POTENTIAL ECONOMIC BENEFITS OF THE FEINSTEIN-BILBRAY BILL

An analysis performed for

Chevron Products Company and Tosco Corporation

by

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MathPro Inc. has conducted an analysis to assess the potential economic benefits of the Feinstein-Bilbray bill, which would increase refiners' flexibility in marketing gasoline in the federal RFG areas in California. More specifically, this study assesses whether, and to what extent, California refineries could reduce their costs of complying with an MTBE ban by producing two types of CARB gasoline – one blended with ethanol and the other containing no oxygenate.

This work is an extension of the refining analysis that MathPro recently conducted for the California Energy Commission (CEC) to assess the cost of a ban on MTBE in CARB gasoline [Ref. 1 & 2]. Because of time and budget constraints and the large number of options considered, that study examined only cases in which *all* CARB gasoline was either blended with ethanol (or other oxygenates) or contained no oxygenate.

1. Methodology

We used the same refinery LP model, data, and assumptions for this analysis as in the CEC study, with two exceptions. We split the CARB gasoline pool into two separate pools, one blended with ethanol and the other containing no oxygenates; and we consolidated the Arizona and conventional gasoline pools (with specified properties equal to the weighted average of properties of the Arizona and conventional gasoline pools estimated in corresponding cases in the CEC study).[1]

We estimated the refining cost savings associated with progressively larger shares of the CARB gasoline pool being non-oxygenated, in both the intermediate term and long term (as defined in the CEC study) and under both the averaging and flat limit modes of the Predictive Model.

> *Refining cost savings* are the reductions in costs incurred by refiners to comply with an MTBE ban, i.e.,
>
> Refining cost savings = (Refining costs *without* Feinstein-Bilbray) –
> (Refining costs *with* Feinstein-Bilbray)

We estimated refining cost savings under alternative assumptions regarding the delivered price of ethanol, to wit, that ethanol's delivered price was the same as, 10¢/gal higher, and 20¢/gal higher than assumed in the CEC study.[2]

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[1] In the CEC study, we modeled the three gasoline pools produced in California refineries: CARB gasoline, Arizona gasoline, and conventional gasoline. In this study, we split CARB gasoline into two separate pools – ethanol blended and oxygenate free. Because of time and cost considerations, we consolidated the Arizona and conventional gasoline into a third pool, rather than adding a fourth pool to our refinery model to handle Arizona and conventional gasoline separately.

[2] Some observers have raised concerns that the prices at which ethanol will be available to California, in the event of an MTBE ban, could be substantially higher than indicated by the ethanol supply curves used in the CEC study. The CEC study's intermediate term ethanol supply curve was developed using a "competitive pricing model," in

2. Results

The primary results of our analysis are shown in **Exhibits 1-4**.

- **Exhibit 1** shows estimated per gallon refining cost savings as a function of: time period, Predictive Model mode, ethanol price assumption, and the non-oxygenated share of the CARB gasoline pool. The bolded numbers designate cases for which more detailed results are reported in Exhibit 4 and in Appendix A.

- **Exhibit 2** graphs the results for the four cases in which we assumed the price of ethanol was the same as in the CEC study.

- **Exhibits 3A and 3B** show, for the averaging and flat limit modes respectively, results for cases in which the price of ethanol was assumed to be the same as (designated as 0¢/gal) and 20¢/gal higher than in the CEC study. (The 10¢/gal results lie between the two curves shown.)

- **Exhibit 4** shows results for four selected cases from this analysis and for corresponding cases in the CEC study. The first four cost categories shown in Exhibit 4 -- variable cost, refinery capital charge, ancillary refining cost, and logistics cost -- are costs that would be incurred by the refining sector to comply with an MTBE ban. The cost of mileage loss (due to changes in fuel economy related primarily to oxygenate blending) would be incurred by California motorists, but not the refining sector, which is why such costs are not incorporated in estimates of refining cost savings shown in Exhibit 1.

The analytical results from this study are consistent with those from the CEC study. In brief, they indicate that:

- Refineries could reduce the cost of complying with an MTBE ban by producing two types of CARB compliant gasolines – one blended with ethanol and the other oxygenate free – in both the Federal RFG areas and the rest of the state.

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which California refiners would pay prices just high enough to bid ethanol away from current ethanol users (primarily in the Midwest) [Ref. 3]. In addition, ethanol suppliers were assumed to face strong competition from alternative oxygenates (e.g., TBA and TAME), which would tend to limit their pricing discretion. However, ethanol production is concentrated in relatively few companies and, as events have unfolded in California, it has become clear that other oxygenates are non-starters because they have the same drawbacks as MTBE. This suggests that prices in the intermediate term could well be higher than estimated in the CEC study. The CEC study's long term supply curve assumed that a large volume of new ethanol production capacity could be added relatively quickly and would be fully on line by 2005 [Ref. 3]. In view of the risks associated with regulation-driven investments and the volume of additional ethanol production capacity needed to satisfy California's demands, ethanol prices could be higher during some portion of the "long term" than assumed in the CEC study. Because of these concerns, we assessed the sensitivity of our analytical results to changes in assumptions regarding ethanol prices.

- Estimated refining cost savings (in ¢/gal) from producing a "split" CARB gasoline pool vary depending on the Predictive Model mode, time period, and ethanol price assumption and are as follows:

	Averaging Mode	Flat Mode
Intermediate Term	2.0 – 2.6	2.6 – 3.2
Long Term	0.2 – 0.6	0.3 – 0.9

  These savings would apply to the entire CARB gasoline pool (ethanol-blended and oxygenate free).

- The "optimal" (cost-minimizing) share of non-oxygenated CARB gasoline ranges from about 20 to 40 percent, depending on the time period and Predictive Model mode.

- Increases in the assumed price of ethanol increase the cost savings to refineries of producing two CARB gasoline pools and tend to increase the "optimal" share of non-oxygenated CARB gasoline.

- There are strong incentives to blend ethanol at 2.7 wt% oxygen (or, in some situations, at 3.5 wt% oxygen) in ethanol-blended CARB gasoline.

3. Discussion

The cost savings estimated in this analysis would be realized by individual refineries, each producing two types of CARB gasoline (as opposed to a group of refineries specializing in ethanol-blended CARB gasoline and another group specializing in non-oxygenated CARB gasoline). Cost savings result from the interaction of refining techno-economics and the blending flexibility allowed by the Predictive Model. Producing two CARB gasoline pools would allow individual refineries to shift gasoline blendstocks (and properties) between the CARB gasoline pools to reduce refining costs while meeting CARB emission standards.

An individual refinery's ability to take advantage of this potential opportunity would depend on its process capabilities, blending flexibility, and mix of CARB and other gasoline production, and may be more or less than estimated in this analysis.

By allowing refiners to produce non-oxygenated CARB gasoline, the Feinstein-Bilbray bill likely would: (1) reduce the cost of producing CARB gasoline; (2) reduce California's draw on limited supplies of mid-western ethanol; and (3) moderate possible increases in the price of ethanol or shortfalls in the supply of ethanol.

4. References

1. *Evaluating the Cost and Supply of Alternatives to MTBE in California's Reformulated Gasoline*, Task 2: Calibration of the Refinery Model, MathPro Inc., prepared for the California Energy Commission, June 24, 1998.

2. *Evaluating the Cost and Supply of Alternatives to MTBE in California's Reformulated Gasoline*, Task 3: Supply Scenario Modeling Runs, MathPro Inc., prepared for the California Energy Commission, December 9, 1998.

3. *Evaluating the Cost and Supply of Alternatives to MTBE in California's Reformulated Gasoline*, Task 2: Report on the Oxygenate Market: Current Production Capacity, Future Supply Prospects, and Cost Estimates, Energy Security Analysis, Inc., prepared for the California Energy Commission, October 5, 1998.

Exhibit 1: Estimated Savings in the Refining Costs of an MTBE Ban from Producing Alternative Levels of non-Oxygenated CARB Gasoline,
by Term, Predictive Model Mode, and Ethanol Price Assumptions

	Non-Oxygenated CARB Gasoline		Reduction in Refining Cost of MTBE Ban (¢/gal)					
			Averaging Mode			Flat Mode		
	Volume (K bbl/d)	% of CARB Pool	0¢/gal	10¢/gal	20¢/gal	0¢/gal	10¢/gal	20¢/gal
Intermediate Term	0	0.0	-	-	-	-	-	-
	50	5.2	0.2	0.3	0.3	0.3	0.4	0.4
	200	20.7	1.5	1.6	1.8	2.0	2.2	2.3
	300	31.1	1.7	1.9	2.1	2.2	2.5	2.7
	350	36.3	2.0	2.3	2.6	2.5	2.8	3.1
	375	38.9	2.0	2.3	2.6	2.6	2.9	3.2
	400	41.5	1.7	2.0	2.4	2.6	2.9	3.2
	450	46.6	1.5	1.8	2.2	2.5	2.9	3.2
	500	51.8	0.3	0.7	1.1	2.4	2.8	3.2
Long Term	0	0.0	-	-	-	-	-	-
	50	4.9	0.0	0.0	0.0	0.1	0.1	0.1
	200	19.6	0.2	0.3	0.4	0.3	0.4	0.5
	300	29.4	0.1	0.3	0.5	0.3	0.5	0.7
	400	39.1	0.0	0.3	0.6	0.3	0.6	0.8
	500	48.9	-0.3	0.1	0.4	0.2	0.6	0.9
	600	58.7	-0.5	-0.1	0.4	0.1	0.5	0.9

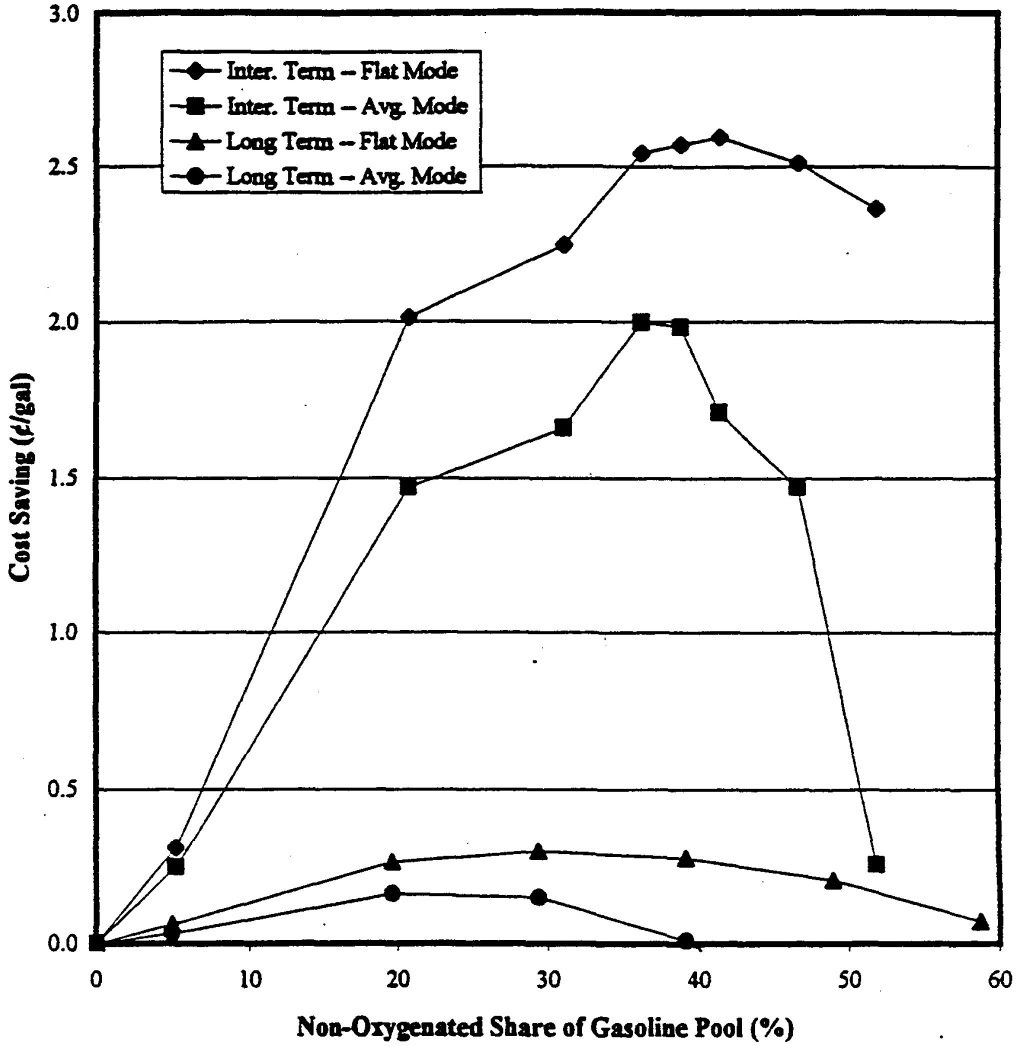
Notes:

(1) Refining costs correspond to the sum of variable costs and capital charges in Exhibit 4.

(2) The oxygen content of the ethanol-blended portion of the CARB gasoline pool is 2.7 wt%.

(3) The cent per gallon headings indicate differences between ethanol prices in the CEC study and those assumed here, e.g., the 10¢/gal heading indicates that the supply curve for ethanol is higher by 10¢/gallon across all ethanol volumes.

Exhibit 2: Estimated Refinery Cost Savings vs. Non-Oxygenated Share of Gasoline Pool



Note: Ethanol priced as in CEC study.

Exhibit 3A: Estimated Refinery Cost Savings vs. Non-Oxygenated Share of Gasoline Pool, by Ethanol Price Assumption – Averaging Mode

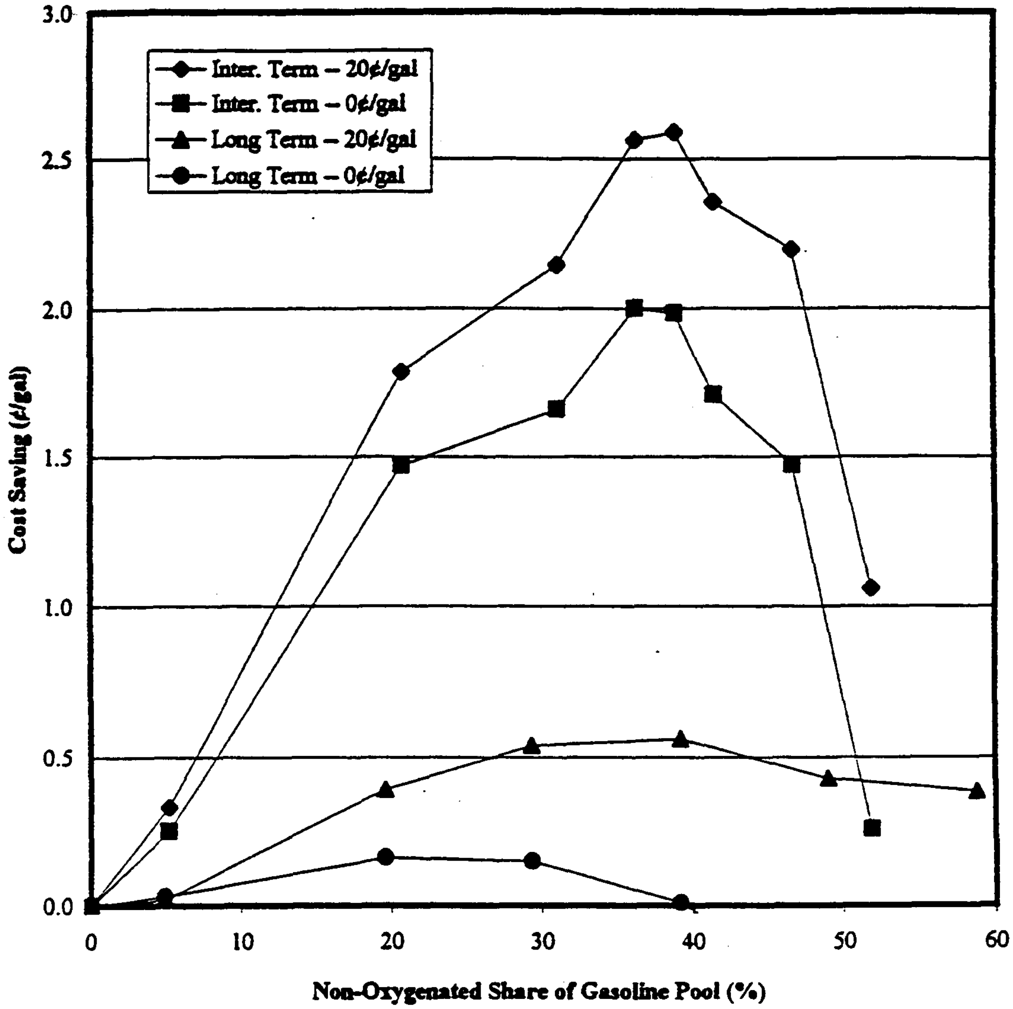


Exhibit 3B: Estimated Refinery Cost Savings vs. Non-Oxygenated Share of Gasoline Pool, by Ethanol Price Assumption – Flat Limit Mode

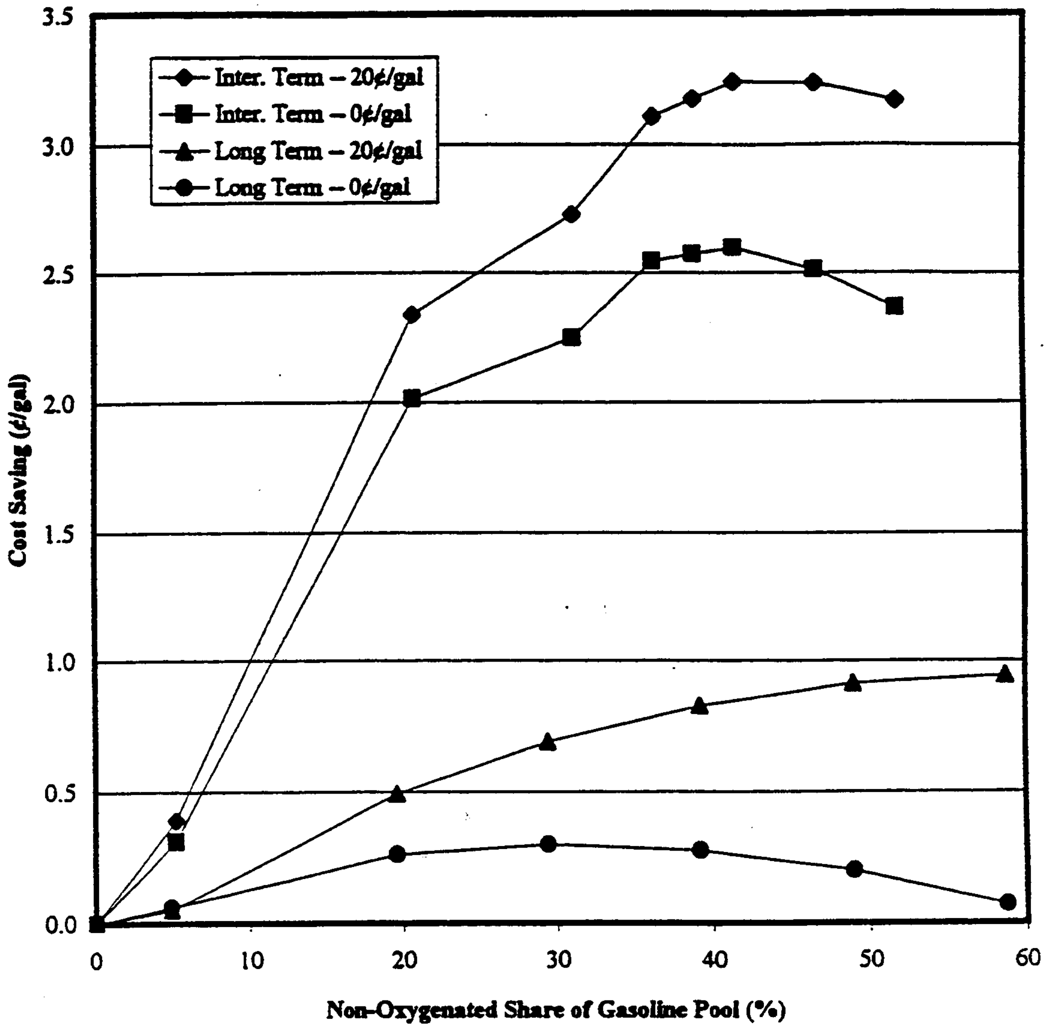


Exhibit 4: Summary of Effects of California MTBE Ban, by Case

	Intermediate Term								Long Term							
	Averaging Mode				Flat Limit Mode				Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
Measure	Ref 2002	HR630	BestU Alk-100	Split 2.7wt%	Ref 2002	HR 630	BestU Alk-100	Split 2.7wt%	Ref 2005	HR630	BestU Alk-100	Split 2.7wt%	Ref 2005	HR 630	BestU Alk-100	Split 2.7wt%
COSTS																
Total Average Cost (¢/gal.)	-	**8.8**	**7.5**	**4.8**	-	**4.3**	**6.1**	**2.7**	-	**3.7**	**2.4**	**1.9**	-	**0.9**	**1.9**	**1.2**
Variable Cost		8.0	5.6	3.6		4.3	4.3	1.9		1.8	1.3	1.0		1.1	0.9	0.7
Refinery Capital Charge		0.0	0.0	0.0		0.0	0.2	0.0		2.2	0.2	0.2		0.8	0.1	0.1
Ancillary Refining Cost		1.3	0.9	0.9		0.7	0.8	0.8		0.7	0.3	0.3		0.4	0.3	0.3
Logistics Cost			0.1	0.1			0.1	0.0			0.1	0.1			0.1	0.1
Mileage Loss		-0.5	0.9	0.1		-0.8	0.7	0.0		-0.9	0.6	0.2		-1.3	0.6	0.2
Total Seasonal Cost ($ million)	-	**660**	**560**	**350**	-	**320**	**450**	**200**	-	**290**	**190**	**140**	-	**70**	**150**	**90**
Variable Cost		600	410	270		320	320	140		140	100	80		80	70	50
Refinery Capital Charge		0	0	0		0	10	0		170	10	20		60	10	10
Ancillary Refining Cost		100	70	70		60	60	60		50	20	20		30	20	20
Logistics Cost			6	4			6	4			6	5			6	4
Mileage Loss		-40	70	10		-60	50	0		-70	50	20		-100	40	10
Refinery Investment ($million)	-	**3**	**23**	**19**	-	**4**	**75**	**10**	-	**1,104**	**86**	**123**	-	**394**	**38**	**36**
IMPORTS/EXPORTS (K bbl/d)																
Oxygenates	**108**	**6**	**78**	**56**	**108**	**12**	**79**	**57**	**115**	**14**	**88**	**76**	**115**	**19**	**84**	**68**
MTBE	108	6	3	9	108	12	4	14	115	14	9	12	115	19	5	12
Ethanol			75	48			75	44			79	64			79	56
TBA																
ETBE																
TAME																
Other Imports	**11**	**430**	**249**	**238**	**11**	**302**	**174**	**144**	**11**	**186**	**120**	**120**	**11**	**143**	**102**	**112**
Isobutane		11	13	10		7	11	7		34	8	9		12	4	5
Alkylate	11	111	111	111	11	111	111	111	11	111	111	111	11	111	98	107
CARBOB		255	65	65		140				40				20		
Jet Fuel & EPA Diesel		54	60	53		44	52	26								
Rejected Blendstocks	**0**	**203**	**64**	**61**	**0**	**126**	**42**	**14**	**0**	**16**	**45**	**43**	**0**	**29**	**44**	**14**
Mixed Butylenes										16	12	22		29	8	0
Pentanes		0	2	0		0	2	0			25	20			24	14
Light Coker Naphtha							1									
Light FCC Gasoline		8	19	7			20	2			8				12	
Heavy FCC Gasoline		9	12	12		9	11	12								
Naphtha (250 - 325 °F)		158	31	42		116	7									
Heavy Reformate		28														
CAPACITY UTILIZATION (%)																
Crude Distillation	97	91	90	91	97	93	93	94	98	94	97	97	98	98	98	97
Conversion	95	90	88	91	95	93	92	94	97	93	96	96	97	97	96	96
Upgrading	79	68	69	76	78	74	74	83	83	94	81	85	83	96	82	87

Note: Cases developed in this analysis are designated as "Split 2.7wt%" and correspond to the bolded numbers in Exhibit 1.

APPENDIX A

Detailed Refinery Modeling Results

This Appendix contains a series of exhibits that provide detailed modeling results for the four cases designated by bolded numbers in Exhibit 1. It also contains results from selected cases in the CEC study, to facilitate comparison between that study and this analysis. The exhibits use the same numbering scheme as in the CEC study. A brief description of the exhibits follows.

Exhibit A-4 shows the factors (replacement oxygenate, period of analysis, and other policies) defining each Case. (Case numbers are as in the CEC study, with the exception that cases numbered "9" are the four cases from this analysis.)

Exhibit A-5 shows process unit utilization and operations.

Exhibit A-6A shows refinery inputs; **Exhibits A-6B** and **A-6C** define the supply curves for refinery inputs; and **Exhibit A-6D** shows cost adjustments so that input costs reflect "market costs," i.e., the entire volume of a given input being purchased at a single "market equilibrium" price, rather incremental volumes being purchased at progressively higher prices.

Exhibit A-7 shows refinery production of refined product outputs.

Exhibit A-8 shows the properties of CARB, Arizona, conventional, and other (combined Arizona and conventional) gasoline and the percent change in emissions (% emissions) calculated using the Predictive Model. In this analysis, as in the CEC study, we use a target minimum for % emissions of -0.30 for the Predictive Model in averaging mode and -0.50 for the Predictive Model in flat limit mode.

Exhibit A-9 shows the composition of CARB, Arizona, conventional, and other (combined Arizona and conventional) gasoline.

Exhibit A-10 provides a summary of key results for each case in terms of costs, investment, imports of blendstocks and refined products, sales of rejected blendstocks, and capacity utilization rates. Exhibit 10 includes several cost categories:

- **Variable cost** equals the difference between the estimated cost of supplying projected refined product demand in the Reference Case and the given Supply Scenario case, not including any capital charges, ancillary costs, or infrastructure costs. Factors accounted for in this cost category are operating costs; costs of crude oil inputs, imported blendstocks, and imported refined products; sales of rejected blendstocks; and energy purchases.

- **Refinery capital charges** are the annualized costs associated with investments made by refineries to expand or add new refining process capacity.

- **Ancillary refining costs** are costs that refineries may incur under an MTBE ban, but that are not registered in a refinery LP model (ARMS, in this instance). Refinery LP models do not register ancillary costs not because they are imaginary, but because it is hard to express them as explicit functions of refinery operating variables. The primary cost elements comprising ancillary costs in this study include additional blendstock tankage and inventory, over-optimization due to the profusion of blendstocks in ARMS, over-optimization because the model measures compliance with the Predictive Model for the gasoline pool rather than for each gasoline grade, and over-optimization because of the use of an aggregate refinery model to represent the California refining sector. In the CEC study, ancillary costs were estimated as 0.1 ¢/gal (for blendstock tankage and inventory) plus 15% of variable costs and capital charges. Thus, ancillary costs were roughly proportional to calculated refining costs for each Supply Scenario. In this analysis, we assumed that ancillary costs would be the same as estimated in the CEC study for the corresponding "all-ethanol" cases.

- **Logistics costs** are the annualized terminal and transportation costs associated with ethanol blending.

- **Mileage loss** is the cost (not including federal or state taxes) of producing and distributing the additional gasoline needed because of the mileage loss, if any, of replacing MTBE with alternative oxygenates. We assume the mileage loss is directly proportional to changes in gasoline energy density.

The difference between the sum of variable costs and capital charges for the two ethanol cases – "business as usual" and "Split" – is equal to the refinery cost saving shown in Exhibit 1 for each of the "bolded" cases.

Exhibit A-10backup shows the calculations underlying the cost estimates shown in Exhibit 10.

Exhibit A-4: Regulatory Scenarios and Modeling Assumptions

	Intermediate Term								Long Term							
	Averaging Mode				Flat Limit Mode				Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
Case Number -->	1	1	1a	9	1	1	1	9	1	1	1a	9	1	1	1	9
SCENARIO DEFINITION																
Period																
Intermediate term	x	x	x	x	x	x	x	x								
Long term									x	x	x	x	x	x	x	x
Oxygenate																
MTBE	x				x				x				x			
Ethanol			x	x			x	x			x	x			x	x
MTBE Ban Region																
California		x	x	x		x	x	x		x	x	x		x	x	x
United States																
Other Policies																
Busines as Usual	x		x		x		x		x		x		x		x	
H.R. 630 passed		x		x		x		x		x		x		x		x
1 psi RVP Ethanol Waiver																
MODELING ASSUMPTIONS																
Process Capacity Addition																
Only Debottlenecking		x	x	x		x	x	x								
New Capacity Allowed										x	x	x		x	x	x
Predictive Model																
Averaging Mode	x	x	x	x					x	x	x	x				
Flat Limit Mode					x	x	x	x					x	x	x	x
Split CARB Pool																
EOH=2.7 wt%				x				x				x				x
Combined Ariz. & Conv. Pool				x				x				x				x
California RFG																
RVP = 6.8 psi	x	x		x	x	x		x	x	x		x	x	x		x
RVP = 5.5 psi + 1.3 psi (1)			x	x			x	x			x	x			x	x
RVP = 6.5 psi + 1.3 psi (2)																
Arizona RFG																
MTBE blending	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
TAME blending	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
RVP = 6.6 to 6.8 psi	x	x	x		x	x	x		x	x	x		x	x	x	
Conventional Gasoline																
MTBE blending	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
TAME blending	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Maximum Alkylate Imports (3)																
100 K bbl/d		x	x	x		x	x	x		x	x	x		x	x	x
FCC Feed Hydrotreating																
Conventional	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Deep	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x

Note: Oxygenate, CARBOB, and Alkylate supply curves set to match specifications for each case.

(1) The RVP of finished, ethanol-blended gasoline is 1.3 psi higher than the RVP specified in ARMS to account for ethanol's RVP effect on a 5.5 psi RVP base blend.

(2) The RVP of finished, ethanol-blended gasoline is 1.3 psi higher than the RVP specified in ARMS to account for ethanol's RVP effect on a 6.5 psi RVP base blend.

(3) In addition to imports in the Reference cases.

Exhibit A-5: Modeling Results Process Unit Utilization, Additions, and Operations, by Case
(K bbl/d)

Type of Process	Process	Intermediate Term							
		Averaging Mode				Flat Limit Mode			
		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
		Ref 2002	HR630	BestU Alk-100	Split 2.7wt%	Ref 2002	HR 630	BestU Alk-100	Split 2.7wt%
	Case Number -->	1	1	1a	9	1	1	1	9
USE OF EXISTING CAPACITY									
Crude Distillation	Atmospheric	1,876	1,756	1,739	1,771	1,873	1,807	1,798	1,824
Conversion	Fluid Cat Cracker	678	665	676	677	677	688	688	688
	Hydrocracker - Distillate Feed	266	240	211	234	261	243	240	247
	Hydrocracker - Gas Oil Feed	137	126	111	123	137	127	126	129
	Coking - Delayed	356	324	319	328	356	337	334	342
	Coking - Fluid & Flexi	103	103	103	103	103	103	103	103
Upgrading	Alkylation	159	167	167	167	154	167	167	167
	Dimersol	1							
	Pen/Hex Isomerization	64	84	63	84	63	84	55	84
	Polymerization	6	6	6	6	6	6	6	6
	Reforming (150-350 psi)	310	208	232	261	311	246	272	304
Oxygenate Prod.	MTBE Plant	12	12	12	12	12	12	12	12
	Tame Plant	2	2	2	2	2	2	2	2
Hydrotreating	Naphtha & Isom Feed Desulf.	70	71	115	123	70	73	121	125
	Reformer Feed Desulfurization	267	179	170	175	266	185	200	213
	Distillate Desulfurization	334	306	345	313	337	308	297	327
	Distillate Dearomatization	108	109	115	110	108	108	107	110
	FCC Feed Desulf. -- Conv.	324	305	309	310	323	315	314	317
	FCC Feed Desulf. -- Deep	351	330	335	335	350	341	340	343
	FCC Naphtha Hydrotreater	73	96	83	101	71	84	82	91
	Benzene Saturation	60	52	38	64	45	64	46	64
Hydrogen (foeb)	Hydrogen Plant (foeb)	59	59	55	57	58	58	56	57
Other	Butane Isomerization	18	18	18	18	18	18	18	18
	Lubes & Waxes	24	24	24	24	24	24	24	24
	Solvent Deasphalting	50	50	50	50	50	50	50	50
	Sulfur Recovery (K tons/d)	6	5	5	5	6	5	5	5
Fractionation	Debutanization	193	190	191	196	185	199	202	200
	Depentanization	60	60	60	60	60	60	60	60
	Lt. Naphtha Spl. (Benz. Prec.)	103	108	108	108	103	108	108	108
	FCC Naphtha Splitter	144	152	152	152	131	152	152	152
	FCC Naphtha T90 Control	153	161	161	161	48	161	161	161
NEW CAPACITY									
Upgrading	Alkylation			2	1			8	0
	Pen/Hex Isomerization								
	Polymerization								
Hydrotreating	FCC Naphtha Hydrotreater								
	Benzene Saturation						0		
Hydrogen (foeb)	Hydrogen Plant (foeb)								
Other	Butane Isomerization								
	Propane Dehydrogenation								
	FCC Gas Processing								
	Sulfur Recovery (K tons/d)								
Fractionation	Debutanization								
	Depentanization								
	Lt. Naphtha Spl. (Benz. Prec.)		5	5	5		5	5	5
	Naphtha Splitter (T90 Control)								
	Heavy Reformate Splitter								
	FCC Naphtha Splitter			8	8			8	8
	FCC Naphtha (T90 Control)		8	8	8		8	8	8
OPERATIONS									
Operating Indices	FCC Conversion (Vol %)	73.7	77.1	78.5	78.1	71.3	78.3	79.2	76.3
	Reformer Severity (RON)	99.9	100.0	100.0	100.0	99.9	100.0	100.0	100.0
Charge Rates	Fluid Cat Cracker	678	639	647	648	677	659	657	664
	Reformer (150-350 psi)	310	208	232	261	311	246	272	304
FCC Olefin Max Cat. (%)									

March 18, 1999

MathPro

Exhibit A-5: Modeling Results Process Unit Utilization, Additions, and Operations, by Case
(K bbl/d)

Type of Process	Process	Long Term							
		Averaging Mode				Flat Limit Mode			
		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
		Ref 2005	HR630	BenU Alk-100	Split 2.7wt%	Ref 2005	HR 630	BenU Alk-100	Split 2.7wt%
	Case Number -->	1	1	1a	9	1	1	1	9
USE OF EXISTING CAPACITY									
Crude Distillation	Atmospheric	1,986	1,908	1,957	1,969	1,981	1,989	1,982	1,958
Conversion	Fluid Cat Cracker	718	686	706	711	716	720	717	706
	Hydrocracker - Distillate Feed	285	284	284	284	284	284	284	284
	Hydrocracker - Gas Oil Feed	143	143	143	143	143	143	143	143
	Coking - Delayed	383	361	374	377	383	383	380	374
	Coking - Fluid & Flexi	106	106	106	106	106	106	106	106
Upgrading	Alkylation	167	172	172	172	161	172	172	172
	Dimersol	2				1			
	Pen/Hex Isomerization	67	86	53	67	67	86	51	84
	Polymerization	6	6	6	6	6	6	6	6
	Reforming (150-350 psi)	330	374	324	337	333	395	334	337
Oxygenate Prod.	MTBE Plant	12	12	12	12	12	12	12	12
	Tame Plant	2	2	2	2	2	2	2	2
Hydrotreating	Naphtha & Isom Feed Desulf.	74	78	111	87	74	81	98	106
	Reformer Feed Desulfurization	283	294	223	255	283	284	241	239
	Distillate Desulfurization	351	361	350	350	352	370	353	350
	Distillate Dearomatization	116	109	120	118	117	110	115	119
	FCC Feed Desulf. -- Conv.	343	327	337	340	342	344	342	337
	FCC Feed Desulf. -- Deep	372	355	365	368	371	372	371	365
	FCC Naphtha Hydrotreater	79	72	101	101	76	77	101	101
	Benzene Saturation	64	52	66	66	51	66	66	66
Hydrogen (foeb)	Hydrogen Plant (foeb)	63	59	63	63	62	61	63	63
Other	Butane Isomerization	18	18	18	18	18	18	18	18
	Lubes & Waxes	25	25	25	25	25	25	25	25
	Solvent Deasphalting	50	50	50	50	50	50	50	50
	Sulfur Recovery (K tons/d)	6	6	6	6	6	6	6	6
Fractionation	Debutanization	205	215	211	215	195	215	215	210
	Depentanization	60	60	60	60	60	60	60	60
	Lt. Naphtha Spl. (Benz. Prec.)	109	114	114	114	109	114	114	114
	FCC Naphtha Splitter	153	150	153	149	139	140	155	161
	FCC Naphtha T90 Control	164	171	171	171	33	171	171	171
NEW CAPACITY									
Upgrading	Alkylation		43						
	Pen/Hex Isomerization								
	Polymerization		38		1		23		
Hydrotreating	FCC Naphtha Hydrotreater								
	Benzene Saturation								
Hydrogen (foeb)	Hydrogen Plant (foeb)								
Other	Butane Isomerization		23				3		
	Propane Dehydrogenation								
	FCC Gas Processing		621	100	168		375	42	16
	Sulfur Recovery (K tons/d)								
Fractionation	Debutanization						4		
	Depentanization			63	52			61	36
	Lt. Naphtha Spl. (Benz. Prec.)		86	34	29		95	2	33
	Naphtha Splitter (T90 Control)		82				3		
	Heavy Reformate Splitter		11						
	FCC Naphtha Splitter								
	FCC Naphtha (T90 Control)		44	48	43		30	51	60
OPERATIONS									
Operating Indices	FCC Conversion (Vol %)	73.7	74.0	73.5	74.1	70.6	75.0	74.8	73.8
	Reformer Severity (RON)	99.9	99.8	100.0	100.0	99.9	100.0	100.0	100.0
Charge Rates	Fluid Cat Cracker	718	686	706	711	716	720	717	706
	Reformer (150-350 psi)	331	374	324	337	334	395	334	337
FCC Olefin Max Cat. (%)			81.5	12.8	21.2		46.9	5.3	2.0

Exhibit A-6A: Modeling Results – Refinery Inputs, by Case

(K barrels/day)

	Intermediate Term								Long Term							
	Averaging Mode				Flat Limit Mode				Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
	Ref 2002	HR630	BestU Alk-100	Split 2.7wt%	Ref 2002	HR 630	BestU Alk-100	Split 2.7wt%	Ref 2005	HR630	BestU Alk-100	Split 2.7wt%	Ref 2005	HR 630	BestU Alk-100	Split 2.7wt%
Inputs	1	1	1a	9	1	1	1	9	1	1	1a	9	1	1	1	9
Crude Oil	1,876	1,756	1,739	1,770	1,872	1,806	1,798	1,824	1,986	1,988	1,957	1,969	1,981	1,988	1,982	1,957
Specified Inputs	65	65	65	65	65	65	65	65	68	68	68	68	68	68	68	68
Propylene Alkylate	5	5	5	5	5	5	5	5	6	6	6	6	6	6	6	6
Butylene Alkylate	5	5	5	5	5	5	5	5	6	6	6	6	6	6	6	6
Heavy Gas Oils	18	18	18	18	18	18	18	18	19	19	19	19	19	19	19	19
Residuum	36	36	36	36	36	36	36	36	38	38	38	38	38	38	38	38
Isobutane	0	11	13	10	0	7	11	7	0	34	8	9	0	12	4	5
P1		11	12	10		7	11	7		12	8	9		12	4	5
P2			1							22						
Isomerate	0	0	0	0	0	10	0	0	0	30	0	0	0	11	0	0
P1						10				10				10		
P2										10				1		
P3										10						
Mixed Alkylate	0	100	100	100	0	100	100	100	0	100	100	99	0	100	86	95
P1		16	16	16		16	16	16		16	16	16		16	16	16
P2		22	22	22		22	22	22		22	22	22		22	22	22
P3		62	62	62		62	62	62		62	62	61		62	48	57
MTBE	108	6	3	9	108	12	4	14	115	14	9	12	115	19	5	12
P1	16	6	3	9	16	12	4	14	31	14	9	12	31	19	5	12
P2	25				25				60				60			
P3	67				67				24				24			
Ethanol	0	0	75	48	0	0	75	44	0	0	79	64	0	0	79	56
P1			51	48			51	44			79	64			79	56
P2			10				10									
P3			14				14									
TBA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
P1																
P2																
P3																
ETBE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
P1																
P2																
P3																
TAME	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
P1																
P2																
P3																
CARBOB	0	255	65	65	0	140	0	0	0	40	0	0	0	20	0	0
P1		130	65	65		130				40				20		
P2		26				10										
P3		99														
Methanol	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Distillate Blendstocks																
Jet Fuel		4	41	10				0				0				0
EPA Diesel		50	19	44		44	52	26				0				0
Purchased Energy																
Electricity (K Kwh)	15,582	14,490	14,105	14,779	15,363	14,903	14,886	15,430	16,575	17,374	16,817	16,984	16,358	17,470	16,803	16,940
Fuel (foeb)	198	190	182	186	198	185	183	189	208	212	205	203	208	200	203	205

Exhibit A-6B: Modeling Results -- Prices of Refinery Inputs, by Case

($ per barrel)

	Intermediate Term								Long Term							
	Averaging Mode				Flat Limit Mode				Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
	Ref 2002	HR630	BestU Alk-100	Split 2.7wt%	Ref 2002	HR 630	BestU Alk-100	Split 2.7wt%	Ref 2005	HR630	BestU Alk-100	Split 2.7wt%	Ref 2005	HR 630	BestU Alk-100	Split 2.7wt%
Inputs	1	1	1a	9	1	1	1	9	1	1	1a	9	1	1	1	9
Isobutane																
P1	22.19	22.19	22.19	22.19	22.19	22.19	22.19	22.19	22.19	22.19	22.19	22.19	22.19	22.19	22.19	22.19
P2	24.36	24.36	24.36	24.36	24.36	24.36	24.36	24.36	24.36	24.36	24.36	24.36	24.36	24.36	24.36	24.36
Isomerate																
P1	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00
P2	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00
P3	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00
Mixed Alkylate																
P1	32.34	32.34	32.34	32.34	32.34	32.34	32.34	32.34	32.34	32.34	32.34	32.34	32.34	32.34	32.34	32.34
P2	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92
P3	34.23	34.23	34.23	34.23	34.23	34.23	34.23	34.23	34.23	34.23	34.23	34.23	34.23	34.23	34.23	34.23
MTBE																
P1	31.92	31.92	31.92	31.92	31.92	31.92	31.92	31.92	31.92	31.92	31.92	31.92	31.92	31.92	31.92	31.92
P2	34.86	34.86	34.86	34.86	34.86	34.86	34.86	34.86	34.86	34.86	34.86	34.86	34.86	34.86	34.86	34.86
P3	39.90	39.90	39.90	39.90	39.90	39.90	39.90	39.90	39.06	39.06	39.06	39.06	39.06	39.06	39.06	39.06
Ethanol																
P1			37.80	37.80		37.80	37.80	37.80			28.98	28.98			28.98	28.98
P2			39.48	39.48		39.48	39.48	39.48			29.40	29.40			29.40	29.40
P3			43.68	43.68		43.68	43.68	43.68			30.24	30.24			30.24	30.24
TBA																
P1																
P2																
P3																
ETBE																
P1																
P2																
P3																
TAME																
P1																
P2																
P3																
CARBOB																
P1		28.98	28.90	28.90		28.98	28.90	28.90		28.98	28.90	28.90		28.98	28.90	28.90
P2		29.11	29.06	29.06		29.11	29.06	29.06		29.11	29.06	29.06		29.11	29.06	29.06
P3		30.66	30.48	30.48		30.66	30.48	30.48		30.66	30.48	30.48		30.66	30.48	30.48
Methanol	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56
Distillate Blendstock	25.50	25.50	25.50	25.50	25.50	25.50	25.50	25.50	25.50	25.50	25.50	25.50	25.50	25.50	25.50	25.50
Jet Fuel	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50
EPA Diesel	25.80	25.80	25.80	25.80	25.80	25.80	25.80	25.80	25.80	25.80	25.80	25.80	25.80	25.80	25.80	25.80

Exhibit A-6C: Modeling Results – Availability of Refinery Inputs, by Case
(K bbl/d)

	Intermediate Term								Long Term							
	Averaging Mode				Flat Limit Mode				Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
	Ref 2002	HR630	BestU Alk-100	Split 2.7wt%	Ref 2002	HR 630	BestU Alk-100	Split 2.7wt%	Ref 2005	HR630	BestU Alk-100	Split 2.7wt%	Ref 2005	HR 630	BestU Alk-100	Split 2.7wt%
Inputs	1	1	1a	9	1	1	1	9	1	1	1a	9	1	1	1	9
Isobutane																
P1	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
P2																
Isomerate																
P1	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
P2	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
P3	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Mixed Alkylate																
P1	16	16	16	16	16	16	16	16	16	16	16	27	16	16	16	16
P2	22	22	22	22	22	22	22	22	22	22	22	36	22	22	22	22
P3	62	62	62	62	62	62	62	62	62	62	62	108	62	62	62	62
MTBE																
P1	16	16	16	16	16	16	16	16	31	31	31	31	31	31	31	31
P2	25	25	25	25	25	25	25	25	60	60	60	60	60	60	60	60
P3																
Ethanol																
P1	0	0	51	51	0	0	51	51	0	0	80	80	0	0	80	80
P2			10	10			10	10			40	40			40	40
P3			33	33			33	33			70	70			70	70
TBA																
P1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
P2																
P3																
ETBE																
P1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
P2																
P3																
TAME																
P1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
P2																
P3																
CARBOB																
P1	0	130	130	130	0	130	130	130	0	130	130	130	0	130	130	130
P2		26	26	26		26	26	26		26	26	26		26	26	26
P3		279	279	279		279	214	214		279	214	214		279	214	214
Methanol																
Distillate Blendstocks																
Jet Fuel																
EPA Diesel																

Exhibit A-6D: Cost Adjustment for Blendstock and Refined Product Supply Curves

	Intermediate Term								Long Term							
	Averaging Mode				Flat Limit Mode				Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
	Ref 2002	HR630	BestU Alk-100	Split 2.7wt%	Ref 2002	HR 630	BestU Alk-100	Split 2.7wt%	Ref 2005	HR630	BestU Alk-100	Split 2.7wt%	Ref 2005	HR 630	BestU Alk-100	Split 2.7wt%
Inputs	1	1	1a	9	1	1	1	9	1	1	1a	9	1	1	1	9
Isobutane																
ARMS Cost	0	234	294	212	0	156	245	152	0	813	183	209	0	266	93	114
Market Cost	0	234	320	212	0	156	245	152	0	839	183	209	0	266	93	114
Adjustment	0	0	26	0	0	0	0	0	0	26	0	0	0	0	0	0
Isomerate																
ARMS Cost	0	0	0	0	0	260	0	0	0	808	0	0	0	282	0	0
Market Cost	0	0	0	0	0	260	0	0	0	838	0	0	0	292	0	0
Adjustment	0	0	0	0	0	0	0	0	0	30	0	0	0	10	0	0
Mixed Alkylate																
ARMS Cost	0	3,364	3,364	3,364	0	3,364	3,364	3,364	0	3,364	3,364	3,336	0	3,353	2,894	3,199
Market Cost	0	3,423	3,423	3,423	0	3,423	3,423	3,423	0	3,423	3,423	3,395	0	3,412	2,953	3,258
Adjustment	0	59	59	59	0	59	59	59	0	59	59	59	0	59	59	59
MTBE																
ARMS Cost	4,045	201	100	277	4,045	391	128	432	4,017	447	280	395	4,017	613	162	377
Market Cost	4,299	201	100	277	4,299	391	128	432	4,491	447	280	395	4,491	613	162	377
Adjustment	254	0	0	0	254	0	0	0	473	0	0	0	473	0	0	0
Ethanol																
ARMS Cost	0	0	2,927	1,802	0	0	2,928	1,657	0	0	2,298	1,848	0	0	2,298	1,623
Market Cost	0	0	3,269	1,802	0	0	3,270	1,657	0	0	2,298	1,848	0	0	2,298	1,623
Adjustment	0	0	342	0	0	0	342	0	0	0	0	0	0	0	0	0
TBA																
ARMS Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Market Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ETBE																
ARMS Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Market Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TAME																
ARMS Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Market Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CARBOB																
ARMS Cost	0	7,560	1,867	1,867	0	4,059	0	0	0	1,159	0	0	0	580	0	0
Market Cost	0	7,818	1,867	1,867	0	4,075	0	0	0	1,159	0	0	0	580	0	0
Adjustment	0	259	0	0	0	17	0	0	0	0	0	0	0	0	0	0
Total Adjustment	254	318	427	59	254	76	401	59	473	115	59	59	473	69	59	59

Exhibit A-7: Modeling Results – Refined Product Outputs and Sales of Rejected Blendstocks, by Case

(K barrels/day)

	Intermediate Term							
	Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
	Ref 2002	HR630	BasU Alk-100	Split 2.7wt%	Ref 2002	HR 630	BasU Alk-100	Split 2.7wt%
Outputs	1	1	1a	9	1	1	1	9
REFINED PRODUCTS*	**2,114**	**1,792**	**1,973**	**1,982**	**2,114**	**1,924**	**2,055**	**2,084**
Propane	36	36	36	36	36	36	36	36
Propylene	2	2	2	2	2	2	2	2
Butane	29	29	29	29	29	29	29	29
Mixed Butylenes	4	1	4	4	4	4	4	4
Naphtha	3	3	3	3	3	3	3	3
Gasoline:								
California RFG								
Single Pool	965	710	895		965	825	965	
Split Pool – EOH blend				545				565
– No Oxygenate				350				400
Other Gasoline								
Arizona RFG	64	64	64		64	64	64	
Conventional	150	150	150		150	150	150	
Combined				214				214
Aviation Gasoline	5	5	5	5	5	5	5	5
Jet Fuel	319	315	278	309	319	319	319	319
Diesel Fuel:								
CARB Diesel	192	192	192	192	192	192	192	192
EPA Diesel	114	64	95	70	114	70	62	88
Other	17	17	17	17	17	17	17	17
Lubes & Waxes	24	24	24	24	24	24	24	24
Residual Fuel Oil	55	55	57	55	55	55	55	55
Asphalt								
Coke	135	125	123	126	135	129	128	130
Sulfur (K tons/d)	6	5	5	5	6	5	5	5
REJECTED BLENDSTOCKS	**0**	**203**	**64**	**61**	**0**	**126**	**42**	**14**
Mixed Butylenes								
Pentanes		0	2	0		0	2	0
Light Coker Naphtha							1	
Light FCC Gasoline		8	19	7			20	2
Heavy FCC Gasoline		9	12	12		9	11	12
Naphtha (250 - 325 °F)		158	31	42		116	7	
Heavy Reformate		28						
TOTAL	**2,114**	**1,995**	**2,037**	**2,043**	**2,114**	**2,050**	**2,097**	**2,098**

* Excludes Sulfur

Exhibit A-7: Modeling Results – Refined Product Outputs and Sales of Rejected Blendstocks, by Case

(K barrels/day)

	Long Term							
	Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
	Ref 2005	HR630	BasU Alk-100	Split 2.7wt%	Ref 2005	HR 630	BasU Alk-100	Split 2.7wt%
Outputs	1	1	1a	9	1	1	1	9
REFINED PRODUCTS*	**2,235**	**2,190**	**2,234**	**2,235**	**2,235**	**2,215**	**2,236**	**2,234**
Propane	37	37	37	37	37	37	37	37
Propylene	2	2	2	2	2	2	2	2
Butane	30	30	30	30	30	30	30	30
Mixed Butylenes	4	4	4	4	4	4	4	4
Naphtha	3	3	3	3	3	3	3	3
Gasoline:								
California RFG								
Single Pool	1,022	982	1,022		1,022	1,002	1,022	
Split Pool – EOH blend				822				722
– No Oxygenate				200				300
Other Gasoline								
Arizona RFG	68	68	68		68	68	68	
Conventional	161	161	161		161	161	161	
Combined				229				229
Aviation Gasoline	5	5	5	5	5	5	5	5
Jet Fuel	333	333	333	333	333	333	333	333
Diesel Fuel:								
CARB Diesel	204	204	204	204	204	204	204	204
EPA Diesel	122	122	122	122	122	122	122	122
Other	18	18	18	18	18	18	18	18
Lubes & Waxes	25	25	25	25	25	25	25	25
Residual Fuel Oil	57	59	58	58	57	57	58	59
Asphalt								
Coke	144	137	141	142	144	144	143	141
Sulfur (K tons/d)	6	6	6	6	6	6	6	6
REJECTED BLENDSTOCKS	**0**	**16**	**45**	**43**	**0**	**29**	**44**	**14**
Mixed Butylenes		16	12	22		29	8	0
Pentanes			25	20			24	14
Light Coker Naphtha								
Light FCC Gasoline			8				12	
Heavy FCC Gasoline								
Naphtha (250 - 325 °F)								
Heavy Reformate								
TOTAL	**2,235**	**2,205**	**2,278**	**2,277**	**2,235**	**2,244**	**2,280**	**2,248**

* Excludes Sulfur

Exhibit A-8: Modeling Results – Gasoline Properties by Case and Gasoline Type

Property & Predictive Model % Emissions	Intermediate Term											
	Averaging Mode											
	MTBE			No Oxygenate			Ethanol					
	Ref 2002 1			HR630 1			BasU Alk-100 1a			Split 2.7wt% 9		
	CARB	Ariz.	Conv.	CARB	Ariz.	Conv.	CARB	Ariz.	Conv.	EOH	NoOxy	Other
Property												
RVP (psi) (1)	6.8	6.6	7.7	6.8	6.6	7.7	5.5	6.6	7.7	5.5	6.8	7.4
Oxygen (wt%)	2.1	2.1	0.3	0.0	2.7	1.2	2.7	2.7	0.9	2.7	0.0	1.9
Aromatics (vol%)	23.2	22.6	34.4	16.7	28.0	34.4	18.8	28.0	34.4	25.0	12.0	32.5
Benzene (vol%)	0.53	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.76	0.67	0.80
Olefins (vol%)	4.4	5.6	12.4	3.7	5.6	12.4	2.9	5.6	12.1	1.1	6.0	10.2
Sulfur (ppm)	19	38	153	16	38	106	25	30	71	16	30	59
E200 (vol% off)	50.5	43.0	38.9	52.0	47.2	41.8	48.6	45.6	42.6	48.8	49.6	43.5
E300 (vol% off)	88.9	85.7	76.4	94.1	84.0	76.4	90.4	85.7	76.4	92.3	86.5	79.2
T10 (2)	134	137	138	135	137	135	129	135	138	131	133	135
T50 (3)	199	219	229	195	207	222	204	212	219	203	201	217
T90 (4)	303	312	338	288	317	338	299	312	338	293	310	330
Estimated DI	1100	1173	1233	1075	1145	1207	1103	1149	1204	1099	1112	1184
En. Den. (MM Btu/bbl)	5.129	5.159	5.257	5.158	5.164	5.231	5.080	5.147	5.304	5.107	5.147	5.229
Predictive Model % Emissions (5)												
VOCs	-0.43			-0.35			-0.40			-0.43	-0.29	
NOx	-0.33			-1.89			-0.30			-0.79	-1.51	
Toxics	-0.64			-8.11			-0.94			-0.53	-2.52	

(1) The RVP of ethanol blends is 1.3 psi higher than shown.
(2) Linear interpolations from ARMS generated distillation curves.
(3) Calculated using formula: T50 = (125.385 - E200)/0.377.
(4) Calculated using formula: T90 = (196.154 - E300)/0.354.
(5) % emissions for the Flat Limits Mode are calculated using the average gasoline properties, shown above, plus the average flat limit differentials estimated by CEC.

Exhibit A-8: Modeling Results – Gasoline Properties by Case and Gasoline Type

Property & Predictive Model % Emissions	Intermediate Term											
	Flat Limit Mode											
	MTBE			No Oxygenate			Ethanol					
	Ref 2002 1			HR 630 1			BasU Alk-100 1			Split 2.7wt% 9		
	CARB	Ariz.	Conv.	CARB	Ariz.	Conv.	CARB	Ariz.	Conv.	EOH	NoOxy	Other
Property												
RVP (psi) (1)	6.8	6.6	7.7	6.8	6.6	7.7	5.5	6.6	7.7	5.5	6.8	7.4
Oxygen (wt%)	2.1	2.1	0.3	0.0	2.7	2.0	2.7	2.7	1.0	2.7	0.0	2.3
Aromatics (vol%)	24.0	22.6	34.4	20.4	28.0	34.4	20.4	25.7	34.4	26.1	14.4	31.8
Benzene (vol%)	0.67	0.80	0.80	0.80	0.80	0.80	0.80	0.76	0.80	0.80	0.80	0.79
Olefins (vol%)	4.3	5.6	12.4	5.0	5.6	12.4	2.9	5.6	12.2	1.8	5.8	10.2
Sulfur (ppm)	24	38	153	25	38	98	25	30	76	21	30	48
E200 (vol% off)	49.9	43.0	38.9	50.4	47.4	40.4	47.8	45.6	43.7	47.5	49.2	43.0
E300 (vol% off)	87.5	85.7	76.4	91.7	83.8	76.4	89.8	83.5	76.4	91.8	86.2	78.5
T10 (2)	134	137	139	137	137	133	130	133	136	131	134	134
T50 (3)	200	219	229	199	207	225	206	212	217	206	202	219
T90 (4)	307	312	338	295	317	338	300	318	338	295	311	332
Estimated DI	1108	1173	1234	1097	1143	1213	1113	1154	1193	1111	1118	1189
En. Den. (MM Btu/bbl)	5.134	5.155	5.285	5.178	5.164	5.227	5.092	5.139	5.292	5.111	5.163	5.214
Predictive Model % Emissions (5)												
VOCs	-0.75			-0.53			-0.61			-0.61	-0.61	
NOx	-0.53			-0.83			-0.54			-0.61	-1.45	
Toxics	-0.64			-4.85			-2.85			-0.60	-3.53	

(1) The RVP of ethanol blends is 1.3 psi higher than shown.
(2) Linear interpolations from ARMS generated distillation curves.
(3) Calculated using formula: T50 = (125.385 - E200)/0.377.
(4) Calculated using formula: T90 = (196.154 - E300)/0.354.
(5) % emissions for the Flat Limits Mode are calculated using the average gasoline properties, shown above, plus the average flat limit differentials estimated by CEC.

Exhibit A-8: Modeling Results – Gasoline Properties by Case and Gasoline Type

Property & Predictive Model % Emissions	Long Term											
	Averaging Mode											
	MTBE			No Oxygenate			Ethanol					
	Ref 2005 1			HR630 1			BasU Alk-100 1a			Split 2.7wt% 9		
	CARB	Ariz.	Conv.	CARB	Ariz.	Conv.	CARB	Ariz.	Conv.	EOH	NoOxy	Other
Property												
RVP (psi) (1)	6.8	6.6	7.7	6.8	6.6	7.7	5.5	6.6	7.7	5.5	6.8	7.4
Oxygen (wt%)	2.1	2.1	0.3	0.0	2.7	2.0	2.7	2.7	1.4	2.7	0.0	2.1
Aromatics (vol%)	23.2	22.6	34.4	22.1	28.0	34.4	20.9	28.0	34.4	24.2	12.0	32.5
Benzene (vol%)	0.52	0.80	0.80	0.80	0.80	0.80	0.73	0.80	0.80	0.63	0.80	0.80
Olefins (vol%)	4.5	5.6	12.4	5.7	5.6	12.4	2.8	5.6	12.4	2.4	6.0	10.4
Sulfur (ppm)	18	38	153	15	30	149	22	30	66	18	29	55
E200 (vol% off)	50.4	43.0	38.9	53.7	44.7	38.9	49.3	45.7	41.1	49.3	49.6	42.5
E300 (vol% off)	88.9	85.7	76.4	90.7	88.4	76.4	89.3	85.6	76.4	89.9	86.5	79.1
T10 (2)	134	136	138	137	138	134	131	135	136	131	133	135
T50 (3)	199	219	229	190	214	229	202	211	224	202	201	220
T90 (4)	303	312	338	298	304	338	302	312	338	300	310	331
Estimated DI	1100	1172	1233	1074	1154	1227	1104	1149	1213	1103	1112	1193
En. Den. (MM Btu/bbl)	5.130	5.157	5.255	5.183	5.150	5.213	5.095	5.147	5.273	5.108	5.146	5.229
Predictive Model % Emissions (5)												
VOCs	-0.44			-0.31			-0.47			-0.36	-0.37	
NOx	-0.31			-0.33			-0.32			-0.32	-1.54	
Toxics	-0.50			-0.88			-0.42			-0.30	-1.14	

(1) The RVP of ethanol blends is 1.3 psi higher than shown.
(2) Linear interpolations from ARMS generated distillation curves.
(3) Calculated using formula: T50 = (125.385 - E200)/0.377.
(4) Calculated using formula: T90 = (196.154 - E300)/0.354.
(5) % emissions for the Flat Limits Mode are calculated using the average gasoline properties, shown above, plus the average flat limit differentials estimated by CEC.

Exhibit A-8: Modeling Results – Gasoline Properties by Case and Gasoline Type

Property & Predictive Model % Emissions	Long Term											
	Flat Limit Mode											
	MTBE			No Oxygenate			Ethanol					
	Ref 2005 1			HR 630 1			BaseU Alk-100 1			Split 2.7wt% 9		
	CARB	Ariz.	Conv.	CARB	Ariz.	Conv.	CARB	Ariz.	Conv.	EOH	NoOxy	Other
Property												
RVP (psi) (1)	6.8	6.6	7.7	6.8	6.6	7.7	5.5	6.6	7.7	5.5	6.8	7.4
Oxygen (wt%)	2.1	2.1	0.3	0.0	2.7	2.6	2.7	2.7	1.0	2.7	0.0	2.0
Aromatics (vol%)	24.1	22.6	34.4	25.8	21.7	31.8	22.3	25.6	34.4	26.1	11.6	31.8
Benzene (vol%)	0.66	0.80	0.80	0.73	0.80	0.80	0.80	0.80	0.80	0.73	0.80	0.80
Olefins (vol%)	4.3	5.6	12.4	5.1	5.6	12.4	2.9	5.6	12.4	2.4	6.0	10.4
Sulfur (ppm)	23	38	153	17	30	150	22	30	88	17	39	53
E200 (vol% off)	49.8	43.0	38.9	50.9	43.0	38.9	48.2	45.5	40.3	47.6	48.5	42.0
E300 (vol% off)	87.3	85.7	76.4	88.6	83.5	76.4	89.0	83.5	76.4	90.5	86.1	78.5
T10 (2)	134	138	139	138	134	132	131	135	137	132	132	134
T50 (3)	201	219	229	197	219	229	205	212	226	206	204	221
T90 (4)	308	312	338	304	318	338	303	318	338	298	311	332
Estimated DI	1109	1175	1235	1103	1175	1225	1114	1155	1221	1115	1120	1198
En. Den. (MM Btu/bbl)	5.134	5.161	5.286	5.212	5.148	5.178	5.101	5.146	5.295	5.122	5.128	5.226
Predictive Model % Emissions (5)												
VOCs	-0.62			-0.53			-0.53			-0.53	-0.58	
NOx	-0.56			-0.54			-0.53			-0.53	-1.45	
Toxics	-0.58			-0.55			-1.30			-0.52	-3.87	

(1) The RVP of ethanol blends is 1.3 psi higher than shown.
(2) Linear interpolations from ARMS generated distillation curves.
(3) Calculated using formula: T50 = (125.385 - E200)/0.377.
(4) Calculated using formula: T90 = (196.154 - E300)/0.354.
(5) % emissions for the Flat Limits Mode are calculated using the average gasoline properties, shown above, plus the average flat limit differentials estimated by CEC.

Exhibit A-9: Modeling Results – Gasoline Composition and Volume, by Type and Case

Gasoline Composition & Volume	Intermediate Term															
	Averaging Mode															
	MTBE				No Oxygenate				Ethanol							
	Ref 2002 1				HR630 1				BasU Alk-100 1a				Split 2.7wt% 9			
	CARB	Artz.	Conv.	Pool	CARB	Artz.	Conv.	Pool	CARB	Artz.	Conv.	Pool	EOH	NoOxy	Other	Pool
Composition (vol%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
C4s:	0.6	1.4	3.4	1.0	0.5	0.5	1.4	0.7	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Butenes																
I-Butane																
N-Butane	0.6	1.4	3.4	1.0	0.5	0.5	1.4	0.7	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
C5s & Isomerate	4.7	0.2	13.4	5.6	11.8		1.6	9.3	6.3	8.6	0.9	5.7	3.0	19.0	1.4	7.9
Raffinate																
Natural Gas Liquids																
Naphtha	2.4	0.0	5.1	2.6	0.2	6.0	0.0	0.6	7.2	1.4	0.7	6.0	7.9	2.3	0.0	4.7
C5-160	2.4		5.1	2.6	0.2	6.0		0.6	1.8	1.4	0.7	1.6	0.3			0.2
Coker Naphtha																
160-250									5.5			4.4	7.6	2.3		4.5
Alkylate	15.6	15.9	0.0	13.8	37.9	0.0	0.0	29.1	30.2	0.0	0.0	24.3	23.2	40.9	0.0	24.6
Hydrocrackate	18.8			15.6	10.6	6.4	2.0	8.9	12.2	15.1		10.7	13.6	2.4	7.6	9.0
Dimate																
Poly Gasoline	0.1	0.4		0.1	0.1			0.1	0.1			0.1		0.3		0.1
FCC Gasoline:	24.4	58.1	52.1	29.1	25.3	55.8	66.0	34.0	19.4	39.0	73.9	27.9	13.7	34.0	59.7	28.0
Full Range	19.7		18.3	18.6	16.4	48.5	29.7	20.8	7.9	37.6	65.6	17.4		24.4	50.2	17.6
Light	2.1			1.7	1.1		9.9	2.4			8.3	1.1		1.7	1.6	0.9
Light - Desulf.	0.2	14.1													7.1	
Medium	0.8	4.2	20.4	3.5			12.6	2.0	3.6	1.4		3.0	1.4	2.5		1.5
Medum - Desulf.	1.6	26.6		2.8	7.9	5.9		6.5	5.5			4.4	12.1			6.0
Heavy															0.8	0.2
Heavy - Desulf.	0.1	13.1	13.4	2.5		1.5	13.8	2.3	2.4			2.0	0.2	5.4		1.8
Reformate	21.7	12.1	24.3	21.7	13.5	16.0	22.2	15.1	16.3	20.1	19.2	16.9	30.3	0.7	20.4	19.3
Light	7.9	12.1	17.9	9.5	13.5	16.0	22.1	15.1	7.0	6.1	10.6	7.4	15.0	0.7	7.3	9.1
Medium																
Heavy	13.8		6.4	12.3			0.1	0.0	9.3	14.1	8.5	9.5	15.3		13.1	10.2
Oxygenate	11.5	11.9	1.6	10.4	0.0	15.2	6.8	2.2	7.8	15.2	4.7	7.8	7.8	0.0	10.4	5.9
MTBE	11.5	9.3	1.6	10.3		12.6	6.8	2.0		12.6	4.7	1.4			9.7	1.9
Ethanol									7.8			6.3	7.8			3.9
TBA																
ETBE																
TAME		2.6		0.1		2.6		0.2		2.6		0.2			0.8	0.2
DIPE																
Volume (K Bbl/day)	965	64	150	1,168	710	64	150	924	895	64	150	1,109	545	350	214	1,094

Exhibit A-9: Modeling Results – Gasoline Composition and Volume, by Type and Case

Gasoline Composition & Volume	Intermediate Term															
	Flat Limit Mode															
	MTBE				No Oxygenate				Ethanol							
	Ref								BasU				Split			
	2002				HR 630				Alk-100				2.7wt%			
	1				1				1				9			
	CARB	Ariz.	Conv.	Pool	CARB	Ariz.	Conv.	Pool	CARB	Ariz.	Conv.	Pool	EOH	NoOxy	Other	Pool
Composition (vol%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
C4s:	0.6	2.7	3.7	1.2	0.5	0.5	1.3	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Butenes					0.4			0.3								
I-Butane																
N-Butane	0.6	2.7	3.7	1.2	0.1	0.5	1.3	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
C5s & Isomerate	6.1	9.9		5.6	11.3		1.6	9.2	4.3	10.8	4.3	4.7	7.0	11.1	1.1	7.4
Raffinate																
Natural Gas Liquids																
Naphtha	2.4	0.0	4.9	2.6	0.7	4.3	0.0	0.8	8.2	0.0	0.0	6.7	9.6	0.0	0.6	4.8
C5-160	2.4		4.9	2.6	0.7	4.3		0.8	2.9			2.4	0.5		0.6	0.4
Coker Naphtha																
160-250									5.2			4.3	9.1			4.4
Alkylate	14.4	13.9	5.7	13.3	32.5	0.0	0.0	25.8	28.4	1.4	0.0	23.4	20.9	37.6	0.0	23.1
Hydrocrackate	17.0	2.5	8.1	15.1	9.2	3.9	12.1	9.3	12.8	13.8	1.1	11.4	7.9	11.4	11.7	9.9
Dimate																
Poly Gasoline	0.1			0.1	0.1			0.1	0.1			0.1		0.2		0.1
FCC Gasoline:	27.0	42.7	46.8	30.4	28.9	60.5	40.3	32.5	19.0	42.2	71.4	26.9	15.9	37.0	43.1	27.1
Full Range	20.0		24.8	19.6	17.5	43.5	22.9	19.9	8.2	42.0	63.2	17.0	2.8	29.3	29.4	16.8
Light	2.2	6.7		2.2	0.9	2.2	14.0	2.9			8.2	1.0			7.3	1.3
Light - Desulf.															6.4	
Medium	1.7	6.8	13.6	3.5	2.9		0.6	2.4	3.6			2.9	2.5	3.1		2.3
Medum - Desulf.	1.2	23.1		2.3	5.6	12.3		5.2	4.9			4.0	9.9			4.8
Heavy							2.8	0.4								
Heavy - Desulf.	1.8	6.1	8.4	2.9	1.9	2.6		1.7	2.2	0.2		1.8	0.6	4.6		1.9
Reformate	20.7	16.8	29.1	21.6	16.7	15.6	33.9	19.1	19.0	16.0	17.4	18.6	30.5	2.2	30.3	21.1
Light	9.5		13.7	9.5	16.7	15.6		14.3	7.8		8.5	7.5	16.9	2.2		8.9
Medium																
Heavy	11.2	16.8	15.3	12.1			33.9	4.9	11.1	16.0	8.9	11.1	13.6		30.3	12.2
Oxygenate	11.6	11.5	1.6	10.3	0.0	15.2	10.8	2.5	7.8	15.2	5.3	7.9	7.8	0.0	12.7	6.1
MTBE	11.4	11.5	1.6	10.2		12.6	10.8	2.3		12.6	5.3	1.4			11.9	2.2
Ethanol									7.8			6.4	7.8			3.8
TBA																
ETBE																
TAME	0.2			0.1		2.6		0.2		2.6		0.1			0.8	0.1
DIPE																
Volume (K Bbl/day)	965	64	150	1,179	825	64	150	1,039	965	64	150	1,179	565	400	214	1,165

Exhibit A-9: Modeling Results -- Gasoline Composition and Volume, by Type and Case

Gasoline Composition & Volume	Long Term															
	Averaging Mode															
	MTBE				No Oxygenate				Ethanol							
	Ref 2005 1				HR630 1				BasU Alk-100 1a				Split 2.7wt% 9			
	CARB	Ariz.	Conv.	Pool	CARB	Ariz.	Conv.	Pool	CARB	Ariz.	Conv.	Pool	EOH	NeOxy	Other	Pool
Composition (vol%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
C4s:	0.6	1.8	3.5	1.0	0.5	0.5	1.9	0.7	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Butenes																
I-Butane																
N-Butane	0.6	1.8	3.5	1.0	0.5	0.5	1.9	0.7	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
C5s & Isomerate	4.4	4.5	13.5	5.6	11.8		1.4	9.7	4.4	7.6	2.3	4.3	5.2	11.8	1.0	5.5
Raffinate																
Natural Gas Liquids																
Naphtha	2.4	0.0	4.8	2.6	1.6	0.7	0.0	1.3	7.3	0.0	0.0	5.9	4.6	0.0	0.0	3.0
C5-160	2.4		4.8	2.6	1.6	0.7		1.3	1.9			1.5	1.5			1.0
Coker Naphtha																
160-250									5.4			4.4	3.1			2.1
Alkylate	15.7	14.1	0.0	13.6	30.8	0.0	0.0	25.0	26.7	0.0	0.0	21.8	22.9	41.1	0.0	21.9
Hydrocrackate	18.8	0.1		15.4	9.0	13.3	9.2	9.2	11.8	13.0	7.0	11.3	12.8	14.0	10.2	12.6
Dimate																
Poly Gasoline	0.2	1.1		0.2	3.4			2.7	0.1			0.1		1.0		0.2
FCC Gasoline:	24.6	52.3	52.8	29.7	19.0	47.4	47.8	24.5	22.3	43.2	50.7	27.1	21.6	29.2	48.4	26.8
Full Range	19.7		18.2	18.4	12.3	44.9	6.4	13.4	12.0	41.5	36.7	16.8	11.3	18.3	36.3	17.2
Light	2.6	8.9		2.6	0.6	0.8	14.3	2.4	-		13.9	1.8		0.8	5.5	1.2
Light - Desulf.															6.6	
Medium	0.5	5.2	20.4	3.3			12.9	1.7	2.0	1.6		1.7	1.4	3.4		1.5
Medum - Desulf.	1.6	29.0		2.9	5.8			4.7	5.7			4.6	7.1			4.7
Heavy							14.3	1.9							0.0	0.0
Heavy - Desulf.	0.2	9.3	14.2	2.5	0.3	1.7		0.4	2.7			2.2	1.7	6.7		2.2
Reformate	21.7	14.5	23.8	21.6	23.9	22.9	28.8	24.5	19.1	20.5	32.0	20.9	24.7	2.5	28.5	22.1
Light	8.2	5.5	19.1	9.4	14.3	22.9		12.9	9.7	12.4	1.2	8.8	13.4	2.5	3.4	9.9
Medium							28.8	3.8								
Heavy	13.6	9.0	4.7	12.2	9.6			7.8	9.4	8.1	30.7	12.1	11.4		25.0	12.2
Oxygenate	11.6	11.5	1.6	10.3	0.0	15.2	10.8	2.3	7.8	15.2	7.5	8.1	7.8	0.0	11.4	7.3
MTBE	11.4	11.5	1.6	10.1		12.7	10.8	2.1		12.7	7.5	1.7			10.6	2.0
Ethanol									7.8			6.3	7.8			5.2
TBA																
ETBE																
TAME	0.2			0.1		2.5		0.1		2.5		0.1			0.7	0.1
DIPE																
Volume (K Bbl/day)	1,022	68	161	1,251	982	68	161	1,211	1,022	68	161	1,251	822	200	229	1,236

Exhibit A-9: Modeling Results – Gasoline Composition and Volume, by Type and Case

Gasoline Composition & Volume	Long Term															
	Flat Limit Mode															
	MTBE				No Oxygenate				Ethanol							
	Ref 2005 1				HR 630 1				BasU Alk-100 1				Split 2.7wt% 9			
	CARB	Ariz.	Conv.	Pool	CARB	Ariz.	Conv.	Pool	CARB	Ariz.	Conv.	Pool	EOH	NoOxy	Other	Pool
Composition (vol%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
C4s:	0.6	3.2	3.9	1.2	0.5	0.5	3.5	0.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Butenes																
I-Butane																
N-Butane	0.6	3.2	3.9	1.2	0.5	0.5	3.5	0.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
C5s & Isomerate	6.3	7.0		5.6	9.6		1.4	8.1	4.4	7.3	1.4	4.2	4.7	16.5	1.0	6.9
Raffinate																
Natural Gas Liquids																
Naphtha	2.4	0.0	4.8	2.6	2.1	1.2	0.0	1.8	6.1	2.9	0.0	5.2	5.4	0.0	0.0	3.2
C5-160	2.4		4.8	2.6	2.1	1.2		1.8	1.9	2.9		1.8				
Coker Naphtha																
160-250									4.1			3.4	5.4			3.2
Alkylate	14.2	13.7	6.0	13.2	25.6	15.5	0.0	21.9	25.3	1.9	0.0	21.0	20.3	40.8	0.0	21.8
Hydrocrackate	17.1	0.1	8.2	15.2	8.8	11.2	14.4	9.8	13.2	12.9	3.5	12.1	11.2	13.0	9.8	11.5
Dimate																
Poly Gasoline	0.1	0.9		0.1	2.0			1.7	0.1			0.1		0.3		0.1
FCC Gasoline:	26.8	45.7	46.9	29.7	24.7	43.6	40.0	27.1	22.0	43.0	59.6	27.1	22.3	26.0	50.1	27.4
Full Range	20.0		24.2	19.7	17.6	32.6	11.0	17.7	11.4	42.9	48.2	18.0	14.2	6.2	38.4	16.9
Light	1.6			1.3	0.6		5.9	1.3			2.0	0.3		1.8	5.1	1.4
Light - Desulf.	0.7	5.9				10.5	2.7				9.4				6.6	
Medium	1.5	8.0	14.2	3.6			10.6	1.4	2.2			1.8	0.3	8.2		2.1
Medum - Desulf.	1.0	26.5		2.2	5.5			4.5	5.6			4.7	7.8			4.6
Heavy						0.3	9.7	1.3								
Heavy - Desulf.	1.9	5.3	8.4	3.0	1.0	0.2		0.8	2.8	0.1		2.3		9.8		2.4
Reformate	21.0	17.6	28.6	22.0	26.7	12.9	26.6	26.1	20.7	16.2	29.7	21.9	27.8	2.9	27.5	22.0
Light	9.8		13.2	9.8	16.5			13.6	10.9	0.4	4.4	9.6	15.6	2.9		9.8
Medium							1.0	0.1								
Heavy	11.2	17.6	15.4	12.2	10.1	12.9	25.6	12.4	9.8	15.8	25.3	12.3	12.2		27.5	12.2
Oxygenate	11.5	11.9	1.6	10.4	0.0	15.2	14.0	2.7	7.8	15.2	5.2	7.9	7.8	0.0	11.1	6.6
MTBE	11.5	9.4	1.6	10.2		12.7	14.0	2.6		12.7	5.2	1.4			10.4	1.9
Ethanol									7.8			6.4	7.8			4.5
TBA																
ETBE																
TAME		2.5		0.1		2.5		0.1		2.5		0.1			0.7	0.1
DIPE																
Volume (K Bbl/day)	1,022	68	161	1,240	1,002	68	161	1,219	1,022	68	161	1,236	722	300	229	1,236

Exhibit A-10: Summary of Effects of California MTBE Ban, by Case

	Intermediate Term							
	Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
	Ref 2002	HR630	BasU Alk-100	Split 2.7wt%	Ref 2002	HR 630	BasU Alk-100	Split 2.7wt%
Measure	1	1	1a	9	1	1	1	9
COSTS								
Total Average Cost (¢/gal.)	**-**	**8.8**	**7.5**	**4.8**	**-**	**4.3**	**6.1**	**2.7**
Variable Cost		8.0	5.6	3.6		4.3	4.3	1.9
Refinery Capital Charge		0.0	0.0	0.0		0.0	0.2	0.0
Ancillary Refining Cost		1.3	0.9	0.9		0.7	0.8	0.8
Logistics Cost			0.1	0.1			0.1	0.0
Mileage Loss		-0.5	0.9	0.1		-0.8	0.7	0.0
Total Seasonal Cost ($ million)	**-**	**660**	**560**	**350**	**-**	**320**	**450**	**200**
Variable Cost		600	410	270		320	320	140
Refinery Capital Charge		0	0	0		0	10	0
Ancillary Refining Cost		100	70	70		60	60	60
Logistics Cost			6	4			6	4
Mileage Loss		-40	70	. 10		-60	50	0
Refinery Investment ($million)	-	3	23	19	-	4	75	10
IMPORTS/EXPORTS (K bbl/d)								
Oxygenates	**108**	**6**	**78**	**56**	**108**	**12**	**79**	**57**
MTBE	108	6	3	9	108	12	4	14
Ethanol			75	48			75	44
TBA								
ETBE								
TAME								
Other Imports	**11**	**430**	**249**	**238**	**11**	**302**	**174**	**144**
Isobutane		11	13	10		7	11	7
Alkylate	11	111	111	111	11	111	111	111
CARBOB		255	65	65		140		
Jet Fuel & EPA Diesel		54	60	53		44	52	26
Rejected Blendstocks	**0**	**283**	**64**	**61**	**0**	**126**	**42**	**14**
Mixed Butylenes								
Pentanes		0	2	0		0	2	0
Light Coker Naphtha							1	
Light FCC Gasoline		8	19	7			20	2
Heavy FCC Gasoline		9	12	12		9	11	12
Naphtha (250 - 325 °F)		158	31	42		116	7	
Heavy Reformate		28						
CAPACITY UTILIZATION (%)								
Crude Distillation	97	91	90	91	97	93	93	94
Conversion	95	90	88	91	95	93	92	94
Upgrading	79	68	69	76	78	74	74	83

Exhibit A-10 backup: Modeling Results – Calculation of Costs and Investments, by Case

Cost Categories	Intermediate Term							
	Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
	Ref 2002	HR630	BasU Alk-100	Split 2.7wt%	Ref 2002	HR 630	BasU Alk-100	Split 2.7wt%
	1	1	1a	9	1	1	1	9
Objective Function ($K/day)	-5,989	-2,792	-3,879	-4,319	-6,099	-4,178	-4,414	-5,138
Investment ($MM)	0	3	23	19	0	4	75	10
Logistics Costs ($MM)			60	38			60	35
Obj. Func – 2 Pools ($K/day) *			-3,888				-4,425	
Accounting Information ($K/day)								
Input Cost	44,093	50,327	47,204	46,664	44,006	47,810	46,228	45,129
Product Revenue	-51,073	-54,057	-52,031	-51,972	-51,073	-52,946	-51,682	-51,276
Process Cost	992	934	923	968	968	954	957	998
Refinery Capital Charge	0	4	25	21	0	4	83	12
Adjusted Obj. Function ($K/day)	-5,736	-2,475	-3,458	-4,256	-5,845	-4,103	-4,033	-5,071
Input Cost (1)	44,346	50,645	47,631	46,723	44,259	47,886	46,629	45,188
Product Revenue	-51,073	-54,057	-52,031	-51,972	-51,073	-52,946	-51,682	-51,276
Process Cost	992	934	923	968	968	954	957	998
2 Pool Obj. Function				10				11
Subtotal:	-5,736	-2,478	-3,477	-4,272	-5,845	-4,106	-4,096	-5,080
Refinery Capital Charge (2)	0	3	19	16	0	3	63	9
Gasoline Energy Density (MM Btu/bbl)								
CARB RFG	5.129	5.158	-5.080	5.122	5.134	5.178	5.092	5.133
CARB RFG plus Arizona RFG	5.131				5.135			
Gasoline Volume (K Bbl/day)								
Total (3)	1179	1179	1179	1179	1179	1179	1179	1179
For Unit Cost Calculations (4)	965	965	965	965	965	965	965	965
Cost Calculations								
Variable (¢/gal.)		8.0	5.6	3.6		4.3	4.3	1.9
Capital Charge (¢/gal.)		0.0	0.0	0.0		0.0	0.2	0.0
Ancillary Costs (¢/gal.)	0.0	1.3	0.9	0.9	0.0	0.7	0.8	0.8
Logistics Costs (¢/gal.)	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.0
Aggregate Refinery Inv. ($MM)		3	23	19		4	75	10
Pool Mileage Loss (%)		-0.55	0.97	0.13		-0.85	0.82	0.02
Ancillary Cost Ratio & Fixed Charge	15.0%	0.1						
Annual Amortization of Logistics Inv.	20.4%							
Capital Recovery Adjustment	0.763							
Gasoline Consumption:	CARB	Arizona	Conv	Total				
2002	965	64	150	1,179				
2005	1,022	68	161	1,251				

* Combining Arizona and conventional gasoline into a single pool improves the objective function slightly.
(1) Adjusted for inputs with supply curves (see Exhibit 6C).
(2) Adjusted to reflect a 10% real, after-tax rate of return, rather than the 15% after-tax hurdle rate for investment.
(3) Production of CARB gasoline, Arizona RFG and conventional gasoline plus blended imported CARBOB.
(4) CARB RFG for California Only MTBE Ban Cases, and CARB RFG plus Arizona RFG for National MTBE Ban Cases.

Exhibit A-10: Summary of Effects of California MTBE Ban, by Case

	Long Term							
	Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
	Ref 2005	HR630	BasU Alk-100	Split 2.7wt%	Ref 2005	HR 630	BasU Alk-100	Split 2.7wt%
Measure	1	1	1a	9	1	1	1	9
COSTS								
Total Average Cost (¢/gal.)	-	3.7	2.4	1.9	-	0.9	1.9	1.2
Variable Cost		1.8	1.3	1.0		1.1	0.9	0.7
Refinery Capital Charge		2.2	0.2	0.2		0.8	0.1	0.1
Ancillary Refining Cost		0.7	0.3	0.3		0.4	0.3	0.3
Logistics Cost			0.1	0.1			0.1	0.1
Mileage Loss		-0.9	0.6	0.2		-1.3	0.6	0.2
Total Seasonal Cost ($ million)	-	290	190	140	-	70	150	90
Variable Cost		140	100	80		80	70	50
Refinery Capital Charge		170	10	20		60	10	10
Ancillary Refining Cost		50	20	20		30	20	20
Logistics Cost			6	5			6	4
Mileage Loss		-70	50	20		-100	40	10
Refinery Investment ($million)	-	1,104	86	123	-	394	38	36
IMPORTS/EXPORTS (K bbl/d)								
Oxygenates	115	14	88	76	115	19	84	68
MTBE	115	14	9	12	115	19	5	12
Ethanol			79	64			79	56
TBA								
ETBE								
TAME								
Other Imports	11	186	128	128	11	143	102	112
Isobutane		34	8	9		12	4	5
Alkylate	11	111	111	111	11	111	98	107
CARBOB		40				20		
Jet Fuel & EPA Diesel								
Rejected Blendstocks	0	16	45	43	0	29	44	14
Mixed Butylenes		16	12	22		29	8	0
Pentanes			25	20			24	14
Light Coker Naphtha								
Light FCC Gasoline			8				12	
Heavy FCC Gasoline								
Naphtha (250 - 325 °F)								
Heavy Reformate								
CAPACITY UTILIZATION (%)								
Crude Distillation	98	94	97	97	98	98	98	97
Conversion	97	93	96	96	97	97	96	96
Upgrading	83	94	81	85	83	96	82	87

Exhibit A-10 backup: Modeling Results – Calculation of Costs and Investments, by Case

Cost Categories	Long Term							
	Averaging Mode				Flat Limit Mode			
	MTBE	No Oxy	Ethanol		MTBE	No Oxy	Ethanol	
	Ref 2005	HR630	BasU Alk-100	Split 2.7wt%	Ref 2005	HR 630	BasU Alk-100	Split 2.7wt%
	1	1	1a	9	1	1	1	9
Objective Function ($K/day)	-6,590	-4,262	-5,546	-5,598	-6,713	-5,422	-5,857	-5,977
Investment ($MM)	0	1,104	86	123	0	394	38	36
Logistics Costs ($MM)			60	48			60	42
Obj. Func – 2 Pools ($K/day) *			-5,549				-5,862	
Accounting Information ($K/day)								
Input Cost	46,352	47,601	47,897	47,749	46,255	47,408	47,653	47,103
Product Revenue	-53,997	-54,195	-54,583	-54,536	-53,997	-54,342	-54,598	-54,191
Process Cost	1,055	1,113	1,048	1,058	1,028	1,080	1,049	1,072
Refinery Capital Charge	0	1,219	91	130	0	433	40	39
Adjusted Obj. Function ($K/day)	-6,117	-4,435	-5,509	-5,567	-6,240	-5,455	-5,807	-5,922
Input Cost (1)	46,825	47,717	47,956	47,808	46,728	47,477	47,712	47,162
Product Revenue	-53,997	-54,195	-54,583	-54,536	-53,997	-54,342	-54,598	-54,191
Process Cost	1,055	1,113	1,048	1,058	1,028	1,080	1,049	1,072
2 Pool Obj. Function				3				5
Subtotal:	-6,117	-5,365	-5,578	-5,667	-6,240	-5,785	-5,838	-5,952
Refinery Capital Charge (2)	0	930	70	100	0	330	31	30
Gasoline Energy Density (MM Btu/bbl)								
CARB RFG	5.130	5.183	5.095	5.115	5.134	5.212	5.101	5.124
CARB RFG plus Arizona RFG	5.131				5.136			
Gasoline Volume (K Bbl/day)								
Total (3)	1251	1251	1251	1251	1251	1251	1251	1251
For Unit Cost Calculations (4)	1022	1022	1022	1022	1022	1022	1022	1022
Cost Calculations								
Variable (¢/gal.)		1.8	1.3	1.0		1.1	0.9	0.7
Capital Charge (¢/gal.)		2.2	0.2	0.2		0.8	0.1	0.1
Ancillary Costs (¢/gal.)	0.0	0.7	0.3	0.3	0.0	0.4	0.3	0.3
Logistics Costs (¢/gal.)	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.1
Aggregate Refinery Inv. ($MM)		1,104	86	123		394	38	36
Pool Mileage Loss (%)		-1.04	0.68	0.27		-1.51	0.65	0.21
Ancillary Cost Ratio & Fixed Charge								
Annual Amortization of Logistics Inv.								
Capital Recovery Adjustment								
Gasoline Consumption:								
2002								
2005								

* Combining Arizona and conventional gasoline into a single pool improves the objective function slightly.

(1) Adjusted for inputs with supply curves (see Exhibit 6C).

(2) Adjusted to reflect a 10% real, after-tax rate of return, rather than the 15% after-tax hurdle rate for investment.

(3) California gasoline consumption (production plus blended imported CARBOB) and production of Arizona RFG and conventi

(4) CARB RFG for California Only MTBE Ban Cases, and CARB RFG plus Arizona RFG for National MTBE Ban Cases.