	128	149	130	134	141	158
	All Other	255		255	255	255	295	258	265	279	314
	Naphtha as % of Out-turns (%)	59.7		54.7	58.0	62.4	57.1	55.8	57.6	56.9	55.0
	Kero & Dist. as % of Out-turns (%)	22.0		27.6	24.1	18.9	25.2	26.6	24.5	25.4	27.8
Reformer	Charge Rate	370		340	344	389	389	345	346	356	376
	Severity (RON)	97.4		94.7	94.2	92.8	95.1	98.9	96.9	95.2	94.5
Fuel Use	All Fuels (foeb)	230		225	227	230	246	246	243	242	241

* Capacity defined in terms of volume of output.

Exhibit C-2: Refinery Modeling Results -- Refinery Inputs and Outputs (K b/d)

	2006	Investment Constrained				Investment Unconstrained				
Inputs/	Calibration	Study Cases				Reference	Study Cases			
Outputs	2.0%	0.0%	2.0%	2.7%	3.5%	2.0%	0.0%	2.0%	2.7%	3.5%
Crude Oil	**1,832**		**1,824**	**1,833**	**1,816**	**1,974**	**1,925**	**1,936**	**1,938**	**1,908**
Other Inputs	**138**		**131**	**155**	**182**	**146**	**169**	**169**	**166**	**188**
Isobutane							79	23		
Butane										
Gasoline Blendstocks	12		12	12	12	9	9	9	9	9
Straight Run Naphtha	7		7	7	7	8	8	8	8	8
Kerosene										
Heavy Gas Oil	67		67	67	67	73	73	73	73	73
Resid										
Ethanol	52		46	69	97	56	0	56	76	98
Purchased Energy										
Electricity (K Kwh/d)	18,177		17,876	18,121	18,103	19,793	21,358	20,262	19,513	19,099
Natural Gas (K foeb/d)	231		227	230	229	248	246	244	245	251
Refined Products[1]	**2,006**		**1,919**	**2,012**	**2,030**	**2,159**	**2,120**	**2,139**	**2,150**	**2,162**
Aromatics										
Ethane/Ethylene										
Propane	66		63	63	64	69	73	70	68	64
Propylene										
Butane/Butylene	57		53	52	58	45	3	24	38	54
Aviation Gas	3		3	3	3	3	3	3	3	3
Naphtha to PetroChem	9		9	9	9	10	10	10	10	10
Special Naphthas	1		1	1	1	1	1	1	1	1
Gasoline:	1,120		1,000	1,095	1,170	1,195	1,195	1,195	1,195	1,195
California RFG	930		810	905	980	993	993	993	993	993
Arizona CBG	53		53	53	53	57	57	57	57	57
All Other	137		137	137	137	145	145	145	145	145
Jet Fuel	252		280	296	227	305	305	305	305	305
Diesel Fuel	377		388	371	376	395	395	395	395	395
CARB Diesel	264		275	258	263	270	270	270	270	270
EPA Diesel	75		75	75	75	83	83	83	83	83
Other diesel	38		38	38	38	42	42	42	42	42
Unf. Oil to PetroChem	8		8	8	8	9	9	9	9	9
Residual Oil	50		50	50	50	56	56	56	56	56
Asphalt	41		41	41	41	45	45	45	45	45
Lubes & Waxes	23		23	23	23	25	25	25	25	25
Coke	88		87	89	88	89	77	87	86	78
Sulfur (s tons/d)	6.6		6.6	6.6	6.5	7.1	7.2	7.0	7.0	7.0
Excessed Material	**2.0**		**72.2**	**17.4**	**10.4**	**9.8**				
Butylene				1.0	0.5					
C5s	2.0		36.6	16.3	9.9	9.8				
FCC Naphtha			35.6							
Straight Run Naphtha										

Exhibit C-3: Refinery Modeling Results -- Average Properties of CARBOB, Flat Limit Deltas, and % Change in Emissions

	2006		Investment Constrained				Investment Unconstrained				
	Reported	Calibration	Study Cases				Reference	Study Cases			
Oxygen in Final Blend -->	2.0%	2.0%	0.0%	2.0%	2.7%	3.5%	2.0%	0.0%	2.0%	2.7%	3.5%
CARBOB Properties											
RVP (psi)	5.60	5.58		5.34	5.48	5.47	5.58	6.48	5.43	5.58	5.58
Oxygen (wt%)											
Aromatics (vol%)	24.6	25.9		22.2	22.7	22.9	23.7	21.0	21.9	22.7	22.9
Benzene (vol%)	0.58	0.58		0.66	0.70	0.77	0.65	0.53	0.67	0.75	0.77
Olefins (vol%)	5.9	6.7		7.7	7.4	5.4	6.7	6.7	6.5	7.1	5.4
Sulfur (ppm)	10	10		14	12	7	12	7	8	9	7
T50	215	215		213	216	220	216	208	214	216	220
T90	311	308		310	303	305	304	296	310	310	306
E200 (vol% off)	42.6	42.4		43.4	42.2	40.3	41.9	46.1	43.0	42.1	40.1
E300 (vol% off)	87.2	88.0		87.6	89.2	88.7	88.9	90.9	87.5	87.5	88.4
Flat Limit Deltas for											
RVP (psi)	0.12	0.12		0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Oxygen (wt%)	-	-		-	-	-	-	-	-	-	-
Aromatics (vol%)	1.0	1.0		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Benzene (vol%)	0.11	0.11		0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Olefins (vol%)	2.6	1.2		2.8	1.2	1.2	1.2	3.3	4.0	1.5	1.2
Sulfur (ppm)	2	2		2	2	2	2	2	2	2	2
T50	1	1		1	1	1	1	1	1	1	1
T90	3.0	3.0		4.6	5.7	3.0	3.0	21.0	3.0	3.0	3.0
E200 (vol% off)	-0.50	-0.50		-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50
E300 (vol% off)	-0.74	-0.74		-1.15	-1.41	-0.74	-0.74	-5.20	-0.74	-0.74	-0.74
Compliance Properties											
RVP (psi)	6.94	6.92		6.69	6.83	6.82	6.80	6.60	6.78	6.92	6.92
Oxygen (wt%)	2.0	2.0		2.0	2.7	3.5	2.0	0.0	2.0	2.7	3.5
Aromatics (vol%)	24.3	25.5		22.0	22.0	21.7	22.4	22.0	21.7	22.0	21.7
Benzene (vol%)	0.65	0.65		0.73	0.75	0.80	0.61	0.64	0.74	0.80	0.80
Olefins (vol%)	8.0	7.5		10.0	8.0	6.0	6.3	10.0	10.0	7.7	6.0
Sulfur (ppm)	12	12		16	14	9	12	9	10	11	9
T50	212	212		210	212	216	213	209	211	211	216
T90	312	309		312	306	305	302	317	311	310	306
E200 (vol% off)	44.2	43.9		45.0	44.1	42.3	43.8	45.6	44.5	44.4	42.2
E300 (vol% off)	87.0	87.8		87.1	88.6	88.9	89.4	85.7	87.4	87.6	88.6
Energy Density (MM btu/b)		5.169		5.172	5.134	5.099	5.163	5.205	5.154	5.128	5.091
% Change in Emissions											
Total THC & CO	-0.73	-0.92		-0.55	-0.41	-0.57	-0.68	-0.62	-0.50	-0.41	-0.19
NOx	-0.71	-0.70		-0.60	-0.41	-0.67	-0.65	-4.12	-3.08	-1.64	-0.65
Potency Weighted Toxics	-1.87	-2.12		-0.61	-2.72	-3.26	-1.85	-0.76	-0.39	-0.94	-2.67
Predictive Model	PM-3	PM-3		PM-4	PM-4	PM-4	PM-3	PM-4	PM-4	PM-4	PM-4

Exhibit C-4: Refinery Modeling -- Finished Gasoline Properties

Property, Octane & Volume	2006 Calibration				Investment Constrained Study Cases															
					No Oxygen				2.0 wt% Oxygen				2.7 wt% Oxygen				3.5 wt% Oxygen			
	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool
Property																				
RVP (psi)	6.8	7.0	8.0	7.0					6.6	7.0	8.0	6.8	6.7	7.0	8.0	6.9	6.7	7.0	8.0	6.9
Oxygen (wt%)	2.0			1.7					2.0			1.6	2.7			2.2	3.5			2.9
Aromatics (vol%)	24.5	25.7	30.8	25.3					21.0	25.7	30.8	22.6	21.0	25.7	30.8	22.5	20.7	25.7	30.8	22.1
Benzene (vol%)	0.54	0.71	0.51	0.5					0.62	0.71	0.57	0.6	0.64	0.71	0.34	0.6	0.69	0.71	0.34	0.7
Olefins (vol%)	6.3	11.0	6.8	6.6					7.3	11.0	6.8	7.4	6.8	11.0	6.8	7.0	4.8	11.0	6.8	5.3
Sulfur (ppm)	10	22	23	12					14	22	23	16	12	22	23	14	7	22	23	10
E200 (vol% off)	44.4	42.4	42.4	44.1					45.3	42.4	42.4	44.7	44.6	42.4	42.4	44.2	42.8	42.4	42.4	42.7
E300 (vol% off)	88.5	85.5	80.0	87.4					87.8	93.6	99.6	89.7	90.0	85.7	80.0	88.5	89.6	85.5	80.0	88.3
T50[1]	211	215	215	212					210	215	215	211	211	215	215	212	214	215	215	215
T90[2]	306	318	340	311					309	285	261	301	300	317	340	306	302	318	340	307
En. Den. (MM Btu/bbl)	5.169	5.152	5.223	5.174					5.172	5.155	5.175	5.171	5.134	5.135	5.182	5.140	5.099	5.227	5.177	5.114
Octane ((R+M)/2)	**87.5**	**87.2**	**87.8**	**87.5**					**87.5**	**87.2**	**87.8**	**87.5**	**87.5**	**87.2**	**87.8**	**87.5**	**87.5**	**87.2**	**87.8**	**87.5**
Volume	**930**	**53**	**137**	**1,120**					**810**	**53**	**137**	**1,000**	**905**	**53**	**137**	**1,095**	**980**	**53**	**137**	**1,170**

1 T50 = 300.8347 - 2.0167 * E200
2 T90 = 663.5586 - 4.0395 * E300

Exhibit C-4: Refinery Modeling -- Finished Gasoline Properties

Property, Octane & Volume	Investment Unconstrained																			
	Reference Case				Study Cases															
					No Oxygen				2.0 wt% Oxygen				2.7 wt% Oxygen				3.5 wt% Oxygen			
	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool
Property																				
RVP (psi)	6.8	7.0	8.0	7.0	6.5	7.0	8.0	6.7	6.7	7.0	8.0	6.8	6.8	7.0	8.0	6.9	6.8	7.0	8.0	7.0
Oxygen (wt%)	2.0			1.7	0.0			0.0	2.0			1.7	2.7			2.2	3.5			2.9
Aromatics (vol%)	22.4	25.7	30.8	23.6	21.0	25.7	30.8	22.4	20.7	25.7	30.8	22.2	21.0	25.7	30.8	22.4	20.7	25.7	30.8	22.2
Benzene (vol%)	0.61	0.71	0.60	0.6	0.53	0.71	0.60	0.6	0.63	0.71	0.60	0.6	0.69	0.71	0.60	0.7	0.69	0.71	0.60	0.7
Olefins (vol%)	6.3	11.0	6.8	6.6	6.7	5.0	6.8	6.7	6.0	2.0	6.8	5.9	6.5	2.2	6.8	6.3	4.8	11.0	6.8	5.3
Sulfur (ppm)	12	22	23	14	7	5	21	9	8	3	15	8	9	4	10	9	7	7	23	9
E200 (vol% off)	43.8	42.4	42.4	43.6	46.1	42.4	42.4	45.5	45.0	42.4	42.4	44.6	44.9	42.4	42.4	44.5	42.7	43.8	42.4	42.8
E300 (vol% off)	89.4	85.5	80.0	88.1	90.9	85.5	85.3	89.9	88.1	89.0	98.9	89.5	88.3	85.5	94.0	88.9	89.3	85.5	83.4	88.4
T50[1]	212	215	215	213	208	215	215	209	210	215	215	211	210	215	215	211	215	212	215	215
T90[2]	303	318	340	308	296	318	319	300	308	304	264	302	307	318	284	304	303	318	327	307
En. Den. (MM Btu/bbl)	5.163	5.167	5.207	5.169	5.205	5.139	5.231	5.205	5.154	5.138	5.178	5.156	5.128	5.138	5.178	5.134	5.091	5.159	5.215	5.109
Octane ((R+M)/2)	**87.5**	**87.2**	**87.8**	**87.5**	**87.5**	**87.2**	**87.8**	**87.5**	**87.5**	**87.2**	**87.8**	**87.5**	**87.5**	**87.2**	**87.8**	**87.5**	**87.5**	**87.2**	**87.8**	**87.5**
Volume	**993**	**57**	**145**	**1,195**	**993**	**57**	**145**	**1,195**	**993**	**57**	**145**	**1,195**	**993**	**57**	**145**	**1,195**	**993**	**57**	**145**	**1,195**

1 T50 = 300.8347 - 2.0167 * E200
2 T90 = 663.5586 - 4.0395 * E300

Exhibit C-5: Refinery Modeling Results -- Average Composition of the Gasoline Pool

Gasoline Composition & Volume	2006 Calibration	Investment Constrained				Investment Unconstrained				
		Study Cases				Reference	Study Cases			
	2.0%	0.0%	2.0%	2.7%	3.5%	2.0%	0.0%	2.0%	2.7%	3.5%
Composition (vol%)	**100.0%**		**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**
C4s	0.5%		0.5%	0.5%	0.6%	0.7%	2.4%	0.5%	0.5%	0.7%
C5s & Isomerate	10.2%		11.2%	11.2%	9.7%	8.9%	8.5%	8.8%	9.3%	6.4%
Raffinate										
Natural Gas Liquids	0.2%		0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Naphtha (Str Run & Coker)	6.4%		3.7%	4.2%	4.7%	3.6%	2.5%	5.5%	5.2%	6.1%
Polymerate	0.5%		0.7%	0.6%	0.4%	0.1%	0.6%			0.3%
Alkylate	14.3%		16.0%	14.6%	14.3%	16.3%	26.8%	21.2%	16.8%	15.2%
Iso-Octane/Octene	0.1%		0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Hydrocrackate	6.7%		8.3%	7.5%	8.1%	8.7%	7.6%	7.5%	7.9%	9.0%
FCC Naphtha	28.8%		25.8%	27.7%	24.6%	28.9%	27.6%	27.2%	28.4%	26.8%
Reformate	27.6%		29.0%	27.0%	29.0%	27.8%	23.7%	24.3%	25.4%	27.0%
Ethanol	4.7%		4.6%	6.3%	8.3%	4.7%	0.0%	4.7%	6.3%	8.2%
Volume (K B/d)	**1,120**		**1,000**	**1,095**	**1,170**	**1,195**	**1,195**	**1,195**	**1,195**	**1,195**

Exhibit C-6: Refinery Modeling Results -- Estimated Refining Investment & Cost

	Investment Unconstrained Study Cases			
Measures	**0.0%**	**2.0%**	**2.7%**	**3.5%**
Refining Investment ($MM)	2,125	901	458	559
Refining Cost				
$K/d	3,133	1,616	624	359
¢/g	7.5	3.9	1.5	0.9
Cost of Mileage Loss				
$K/d	-499	115	436	879
¢/g	-1.2	0.3	1.0	2.1
Refining Cost + Mileage Loss				
$K/d	2,634	1,731	1,060	1,238
¢/g	6.3	4.2	2.5	3.0
Refining Cost Adjustment at Alternative Ethanol Prices				
$K/d				
$53/b	-3	-559	-757	-982
$63/b	-	-	-	-
$73/b	3	559	757	982
¢/g				
$53/b	-	-1.3	-1.8	-2.4
$63/b	-	-	-	-
$73/b	-	1.3	1.8	2.4

Exhibit D-1: Refinery Modeling Results -- Refinery Operations and New Capacity
All California RFG in Study Cases
(K b/d, except as noted)

Type of Process	Process	2006 Calibration	Investment Constrained Study Cases				Investment Unconstrained Reference	Investment Unconstrained Study Cases			
	Wt% Oxygen -->	2.0%	0.0%	2.0%	2.7%	3.5%	2.0%	0.0%	2.0%	2.7%	3.5%
USE OF IN-PLACE CAPACITY											
Crude Distillation	Atmospheric	1,832		1,734	1,833	1,798	1,920	1,911	1,901	1,916	1,886
Conversion	Fluid Cat Cracker	644		644	644	644	696	696	696	696	678
	Hydrocracking	383		383	383	383	385	385	385	385	385
	Coking	447		367	447	447	456	412	433	439	406
Upgrading	Alkylation*	165		165	165	165	175	175	175	175	175
	Iso-octene/octane	1		1	1	1	1	1	1	1	1
	Catalytic Polymerization*	1		2	2						
	Dimersol*	5		5	5	5	2	5			
	Pen/Hex Isomerization	82		82	82	82	82	82	82	82	75
	Reforming	360		271	321	403	370	325	290	294	312
Hydrotreating	Naphtha Desulf.	311		275	301	297	323	328	314	322	308
	FCC Naphtha Desulfurization	66		48	48	65	55	47	56	62	63
	Benzene Saturation	26		18	18	26	15	9			
	Distillate Desulfurization	340		367	340	378	361	356	352	358	349
	Distillate Dearomatization	194		185	194	192	163	185	192	202	179
	FCC Feed Desulfurization	638		638	638	627	647	647	647	647	647
Hydrogen	Hydrogen* (MM scf/d)	1,289		1,289	1,289	1,289	1,289	1,289	1,289	1,289	1,289
Fractionation	Debutanization	200		186	201	202	202	202	202	202	198
	Depentanization	174		200	200	200	200		39	46	143
	Lt. Naphtha Spl. (Benz. Prec.)	190		148	151	153	159	161	140	147	121
	Med. Naphtha Spl.	18		18	18		18	18	18	18	18
	Hvy. Reformate Spl.	12					12	5			
	FCC Naphtha Splitting	346		314	334	309	346	345	346	346	340
	Heavy FCC/Lt Cycle Oil Splitting	64		70	70	70	70	70	70	70	70
Other	Benzene Saturation	26		18	18	26	15	9			
	Butane Isomerization	4		15	6	1	17	39	39	39	28
	Lubes & Waxes*	23		23	23	23	24	24	24	24	24
	Sulfur Recovery* (K s tons/d)	7		6	7	7	7	7	7	7	7
	Steam Generation (K lb/hr)	10,845		10,359	10,735	11,098	11,791	12,619	11,992	11,575	11,270

Exhibit D-1: Refinery Modeling Results -- Refinery Operations and New Capacity
All California RFG in Study Cases
(K b/d, except as noted)

Type of Process	Process	2006 Calibration	Investment Constrained Study Cases				Investment Unconstrained Reference	Investment Unconstrained Study Cases			
	Wt% Oxygen -->	2.0%	0.0%	2.0%	2.7%	3.5%	2.0%	0.0%	2.0%	2.7%	3.5%
NEW CAPACITY											
Crude Distillation	Atmospheric						60				
Conversion	Fluid Cat Cracker						5	29			
	Hydrocracker						65	3	3	3	84
	Coker										
Upgrading	Alkylation*						23	222	163	83	28
	Pen/Hex Isomerization							34			
	Reforming										
Hydrotreating	FCC Naphtha Desulfurization							149	143	152	141
	Benzene Saturation					7					
	Distillate Desulfurization										
	FCC Feed Desulfurization						52	66	41	47	27
Hydrogen	Hydrogen Plant* (MM scf/d)	108		47	109	157	199	122	153	208	240
Fractionation	Debutanization					9	13	8	19	14	
	Depentanization			215	99	186					
	Medium Naphtha Spl.			21	61			98	97	118	75
	Hvy. Reformate Spl.										
	Heavy FCC/Lt Cycle Oil Splitting			22	24	19	2	20	28	65	5
Other	FCC Gas Processing			51	55	127		756	472	173	21
	Lube Oil Production						1	1	1	1	1
OPERATIONS											
Fluid Cat Cracker	Charge Rate	644		644	644	633	700	714	690	696	678
	Conversion (Vol %)	73.1		72.0	74.8	73.9	72.5	76.1	75.8	75.0	66.5
	Olefin Max Cat. (%)			12.2	12.8	23.3	4.7	100.0	66.3	27.2	7.6
Hydrocracker	Charge Rate: Gas Oils	128		128	128	128	149	130	130	130	154
	All Other	255		255	255	255	295	258	258	258	307
	Naphtha as % of Out-turns (%)	59.7		47.1	58.2	62.4	57.1	52.7	52.9	57.0	55.1
	Kero & Dist. as % of Out-turns (%)	22.0		36.2	23.8	18.9	25.2	29.9	29.8	25.2	27.6
Reformer	Charge Rate	370		285	346	445	389	332	304	309	327
	Severity (RON)	97.4		95.0	92.7	90.6	95.1	98.1	95.5	95.4	95.4
Fuel Use	All Fuels (foeb)	230		214	226	230	246	243	237	239	238

* Capacity defined in terms of volume of output.

Exhibit D-2: Refinery Modeling Results -- Refinery Inputs and Outputs All California RFG in Study Cases (K b/d)

Inputs/ Outputs	2006 Calibration 2.0%	Investment Constrained Study Cases 0.0%	Investment Constrained Study Cases 2.0%	Investment Constrained Study Cases 2.7%	Investment Constrained Study Cases 3.5%	Investment Unconstrained Reference 2.0%	Investment Unconstrained Study Cases 0.0%	Investment Unconstrained Study Cases 2.0%	Investment Unconstrained Study Cases 2.7%	Investment Unconstrained Study Cases 3.5%
Crude Oil	**1,832**		**1,734**	**1,833**	**1,798**	**1,974**	**1,911**	**1,901**	**1,916**	**1,886**
Other Inputs	**138**		**137**	**166**	**200**	**146**	**202**	**231**	**202**	**208**
Isobutane							111	74	21	
Butane										
Gasoline Blendstocks	12		14	14	14	9	9	9	9	9
Straight Run Naphtha	7		7	7	7	8	8	8	8	8
Kerosene										
Heavy Gas Oil	67		67	67	67	73	73	73	73	73
Resid										
Ethanol	52		50	78	112	56	0	67	91	118
Purchased Energy										
Electricity (K Kwh/d)	18,177		16,868	17,980	18,526	19,793	21,852	20,703	19,825	19,294
Natural Gas (K foeb/d)	231		221	230	236	248	241	239	243	249
Refined Products[1]	**2,006**		**1,770**	**1,921**	**1,938**	**2,159**	**2,124**	**2,135**	**2,134**	**2,139**
Aromatics										
Ethane/Ethylene										
Propane	66		58	62	65	69	72	68	68	63
Propylene										
Butane/Butylene	57		40	53	61	45	7	23	22	32
Aviation Gas	3		3	3	3	3	3	3	3	3
Naphtha to PetroChem	9		9	9	9	10	10	10	10	10
Special Naphthas	1		1	1	1	1	1	1	1	1
Gasoline:	1,120		880	1,020	1,130	1,195	1,195	1,195	1,195	1,195
California RFG	930		880	1,020	1,130	993	1,195	1,195	1,195	1,195
Arizona CBG RFG	53					57				
All Other	137					145				
Jet Fuel	252		280	274	200	305	305	305	305	305
Distillate Fuel	377		377	376	346	395	395	395	395	395
CARB Diesel	264		264	263	233	270	270	270	270	270
EPA Diesel	75		75	75	75	83	83	83	83	83
Other diesel	38		38	38	38	42	42	42	42	42
Unf. Oil to PetroChem	8		8	8	8	9	9	9	9	9
Residual Oil	50		50	50	50	56	56	56	56	56
Asphalt	41		41	41	41	45	45	45	45	45
Lubes & Waxes	23		23	23	23	25	25	25	25	25
Coke	88		72	88	90	89	79	84	85	78
Sulfur (s tons/d)	6.6		6.4	6.6	6.5	7.1	7.1	6.9	7.0	6.9
Excessed Material	**2.0**		**136.5**	**121.7**	**78.1**	**9.8**		**18.4**	**21.8**	**15.6**
Butylene			6.1	13.5	24.3					
C5s	2.0		55.8	46.4	53.8	9.8		18.4	21.8	15.6
Light Hydrocrackate			13.5	9.6						
FCC Naphtha			61.1	52.3						
Straight Run Naphtha										

Exhibit D-3: Refinery Modeling Results -- Average Properties of CARBOB, Flat Limit Deltas, and % Change in Emissions All California RFG in Study Cases

	2006		Investment Constrained				Investment Unconstrained				
	Reported	Calibration	Study Cases				Reference	Study Cases			
Oxygen in Final Blend -->	**2.0%**	**2.0%**	**0.0%**	**2.0%**	**2.7%**	**3.5%**	**2.0%**	**0.0%**	**2.0%**	**2.7%**	**3.5%**
CARBOB Properties											
RVP (psi)	5.60	5.58		5.27	5.48	6.48	5.58	6.49	5.52	5.58	5.58
Oxygen (wt%)											
Aromatics (vol%)	24.6	25.9		22.2	22.7	23.2	23.7	21.0	20.7	21.9	22.4
Benzene (vol%)	0.58	0.58		0.68	0.70	0.68	0.65	0.53	0.67	0.72	0.72
Olefins (vol%)	5.9	6.7		7.3	7.2	6.1	6.7	6.1	6.4	6.9	5.4
Sulfur (ppm)	10	10		13	12	7	12	7	8	8	7
T50	215	215		214	216	219	216	208	214	216	220
T90	311	308		300	303	304	304	298	303	305	308
E200 (vol% off)	42.6	42.4		43.0	42.2	40.6	41.9	45.9	43.0	42	40
E300 (vol% off)	87.2	88.0		90.1	89.3	89.1	88.9	90.4	89.3	88.7	88.1
Flat Limit Deltas for											
RVP (psi)	0.12	0.12		0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Oxygen (wt%)	-	-		-	-	-	-	-	-	-	-
Aromatics (vol%)	1.0	1.0		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Benzene (vol%)	0.11	0.11		0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Olefins (vol%)	2.6	1.2		3.2	1.4	1.2	1.2	3.9	4.1	1.7	1.2
Sulfur (ppm)	2	2		2	2	2	2	2	2	2	2
T50	1	1		1	1	1	1	1	1	1	1
T90	3.0	3.0		10.8	5.9	3.0	3.0	19.3	11.3	3.4	3.0
E200 (vol% off)	-0.50	-0.50		-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50
E300 (vol% off)	-0.74	-0.74		-2.68	-1.45	-0.74	-0.74	-4.77	-2.81	-0.83	-0.74
Compliance Properties											
RVP (psi)	6.94	6.92		6.63	6.83	6.83	6.80	6.61	6.87	6.92	6.92
Oxygen (wt%)	2.0	2.0		2.0	2.7	3.5	2.0	0.0	2.0	2.7	3.5
Aromatics (vol%)	24.3	25.5		22.0	22.0	22.0	22.4	22.0	20.6	21.3	21.3
Benzene (vol%)	0.65	0.65		0.75	0.75	0.63	0.61	0.64	0.74	0.77	0.75
Olefins (vol%)	8.0	7.5		10.0	8.0	5.7	6.3	10.0	10.0	8	6.0
Sulfur (ppm)	12	12		16	14	9	12	9	10	10	9
T50	212	212		211	212	215	213	209	211	212	216
T90	312	309		308	306	303	302	318	312	306	307
E200 (vol% off)	44.2	43.9		44.4	44.1	42.6	43.8	45.4	44.6	43.9	42
E300 (vol% off)	87.0	87.8		87.9	88.6	89.3	89.4	85.6	87.1	88.6	88.4
Energy Density (MM btu/b)		5.169		5.162	5.129	5.098	5.163	5.200	5.136	5.114	5.079
% Change in Emissions											
Total THC & CO	-0.73	-0.92		-0.69	-0.41	-0.62	-0.68	-0.56	-0.45	-0.5	-0.19
NOx	-0.71	-0.70		-1.02	-0.41	-0.60	-0.65	-4.11	-3.29	-2.17	-0.65
Potency Weighted Toxics	-1.87	-2.12		-0.74	-2.72	-8.17	-1.85	-0.52	-0.63	-2.52	-2.67
Predictive Model	PM-3	PM-3		PM-4	PM-4	PM-4	PM-3	PM-4	PM-4	PM-4	PM-4

Exhibit D-4: Refinery Modeling -- Finished Gasoline Properties
All California RFG in Study Cases

Property, Octane & Volume	2006 Calibration				Investment Constrained Study Cases															
					No Oxygen				2.0 wt% Oxygen				2.7 wt% Oxygen				3.5 wt% Oxygen			
	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool
Property																				
RVP (psi)	6.8	7.0	8.0	7.0					6.5			6.5	6.7			6.7	6.7			6.7
Oxygen (wt%)	2.0			1.7					2.0			2.0	2.7			2.7	3.5			3.5
Aromatics (vol%)	24.5	25.7	30.8	25.3					21.0			21.0	21.0			21.0	21.0			21.0
Benzene (vol%)	0.54	0.71	0.51	0.55					0.64			0.64	0.64			0.64	0.52			0.52
Olefins (vol%)	6.3	11.0	6.8	6.6					6.8			6.8	6.6			6.6	4.5			4.5
Sulfur (ppm)	10	22	23	12					13			13	12			12	7			7
E200 (vol% off)	44.4	42.4	42.4	44.1					44.9			44.9	44.6			44.6	43.1			43.1
E300 (vol% off)	88.5	85.5	80.0	87.4					90.6			90.6	90.0			90.0	90.0			90.0
T50[1]	211	215	215	212					210			210	211			211	214			214
T90[2]	306	318	340	311					298			298	300			300	300			300
En. Den. (MM Btu/bbl)	5.169	5.152	5.223	5.174					5.162			5.162	5.129			5.129	5.098			5.098
Octane ((R+M)/2)	**87.5**	**87.2**	**87.8**	**87.5**					**87.5**			**87.5**	**87.5**			**87.5**	**87.5**			**87.5**
Volume	**930**	**53**	**137**	**1,120**					**880**			**880**	**1,020**			**1,020**	**1,130**			**1,130**

1 T50 = 300.8347 - 2.0167 * E200
2 T90 = 663.5586 - 4.0395 * E300

Exhibit D-4: Refinery Modeling -- Finished Gasoline Properties All California RFG in Study Cases

Property, Octane & Volume	Investment Unconstrained																			
	Reference Case				Study Cases															
					No Oxygen				2.0 wt% Oxygen				2.7 wt% Oxygen				3.5 wt% Oxygen			
	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool	CA RFG	AZ CBG	All Other	Pool
Property																				
RVP (psi)	6.8	7.0	8.0	7.0	6.5			6.5	6.8			6.8	6.8			6.8	6.8			6.8
Oxygen (wt%)	2.0			1.7	0.0			0.0	2.0			2.0	2.7			2.7	3.5			3.5
Aromatics (vol%)	22.4	25.7	30.8	23.6	21.0			21.0	19.6			19.6	20.3			20.3	20.3			20.3
Benzene (vol%)	0.61	0.71	0.60	0.61	0.53			0.53	0.63			0.63	0.66			0.66	0.64			0.64
Olefins (vol%)	6.3	11.0	6.8	6.6	6.1			6.1	5.9			5.9	6.3			6.3	4.8			4.8
Sulfur (ppm)	12	22	23	14	7			7	8			8	8			8	7			7
E200 (vol% off)	43.8	42.4	42.4	43.6	45.9			45.9	45.1			45.1	44.4			44.4	42.5			42.5
E300 (vol% off)	89.4	85.5	80.0	88.1	90.4			90.4	89.9			89.9	89.4			89.4	89.1			89.1
T50[1]	212	215	215	213	208			208	210			210	211			211	215			215
T90[2]	303	318	340	308	298			298	300			300	302			302	304			304
En. Den. (MM Btu/bbl)	5.163	5.167	5.207	5.169	5.200			5.200	5.136			5.136	5.114			5.114	5.079			5.079
Octane ((R+M)/2)	**87.5**	**87.2**	**87.8**	**87.5**	**87.5**			**87.5**	**87.5**			**87.5**	**87.5**			**87.5**	**87.5**			**87.5**
Volume	**993**	**57**	**145**	**1,195**	**1,195**			**1,195**	**1,195**			**1,195**	**1,195**			**1,195**	**1,195**			**1,195**

1 T50 = 300.8347 - 2.0167 * E200
2 T90 = 663.5586 - 4.0395 * E300

Exhibit D-5: Refinery Modeling Results -- Average Composition of the Gasoline Pool All California RFG in Study Cases

Gasoline Composition & Volume	2006 Calibration	Investment Constrained Study Cases				Investment Unconstrained Reference	Investment Unconstrained Study Cases			
	2.0%	0.0%	2.0%	2.7%	3.5%	2.0%	0.0%	2.0%	2.7%	3.5%
Composition (vol%)	**100.0%**		**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**
C4s	0.5%		0.5%	0.5%	0.5%	0.7%	2.0%	0.5%	0.5%	0.5%
C5s & Isomerate Raffinate	10.2%		10.2%	8.8%	7.9%	8.9%	9.2%	6.7%	6.7%	6.1%
Natural Gas Liquids	0.2%		0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Naphtha (Str Run & Coker)	6.4%		6.2%	5.8%	2.6%	3.6%	1.8%	5.1%	5.2%	5.0%
Polymerate	0.5%		0.8%	0.7%	0.4%	0.1%	0.4%			
Alkylate	14.3%		18.1%	15.6%	13.9%	16.3%	30.2%	26.1%	20.5%	16.8%
Iso-Octane/Octene	0.1%		0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Hydrocrackate	6.7%		6.0%	6.9%	9.2%	8.7%	7.4%	7.7%	8.8%	12.1%
FCC Naphtha	28.8%		24.9%	24.2%	20.3%	28.9%	26.1%	26.6%	28.6%	26.1%
Reformate	27.6%		27.4%	29.6%	35.0%	27.8%	22.7%	21.4%	21.8%	23.2%
Ethanol	4.7%		5.6%	7.6%	9.9%	4.7%	0.0%	5.6%	7.6%	9.9%
Volume (K B/d)	**1,120**		**880**	**1,020**	**1,130**	**1,195**	**1,195**	**1,195**	**1,195**	**1,195**

Exhibit D-6: Refinery Modeling Results --
Estimated Refining Investment & Cost
All California RFG in Study Cases

Measures	**Investment Unconstrained Study Cases 0.0%**	**2.0%**	**2.7%**	**3.5%**
Refining Investment ($MM)	2,707	1,481	797	664
Refining Cost				
$K/d	4,521	3,733	2,259	1,393
¢/g	9.0	7.4	4.5	2.8
Cost of Mileage Loss				
$K/d	-442	327	601	1,027
¢/g	-0.9	0.7	1.2	2.0
Refining Cost + Mileage Loss				
$K/d	4,080	4,060	2,860	2,420
¢/g	8.1	8.1	5.7	4.8
Refining Cost Adjustment at Alternative Ethanol Prices				
$K/d				
$53/b	-3	-673	-911	-1,182
$63/b	-	-	-	-
$73/b	3	673	911	1,182
¢/g				
$53/b	-	-1.3	-1.8	-2.4
$63/b	-	-	-	-
$73/b	-	1.3	1.8	2.4