JPMORGAN CHASE & CO
Form 424B2
April 05, 2019

Pricing supplement
To prospectus dated April 5, 2018,
prospectus supplement dated April 5, 2018 and
product supplement no. 4-I dated April 5, 2018

Registration Statement Nos. 333-222672 and 333-222672-01
Dated April 3, 2019
Rule 424(b)(2)

JPMorgan Chase Financial Company LLC

Structured Investments	$2,005,000 Auto Callable Contingent Interest Notes Linked to the Common Stock of The Williams Companies, Inc. due April 22, 2020
General	Fully and Unconditionally Guaranteed by JPMorgan Chase & Co.

The notes are designed for investors who seek a Contingent Interest Payment if, (1) with respect to any Review Date (other than the final Review Date), the closing price of one share of the Reference Stock or, (2) with respect to the final Review Date, the Final Stock Price is greater than or equal to 75.00% of the Initial Stock Price, which we refer to as the Interest Barrier. Investors should be willing to forgo fixed interest and dividend payments, in exchange for the opportunity to receive Contingent Interest Payments.
Investors in the notes should be willing to accept the risk of losing some or all of their principal if a Trigger Event (as defined below) has occurred and the risk that no Contingent Interest Payment may be made with respect to some or all Review Dates. Contingent Interest Payments should not be viewed as periodic interest payments.
The notes will be automatically called if the closing price of one share of the Reference Stock on any Review Date (other than the final Review Date) is greater than or equal to the Initial Stock Price. The earliest date on which an automatic call may be initiated, is July 18, 2019.
The notes are unsecured and unsubordinated obligations of JPMorgan Chase Financial Company LLC, which we refer to as JPMorgan Financial, the payment on which is fully and unconditionally guaranteed by JPMorgan Chase & Co.
Any payment on the notes is subject to the credit risk of JPMorgan Financial, as issuer of the notes, and the credit risk of JPMorgan Chase & Co., as guarantor of the notes.
Minimum denominations of $10,000 and integral multiples of $1,000 in excess thereof
Key Terms

Issuer:	JPMorgan Chase Financial Company LLC, an indirect, wholly owned finance subsidiary of JPMorgan Chase & Co.
Guarantor:	JPMorgan Chase & Co.
Reference Stock:	The common stock of The Williams Companies, Inc., par value $1.00 per share (Bloomberg Ticker: WMB). We refer to The Williams Companies, Inc. as “The Williams Companies.”
Contingent Interest Payments:	If the notes have not been automatically called and (1) with respect to any Review Date (other than the final Review Date), the closing price of one share of the Reference Stock on that Review Date or (2) with respect to the final Review Date, the Final Stock Price is greater than or equal to the Interest Barrier, you will receive on the applicable Interest Payment Date for each $1,000 principal amount note a Contingent Interest Payment equal to $28.25.

	If (1) with respect to any Review Date (other than the final Review Date), the closing price of one share of the Reference Stock on that Review Date or, (2) with respect to the final Review Date, the Final Stock Price is less than the Interest Barrier, no Contingent Interest Payment will be made with respect to that Review Date.
Interest Barrier / Trigger Level:	$21.6825, which is an amount that represents 75.00% of the Initial Stock Price
Automatic Call:	If, with respect to any Review Date (other than the final Review Date), the closing price of one share of the Reference Stock is ***greater than or equal to*** the Initial Stock Price, the notes will be automatically called for a cash payment, for each $1,000 principal amount note, equal to (a) $1,000 *plus* (b) the Contingent Interest Payment applicable to that Review Date, payable on the applicable Call Settlement Date.
Payment at Maturity:	If the notes have not been automatically called and a Trigger Event has ***not*** occurred, you will receive a cash payment at maturity, for each $1,000 principal amount note, equal to (a) $1,000 *plus* (b) the Contingent Interest Payment applicable to the final Review Date. If the notes have not been automatically called and a Trigger Event ***has*** occurred, at maturity you will lose 1% of the principal amount of your notes for every 1% that the Final Stock Price is less than the Initial Stock Price. Under these circumstances, your payment at maturity per $1,000 principal amount note will be calculated as follows: $1,000 + ($1,000 x Stock Return) *If the notes have not been automatically called and a Trigger Event has occurred, you will lose more than 25.00% of the principal amount of your notes at maturity and could lose all of the principal amount of your notes at maturity.*
Trigger Event:	A Trigger Event occurs if the Final Stock Price (*i.e.,* the arithmetic averaging of the closing prices of one share of the Reference Stock on the Ending Averaging Dates) is less than the Trigger Level.
Stock Return:	$\frac{\text{(Final Stock Price – Initial Stock Price)}}{\text{Initial Stock Price}}$
Initial Stock Price:	The closing price of one share of the Reference Stock on the Pricing Date, which was $28.91
Final Stock Price:	The arithmetic average of the closing prices of one share of the Reference Stock on the Ending Averaging Dates
Stock Adjustment Factor:	The Stock Adjustment Factor is referenced in determining the closing price of one share of the Reference Stock and is set initially at 1.0 on the Pricing Date. The Stock Adjustment Factor is subject to adjustment upon the occurrence of certain corporate events affecting the Reference Stock. See "The Underlyings —Reference Stocks— Anti-Dilution Adjustments" and "The Underlyings — Reference Stocks — Reorganization Events" in the accompanying product supplement for further information.
Pricing Date:	April 3, 2019
Original Issue Date (Settlement Date):	On or about April 8, 2019
Review Dates†:	July 18, 2019 (first Review Date), October 17, 2019 (second Review Date), January 16, 2020 (third Review Date) and April 17, 2020 (final Review Date)
Ending Averaging Dates†:	April 13, 2020, April 14, 2020, April 15, 2020, April 16, 2020 and the final Review Date
Interest Payment Dates†:	July 23, 2019, October 22, 2019, January 22, 2020 and the Maturity Date
Call Settlement Date†:	If the notes are automatically called on any Review Date (other than the final Review Date), the first Interest Payment Date immediately following that Review Date

Maturity Date:†	April 22, 2020
CUSIP:	48132CAU7
Other Key Terms:	See “Additional Key Terms” in this pricing supplement

† Subject to postponement in the event of certain market disruption events and as described under “General Terms of Notes — Postponement of a Determination Date — Notes Linked to a Single Underlying — Notes Linked to a Single Underlying (Other Than a Commodity Index)” and “General Terms of Notes — Postponement of a Payment Date” in the accompanying product supplement.

Investing in the notes involves a number of risks. See “Risk Factors” beginning on page PS-10 of the accompanying product supplement and “Selected Risk Considerations” beginning on page PS-5 of this pricing supplement.

Neither the Securities and Exchange Commission (the “SEC”) nor any state securities commission has approved or disapproved of the notes or passed upon the accuracy or the adequacy of this pricing supplement or the accompanying product supplement, prospectus supplement and prospectus. Any representation to the contrary is a criminal offense.

	Price to Public (1)	Fees and Commissions (2)	Proceeds to Issuer
Per note	$1,000	$10	$990
Total	$2,005,000	$20,050	$1,984,950

(1) See “Supplemental Use of Proceeds” in this pricing supplement for information about the components of the price to public of the notes.

(2) J.P. Morgan Securities LLC, which we refer to as JPMS, acting as agent for JPMorgan Financial, will pay all of the selling commissions of $10.00 per $1,000 principal amount note it receives from us to other affiliated or unaffiliated dealers. See “Plan of Distribution (Conflicts of Interest)” in the accompanying product supplement.

The estimated value of the notes, when the terms of the notes were set, was $982.10 per $1,000 principal amount note. See “The Estimated Value of the Notes” in this pricing supplement for additional information.

The notes are not bank deposits, are not insured by the Federal Deposit Insurance Corporation or any other governmental agency, and are not obligations of, or guaranteed by, a bank.

Additional Terms Specific to the Notes

You should read this pricing supplement together with the accompanying prospectus, as supplemented by the accompanying prospectus supplement, relating to our Series A medium-term notes of which these notes are a part, and the more detailed information contained in the accompanying product supplement. **This pricing supplement, together with the documents listed below, contains the terms of the notes and supersedes all other prior or contemporaneous oral statements as well as any other written materials including preliminary or indicative pricing terms, correspondence, trade ideas, structures for implementation, sample structures, fact sheets, brochures or other educational materials of ours.** You should carefully consider, among other things, the matters set forth in the "Risk Factors" section of the accompanying product supplement, as the notes involve risks not associated with conventional debt securities. We urge you to consult your investment, legal, tax, accounting and other advisers before you invest in the notes.

You may access these documents on the SEC website at www.sec.gov as follows (or if such address has changed, by reviewing our filings for the relevant date on the SEC website):

Product supplement no. 4-I dated April 5, 2018:
http://www.sec.gov/Archives/edgar/data/19617/000095010318004519/dp87528_424b2-ps4i.pdf
Prospectus supplement and prospectus, each dated April 5, 2018:
http://www.sec.gov/Archives/edgar/data/19617/000095010318004508/dp87767_424b2-ps.pdf
Our Central Index Key, or CIK, on the SEC website is 1665650, and JPMorgan Chase & Co.'s CIK is 19617. As used in this pricing supplement, "we," "us" and "our" refer to JPMorgan Financial.

What Are the Payments on the Notes, Assuming a Range of Performances for the Reference Stock?

If the notes have not been automatically called and, (1) with respect to any Review Date (other than the final Review Date), the closing price of one share of the Reference Stock or, (2) with respect to the final Review Date, the Final Stock Price is greater than or equal to the Interest Barrier, you will receive on the applicable Interest Payment Date for each $1,000 principal amount note a Contingent Interest Payment equal to $28.25. If, (1) with respect to any Review Date (other than the final Review Date), the closing price of one share of the Reference Stock or, (2) with respect to the final Review Date, the Final Stock Price is less than the Interest Barrier, no Contingent Interest Payment will be made with respect to that Review Date. We refer to the Interest Payment Date immediately following any Review Date on which the closing price of one share of the Reference Stock or Final Stock Price, as applicable, is less than the Interest Barrier as a “No-Coupon Date.” The following table reflects the Contingent Interest Payment of $28.25 per $1,000 principal amount note and illustrates the hypothetical total Contingent Interest Payments per $1,000 principal amount note over the term of the notes depending on how many No-Coupon Dates occur.

Number of No-Coupon Dates	**Total Contingent Coupon Payments**
0 No-Coupon Dates	$113.00
1 No-Coupon Date	$84.75
2 No-Coupon Dates	$56.50
3 No-Coupon Dates	$28.25
4 No-Coupon Dates	$0.00

The following table illustrates the hypothetical payments on the notes in different hypothetical scenarios. Each hypothetical payment set forth below assumes an Initial Stock Price of $30 and an Interest Barrier and a Trigger Level of $22.50 (equal to 75.00% of the hypothetical Initial Stock Price) and reflects the Contingent Interest Payment of $28.25 per $1,000 principal amount note. Each hypothetical payment set forth below is for illustrative purposes only and may not be the actual payment applicable to a purchaser of the notes. The numbers appearing in the following table and examples have been rounded for ease of analysis.

	Review Dates Prior to the Final Review Date		**Final Review Date**			
Closing Price of One Share of the Reference Stock	**Appreciation / Depreciation of the Reference Stock at Review Date**	**Payment on Interest Payment Date or Call Settlement Date (1)(2)**	**Final Stock Price**	**Appreciation / Depreciation of the Reference Stock at Final Review Date**	**Payment at Maturity If a Trigger Event Has Not Occurred (2)(3)**	**Payment at Maturity If a Trigger Event Has Occurred (3)**
$54.000	80.00%	$1,028.25	$54.000	80.00%	$1,028.25	N/A
$51.000	70.00%	$1,028.25	$51.000	70.00%	$1,028.25	N/A
$48.000	60.00%	$1,028.25	$48.000	60.00%	$1,028.25	N/A
$45.000	50.00%	$1,028.25	$45.000	50.00%	$1,028.25	N/A
$42.000	40.00%	$1,028.25	$42.000	40.00%	$1,028.25	N/A
$39.000	30.00%	$1,028.25	$39.000	30.00%	$1,028.25	N/A
$37.500	25.00%	$1,028.25	$37.500	25.00%	$1,028.25	N/A
$36.000	20.00%	$1,028.25	$36.000	20.00%	$1,028.25	N/A

$34.500	15.00%	$1,028.25	$34.500	15.00%	$1,028.25	N/A
$33.000	10.00%	$1,028.25	$33.000	10.00%	$1,028.25	N/A
$31.500	5.00%	$1,028.25	$31.500	5.00%	$1,028.25	N/A
$30.000	**0.00%**	**$1,028.25**	**$30.000**	**0.00%**	**$1,028.25**	**N/A**
$28.500	**-5.00%**	$28.25	**$28.500**	**-5.00%**	$1,028.25	N/A
$27.000	**-10.00%**	$28.25	**$27.000**	**-10.00%**	$1,028.25	N/A
$25.500	**-15.00%**	$28.25	**$25.500**	**-15.00%**	$1,028.25	N/A
$24.000	**-20.00%**	$28.25	**$24.000**	**-20.00%**	$1,028.25	N/A
$22.500	**-25.00%**	$28.25	**$22.500**	**-25.00%**	$1,028.25	N/A
$22.497	-25.01%	N/A	$22.497	-25.01%	N/A	$749.90
$21.000	-30.00%	N/A	$21.000	-30.00%	N/A	$700.00
$18.000	-40.00%	N/A	$18.000	-40.00%	N/A	$600.00
$15.000	-50.00%	N/A	$15.000	-50.00%	N/A	$500.00
$12.000	-60.00%	N/A	$12.000	-60.00%	N/A	$400.00
$9.000	-70.00%	N/A	$9.000	-70.00%	N/A	$300.00
$6.000	-80.00%	N/A	$6.000	-80.00%	N/A	$200.00
$3.000	-90.00%	N/A	$3.000	-90.00%	N/A	$100.00
$0.000	-100.00%	N/A	$0.000	-100.00%	N/A	$0.00

(1) The notes will be automatically called if the closing price of one share of the Reference Stock on any Review Date (other than the final Review Date) is greater than or equal to the Initial Stock Price.

(2) You will receive a Contingent Interest Payment in connection with a Review Date if, (1) with respect to any Review Date (other than the final Review Date), the closing price of one share of the Reference Stock or, (2) with respect to the final Review Date, the Final Stock Price is greater than or equal to the Interest Barrier.

(3) A Trigger Event occurs if the Final Stock Price (*i.e.*, the arithmetic average of the closing prices of one share of the Reference Stock on the Ending Averaging Dates) is less than the Trigger Level.

Hypothetical Examples of Amounts Payable on the Notes

The following examples illustrate how payments on the notes in different hypothetical scenarios are calculated.

Example 1: The price of one share of the Reference Stock increases from the Initial Stock Price of $30 to a closing level of $33 on the first Review Date. Because the closing price of one share of the Reference Stock on the first Review Date is greater than the Interest Barrier, the investor is entitled to receive a Contingent Interest Payment in connection with the first Review Date. In addition, because the closing price of one share of the Reference Stock on the first Review Date is greater than the Initial Stock Price, the notes are automatically called. Accordingly, the investor receives a payment of $1,028.25 per $1,000 principal amount note on the relevant Call Settlement Date, consisting of a Contingent Interest Payment of $28.25 per $1,000 principal amount note and repayment of principal equal to $1,000 per $1,000 principal amount note.

Example 2: A Contingent Interest Payment is paid in connection with one of the Review Dates preceding the third Review Date, the closing price of one share of the Reference Stock is less than the Initial Stock Price of $30 on each of the Review Dates preceding the third Review Date and the price of one share of the Reference Stock increases from the Initial Stock Price of $30 to a closing price of $36 on the third Review Date. The investor receives a payment of $28.25 per $1,000 principal amount note in connection with one of the Review Dates preceding the third Review Date, but the notes are not automatically called on any of the Review Dates preceding the third Review Date because the closing price of one share of the Reference Stock is less than the Initial Stock Price on each of the Review Dates preceding the third Review Date. Because the closing price of one share of the Reference Stock on the third Review Date is greater than the Interest Barrier, the investor is entitled to receive a Contingent Interest Payment in connection with the third Review Date. In addition, because the closing price of one share of the Reference Stock on the third Review Date is greater than the Initial Stock Price, the notes are automatically called. Accordingly, the investor receives a payment of $1,028.25 per $1,000 principal amount note on the relevant Call Settlement Date, consisting of a Contingent Interest Payment of $28.25 per $1,000 principal amount note and repayment of principal equal to $1,000 per $1,000 principal amount note. As a result, the total amount paid on the notes over the term of the notes is $1,056.50 per $1,000 principal amount note.

Example 3: The notes are not automatically called prior to maturity, Contingent Interest Payments are paid in connection with each of the Review Dates preceding the final Review Date and the price of one share of the Reference Stock increases from the Initial Stock Price of $30 to a Final Stock Price of $36 — A Trigger Event has not occurred. The investor receives a payment of $28.25 per $1,000 principal amount note in connection with each of the Review Dates preceding the final Review Date. Because the notes are not automatically called prior to maturity and a Trigger Event has not occurred, the investor receives at maturity a payment of $1,028.25 per $1,000 principal amount note. This payment consists of a Contingent Interest Payment of $28.25 per $1,000 principal amount note and repayment of principal equal to $1,000 per $1,000 principal amount note. The total amount paid on the notes over the term of the notes is $1,113.00 per $1,000 principal amount note. ***This represents the maximum total payment an investor may receive over the term of the notes.***

Example 4: The notes are not automatically called prior to maturity, Contingent Interest Payments are paid in connection with two of the Review Dates preceding the final Review Date and the price of one share of the Reference Stock decreases from the Initial Stock Price of $30 to a Final Stock Price of $23 — A Trigger Event has not occurred. The investor receives a payment of $28.25 per $1,000 principal amount note in connection with two of the Review Dates preceding the final Review Date. Because the notes are not automatically called prior to maturity and a Trigger Event has not occurred, even though the Final Stock Price is less than the Initial Stock Price, the investor receives at maturity a payment of $1,028.25 per $1,000 principal amount note. This payment consists of a Contingent Interest Payment of $28.25 per $1,000 principal amount note and repayment of principal equal to $1,000 per $1,000 principal amount note. The total amount paid on the notes over the term of the notes is $1,084.75 per $1,000 principal amount note.

Example 5: The notes are not automatically called prior to maturity, Contingent Interest Payments are paid in connection with each of the Review Dates preceding the final Review Date and the price of one share of the Reference Stock decreases from the Initial Stock Price of $30 to a Final Stock Price of $12 — A Trigger Event has occurred. The investor receives a payment of $28.25 per $1,000 principal amount note in connection with each of the Review Dates preceding the final Review Date. Because the notes are not automatically called prior to maturity, a Trigger Event has occurred and the Stock Return is -60%, the investor receives at maturity of $400 per $1,000 principal amount note, calculated as follows:

$1,000 + ($1,000 × -60%) = $400

The total value of the payments on the notes over the term of the notes is $484.75 per $1,000 principal amount note.

Example 6: The notes are not automatically called prior to maturity, no Contingent Interest Payments are paid in connection with the Review Dates preceding the final Review Date and the price of one share of the Reference Stock decreases from the Initial Stock Price of $30 to a Final Stock Price of $9 — A Trigger Event has occurred. Because the notes are not automatically called prior to maturity, no Contingent Interest Payments are paid in connection with the Review Dates preceding the final Review Date, a Trigger Event has occurred and the Stock Return is -70%, the investor receives no payments over the term of the notes, other than a payment at maturity of $300 per $1,000 principal amount note, calculated as follows:

$\$1,000 + (\$1,000 \times -70\%) = \$300$

The hypothetical payments on the notes shown above apply **only if you hold the notes for their entire term or until automatically called.** These hypotheticals do not reflect fees or expenses that would be associated with any sale in the secondary market. If these fees and expenses were included, the hypothetical payments shown above would likely be lower.

Selected Purchase Considerations

CONTINGENT INTEREST PAYMENTS — The notes offer the potential to earn a Contingent Interest Payment in connection with each Review Date of $28.25 per $1,000 principal amount note. If the notes have not been automatically called and, (1) with respect to any Review Date (other than the final Review Date), the closing price of one share of the Reference Stock or, (2) with respect to the final Review Date, the Final Stock Price is greater than or equal to the Interest Barrier, you will receive on the applicable Interest Payment Date a Contingent Interest Payment for that Review Date. If, (1) with respect to any Review Date (other than the final Review Date), the closing price of one share of the Reference Stock or, (2) with respect to the final Review Date, the Final Stock Price is less than the Contingent Interest Barrier, no Contingent Interest Payment will be made with respect to that Review Date. If payable, a Contingent Interest Payment will be made to the holders of record at the close of business on the business day immediately preceding the applicable Interest Payment Date. **Because the notes are our unsecured and unsubordinated obligations, the payment of which is fully and unconditionally guaranteed by JPMorgan Chase & Co., payment of any amount on the notes is subject to our ability to pay our obligations as they become due and JPMorgan Chase & Co.'s ability to pay its obligations as they become due.**

POTENTIAL EARLY EXIT AS A RESULT OF THE AUTOMATIC CALL FEATURE — If the closing price of one share of the Reference Stock on any Review Date (other than the final Review Date) is greater than or equal to the Initial Stock Price, your notes will be automatically called prior to the Maturity Date. Under these circumstances, you will receive a cash payment, for each $1,000 principal amount note, equal to (a) $1,000 *plus* (b) the Contingent Interest Payment applicable to that Review Date, payable on the applicable Call Settlement Dates. Even in cases where the notes are called before maturity, you are not entitled to any fees and commissions described on the front cover of this pricing supplement.

THE NOTES DO NOT GUARANTEE THE RETURN OF YOUR PRINCIPAL IF THE NOTES HAVE NOT BEEN AUTOMATICALLY CALLED — If the notes have not been automatically called, we will pay you your principal back at maturity only if a Trigger Event has not occurred. **However, if the notes have not been automatically called and a Trigger Event has occurred, you will lose some or all of the principal amount of your notes at maturity.**

RETURN LINKED TO A SINGLE REFERENCE STOCK — The return on the notes is linked to the performance of a single Reference Stock, which is the common stock of The Williams Companies. For additional information see "The Reference Stock" in this pricing supplement.

TAX TREATMENT — You should review carefully the section entitled "Material U.S. Federal Income Tax Consequences" in the accompanying product supplement no. 4-I. In determining our reporting responsibilities we intend to treat (i) the notes for U.S. federal income tax purposes as prepaid forward contracts with associated contingent coupons and (ii) any Contingent Interest Payments as ordinary income, as described in the section entitled "Material U.S. Federal Income Tax Consequences — Tax Consequences to U.S. Holders — Notes Treated as Prepaid Forward Contracts with Associated Contingent Coupons" in the accompanying product supplement. Based on the advice of Davis Polk & Wardwell LLP, our special tax counsel, we believe that this is a reasonable treatment, but that there are other reasonable treatments that the IRS or a court may adopt, in which case the timing and character of any income or loss on the notes could be materially affected. In addition, in 2007 Treasury and the IRS released a notice requesting comments on the U.S. federal income tax treatment of "prepaid forward contracts" and similar instruments. The notice focuses in particular on whether to require investors in these instruments to accrue income over the term of their investment. It also asks for comments on a number of related topics, including the character of income or loss with respect to these instruments and the relevance of factors such as the nature of the underlying property to which the instruments are linked. While the notice requests comments on appropriate transition rules and effective dates, any Treasury regulations or other guidance promulgated after consideration of these issues could materially affect the tax consequences of an investment in the notes, possibly with retroactive effect. The discussions above and in the accompanying product supplement do not address the consequences to taxpayers subject to special tax accounting rules under Section 451(b) of the Code. You should consult your tax adviser regarding the U.S. federal income tax consequences of an investment in the notes, including possible alternative treatments and the issues presented by the notice described above.

Non-U.S. Holders — Tax Considerations. The U.S. federal income tax treatment of Contingent Interest Payments is uncertain, and although we believe it is reasonable to take a position that Contingent Interest Payments are not subject to U.S. withholding tax (at least if an applicable Form W-8 is provided), a withholding agent may nonetheless withhold on these payments (generally at a rate of 30%, subject to the possible reduction of that rate under an applicable income tax treaty), unless income from your notes is effectively connected with your conduct of a trade or business in the United States (and, if an applicable treaty so requires, attributable to a permanent establishment in the United States). If you are not a United States person, you are urged to consult your tax adviser regarding the U.S. federal income tax consequences of an investment in the notes in light of your particular circumstances.

Other income (expense), net	(5)	10	1	27
Interest and debt expense, net of capitalized interest	(74)	(107)	(173)	(224)
Income from continuing operations before income tax expense	1,282	1,193	945	1,337
Income tax expense	452	449	547	489
Income from continuing operations	830	744	398	848
Loss from discontinued operations, net of income taxes	—	(1)	—	(7)
Net income	830	743	398	841
Less: Net loss attributable to noncontrolling interest	(1)	(1)	(1)	(1)
Net income attributable to Valero Energy Corporation stockholders	$831	$744	$399	$842
Net income attributable to Valero Energy Corporation stockholders:				
Continuing operations	$831	$745	$399	$849
Discontinued operations	—	(1)	—	(7)
Total	$831	$744	$399	$842
Earnings per common share:				
Continuing operations	$1.50	$1.31	$0.72	$1.49
Discontinued operations	—	—	—	(0.01)
Total	$1.50	$1.31	$0.72	$1.48
Weighted-average common shares outstanding (in millions)	550	567	550	567
Earnings per common share – assuming dilution:				
Continuing operations	$1.50	$1.30	$0.72	$1.48
Discontinued operations	—	—	—	(0.01)

Total	$1.50	$1.30	$0.72	$1.47
Weighted-average common shares outstanding – assuming dilution (in millions)	555	574	556	573
Dividends per common share	$0.15	$0.05	$0.30	$0.10
Supplemental information:				
(a) Includes excise taxes on sales by our U.S. retail system	$241	$227	$475	$441

See Condensed Notes to Consolidated Financial Statements.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Millions of Dollars)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net income	$830	$743	$398	$841
Other comprehensive income (loss):				
Foreign currency translation adjustment	(91)	20	32	112
Pension and other postretirement benefits:				
(Gain) loss reclassified into income related to:				
Prior service credit	(6)	(5)	(10)	(10)
Net actuarial loss	9	4	17	7
Net gain (loss) on pension and other postretirement benefits	3	(1)	7	(3)
Derivative instruments designated and qualifying as cash flow hedges:				
Net gain (loss) arising during the period	(31)	—	16	—
Net (gain) loss reclassified into income	12	—	(36)	—
Loss on cash flow hedges	(19)	—	(20)	—
Other comprehensive income (loss), before income tax benefit	(107)	19	19	109
Income tax benefit related to items of other comprehensive income (loss)	(5)	—	(4)	(1)
Other comprehensive income (loss)	(102)	19	23	110
Comprehensive income	728	762	421	951
Less: Comprehensive loss attributable to noncontrolling interest	(1)	(1)	(1)	(1)
Comprehensive income attributable to Valero Energy Corporation stockholders	$729	$763	$422	$952

See Condensed Notes to Consolidated Financial Statements.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions of Dollars)
(Unaudited)

	Six Months Ended June 30, 2012	2011
Cash flows from operating activities:		
Net income	$398	$841
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	770	751
Asset impairment loss	611	—
Noncash interest expense and other income, net	11	21
Stock-based compensation expense	20	23
Deferred income tax expense	480	166
Changes in current assets and current liabilities	725	1,147
Changes in deferred charges and credits and other operating activities, net	(21)	5
Net cash provided by operating activities	2,994	2,954
Cash flows from investing activities:		
Capital expenditures	(1,420)	(969)
Deferred turnaround and catalyst costs	(264)	(432)
Advance payment related to acquisition of Pembroke Refinery	—	(37)
Minor acquisitions	(66)	(37)
Other investing activities, net	9	(19)
Net cash used in investing activities	(1,741)	(1,494)
Cash flows from financing activities:		
Non-bank debt:		
Borrowings	300	—
Repayments	(862)	(718)
Bank credit agreements:		
Borrowings	1,100	—
Repayments	(1,100)	—
Accounts receivable sales program:		
Proceeds from the sale of receivables	1,300	—
Repayments	(1,450)	—
Purchase of common stock for treasury	(147)	—
Proceeds from the exercise of stock options	11	30
Common stock dividends	(166)	(57)
Contributions from noncontrolling interest	25	9
Other financing activities, net	(2)	7
Net cash used in financing activities	(991)	(729)
Effect of foreign exchange rate changes on cash	9	42
Net increase in cash and temporary cash investments	271	773
Cash and temporary cash investments at beginning of period	1,024	3,334
Cash and temporary cash investments at end of period	$1,295	$4,107

See Condensed Notes to Consolidated Financial Statements.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

General

As used in this report, the terms “Valero,” “we,” “us,” or “our” may refer to Valero Energy Corporation, one or more of its consolidated subsidiaries, or all of them taken as a whole.

These unaudited financial statements have been prepared in accordance with United States (U.S.) generally accepted accounting principles (GAAP) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities Exchange Act of 1934. Accordingly, they do not include all of the information and notes required by U.S. GAAP for complete financial statements. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. All such adjustments are of a normal recurring nature unless disclosed otherwise. Financial information for the three and six months ended June 30, 2012 and 2011 included in these Condensed Notes to Consolidated Financial Statements is derived from our unaudited financial statements. Operating results for the three and six months ended June 30, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012.

The balance sheet as of December 31, 2011 has been derived from our audited financial statements as of that date. For further information, refer to our financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2011.

Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires us to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. On an ongoing basis, we review our estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

Comprehensive Income

Effective January 1, 2012, we adopted the provisions of Accounting Standards Codification (ASC) Topic 220, “Comprehensive Income,” and have elected to present comprehensive income in a statement that is separate from the statement of income but placed directly after the statement of income.

Fair Value Measurements

Effective January 1, 2012, we adopted the provisions of ASC Topic 820, “Fair Value Measurement,” which clarified the application of existing fair value measurement requirements and changed certain fair value measurement and disclosure requirements. The adoption of these provisions did not affect our financial position or results of operations as these requirements only affected disclosures as reflected in Note 12.

New Accounting Pronouncements

In December 2011, the provisions of ASC Topic 210, “Balance Sheet,” were amended to require an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of these arrangements on its financial position. The guidance requires entities to disclose both gross information and net information about both instruments and transactions eligible for offset in the balance sheet and instruments and transactions subject to an agreement similar to a master

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netting arrangement. These provisions are effective for interim and annual reporting periods beginning on January 1, 2013. The adoption of this guidance effective January 1, 2013 will not affect our financial position or results of operations, but may result in additional disclosures.

2. ACQUISITIONS

The acquired refining and marketing businesses discussed below involve the production and marketing of refined petroleum products. These acquisitions are consistent with our general business strategy and complement our existing refining and marketing network.

Meraux Acquisition

On October 1, 2011, we acquired the Meraux Refinery and related logistics assets from Murphy Oil Corporation for an initial payment of $586 million, which was funded from available cash. In the fourth quarter of 2011, we recorded an adjustment related to inventories acquired that reduced the purchase price to $547 million. The assets acquired and liabilities assumed in this acquisition were recognized at their acquisition-date estimated fair values, as disclosed in Note 2 of Notes to Consolidated Financial Statements included in our annual report on Form 10-K for the year ended December 31, 2011, and no adjustments to those estimated amounts have been made during the six months ended June 30, 2012. We are, however, awaiting the completion of an independent appraisal and other evaluations of the fair values of the assets acquired and liabilities assumed.

Pembroke Acquisition

On August 1, 2011, we acquired 100 percent of the outstanding shares of Chevron Limited from a subsidiary of Chevron Corporation (Chevron), and we subsequently changed the name of Chevron Limited to Valero Energy Ltd. On the acquisition date, we initially paid $1.8 billion from available cash, of which $1.1 billion was for working capital. In the fourth quarter of 2011, we recorded adjustments to working capital (primarily inventory), resulting in an adjusted purchase price of $1.7 billion. The assets acquired and liabilities assumed in this acquisition were recognized at their acquisition-date estimated fair values, as disclosed in Note 2 of Notes to Consolidated Financial Statements included in our annual report on Form 10-K for the year ended December 31, 2011, and no adjustments to those estimated amounts have been made during the six months ended June 30, 2012. We are, however, awaiting the completion of an independent appraisal and other evaluations of the fair values of the assets acquired and liabilities assumed. This acquisition is referred to as the Pembroke Acquisition.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. IMPAIRMENT

In March 2012, we suspended the operations of the Aruba Refinery because of the refinery's inability to generate positive cash flows on a sustained basis subsequent to its restart in January 2011 and the sensitivity of its profitability to sour crude oil differentials, which narrowed significantly in the fourth quarter of 2011. We considered the use of alternative feedstocks or configuration changes that might improve the refinery's cash flows and we also considered a temporary or permanent shutdown of the refinery facilities. We ultimately decided to shut down the refinery and to maintain it in a state that would allow for operations to be resumed.

On March 28, 2012, we received a non-binding indication of interest from an unrelated interested party to purchase the Aruba Refinery for $350 million, plus working capital as of the closing date, subject to completion of due diligence and further negotiations. We accepted this offer, subject to the finalization of the purchase and sale agreement. Negotiations are currently ongoing and no final agreement has been reached to sell the refinery. The Aruba Refinery is classified as "held and used" because all of the accounting criteria required for "held for sale" classification have not been met.

Because of our decision to suspend the operations of the Aruba Refinery and the possibility that we may sell the refinery, we evaluated the refinery for potential impairment and concluded that the Aruba Refinery was impaired as of March 31, 2012. As a result, we were required to determine the fair value of the Aruba Refinery and to write down its carrying value to that amount. We determined that the best measure of the refinery's fair value as of March 31, 2012 was the $350 million offer described above, which was based on the interested party's specific knowledge of the refinery, experience in the refining and marketing industry, and extensive knowledge of the current economic factors of our business. The carrying value of the Aruba Refinery's long-lived assets as of March 31, 2012 was $945 million; therefore, we recognized an asset impairment loss of $595 million in March 2012.

The operations of the Aruba Refinery remained suspended throughout the second quarter of 2012, and the interested party has continued its negotiations process, including discussions with the Government of Aruba. As a result, we updated our impairment evaluation of the Aruba Refinery as of June 30, 2012 and concluded that the refinery was not further impaired as of that date. The carrying value of the Aruba Refinery's long-lived assets as of June 30, 2012 was $347 million, reflecting the revised carrying value of $350 million established as of March 31, 2012 less depreciation recognized in the second quarter of 2012.

There is no certainty that we will sell the refinery to the interested party, or to any other party, and if we ultimately sell the refinery, there is no certainty that we will sell it for $350 million. In addition, should we be unable to sell the refinery, we may have to recognize an additional asset impairment loss.

The variation in the customary relationship between income tax expense and income from continuing operations before income tax expense for the six months ended June 30, 2012 was primarily due to not recognizing the tax benefit associated with the asset impairment loss of $595 million related to the Aruba Refinery as we do not expect to realize this tax benefit.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. INVENTORIES

Inventories consisted of the following (in millions):

	June 30, 2012	December 31, 2011
Refinery feedstocks	$2,140	$2,474
Refined products and blendstocks	2,797	2,633
Ethanol feedstocks and products	178	195
Convenience store merchandise	105	103
Materials and supplies	223	218
Inventories	$5,443	$5,623

As of June 30, 2012 and December 31, 2011, the replacement cost (market value) of last in, first out (LIFO) inventories exceeded their LIFO carrying amounts by approximately $6.5 billion and $6.8 billion, respectively.

5. DEBT

Non-Bank Debt

During the six months ended June 30, 2012, the following activity occurred:

- in June 2012, we remarketed and received proceeds of $300 million related to the 4.0% Gulf Opportunity Zone Revenue Bonds Series 2010 issued by the Parish of St. Charles, State of Louisiana (GO Zone Bonds), which are due December 1, 2040, but are subject to mandatory tender on June 1, 2022;
- in April 2012, we made scheduled debt repayments of $4 million related to our Series 1997A 5.45% industrial revenue bonds and $750 million related to our 6.875% notes; and
- in March 2012, we exercised the call provisions on our Series 1997 5.6%, Series 1998 5.6%, Series 1999 5.7%, Series 2001 6.65%, and Series 1997A 5.45% industrial revenue bonds, which were redeemed on May 3, 2012 for $108 million, or 100 percent of their outstanding stated values.

During the six months ended June 30, 2011, the following activity occurred:

- in May 2011, we made a scheduled debt repayment of $200 million related to our 6.125% senior notes;
- in April 2011, we made scheduled debt repayments of $8 million related to out Series 1997A 5.45%, Series 1997B 5.40%, and Series 1997C 5.40% industrial revenue bonds;
- in February 2011, we made a scheduled debt repayment of $210 million related to our 6.75% senior notes; and
- also in February 2011, we paid $300 million to acquire the GO Zone Bonds, which were subject to mandatory tender.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Bank Debt and Credit Facilities
We have a $3 billion revolving credit facility (the Revolver) that has a maturity date of December 2016. The Revolver has certain restrictive covenants, including a maximum debt-to-capitalization ratio of 60 percent. As of June 30, 2012 and December 31, 2011, our debt-to-capitalization ratios, calculated in accordance with the terms of the Revolver, were 26 percent and 29 percent, respectively. We believe that we will remain in compliance with this covenant.

In addition to the Revolver, one of our Canadian subsidiaries has a committed revolving credit facility under which it may borrow and obtain letters of credit up to C$115 million.

During the six months ended June 30, 2012, we borrowed and repaid $1.1 billion under our Revolver. During the six months ended June 30, 2011, we had no borrowings or repayments under our Revolver. We had no borrowings or repayments under the Canadian revolving credit facility during the six months ended June 30, 2012 and 2011. As of June 30, 2012 and December 31, 2011, we had no borrowings outstanding under the Revolver or the Canadian revolving credit facility.

We had outstanding letters of credit under our committed lines of credit as follows (in millions):

			Amounts Outstanding	
	Borrowing Capacity	Expiration	June 30, 2012	December 31, 2011
Letter of credit facilities	$ 550	June 2013	$ 300	$ 300
Revolver	$ 3,000	December 2016	$ 70	$ 119
Canadian revolving credit facility	C$115	December 2012	C$11	C$20

In July 2012, one of our letter of credit facilities was amended to extend its maturity date through June 2013 and to increase its borrowing capacity by $50 million. The borrowing capacity and expiration shown in the table above reflect these changes.

As of June 30, 2012 and December 31, 2011, we had $649 million and $391 million, respectively, of letters of credit outstanding under our uncommitted short-term bank credit facilities.

Accounts Receivable Sales Facility
As of June 30, 2012, we had an accounts receivable sales facility with a group of third-party entities and financial institutions to sell on a revolving basis up to $1.0 billion of eligible trade receivables. In July 2012, we amended our agreement to increase the facility to $1.5 billion and to extend the maturity date to July 2013. Proceeds from the sale of receivables under this facility are reflected as debt. Under this program, one of our marketing subsidiaries (Valero Marketing) sells eligible receivables, without recourse, to another of our subsidiaries (Valero Capital), whereupon the receivables are no longer owned by Valero Marketing. Valero Capital, in turn, sells an undivided percentage ownership interest in the eligible receivables, without recourse, to the third-party entities and financial institutions. To the extent that Valero Capital retains an ownership interest in the receivables it has purchased from Valero Marketing, such interest is included in our financial statements solely as a result of the consolidation of the financial statements of Valero Capital with those of Valero Energy Corporation; the receivables are not available to satisfy the claims of the creditors of Valero Marketing or Valero Energy Corporation.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Changes in the amounts outstanding under our accounts receivable sales facility were as follows (in millions):

	Six Months Ended June 30, 2012	2011
Balance as of beginning of period	$250	$100
Proceeds from the sale of receivables	1,300	—
Repayments	(1,450)	—
Balance as of end of period	$100	$100

Capitalized Interest
Capitalized interest was $53 million and $33 million for the three months ended June 30, 2012 and 2011, respectively, and $105 million and $60 million for the six months ended June 30, 2012 and 2011, respectively.

6. COMMITMENTS AND CONTINGENCIES

Environmental Matters
The U.S. Environmental Protection Agency (EPA) began regulating greenhouse gases on January 2, 2011, under the Clean Air Act Amendments of 1990 (Clean Air Act). Any new construction or material expansions will require that, among other things, a greenhouse gas permit be issued at either or both the state or federal level in accordance with the Clean Air Act and regulations, and we will be required to undertake a technology review to determine appropriate controls to be implemented with the project in order to reduce greenhouse gas emissions. The determination would be on a case by case basis, and the EPA has provided only general guidance on which controls will be required.

Furthermore, the EPA is currently developing refinery-specific greenhouse gas regulations and performance standards that are expected to impose, on new and existing operations, greenhouse gas emission limits and/or technology requirements. These control requirements may affect a wide range of refinery operations but have not yet been delineated. Any such controls, however, could result in material increased compliance costs, additional operating restrictions for our business, and an increase in the cost of the products we produce, which could have a material adverse effect on our financial position, results of operations, and liquidity.

Certain states and foreign governments have pursued regulation of greenhouse gases independent of the EPA. For example, the California Global Warming Solutions Act, also known as AB 32, directs the California Air Resources Board (CARB) to develop and issue regulations to reduce greenhouse gas emissions in California to 1990 levels by 2020. The CARB has issued a variety of regulations aimed at reaching this goal, including a Low Carbon Fuel Standard (LCFS) as well as a statewide cap-and-trade program.

- The LCFS was scheduled to become effective in 2011, but rulings by the U.S. District Court stayed enforcement of the LCFS until certain legal challenges to the LCFS were resolved. Most notably, the court determined that the LCFS violates the Commerce Clause of the U.S. Constitution to the extent that the standard discriminates against out-of-state crude oils and corn ethanol. CARB appealed the lower court's ruling to the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit Court).

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The Ninth Circuit Court lifted the stay on April 23, 2012. We anticipate that the Ninth Circuit Court will hear arguments on the merits of the appeal this year, with a final ruling sometime thereafter.

- A California statewide cap-and-trade program will begin in late 2012. Initially, the program will apply only to stationary sources of greenhouse gases (e.g., refinery and power plant greenhouse gas emissions). Greenhouse gas emissions from fuels that we sell in California will be covered by the program beginning in 2015. We anticipate that free allocations of credits will be available in the early years of the program to cover most of our stationary emissions, but we expect that compliance costs will increase significantly beginning in 2015, when transportation fuels are included in the program.
- Complying with AB 32, including the LCFS and the cap-and-trade program, could result in material increased compliance costs for us, increased capital expenditures, increased operating costs, and additional operating restrictions for our business, resulting in an increase in the cost of, and decreases in the demand for, the products we produce. To the degree we are unable to recover these increased costs, these matters could have a material adverse effect on our financial position, results of operations, and liquidity.

In the first quarter of 2012, CARB adopted amendments to its Clean Fuels Outlet (CFO) Regulation. CARB states that the CFO Regulation is intended to provide outlets of clean fuel to meet the needs of alternative fuel vehicles. We understand that CARB is preparing to submit the CFO Regulation to the State Office of Administrative Law for approval. Under the regulation, projections of zero-emission vehicle availability in the California market would trigger a requirement for major refiners and importers of gasoline, including us, to install clean fuel outlets in designated areas in proportion to each refiner or importer’s share in the California gasoline market. We expect this regulation to be challenged, but we could be required to make significant capital expenditures if the regulation is implemented as presently adopted.

The EPA has disapproved certain permitting programs of the Texas Commission on Environmental Quality (TCEQ) that historically have streamlined the environmental permitting process in Texas. For example, the EPA disapproved the TCEQ pollution control standard permit, thus requiring conventional permitting for future pollution control equipment. The Fifth Circuit Court of Appeals recently overturned the EPA’s disapproval and sent it back to the EPA to re-evaluate the decision. Litigation is pending from industry groups and others against the EPA for each of these actions. In some instances, the EPA’s decisions have been initially upheld and others are still pending before the courts. The EPA has also objected to numerous Title V permits in Texas and other states, including permits at our Port Arthur, Corpus Christi East, and McKee Refineries. Environmental activist groups have filed a notice of intent to sue the EPA, seeking to require the EPA to assume control of these permits from the TCEQ. Finally, as part of its regulation of greenhouse gases discussed above, the EPA has federalized the permitting of greenhouse gas emissions in Texas. This creates a dual permitting structure that must be navigated for material projects in Texas. All of these developments have created substantial uncertainty regarding existing and future permitting. Because of this uncertainty, we are unable to determine the costs or effects of the EPA’s actions on our permitting activity. The EPA’s disruption of the Texas permitting system could result in material increased compliance costs for us, increased capital expenditures, increased operating costs, and additional operating restrictions for our business, resulting in an increase in the cost of, and decreases in the demand for, the products we produce, which could have a material adverse effect on our financial position, results of operations, and liquidity.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Tax Matters

We are subject to extensive tax liabilities imposed by multiple jurisdictions, including income taxes, transactional taxes (excise/duty, sales/use, and value-added taxes), payroll taxes, franchise taxes, withholding taxes, and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted or proposed that could result in increased expenditures for tax liabilities in the future. Many of these liabilities are subject to periodic audits by the respective taxing authority. Subsequent changes to our tax liabilities as a result of these audits may subject us to interest and penalties.

As of June 30, 2012, the Internal Revenue Service (IRS) has ongoing tax audits related to our U.S. federal tax returns from 2002 through 2009. We have received Revenue Agent Reports on our tax years for 2002 through 2007 and we are vigorously contesting the tax positions and assertions from the IRS. Although we believe our tax liabilities are fairly stated and properly reflected in our financial statements, should the IRS eventually prevail, it could result in a material amount of our deferred tax liabilities being reclassified to current liabilities which could have a material adverse effect on our liquidity.

Litigation Matters

We are party to claims and legal proceedings arising in the ordinary course of business. We have not recorded a loss contingency liability with respect to some of these matters because we have determined that it is remote that a loss has been incurred. For other matters, we have recorded a loss contingency liability where we have determined that it is probable that a loss has been incurred and that the loss is reasonably estimable. These loss contingency liabilities are not material to our financial position. We re-evaluate and update our loss contingency liabilities as matters progress over time, and we believe that any changes to the recorded liabilities will not be material to our financial position or results of operations.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. EQUITY

The following is a reconciliation of the beginning and ending balances (in millions) of equity attributable to our stockholders, equity attributable to the noncontrolling interest, and total equity for the six months ended June 30, 2012 and 2011:

	2012 Valero Stockholders' Equity	Non-controlling Interest	Total Equity	2011 Valero Stockholders' Equity	Non-controlling Interest	Total Equity
Balance as of beginning of period	$16,423	$22	$16,445	$15,025	$—	$15,025
Net income (loss)	399	(1)	398	842	(1)	841
Dividends	(166)	—	(166)	(57)	—	(57)
Stock-based compensation expense	20	—	20	23	—	23
Tax deduction in excess of stock-based compensation expense	3	—	3	11	—	11
Transactions in connection with stock-based compensation plans:						
Stock issuances	11	—	11	30	—	30
Stock repurchases	(136)	—	(136)	(2)	—	(2)
Contributions from noncontrolling interest	—	25	25	—	11	11
Other comprehensive income	23	—	23	110	—	110
Balance as of end of period	$16,577	$46	$16,623	$15,982	$10	$15,992

The noncontrolling interest relates to a third-party ownership interest in Diamond Green Diesel Holdings LLC, a company whose financial statements we consolidate due to our controlling interest.

Share Activity

Activity in the number of shares of common stock and treasury stock was as follows (in millions) for the six months ended June 30, 2012 and 2011:

	2012 Common Stock	Treasury Stock	2011 Common Stock	Treasury Stock
Balance as of beginning of period	673	(117)	673	(105)
Transactions in connection with stock-based compensation plans:				
Stock issuances	—	1	—	2
Stock purchases	—	(6)	—	—
Balance as of end of period	673	(122)	673	(103)

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Common Stock Dividends
On July 26, 2012, our board of directors declared a quarterly cash dividend of $0.175 per common share payable on September 12, 2012 to holders of record at the close of business on August 15, 2012.

8. EMPLOYEE BENEFIT PLANS

The components of net periodic benefit cost related to our defined benefit plans were as follows (in millions) for the three and six months ended June 30, 2012 and 2011:

	Pension Plans		Other Postretirement Benefit Plans	
	2012	2011	2012	2011
Three months ended June 30:				
Service cost	$35	$22	$3	$2
Interest cost	23	22	6	5
Expected return on plan assets	(31)	(28)	—	—
Amortization of:				
Prior service credit	—	—	(6)	(5)
Net actuarial loss	9	3	—	1
Net periodic benefit cost	$36	$19	$3	$3
Six months ended June 30:				
Service cost	$70	$45	$6	$5
Interest cost	46	43	11	11
Expected return on plan assets	(62)	(56)	—	—
Amortization of:				
Prior service cost (credit)	1	1	(11)	(11)
Net actuarial loss	17	6	—	1
Net periodic benefit cost	$72	$39	$6	$6

Our anticipated contributions to our pension plans during 2012 have not changed from amounts previously disclosed in our financial statements for the year ended December 31, 2011. During the six months ended June 30, 2012, we contributed approximately $13 million to our pension plans. There were no significant contributions made to our pension plans during the six months ended June 30, 2011. In July 2012, we contributed $50 million to our pension plans.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. EARNINGS PER COMMON SHARE

Earnings per common share from continuing operations were computed as follows (dollars and shares in millions, except per share amounts):

	Three Months Ended June 30,			
	2012		2011	
	Restricted Stock	Common Stock	Restricted Stock	Common Stock
Earnings per common share from continuing operations:				
Net income attributable to Valero stockholders from continuing operations		$831		$745
Less dividends paid:				
Common stock		82		29
Nonvested restricted stock		1		—
Undistributed earnings		$748		$716
Weighted-average common shares outstanding	3	550	3	567
Earnings per common share from continuing operations:				
Distributed earnings	$0.15	$0.15	$0.05	$0.05
Undistributed earnings	1.35	1.35	1.26	1.26
Total earnings per common share from continuing operations	$1.50	$1.50	$1.31	$1.31
Earnings per common share from continuing operations – assuming dilution:				
Net income attributable to Valero stockholders from continuing operations		$831		$745
Weighted-average common shares outstanding		550		567
Common equivalent shares:				
Stock options		3		5
Performance awards and unvested restricted stock		2		2
Weighted-average common shares outstanding – assuming dilution		555		574
Earnings per common share from continuing operations – assuming dilution		$1.50		$1.30

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Six Months Ended June 30,			
	2012		2011	
	Restricted Stock	Common Stock	Restricted Stock	Common Stock
Earnings per common share from continuing operations:				
Net income attributable to Valero stockholders from continuing operations		$399		$849
Less dividends paid:				
Common stock		165		57
Nonvested restricted stock		1		—
Undistributed earnings		$233		$792
Weighted-average common shares outstanding	3	550	3	567
Earnings per common share from continuing operations:				
Distributed earnings	$0.30	$0.30	$0.10	$0.10
Undistributed earnings	0.42	0.42	1.39	1.39
Total earnings per common share from continuing operations	$0.72	$0.72	$1.49	$1.49
Earnings per common share from continuing operations – assuming dilution:				
Net income attributable to Valero stockholders from continuing operations		$399		$849
Weighted-average common shares outstanding		550		567
Common equivalent shares:				
Stock options		4		5
Performance awards and unvested restricted stock		2		1
Weighted-average common shares outstanding – assuming dilution		556		573
Earnings per common share from continuing operations – assuming dilution		$0.72		$1.48

The following table reflects potentially dilutive securities (in millions) that were excluded from the calculation of "earnings per common share from continuing operations – assuming dilution" as the effect of including such securities would have been antidilutive. These potentially dilutive securities included stock options for which the exercise prices were greater than the average market price of our common shares during each respective reporting period.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011

Stock options	6	6	6	6

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. SEGMENT INFORMATION

The following table reflects activity related to continuing operations (in millions):

	Refining	Retail	Ethanol	Corporate	Total
Three months ended June 30, 2012:					
Operating revenues from external customers	$30,488	$3,062	$1,112	$—	$34,662
Intersegment revenues	2,203	—	46	—	2,249
Operating income (loss)	1,364	172	5	(180)	1,361
Three months ended June 30, 2011:					
Operating revenues from external customers	26,921	3,128	1,244	—	31,293
Intersegment revenues	2,311	—	52	—	2,363
Operating income (loss)	1,253	135	64	(162)	1,290
Six months ended June 30, 2012:					
Operating revenues from external customers	61,638	5,997	2,194	—	69,829
Intersegment revenues	4,458	—	60	—	4,518
Operating income (loss)	1,245	212	14	(354)	1,117
Six months ended June 30, 2011:					
Operating revenues from external customers	49,483	5,812	2,306	—	57,601
Intersegment revenues	4,308	—	100	—	4,408
Operating income (loss)	1,529	201	108	(304)	1,534

Total assets by reportable segment were as follows (in millions):

	June 30, 2012	December 31, 2011
Refining	$36,602	$38,164
Retail	1,973	1,999
Ethanol	926	943
Corporate	1,687	1,677
Total assets	$41,188	$42,783

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. SUPPLEMENTAL CASH FLOW INFORMATION

In order to determine net cash provided by operating activities, net income is adjusted by, among other things, changes in current assets and current liabilities as follows (in millions):

	Six Months Ended June 30,	
	2012	2011
Decrease (increase) in current assets:		
Receivables, net	$2,087	$(1,422)
Inventories	198	978
Income taxes receivable	(79)	175
Prepaid expenses and other	(15)	(3)
Increase (decrease) in current liabilities:		
Accounts payable	(1,413)	1,147
Accrued expenses	(60)	202
Taxes other than income taxes	67	(52)
Income taxes payable	(60)	122
Changes in current assets and current liabilities	$725	$1,147

The above changes in current assets and current liabilities differ from changes between amounts reflected in the applicable balance sheets for the respective periods for the following reasons:

- the amounts shown above exclude changes in cash and temporary cash investments, deferred income taxes, and current portion of debt and capital lease obligations, as well as the effect of certain noncash investing and financing activities discussed below;
- amounts accrued for capital expenditures and deferred turnaround and catalyst costs are reflected in investing activities when such amounts are paid;
- amounts accrued for common stock purchases in the open market that are not settled as of the balance sheet date are reflected in financing activities when the purchases are settled and paid; and
- certain differences between balance sheet changes and the changes reflected above result from translating foreign currency denominated balances at the applicable exchange rates as of each balance sheet date.

There were no significant noncash investing or financing activities for the six months ended June 30, 2012 or 2011.

Cash flows related to interest and income taxes were as follows (in millions):

	Six Months Ended June 30,	
	2012	2011
Interest paid in excess of amount capitalized	$164	$221
Income taxes paid, net	204	10

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12. FAIR VALUE MEASUREMENTS

General

GAAP requires that certain financial instruments, such as derivative instruments, be recognized at their fair values in our balance sheets. However, other financial instruments, such as debt obligations, are not required to be recognized at their fair values, but GAAP provides an option to elect fair value accounting for these instruments. GAAP requires the disclosure of the fair values of all financial instruments, regardless of whether they are recognized at their fair values or carrying amounts in our balance sheets. For financial instruments recognized at fair value, GAAP requires the disclosure of their fair values by type of instrument, along with other information, including changes in the fair values of certain financial instruments recognized in income or other comprehensive income, and this information is provided below under “Recurring Fair Value Measurements.” For financial instruments not recognized at fair value, the disclosure of their fair values is provided below under “Other Financial Instruments.”

Nonfinancial assets, such as property, plant and equipment, and nonfinancial liabilities are recognized at their carrying amounts in our balance sheets. GAAP does not permit nonfinancial assets and liabilities to be remeasured at their fair values. However, GAAP requires the remeasurement of such assets and liabilities to their fair values upon the occurrence of certain events, such as the impairment of property, plant and equipment. In addition, if such an event occurs, GAAP requires the disclosure of the fair value of the asset or liability along with other information, including the gain or loss recognized in income in the period the remeasurement occurred. This information is provided below under “Nonrecurring Fair Value Measurements.”

GAAP provides a framework for measuring fair value and establishes a three-level fair value hierarchy that prioritizes inputs to valuation techniques based on the degree to which objective prices in external active markets are available to measure fair value. Following is a description of each of the levels of the fair value hierarchy.

- Level 1 - Observable inputs, such as unadjusted quoted prices in active markets for identical assets or liabilities.
- Level 2 - Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.
- Level 3 - Unobservable inputs for the asset or liability for which there is little, if any, market activity at the measurement date. Unobservable inputs reflect our own assumptions about what market participants would use to price the asset or liability. The inputs are developed based on the best information available in the circumstances, which might include occasional market quotes or sales of similar instruments or our own financial data such as internally developed pricing models, discounted cash flow methodologies, as well as instruments for which the fair value determination requires significant judgment.

The financial instruments and nonfinancial assets and liabilities included in our disclosure of recurring and nonrecurring fair value measurements are categorized according to the fair value hierarchy based on the inputs used to measure their fair values.

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
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Recurring Fair Value Measurements
The tables below present information (in millions) about our financial instruments recognized at their fair values in our balance sheets categorized according to the fair value hierarchy of the inputs utilized by us to determine the fair values as of June 30, 2012 and December 31, 2011.
Cash received from brokers of $81 million and cash collateral deposits with brokers of $136 million under master netting arrangements are included in the fair value of the commodity derivatives reflected in Level 1 as of June 30, 2012 and December 31, 2011, respectively. Certain of our commodity derivative contracts under master netting arrangements include both asset and liability positions. We have elected to offset the fair value amounts recognized for multiple similar derivative instruments executed with the same counterparty, including any related cash collateral asset or obligation under the column "Netting Adjustments" below; however, fair value amounts by hierarchy level are presented on a gross basis in the tables below.

	Fair Value Measurements Using				
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments	Total Fair Value as of June 30, 2012
Assets:					
Commodity derivative contracts	$2,781	$144	$—	$(2,836)	$89
Physical purchase contracts	—	18	—	—	18
Investments of certain benefit plans	85	—	11	—	96
Other investments	—	—	—	—	—
Liabilities:					
Commodity derivative contracts	2,701	143	—	(2,836)	8
Foreign currency contracts	5	—	—	—	5

	Fair Value Measurements Using				
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments	Total Fair Value as of December 31, 2011
Assets:					
Commodity derivative contracts	$2,038	$78	$—	$(1,940)	$176
Physical purchase contracts	—	(2)	—	—	(2)
Investments of certain benefit plans	84	—	11	—	95
Other investments	—	—	—	—	—
Liabilities:					
Commodity derivative contracts	1,864	101	—	(1,940)	25
Foreign currency contracts	3	—	—	—	3

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A description of our financial instruments and the valuation methods used to measure those instruments at fair value are as follows:

- Commodity derivative contracts consist primarily of exchange-traded futures and swaps, and as disclosed in Note 13, some of these contracts are designated as hedging instruments. These contracts are measured at fair value using the market approach. Exchange-traded futures are valued based on quoted prices from the exchange and are categorized in Level 1 of the fair value hierarchy. Swaps are priced using third-party broker quotes, industry pricing services, and exchange-traded curves, with appropriate consideration of counterparty credit risk, but because they have contractual terms that are not identical to exchange-traded futures instruments with a comparable market price, these financial instruments are categorized in Level 2 of the fair value hierarchy.
- Physical purchase contracts to purchase inventories represent the fair value of firm commitments to purchase crude oil feedstocks and the fair value of fixed-price corn purchase contracts, and as disclosed in Note 13, some of these contracts are designated as hedging instruments. The fair values of these firm commitments and purchase contracts are measured using a market approach based on quoted prices from the commodity exchange, but because these commitments have contractual terms that are not identical to exchange-traded futures instruments with a comparable market price, they are categorized in Level 2 of the fair value hierarchy.
- Investments of certain benefit plans consist of investment securities held by trusts for the purpose of satisfying a portion of our obligations under certain U.S. nonqualified benefit plans. The assets categorized in Level 1 of the fair value hierarchy are measured at fair value using a market approach based on quoted prices from national securities exchanges. The assets categorized in Level 3 of the fair value hierarchy represent insurance contracts, the fair value of which is provided by the insurer.
- Foreign currency contracts consist of foreign currency exchange and purchase contracts entered into by our international operations to manage our exposure to exchange rate fluctuations on transactions denominated in currencies other than the local (functional) currencies of those operations. These contracts are valued based on quoted prices from the exchange and are categorized in Level 1 of the fair value hierarchy.
- Other investments consist of (i) equity securities of private companies over which we do not exercise significant influence nor whose financial statements are consolidated into our financial statements and (ii) debt securities of a private company whose financial statements are not consolidated into our financial statements. We have elected to account for these investments at their fair values. These investments are categorized in Level 3 of the fair value hierarchy as the fair values of these investments are determined using the income approach based on internally developed analyses.

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The following is a reconciliation of the beginning and ending balances (in millions) for fair value measurements developed using significant unobservable inputs (Level 3) for the three and six months ended June 30, 2012 and 2011.

	2012		2011	
	Investments of Certain Benefit Plans	Other Investments	Investments of Certain Benefit Plans	Other Investments
Three months ended June 30:				
Balance as of beginning of period	$11	$—	$11	$—
Purchases	—	—	—	10
Total gains (losses) included in income	—	—	—	(10)
Transfers in and/or out of Level 3	—	—	—	—
Balance as of end of period	$11	$—	$11	$—
The amount of total gains (losses) included in income attributable to the change in unrealized gains (losses) relating to assets still held at end of period	$—	$—	$—	$(10)
Six months ended June 30:				
Balance as of beginning of period	$11	$—	$10	$—
Purchases	—	—	—	16
Total gains (losses) included in income	—	—	1	(16)
Transfers in and/or out of Level 3	—	—	—	—
Balance as of end of period	$11	$—	$11	$—
The amount of total gains (losses) included in income attributable to the change in unrealized gains (losses) relating to assets still held at end of period	$—	$—	$1	$(16)

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Nonrecurring Fair Value Measurements
As discussed in Note 3, we concluded that the Aruba Refinery was impaired as of March 31, 2012. As a result, we were required to determine the fair value of the Aruba Refinery and to write down its carrying value to that amount. We determined that the best measure of the refinery's fair value as of March 31, 2012 was the $350 million offer received and accepted, subject to the finalization of the purchase and sale agreement. We believe this offer represents what a market participant would pay us for the assets in their highest and best use, as more fully discussed in Note 3. The fair value of the Aruba Refinery was measured using the market approach and was categorized in Level 3 within the fair value hierarchy. The carrying value of the Aruba Refinery's long-lived assets as of March 31, 2012 was $945 million; therefore, we recognized an asset impairment loss of $595 million in March 2012.

We recognized an asset impairment loss of $16 million in March 2012 related to equipment associated with a capital project that was cancelled permanently in 2009. We had written down the carrying value of this equipment to fair value in 2009, but we have been unable to sell the equipment. As a result, we wrote down the carrying amount of the equipment to scrap value.

There were no assets or liabilities that were measured at fair value on a nonrecurring basis as of June 30, 2012 or December 31, 2011. During the six months ended June 30, 2012, we recognized an asset impairment loss of $611 million as described above.

Other Financial Instruments
Financial instruments that we recognize in our balance sheets at their carrying amounts are shown in the table below (in millions):

	June 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets:				
Cash and temporary cash investments	$1,295	$1,295	$1,024	$1,024
Financial liabilities:				
Debt (excluding capital leases)	6,995	8,187	7,690	9,298

The methods and significant assumptions used to estimate the fair value of these financial instruments are as follows:

- The fair value of cash and temporary cash investments approximates the carrying value due to the low level of credit risk of these assets combined with their short maturities and market interest rates (Level 1).
- The fair value of debt is determined primarily using the market approach based on quoted prices in active markets (Level 1).

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13. PRICE RISK MANAGEMENT ACTIVITIES

We are exposed to market risks related to the volatility in the price of commodities, the price of financial instruments associated with governmental and regulatory compliance programs, interest rates, and foreign currency exchange rates, and we enter into derivative instruments to manage some of these risks. We also enter into derivative instruments to manage the price risk on other contractual derivatives into which we have entered. The only types of derivative instruments we enter into are those related to the various commodities we purchase or produce, financial instruments we must purchase to maintain compliance with various governmental and regulatory programs, interest rate swaps, and foreign currency exchange and purchase contracts, as described below. All derivative instruments are recorded as either assets or liabilities measured at their fair values (see Note 12).

When we enter into a derivative instrument, it is designated as a fair value hedge, a cash flow hedge, an economic hedge, or a trading derivative. The gain or loss on a derivative instrument designated and qualifying as a fair value hedge, as well as the offsetting loss or gain on the hedged item attributable to the hedged risk, is recognized currently in income in the same period. The effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedge is initially reported as a component of other comprehensive income and is then recorded in income in the period or periods during which the hedged forecasted transaction affects income. The ineffective portion of the gain or loss on the cash flow derivative instrument, if any, is recognized in income as incurred. For our economic hedges (derivative instruments not designated as fair value or cash flow hedges) and for derivative instruments entered into by us for trading purposes, the derivative instrument is recorded at fair value and changes in the fair value of the derivative instrument are recognized currently in income. The cash flow effects of all of our derivative instruments are reflected in operating activities in our statements of cash flows for all periods presented.

Commodity Price Risk

We are exposed to market risks related to the volatility in the price of crude oil, refined products (primarily gasoline and distillate), grain (primarily corn), and natural gas used in our operations. To reduce the impact of price volatility on our results of operations and cash flows, we use commodity derivative instruments, including futures, swaps, and options. We use the futures markets for the available liquidity, which provides greater flexibility in transacting our hedging and trading operations. We use swaps primarily to manage our price exposure. Our positions in commodity derivative instruments are monitored and managed on a daily basis by a risk control group to ensure compliance with our stated risk management policy that has been approved by our board of directors.

For risk management purposes, we use fair value hedges, cash flow hedges, and economic hedges. In addition to the use of derivative instruments to manage commodity price risk, we also enter into certain commodity derivative instruments for trading purposes. Our objective for entering into each type of hedge or trading derivative is described below.

Fair Value Hedges

Fair value hedges are used to hedge price volatility in certain refining inventories and firm commitments to purchase inventories. The level of activity for our fair value hedges is based on the level of our operating inventories, and generally represents the amount by which our inventories differ from our previous year-end LIFO inventory levels.

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As of June 30, 2012, we had the following outstanding commodity derivative instruments that were entered into to hedge crude oil and refined product inventories and commodity derivative instruments related to the physical purchase of crude oil and refined products at a fixed price. The information presents the notional volume of outstanding contracts by type of instrument and year of maturity (volumes in thousands of barrels).

Derivative Instrument	Notional Contract Volumes by Year of Maturity 2012
Crude oil and refined products:	
Futures – long	4,869
Futures – short	9,052
Physical contracts - long	4,183

Cash Flow Hedges

Cash flow hedges are used to hedge price volatility in certain forecasted feedstock and refined product purchases, refined product sales, and natural gas purchases. The objective of our cash flow hedges is to lock in the price of forecasted feedstock, product or natural gas purchases or refined product sales at existing market prices that we deem favorable.

As of June 30, 2012, we had the following outstanding commodity derivative instruments that were entered into to hedge forecasted purchases or sales of crude oil and refined products. The information presents the notional volume of outstanding contracts by type of instrument and year of maturity (volumes in thousands of barrels).

Derivative Instrument	Notional Contract Volumes by Year of Maturity 2012
Crude oil and refined products:	
Swaps – long	5,511
Swaps – short	5,511
Futures – long	18,386
Futures – short	10,768
Physical contracts – short	7,618

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CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Economic Hedges

Economic hedges represent commodity derivative instruments that are not designated as fair value or cash flow hedges and are used to manage price volatility in certain (i) refinery feedstock, refined product, and corn inventories, (ii) forecasted refinery feedstock, refined product, and corn purchases, and refined product sales, and (iii) fixed-price corn purchase contracts. Our objective for entering into economic hedges is consistent with the objectives discussed above for fair value hedges and cash flow hedges. However, the economic hedges are not designated as a fair value hedge or a cash flow hedge for accounting purposes, usually due to the difficulty of establishing the required documentation at the date that the derivative instrument is entered into that would allow us to achieve "hedge deferral accounting."

As of June 30, 2012, we had the following outstanding commodity derivative instruments that were used as economic hedges and commodity derivative instruments related to the physical purchase of corn at a fixed price. The information presents the notional volume of outstanding contracts by type of instrument and year of maturity (volumes in thousands of barrels, except those identified as corn contracts that are presented in thousands of bushels).

	Notional Contract Volumes by Year of Maturity	
Derivative Instrument	2012	2013
Crude oil and refined products:		
Swaps – long	30,879	—
Swaps – short	28,174	—
Futures – long	58,610	85
Futures – short	79,986	—
Corn:		
Futures – long	49,750	55
Futures – short	91,035	3,375
Physical contracts – long	38,336	3,610

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Trading Derivatives
Our objective in entering into commodity derivative instruments for trading purposes is to take advantage of existing market conditions related to future results of operations and cash flows.

As of June 30, 2012, we had the following outstanding commodity derivative instruments that were entered into for trading purposes. The information presents the notional volume of outstanding contracts by type of instrument and year of maturity (volumes represent thousands of barrels, except those identified as natural gas contracts that are presented in billions of British thermal units and corn contracts that are presented in thousands of bushels).

	Notional Contract Volumes by Year of Maturity	
Derivative Instrument	2012	2013
Crude oil and refined products:		
Swaps – long	19,043	27,930
Swaps – short	17,917	28,321
Futures – long	101,095	18,832
Futures – short	102,208	17,760
Options – long	11,900	—
Options – short	12,271	—
Natural gas:		
Futures – long	6,800	200
Futures – short	6,400	—
Corn:		
Swaps - long	2,605	—
Swaps - short	12,460	1,580
Futures – long	19,360	—
Futures – short	19,360	—

Compliance Program Price Risk
We are exposed to market risks related to the volatility in the price of financial instruments associated with various governmental and regulatory compliance programs that we must purchase in the open market to comply with these programs. These programs are described below.

Obligation to Blend Biofuels
We are obligated to blend biofuels into the products we produce in most of the countries in which we operate, and these countries set annual quotas for the percentage of biofuels that must be blended into the motor fuels consumed in these countries. As a producer of motor fuels from petroleum, we are obligated to blend biofuels into the products we produce at a rate that is at least equal to the applicable quota. To the degree we are unable to blend at the applicable rate in the U.S. and the United Kingdom (U.K.), we must purchase Renewable Identification Numbers (RINs) in the U.S. and Renewable Transport Fuel Obligation certificates (RTFCs) in the U.K., and as such, we are exposed to the volatility in the market price of these financial instruments.

VALERO ENERGY CORPORATION AND SUBSIDIARIES
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We have not entered into derivative instruments to manage this risk, but we purchase RINs and RTFCs when the price of these instruments is deemed favorable. The cost of meeting our obligations under this compliance program was $59 million and $39 million for the three months ended June 30, 2012 and 2011, respectively, and $126 million and $95 million for the six months ended June 30, 2012 and 2011. These amounts are reflected in cost of sales.

Maintaining Minimum Inventory Quantities

In the U.K., we are required to maintain a minimum quantity of crude oil and refined products as a reserve against shortages or interruptions in the supply of these products. To the degree we decide not to physically hold the minimum quantity of crude oil and refined products, we must purchase Compulsory Stock Obligation (CSO) tickets from other suppliers of refined products in the U.K. or other European Union (EU) member countries, and we make economic decisions as to the cost of maintaining certain quantities of crude oil and refined products versus the cost of purchasing CSO tickets. We have not entered into derivative instruments to manage the price volatility of CSO tickets. For the three and six months ended June 30, 2012, the cost of purchasing CSO tickets to help meet our obligations under this compliance program was $1 million and $3 million, respectively and this amount was reflected in cost of sales. We had no obligations under this compliance program prior to completing the Pembroke Acquisition in 2011.

Emission Allowances

Our Pembroke Refinery is subject to a maximum amount of carbon dioxide that it can emit each year under the EU Emissions Trading Scheme. Under this cap-and-trade program, we purchase emission allowances on the open market for the difference between the amount of carbon dioxide emitted and the maximum amount allowed under the program. Therefore, we are exposed to the volatility in the market price of these allowances. For the three months ended June 30, 2012, no costs were incurred to meet our obligation under this compliance program. For the six months ended June 30, 2012, the cost of meeting our obligation under this compliance program was $1 million, which is reflected in refining operating expenses. We had no obligations under this compliance program prior to completing the Pembroke Acquisition in 2011.

We enter into derivative instruments (futures) to reduce the impact of this risk on our results of operations and cash flows. Our positions in these derivative instruments are monitored and managed on a daily basis by a risk control group to ensure compliance with our stated risk management policy that has been approved by our board of directors. As of June 30, 2012, we had purchased futures contracts – long for 55,000 metric tons of EU emission allowances that were entered into as economic hedges. As of June 30, 2012, the fair value of these futures contracts was immaterial and therefore not separately presented in the table below under "Fair Values of Derivative Instruments." For the three and six months ended June 30, 2012, the gain (loss) recognized in income on these derivative instruments designated as economic hedges were also immaterial and therefore not separately presented in the table below under "Effect of Derivative Instruments on Income and Other Comprehensive Income."

Interest Rate Risk

Our primary market risk exposure for changes in interest rates relates to our debt obligations. We manage our exposure to changing interest rates through the use of a combination of fixed-rate and floating-rate debt. In addition, at times we have used interest rate swap agreements to manage our fixed to floating interest rate position by converting certain fixed-rate debt to floating-rate debt. We had no interest rate derivative instruments outstanding as of June 30, 2012 or December 31, 2011, or during the three and six months ended June 30, 2012 and 2011.

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Foreign Currency Risk

We are exposed to exchange rate fluctuations on transactions entered into by our international operations that are denominated in currencies other than the local (functional) currencies of those operations. To manage our exposure to these exchange rate fluctuations, we use foreign currency exchange and purchase contracts. These contracts are not designated as hedging instruments for accounting purposes, and therefore they are classified as economic hedges. As of June 30, 2012, we had commitments to purchase $634 million of U.S. dollars. These commitments matured on or before July 31, 2012.

Fair Values of Derivative Instruments

The following tables provide information about the fair values of our derivative instruments as of June 30, 2012 and December 31, 2011 (in millions) and the line items in the balance sheets in which the fair values are reflected. See Note 12 for additional information related to the fair values of our derivative instruments.

As indicated in Note 12, we net fair value amounts recognized for multiple similar derivative instruments executed with the same counterparty under master netting arrangements. The tables below, however, are presented on a gross asset and gross liability basis, which results in the reflection of certain assets in liability accounts and certain liabilities in asset accounts. In addition, in Note 12, we included cash collateral on deposit with or received from brokers in the fair value of the commodity derivatives; these cash amounts are not reflected in the tables below.

	Balance Sheet Location	June 30, 2012	
		Asset Derivatives	Liability Derivatives
Derivatives designated as hedging instruments			
Commodity contracts:			
Futures	Accrued expenses	$2	$1
Futures	Receivables, net	95	95
Swaps	Receivables, net	4	2
Swaps	Accrued expenses	31	32
Total		$132	$130
Derivatives not designated as hedging instruments			
Commodity contracts:			
Futures	Accrued expenses	$1,217	$1,141
Futures	Receivables, net	1,470	1,385
Swaps	Receivables, net	45	46
Swaps	Prepaid expenses and other	49	42
Swaps	Accrued expenses	13	20
Options	Receivables, net	1	1
Physical purchase contracts	Inventories	18	—
Foreign currency contracts	Accrued expenses	—	5
Total		$2,813	$2,640
Total derivatives		$2,945	$2,770

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	Balance Sheet Location	December 31, 2011	
		Asset Derivatives	Liability Derivatives
Derivatives designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$264	$240
Swaps	Accrued expenses	36	46
Total		$300	$286
Derivatives not designated as hedging instruments			
Commodity contracts:			
Futures	Receivables, net	$1,636	$1,624
Swaps	Prepaid expenses and other	4	2
Swaps	Accrued expenses	38	51
Options	Receivables, net	2	—
Options	Accrued expenses	—	2
Physical purchase contracts	Inventories	—	2
Foreign currency contracts	Accrued expenses	—	3
Total		$1,680	$1,684
Total derivatives		$1,980	$1,970

Market and Counterparty Risk

Our price risk management activities involve the receipt or payment of fixed price commitments into the future. These transactions give rise to market risk, which is the risk that future changes in market conditions may make an instrument less valuable. We closely monitor and manage our exposure to market risk on a daily basis in accordance with policies approved by our board of directors. Market risks are monitored by a risk control group to ensure compliance with our stated risk management policy. Concentrations of customers in the refining industry may impact our overall exposure to counterparty risk because these customers may be similarly affected by changes in economic or other conditions. In addition, financial services companies are the counterparties in certain of our price risk management activities, and such financial services companies may be adversely affected by periods of uncertainty and illiquidity in the credit and capital markets.

As of June 30, 2012, we had net receivables related to derivative instruments of $7 million from counterparties in the refining industry and no amounts from counterparties in the financial services industry. As of December 31, 2011, we had net receivables related to derivative instruments of $2 million from counterparties in the refining industry and no amounts from counterparties in the financial services industry. These amounts represent the aggregate amount payable to us by companies in those industries, reduced by payables from us to those companies under master netting arrangements that allow for the setoff of amounts receivable from and payable to the same party. We do not require any collateral or other security to support derivative instruments into which we enter. We also do not have any derivative instruments that require us to maintain a minimum investment-grade credit rating.

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Effect of Derivative Instruments on Income and Other Comprehensive Income
The following tables provide information about the gain or loss recognized in income and other comprehensive income on our derivative instruments and the line items in the financial statements in which such gains and losses are reflected (in millions).

Derivatives in Fair Value Hedging Relationships	Location of Gain (Loss) Recognized in Income on Derivatives	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Commodity contracts:					
Gain (loss) recognized in income on derivatives	Cost of sales	$87	$140	$(180)	$49
Gain (loss) recognized in income on hedged item	Cost of sales	(91)	(147)	137	(61)
Loss recognized in income on derivatives (ineffective portion)	Cost of sales	(4)	(7)	(43)	(12)

For fair value hedges, no component of the derivative instruments' gains or losses was excluded from the assessment of hedge effectiveness for the three and six months ended June 30, 2012 and 2011. We recognized a gain of $28 million in income for hedged firm commitments that no longer qualified as fair value hedges during the three and six months ended June 30, 2012. No amounts were recognized in income for hedged firm commitments that no longer qualify as fair value hedges for the three and six months ended June 30, 2011.

Derivatives in Cash Flow Hedging Relationships	Location of Gain (Loss) Recognized in Income on Derivatives	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Commodity contracts:					
Gain (loss) recognized in OCI on derivatives (effective portion)		$(31)	$—	$16	$—
Gain (loss) reclassified from accumulated OCI into income (effective portion)	Cost of sales	(12)	—	36	—
Gain recognized in income on derivatives (ineffective portion)	Cost of sales	31	—	26	—

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VALERO ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For cash flow hedges, no component of the derivative instruments' gains or losses was excluded from the assessment of hedge effectiveness for the three and six months ended June 30, 2012 and 2011. For the three and six months ended June 30, 2012, cash flow hedges primarily related to forward sales of gasoline and distillates, and associated forward purchases of crude oil, with $5 million of cumulative after-tax gains on cash flow hedges remaining in accumulated other comprehensive income. We estimate that $9 million of the deferred gains as of June 30, 2012 will be reclassified into cost of sales over the next 12 months as a result of hedged transactions that are forecasted to occur. For the three and six months ended June 30, 2012 and 2011, there were no amounts reclassified from accumulated other comprehensive income into income as a result of the discontinuance of cash flow hedge accounting.

Derivatives Designated as Economic Hedges and Other Derivative Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Three Months Ended June 30,		Six Months Ended June 30,	
		2012	2011	2012	2011
Commodity contracts	Cost of sales	$574	$(72)	$423	$(371)
Foreign currency contracts	Cost of sales	1	5	(22)	(9)
Total		$575	$(67)	$401	$(380)

The loss of $371 million on commodity contracts for the six months ended June 30, 2011 includes a $542 million loss related to forward sales of refined product.

Trading Derivatives	Location of Gain (Loss) Recognized in Income on Derivatives	Three Months Ended June 30,		Six Months Ended June 30,	
		2012	2011	2012	2011
Commodity contracts	Cost of sales	$8	$8	$4	$14

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

CAUTIONARY STATEMENT FOR THE PURPOSE OF SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Form 10-Q, including without limitation our discussion below under the heading "OVERVIEW AND OUTLOOK," includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. You can identify our forward-looking statements by the words "anticipate," "believe," "expect," "plan," "intend," "estimate," "project," "projection," "predict," "budget," "forecast," " "target," "could," "should," "may," and similar expressions.

These forward-looking statements include, among other things, statements regarding:

- future refining margins, including gasoline and distillate margins;
- future retail margins, including gasoline, diesel, home heating oil, and convenience store merchandise margins;
- future ethanol margins;
- expectations regarding feedstock costs, including crude oil differentials, and operating expenses;
- anticipated levels of crude oil and refined product inventories;
- our anticipated level of capital investments, including deferred refinery turnaround and catalyst costs and capital expenditures for environmental and other purposes, and the effect of those capital investments on our results of operations;
- anticipated trends in the supply of and demand for crude oil and other feedstocks and refined products globally and in the regions where we operate;
- expectations regarding environmental, tax, and other regulatory initiatives; and
- the effect of general economic and other conditions on refining, retail, and ethanol industry fundamentals.

We based our forward-looking statements on our current expectations, estimates, and projections about ourselves and our industry. We caution that these statements are not guarantees of future performance and involve risks, uncertainties, and assumptions that we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual results may differ materially from the future performance that we have expressed or forecast in the forward-looking statements. Differences between actual results and any future performance suggested in these forward-looking statements could result from a variety of factors, including the following:

- acts of terrorism aimed at either our facilities or other facilities that could impair our ability to produce or transport refined products or receive feedstocks;
- political and economic conditions in nations that produce crude oil or consume refined products;
- demand for, and supplies of, refined products such as gasoline, diesel fuel, jet fuel, home heating oil, petrochemicals, and ethanol;
- demand for, and supplies of, crude oil and other feedstocks;
- the ability of the members of the Organization of Petroleum Exporting Countries (OPEC) to agree on and to maintain crude oil price and production controls;
- the level of consumer demand, including seasonal fluctuations;
- refinery overcapacity or undercapacity;
- our ability to successfully integrate any acquired businesses into our operations;
- the actions taken by competitors, including both pricing and adjustments to refining capacity in response to market conditions;

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- the level of competitors' imports into markets that we supply;
- accidents, unscheduled shutdowns, or other catastrophes affecting our refineries, machinery, pipelines, equipment, and information systems, or those of our suppliers or customers;
- changes in the cost or availability of transportation for feedstocks and refined products;
- the price, availability, and acceptance of alternative fuels and alternative-fuel vehicles;
- the levels of government subsidies for ethanol and other alternative fuels;
- delay of, cancellation of, or failure to implement planned capital projects and realize the various assumptions and benefits projected for such projects or cost overruns in constructing such planned capital projects;
- earthquakes, hurricanes, tornadoes, and irregular weather, which can unforeseeably affect the price or availability of natural gas, crude oil, grain and other feedstocks, and refined products and ethanol;
- rulings, judgments, or settlements in litigation or other legal or regulatory matters, including unexpected environmental remediation costs, in excess of any reserves or insurance coverage;
- legislative or regulatory action, including the introduction or enactment of legislation or rulemakings by governmental authorities, including tax and environmental regulations, such as those to be implemented under the California Global Warming Solutions Act (also known as AB 32) and the United States (U.S.) Environmental Protection Agency's (EPA) regulation of greenhouse gases, which may adversely affect our business or operations;
- changes in the credit ratings assigned to our debt securities and trade credit;
- changes in currency exchange rates, including the value of the Canadian dollar, the pound sterling, and the euro relative to the U.S. dollar; and
- overall economic conditions, including the stability and liquidity of financial markets.

Any one of these factors, or a combination of these factors, could materially affect our future results of operations and whether any forward-looking statements ultimately prove to be accurate. Our forward-looking statements are not guarantees of future performance, and actual results and future performance may differ materially from those suggested in any forward-looking statements. We do not intend to update these statements unless we are required by the securities laws to do so.

All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the foregoing. We undertake no obligation to publicly release any revisions to any such forward-looking statements that may be made to reflect events or circumstances after the date of this report or to reflect the occurrence of unanticipated events.

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OVERVIEW AND OUTLOOK

Overview

For the second quarter of 2012, we reported net income attributable to Valero stockholders from continuing operations of $831 million, or $1.50 per share (assuming dilution), compared to $745 million, or $1.30 per share (assuming dilution), for the second quarter of 2011. The increase in net income attributable to Valero stockholders from continuing operations of $86 million was primarily due to the increase of $71 million in our operating income as outlined by business segment in the following table (in millions):

	Three Months Ended June 30,		
	2012	2011	Change
Operating income (loss) by business segment:			
Refining	$1,364	$1,253	$111
Retail	172	135	37
Ethanol	5	64	(59)
Corporate	(180)	(162)	(18)
Total	$1,361	$1,290	$71

The increase of $71 million in operating income was primarily due to the increase of $111 million in our refining segment's operating income, and this increase was largely the result of the additional operating income generated by our Meraux and Pembroke Refineries, which were acquired during the last six months of 2011. The increase in our refining segment's operating income, however, was partially offset by the decrease of $59 million in our ethanol segment's operating income. This decrease was due to lower margins caused by excess supplies of ethanol in the U.S.

For the first six months of 2012, we reported net income attributable to Valero stockholders from continuing operations of $399 million, or $0.72 per share (assuming dilution), compared to $849 million, or $1.48 per share (assuming dilution), for the first six months of 2011. The decrease in net income attributable to Valero stockholders from continuing operations of $450 million was primarily due to the decrease of $417 million in our operating income as outlined by business segment in the following table (in millions):

	Six Months Ended June 30,		
	2012	2011	Change
Operating income (loss) by business segment:			
Refining	$1,245	$1,529	$(284)
Retail	212	201	11
Ethanol	14	108	(94)
Corporate	(354)	(304)	(50)
Total	$1,117	$1,534	$(417)

The decrease of $417 million in operating income was primarily due to the decrease of $284 million in our refining segment's operating income, and this decrease was largely the result of the decrease in the discount of the price of sour crude oils versus the price of sweet crude oils, which was partially offset by the increase in gasoline and distillate margins. In addition, our ethanol segment's operating income decreased by $94 million, which was due to lower margins caused by excess supplies of ethanol in the U.S.

In March 2012, we suspended the operations of the Aruba Refinery because of the refinery's inability to generate positive cash flows on a sustained basis subsequent to its restart in January 2011 and the sensitivity

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of its profitability to sour crude oil differentials, which narrowed significantly in the fourth quarter of 2011. On March 28, 2012, we received a non-binding indication of interest from an unrelated interested party to purchase the Aruba Refinery for $350 million, plus working capital as of the closing date, subject to completion of due diligence and further negotiations. We accepted this offer, subject to the finalization of the purchase and sale agreement. Because of our decision to suspend the operations of the Aruba Refinery and the possibility that we may sell the refinery, we evaluated the refinery for potential impairment as of March 31, 2012 and recognized an asset impairment loss of $595 million at that time. The interested party has continued its negotiations process throughout the second quarter of 2012, including discussions with the Government of Aruba. This matter is more fully discussed in Note 3 of Notes to Condensed Consolidated Financial Statements.

Outlook

Throughout 2011 and the first six months of 2012, our refining business has benefited from processing sweet crude oils sourced from the inland U.S., such as West Texas Intermediate (WTI) crude oil, due to the favorable difference between the price of these crude oils versus the price of benchmark sweet crude oils, such as Louisiana Light Sweet (LLS) and Brent crude oils. Historically, the price of WTI-type crude oil has closely approximated LLS and Brent crude oils, but due to the significant development of crude oil reserves within the U.S. Mid-Continent region and increased deliveries of crude oil from Canada into the U.S. Mid-Continent region, the increased supply of WTI-type crude oil has resulted in WTI-type crude oil being priced at a significant discount to LLS and Brent crude oils. This benefit, however, may decline as various crude oil pipeline and logistics projects are completed in coming months. These projects will allow sweet crude oils from the inland U.S. to be transported to the U.S. Gulf Coast region, which is expected to result in a narrowing of the price differential of WTI-priced crude oils relative to Brent-priced crude oil. As a result, the margins for refined products for refiners that process WTI-priced crude oils may decline.

The U.S. and worldwide refining business continues to experience capacity rationalization, particularly in Europe, the U.S. East Coast, and the Caribbean, where declining product margins have negatively impacted refineries in those regions. Refineries in those regions have closed, such as the Aruba Refinery discussed above, and others may close in coming months. However, some of these refineries may continue to be operated, which could have a negative impact on refined product margins. In addition, ethanol margins continue to remain depressed in the third quarter of 2012 due to higher corn prices caused by the drought in corn-producing regions of the U.S. Mid-Continent. As a result, we have temporarily suspended operations at two of our ethanol plants and reduced utilization at other plants.

Because of these matters, we expect energy markets and margins to be volatile in the near to mid-term.

In July 2012, we announced that our board of directors has authorized us to pursue a plan to separate our retail business from Valero as part of a strategy to maximize shareholder value. We are currently reviewing several potential separation transactions, including a tax-efficient distribution of the retail business to our shareholders.

Also in July 2012, our board of directors increased our quarterly dividend from $0.15 per share to $0.175 per share.

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RESULTS OF OPERATIONS

The following tables highlight our results of operations, our operating performance, and market prices that directly impact our operations. The narrative following these tables provides an analysis of our results of operations.
Financial Highlights (a) (b)
(millions of dollars, except per share amounts)

	Three Months Ended June 30,		
	2012	2011	Change
Operating revenues	$34,662	$31,293	$3,369
Costs and expenses:			
Cost of sales	31,621	28,380	3,241
Operating expenses:			
Refining	868	813	55
Retail	170	169	1
Ethanol	85	104	(19)
General and administrative expenses	171	151	20
Depreciation and amortization expense:			
Refining	338	339	(1)
Retail	29	27	2
Ethanol	10	9	1
Corporate	9	11	(2)
Total costs and expenses	33,301	30,003	3,298
Operating income	1,361	1,290	71
Other income (expense), net	(5)	10	(15)
Interest and debt expense, net of capitalized interest	(74)	(107)	33
Income from continuing operations before income tax expense	1,282	1,193	89
Income tax expense	452	449	3
Income from continuing operations	830	744	86
Loss from discontinued operations, net of income taxes	—	(1)	1
Net income	830	743	87
Less: Net loss attributable to noncontrolling interests	(1)	(1)	—
Net income attributable to Valero stockholders	$831	$744	$87
Net income attributable to Valero stockholders:			
Continuing operations	$831	$745	$86
Discontinued operations	—	(1)	1
Total	$831	$744	$87
Earnings per common share – assuming dilution:			
Continuing operations	$1.50	$1.30	$0.20
Discontinued operations	—	—	—
Total	$1.50	$1.30	$0.20

See note references on page 44.

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Operating Highlights
(millions of dollars, except per barrel amounts)

	Three Months Ended June 30,		
	2012	2011	Change
Refining (a) (b):			
Operating income	$1,364	$1,253	$111
Throughput margin per barrel (c)	$10.63	$11.41	$(0.78)
Operating costs per barrel:			
Operating expenses	3.59	3.86	(0.27)
Depreciation and amortization expense	1.40	1.61	(0.21)
Total operating costs per barrel	4.99	5.47	(0.48)
Operating income per barrel	$5.64	$5.94	$(0.30)
Throughput volumes (thousand barrels per day):			
Feedstocks:			
Heavy sour crude	390	450	(60)
Medium/light sour crude	609	418	191
Acidic sweet crude	136	128	8
Sweet crude	886	679	207
Residuals	215	293	(78)
Other feedstocks	122	105	17
Total feedstocks	2,358	2,073	285
Blendstocks and other	300	243	57
Total throughput volumes	2,658	2,316	342
Yields (thousand barrels per day):			
Gasolines and blendstocks	1,294	1,054	240
Distillates	918	786	132
Other products (d)	469	487	(18)
Total yields	2,681	2,327	354

See note references on page 44.

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Refining Operating Highlights by Region (e)
(millions of dollars, except per barrel amounts)

	Three Months Ended June 30, 2012	2011	Change
U.S. Gulf Coast (a):			
Operating income	$637	$786	$(149)
Throughput volumes (thousand barrels per day)	1,491	1,432	59
Throughput margin per barrel (c)	$9.50	$11.30	$(1.80)
Operating costs per barrel:			
Operating expenses	3.40	3.74	(0.34)
Depreciation and amortization expense	1.41	1.54	(0.13)
Total operating costs per barrel	4.81	5.28	(0.47)
Operating income per barrel	$4.69	$6.02	$(1.33)
U.S. Mid-Continent:			
Operating income	$444	$393	$51
Throughput volumes (thousand barrels per day)	404	398	6
Throughput margin per barrel (c)	$17.61	$16.50	$1.11
Operating costs per barrel:			
Operating expenses	3.97	4.01	(0.04)
Depreciation and amortization expense	1.55	1.65	(0.10)
Total operating costs per barrel	5.52	5.66	(0.14)
Operating income per barrel	$12.09	$10.84	$1.25
North Atlantic (b):			
Operating income (loss)	$172	$(17)	$189
Throughput volumes (thousand barrels per day)	473	207	266
Throughput margin per barrel (c)	$8.01	$3.36	$4.65
Operating costs per barrel:			
Operating expenses	3.22	3.04	0.18
Depreciation and amortization expense	0.80	1.22	(0.42)
Total operating costs per barrel	4.02	4.26	(0.24)
Operating income (loss) per barrel	$3.99	$(0.90)	$4.89
U.S. West Coast:			
Operating income	$111	$91	$20
Throughput volumes (thousand barrels per day)	290	279	11
Throughput margin per barrel (c)	$10.95	$10.65	$0.30
Operating costs per barrel:			
Operating expenses	4.62	4.84	(0.22)
Depreciation and amortization expense	2.11	2.21	(0.10)
Total operating costs per barrel	6.73	7.05	(0.32)
Operating income per barrel	$4.22	$3.60	$0.62
Total refining operating income	$1,364	$1,253	$111

See note references on page 44.

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Average Market Reference Prices and Differentials (f)
(dollars per barrel, except as noted)

	Three Months Ended June 30, 2012	2011	Change
Feedstocks:			
Brent crude oil	$108.95	$117.17	$(8.22)
Brent less WTI crude oil	15.51	14.68	0.83
Brent less Alaska North Slope (ANS) crude oil	(0.65)	2.15	(2.80)
Brent less LLS crude oil	0.02	(0.79)	0.81
Brent less Mars crude oil	4.22	5.25	(1.03)
Brent less Maya crude oil	9.86	13.79	(3.93)
LLS crude oil	108.93	117.96	(9.03)
LLS less Mars crude oil	4.20	6.04	(1.84)
LLS less Maya crude oil	9.84	14.58	(4.74)
WTI crude oil	93.44	102.49	(9.05)
Natural gas (dollars per million British thermal units)	2.24	4.34	(2.10)
Products:			
U.S. Gulf Coast:			
Conventional 87 gasoline less Brent	8.32	11.04	(2.72)
Ultra-low-sulfur diesel less Brent	14.65	12.27	2.38
Propylene less Brent	(10.39)	26.96	(37.35)
Conventional 87 gasoline less LLS	8.34	10.26	(1.92)
Ultra-low-sulfur diesel less LLS	14.67	11.49	3.18
Propylene less LLS	(10.37)	26.03	(36.40)
U.S. Mid-Continent:			
Conventional 87 gasoline less WTI	27.33	26.38	0.95
Ultra-low-sulfur diesel less WTI	30.32	28.83	1.49
North Atlantic:			
Conventional 87 gasoline less Brent	12.43	8.88	3.55
Ultra-low-sulfur diesel less Brent	16.11	13.96	2.15
U.S. West Coast:			
CARBOB 87 gasoline less ANS	18.20	14.54	3.66
CARB diesel less ANS	15.09	19.21	(4.12)
CARBOB 87 gasoline less WTI	34.36	27.07	7.29
CARB diesel less WTI	31.25	31.74	(0.49)
New York Harbor corn crush (dollars per gallon)	(0.06)	0.07	(0.13)

See note references on page 44.

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Operating Highlights (continued)
(millions of dollars, except per gallon amounts)

	Three Months Ended June 30, 2012	2011	Change
Retail–U.S.:			
Operating income	$134	$87	$47
Company-operated fuel sites (average)	998	995	3
Fuel volumes (gallons per day per site)	5,162	5,094	68
Fuel margin per gallon	$0.303	$0.204	$0.099
Merchandise sales	$320	$323	$(3)
Merchandise margin (percentage of sales)	30.1%	28.4%	1.7%
Margin on miscellaneous sales	$22	$22	$—
Operating expenses	$106	$103	$3
Depreciation and amortization expense	$20	$18	$2
Retail–Canada:			
Operating income	$38	$48	$(10)
Fuel volumes (thousand gallons per day)	3,117	3,182	(65)
Fuel margin per gallon	$0.285	$0.319	$(0.034)
Merchandise sales	$65	$68	$(3)
Merchandise margin (percentage of sales)	29.3%	29.8%	(0.5)%
Margin on miscellaneous sales	$11	$11	$—
Operating expenses	$64	$66	$(2)
Depreciation and amortization expense	$9	$9	$—
Ethanol:			
Operating income	$5	$64	$(59)
Production (thousand gallons per day)	3,352	3,397	(45)
Gross margin per gallon of production (c)	$0.32	$0.57	$(0.25)
Operating costs per gallon of production:			
Operating expenses	0.28	0.33	(0.05)
Depreciation and amortization expense	0.03	0.03	—
Total operating costs per gallon of production	0.31	0.36	(0.05)
Operating income per gallon of production	$0.01	$0.21	$(0.20)

See note references on page 44.

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The following notes relate to references on pages 39 through 43.

(a) For the three months ended June 30,2012, the financial highlights and operating highlights for the refining segment and U.S. Gulf Coast region include the results of operations of our Meraux Refinery, including related logistics assets, from the date of its acquisition on October 1, 2011.

(b) For the three months ended June 30, 2012, the financial highlights and operating highlights for the refining segment and North Atlantic region include the results of operations of our Pembroke Refinery, including the related marketing and logistics business, from the date of its acquisition on August 1, 2011.

(c) Throughput margin per barrel represents operating revenues less cost of sales of our refining segment divided by throughput volumes. Gross margin per gallon of production represents operating revenues less cost of sales of our ethanol segment divided by production volumes.

(d) Other products primarily include petrochemicals, gas oils, No. 6 fuel oil, petroleum coke, and asphalt.

(e) The regions reflected herein contain the following refineries: the U.S. Gulf Coast region includes the Corpus Christi East, Corpus Christi West, Texas City, Houston, Three Rivers, St. Charles, Aruba, Port Arthur, and Meraux Refineries; the U.S. Mid-Continent region includes the McKee, Ardmore, and Memphis Refineries; the North Atlantic region includes the Pembroke and Quebec City Refineries; and the U.S.West Coast region includes the Benicia and Wilmington Refineries.

(f) Average market reference prices for Brent crude oil, along with price differentials between the price of Brent crude oil and other types of crude oil, have been included in the table of Average Market Reference Prices and Differentials. The table also includes price differentials by region between the prices of certain products and the benchmark crude oil that provides a relevant indicator of product margins for each region. We previously provided feedstock and product differentials based on the price of WTI crude oil. However, the price of WTI crude oil no longer provides a reasonable benchmark price of crude oil for all regions. Beginning in late 2010, WTI crude oil began to price at a discount to benchmark sweet crude oils, such as Brent and LLS, because of increased WTI supplies resulting from greater U.S. production and increased deliveries of crude oil from Canada into the U.S. Mid-Continent region. We utilize Brent crude oil for price differentials because we believe it represents sweet crude oil prices for marginal refineries in the Atlantic Basin, and thus sets refined-product prices.

General

Operating revenues increased 11 percent (or $3.4 billion) for the second quarter of 2012 compared to the second quarter of 2011 primarily as a result of higher throughput volumes between the two periods related to our refining segment operations. The higher throughput volumes resulted primarily from the incremental throughput of 136,000 barrels per day from the Meraux Refinery, which was acquired on October 1, 2011, and incremental throughput of 250,000 barrels per day from the Pembroke Refinery, which was acquired on August 1, 2011. Operating income increased $71 million and income from continuing operations before income tax expense increased $89 million for the second quarter of 2012 compared to amounts reported for the second quarter of 2011 primarily due to a $111 million increase in refining segment operating income which was partially offset by a $59 million decrease in ethanol segment operating income discussed below.

Refining

Refining segment operating income increased 9 percent (or $111 million) from $1.3 billion for the second quarter of 2011 to $1.4 billion for the second quarter of 2012. The $111 million increase in operating income was primarily due to a $165 million increase in refining margin, partially offset by a $55 million increase in operating expenses.

The $165 million refining margin improvement was primarily due to the margin generated by our Meraux and Pembroke Refineries of $71 million and $173 million, respectively, during the second quarter of 2012. We acquired both of these refineries in the last half of 2011 as discussed above, but the increase in margin generated by these refineries was partially offset by a decrease in margin of $45 million related to our Aruba Refinery due to our decision to temporarily suspend its operations in March 2012. Those operations remained suspended throughout the second quarter of 2012.

Despite the refining margin improvement and a 15 percent increase in total throughput volumes (a 342,000 barrel per day increase) quarter over quarter, throughput margin per barrel decreased by 7 percent (or $0.78 per barrel). This decrease was largely due to decreases in product margins in the U.S. Gulf Coast region. For example, the Brent and LLS-based benchmark reference margins for U.S. Gulf Coast conventional

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87 gasoline were $8.32 per barrel and $8.34 per barrel, respectively, for the second quarter of 2012 compared to $11.04 per barrel and $10.26 per barrel, respectively, for the second quarter of 2011, representing unfavorable decreases of $2.72 per barrel and $1.92 per barrel, respectively. These decreases in U.S. Gulf Coast product margins had a significant impact to our overall refining margin because our U.S. Gulf Coast throughput volumes of 1.5 million barrels per day composed the majority (56 percent) of our total throughput volumes of 2.7 million barrels per day during the second quarter of 2012. In addition, throughput margin per barrel in the second quarter of 2012 was unfavorably impacted by the decrease in sour crude oil differentials as compared to the second quarter of 2011. For example, Maya crude oil, which is a type of sour crude oil, sold at a discount of $9.86 per barrel to Brent crude oil, which is a type of sweet crude oil, during the second quarter of 2012. This compares to a discount of $13.79 per barrel during the second quarter of 2011, representing an unfavorable decrease of $3.93 per barrel.

The increase of $55 million in refining operating expenses discussed above was primarily due to $36 million in operating expenses incurred by the Meraux Refinery, which was acquired on October 1, 2011, and $91 million in operating expenses incurred by the Pembroke Refinery, which was acquired on August 1, 2011. The remaining decrease in refining operating expenses of $72 million was primarily due to a $40 million decrease in energy costs, a $25 million decrease in maintenance expenses, and a $13 million decrease in employee-related expenses, partially offset by a $14 million increase in catalyst and chemical costs.

Retail

Retail segment operating income was $172 million for the second quarter of 2012 compared to $135 million for the second quarter of 2011. This 27 percent (or $37 million) increase was primarily due to an increase in the fuel margins generated by our U.S. retail operations of $48 million, partially offset by a decrease in the fuel margins generated by our Canadian retail operations of $11 million. The significant improvement in fuel margins in the U.S. was largely the result of decreases in the wholesale prices for gasoline and diesel in the second quarter of 2012.

Ethanol

Ethanol segment operating income was $5 million for the second quarter of 2012 compared to $64 million for the second quarter of 2011. The $59 million decrease in operating income was primarily due to a $77 million decrease in gross margin, partially offset by a $19 million decrease in operating expenses.

The decrease in gross margin was due to a 44 percent decrease in the gross margin per gallon of ethanol production (a $0.25 per gallon decrease between the comparable periods) primarily due to lower ethanol prices between the second quarter of 2011 and the second quarter of 2012. Ethanol prices in the second quarter of 2012 were pressured by a surplus of ethanol supply during the quarter due to reduced demand for ethanol associated with the decline in gasoline demand in the U.S. In addition, ethanol production decreased 45,000 gallons per day between the comparable periods, resulting from lower utilization rates during the second quarter of 2012 in response to the surplus of ethanol supply.

The reduction in operating expenses was due primarily to an $18 million decrease in energy costs due to lower natural gas prices compared to the second quarter of 2011.

Corporate Expenses and Other

General and administrative expenses increased $20 million from the second quarter of 2011 to the second quarter of 2012 primarily due to $29 million in administrative costs related to our European operations, partially offset by an $11 million decrease in employee-related expenses.

"Interest and debt expense, net of capitalized interest" for the second quarter of 2012 decreased $33 million from the second quarter of 2011. This decrease was primarily due to a $21 million increase in capitalized interest due to a corresponding increase in capital expenditures between the quarters.

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Financial Highlights (a) (b)
(millions of dollars, except per share amounts)

	Six Months Ended June 30, 2012	2011	Change
Operating revenues	$69,829	$57,601	$12,228
Costs and expenses:			
Cost of sales (c)	64,656	52,948	11,708
Operating expenses:			
Refining	1,832	1,557	275
Retail	336	331	5
Ethanol	172	199	(27)
General and administrative expenses	335	281	54
Depreciation and amortization expense:			
Refining	675	655	20
Retail	56	55	1
Ethanol	20	18	2
Corporate	19	23	(4)
Asset impairment loss (d)	611	—	611
Total costs and expenses	68,712	56,067	12,645
Operating income	1,117	1,534	(417)
Other income, net	1	27	(26)
Interest and debt expense, net of capitalized interest	(173)	(224)	51
Income from continuing operations before income tax expense	945	1,337	(392)
Income tax expense	547	489	58
Income from continuing operations	398	848	(450)
Income (loss) from discontinued operations, net of income taxes	—	(7)	7
Net income	398	841	(443)
Less: Net loss attributable to noncontrolling interests	(1)	(1)	—
Net income attributable to Valero stockholders	$399	$842	$(443)
Net income attributable to Valero stockholders:			
Continuing operations	$399	$849	$(450)
Discontinued operations	—	(7)	7
Total	$399	$842	$(443)
Earnings per common share – assuming dilution:			
Continuing operations	$0.72	$1.48	$(0.76)
Discontinued operations	—	(0.01)	0.01
Total	$0.72	$1.47	$(0.75)

See note references on page 51.

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Operating Highlights
(millions of dollars, except per barrel amounts)

	Six Months Ended June 30, 2012	2011	Change
Refining (a) (b):			
Operating income (c)	$1,245	$1,529	$(284)
Throughput margin per barrel (c)	$9.20	$10.70	$(1.50)
Operating costs per barrel:			
Operating expenses	3.86	3.89	(0.03)
Depreciation and amortization expense	1.43	1.64	(0.21)
Total operating costs per barrel (d)	5.29	5.53	(0.24)
Operating income per barrel	$3.91	$5.17	$(1.26)
Throughput volumes (thousand barrels per day):			
Feedstocks:			
Heavy sour crude	420	412	8
Medium/light sour crude	582	395	187
Acidic sweet crude	104	100	4
Sweet crude	885	672	213
Residuals	192	271	(79)
Other feedstocks	133	121	12
Total feedstocks	2,316	1,971	345
Blendstocks and other	290	241	49
Total throughput volumes	2,606	2,212	394
Yields (thousand barrels per day):			
Gasolines and blendstocks	1,243	1,005	238
Distillates	915	741	174
Other products (f)	468	476	(8)
Total yields	2,626	2,222	404

See note references on page 51.

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Refining Operating Highlights by Region (g)
(millions of dollars, except per barrel amounts)

	Six Months Ended June 30, 2012	2011	Change
U.S. Gulf Coast: (a)			
Operating income (c)	$872	$1,269	$(397)
Throughput volumes (thousand barrels per day)	1,483	1,366	117
Throughput margin per barrel (c) (e)	$8.21	$10.52	$(2.31)
Operating costs per barrel:			
Operating expenses	3.53	3.80	(0.27)
Depreciation and amortization expense	1.45	1.58	(0.13)
Total operating costs per barrel (d)	4.98	5.38	(0.40)
Operating income per barrel (d)	$3.23	$5.14	$(1.91)
U.S. Mid-Continent:			
Operating income (c)	$698	$682	$16
Throughput volumes (thousand barrels per day)	401	401	—
Throughput margin per barrel (c) (e)	$15.72	$14.77	$0.95
Operating costs per barrel:			
Operating expenses	4.64	3.83	0.81
Depreciation and amortization expense	1.52	1.54	(0.02)
Total operating costs per barrel	6.16	5.37	0.79
Operating income per barrel	$9.56	$9.40	$0.16
North Atlantic (b):			
Operating income	$233	$39	$194
Throughput volumes (thousand barrels per day)	467	208	259
Throughput margin per barrel (e)	$6.84	$5.19	$1.65
Operating costs per barrel:			
Operating expenses	3.37	2.93	0.44
Depreciation and amortization expense	0.73	1.20	(0.47)
Total operating costs per barrel	4.10	4.13	(0.03)
Operating income per barrel	$2.74	$1.06	$1.68
U.S. West Coast:			
Operating income (c)	$53	$81	$(28)
Throughput volumes (thousand barrels per day)	255	237	18
Throughput margin per barrel (c) (e)	$8.96	$9.71	$(0.75)
Operating costs per barrel:			
Operating expenses	5.46	5.37	0.09
Depreciation and amortization expense	2.35	2.46	(0.11)
Total operating costs per barrel	7.81	7.83	(0.02)
Operating income per barrel	$1.15	$1.88	$(0.73)
Operating income for regions above	$1,856	$2,071	$(215)
Asset impairment loss (d)	(611)	—	(611)
Loss on derivative contracts related to the forward sales of refined product (c)	—	(542)	542
Total refining operating income	$1,245	$1,529	$(284)

See note references on page 51.

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Average Market Reference Prices and Differentials (h)
(dollars per barrel, except as noted)

	Six Months Ended June 30, 2012	2011	Change
Feedstocks:			
Brent crude oil	$113.64	$111.17	$2.47
Brent less WTI crude oil	15.48	12.95	2.53
Brent less ANS crude oil	(0.01)	3.04	(3.05)
Brent less LLS crude oil	(0.91)	(0.32)	(0.59)
Brent less Mars crude oil	3.30	4.49	(1.19)
Brent less Maya crude oil	9.59	14.81	(5.22)
LLS crude oil	114.55	111.49	3.06
LLS less Mars crude oil	4.21	4.81	(0.60)
LLS less Maya crude oil	10.50	15.13	(4.63)
WTI crude oil	98.16	98.22	(0.06)
Natural gas (dollars per million British thermal units)	2.32	4.24	(1.92)
Products:			
U.S. Gulf Coast:			
Conventional 87 gasoline less Brent	7.72	7.36	0.36
Ultra-low-sulfur diesel less Brent	14.44	12.86	1.58
Propylene less Brent	(11.44)	23.16	(34.60)
Conventional 87 gasoline less LLS	6.81	7.04	(0.23)
Ultra-low-sulfur diesel less LLS	13.53	12.54	0.99
Propylene less LLS	(12.35)	22.76	(35.11)
U.S. Mid-Continent:			
Conventional 87 gasoline less WTI	22.80	21.14	1.66
Ultra-low-sulfur diesel less WTI	29.03	26.97	2.06
North Atlantic:			
Conventional 87 gasoline less Brent	10.08	6.54	3.54
Ultra-low-sulfur diesel less Brent	15.99	14.63	1.36
U.S. West Coast:			
CARBOB 87 gasoline less ANS	16.22	14.95	1.27
CARB diesel less ANS	16.69	19.96	(3.27)
CARBOB 87 gasoline less WTI	31.71	24.86	6.85
CARB diesel less WTI	32.18	29.87	2.31
New York Harbor corn crush (dollars per gallon)	(0.05)	0.07	(0.12)

See note references on page 51.

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Operating Highlights (continued)
(millions of dollars, except per gallon amounts)

	Six Months Ended June 30, 2012	2011	Change
Retail–U.S.:			
Operating income	$145	$106	$39
Company-operated fuel sites (average)	998	994	4
Fuel volumes (gallons per day per site)	5,104	4,995	109
Fuel margin per gallon	$0.178	$0.142	$0.036
Merchandise sales	$608	$606	$2
Merchandise margin (percentage of sales)	29.8%	28.3%	1.5%
Margin on miscellaneous sales	$46	$44	$2
Operating expenses	$210	$201	$9
Depreciation and amortization expense	$38	$37	$1
Retail–Canada:			
Operating income	$67	$95	$(28)
Fuel volumes (thousand gallons per day)	3,107	3,208	(101)
Fuel margin per gallon	$0.271	$0.318	$(0.047)
Merchandise sales	$123	$125	$(2)
Merchandise margin (percentage of sales)	29.3%	29.8%	(0.5)%
Margin on miscellaneous sales	$22	$22	$—
Operating expenses	$126	$130	$(4)
Depreciation and amortization expense	$18	$18	$—
Ethanol:			
Operating income	$14	$108	$(94)
Production (thousand gallons per day)	3.415	3,340	75
Gross margin per gallon of production (e)	$0.33	$0.54	$(0.21)
Operating costs per gallon of production:			
Operating expenses	0.28	0.33	(0.05)
Depreciation and amortization expense	0.03	0.03	—
Total operating costs per gallon of production	0.31	0.36	(0.05)
Operating income per gallon of production	$0.02	$0.18	$(0.16)

See note references on page 51.

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The following notes relate to references on pages 46 through 50.

(a) For the six months ended June 30, 2012, the financial highlights and operating highlights for the refining segment and U.S. Gulf Coast region include the results of operations of our Meraux Refinery, including related logistics assets, from the date of its acquisition on October 1, 2011.

(b) For the six months ended June 30, 2012, the financial highlights and operating highlights for the refining segment and North Atlantic region include the results of operations of our Pembroke Refinery, including the related marketing and logistics business, from the date of its acquisition on August 1, 2011.

(c) Cost of sales for the six months ended June 30, 2011 includes a loss of $542 million ($352 million after taxes) on commodity derivative contracts related to the forward sales of refined product. These contracts were closed and realized during the first quarter of 2011. The loss is reflected in refining segment operating income for the six months ended June 30, 2011, but throughput margin per barrel for the refining segment has been restated for the amount previously presented to exclude this $542 million loss ($1.35 per barrel). In addition, operating income and throughput margin per barrel for the U.S. Gulf Coast, U.S. Mid-Continent, and U.S. West Coast regions for the six months ended June 30, 2011 have been restated from the amounts previously presented to exclude the portion of this loss that had been allocated to them of $372 million ($1.51 per barrel); $122 million ($1.68 per barrel), and $48 million ($1.11 per barrel), respectively.

(d) In March 2012, we concluded our evaluation of strategic alternatives for our refinery in Aruba (Aruba Refinery) and announced that we would temporarily suspend the refinery's operations by the end of March. Because of this decision, we analyzed the Aruba Refinery for potential impairment and concluded that the refinery's net book value (carrying amount) of $945 million was not recoverable through the future operations and disposition of the refinery. We determined that the fair value of the Aruba Refinery was $350 million; therefore, we recognized an asset impairment loss of $595 million. In addition, we recognized an asset impairment loss of $16 million related to equipment associated with a permanently cancelled capital project at another refinery. The total asset impairment loss of $611 million is reflected in refining segment operating income for the six months ended June 30, 2012, but it is excluded from operating costs per barrel for the refining segment and U.S. Gulf Coast region.

(e) Throughput margin per barrel represents operating revenues less cost of sales of our refining segment divided by throughput volumes. Gross margin per gallon of production represents operating revenues less cost of sales of our ethanol segment divided by production volumes.

(f) Other products primarily include petrochemicals, gas oils, No. 6 fuel oil, petroleum coke, and asphalt.

(g) The regions reflected herein contain the following refineries: the U.S. Gulf Coast region includes the Corpus Christi East, Corpus Christi West, Texas City, Houston, Three Rivers, St. Charles, Aruba, Port Arthur, and Meraux Refineries; the U.S. Mid-Continent region includes the McKee, Ardmore, and Memphis Refineries; the North Atlantic region includes the Pembroke and Quebec City Refineries; and the U.S. West Coast region includes the Benicia and Wilmington Refineries.

(h) Average market reference prices for Brent crude oil, along with price differentials between the price of Brent crude oil and other types of crude oil, have been included in the table of Average Market Reference Prices and Differentials. The table also includes price differentials by region between the prices of certain products and the benchmark crude oil that provides a relevant indicator of product margins for each region. We previously provided feedstock and product differentials based on the price of WTI crude oil. However, the price of WTI crude oil no longer provides a reasonable benchmark price of crude oil for all regions. Beginning in late 2010, WTI crude oil began to price at a discount to benchmark sweet crude oils, such as Brent and LLS, because of increased WTI supplies resulting from greater U.S. production and increased deliveries of crude oil from Canada into the U.S. Mid-Continent region. We utilize Brent crude oil for price differentials because we believe it represents sweet crude oil prices for marginal refineries in the Atlantic Basin, and thus sets refined-product prices.

General

Operating revenues increased 21 percent (or $12.2 billion) for the first six months of 2012 compared to the first six months of 2011 primarily as a result of higher refined product prices and higher throughput volumes between the two periods related to our refining segment operations. The higher throughput volumes resulted primarily from the incremental throughput of 130,000 barrels per day from the Meraux Refinery, which was acquired on October 1, 2011, and incremental throughput of 248,000 barrels per day from the Pembroke Refinery, which was acquired on August 1, 2011. Operating income decreased $417 million and income from continuing operations before income tax expense decreased $392 million for the first six months of 2012 compared to amounts reported for the first six months of 2011 primarily due to a $284 million decrease in refining segment operating income and a $94 million decrease in ethanol segment operating income discussed below.

Refining

Refining segment operating income decreased 19 percent (or $284 million) from $1.5 billion for the first six months of 2011 to $1.2 billion for the first six months of 2012. This decrease was impacted by the

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$542 million loss on derivative contracts in the second quarter of 2011 and the $611 million asset impairment loss in the first quarter of 2012. (See Note 3 of Condensed Notes to Consolidated Financial Statements for further discussion of this asset impairment loss). Excluding these losses, refining segment operating income decreased $215 million from $2.1 billion in the first six months of 2011 to $1.9 billion in the first six months of 2012. This $215 million decrease was due primarily to a $275 million increase in operating expenses, partially offset by an $80 million increase in refining margin.

The increase of $275 million in operating expenses was primarily due to $73 million in operating expenses incurred by the Meraux Refinery and $184 million in operating expenses incurred by the Pembroke Refinery. The remaining increase of operating expenses of $18 million was primarily due to an increase in maintenance expenses.

The $80 million refining margin improvement was due to the margin generated by our Meraux and Pembroke Refineries of $91 million and $264 million, respectively, offset by a decrease in margin generated by the other refineries of our refining segment of $275 million. We acquired our Meraux and Pembroke Refineries in the last half of 2011; therefore, the margin generated by these refineries in the first six months of 2012 was fully incremental to our overall refining margin as compared to the first six months of 2011. The $275 million decrease in refining segment margin related to our other refineries was primarily due to an unfavorable decrease in the discount of the price of sour crude oils versus the price of sweet crude oils in the first six months of 2012 as compared to the first six months of 2011, partially offset by an increase in gasoline and distillate margins in the first six months of 2012 as compared to the first six months of 2011.

We estimate that the decrease in the discount of the price of sour crude oils versus the price of sweet crude oils reduced our refining margin by approximately $800 million for the first six months of 2012 versus the comparable 2011 period. For example, Maya crude oil, which is a type of sour crude oil, sold at a discount of $9.59 per barrel to Brent crude oil, which is a type of sweet crude oil, during the first six months of 2012. This compares to a discount of $14.81 per barrel during the first six months of 2011, representing an unfavorable decrease of $5.22 per barrel. We processed 1.0 million barrels per day of sour crude oils during the first six months of 2012; therefore, changes in the discount of the price of sour crude oils versus the price of sweet crude oils have a significant impact on our refining margins.

We estimate that the increase in gasoline and distillate margins increased our refining margin by approximately $600 million for the first six months of 2012 versus the comparable 2011 period. For example, the WTI-based benchmark reference margin for U.S. Mid-Continent conventional 87 gasoline and ultra-low-sulfur diesel (a type of distillate) was $22.80 per barrel and $29.03 per barrel, respectively, for the first six months of 2012 compared to $21.14 per barrel and $26.97 per barrel, respectively, for the first six months of 2011, representing a favorable increase of $1.66 per barrel and $2.06 per barrel, respectively. Other regions also experienced increases in gasoline and distillate margins. We produced 1.2 million barrels per day of gasoline and 0.9 million barrels per day of distillate during the first six months of 2012; therefore, changes in the margin we earn on these products have a significant impact on our refining margins.

Despite the refining margin improvement of $80 million and an 18 percent increase in total throughput volumes (a 394,000 barrel per day increase) between the comparable six-month periods, throughput margin per barrel decreased by 14 percent (or $1.50 per barrel). This decrease was largely due to the decrease in the discount of the price of sour crude oils versus the price of sweet crude oils in the first six months of 2012 versus the comparable 2011 period, which unfavorably impacted the margin we earn on the products we produce.

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Retail

Retail segment operating income was $212 million for the first six months of 2012 compared to $201 million for the first six months of 2011. This 5 percent (or $11 million) increase was primarily due to an increase in merchandise margins of $9 million and an increase in fuel margins from our U.S. retail operations of $37 million, partially offset by a $33 million decrease in fuel margins from our Canadian retail operations.

Ethanol

Ethanol segment operating income was $14 million for the first six months of 2012 compared to $108 million for the first six months of 2011. The $94 million decrease in operating income was primarily due to a $119 million decrease in gross margin, partially offset by a $27 million decrease in operating expenses.

The decrease in gross margin was due to a 39 percent decrease in the gross margin per gallon of ethanol production (a $0.21 per gallon decrease between the comparable periods) primarily due to lower ethanol prices in the first six months of 2012 versus the first six months of 2011. Ethanol prices in the first half of 2012 were pressured by a surplus of ethanol supply due to reduced demand for ethanol associated with the decline in gasoline demand in the U.S. In addition, ethanol production decreased 75,000 gallons per day between the comparable periods, resulting from lower utilization rates during the first half of 2012. The reduction in operating expenses was due primarily to a $32 million decrease in energy costs due to lower natural gas prices versus the comparable period of 2011, partially offset by a $4 million increase in chemical expenses between the periods.

Corporate Expenses and Other

General and administrative expenses increased $54 million from the first six months of 2011 to the first six months of 2012 primarily due to $48 million in administrative costs related to our European operations.

“Interest and debt expense, net of capitalized interest” for the first six months of 2012 decreased $51 million from the first six months of 2011. This decrease was primarily due to an increase of $46 million in capitalized interest due to a corresponding increase in capital expenditures between the six-month periods.

Income tax expense increased $58 million from the first six months of 2011 to the first six months of 2012 even though we reported lower income from continuing operations before income tax expense. The variation in the customary relationship between income tax expense and income from continuing operations before income tax expense for the six months ended June 30, 2012 was primarily due to not recognizing the tax benefit associated with the asset impairment loss of $595 million related to the Aruba Refinery as we do not expect to realize this tax benefit.

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LIQUIDITY AND CAPITAL RESOURCES

Cash Flows for the Six Months Ended June 30, 2012 and 2011

Net cash provided by operating activities for the first six months of 2012 was $3.0 billion, which was comparable to the first six months of 2011. The changes in cash provided by or used in working capital during the first six months of 2012 and 2011 are shown in Note 11 of Condensed Notes to Consolidated Financial Statements.

The net cash provided by operating activities during the first six months of 2012 combined with $300 million of proceeds from the remarketing of the 4.0% Gulf Opportunity Zone Revenue Bonds Series 2010 (GO Zone Bonds), $1.1 billion in borrowings under our revolving credit facility, and $1.3 billion of proceeds from the sale of receivables under our accounts receivable sales facility were used mainly to:

- fund $1.7 billion of capital expenditures and deferred turnaround and catalyst costs;
- redeem our Series 1997 5.6%, Series 1998 5.6%, Series 1999 5.7%, Series 2001 6.65%, and Series 1997A 5.45% industrial revenue bond for $108 million;
- make scheduled long-term note repayments of $754 million;
- repay borrowings under our revolving credit facility of $1.1 billion;
- make repayments under our accounts receivable sales facility of $1.5 billion;
- purchase common stock for treasury of $147 million;
- pay common stock dividends of $166 million; and
- increase available cash on hand by $271 million.

The net cash provided by operating activities during the first six months of 2011 was used mainly to:

- fund $1.4 billion of capital expenditures and deferred turnaround and catalyst costs;
- make scheduled long-term note repayments of $418 million and acquire the GO Zone Bonds for $300 million;
- pay common stock dividends of $57 million; and
- increase available cash on hand by $773 million.

Capital Investments

Our operations, especially those of our refining segment, are highly capital intensive. Each of our refineries comprises a large base of property assets, consisting of a series of interconnected, highly integrated and interdependent crude oil processing facilities and supporting logistical infrastructure (Units), and these Units are improved continuously. The cost of improvements, which consist of the addition of new Units and betterments of existing Units, can be significant. We have historically acquired our refineries at amounts significantly below their replacement costs, whereas our improvements are made at full replacement value. As such, the costs for improving our refinery assets increase over time and are significant in relation to the amounts we paid to acquire our refineries. We plan for these improvements by developing a multi-year capital program that is updated and revised based on changing internal and external factors.

We make improvements to our refineries in order to maintain and enhance their operating reliability, to meet environmental obligations with respect to reducing emissions and removing prohibited elements from the products we produce, or to enhance their profitability. Reliability and environmental improvements generally do not increase the throughput capacities of our refineries. Improvements that enhance refinery profitability may increase throughput capacity, but many of these improvements allow our refineries to process higher volumes of sour crude oil, which lowers our feedstock costs, and enables us to refine crude oil into products with higher market values. Therefore, many of our improvements do not increase throughput capacity significantly.

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During the six months ended June 30, 2012, we expended $1.4 billion for capital expenditures and $264 million for deferred turnaround and catalyst costs. Capital expenditures for the six months ended June 30, 2012 included $41 million of costs related to environmental projects.

For 2012, we expect to incur approximately $3.1 billion for capital investments (approximately $100 million of which is for environmental projects) and $530 million for deferred turnaround and catalyst costs. The capital expenditure estimate excludes expenditures related to strategic business acquisitions. We continuously evaluate our capital budget and make changes as conditions warrant.

Contractual Obligations
As of June 30, 2012, our contractual obligations included debt, capital lease obligations, operating leases, purchase obligations, and other long-term liabilities.

During the six months ended June 30, 2012, we had no material changes outside the ordinary course of our business with respect to our debt, capital lease obligations, operating leases, purchase obligations, or other long-term liabilities.

During the six months ended June 30, 2012, the following debt activity occurred:

- in March 2012, we exercised the call provisions on our Series 1997 5.6%, Series 1998 5.6%, Series 1999 5.7%, Series 2001 6.65%, and Series 1997A 5.45% industrial revenue bonds, which were redeemed on May 3, 2012 for $108 million, or 100 percent of their outstanding stated values;
- in April 2012, we made scheduled debt repayments of $4 million related to our Series 1997A 5.45% industrial revenue bonds and $750 million related to our 6.875% notes;
- in May 2012, we borrowed $1.1 billion under our revolving credit facility;
- in June 2012, we repaid $1.1 billion under our revolving credit facility; and
- also in June 2012, we received proceeds of $300 million from the remarketing of the 4.0% GO Zone Bonds, which are due December 1, 2040, but are subject to mandatory tender on June 1, 2022.

As of June 30, 2012, we had an accounts receivable sales facility with a group of third-party entities and financial institutions to sell on a revolving basis up to $1.0 billion of eligible trade receivables. In July 2012, we amended our agreement to increase the facility to $1.5 billion and to extend the maturity date to July 2013. During the six months ended June 30, 2012, we sold $1.3 billion of interests in eligible receivables to the third-party entities and financial institutions under this facility, and we repaid $1.5 billion under this facility. As of June 30, 2012, the amount of interests in eligible receivables sold was $100 million.

Our agreements do not have rating agency triggers that would automatically require us to post additional collateral. However, in the event of certain downgrades of our senior unsecured debt to below investment grade ratings by Moody's Investors Service, Standard & Poor's Ratings Services, and Fitch Ratings, the cost of borrowings under some of our bank credit facilities and other arrangements would increase. All of our ratings on our senior unsecured debt are at or above investment grade level as follows:

Rating Agency	Rating
Standard & Poor's Ratings Services	BBB (negative outlook)
Moody's Investors Service	Baa2 (stable outlook)
Fitch Ratings	BBB (stable outlook)

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We cannot provide assurance that these ratings will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are not recommendations to buy, sell, or hold our securities and may be revised or withdrawn at any time by the rating agency. Each rating should be evaluated independently of any other rating. Any future reduction below investment grade or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to obtain short- and long-term financing and the cost of such financings.

Other Commercial Commitments

As of June 30, 2012, we had outstanding letters of credit under our committed lines of credit as follows (in millions):

	Borrowing Capacity	Expiration	Outstanding Letters of Credit
Letter of credit facilities	$ 550	June 2013	$ 300
Revolving credit facility	$ 3,000	December 2016	$ 70
Canadian revolving credit facility	C$115	December 2012	C$11

In July 2012, one of our letter of credit facilities was amended to extend its maturity date through June 2013 and to increase its borrowing capacity by $50 million. The borrowing capacity and expiration shown in the table above reflect these changes. As of June 30, 2012, we had no amounts borrowed under our revolving credit facilities. The letters of credit outstanding as of June 30, 2012 expire during 2012 and 2013.

Other Matters Impacting Liquidity and Capital Resources

Pension Plan Funded Status

We have minimum required contributions of $2 million during 2012 to our pension plans that have minimum funding requirements; however, we plan to contribute approximately $100 million to our pension plans during 2012. During the six months ended June 30, 2012, we contributed $13 million to our pension plans. In July 2012, we contributed $50 million to our pension plans.

Stock Purchase Programs

As of June 30, 2012, we have approvals under common stock purchase programs to purchase approximately $3.5 billion of our common stock.

Environmental Matters

Our operations are subject to extensive environmental regulations by governmental authorities relating to the discharge of materials into the environment, waste management, pollution prevention measures, greenhouse gas emissions, and characteristics and composition of gasolines and distillates. Because environmental laws and regulations are becoming more complex and stringent and new environmental laws and regulations are continuously being enacted or proposed, the level of future expenditures required for environmental matters could increase in the future. In addition, any major upgrades in any of our operating facilities could require material additional expenditures to comply with environmental laws and regulations. See Note 6 of Condensed Notes to Consolidated Financial Statements for a further discussion of our environmental matters.

Tax Matters

We are subject to extensive tax liabilities imposed by multiple jurisdictions, including income taxes, transactional taxes (excise/duty, sales/use, and value-added taxes), payroll taxes, franchise taxes, withholding

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taxes, and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted or proposed that could result in increased expenditures for tax liabilities in the future. Many of these liabilities are subject to periodic audits by the respective taxing authority. Subsequent changes to our tax liabilities as a result of these audits may subject us to interest and penalties. See Note 6 of Condensed Notes to Consolidated Financial Statements for a further discussion of our tax matters.

As of June 30, 2012, the Internal Revenue Service (IRS) has ongoing tax audits related to our U.S. federal tax returns from 2002 through 2009, as discussed in Note 6 of Condensed Notes to Consolidated Financial Statements. We have received Revenue Agent Reports on our tax years for 2002 through 2007 and we are vigorously contesting the tax positions and assertions from the IRS. Although we believe our tax liabilities are fairly stated and properly reflected in our financial statements, should the IRS eventually prevail, it could result in a material amount of our deferred tax liabilities being reclassified to current liabilities which could have a material adverse effect on our liquidity.

Cash Held by Our International Subsidiaries
We operate in countries outside the U.S. through subsidiaries incorporated in these countries, and the earnings of these subsidiaries are taxed by the countries in which they are incorporated. We intend to reinvest these earnings indefinitely in our international operations even though we are not restricted from repatriating such earnings to the U.S. in the form of cash dividends. Should we decide to repatriate such earnings, we would incur and pay taxes on the amounts repatriated. In addition, such repatriation could cause us to record deferred tax expense that could significantly impact our results of operations. We believe, however, that a substantial portion of our international cash can be returned to the U.S. without significant tax consequences through means other than a repatriation of earnings. As of June 30, 2012, $1.1 billion of our cash and temporary cash investments was held by our international subsidiaries.

Financial Regulatory Reform
On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (Wall Street Reform Act). Key provisions of the Wall Street Reform Act create new statutory requirements that require most derivative instruments to be traded on exchanges and routed through clearinghouses, as well as impose new recordkeeping and reporting responsibilities on market participants. Final rules implementing the Wall Street Reform Act are expected to become effective in late 2012 and early 2013; therefore, the impact to our operations is yet unknown. However, the implementation could result in higher clearing costs and more reporting requirements with respect to our derivative activities.

Concentration of Customers
Our refining and marketing operations have a concentration of customers in the refining industry and customers who are refined product wholesalers and retailers. These concentrations of customers may impact our overall exposure to credit risk, either positively or negatively, in that these customers may be similarly affected by changes in economic or other conditions. However, we believe that our portfolio of accounts receivable is sufficiently diversified to the extent necessary to minimize potential credit risk. Historically, we have not had any significant problems collecting our accounts receivable.

Sources of Liquidity
We believe that we have sufficient funds from operations and, to the extent necessary, from borrowings under our credit facilities, to fund our ongoing operating requirements. We expect that, to the extent necessary, we can raise additional funds from time to time through equity or debt financings in the public and private capital markets or the arrangement of additional credit facilities. However, there can be no assurances regarding the availability of any future financings or additional credit facilities or whether such financings or additional credit facilities can be made available on terms that are acceptable to us.

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CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with U. S. generally accepted accounting principles requires us to make estimates and assumptions that affect the amounts reported in our financial statements and accompanying notes. Actual results could differ from those estimates. Our critical accounting policies are disclosed in our annual report on Form 10-K for the year ended December 31, 2011.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

COMMODITY PRICE RISK

We are exposed to market risks related to the volatility in the price of crude oil, refined products (primarily gasoline and distillate), grain (primarily corn), and natural gas used in our operations. To reduce the impact of price volatility on our results of operations and cash flows, we use commodity derivative instruments, including swaps, futures, and options to hedge:

- inventories and firm commitments to purchase inventories generally for amounts by which our current year inventory levels (determined on a last-in, first-out (LIFO) basis) differ from our previous year-end LIFO inventory levels and
- forecasted feedstock and refined product purchases, refined product sales, natural gas purchases, and corn purchases to lock in the price of those forecasted transactions at existing market prices that we deem favorable.

We use the futures markets for the available liquidity, which provides greater flexibility in transacting our hedging and trading operations. We use swaps primarily to manage our price exposure. We also enter into certain commodity derivative instruments for trading purposes to take advantage of existing market conditions related to future results of operations and cash flows.

Our positions in commodity derivative instruments are monitored and managed on a daily basis by a risk control group to ensure compliance with our stated risk management policy that has been approved by our board of directors.

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The following sensitivity analysis includes all positions at the end of the reporting period with which we have market risk (in millions):

	Derivative Instruments Held For Non-Trading Purposes	Derivative Instruments Held For Trading Purposes
June 30, 2012:		
Gain (loss) in fair value resulting from:		
10% increase in underlying commodity prices	$(196)	$(10)
10% decrease in underlying commodity prices	196	9
December 31, 2011:		
Gain (loss) in fair value resulting from:		
10% increase in underlying commodity prices	(156)	1
10% decrease in underlying commodity prices	156	2

See Note 13 of Condensed Notes to Consolidated Financial Statements for notional volumes associated with these derivative contracts as of June 30, 2012.

COMPLIANCE PROGRAM PRICE RISK

We are exposed to market risks related to the volatility in the price of financial instruments associated with various governmental and regulatory compliance programs that we must purchase in the open market to comply with these programs. To reduce the impact of this risk on our results of operations and cash flows, we may enter into derivative instruments, such as futures. As of June 30, 2012, there was no significant gain or loss in the fair value of derivative instruments that would result from a 10 percent increase or decrease in the underlying price of the futures contracts. See Note 13 of Condensed Notes to Consolidated Financial Statements for a discussion about these compliance programs and notional volumes associated with these derivative contracts as of June 30, 2012.

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INTEREST RATE RISK

The following table provides information about our debt instruments, excluding capital lease obligations (dollars in millions), the fair values of which are sensitive to changes in interest rates. Principal cash flows and related weighted-average interest rates by expected maturity dates are presented. We had no interest rate derivative instruments outstanding as of June 30, 2012 or December 31, 2011.

	June 30, 2012 Expected Maturity Dates							
	2012	2013	2014	2015	2016	There-after	Total	Fair Value
Debt:								
Fixed rate	$—	$480	$200	$475	$—	$5,774	$6,929	$8,087
Average interest rate	— %	5.5 %	4.8 %	5.2 %	— %	7.1 %	6.8 %	
Floating rate	$100	$—	$—	$—	$—	$—	$100	$100
Average interest rate	0.6 %	— %	— %	— %	— %	— %	0.6 %	

	December 31, 2011 Expected Maturity Dates							
	2012	2013	2014	2015	2016	There-after	Total	Fair Value
Debt:								
Fixed rate	$754	$484	$200	$475	$—	$5,578	$7,491	$9,048
Average interest rate	6.9 %	5.5 %	4.8 %	5.2 %	— %	7.3 %	6.9 %	
Floating rate	$250	$—	$—	$—	$—	$—	$250	$250
Average interest rate	0.6 %	— %	— %	— %	— %	— %	0.6 %	

FOREIGN CURRENCY RISK

As of June 30, 2012, we had commitments to purchase $634 million of U.S. dollars. Our market risk was minimal on these contracts, as they matured on or before July 31, 2012, resulting in a loss of approximately $1 million in the third quarter of 2012.

Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures.

Our management has evaluated, with the participation of our principal executive officer and principal financial officer, the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report, and has concluded that our disclosure controls and procedures were effective as of June 30, 2012.

(b) Changes in internal control over financial reporting.

There has been no change in our internal control over financial reporting that occurred during our last fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings
The information below describes new proceedings or material developments in proceedings that we previously reported in our annual report on Form 10-K for the year ended December 31, 2011, or our quarterly report on Form 10-Q for the quarter ended March 31, 2012.
Litigation
We hereby incorporate by reference into this Item our disclosures made in Part I, Item 1 of this Report included in Note 6 of Condensed Notes to Consolidated Financial Statements under the caption "Litigation Matters."

Environmental Enforcement Matters
While it is not possible to predict the outcome of the following environmental proceedings, if any one or more of them were decided against us, we believe that there would be no material effect on our financial position or results of operations. We are reporting these proceedings to comply with SEC regulations, which require us to disclose certain information about proceedings arising under federal, state, or local provisions regulating the discharge of materials into the environment or protecting the environment if we reasonably believe that such proceedings will result in monetary sanctions of $100,000 or more.

Bay Area Air Quality Management District (BAAQMD) (Benicia Refinery). In our annual report on Form 10-K for the year ended December 31, 2011, we reported that we had several outstanding violation notices (VNs) issued by the BAAQMD for alleged air regulation and air permit violations at our Benicia Refinery and asphalt plant. In the second quarter of 2012, we settled 14 VNs that were issued in 2010 and 2011.

South Coast Air Quality Management District (SCAQMD) (Wilmington Refinery). The SCAQMD has issued 27 notices of violation (NOVs) to our Wilmington Refinery and asphalt plant for alleged excess emission events, reporting issues, and administrative errors in 2010 and 2011. We are negotiating with the SCAQMD to resolve these matters.

Item 1A. Risk Factors
We are updating one of our risk factors to describe the cybersecurity risks that we face. Except for the modified risk factor presented below, there have been no material changes from the risk factors disclosed in our annual report on Form 10-K for the year ended December 31, 2011.

A significant interruption in one or more of our refineries could adversely affect our business.
Our refineries are our principal operating assets. As a result, our operations could be subject to significant interruption if one or more of our refineries were to experience a major accident or mechanical failure, encounter work stoppages relating to organized labor issues, be damaged by severe weather or other natural or man-made disaster, such as an act of terrorism, or otherwise be forced to shut down. If any refinery were to experience an interruption in operations, earnings from the refinery could be materially adversely affected (to the extent not recoverable through insurance) because of lost production and repair costs. Significant interruptions in our refining system could also lead to increased volatility in prices for crude oil feedstocks and refined products, and could increase instability in the financial and insurance markets, making it more difficult for us to access capital and to obtain insurance coverage that we consider adequate.

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In addition, our information technology systems and network infrastructure are subject to unauthorized access or attack, which could result in a loss of sensitive business information, systems interruption, or the disruption of our business operations. To protect against unauthorized access or attacks, we have implemented infrastructure protection technologies and disaster recovery plans, but there can be no assurance that a technology systems breach or systems failure will not have a material adverse effect on our financial condition or results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) Unregistered Sales of Equity Securities. Not applicable.

(b) Use of Proceeds. Not applicable.

(c) Issuer Purchases of Equity Securities. The following table discloses purchases of shares of our common stock made by us or on our behalf for the periods shown below.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Not Purchased as Part of Publicly Announced Plans or Programs (a)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (b)
April 2012	204,364	$23.97	204,364	—	$3.46 billion
May 2012	588,845	$21.79	588,845	—	$3.46 billion
June 2012	1,051,618	$22.30	1,051,618	—	$3.46 billion
Total	1,844,827	$22.32	1,844,827	—	$3.46 billion

(a) The shares reported in this column represent purchases settled during the three months ended June 30, 2012 relating to (a) our purchases of shares in open-market transactions to meet our obligations under employee stock compensation plans, and (b) our purchases of shares from our employees and non-employee directors in connection with the exercise of stock options, the vesting of restricted stock, and other stock compensation transactions in accordance with the terms of our incentive compensation plans.

(b) On April 26, 2007, we publicly announced an increase in our common stock purchase program from $2 billion to $6 billion, as authorized by our board of directors on April 25, 2007. The $6 billion common stock purchase program has no expiration date. On February 28, 2008, we announced that our board of directors approved a $3 billion common stock purchase program. This program is in addition to the $6 billion program. This $3 billion program has no expiration date.

Item 6. Exhibits

Exhibit No.	Description
12.01	Statements of Computations of Ratios of Earnings to Fixed Charges.
31.01	Rule 13a-14(a) Certification (under Section 302 of the Sarbanes-Oxley Act of 2002) of principal executive officer.
31.02	Rule 13a-14(a) Certification (under Section 302 of the Sarbanes-Oxley Act of 2002) of principal financial officer.
32.01	Section 1350 Certifications (as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).
101	Interactive Data Files

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VALERO ENERGY CORPORATION
(Registrant)

By: /s/ Michael S. Ciskowski
Michael S. Ciskowski
Executive Vice President and
Chief Financial Officer
(Duly Authorized Officer and Principal
Financial and Accounting Officer)

Date: August 8, 2012