OCWEN FINANCIAL CORP
Form 10-Q
August 04, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2010

or

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from: ____________________ to ____________________

Commission File Number: 1-13219

Ocwen Financial Corporation
(Exact name of registrant as specified in its charter)

Florida (State or other jurisdiction of incorporation or organization)	65-0039856 (I.R.S. Employer Identification No.)

1661 Worthington Road, Suite 100, West Palm Beach, Florida 33409
(Address of principal executive offices) (Zip Code)

(561) 682-8000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes o No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	o		Accelerated filer	x
Non-accelerated filer	o	(Do not check if a smaller reporting company)	Smaller reporting company	o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
Yes o No x

Number of shares of Common Stock, $0.01 par value, outstanding as of July 30, 2010: 100,192,127 shares.

OCWEN FINANCIAL CORPORATION
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FORWARD-LOOKING STATEMENTS

This Quarterly Report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, including, but not limited to the following:

- assumptions related to the sources of liquidity, our ability to fund advances and the adequacy of financial resources;
- estimates regarding prepayment speeds, float balances, delinquency rates, advances and other servicing portfolio characteristics;
- assumptions about our ability to grow our business;
- our plans to continue to sell our non-core assets;
- our ability to reduce our cost structure;
- our analysis in support of the decision to spin Ocwen Solutions as a separate company;
- our continued ability to successfully modify delinquent loans and sell foreclosed properties;
- estimates regarding our reserves, valuations and anticipated realization on assets; and
- expectations as to the effect of resolution of pending legal proceedings on our financial condition.

Forward-looking statements are not guarantees of future performance and involve a number of assumptions, risks and uncertainties that could cause actual results to differ materially. Important factors that could cause actual results to differ include, but are not limited to, the risks discussed in “Risk Factors” below and the following:

- availability of adequate and timely sources of liquidity;
- delinquencies, advances and availability of servicing;
- general economic and market conditions;
- uncertainty related to government programs, regulations and policies; and
- uncertainty related to dispute resolution and litigation.

Further information on the risks specific to our business are detailed within this report and our other reports and filings with the Securities and Exchange Commission including our Annual report on Form 10-K for the year ended December 31, 2009, our quarterly reports on Form 10-Q and our current reports on Form 8-K. Forward-looking statements speak only as of the date they are made and should not be relied upon. Ocwen Financial Corporation undertakes no obligation to update or revise forward-looking statements.

PART I – FINANCIAL INFORMATION
ITEM 1. INTERIM CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

OCWEN FINANCIAL CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands, except share data)

		June 30, 2010			December 31, 2009	
Assets						
Cash	$	143,386		$	90,919	
Restricted cash – for securitization investors		1,012			—	
Trading securities, at fair value:						
Auction rate		78,073			247,464	
Subordinates and residuals		52			3,692	
Loans held for resale, at lower of cost or fair value		30,696			33,197	
Advances		150,870			145,914	
Match funded advances		1,184,851			822,615	
Loans, net – restricted for securitization investors		70,860			—	
Mortgage servicing rights		126,668			117,802	
Receivables, net		56,939			67,095	
Deferred tax assets, net		117,253			132,683	
Premises and equipment, net		3,528			3,325	
Investments in unconsolidated entities		13,533			15,008	
Other assets		99,808			89,636	
Total assets	$	2,077,529		$	1,769,350	
Liabilities and Equity						
Liabilities						
Match funded liabilities	$	835,172		$	465,691	
Secured borrowings – owed to securitization investors		67,199			—	
Lines of credit and other secured borrowings		100,667			55,810	
Investment line		—			156,968	
Servicer liabilities		1,970			38,672	
Debt securities		82,554			95,564	
Other liabilities		90,037			90,782	
Total liabilities		1,177,599			903,487	
Commitments and Contingencies (Note 25)						
Equity						
Ocwen Financial Corporation stockholders' equity						
Common stock, $.01 par value; 200,000,000 shares authorized; 100,192,127 and 99,956,833 shares issued and outstanding at June 30, 2010 and December 31, 2009, respectively		1,002			1,000	
Additional paid-in capital		461,890			459,542	
Retained earnings		444,370			405,198	
Accumulated other comprehensive loss, net of income taxes		(7,572	)		(129	)

Total Ocwen Financial Corporation stockholders’ equity		899,690		865,611
Non-controlling interest in subsidiaries		240		252
Total equity		899,930		865,863
Total liabilities and equity	$	2,077,529	$	1,769,350

The accompanying notes are an integral part of these consolidated financial statements.

OCWEN FINANCIAL CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands)

For the periods ended June 30,	Three months		Six months	
	2010	2009	2010	2009
Revenue				
Servicing and subservicing fees	$65,936	$65,488	$132,416	$144,298
Process management fees	8,315	40,086	16,221	73,778
Other revenues	1,702	3,605	2,902	5,693
Total revenue	75,953	109,179	151,539	223,769
Operating expenses				
Compensation and benefits	13,089	27,254	25,866	55,799
Amortization of mortgage servicing rights	7,854	8,543	14,229	18,584
Servicing and origination	2,458	15,835	3,049	28,473
Technology and communications	6,191	4,481	11,855	9,289
Professional services	9,134	8,208	12,389	15,394
Occupancy and equipment	3,870	4,818	8,316	10,864
Other operating expenses	2,062	3,511	4,131	6,513
Total operating expenses	44,658	72,650	79,835	144,916
Income from operations	31,295	36,529	71,704	78,853
Other income (expense)				
Interest income	1,900	2,254	5,545	4,419
Interest expense	(13,359)	(17,300)	(25,830)	(33,963)
Gain (loss) on trading securities	(1,710)	5,435	(945)	5,055
Loss on loans held for resale, net	(1,049)	(2,987)	(2,087)	(7,541)
Equity in earnings (losses) of unconsolidated entities	343	(576)	1,078	(549)
Other, net	(4,158)	2,990	(4,758)	3,335
Other expense, net	(18,033)	(10,184)	(26,997)	(29,244)
Income from continuing operations before income taxes	13,262	26,345	44,707	49,609
Income tax expense (benefit)	(2,777)	9,472	7,797	17,509
Income from continuing operations	16,039	16,873	36,910	32,100
Income from discontinued operations, net of income taxes	—	1,052	—	864
Net income	16,039	17,925	36,910	32,964
Net income attributable to non-controlling interest in subsidiaries	(1)	(95)	(12)	(25)
Net income attributable to Ocwen Financial Corporation (OCN)	$16,038	$17,830	$36,898	$32,939
Basic earnings per share				
Income from continuing operations attributable to OCN	$0.16	$0.25	$0.37	$0.49

Income from discontinued operations attributable to OCN	—	0.01	—	0.02
Net income attributable to OCN	$0.16	$0.26	$0.37	$0.51
Diluted earnings per share				
Income from continuing operations attributable to OCN	$0.15	$0.24	$0.35	$0.48
Income from discontinued operations attributable to OCN	—	0.02	—	0.01
Net income attributable to OCN	$0.15	$0.26	$0.35	$0.49
Weighted average common shares outstanding				
Basic	100,168,953	67,316,446	100,072,950	65,045,842
Diluted	107,728,092	72,854,415	107,526,786	70,375,555

The accompanying notes are an integral part of these consolidated financial statements.

OCWEN FINANCIAL CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Dollars in thousands)

For the periods ended June 30,	Three months 2010	2009	Six months 2010	2009
Net income	$ 16,039	$ 17,925	$ 36,910	$ 32,964
Other comprehensive loss, net of income taxes:				
Unrealized foreign currency translation loss arising during the period (1)	(14)	(187)	(85)	(227)
Change in deferred loss on cash flow hedges arising during the period (2)	(7,383)	—	(7,383)	—
	(7,397)	(187)	(7,468)	(227)
Comprehensive income	8,642	17,738	29,442	32,737
Comprehensive loss attributable to non-controlling interests	4	(5)	12	97
Comprehensive income attributable to OCN	$ 8,646	$ 17,733	$ 29,454	$ 32,834

(1) Net of income tax benefit (expense) of $5 and $110 for the three months ended June 30, 2010 and 2009, respectively, and $35 and $133 for the six months ended June 30, 2010 and 2009, respectively.

(2) Net of tax benefit of $4,336 for the three and six months ended June 30, 2010.

The accompanying notes are an integral part of these consolidated financial statements.

OCWEN FINANCIAL CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
FOR THE SIX MONTHS ENDED JUNE 30, 2010 AND 2009
(Dollars in thousands, except share data)

	OCN Shareholders						
	Common Stock		Additional Paid-in	Retained	Accumulated Other Comprehensive Loss, Net of	Non-controlling Interest in	
	Shares	Amount	Capital	Earnings	Taxes	Subsidiaries	Total
Balance at December 31, 2009	99,956,833	$ 1,000	$ 459,542	$ 405,198	$ (129)	$ 252	$ 865,863
Adoption of ASC 810 (FASB Statement No. 167), net of tax	—	—	—	2,274	—	—	2,274
Net income	—	—	—	36,898	—	12	36,910
Exercise of common stock options	217,775	2	1,023	—	—	—	1,025
Issuance of common stock awards to employees	9,865	—	—	—	—	—	—
Equity-based compensation	7,654	—	1,325	—	—	—	1,325
Other comprehensive loss, net of income taxes	—	—	—	—	(7,443)	(24)	(7,467)
Balance at June 30, 2010	100,192,127	$ 1,002	$ 461,890	$ 444,370	$ (7,572)	$ 240	$ 899,930
Balance at December 31, 2008	62,716,530	$ 627	$ 201,831	$ 404,901	$ 1,876	$ 406	$ 609,641
Net income	—	—	—	32,939	—	25	32,964
Issuance of common stock	5,471,500	55	60,132	—	—	—	60,187
Repurchase of common stock	(1,000,000)	(10)	(10,990)	—	—	—	(11,000)
Exercise of common stock options	282,012	3	1,861	—	—	—	1,864

Issuance of common stock awards to employees	29,907	—	(138)	—	—	—	(138)
Equity-based compensation	12,147	—	1,379	—	—	—	1,379
Repurchase of 3.25% Convertible Notes	—	—	(4)	—	—	—	(4)
Other comprehensive loss, net of income taxes	—	—	—	—	(227)	(122)	(349)
Balance at June 30, 2009	67,512,096	$ 675	$ 254,071	$ 437,840	$ 1,649	$ 309	$ 694,544

The accompanying notes are an integral part of these consolidated financial statements.

OCWEN FINANCIAL CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)

	For the six months ended June 30, 2010	2009
Cash flows from operating activities		
Net income	$ 36,910	$ 32,964
Adjustments to reconcile net income to net cash provided by operating activities		
Amortization of mortgage servicing rights	14,229	18,584
Premium amortization and discount accretion	—	1,445
Depreciation and other amortization	741	4,862
Write-off of investment in commercial real estate partnership	3,000	—
Reversal of valuation allowance on mortgage servicing assets	(101)	—
Reversal of valuation allowance on discontinued operations	—	(1,227)
Loss (gain) on trading securities	945	(5,055)
Loss on loans held for resale, net	2,087	7,541
Equity in (earnings) losses of unconsolidated entities	(1,078)	549
Decrease in deferred tax assets	12,838	12,590
Net cash provided by trading activities	168,453	2,000
Net cash provided by loans held for resale activities	849	2,738
Changes in assets and liabilities:		
Decrease in advances and match funded advances	153,997	164,979
Decrease in receivables and other assets, net	11,983	15,089
Decrease in servicer liabilities	(36,702)	(57,977)
Decrease in other liabilities	(11,178)	(5,626)
Other, net	3,822	(337)
Net cash provided by operating activities	360,795	193,119
Cash flows from investing activities		
Purchase of mortgage servicing rights	(23,425)	(10,241)
Acquisition of advances and other assets in connection with the purchase of mortgage servicing rights	(528,882)	—
Distributions of capital from unconsolidated entities	2,146	3,246
Additions to premises and equipment	(2,202)	(1,110)
Proceeds from sales of real estate	2,046	1,322
Increase in restricted cash – for securitization investors	743	—
Principal payments received on loans – restricted for securitization investors	2,223	396
Net cash used by investing activities	(547,351)	(6,387)
Cash flows from financing activities		
Proceeds from (repayment of) match funded liabilities	369,481	(195,226)
Repayment of secured borrowings – owed to securitization investors	(4,852)	—
Proceeds from lines of credit and other secured borrowings	96,657	102,106
Repayment of lines of credit and other secured borrowings	(53,904)	(83,685)
Repayment of investment line	(156,968)	(24,051)
Repurchase of debt securities	(11,659)	(24,602)

Repurchase of common stock	—	(11,000)
Issuance of common stock	—	60,187
Exercise of common stock options	935	1,515
Other	(667)	910
Net cash provided (used) by financing activities	239,023	(173,846)
Net increase in cash	52,467	12,886
Cash at beginning of period	90,919	201,025
Cash at end of period	$ 143,386	$ 213,911

The accompanying notes are an integral part of these consolidated financial statements.

OCWEN FINANCIAL CORPORATION AND SUBSIDIARIES
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
JUNE 30, 2010
(Dollars in thousands, except share data)

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

Ocwen Financial Corporation (NYSE: OCN) (Ocwen or OCN), through its subsidiaries, is a leading provider of residential and commercial mortgage loan servicing, special servicing and asset management services. Ocwen is headquartered in West Palm Beach, Florida with offices in California, the District of Columbia, Florida, Georgia and global operations in India and Uruguay. Ocwen is a Florida corporation organized in February 1988. Ocwen Loan Servicing, LLC (OLS), a wholly-owned subsidiary of Ocwen, is a licensed mortgage servicer in all 50 states, the District of Columbia and two U.S. territories.

At June 30, 2010, Ocwen owned all of the outstanding stock of its primary subsidiaries: OLS; Ocwen Financial Solutions, Private Limited (OFSPL); and Investors Mortgage Insurance Holding Company. OCN also holds a 45% interest in BMS Holdings, Inc. (BMS Holdings), a 25% interest in Ocwen Structured Investments, LLC (OSI) and an approximate 25% interest in Ocwen Nonperforming Loans, LLC (ONL) and Ocwen REO, LLC (OREO). While OCN continues to own 70% of Global Servicing Solutions, LLC (GSS) with the remaining 30% interest held by ML IBK Positions, Inc., GSS had no material operations during the first six months of 2010 and 2009 and no material assets as of June 30, 2010.

On August 10, 2009, we completed the distribution of our Ocwen Solutions line of business, except for BMS Holdings and GSS, via the spin-off of a separate publicly-traded company, Altisource Portfolio Solutions S.A. (Altisource). Altisource common stock is listed on the NASDAQ market under the ticker symbol “ASPS.” We distributed all of the shares of Altisource common stock to OCN’s shareholders of record as of August 4, 2009 (the Separation). We eliminated the assets and liabilities of Altisource from our Consolidated Balance Sheet effective at the close of business on August 9, 2009. Beginning August 10, 2009, the operating results of Altisource are no longer included in our operating results. We do not report the historical operating results of Altisource as a discontinued operation because of the significance of the continuing involvement between Altisource and Ocwen under the long-term services agreements described in Note 24. Accordingly, for periods prior to August 10, 2009, the historical operating results of Altisource are presented in continuing operations.

Principles of Consolidation

Our financial statements include the accounts of Ocwen and its majority-owned subsidiaries. We apply the equity method of accounting to investments when the entity is not a variable interest entity (VIE) and we are able to exercise significant influence, but not control, over the policies and procedures of the entity but own less than 50% of the voting securities. We have eliminated intercompany accounts and transactions in consolidation.

Variable Interest Entities

We evaluate each special purpose entity (SPE) for classification as a VIE. When an SPE meets the definition of a VIE and we determine that Ocwen is the primary beneficiary, we include the SPE in our consolidated financial statements.

We have determined that the SPEs created in connection with the match funded financing facilities discussed below are VIEs of which we are the primary beneficiary. We have also determined that we are the primary beneficiary for certain residential mortgage loan securitization trusts. The accounts of these SPEs are included in our consolidated financial statements.

Securitizations or Asset Backed Financing Arrangements

Ocwen or its subsidiaries have been a transferor in connection with a number of securitizations or asset-backed financing arrangements. As of January 1, 2010, we had continuing involvement with the financial assets of eight of these securitizations or asset-backed financing arrangements. We also hold residual interests in and are the servicer for three securitizations where we were not a transferor.

We have aggregated these securitizations and asset-backed financing arrangements into two groups: (1) securitizations of residential mortgage loans and (2) financings of advances on loans serviced for others.

Securitizations of Residential Mortgage Loans. In prior years, we securitized residential mortgage loans using certain trusts. These transactions were accounted for as sales even though we continued to be involved with the trusts, typically by acting as the servicer or sub-servicer for the loans held by the trust and by retaining a beneficial ownership interest in the trust. The beneficial interests we held consisted of both subordinate and residual securities that were either retained at the time of the securitization or acquired subsequently.

As a result of our adoption of Accounting Standards Update (ASU) No. 2009-16 (ASC 860, Transfers and Servicing) and ASU 2009-17 (ASC 810, Consolidation), we have included four of these trusts in our consolidated financial statements. The remaining trusts are currently excluded from our consolidated financial statements because we have determined that Ocwen is not the primary beneficiary.

We have determined that Ocwen is the primary beneficiary of the consolidated securitization trusts because:

1. as the servicer we have the right to direct the activities that most significantly impact the economic performance of the trusts through our ability to manage the delinquent assets of the trusts and

2. as holder of all or a portion of the residual tranches of the securities issued by the trust, we have the obligation to absorb losses of the trusts, to the extent of the value of our investment, and the right to receive benefits from the trust both of which could potentially be significant to the trusts.

Upon adoption of ASU 2009-17 (ASC 810, Consolidation) on January 1, 2010 we began consolidating the four trusts and recorded a $75,506 increase in total assets, a $73,232 increase in liabilities and a $2,274 increase in the opening balance of retained earnings. Included in these amounts were the following transition adjustments:

Consolidation of $1,755 of cash held by the trusts (Restricted cash – for securitization investors);

Consolidation of loans held by the trust with an unpaid principal balance (UPB) of $77,939 (Loans, net – restricted for securitization investors), including $14,780 of non-performing collateral;

Recording of an allowance for loan losses of $4,461, not previously required, for the newly consolidated loans;

Consolidation of $2,346 of real estate owned from the trusts (included in Other assets);

Consolidation of $72,918 of certificates issued by the trusts (Secured borrowings – owed to securitization investors);

Elimination of our $3,634 investment in trading securities that were issued by the newly consolidated trusts against $867 of the face amount of the related certificates and retained earnings;

Recording of net deferred tax assets of $1,561, principally related to establishing an allowance for loan losses for the newly consolidated loans; and

Recording of $1,181 of other liabilities representing accrued interest payable and the fair value of interest rate swap instruments entered into by one of the consolidated trusts.

The consolidation of the four trusts on January 1, 2010 did not affect Cash and, therefore, the transition adjustments are not reported in the Consolidated Statement of Cash Flows.

Our Consolidated Statement of Operations for the three and six months ended June 30, 2009 and our Consolidated Balance Sheet at December 31, 2009 have not been retroactively adjusted to reflect the effect of our adoption of ASU 2009-16 and ASU 2009-17. Therefore, current period results and balances will not be comparable to prior period amounts particularly with regard to the following:

Trading securities (Subordinates and residuals)

Loans, net – restricted for securitization investors

Deferred tax assets, net

Secured borrowings – owed to securitization investors

Interest income

Interest expense

Gain (loss) on trading securities

Beginning January 1, 2010, interest income on the securities that we hold that were issued by the securitization trusts is eliminated in consolidation against the interest expense of the trusts.

Ocwen has no obligation to provide financial support to the trusts and has provided no such support. The creditors of the trusts can look only to the assets of the trusts themselves for satisfaction of the debt and have no recourse against the assets of Ocwen. Similarly, the general creditors of Ocwen have no claim on the assets of the trusts. Our exposure to loss as a result of our continuing involvement is limited to the carrying values of our investments in the residual and subordinate securities of the trusts, our mortgage servicing rights that are related to the trusts and our advances to the trusts.

The following table presents a summary of the involvement of Ocwen with seven unconsolidated securitization trusts and summary financial information for the trusts. Although we are the servicer for these trusts, the residual interests that we hold in these entities have little to no value. As a result, we are exposed to no loss from these holdings. Further, since our valuation of the residual interest is based on anticipated cash flows, we are unlikely to receive any benefits from these trusts.

For the periods ended June 30,	Three months		Six months	
	2010	2009	2010	2009
Total cash received on beneficial interests held	$—	$8	$—	$62
Total servicing and subservicing fee revenues	923	975	1,874	2,203

	As of	
	June 30, 2010	December 31, 2009
Total servicing advances	$ 17,545	$ 19,027
Total beneficial interests held at fair value (1)	52	58
Total mortgage servicing rights at amortized cost	1,466	1,659

(1) Includes investments in subordinate and residual securities that we retained in connection with the loan securitization transactions completed in prior years.

With regard to these unconsolidated securitization trusts, we have no obligation to provide financial support to the trusts and have provided no such support. Our exposure to loss as a result of our continuing involvement is limited to the carrying values of our investments in the residual and subordinate securities of the trusts, our mortgage servicing rights that are related to the trusts and our advances to the trusts. We consider the probability of loss arising from our advances to be remote because of their position ahead of most of the other liabilities of the trusts. See Note 5, Note 6, Note 7 and Note 9 for additional information regarding Trading securities, Advances, Match funded advances and Mortgage servicing rights.

Match Funded Advances on Loans Serviced for Others. Match funded advances on loans serviced for others result from our transfers of residential loan servicing advances to SPEs in exchange for cash. These SPEs issue debt supported by collections on the transferred advances. We made these transfers under the terms of four advance facility agreements. These transfers do not qualify for sales accounting because we retain control over the transferred assets. As a result, we account for these transfers as financings and classify the transferred advances on our Consolidated Balance Sheet as Match funded advances and the related liabilities as Match funded liabilities. Collections on the advances pledged to the SPEs are used to repay principal and interest and to pay the expenses of the entity. Holders of the debt issued by these entities can look only to the assets of the entities themselves for satisfaction of the debt and have no recourse against OCN. However, OLS has guaranteed the payment of the obligations under the securitization documents of one of the entities, Ocwen Servicer Advance Funding (Wachovia), LLC (OSAFW). The maximum amount payable under the guarantee is limited to 10% of the notes outstanding at the end of the facility's revolving period on May 5, 2011. As of June 30, 2010, OSAFW had $250,000 of notes outstanding.

The following table summarizes the assets and liabilities of the SPEs formed in connection with our match funded advance facilities, at the dates indicated:

	June 30, 2010	December 31, 2009
Match funded advances	$ 1,184,851	$ 822,615
Other assets	48,776	19,343
Total assets	$ 1,233,627	$ 841,958
Match funded liabilities	$ 835,172	$ 465,691
Other liabilities	104,046	138,210
Total liabilities	$ 939,218	$ 603,901

Reclassification

Certain immaterial amounts in our 2009 consolidated financial statements have been reclassified to conform to the 2010 presentation. In the fourth quarter of 2009, we reclassified gains and losses on debt redemptions to Other, net on the Consolidated Statements of Operations. On the Consolidated Statements of Changes in Equity, we condensed share-based compensation amounts and associated excess tax benefits into one line item, Equity-based compensation. Within the operating activities section of the Consolidated Statements of Cash Flows we condensed several immaterial items to Other, net. Similarly, in the financing section of the Consolidated Statements of Cash Flows we condensed several immaterial items to Other.

NOTE 2 RECENT ACCOUNTING PRONOUNCEMENTS

In June 2009, the Financial Accounting Standards Board (FASB) issued SFAS No. 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles. This establishes the FASB Accounting Standards Codification (ASC) as the only source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with GAAP, with the exception of Statements of Financial Accounting Standards not yet included in the Codification.

ASU 2009-16 (ASC 860, Transfers and Servicing). This statement eliminates the exceptions for qualifying special purpose entities (QSPE) from the consolidation guidance (ASC 810) and clarifies that the objective of the standard is to determine whether a transferor and all of the entities included in the transferor’s financial statements being presented have surrendered control over transferred financial assets. That determination must consider the transferor’s continuing involvements in the transferred financial asset including all arrangements or agreements made contemporaneously with, or in contemplation of, the transfer, even if they were not entered into at the time of the transfer. This statement modifies the financial-components approach currently used and limits the circumstances in which a financial asset, or portion of a financial asset, should be derecognized when the transferor has not transferred the entire original financial asset to an entity that is not consolidated with the transferor in the financial statements being presented and/or when the transferor has continuing involvement with the transferred financial asset.

This statement defines the term participating interest to establish specific conditions for reporting a transfer of a portion of a financial asset as a sale. If the transfer does not meet those conditions, a transferor should account for the transfer as a sale only if it transfers an entire financial asset or a group of entire financial assets and surrenders control over the entire transferred asset(s). This statement requires that a transferor recognize and initially measure at fair value all assets obtained (including a transferor’s beneficial interest) and liabilities incurred as a result of a transfer of financial assets accounted for as a sale. Enhanced disclosures are required to provide financial statement users with greater transparency about transfers of financial assets and a transferor’s continuing involvement with transferred financial assets.

The provisions for guaranteed mortgage securitizations are removed to require those securitizations to be treated the same as any other transfer of financial assets within the scope of the standard. If such a transfer does not meet the requirements for sale accounting, the securitized mortgage loans should continue to be classified as loans in the transferor’s statement of financial position.

We adopted this standard effective January 1, 2010 as a result of which, we reevaluated certain QSPEs with which we had ongoing relationships as further described under ASU 2009-17, below, and reassessed the adequacy of our disclosures with regard to our servicing assets and servicing liabilities.

ASU 2009-17 (ASC 810, Consolidation). This standard requires an enterprise to perform ongoing periodic assessments to determine whether the enterprise’s variable interest or interests give it a controlling financial interest in a VIE. We adopted this standard effective January 1, 2010. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both of the following characteristics:

(a) The power to direct the activities of a variable interest entity that most significantly impact the entity's economic performance

(b) The obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

In addition to reintroducing the concept of control into the determination of the primary beneficiary of a VIE, this statement makes numerous other amendments to the current standards primarily to reflect the elimination of the concept of a QSPE under ASC 860 (above). This statement also amends the current standards to require enhanced disclosures that will provide users of financial statements with more transparent information about an enterprise's involvement in a variable interest entity. The enhanced disclosures are required for any enterprise that holds a variable interest in a VIE. The additional disclosures required by this statement are included in Note 1—Summary of Significant Accounting Policies.

As also disclosed in Note 1—Securitizations of Residential Mortgage Loans, we previously excluded certain loan securitization trusts from our consolidated financial statements because each was a QSPE. Effective January 1, 2010, we reevaluated these QSPEs as well as all other potentially significant interests in other unconsolidated entities to determine if we should include them in our consolidated financial statements.

ASU No. 2010-06 (ASC 820, Fair Value Measurements and Disclosures). ASU 2010-06 revises two disclosure requirements concerning fair value measurements and clarifies two others. It requires separate presentation of significant transfers into and out of Levels 1 and 2 of the fair value hierarchy and disclosure of the reasons for such transfers. It will also require the presentation of purchases, sales, issuances and settlements within Level 3 on a gross basis rather than a net basis. The amendments also clarify that disclosures should be disaggregated by class of asset or liability and that disclosures about inputs and valuation techniques should be provided for both recurring and non-recurring fair value measurements. These new disclosure requirements became effective for our financial statements for the period ending June 30, 2010, except for the requirement concerning gross presentation of Level 3 activity, which will become effective for fiscal years beginning after December 15, 2010. See Note 4 for our fair value disclosures related to financial instruments.

ASU No. 2010-20 (ASC 310, Receivables). On July 21, 2010, the FASB issued ASU 2010-20, Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses. This standard outlines specific disclosures required for the allowance for credit losses and all finance receivables, as defined. A finance receivable is defined as a contractual right to receive money on demand or on fixed or determinable dates that is recognized as an asset in the entity's statement of financial position. This definition includes instruments such as certain trade receivables, notes receivable and lease receivables as well as the instruments more traditionally associated with an allowance for credit loss, such as mortgage loans, auto loans, credit card loans and other consumer or commercial lending agreements.

A significant change from the current disclosure requirements will be to provide information for both the finance receivables and the related allowance for credit losses at disaggregated levels. The standard introduces two new defined terms that will govern the level of disaggregation. These include a "portfolio segment" and a "class" of financing receivable. A portfolio segment is defined as the level at which an entity determines its allowance for credit losses. For example, this may be by type of receivable, industry or risk. A class of financing receivable is defined as a group of finance receivables determined on the basis of their initial measurement attribute (i.e., amortized cost or purchased credit impaired), risk characteristics, and an entity's method for monitoring and assessing credit risk.

The new guidance requires an entity to provide the extensive disclosures or information for the reporting periods presented including, but not limited to:

Presented by portfolio segment: A rollforward schedule of the allowance for credit losses (with the ending allowance balance further disaggregated based on impairment methodology) together with the related ending balance of the finance receivables; and significant purchases and sales of financing receivables.

Presented by class: The credit quality of the financing receivables portfolio at the end of the reporting period; the aging of past due financing receivables at the end of the period; the nature and extent of troubled debt restructurings that occurred during the period and their impact on the allowance for credit losses; the nature and extent of troubled debt restructurings, that occurred within the last year, that have defaulted in the current reporting period, and their impact on allowance for credit losses; the nonaccrual status of financing receivables; and impaired financing receivables.

Disclosures of information as of the end of a reporting period will become effective for both interim and annual reporting periods ending after December 15, 2010. Specific items regarding activity that occurred prior to the issuance of the ASU, such as the allowance rollforward and modification disclosures will be required for periods beginning after December 15, 2010.

NOTE 3 PENDING ACQUISITION

On May 28, 2010, Barclays Bank PLC and Barclays Capital Real Estate Inc. (together the "Sellers"), OLS and Ocwen entered into an Asset Purchase Agreement pursuant to which, among other things, OLS has agreed to acquire the Sellers' U.S. non-prime mortgage servicing business known as "HomEq Servicing" including, but not limited to, the mortgage servicing rights and associated servicer advances of HomEq Servicing as well as the servicing platform.

The aggregate purchase price is approximately $1,300,000, payable in cash upon consummation of the acquisition. The purchase price is subject to adjustment mechanisms and repurchase rights in limited circumstances.

As part of the acquisition, the Sellers have agreed to provide OLS with approximately $1,045,000 in secured financing. In addition, OLS obtained a syndicated $350,000 five year senior secured term loan facility on July 29, 2010 that will be used in part to fund the acquisition. See Note 26 for additional information.

Consummation of the acquisition is subject to closing conditions, including, among other things, the absence of legal impediments or an injunction and the receipt of required consents. Unless agreed to by the parties, the acquisition will be consummated no earlier than 90 days from the signing of the Asset Purchase Agreement.

The transaction is expected to close on September 1, 2010. Through June 30, 2010, we have incurred approximately $1,250 of fees for professional services related to the acquisition which are included in operating expenses for the second quarter of 2010. Also included in operating expenses was approximately $1,500 of additional compensation, telecommunications and occupancy expenses related to the acquisition.

NOTE 4 FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts and the estimated fair values of our financial instruments are as follows at the dates indicated:

	June 30, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Trading securities:				
Auction rate	$78,073	$78,073	$247,464	$247,464
Subordinates and residuals	52	52	3,692	3,692
Loans held for resale	30,696	30,696	33,197	33,197
Loans, net – restricted for securitization investors	70,860	69,341	—	—
Advances	1,335,721	1,335,721	968,529	968,529
Receivables, net	56,939	56,939	67,095	67,095
Financial liabilities:				
Match funded liabilities	$835,172	$758,024	$465,691	$463,716
Lines of credit and other secured borrowings	100,667	101,766	55,810	56,220
Secured borrowings – owed to securitization investors	67,199	66,325	—	—
Investment line	—	—	156,968	156,968
Servicer liabilities	1,970	1,970	38,672	38,672
Debt securities	82,554	76,807	95,564	84,551
Derivative financial instruments, net	$(12,278)	$(12,278)	$781	$781

Fair value is estimated based on a hierarchy that maximizes the use of observable inputs and minimizes the use of unobservable inputs. Observable inputs are inputs that reflect the assumptions market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the reporting entity. Unobservable inputs are inputs that reflect the reporting entity's own assumptions about the assumptions market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The fair value hierarchy prioritizes the inputs to valuation techniques into three broad levels whereby the highest priority is given to Level 1 inputs and the lowest to Level 3 inputs. The three broad categories are:

Level 1: Quoted prices in active markets for identical assets or liabilities.

Level 2: Inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly for substantially the full term of the financial instrument.

Level 3: Unobservable inputs for the asset or liability.

Where available, we utilize quoted market prices or observable inputs rather than unobservable inputs to determine fair value. We classify assets in their entirety based on the lowest level of input that is significant to the fair value measurement.

The following table sets forth assets and liabilities measured at fair value categorized by input level within the fair value hierarchy:

	Carrying value	Level 1	Level 2	Level 3
At June 30, 2010:				
Measured at fair value on a recurring basis:				
Trading securities (1):				
Auction rate	$78,073	$—	$—	$78,073
Subordinates and residuals (2)	52	—	—	52
Derivative financial instruments, net (3)	(12,278)	—	—	(12,278)
Measured at fair value on a non-recurring basis:				
Loans held for resale (4)	30,696	—	—	30,696
Mortgage servicing rights (5)	348	—	—	348
At December 31, 2009:				
Measured at fair value on a recurring basis:				
Trading securities (1):				
Auction rate	$247,464	$—	$—	$247,464
Subordinates and residuals (2)	3,692	—	—	3,692
Derivative financial instruments, net (3)	781	—	—	781
Measured at fair value on a non-recurring basis:				
Loans held for resale (4)	33,197	—	—	33,197
Mortgage servicing rights (5)	613	—	—	613

(1) Because our internal valuation model requires significant use of unobservable inputs, these securities are classified within Level 3 of the fair value hierarchy.

(2) Effective January 1, 2010, we eliminated our investment in trading securities that were issued by newly consolidated securitization trusts as more fully described in Note 1—Securitizations of Residential Mortgage Loans.

(3) The fair values of derivative financial instruments as of January 1, 2010 were adjusted to include $(826) related to an interest rate swap that is held by one of the newly consolidated securitization trusts. Derivative financial instruments consist of interest: rate caps that we use to protect against our exposure to rising interest rates on two of our match funded variable funding notes; interest rate swaps to protect against our exposure to rising interest rates on a third match funded facility and a match funded facility forecast in connection with the HomEq Servicing acquisition; the interest rate swap that is held by one of the newly consolidated loan securitization trusts; and foreign exchange forward contracts to protect against changes in the value of the Indian Rupee. See Note 18 for additional information on our derivative financial instruments.

(4) Loans held for resale are measured at fair value on a non-recurring basis. At June 30, 2010 and December 31, 2009, the carrying value of loans held for resale is net of a valuation allowance of $13,546 and $15,963, respectively. Current market illiquidity has reduced the availability of observable pricing data. Consequently, we classify loans within level 3 of the fair value

hierarchy.

(5) The carrying value of MSRs at June 30, 2010 and December 31, 2009 is net of a valuation allowance for impairment of $2,853 and $2,954, respectively. The carrying value of the impaired stratum, net of the valuation allowance, was $348 and $613 at June 30, 2010 and December 31, 2009, respectively. The estimated fair value exceeded amortized cost for all other strata. See Note 9 for additional information on MSRs.

The following table sets forth a reconciliation of the changes in fair value of our Level 3 assets that we measure at fair value on a recurring basis:

	Fair value at beginning of period	Purchases, collections and settlements, net (1)	Total realized and unrealized gains and (losses) (2)(3)	Transfers in and/or out of Level 3	Fair value at June 30
For the three months ended June 30, 2010:					
Trading securities:					
Auction rate	$125,036	$(45,260)	$(1,703)	$—	$78,073
Subordinates and residuals	59	—	(7)	—	52
Derivative financial instruments	(480)	76	(11,874)	—	(12,278)
For the three months ended June 30, 2009:					
Trading securities:					
Auction rate	$238,161	$(900)	$6,024	$—	$243,285
Subordinates and residuals	4,028	1	(589)	—	3,440
Derivative financial instruments	355	—	602	—	957
For the six months ended June 30, 2010:					
Trading securities:					
Auction rate	$247,464	$(168,453)	$(938)	$—	$78,073
Subordinates and residuals	59	—	(7)	—	52
Derivative financial instruments	(45)	76	(12,309)	—	(12,278)
For the six months ended June 30, 2009:					
Trading securities:					
Auction rate	$239,301	$(2,000)	$5,984	$—	$243,285
Subordinates and residuals	4,369	—	(929)	—	3,440
Derivative financial instruments	193	—	764	—	957

(1) Purchases, collections and settlements, net, related to trading securities exclude interest received.

(2)

Total gains and (losses) on auction rate securities for the second quarter include unrealized gains (losses) of $(53) and $6,024 on auction rate securities still held at June 30, 2010 and 2009, respectively. For the year to date periods, unrealized gains on auction rate securities still held at June 30, 2010 and 2009 were $559 and $5,984, respectively. The total gains and (losses) attributable to subordinates and residuals and derivative financial instruments were comprised principally of unrealized gains (losses) on assets held at June 30, 2010 and 2009.

(3) Total gains (losses) on derivatives for the three and six months ended June 30, 2010 include unrealized losses of $11,719 reported in changes in Other comprehensive loss. All other unrealized gains (losses) on derivatives for the 2010 and 2009 periods are reported in Other, net. The total gains and (losses) attributable to derivative financial instruments were comprised principally of unrealized gains (losses) on assets still held at June 30, 2010 and 2009.

The methodologies that we use and key assumptions that we make to estimate the fair value of instruments are described in more detail by instrument below:

Trading Securities

Auction Rate Securities. We estimated the fair value of the auction rate securities based on a combination of observable market inputs provided by actual orderly sales of similar auction rate securities and a discounted cash flow analysis. This discounted cash flow analysis incorporates expected future cash flows based on our best estimate of market participant assumptions. In periods of market illiquidity, the fair value of auction rate securities is determined after consideration of the credit quality of the securities held and the underlying collateral, market activity and general market conditions affecting auction rate securities.

The discounted cash flow analysis included the following range of assumptions at June 30, 2010:

Expected term	18 months
Illiquidity premium	0.61%
Discount rate	1.50% – 3.67%

The expected term was based upon our best estimate of market participants' expectations of future successful auctions. The discount rate and illiquidity premium are consistent with prevailing rates for similar securities. Other significant assumptions that we considered in our analysis included the credit risk profiles of the issuers, the impact on the issuers of the increased debt service costs associated with the payment of penalty interest rates and the collateralization of the securitization trusts. We do not assume defaults in our valuation due to the high credit quality of both the securities we hold and the underlying collateral.

Subordinates and Residuals. Our subordinate and residual securities are not actively traded, and, therefore, we estimate the fair value of these securities based on the present value of expected future cash flows from the underlying mortgage pools. We use our best estimate of the key assumptions we believe are used by market participants. We calibrate our internally developed discounted cash flow models for trading activity when appropriate to do so in light of market liquidity levels. Key inputs include expected prepayment rates, delinquency and cumulative loss curves and discount rates commensurate with the risks. Where possible, we use observable inputs in the valuation of our securities. However, the subordinate and residual securities in which we invest typically trade infrequently and therefore have few or no observable inputs and little price transparency. Additionally, during periods of market dislocation, the observability of inputs is further reduced.

Discount rates for the subordinate and residual securities range are determined based upon an assessment of prevailing market conditions and prices for similar assets. We project the delinquency, loss and prepayment assumptions based on a comparison to actual historical performance curves adjusted for prevailing market conditions.

Derivative Financial Instruments

Exchange-traded derivative financial instruments are valued based on quoted market prices. If quoted market prices or other observable inputs are not available, fair value is based on estimates provided by third-party pricing sources.

Loans Held for Resale

Loans held for resale are reported at the lower of cost or fair value. We account for the excess of cost over fair value as a valuation allowance with changes in the valuation allowance included in Gain (loss) on loans held for resale, net, in the period in which the change occurs. All loans held for resale were measured at fair value because the cost of

$44,242 exceeded the estimated fair value of $30,696 at June 30, 2010.

When we enter into an agreement to sell a loan to an investor at a set price, the loan is valued at the commitment price. The fair value of loans for which we do not have a firm commitment to sell is based upon a discounted cash flow analysis. We stratify our fair value estimate of uncommitted loans held for resale based upon the delinquency status of the loans. We base the fair value of our performing loans on the expected future cash flows discounted at a rate commensurate with the risk of the estimated cash flows. Significant assumptions include collateral and loan characteristics, prevailing market conditions and the creditworthiness of the borrower. The fair value of our non-performing loans is determined based upon the underlying collateral of the loan and the estimated period and cost of disposition.

Loans – Restricted for Securitization Investors

Loans – restricted for securitization investors are reported at cost, less an allowance for loan losses and are comprised of loans that are secured by first or second liens on one- to four-family residential properties. We base the fair value of our loans on the expected future cash flows discounted at a rate commensurate with the risk of the estimated cash flows. Significant assumptions include expected prepayment rates and delinquency and cumulative loss curves.

Mortgage Servicing Rights

We estimate the fair value of our MSRs by calculating the present value of expected future cash flows utilizing assumptions that we believe are used by market participants. The most significant assumptions used in our internal valuation are the speed at which mortgages prepay and delinquency experience both of which we derive from our historical experience and available market data. Other assumptions used in our internal valuation are:

- Cost of servicing
- Discount rate
- Interest rate used for computing the cost of servicing advances
- Interest rate used for computing float earnings
- Compensating interest expense

The significant components of the estimated future cash inflows for MSRs include servicing fees, late fees, prepayment penalties, float earnings and other ancillary revenues. Significant cash outflows include the cost of servicing, the cost of financing servicing advances and compensating interest payments. We derive prepayment speeds and delinquency assumptions from historical experience adjusted for prevailing market conditions. We develop the discount rate internally, and we consider external market-based assumptions in determining the interest rate for the cost of financing advances, the interest rate for float earnings and the cost of servicing. The more significant assumptions used in the June 30, 2010 valuation include prepayment speeds ranging from 14.03% to 19.55% (depending on loan type) and delinquency rates ranging from 13.25% to 31.88% (depending on loan type). Other assumptions include an interest rate of 1-month LIBOR plus 4% for computing the cost of financing advances, an interest rate of 1-month LIBOR for computing float earnings and a discount rate of 20%.

We perform an impairment analysis based on the difference between the carrying amount and fair value after grouping our loans into the applicable strata based on one or more of the predominant risk characteristics of the underlying loans. The risk factors used to assign loans to strata include the credit score (FICO) of the borrower, the loan to value ratio and the default risk. Our strata include:

- Subprime
- ALT A
- High-loan-to-value
- Re-performing
- Special servicing
- Other

Advances

We value advances that we make on loans that we service for others at their carrying amounts because they have no stated maturity, generally are realized within a relatively short period of time and do not bear interest.

Receivables

The carrying value of receivables generally approximates fair value because of the relatively short period of time between their origination and realization.

Borrowings

Borrowings not subject to a hedging relationship are carried at amortized cost. We base the fair value of our debt securities on quoted market prices. The carrying value of match funded liabilities and secured borrowings that bear interest at a rate that is adjusted regularly based on a market index approximates fair value. For other match funded or secured borrowings that bear interest at a fixed rate, we determine fair value by discounting the contractual future principal and interest repayments at a market rate commensurate with the risk of the estimated cash flows. We carry certain zero-coupon long-term secured borrowings with an implicit fixed rate at a discounted value and determine fair value by discounting the contractual future principal repayments at a market rate that is commensurate with the risk of the estimated cash flows.

Servicer Liabilities

The carrying value of servicer liabilities approximates fair value due to the short period of time the funds are held until they are deposited in collection accounts, paid directly to an investment trust or refunded to borrowers.

NOTE 5 TRADING SECURITIES

Trading securities consisted of the following at the dates indicated:

	June 30, 2010	December 31, 2009
Auction rate (Corporate Items and Other)	$ 78,073	$ 247,464
Subordinates and residuals:		
Loans and Residuals (1)	$ —	$ 3,634
Corporate Items and Other	52	58
	$ 52	$ 3,692

Gain (loss) on trading securities for the periods ended June 30, was comprised of the following:

	Three months		Six months	
	2010	2009	2010	2009
Unrealized gains (losses):				
Auction rate securities	$(53)	$6,024	$969	$5,984
Subordinates and residuals (1)	(7)	(589)	(7)	(929)
	$(60)	$5,435	$962	$5,055
Realized losses (2)	(1,650)	—	(1,907)	—
	$(1,710)	$5,435	$(945)	$5,055

(1) Effective January 1, 2010, we eliminated our investment in trading securities that were issued by newly consolidated securitization trusts as more fully described in Note 1—Securitizations of Residential Mortgage Loans, as well as the related unrealized gains and losses.

(2) The realized losses for the 2010 periods were incurred on sales of auction rate securities.

Auction Rate Securities

During the first quarter of 2008, we invested investment line borrowings (see Note 15) in auction rate securities backed by student loans originated under the U. S. Department of Education's Federal Family Education Loan Program (FFELP). Auction rate securities are long-term variable rate bonds tied to short-term interest rates that reset through an auction process that historically occurred every 7 to 35 days. The student loans underlying the auction rate securities carry a U.S Government guarantee of at least 97% of the unpaid principal balance in the event of default. The auction rate securities that we hold are in the senior-most position and are smaller in amount than the federally guaranteed portion of the underlying loans.

On January 21, 2010 and March 4, 2010, we negotiated settlements of two of our auction rate securities litigation actions. Under the terms of these settlements, the broker/dealers repurchased $103,625 par value of auction rate securities for cash proceeds of $92,745. On February 10, 2010, we sold auction rate securities with a par value of $33,350 for cash proceeds of $29,848.

Under the terms of the liquidity option agreement we entered into in October 2009, we have the right to sell specific securities for cash. We also have the right to repurchase the same following the initial sale at the same price. On February 11, 2010, we exercised a portion of our option to sell auction rate securities with a par value of $88,150 and received proceeds of $74,953. We recognized the sale as a secured borrowing because of our ability to repurchase the same securities until the maturity of the liquidity option in October 2012. On June 24, 2010, we repurchased $46,800 par value of these securities at the initial sale price of $40,504 and sold them for cash proceeds of $44,460. We continue to report on our Consolidated Balance Sheet the remaining $41,350 par value of these auction rate securities, with a fair value of $41,128 as of June 30, 2010. However, these securities are pledged to collateralize a $34,449 borrowing reflecting the proceeds received upon exercise of the option. We no longer receive cash interest income on the pledged securities nor do we pay cash interest on this secured borrowing. The remaining $2,400 par value of auction rate securities are not financed. See Note 14 for additional information on this secured borrowing.

Proceeds from the January 21, 2010 litigation settlement and the February 10, 2010 sale were used to pay down the investment line. On February 17, 2010, we used the proceeds from the February 11, 2010 exercise of the liquidity option and an additional $3,664 cash to repay the remaining balance of the investment line.

In June 2010, we sold auction rate securities with a par value of $35,000 under an agreement to repurchase and received proceeds of $21,704. We report repurchase agreements as collateralized financings and report the obligations to repurchase the assets sold as a liability on our Consolidated Balance Sheet. See Note 14 for additional details regarding the terms of the financing obligation. We report the auction rate securities underlying the repurchase agreement, which had a fair value of $34,635 at June 30, 2010, in our Consolidated Balance Sheet.

During the six months ended June 30, 2010, issuers also redeemed, at par, auction rate securities that we held that had a face value of $1,400.

Subordinates and Residuals

Through our investment in subordinate and residual securities, we support senior classes of securities. Principal from the underlying mortgage loans generally is allocated first to the senior classes with the most senior class having a priority right to the cash flow from the mortgage loans until its payment requirements are satisfied. To the extent that there are defaults and unrecoverable losses on the underlying mortgage loans, resulting in reduced cash flows, the most subordinate security will be the first to bear this loss.

NOTE 6 ADVANCES

Advances consisted of the following at the dates indicated:

		June 30, 2010		December 31, 2009
Servicing:				
Principal and interest	$	62,184	$	51,598
Taxes and insurance		46,191		52,813
Foreclosure and bankruptcy costs		24,260		28,021
Other		14,009		8,998
		146,644		141,430
Loans and Residuals		4,088		4,321
Corporate Items and Other		138		163
	$	150,870	$	145,914

During any period in which the borrower does not make payments, most of our servicing agreements require that we advance our own funds to meet contractual principal and interest remittance requirements for the investors, pay property taxes and insurance premiums and process foreclosures. We also advance funds to maintain, repair and market foreclosed real estate properties on behalf of investors.

Servicing advances of $64,466 and $72,670 were pledged as collateral under the terms of the term reimbursement advance borrowing as of June 30, 2010 and December 31, 2009, respectively.

NOTE 7 MATCH FUNDED ADVANCES

Match funded advances on residential loans we service for others, as more fully described in Note 1—Principles of Consolidation-Match Funded Advances on Loans Serviced for Others, are comprised of the following at the dates indicated:

		June 30, 2010		December 31, 2009
Principal and interest	$	562,895	$	345,924
Taxes and insurance		441,570		332,326

Foreclosure and bankruptcy costs		81,529		72,385
Real estate servicing costs		64,225		49,446
Other		34,632		22,534
	$	1,184,851	$	822,615

NOTE 8 LOANS – RESTRICTED FOR SECURITIZATION INVESTORS

Loans – restricted for securitization investors are held by four securitization trusts that we include in our consolidated financial statements under the provisions of ASC 810, Consolidation, as more fully described in Note 1—Securitizations of Residential Mortgage Loans. Loans – restricted for securitization investors consisted of the following at June 30, 2010:

Single family residential loans (1)	$74,245
Allowance for loans losses	(3,385)
	$70,860

(1) Includes nonperforming loans of $14,108.

We report loans held by the consolidated securitization trusts at cost, less an allowance for loan losses. We consider loans held by the trusts to be nonperforming if they are delinquent greater than 89 days or if the loan is in foreclosure or in bankruptcy. We do not accrue for interest on nonperforming loans. In situations where the trusts foreclose upon the collateral, we classify the loans as real estate, a component of Other assets. We report as Other, net the losses that are realized by the trusts on loans or real estate resolved through repayment of less than the unpaid principal balance of the loan in full plus any costs incurred by the servicer to resolve the loan or real estate.

We maintain an allowance for loan losses for loans and real estate held by the trusts at a level that, based upon our evaluation of known and inherent risks in the collateral of the trusts, we consider to be adequate to provide for probable losses. We base our ongoing evaluation of the allowance for loan losses upon an analysis of the collateral of the trusts, historical loss experience, economic conditions and trends, collateral values and other relevant factors.

At June 30, 2010, the trusts held 1,670 loans that are secured by first or second liens on one- to four-family residential properties. These loans have a weighted average coupon rate of 9.56% and a weighted average remaining life of 140 months.

NOTE 9 MORTGAGE SERVICING RIGHTS

Servicing Assets. The following table summarizes the activity in the carrying value of residential servicing assets for the six months ended June 30, 2010:

Carrying value at December 31, 2009	$117,802
Purchases	23,425
Servicing transfers and adjustments	(29)
Decrease in impairment valuation allowance	101
Amortization	(14,631)
Carrying value at June 30, 2010	$126,668

The following table presents the composition of our servicing and subservicing portfolios by type of property serviced as measured by UPB. The servicing portfolio represents purchased mortgage servicing rights while subservicing generally represents all other mortgage servicing rights.

	Residential	Commercial	Total
UPB of Assets Serviced:			
June 30, 2010:			
Servicing	$32,121,983	$—	$32,121,983

Subservicing (1)	23,122,593	315,661	23,438,254
	$55,244,576	$315,661	$55,560,237
December 31, 2009:			
Servicing	$27,408,436	$—	$27,408,436
Subservicing (1)	22,571,641	211,603	22,783,244
	$49,980,077	$211,603	$50,191,680

(1) Includes non-performing loans serviced for Freddie Mac.

MSRs are an intangible asset representing the right to service a portfolio of mortgage loans. We generally obtain MSRs by purchasing them from the owners of the mortgage loans. Residential assets serviced consist principally of mortgage loans, primarily subprime, but also include real estate. Assets serviced for others are not included on our Consolidated Balance Sheet.

Custodial accounts, which hold funds representing collections of principal and interest we receive from borrowers, are escrowed with an unaffiliated bank and excluded from our Consolidated Balance Sheet. Custodial accounts amounted to approximately $322,895 and $234,100 at June 30, 2010 and December 31, 2009, respectively.

Valuation Allowance for Impairment. During 2008, we established a valuation allowance for impairment of $3,624 on the high-loan-to-value stratum of our mortgage servicing rights as the estimated fair value was less than the carrying value. Changes in the valuation allowance for impairment are reflected in Servicing and origination expenses in our Consolidated Statement of Operations. Net of the valuation allowance of $2,853, the carrying value of this stratum was $348 at June 30, 2010. For all other strata, the fair value was above the carrying value at June 30, 2010.

Estimated fair value of MSRs:	
June 30, 2010	$153,641
December 31, 2009	$127,268

Servicing Liabilities. We recognize a servicing liability for those agreements that we do not expect to compensate us adequately for performing the servicing. Servicing liabilities were $2,477 and $2,878 at June 30, 2010 and December 31, 2009, respectively, and are included in Other liabilities. During the first six months of 2010, amortization of servicing liabilities exceeded the amount of charges we recognized to increase servicing liability obligations by $401, and we have reported this net amount as a reduction of Amortization of mortgage servicing rights in our Consolidated Statement of Operations.

NOTE 10 RECEIVABLES

Receivables consisted of the following at the dates indicated:

	June 30, 2010	December 31, 2009
Accounts receivable by segment:		
Servicing (1)	$ 28,764	$ 41,940
Loans and Residuals	844	845
Asset Management Vehicles	106	334
Corporate Items and Other	1,909	1,795
	31,623	44,914
Other receivables:		
Income taxes	19,312	17,865
Receivable from Altisource	3,790	3,310
Other	2,214	1,006
	$ 56,939	$ 67,095

(1) The balances at June 30, 2010 and December 31, 2009 primarily include reimbursable expenditures due from investors. The total balance of receivables for this segment is net of reserves of $579 and $547 at June 30, 2010 and December 31, 2009, respectively. The balances at June 30, 2010 and December 31, 2009 include $16,958 and $37,226, respectively, due from Freddie Mac in connection with loans we service under a subservicing agreement.

NOTE 11 OTHER ASSETS

Other assets consisted of the following at the dates indicated:

	June 30, 2010	December 31, 2009
Debt service accounts (1)	$ 42,445	$ 50,221

Interest earning collateral deposits (2)		23,408		8,671
Debt issuance costs, net (3)		12,079		8,223
Term note (4)		5,600		7,000
Real estate, net		4,566		8,133
Other		11,710		7,388
	$	99,808	$	89,636

(1) Under our four advance funding facilities, we are contractually required to remit collections on pledged advances to the trustee within two days of receipt. The collected funds are not applied to reduce the related match funded debt until the payment dates specified in the indenture. The balance also includes amounts that have been set aside from the proceeds of our four match funded advance facilities to provide for possible shortfalls in the funds available to pay certain expenses and interest. These funds are held in interest earning accounts.

(2) The balance at June 30, 2010 includes $15,732 of cash collateral held by the counterparties to certain of our interest rate swap agreements.

(3) Issuance costs are amortized to the earliest contractual maturity date of the debt.

(4) In March 2009, we issued a note receivable, maturing on April 1, 2014, in connection with advances funded by the Ocwen Servicer Advance Funding, LLC (OSAF) term note pledged as collateral, as described in Note 14. We receive 1-Month LIBOR plus 300 basis points (bps) under the terms of this note receivable. Under the terms of the note, repayments of $1,400 per year are required beginning April 1, 2010. We are obligated to pay 1-Month LIBOR plus 350 bps under the terms of a five-year note payable to the same counterparty. We do not have a contractual right to offset these payments.

NOTE 12 MATCH FUNDED LIABILITIES

Match funded liabilities are comprised of the following at the dates indicated:

Borrowing Type	Interest Rate	Maturity (1)	Amortization Date (1)	Unused Borrowing Capacity (2)	Balance Outstanding June 30, 2010	Balance Outstanding December 31, 2009
Advance Receivable Backed Note Series2009-3 (3)	4.14%	Jul. 2023	Jul. 2012	$ —	$ 210,000	$ 210,000
Variable Funding Note Series 2009-2 (4)	1-Month LIBOR + 350 bps	Nov. 2023	Nov. 2012	—	28,000	—
Variable Funding Note Series 2009-1 (5)	Commercial paper rate + 200 bps	Dec. 2022	Feb. 2011	248,170	51,830	—
Advance Receivable Backed Note Series2010-1 (3)	3.59%	Sep. 2023	Feb. 2011	—	200,000	—
Variable Funding Note (6)	Commercial paper rate + 150 bps	Dec. 2013	Dec. 2010	164,933	85,067	158,412
Advance Receivable Backed Notes	1-Month LIBOR + 400 bps	Mar. 2020	Mar. 2011	89,725	10,275	27,421
Advance Receivable Backed Notes (7)	1-Month LIBOR + 200 bps	May 2012	May 2011	250,000	250,000	69,858
				$ 752,828	$ 835,172	$ 465,691

(1)

The amortization date of our facilities is the date on which the revolving period ends under each advance facility note and repayment of the outstanding balance must begin if the note is not renewed or extended. The maturity date is the date on which all outstanding balances must be repaid. In all but one advance facility, there is a single note outstanding. For each of these facilities, after the amortization date, all collections that represent the repayment of advances pledged to the facility must be applied to reduce the balance of the note outstanding, and any new advances are ineligible to be financed.

(2) Our unused borrowing capacity is available to us provided that we have additional eligible collateral to pledge. Collateral may only be pledged to one facility.

(3) These notes were issued under the Term Asset-Backed Securities Loan Facility (TALF) program administered by the Federal Reserve Bank of New York.

(4) Under the terms of the note purchase agreement, the purchaser had no obligation to fund borrowings under this note until January 2010 at which time the maximum funding obligation was $28,000. The maximum funding obligation increases to $88,000 in November 2010 and to $100,000 in November 2011.

(5) The interest rate for this note is determined using a commercial paper rate that reflects the borrowing costs of the lender plus a margin of 200 bps.

(6) The interest rate for this note is determined using a commercial paper rate that reflects the borrowing costs of the lender plus a margin of 150 bps which has approximated 1-Month LIBOR plus 150 bps over time.

(7) Under the terms of the facility, we pay interest on drawn balances at 1-Month LIBOR plus 200 bps. In addition, we pay, in twelve monthly installments, a facility fee of 1.30% of the maximum borrowing capacity of $500,000.

NOTE 13 SECURED BORROWINGS – OWED TO SECURITIZATION INVESTORS

Secured borrowings – owed to securitization investors of $67,199 at June 30, 2010 consist of certificates that represent beneficial ownership interests in four securitization trusts that we include in our consolidated financial statements under the provisions of ASC 810, Consolidations, as more fully described in Note 1—Securitizations of Residential Mortgage Loans. The holders of these certificates have no recourse against the assets of Ocwen.

As disclosed in Note 8, the trusts consist principally of mortgage loans that are secured by first and second liens on one- to four-family residential properties. Except for the residuals, the certificates generally pay interest based on 1-Month LIBOR plus a margin of from 8 to 250 basis points. Interest rates on the certificates are generally capped at the weighted average of the net mortgage rates of the mortgage loans in the respective loan pools.

NOTE 14 LINES OF CREDIT AND OTHER SECURED BORROWINGS

Secured lines of credit from various unaffiliated financial institutions are as follows:

Borrowings	Collateral	Interest Rate	Maturity	Unused Borrowing Capacity	Balance Outstanding June 30, 2010	Balance Outstanding December 31, 2009
Servicing:						
Fee reimbursement advance	Term note (1)	Zero coupon	March 2014	$ —	$ 48,000	$ 60,000
Term note (2)	Advances	1-Month LIBOR + 350 basis points	March 2014	—	5,600	7,000
				—	53,600	67,000
Corporate Items and Other						
Securities sold with an option to repurchase (3)	Auction rate securities	(3)	October 2012	—	34,449	—
Securities sold under an agreement to repurchase (4)	Auction rate securities	1-Month LIBOR + 135 basis points	(4)	—	21,704	—
				—	56,153	—
					109,753	67,000
Discount (1)				—	(9,086)	(11,190)
				$ —	$ 100,667	$ 55,810

(1) This advance is secured by the pledge to the lender of our interest in a $60,000 term note issued by OSAF on March 31, 2009. The OSAF note, in turn, is secured by advances on loans serviced for others, similar to match funded advances and liabilities. The fee reimbursement advance is payable annually in five installments of $12,000. The advance does not carry a stated rate of interest. However, we are compensating the lender for the advance of funds by forgoing the

receipt of fees due from the lender over the five-year term of the advance. Accordingly, we recorded the advance as a zero-coupon bond issued at an initial implied discount of $14,627. We used an implicit market rate to compute the discount that we are amortizing to interest expense over the five-year term of the advance.

(2) This note was issued by OSAF and is secured by advances on loans serviced for others, similar to match funded advances and liabilities. The lender has pledged its interest in this note to us as collateral against the $7,000 term note receivable. See Note 11 additional information.

(3) In October 2009, we entered into a liquidity option related to $92,850 face amount of auction rate securities. Under the terms of this agreement, we have the right to sell specific securities for cash. We also have the right to repurchase the same following the initial sale at the same price. In February 2010, we exercised a portion of our option to sell auction rate securities with a par value of $88,150 and received proceeds of $74,953. We recognized the sale as a secured borrowing because of our ability to repurchase the same securities until the maturity of the liquidity option. In June 2010, we repurchased $46,800 par value of these securities at the initial sale price of $40,504 and reduced the liability. We no longer receive cash interest income on the pledged securities nor do we pay cash interest on the secured borrowing. We continue to retain a liquidity option in respect of $2,400 par value of auction rate securities.

(4) In June 2010, we obtained financing under a repurchase agreement for auction rate securities with a face value of $35,000. This agreement has no stated credit limit and lending is determined for each transaction based on the acceptability of the securities presented as collateral. Borrowings mature and are renewed monthly.

NOTE 15 INVESTMENT LINE

The investment line term note was secured by our investment in auction rate securities. Under the term note, we received the interest on the auction rate securities while the proceeds from the redemption or sale of auction rate securities were applied to the outstanding balance. On April 30, 2009, we negotiated a one-year extension of the term note maturity to June 30, 2010. Proceeds from the settlement of a litigation action related to auction rate securities on January 21, 2010 were used to pay down the investment line. Proceeds from the sale of auction rate securities on February 10, 2010 were also used to pay down the investment line. On February 11, 2010, we exercised a portion of our option to sell auction rate securities with a par value of $88,150 and used the proceeds from this exercise and an additional $3,664 of cash to repay the remaining outstanding balance of the investment line on February 17, 2010. As of December 31, 2009, the outstanding balance of the investment line was $156,968.

NOTE 16 DEBT SECURITIES

Debt securities consisted of the following at the dates indicated:

	June 30, 2010	December 31, 2009
3.25% Contingent Convertible Unsecured Senior Notes due August 1, 2024	$ 56,435	$ 56,435
10.875% Capital Trust Securities due August 1, 2027	26,119	39,129
	$ 82,554	$ 95,564

Convertible Notes. In July 2004, Ocwen issued $175,000 aggregate principal amount of 3.25% Convertible Notes due 2024. The Convertible Notes are senior general unsecured obligations not guaranteed by any of our subsidiaries and bear interest at the rate of 3.25% per year.

Interest expense on the Convertible Notes for the first six months of 2009 includes amortization of debt discount of $1,471 and cash interest expense of $987 at the contractual rate. We amortized the debt discount over the period from the date of issuance to August 1, 2009, the first date at which holders could require us to repurchase their notes. We recognized interest on the debt at an effective annual rate of 8.25% from the date of issuance to August 1, 2009. Since August 1, 2009, the effective interest rate on the debt is the coupon rate of 3.25%.

In February 2009, we repurchased $25,910 of our Convertible Notes in the open market at a price equal to 95% of the principal amount and recognized total gains of $534, net of the write-off of unamortized issuance costs and debt discount. We did not repurchase any of our Convertible Notes during the first six months of 2010.

Holders may convert all or a portion of their notes into shares of our common stock under the following circumstances: (1) at any time during any calendar quarter (and only during such calendar quarter) commencing after December 31, 2004, if the closing sale price of our common stock for at least 20 consecutive trading days in a period of 30 consecutive trading days ending on the last trading day of the preceding calendar quarter is greater than 125% of the conversion price per share of common stock on such last day; (2) subject to certain exceptions, during the five business day period after any five-consecutive-trading-day period in which the trading price per $1 principal amount of the notes for each day of the five-consecutive-trading-day period was less than 98% of the product of the closing sale price of our common stock and the number of shares issuable upon conversion of $1,000 (actual dollars) principal amount of the notes; (3) if the notes have been called for redemption; or (4) upon the occurrence of specified corporate transactions.

The conversion rate is 82.1693 shares of our common stock per $1,000 (actual dollars) principal amount of the notes, subject to adjustment. Events that may cause the conversion rate to be adjusted primarily relate to cash dividends or other distributions to holders of our common stock. Upon conversion, we may, at our option, choose to deliver, in lieu of our common stock, cash or a combination of cash and common stock. At June 30, 2010 and December 31, 2009, the if-converted value of the Convertible Notes was $47,253 and $44,378, respectively.

Beginning August 1, 2009, we may redeem all or a portion of the notes for cash for a price equal to 100% of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any.

Capital Trust Securities. In August 1997, Ocwen Capital Trust (OCT) issued $125,000 of 10.875% Capital Securities (the Capital Trust Securities). OCT invested the proceeds from issuance of the Capital Trust Securities in 10.875% Junior Subordinated Debentures issued by Ocwen. The Junior Subordinated Debentures, which represent the sole assets of OCT, will mature on August 1, 2027. For financial reporting purposes, we treat OCT as a subsidiary and, accordingly, the accounts of OCT are included in our consolidated financial statements. We consolidate OCT because we own all of the Common Securities that were issued by OCT and have repurchased 79% of the Capital Trust Securities that were originally issued. We eliminate intercompany balances and transactions with OCT, including the balance of Junior Subordinated Debentures outstanding, in our consolidated financial statements.

In January 2010, we repurchased $12,930 of the Capital Securities and recognized a gain of $717 on these repurchases, net of the write-off of unamortized issuance costs. In June 2010, we repurchased an additional $80 of the Capital Securities and recognized a net gain of $6.

Holders of the Capital Trust Securities are entitled to receive cumulative cash distributions accruing from the date of original issuance and payable semiannually in arrears on February 1 and August 1 of each year at an annual rate of 10.875% of the liquidation amount of $1,000 (actual dollars) per Capital Security. Ocwen guarantees payment of distributions out of monies held by OCT and payments on liquidation of OCT or the redemption of Capital Trust Securities to the extent OCT has funds available. If Ocwen does not make principal or interest payments on the Junior Subordinated Debentures, OCT will not have sufficient funds to make distributions on the Capital Trust Securities in which event the guarantee shall not apply to such distributions until OCT has sufficient funds available.

We have the right to defer payment of interest on the Junior Subordinated Debentures at any time or from time to time for a period not exceeding 10 consecutive semiannual periods (an Extension Period), provided that no Extension Period may extend beyond the stated maturity of the Junior Subordinated Debentures. Upon the termination of any such Extension Period and the payment of all amounts then due on any interest payment date, we may elect to begin a new Extension Period. Accordingly, there could be multiple Extension Periods of varying lengths throughout the term of the Junior Subordinated Debentures. If we defer interest payments on the Junior Subordinated Debentures, distributions on the Capital Trust Securities will also be deferred, and we may not, nor may any of our subsidiaries, (i) declare or pay any dividends or distributions on, or redeem, purchase, acquire, or make a liquidation payment with respect to, their capital stock or (ii) make any payment of principal, interest or premium, if any, on or repay, repurchase or redeem any debt securities that rank pari passu with or junior to the Junior Subordinated Debentures. During an Extension Period, interest on the Junior Subordinated Debentures will continue to accrue at the rate of 10.875% per annum, compounded semiannually.

We may redeem the Junior Subordinated Debentures before maturity at our option subject to the receipt of any necessary prior regulatory approval, in whole or in part at the redemption prices (expressed as a percentage of the principal amount) set forth below, plus accrued interest thereon, if redeemed during the twelve-month period beginning on August 1 of the years indicated below:

	Percentages
2010	103.806 %
2011	103.263
2012	102.719
2013	102.175
2014	101.631
2015	101.088

2016	100.544
2017 to maturity	100.000

We may also redeem the Junior Subordinated Debentures at any time upon the occurrence and continuation of a special event (defined as a tax event, regulatory capital event or an investment company event) at 100%. The Capital Trust Securities are subject to mandatory redemption upon repayment of the Junior Subordinated Debentures in an amount equal to the amount of the related Junior Subordinated Debentures maturing or being redeemed and at a redemption price equal to the redemption price of the Junior Subordinated Debentures, plus accumulated and unpaid distributions thereon to the date of redemption.

NOTE 17 OTHER LIABILITIES

The following table sets forth the components of Other liabilities at the dates indicated:

	June 30, 2010	December 31, 2009
Accrued expenses	$ 23,154	$ 21,381
Checks held for escheat	13,062	12,827
Fair value of derivatives	12,360	—
Deferred income	11,975	13,599
Liability for selected tax items (1)	6,978	15,326
Payable to Altisource	3,563	10,655
Accrued interest payable	3,234	3,588
Servicing liability	2,477	2,878
Other	13,234	10,528
	$ 90,037	$ 90,782

(1) On December 31, 2009, we recorded a reserve against a tax receivable of $8,489 related to the wind-down and liquidation of an advance financing structure. In connection with the process of finalizing this structure, we reversed this reserve during the second quarter of 2010. See Note 21 for additional information on the liability for selected tax items.

NOTE 18 DERIVATIVE FINANCIAL INSTRUMENTS

Because our current derivative agreements are not exchange-traded, we are exposed to credit loss in the event of nonperformance by the counterparty to the agreements. We control this risk through credit monitoring procedures including financial analysis, dollar limits and other monitoring procedures. The notional amount of our contracts does not represent our exposure to credit loss.

In our Servicing segment, we have entered into interest rate caps to hedge our exposure to rising interest rates. In connection with our issuance of a match funded variable funding note in December 2007 with a variable rate of interest and a $250,000 maximum borrowing capacity, we entered into interest rate caps with a notional amount of $250,000. We designated this cap as a cash flow hedge but de-designated it as of March 31, 2008 because of ineffectiveness. In connection with our renewal of a match funded variable funding note in February 2008 that carries a variable interest rate and a maximum borrowing capacity of $100,000, we entered into an interest rate cap with an original notional amount of $200,000. This cap began amortizing at the rate of $8,333 per month in February 2009. The notional balance at June 30, 2010 is $58,333. We did not designate this cap as a hedge. Under the terms of these caps, we receive payments when 1-Month LIBOR exceeds 6.5%. We have not received any payments under the terms of these caps.

In April 2010, we entered into a $250,000 interest rate swap to hedge against the effects of a change in 1-Month LIBOR on borrowing of $250,000 under a $500,000 advance funding facility that carries a variable interest rate. Under the terms of the swap, we pay a fixed rate of 2.059% and receive a variable rate equal to 1-Month LIBOR. Settlements under the terms of this swap commence in July 2010. Projected net settlements for the next twelve months total approximately $3,900 of payments to the counterparty. We designated this swap as a cash flow hedge.

In June 2010, we entered into two interest rate swaps totaling $637,201 to hedge against the effect of changes in interest rates on an $840,000 advance funding facility in connection with the HomEq Servicing acquisition. The terms of the facility are the lender’s commercial paper rate plus 3.5–7.5%. Under the terms of the two swaps, we pay fixed rates of 1.575% and 1.5275%, respectively, and receive a variable rate equal to 1-Month LIBOR. Settlements under the terms of these swaps commence in September 2010. Projected net settlements for the next twelve months total approximately $4,300 of payments to the counterparty. We designated these swaps as cash flow hedges.

In our Loans and Residuals segment, effective January 1, 2010 we include certain securitization trusts under the provisions of ASC 810, Consolidation, as more fully described in Note 1—Securitizations of Residential Mortgage Loans. As a result, we report in our Loans and Residuals segment the fair value of an interest rate swap that is held by one of the securitization trusts. Under the terms of the swap, the trust pays a fixed rate of 4.935% and receives a variable rate equal to 1-Month LIBOR. This swap is not designated as a hedge.

We also entered into foreign exchange forward contracts during the second quarter of 2010 to hedge against the effect of changes in the value of the India Rupee on amounts payable to our subsidiary in India, OFSPL. We did not designate these contracts as hedges.

The following table summarizes the use of derivatives during the six months ended June 30, 2010:

	Foreign Exchange Forwards	Interest Rate Caps	Interest Rate Swaps
Notional balance at December 31, 2009	$ —	$ 358,333	$ —
Opening balance adjustment (1)	—	—	17,800
Additions	19,200	—	887,201
Maturities	(3,200)	(50,000)	(4,300)
Notional balance at June 30, 2010 (1)	$ 16,000	$ 308,333	$ 900,701
Fair value (2):			
June 30, 2010 (1)	$ (5)	$ 82	$ (12,324)
December 31, 2009 (1)	$ —	$ 781	$ —
Maturity	July 2010 to April 2011	January 2011 and December 2013	November 2011 to August 2013

(1) As a result of including four securitization trusts in our consolidated financial statements under the provisions of ASC 810, Consolidations, as more fully described in Note 1—Securitizations of Residential Mortgage Loans, we recognized opening balance adjustments as of January 1, 2010 that included the $(826) fair value of the interest swap held by one of the trusts. This swap, which had a notional amount of $13,500 and a fair value of $(572) at June 30, 2010, was not designated as a hedge.

(2) The fair values of derivatives are reported in Other assets or in Other liabilities.

Net realized and unrealized gains (losses) included in Other income (expense), net related to derivative financial instruments were $(154) and $603 for the second quarter of 2010 and 2009, respectively, including $32 of expense in the second quarter of 2010 arising from ineffectiveness of one of the interest rate swaps that we designated as a cash flow hedge. Year to date, the net realized and unrealized gains were $(588) and $764 for 2010 and 2009, respectively. Included in Other comprehensive loss during the second quarter of 2010 were $11,719 of deferred unrealized losses, before taxes of $4,336, on the swaps that we designated as cash flow hedges. There were no accumulated gains or losses on cash flow hedges included in Accumulated other comprehensive loss at December 31, 2009.

NOTE 19 SERVICING AND SUBSERVICING FEES

The following table presents the components of Servicing and subservicing fees for the periods ended June 30:

	Three months		Six months	
	2010	2009	2010	2009
Loan servicing and subservicing fees	$47,347	$42,515	$93,260	$88,615
Late charges	7,235	5,382	15,415	16,080
Loan collection fees	2,113	1,822	—	3,918
Custodial accounts (float earnings) (1)	960	1,191	1,448	3,041
Receivables management and recovery fees (2)	—	11,899	4,256	24,860
Other	8,281	2,679	18,037	7,784
	$65,936	$65,488	$132,416	$144,298

(1) For the for the three months ended June 30, 2010 and 2009, float earnings included $137 and $1,103, respectively, of interest income from our investment in auction rate securities. For the six-month periods, interest income from auction rate securities included in float earnings was $619 and $2,934 for 2010 and 2009, respectively.

(2) These fees were earned by the Financial Services segment which we distributed as part of the Separation. See Note 23 for additional information regarding this former business segment.

NOTE 20 INTEREST EXPENSE

The following table presents the components of Interest expense for each category of our interest-bearing liabilities for the periods ended June 30:

	Three months		Six months	
	2010	2009	2010	2009
Match funded liabilities	$11,962	$9,881	$22,458	$18,703
Lines of credit and other secured borrowings	81	3,989	108	8,207
Secured borrowings – owed to securitization investors	34	—	224	—
Investment line	—	622	376	1,238
Debt securities:				
Convertible Notes	459	1,237	917	2,662
Capital Trust Securities	712	1,451	1,534	2,902
Other	111	120	213	251
	$13,359	$17,300	$25,830	$33,963

NOTE 21 INCOME TAXES

The components of income tax expense (benefit) were as follows for the periods ended June 30:

	Three months		Six months	
	2010	2009	2010	2009
Current:				
Federal	$(5,272)	$3,685	$(5,605)	$3,864
State	163	201	152	412
Foreign	298	295	480	690
	(4,811)	4,181	(4,973)	4,966
Deferred:				
Federal	1,670	5,275	11,915	12,521
State	(116)	239	481	783
Foreign	480	(223)	374	(761)
	2,034	5,291	12,770	12,543
Total	$(2,777)	$9,472	$7,797	$17,509

Income tax expense (benefit) differs from the amounts computed by applying the U.S. Federal corporate income tax rate of 35% as follows for the periods ended June 30:

	Three months		Six months	
	2010	2009	2010	2009
Expected income tax expense (benefit) at statutory rate	$4,642	$9,221	$15,647	$17,363
Differences between expected and actual income tax expense (benefit):				
Indefinite deferral on earnings of non-U.S. affiliates	(235)	(772)	(1,195)	(1,234)
State tax (after Federal tax benefit)	47	440	642	1,633
Reversal of liability for selected tax items	(8,182)	—	(8,348)	—

Foreign tax	778	72	855	(70)
Other	173	511	196	(183)
Actual income tax expense (benefit)	$(2,777)	$9,472	$7,797	$17,509

Net deferred tax assets were comprised of the following at the dates indicated:

	June 30, 2010	December 31, 2009
Deferred tax assets:		
Tax residuals and deferred income on tax residuals	$ 3,382	$ 3,415
State taxes	2,894	3,311
Accrued incentive compensation	1,996	3,739
Valuation allowance on real estate	2,103	1,712
Bad debt and allowance for loan losses	6,667	7,220
Mortgage servicing rights amortization	44,822	50,065
Net operating loss carryforward	21,093	22,098
Partnership losses	10,660	10,245
Foreign deferred assets	2,838	3,211
Net unrealized gains and losses on securities	9,667	16,742
Deferred income or loss on service advance receivables	2,965	—
Interest rate swaps	4,102	—
Foreign basis differences	—	8,489
Other	4,139	2,511
	117,328	132,758
Deferred tax liabilities:		
Deferred interest income on loans	75	75
Net deferred tax assets	$ 117,253	$ 132,683

We conduct periodic evaluations of positive and negative evidence to determine whether it is more likely than not that the deferred tax asset can be realized in future periods. Among the factors considered in this evaluation are estimates of future taxable income, future reversals of temporary differences, tax character and the impact of tax planning strategies that may be implemented if warranted.

We adopted ASC 740 effective January 1, 2007. We recognized total interest and penalties of $397 through June 30, 2010. We classify interest and penalties as a component of income tax expense. As of June 30, 2010, we had a total liability for selected tax items of approximately $6,978. The total decrease reflected in the year to date amount is predominantly related to the wind down and liquidation of an advance financing structure.

A reconciliation of the beginning and ending amount of the liability for selected tax items is as follows for the six months ended June 30, 2010:

Balance at January 1, 2010	$15,326
Additions for tax positions of prior years	416
Reductions for tax positions of prior years	(8,738)
Other	(26)
Balance at June 30, 2010	$6,978

NOTE 22 BASIC AND DILUTED EARNINGS PER SHARE

Basic EPS excludes common stock equivalents and is calculated by dividing net income (loss) attributable to OCN by the weighted average number of common shares outstanding during the year. We calculate diluted EPS by dividing net income attributable to OCN, as adjusted to add back interest expense net of income tax on the Convertible Notes, by the weighted average number of common shares outstanding including the potential dilutive common shares related to outstanding stock options, restricted stock awards and the Convertible Notes. The following is a reconciliation of the calculation of basic EPS to diluted EPS for the periods indicated:

The following is a reconciliation of the calculation of basic EPS to diluted EPS for the three and six months ended June 30:

	Three months		Six months	
	2010	2009	2010	2009
Basic EPS:				
Net income attributable to OCN	$16,038	$17,830	$36,898	$32,939
Weighted average shares of common stock	100,168,953	67,316,446	100,072,950	65,045,842
Basic EPS	$0.16	$0.26	$0.37	$0.51
Diluted EPS:				
Net income attributable to OCN	$16,038	$17,830	$36,898	$32,939
Interest expense on Convertible Notes, net of income tax (1)	302	773	603	1,664
Adjusted net income attributable to OCN	$16,340	$18,603	$37,501	$34,603
Weighted average shares of common stock	100,168,953	67,316,446	100,072,950	65,045,842
Effect of dilutive elements:				
Convertible Notes (1)	4,637,224	4,638,046	4,637,224	4,638,046
Stock options (2) (3)	2,921,915	887,720	2,813,837	680,292
Common stock awards	—	12,203	2,775	11,375
Dilutive weighted average shares of common stock	107,728,092	72,854,415	107,526,786	70,375,555
Diluted EPS	$0.15	$0.26	$0.35	$0.49
Stock options excluded from the computation of diluted EPS:				
Anti-dilutive (2)	12,391	749,810	12,391	1,106,029
Market-based (3)	1,770,000	5,130,000	1,770,000	5,130,000

(1) The effect of our Convertible Notes on diluted EPS is computed using the if-converted method. Interest expense and related amortization costs applicable to the Convertible Notes, net of income tax, are added back to net income. Conversion of the Convertible Notes into shares of common stock is assumed for purposes of computing diluted EPS unless the effect would be anti-dilutive. The effect is anti-dilutive whenever interest expense on the Convertible Notes, net of income tax, per common share obtainable on conversion exceeds basic EPS.

(2) These stock options were anti-dilutive because their exercise price was greater than the average market price of our stock.

(3) Shares that are issuable upon the achievement of certain performance criteria related to OCN’s stock price and an annualized rate of return to investors. On August 10, 2009, the market performance criterion was met for 3,420,000 of these options.

NOTE 23 BUSINESS SEGMENT REPORTING

Prior to the Separation on August 10, 2009, we managed our business through two distinct lines of business, Ocwen Asset Management and Ocwen Solutions. Ocwen Asset Management includes our core residential servicing business, equity investments in asset management vehicles and our remaining investments in subprime loans and residual securities. Ocwen Solutions, our knowledge-based business process outsourcing (BPO) operation, included our residential fee-based loan processing businesses, all of our technology platforms, our unsecured collections business and our equity interest in BMS Holdings. Due to the Separation, as of August 10, 2009, neither the assets and liabilities, nor the subsequent operations of the Ocwen Solutions line of business comprising the Mortgage Services, Financial Services and Technology Products segments, except for BMS Holdings and GSS, are included in our results.

Our business segments reflect the internal reporting that we have used to evaluate operating performance and to assess the allocation of our resources. Our segments are based upon our organizational structure that focuses primarily on the products and services offered. Segment results for prior periods have been restated to conform to the current segment structure.

A brief description of our current and former business segments is as follows:

Ocwen Asset Management

Servicing. This segment provides loan servicing for a fee, including asset management and resolution services, primarily to owners of subprime residential mortgages. Subprime loans represent residential loans we service that were made to borrowers who generally did not qualify under guidelines of Fannie Mae and Freddie Mac (nonconforming loans). This segment is primarily comprised of our core residential servicing business.

Loans and Residuals. This segment includes our trading and investing activities and our former subprime loan origination operation. Our trading and investing activities include our investments in subprime residual mortgage backed trading securities as well as the results of our whole loan purchase and securitization activities. Effective January 1, 2010, the Loans and Residuals segment includes the four securitization trusts that we include in our consolidated financial statements under the provisions of ASC 810, Consolidation.

Asset Management Vehicles. This segment is comprised of our 25% equity investment in OSI and approximately a 25% equity investment in ONL and affiliates, unconsolidated entities engaged in the management of residential assets.

Ocwen Solutions (distributed as part of the Separation, except for BMS Holdings and GSS)

Mortgage Services. This segment provided due diligence, valuation, real estate sales, default processing services, property inspection and preservation services, homeowner outreach, closing and title services and knowledge process outsourcing services. Services provided spanned the lifecycle of a mortgage loan from origination through the disposition of real estate properties. Prior to August 10, 2009, this segment also includes international servicing for commercial loans which we conducted through GSS.

Financial Services. This segment comprised our asset recovery management and customer relationship management offerings to the financial services, consumer products, telecommunications and utilities industries. The primary sources of revenues for this segment were contingency collections and customer relationship management for credit card issuers and other consumer credit providers. Effective June 6, 2007, this segment included the operations of NCI, a receivables management company specializing in contingency collections and customer relationship management for credit card issuers and other consumer and credit providers.

Technology Products. This segment included revenues from the REAL suite of applications that support our Servicing business as well as the servicing and origination businesses of external customers. These products include REALServicing™, REALResolution™, REALTransSM, REALSynergy™ and

REALRemit™. REALServicing is the core residential loan servicing application used by OCN. This segment also earned fees from providing technology support services to OCN that cover IT enablement, call center services and third-party applications. Prior to August 10, 2009, the results of our 45% equity investment in BMS Holdings, which provides technology-based case management solutions to trustees, law firms and debtor companies that administer cases in the federal bankruptcy system, is also included in this segment.

Corporate Items and Other. We report items of revenue and expense that are not directly related to a business, business activities that are individually insignificant, interest income on short-term investments of cash and the related costs of financing these investments and certain other corporate expenses in Corporate Items and Other. Our Convertible Notes and Capital Trust Securities are also included in Corporate Items and Other. Beginning August 10, 2009, the results of BMS and GSS are also included in Corporate Items and Other.

We allocate interest income and expense to each business segment for funds raised or funding of investments made. We also allocate expenses generated by corporate support services to each business segment.

Financial information for our segments is as follows:

	Ocwen Asset Management			Ocwen Solutions					
	Servicing	Loans and Residuals	Asset Manage–ment Vehicles	Mortgage Services	Financial Services	Technology Products	Corporate Items and Other	Corporate Elimina–tions	Business Segments Consolidated
Results of Operations									
For the three months ended June 30, 2010									
Revenue (1) (2)	$ 75,759	$ —	$ 176	$ —	$ —	$ —	$ 425	$ (407)	$ 75,953
Operating expenses (1) (3)	41,241	1,369	443	—	—	—	1,817	(212)	44,658
Income (loss) from operations	34,518	(1,369)	(267)	—	—	—	(1,392)	(195)	31,295
Other income (expense), net:									
Interest income	48	2,107	—	—	—	—	(255)	—	1,900
Interest expense	(13,017)	(39)	—	—	—	—	(303)	—	(13,359)
Other (1) (2)	(124)	(1,619)	149	—	—	—	(5,175)	195	(6,574)
Other income (expense), net	(13,093)	449	149	—	—	—	(5,733)	195	(18,033)
Income (loss) from continuing operations before income taxes	$ 21,425	$ (920)	$ (118)	$ —	$ —	$ —	$ (7,125)	$ —	$ 13,262
For the three months ended June 30, 2009:									
Revenue (1) (2)	$ 62,726	$ —	$ 460	$ 24,165	$ 16,471	$ 12,108	$ 112	$ (6,863)	$ 109,179
Operating expenses (1)	32,955	747	1,016	16,017	17,557	7,121	3,830	(6,593)	72,650

(3)									
Income (loss) from operations	29,771	(747)	(556)	8,148	(1,086)	4,987	(3,718)	(270)	36,529
Other income (expense), net:									
Interest income	19	1,991	—	1	—	—	243	—	2,254
Interest expense	(15,982)	(519)	—	(11)	(667)	(118)	(3)	—	(17,300)
Other (1) (2)	1,695	(3,568)	(846)	710	20	66	6,515	270	4,862
Other income (expense), net	(14,268)	(2,096)	(846)	700	(647)	(52)	6,755	270	(10,184)
Income (loss) from continuing operations before income taxes	$ 15,503	$ (2,843)	$ (1,402)	$ 8,848	$ (1,733)	$ 4,935	$ 3,037	$ —	$ 26,345

	Ocwen Asset Management			Ocwen Solutions					
	Servicing	Loans and Residuals	Asset Manage-ment Vehicles	Mortgage Services	Financial Services	Technology Products	Corporate Items and Other	Corporate Elimina-tions	Business Segments Consolidated
Results of Operations									
For the six months ended June 30, 2010									
Revenue (1) (2)	$ 151,212	$ —	$ 364	$ —	$ —	$ —	$ 774	$ (811)	$ 151,539
Operating expenses (1) (3)	72,028	2,561	910	—	—	—	4,740	(404)	79,835
Income (loss) from operations	79,184	(2,561)	(546)	—	—	—	(3,966)	(407)	71,704
Other income (expense), net:									
Interest income	110	4,948	—	—	—	—	487	—	5,545
Interest expense	(24,154)	(228)	—	—	—	—	(1,448)	—	(25,830)
Other (1) (2)	(1,209)	(3,206)	671	—	—	—	(3,375)	407	(6,712)
Other income (expense), net	(25,253)	1,514	671	—	—	—	(4,336)	407	(26,997)
Income (loss) from continuing operations before income taxes	$ 53,931	$ (1,047)	$ 125	$ —	$ —	$ —	$ (8,302)	$ —	$ 44,707
For the six months ended June 30, 2009									
Revenue (1) (2)	$ 137,421	$ —	$ 997	$ 42,182	$ 33,787	$ 22,682	$ 365	$ (13,665)	$ 223,769
Operating expenses (1) (3)	67,173	1,309	1,778	28,909	35,706	15,294	7,813	(13,066)	144,916
	70,248	(1,309)	(781)	13,273	(1,919)	7,388	(7,448)	(599)	78,853

Income (loss) from operations									
Other income (expense), net:									
Interest income	78	3,875	—	2	—	—	464	—	4,419
Interest expense	(31,484)	(1,149)	—	(22)	(1,138)	(250)	80	—	(33,963)
Other (1) (2)	1,858	(8,398)	(1,148)	742	23	121	6,503	599	300
Other income (expense), net	(29,548)	(5,672)	(1,148)	722	(1,115)	(129)	7,047	599	(29,244)
Income (loss) from continuing operations before income taxes	$ 40,700	$ (6,981)	$ (1,929)	$ 13,995	$ (3,034)	$ 7,259	$ (401)	$ —	$ 49,609
Total Assets									
June 30, 2010	$ 1,550,231	$ 112,891	$ 13,562	$ —	$ —	$ —	$ 400,845	—	$ 2,077,529
December 31, 2009	$ 1,191,212	$ 48,690	$ 15,271	$ —	$ —	$ —	$ 514,177	$ —	$ 1,769,350
June 30, 2009	$ 1,233,929	$ 54,138	$ 21,653	$ 4,958	$ 61,773	$ 8,660	$ 649,420	$ (246)	$ 2,034,285

(1) Intersegment billings for services rendered to other segments are recorded as revenues, as contra-expense or as other income depending on the type of service that is rendered. Intersegment billings are as follows:

	Servicing	Asset Management Vehicles	Technology Products	Business Segments Consolidated
For the three months ended June 30, 2010	$ 363	$ 44	$ —	$ 407
For the three months ended June 30, 2009	1,982	115	8,160	10,257
For the six months ended June 30, 2010	720	91	—	811
For the six months ended June 30, 2009	4,365	256	16,553	21,174

(2)

Servicing has a contractual right to receive interest income on float balances. However, Corporate controls investment decisions associated with the float balances. Accordingly, Servicing receives revenues generated by those investments that are associated with float balances but are reported in Corporate Items and Other. Gains and losses associated with corporate investment decisions are recognized in Corporate Items and Other.

(3) Depreciation and amortization expense are as follows:

	Servicing	Mortgage Services	Financial Services	Technology Products	Corporate Items and Other	Business Segments Consolidated
For the three months ended June 30, 2010:						
Depreciation expense	$ 16	$ —	$ —	$ —	$ 331	$ 347
Amortization of MSRs	7,854	—	—	—	—	7,854
For the three months ended June 30, 2009:						
Depreciation expense	$ 14	$ 7	$ 117	$ 1,245	$ 336	$ 1,719
Amortization of MSRs	8,543	—	—	—	—	8,543
Amortization of intangibles	—	—	669	—	—	669
For the six months ended June 30, 2010:						
Depreciation expense	$ 29	$ —	$ —	$ —	$ 712	$ 741
Amortization of MSRs	14,229	—	—	—	—	14,229
For the six months ended June 30, 2009:						
Depreciation expense	$ 29	$ 15	$ 234	$ 2,576	$ 672	$ 3,526
Amortization of MSRs	18,584	—	—	—	—	18,584
Amortization of intangibles	—	—	1,336	—	—	1,336

NOTE 24 RELATED PARTY TRANSACTIONS

For purposes of governing certain of the ongoing relationships between Ocwen and Altisource after the Separation, and to provide for an orderly transition to the status of two independent companies, we entered into certain agreements with Altisource. A brief description of these agreements follows.

Separation Agreement. This agreement provides for, among other things, the principal corporate transactions required to effect the Separation and certain other agreements relating to the continuing relationship between Altisource and Ocwen after the Separation.

Transition Services Agreement. Under this agreement, Altisource and Ocwen provide to each other services in such areas as human resources, vendor management, corporate services, six sigma, quality assurance, quantitative analytics, treasury, accounting, risk management, legal, strategic planning, compliance and other areas where we, and Altisource, may need transition assistance and support following the Separation.

Tax Matters Agreement. This agreement sets out each party’s rights and obligations with respect to deficiencies and refunds, if any, of federal, state, local or foreign taxes for periods before and after the Separation and related matters such as the filing of tax returns and the conduct of Internal Revenue Service and other audits.

Employee Matters Agreement. This agreement provides for the transition of employee benefit plans and programs sponsored by us for employees of Altisource.

Services Agreement. This agreement provides for Altisource's offering of certain services to us in connection with our business following the Separation for an initial term of eight years, subject to renewal, with pricing terms intended to reflect market rates. Services provided to us under this agreement include residential property valuation, residential property preservation and inspection services, title services and real estate sales.

Technology Products Services Agreement. This agreement provides for Altisource's offering of certain technology products and support services to us in connection with our business, also for an initial term of eight years, subject to renewal, with pricing terms intended to reflect market rates. Technology products provided to us under this agreement include the REAL suite of applications that support our Servicing business.

Intellectual Property Agreement. This agreement provides for the transfer of intellectual property assets to Altisource.

Data Center and Disaster Recovery Services Agreement. This agreement provides for Altisource's offering of certain data center and disaster recovery services in connection with our business.

Our business is currently dependent on many of the services and products provided under these long-term contracts which are effective for up to eight years with renewal rights. Certain services provided by Altisource under these contracts are charged to the borrower and/or loan investor. Accordingly, such services, while derived from our loan servicing portfolio, are not presented as expenses to Ocwen. We believe the rates charged under these agreements are market rates as they are materially consistent with one or more of the following: the fees charged by Altisource to other customers for comparable services and the rates Ocwen pays to or observes from other service providers.

For the three and six months ended June 30, 2010, we generated revenues of $3,843 and $7,034, respectively, under our agreements with Altisource, principally from fees for providing referral services to Altisource. We also incurred expenses of $4,899 and $9,581 for the three and six months ended June 30, 2010, respectively, principally for technology products and support services including the REAL suite of products that support our Servicing business. At June 30, 2010, the net receivable from Altisource was $227.

NOTE 25 COMMITMENTS AND CONTINGENCIES

Litigation

The liability, if any, for the claims noted below against Ocwen Federal Bank FSB (the Bank) has been assumed by OLS as successor in interest under an Assignment and Assumption Agreement, dated June 28, 2005, whereby OLS assumed all of the Bank's remaining assets and liabilities, including contingent liabilities, in connection with its voluntary termination of its status as a federal savings bank.

We have been included as a defendant in multiparty lawsuits brought by borrowers in various federal and state courts challenging the defendants' mortgage servicing practices, including charging improper or unnecessary fees, misapplying borrower payments, and similar allegations. In April 2004, defendants' petition was granted to transfer and consolidate a number of such lawsuits into a single proceeding pending in the United States District Court for the Northern District of Illinois (the MDL Proceeding). Additional lawsuits similar to the MDL Proceeding have subsequently been brought in other courts, some of which have been or may be transferred to and consolidated in the MDL Proceeding. The borrowers in many of these lawsuits seek class action certification. Others have brought individual actions. No class has been certified in the MDL Proceeding or any related lawsuits. In April 2005, the trial court in the MDL Proceeding entered a partial summary judgment in favor of defendants holding that plaintiffs' signed loan contracts authorized the collection of certain fees by Ocwen as servicer for the related mortgages. In May 2006, plaintiffs filed an amended complaint containing various claims under several federal statutes, state deceptive trade practices statutes and common law. No specific amounts of damages are asserted, however, plaintiffs may amend the complaint to seek damages should the matter proceed to trial. In June 2007, the United States Court of Appeals for the Seventh Circuit issued an opinion holding that many of the claims were preempted or failed to satisfy the pleading requirements of the applicable rules of procedure and directing the trial judge to seek clarification from the plaintiffs so as to properly determine which particular claims must be dismissed. In March 2009, the trial court struck the amended complaint in its entirety on the grounds of vagueness. In April 2009, plaintiffs filed a third amended complaint which defendants moved to dismiss. The motion is fully briefed and pending decision by the trial court. We believe the allegations in the MDL Proceeding are without merit. However, in the interests of obtaining finality and cost certainty with regard to this complex and protracted litigated matter, in July 2010, defendants, including Ocwen, have reached an agreement in principle with plaintiffs' counsel with respect to a class settlement. Ocwen's portion of the proposed settlement would be $5,163 plus certain other non-cash consideration. Specific terms remain to be negotiated and any final settlement agreement would be subject to definitive written settlement documents and court approval. If a final settlement is not reached and approved by the court, we will continue to vigorously defend the MDL Proceeding.

In November 2004, a final judgment was entered in litigation brought by Cartel Asset Management, Inc. (Cartel) against OCN, the Bank and Ocwen Technology Xchange, Inc. (OTX), a subsidiary that has been dissolved. This matter involved allegations of misappropriation of trade secrets and contract-related claims brought by a former vendor. Initially, a jury verdict awarded damages of $9,320. However, the November 2004 judgment by the trial court awarded $520 against OTX and nominal damages of two dollars against the Bank. Additionally, the Bank was assessed a statutory award to Cartel for attorneys' fees in an additional amount of $170. The Bank and OTX were further assessed costs in the amount of $9. In September 2007, the United States Court of Appeals for the Tenth Circuit upheld the damage award against OTX and remanded the case for a new trial on damages against the Bank. In December 2007, we paid the full amount of the judgment against OTX, including accrued interest. In March 2008, the trial court entered an order joining OLS, as the Bank's successor-in-interest, and OCN, as guarantor of the Bank's obligations, as additional defendants. The trial court has set a date of September 13, 2010 for the new trial against the Bank, OLS and OCN. Cartel seeks approximately $26,000 in compensatory damages plus punitive damages and attorneys' fees. We do not believe that Cartel is entitled to additional damages, if any, in an amount that would be material to our financial condition, results of operations or cash flows. The parties have agreed to participate in a non-binding meditation before a third-party neutral mediator, currently scheduled for August 26, 2010, in an attempt to resolve this matter. If after the mediation no resolution is reached, we intend to continue to vigorously defend against this matter.

In September 2006, the Bankruptcy Trustee in Chapter 7 proceedings involving American Business Financial Services, Inc. (ABFS) brought an action against multiple defendants, including OLS, in Bankruptcy Court. The action arises out of Debtor-in-Possession financing to ABFS by defendant Greenwich Capital Financial Products, Inc. and the subsequent purchases by OLS of MSRs and certain residual interests in mortgage-backed securities previously held by ABFS. OLS brought a separate action against the Trustee seeking damages of approximately $2,500 arising out of the ABFS MSRs purchase transaction. OLS' separate action against the Trustee was dismissed by agreement without prejudice with the right to replead such claims or otherwise file a separate action should the Trustee's action be dismissed. In February 2007, the court granted OLS' motion to dismiss some claims but refused to dismiss others. The Trustee filed an amended complaint in March 2007. This complaint sets forth claims against all of the original defendants. The claims against OLS include turnover, fraudulent transfers, accounting, breach of fiduciary duty, aiding and abetting breach of fiduciary duty, breach of contract, fraud, civil conspiracy and conversion. The Trustee seeks compensatory damages in excess of $100,000 and punitive damages jointly and severally against all defendants. In March 2008, the court denied OLS' motion to dismiss. In April 2008, OLS filed an answer denying all charges and a counterclaim for breach of contract, fraud, negligent misrepresentation and indemnification in connection with the MSR purchase transaction. Fact discovery is complete and both Ocwen and the Trustee have filed motions for partial summary judgment. We believe that the Trustee's allegations against OLS are without merit and intend to continue to vigorously defend against this matter.

OCN commenced separate arbitrations before the Financial Industry Regulatory Authority against certain Broker/Dealers primarily alleging fraud, breach of duty and statutory violations arising out of the sale of AAA-rated student loan auction rate securities (SLARS) backed by the Federal Family Education Loan Program. In the first quarter of 2010, we settled the remaining arbitration proceedings for cash proceeds.

OCN is subject to various other pending legal proceedings. In our opinion, the resolution of those proceedings will not have a material effect on our financial condition, results of operations or cash flows.

Tax matters

On December 28, 2006, the India tax authorities issued an income tax assessment order (the Order) with respect to IT Enabled services performed for OCN by its wholly-owned Indian subsidiary, OFSPL. The Order relates to the assessment year 2004-05 and indicated that the percent mark-up on operating costs with respect to the IT enabled and software development services that OFSPL provided to OCN was insufficient. On December 15, 2008, the India tax authorities issued an additional income tax assessment order (the Second Order) with respect to assessment year 2005-06. The assessment was made on the same grounds of insufficient mark-up on operating costs with respect to services provided by OFSPL to OCN. OCN had petitioned for assistance to be provided by Competent Authority under the Mutual Agreement Procedures pursuant to the U.S./India income tax treaty. In May 2010, this process yielded an agreement in this matter between the governments of India and the U.S. for assessment years 2004-2005 and 2005-2006. The adjustment for assessment year 2004-2005 results in an additional $388 in tax and interest charges beyond our existing accrual and the adjustment for assessment year 2005-2006 results in a reduction in tax and interest charges of $175 as compared to our existing accrual. OFSPL intends to accept the final assessment and expects to receive the final Competent Authority assessment notice during the third quarter. The Mutual Agreement provides for correlative adjustments to U.S. taxes. As such, it is anticipated that OCN will not suffer double taxation for the additional India charges under the settlement.

On December 21, 2009, the India tax authorities issued a draft income tax assessment order (the Third Order) with respect to assessment year 2006-07. The proposed adjustment would impose upon OFSPL additional tax of INR 41,760 ($896) and interest of INR 18,297 ($393) for the Assessment Year 2006-07. In accordance with standard Indian procedures, penalties may also be assessed in the future in connection with the assessment. OCN and OFSPL intend to vigorously contest this Order and any imposition of tax and interest and do not believe they have violated any statutory provision or rule. OFSPL has filed an application with the Dispute Resolution Panel for the Third Order. Due to the uncertainties inherent in the Appeals and Competent Authority processes, OCN and OFSPL cannot currently estimate any additional exposure beyond the amount detailed in the Orders. We also cannot predict when these tax matters will be resolved. If our application with the Dispute Resolution Panel is denied, we would consider pursuing all other options including, but not limited to, Competent Authority to contest any additional tax assessed. Such Competent Authority assistance requests under the Mutual Agreement Procedures should preserve OCN's right to credit any potential India taxes against OCN's U.S. taxes.

Other Information

In July 2010, OLS received a subpoena from the Federal Housing Finance Agency (FHFA) as conservator for Freddie Mac in connection with ten private label mortgage securitization transactions where Freddie Mac has invested. The transactions include mortgage loans serviced but not originated by OLS or its affiliates. Ocwen Loan Servicing is cooperating with the FHFA's request.

NOTE 26 SUBSEQUENT EVENTS

OLS obtained a syndicated $350,000 five year senior secured term loan facility on July 29, 2010 that will be used in part to fund the HomEq Servicing acquisition. Borrowings under the facility will bear interest, at the election of Ocwen, at a rate per annum equal to either (a) the greatest of (i) the prime rate of Barclays Bank PLC in effect on such day, (ii) the federal funds effective rate in effect on such day plus 0.50% and (iii) the one-month Eurodollar rate (1-Month LIBOR), in each case plus the applicable margin of 6.00% and a floor of 3.00% or (b) 1-Month LIBOR, plus the applicable margin of 7.00% with a 1-Month LIBOR floor of 2.00%.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (Dollars in Thousands, Except Share Data and Unless Otherwise Indicated)

INTRODUCTION

Unless specifically stated otherwise, all references to June 2010 and June 2009 refer to the three and six-month periods ended, or to the dates, as the context requires, June 30, 2010 and June 30, 2009, respectively.

The following discussion of our results of operations, change in financial condition and liquidity should be read in conjunction with our Interim Consolidated Financial Statements and the related notes, all included elsewhere in this report on Form 10-Q, and with our Annual Report on Form 10-K for the year ended December 31, 2009.

OVERVIEW

Strategic Priorities

During 2009, we focused on three key initiatives to reinforce our competitive strengths: liquidity and balance sheet strength; revenue opportunities; and quality and cost structure leadership. Our success in addressing these three initiatives led to our strategic priorities for 2010 and beyond which are to:

1. Establish predictable and sustainable revenue growth in our servicing operations
2. Improve process efficiencies to continuously reduce cost
3. Improve quality
4. Reduce asset intensity

These priorities support our long-term goals for return on equity and earnings per share growth.

For sustainable revenue growth, we have a three-pronged approach:

1. Acquisition of Existing Servicing Platforms. On March 29, 2010, we entered into a Servicing Rights Purchase and Sale Agreement under which we agreed to purchase the rights to service approximately 38,000 mortgage loans with an aggregate unpaid principal balance (UPB) of approximately $6.9 billion. This acquisition was completed on May 3, 2010. On May 28, 2010, we entered into an Asset Purchase Agreement pursuant to which OLS has agreed to acquire the U.S. non-prime mortgage servicing business known as "HomEq Servicing" from Barclays Bank PLC and Barclays Capital Real Estate Inc. The aggregate purchase price is approximately $1.3 billion, payable in cash upon the consummation of the transaction, and the acquisition is expected to result in a combined Servicing portfolio of more than $80 billion in UPB. See Note 3 for additional details regarding the HomEq Servicing acquisition. This transaction is expected to close on September 1, 2010.
2. Special Servicing Opportunities. We continue to pursue opportunities with government-sponsored entities to grow our special servicing portfolio. In February 2009, we were selected as a special servicer on non-performing loans for Freddie Mac under a high-risk-loan pilot program.
3. Flow Servicing. Our goal is to develop flow Federal Housing Administration (FHA) servicing.

The latter three 2010 strategic priorities:

- improve process efficiencies to reduce cost;

- improve quality; and

- reduce asset intensity;

are interrelated, reflecting our belief that continual process improvement leads to higher quality, lower cost (both operational and financial) and higher revenue per dollar of UPB.

The key operating metric to accomplish these priorities is the reduction in non-performing loans which:

- When a delinquent loan becomes current, this prompts (i) the recovery and recognition of deferred servicing fees, (ii) HAMP fees in the case of a HAMP modification and (iii) late fees in the case of a non-HAMP modification.
- Reduces Advances and, hence, asset intensity and interest expense freeing up equity for additional acquisitions.
- Reduces operating expenses since non-performing loans are more costly to service.

Therefore, the key driver of our profitability is our ability to reduce non-performing loans.

Operating Segments

Our current business segments are:

- Servicing
- Loans and Residuals
- Asset Management Vehicles (AMV)

In addition to our core residential servicing business, Ocwen Asset Management (OAM) includes our equity investments in asset management vehicles and our remaining investments in subprime loans and residual securities.

Prior to August 10, 2009, Ocwen Solutions (OS) included our former unsecured collections business, our former residential fee-based loan processing businesses, our former technology platforms, our equity investment in BMS Holdings and the results of our international commercial loan servicing business conducted through GSS. With the exception of our interests in BMS Holdings and GSS, we distributed the assets, liabilities and operations of the OS line of business in the Separation.

See Management's Discussion and Analysis of Financial Condition and Results of Operations—Segment Results and Financial Condition and Note 21 to the Interim Consolidated Financial Statements for additional financial information regarding each of our segments.

Operations Summary

Our consolidated operating results in the three and six months ended June 30, 2009 as compared to the same periods of 2010 were significantly impacted by the Separation of Altisource from Ocwen on August 10, 2009. Ocwen ceased, beginning on August 10, 2009, to record operating results from Mortgage Services, Financial Services and Technology Products segments.

Three Months Ended June 2010 versus June 2009. We generated net income attributable to OCN of $16,038, or $0.15 diluted earnings per share, in the second quarter of 2010 as compared to $17,830 or $0.26 diluted earnings per share for the second quarter of 2009. Income from continuing operations before income taxes was $13,262 for the second quarter of 2010 as compared to $26,345 for 2009.

Significant items affecting Income from continuing operations before income taxes between the quarters include:

- The $11,830 contribution from the former OS segments during the second quarter of 2009;

- A litigation accrual of $5,163 established in the second quarter of 2010 in connection with the proposed settlement of the MDL Proceeding;

- The write-off in the second quarter of 2010 of our $3,000 investment in a real estate partnership that we had determined would not be realizable;

- The realized loss of $1,675 from the sale of $46,800 par value of auction rate securities (compared to $6,024 of unrealized gains in the second quarter of 2009); and

- Professional services of $1,250 incurred through June 30, 2010 for the acquisition of HomEq Servicing. We have also incurred approximately $1,500 of expenses for new facilities and additional telecommunications and compensation costs related to the acquisition.

Income taxes for the second quarter of 2010 were a net benefit of $2,777 as compared to expense of $9,472 for the second quarter of 2009. The 2010 benefit resulted principally from our reversal of a reserve of $8,182 that related principally to an income tax receivable that arose from the wind-down and liquidation of one of our advance funding structures.

Servicing segment revenues grew by $13,033, or 21%, due principally to an increase in UPB resulting from additions of $7,466,279 during the second quarter of 2010, and an increase in modifications (see Segments—Servicing for additional details of this impact). Servicing results were also affected by the $5,163 litigation accrual and the expenses incurred in connection with the HomeEq acquisition.

Loans and Residuals benefited from a decrease in unrealized losses due to slower declines in the estimated fair value of loans and real estate and a portfolio, excluding the securitization trusts that we first consolidated in 2010, that was 30% smaller than the portfolio during the second quarter of 2009. The Asset Management Vehicles segment improved principally because of declines in operating expenses and positive earnings on our investments in asset management vehicles.

Six Months Ended June 2010 versus June 2009. We generated net income attributable to OCN of $36,898, or $0.35 diluted earnings per share, for the six months ended June 2010 compared to $32,939, or $0.49 diluted earnings per share for the six months ended June 2009. Income from continuing operations before income taxes was $44,707 as compared to $49,609 for the six months ended June 2010 and 2009, respectively. The provision for income taxes was reduced by the affect of the reversal of $8,348 of reserves related to income tax receivables.

Our operating results for the six months ended June 2010 benefited from higher fees from modifications and the effects of $8,839,012 of UPB additions to the Servicing portfolio in the first six months of 2010, most of which were acquired during the second quarter. These benefits were offset by the spinoff of the former OS segments to Altisource, which generated Income from continuing operations before income taxes of $18,279 in the six months ended June 30, 2009, the $5,163 MDL litigation accrual, the $3,000 write-off of a commercial real estate investment and $1,250 of professional services fees and approximately $1,500 of occupancy, telecommunications and compensation expenses related to the HomEq Servicing acquisition.

The following table summarizes our consolidated operating results for the periods ended June 30, 2010 and 2009. We have provided a more complete discussion of operating results by line of business in the Segment Results and Financial Condition section.

	Three months			Six months		
	2010	2009	% Change	2010	2009	% Change
Consolidated:						
Revenue	$ 75,953	$ 109,179	(30)%	$ 151,539	$ 223,769	(32)%
Operating expenses	44,658	72,650	(39)	79,835	144,916	(45)
Income from operations	31,295	36,529	(14)	71,704	78,853	(9)
Other expense, net	(18,033)	(10,184)	77	(26,997)	(29,244)	(8)
Income from continuing operations before taxes	13,262	26,345	(50)	44,707	49,609	(10)
Income tax expense (benefit)	(2,777)	9,472	(129)	7,797	17,509	(55)
Income from continuing operations	16,039	16,873	(5)	36,910	32,100	15
Income from discontinued operations, net of taxes	—	1,052	(100)	—	864	(100)
Net income	16,039	17,925	(11)	36,910	32,964	12
Net income (loss) attributable to non-controlling interest in subsidiaries	(1)	(95)	(99)	(12)	(25)	(52)
Net income attributable to Ocwen	$ 16,038	$ 17,830	(10)	$ 36,898	$ 32,939	12
Segment income (loss) from continuing operations before taxes:						
Servicing	$ 21,425	$ 15,503	38 %	$ 53,931	$ 40,700	33 %
Loans and Residuals	(920)	(2,843)	(68)	(1,047)	(6,981)	(85)
Asset Management Vehicles	(118)	(1,402)	(92)	125	(1,929)	(106)
Mortgage Services	—	8,848	(100)	—	13,995	(100)
Financial Services	—	(1,733)	(100)	—	(3,034)	(100)
Technology Products	—	4,935	(100)	—	7,259	(100)
Corporate items and other	(7,125)	3,037	(335)	(8,302)	(401)	1,970
	$ 13,262	$ 26,345	(50)	$ 44,707	$ 49,609	(10)

(1) Excluding revenues earned by GSS and intersegment revenues eliminated in consolidation, OS revenues were $46,135 for the second quarter of 2009.

(2) Excluding expenses incurred by GSS and intersegment expenses eliminated in consolidation, OS operating expenses were $37,296 for the second quarter of 2009.

Change in Financial Condition Summary

The overall increase in our assets of $308,179, or 17%, during the six months ended June 30, 2010 was principally the result of the following changes:

Cash increased by $52,467.

Auction rate securities declined by $169,391 due to sales, the settlement of two litigation actions and redemptions.

Total advances increased by $367,192 primarily because of the $6.9 billion of servicing UPB we acquired in the second quarter.

Loans – restricted for securitization investors of $70,860 represent loans held by four securitization trusts that, effective January 1, 2010, we began to include in our consolidated financial statements under the provisions of ASC 810, Consolidation. See Note 8 to our Interim Consolidated Financial Statements for additional information.

MSRs increased by $8,866 primarily due to purchases in the second quarter of $23,425 offset by amortization expense of $14,631.

Receivables, net, decreased by $10,156 largely due to collections on subservicing and special servicing agreements.

Deferred tax assets, net, declined by $15,430. Income tax expense for the first six months includes $12,770 of deferred expense. In addition, a non-cash tax asset of $8,489 arising from the expected deductibility of losses in a finance vehicle was reclassified from deferred tax assets to current income taxes during the first quarter. The reserve on this asset was reversed in the second quarter. Partially offsetting these declines, we recognized a tax benefit of $4,336 on unrealized losses on cash flow hedges in Accumulated other comprehensive loss.

Liabilities increased by $274,112, or 30%, during the six months ended June 30, 2010 primarily because of the following items:

Match funded liabilities increased by $369,481 reflecting the issuance of $200,000 of notes under the TALF program and an increase in advances.

Secured borrowings – owed to securitization investors of $67,199 consist of certificates issued by the four securitization trusts that we began to include in our consolidated financial statements effective January 1, 2010. See Note 13 to our Interim Consolidated Financial Statements for additional information.

Lines of credit and other secured borrowings increased $44,857 due to secured borrowings of $56,153 in connection with our investment in auction rate securities. These borrowings were partly offset by the first annual $12,000 repayment on our $60,000 fee reimbursement advance in March.

We fully repaid the investment line term note which had an outstanding balance of $156,968 at December 31, 2009.

Servicer liabilities declined by $36,702 largely because of a decrease in partial borrower payments and other unapplied balances.

Debt securities declined $13,010 as a result of repurchases. In January 2010, we repurchased $12,930 par value of our 10.875% Capital Trust Securities at a discount to par value in the open market.

Liquidity Summary

We define liquidity as unencumbered cash balances plus unused, collateralized advance financing capacity. Our liquidity as of June 30, 2010, as measured by cash and available credit, was $229,874, a decrease of $62,241, or 21%, from December 31, 2009 to June 30, 2010. At June 30, 2010, our cash position was $143,386 compared to $90,919 at

December 31, 2009. Our available credit on collateralized but unused advance financing capacity was $86,488 at June 30, 2010 compared to $201,200 at December 31, 2009.

Our investment policies emphasize principal preservation by limiting investments to include:

- Securities issued by the U.S. government, a U.S. agency or a U.S. government-sponsored enterprise
- Money market mutual funds
- Money market demand deposits

Currently, we are primarily invested in money market demand deposits. Furthermore, our investment policies are intended to minimize credit and counterparty risk by establishing risk limits based on each counterparty's equity size and long-term credit ratings. We regularly monitor and project cash flow timing in connection with our efforts to optimize the risk-adjusted yield of our portfolio of investments.

In assessing our liquidity outlook, our primary focus is on maintaining cash and unused borrowing capacity that is sufficient to meet the needs of the business. While we expect to renew or replace advance facility notes as they mature as needed to maintain excess borrowing capacity, it is noteworthy that the cash projected to be generated over the next several years from reducing advance balances approximately offsets the projected reduction in borrowing as our advance facility notes mature, even if these notes are not renewed or replaced.

At June 30, 2010, $752,828 of our total maximum borrowing capacity remained unused. The unused borrowing capacity in the Servicing business may be utilized in the future by pledging additional qualifying collateral to our facilities.

We maintain unused borrowing capacity for three reasons:

- As a protection should Advances increase due to increased delinquencies,
- In the event term financing is unavailable resulting in liabilities maturing faster than assets, as a protection should we be unable to either renew existing facilities or obtain new facilities and
- To provide capacity for the acquisition of additional servicing.

Interest Rate Risk Summary

Interest rate risk is a function of (i) the timing and (ii) the dollar amount of assets and liabilities that re-price at each point in time. We are exposed to interest rate risk to the extent that our interest-bearing liabilities mature or re-price at different speeds, or different bases, than interest-earning assets.

We have executed a hedging strategy aimed to largely neutralize the impact of changes in interest rates. As of June 30, 2010, the value of our outstanding hedges was similar to the net exposure of projected interest rate sensitive liabilities and interest rate sensitive assets for the next several years.

If interest rates increase by 1% on our variable rate advance financing and interest earning cash and float balances, we estimate a net positive impact of approximately $355 resulting from an increase of $4,663 in annual interest income compared to an increase of $4,308 in annual interest expense. This outcome is due in large part to our hedging activities. See Note 18 to our Interim Consolidated Financial Statements for additional information regarding our use of derivatives.

CRITICAL ACCOUNTING POLICIES

Our ability to measure and report our operating results and financial position is heavily influenced by the need to estimate the impact or outcome of risks in the marketplace or other future events. Our critical accounting policies are those that relate to the estimation and measurement of these risks. Because they inherently involve significant judgments and uncertainties, an understanding of these policies is fundamental to understanding Management’s Discussion and Analysis of Results of Operations and Financial Condition. Our significant accounting policies are discussed in detail on pages 29 through 31 of Management’s Discussion and Analysis of Results of Operations and Financial Condition and in Note 1 to our Consolidated Financial Statements for the year ended December 31, 2009 included in our Annual Report on Form 10-K filed March 8, 2010. Such policies have not changed during 2010.

SEGMENT RESULTS AND FINANCIAL CONDITION

For each of our business segments, the following section provides a discussion of the changes in financial condition during the six months ended June 30, 2010 and a discussion of pre-tax results of operations for the three and six months ended June 30, 2010 and 2009. Due to the Separation, as of August 10, 2009, neither the assets and liabilities, nor the subsequent operations of the Mortgage Services, Financial Services and Technology Products segments, except for BMS and GSS, are included in our results. As a separate, publicly-traded company, Altisource Portfolio Solutions S.A. (NASDAQ:ASPS) is required to file a Form 10-Q with the Securities and Exchange Commission.

Servicing

The following table presents selected results of operations of our Servicing segment for the periods ended June 30:

	Three months		Six months	
	2010	2009	2010	2009
Revenue				
Servicing and subservicing fees	$ 66,297	$ 52,898	$ 133,131	$ 117,877
Process management fees	8,302	9,828	16,205	19,544
Other	1,160	—	1,876	—
Total revenue	75,759	62,726	151,212	137,421
Operating expenses				
Compensation and benefits	7,939	7,733	15,760	16,345
Amortization of servicing rights	7,854	8,543	14,229	18,584
Servicing and origination	2,235	2,149	2,666	4,181
Technology and communications	4,789	3,149	9,220	5,968
Professional services	7,416	2,705	8,358	4,619
Occupancy and equipment	2,810	2,143	6,450	5,005
Other operating expenses	8,198	6,533	15,345	12,471
Total operating expenses	41,241	32,955	72,028	67,173
Income from operations	34,518	29,771	79,184	70,248
Other income (expense)				
Interest income	48	19	110	78
Interest expense	(13,017)	(15,982)	(24,154)	(31,484)
Loss on debt redemption	—	—	(571)	—
Other, net	(124)	1,695	(638)	1,858
Total other expense, net	(13,093)	(14,268)	(25,253)	(29,548)
Income from continuing operations before income taxes	$ 21,425	$ 15,503	$ 53,931	$ 40,700

The following table provides selected operating statistics at or for the three and six months ended June 30:

	Three months			Six months		
	2010	2009	% Change	2010	2009	% Change
Residential Assets Serviced						
Unpaid principal balance:						
Performing loans (1)	$ 39,096,968	$ 27,290,158	43 %	$ 39,096,968	$ 27,290,158	43 %
Non-performing loans	11,935,175	8,606,847	39	11,935,175	8,606,847	39
Non-performing real estate	4,212,433	2,509,002	68	4,212,433	2,509,002	68
Total residential assets serviced (2)	$ 55,244,576	$ 38,406,007	44	$ 55,244,576	$ 38,406,007	44

Average residential assets serviced	$	53,892,135		$	39,588,301		36	%	$	52,235,809	$	39,718,475	32	%
Prepayment speed (average CPR)		13.1	%		21.8	%	(40	)%	12.8	%	21.5	%	(40	)%
Percent of total UPB:														
Servicing portfolio		58.1	%		74.5	%	(22	)%	58.1	%	74.5	%	(22	)%
Subservicing portfolio		41.9			25.5		64		41.9		25.5		64	
Non-performing residential assets serviced, excluding Freddie Mac		26.2	%		27.4	%	(4	)	26.2	%	27.4	%	(4	)

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	Three months			Six months		
	2010	2009	% Change	2010	2009	% Change
Number of:						
Performing loans (1)	290,656	230,334	26 %	290,656	230,334	26 %
Non-performing loans	62,073	44,877	38	62,073	44,877	38
Non-performing real estate	21,222	11,311	88	21,222	11,311	88
Total number of residential assets serviced (2)	373,951	286,522	31	373,951	286,522	31
Average number of residential assets serviced	368,390	295,139	25	360,883	304,118	19
Percent of total number:						
Servicing portfolio	58.4 %	66.0 %	(12)%	58.4 %	66.0 %	(12)%
Subservicing portfolio	41.6	34.0	22	41.6	34.0	22
Non-performing residential assets serviced, excluding Freddie Mac	19.1 %	18.5 %	3	19.1 %	18.5 %	3
Residential Servicing and Subservicing Fees						
Loan servicing and subservicing	$47,223	$42,360	11 %	$93,092	$88,238	6 %
Late charges	7,235	5,381	34	15,411	16,079	(4)
HAMP fees	4,585	—	—	11,038	—	—
Loan collection fees	2,113	1,796	18	4,256	3,861	10
Custodial accounts (float earnings)	960	1,191	(19)	1,448	3,040	(52)
Other	3,423	1,803	90	6,649	5,954	12
	$65,539	$52,531	25	$131,894	$117,172	13
Financing Costs						
Average balance of advances and match funded advances	$1,223,892	$1,001,231	22 %	$1,066,360	$1,062,525	— %
Average borrowings	784,882	826,248	(5)	660,350	865,600	(24)
Interest expense on borrowings	12,043	13,766	(13)	22,942	26,812	(14)
Facility costs included in interest expense	4,598	6,405	(28)	9,810	11,273	(23)
Effective average interest rate	6.14 %	6.66 %	(8)	6.95 %	6.19 %	12
Average 1-month LIBOR	0.31 %	0.37 %	(16)	0.27 %	0.42 %	(36)
Average Employment						
India and other	1,554	1,011	54 %	1,452	1,010	44 %
United States	219	281	(22)	226	301	(25)
Total	1,773	1,292	37	1,678	1,311	28
Collections on loans serviced for others	$1,191,802	$1,787,802	(33)%	$2,353,679	$3,631,001	(35)%

(1) Performing loans include those loans that are current or have been delinquent for less than 90 days in accordance with their original terms and those loans for which borrowers are making scheduled payments under loan modification, forbearance or bankruptcy plans. We consider all other loans to be non-performing.

(2) At June 30, 2010, we serviced 261,518 subprime loans with a UPB of $39,712,429. This compares to 243,593 subprime loans with a UPB of $35,682,666 as December 31, 2009. At June 30, 2009, we serviced 203,603 subprime loans and real estate with a UPB of $29,350,298.

The following table provides information regarding the changes in our portfolio of residential assets serviced:

	Amount of UPB		Count	
	2010	2009	2010	2009
Servicing portfolio at beginning of the year	$ 49,980,077	$ 40,171,532	351,595	322,515
Additions	1,372,733	3,626,000	7,203	11,036
Runoff	(1,674,811)	(3,008,397)	(11,813)	(29,451)
Servicing portfolio at March 31	49,677,999	40,789,135	346,985	304,100
Additions	7,466,279	57,000	40,614	180
Runoff	(1,899,702)	(2,440,128)	(13,648)	(17,758)
Servicing portfolio at June 30	$ 55,244,576	$ 38,406,007	373,951	286,522

Three Months Ended June 30, 2010 versus 2009. Residential servicing and subservicing fees increased due to the increase in the UPB of residential assets serviced and an increase in modifications.

The average UPB of assets serviced was 36% higher in the second quarter of 2010 while residential servicing and subservicing fees increased by 25%. Subservicing and special servicing arrangements represent a larger portion of our portfolio as compared to one year ago. However, lower servicing fees earned under subservicing and special servicing arrangements are more than offset by lower amortization and interest expense on advance financing. The percentage of UPB representing subservicing was 41.9% at June 30, 2010, a 64% increase from June 30, 2009.

As compared to March 31, 2010, the percentage of UPB representing servicing increased by 9% as a result of the $6.9 billion of servicing UPB that we acquired in the second quarter. However, revenues from newly acquired servicing are principally the contractual servicing fee. Ancillary revenues which are driven by the resolution of non-performing loans will not ramp up until a few quarters after the acquisition.

We recognize revenue in the form of deferred servicing fees and ancillary revenues whenever we return a loan to performing status whether it be through a HAMP modification, a non-HAMP modification or otherwise. Loan servicing fees and late charges, excluding HAMP fees, that we recognized as a result of modifications completed during the second quarter of 2010 and 2009 totaled $7,606 and $4,075, respectively. HAMP fees were $4,585 in the second quarter of 2010. We began recognizing HAMP fees in the third quarter of 2009. We completed a total of 14,384 modifications during the second quarter of 2010 as compared to 8,157 during the second quarter of 2009. The implementation of HAMP caused loan modifications that ordinarily would have been completed in the second quarter of 2009 to be delayed. In the second quarter of 2010, 29% of completed modifications were HAMP, and the remainder were non-HAMP. This compares to 19,612 modifications in the first quarter of 2010, of which 32% were HAMP.

As of June 30, 2010, we estimate that the balance of uncollected and unrecognized servicing fees related to delinquent borrower payments was $77,231 compared to $55,612 as of December 31, 2009. The increase in 2010 is primarily due to the $6.9 billion of servicing UPB that we acquired in the second quarter of 2010.

Operating expenses increased by $8,286 primarily due to a reserve of $5,163 that we established in connection with a proposed settlement of the MDL Proceeding and $1,250 of professional fees incurred in connection with the pending acquisition of HomEq Servicing. Operating expenses also include approximately $1,500 in additional compensation, telecommunications and occupancy expenses for the HomEq Servicing acquisition. See Note 25 to our Interim Consolidated Financial Statements for additional information for additional details regarding the MDL Proceeding.

The delinquency rate remained relatively stable in the second quarter of 2010. The increase in total advances is primarily the result of advances acquired as part of the $6.9 billion servicing UPB acquisition that we completed in the second quarter of 2010. We expect delinquency rates to remain flat or decline somewhat during the remainder of 2010; however, advances will increase significantly if our pending acquisition of the HomEq Servicing business is completed as expected.

Prepayment speed was 40% lower in the second quarter of 2010 primarily due to a decline in loan payoffs and real estate sales. Real estate sales and other involuntary liquidations accounted for approximately 76% of prepayments during the second quarter of 2010 as compared to over 84% for the same period in 2009.

Interest expense in the second quarter of 2010 was lower than in the same period of 2009 principally because we continued to follow our strategy of reducing advance financing with the proceeds of our equity offering. As a result, average Servicing borrowings declined by 5% during the second quarter of 2010 as compared to the second quarter of 2009 even as average advances and match funded advances increased by 22% during the same period. In addition, our average effective interest rate for the second quarter of 2010 declined as compared to the second quarter of 2009. This is the result of lower spreads over LIBOR charged on new variable rate match funded facilities.

Six Months Ended June 30, 2010 versus 2009. Residential servicing and subservicing fees for the first six months of 2010 were 13% higher than the same period of 2009 despite a 32% increase in the average UPB of residential assets serviced. This was because of a 64% increase in the size of the subservicing portfolio between years. HAMP fees during the first six months of 2010 were $11,038 but were partly offset by the waiver of late charges on loans with HAMP modifications in the first quarter of 2010. We began to implement HAMP in the second quarter of 2009, and both servicing fees and late fees were down significantly in that quarter because of the forfeiture of fees under HAMP and an overall decline in modifications as we adjusted our procedures to conform to the requirements of the HAMP.

Operating expenses for the first six months of 2010 increased by $4,855 over the same period of 2009 principally because of the $5,163 reserve established in connection with the proposed settlement of the MDL Proceeding, a $3,252 increase in technology and communications expense and $1,250 of professional services fees incurred in connection with the HomEq Servicing acquisition. Operating expenses also include the impact of approximately $1,500 of additional compensation, telecommunications and occupancy expenses for the HomEq Servicing acquisition. These increases were offset in part by a decline of $4,355 in amortization expense. Amortization expense declined in the first six months of 2010 as compared to 2009 as the projected average prepayment speed (CPR) fell and our portfolio composition shifted to a greater concentration of subservicing arrangements, leading to an 11% lower average MSR balance in 2010.

Total interest expense for the first six months of 2010 was 23% lower than the same period in 2009 principally because of a 24% decline in the average balance of borrowings. The effective average interest rate has increased modestly as compared to the first six months of 2009 principally because of higher spreads over LIBOR and higher facility fees charged on new facilities, especially in the first quarter of 2010.

The following table shows selected assets and liabilities of our Servicing segment at:

		June 30, 2010		December 31, 2009
Advances	$	146,644	$	141,429
Match funded advances		1,184,851		822,615
Mortgage servicing rights (Residential)		126,668		117,802
Receivables, net		30,192		43,079
Debt service accounts		42,445		50,221
Debt issuance costs, net		12,145		6,802
Other		7,286		9,264
Total assets	$	1,550,231	$	1,191,212
Match funded liabilities	$	835,172	$	465,691
Lines of credit and other secured borrowings		44,514		55,810
Servicer liabilities		1,868		38,570
Deferred income		11,975		13,599
Checks held for escheat		8,017		7,947
Servicing liability		2,477		2,878
Accrued expenses and other (1)		22,898		15,575
Total liabilities	$	926,921	$	600,070

(1) The balance at June 30, 2010 includes the $5,163 accrual established in connection with the settlement of the MDL Proceeding.

Loans and Residuals

The following table presents selected results of operations of our Loans and Residuals segment for the periods ended June 30:

	Three months		Six months	
	2010	2009	2010	2009
Revenue	$ —	$ —	$ —	$ —
Operating expenses	1,369	747	2,561	1,309
Loss from operations	(1,369)	(747)	(2,561)	(1,309)
Other income (expense)				
Interest income	2,107	1,991	4,948	3,875
Interest expense	(39)	(519)	(228)	(1,149)
Loss on trading securities	—	(581)	—	(863)
Loss on loans held for resale, net	(1,233)	(2,987)	(2,271)	(7,541)
Other, net	(386)	—	(935)	6
Other income (expense), net	449	(2,096)	1,514	(5,672)
Loss from continuing operations before income taxes	$ (920)	$ (2,843)	$ (1,047)	$ (6,981)

Effective January 1, 2010, the Loans and Residual segment includes the four securitization trusts that we include in our consolidated financial statements under the provisions of ASC 810, Consolidation. Our results of operations for the three and six months ended June 30, 2010 and our assets and liabilities as of that date include the effects of consolidating these trusts. The securitization trusts are essentially pass-through entities that have not had a significant effect on the Loss from continuing operations before income taxes of the Loans and Residuals segment. For the three and six months ended June 30, 2010, the trusts generated Income (loss) from continuing operations before income taxes of $(9)and $334, respectively. See Note 1 to our Interim Consolidated Financial Statements—Securitizations of Residential Mortgage Loans, for additional information.

Three Months Ended June 2010 versus 2009. Interest income during the second quarter of 2010 was higher than in 2009 largely due to the effects of consolidating the loan securitization trusts which generated interest income of $1,283 in the second quarter of 2010. In addition, interest on loans held for resale declined $231 primarily due to a lower average loan principal balance because of payoffs, foreclosures and charge-offs.

Interest expense was lower in the second quarter of 2010 primarily due to our repayment in September 2009 of the remaining outstanding notes that represented our financing of loans held for resale.

Losses on trading securities reflect the change in fair value on mortgage-backed securities. However, with the consolidation of the securitization trusts, we no longer recognize gains or losses on changes in fair value of the securities that we hold that were issued by the trusts.

Loss on loans held for resale, net, includes the adjustment necessary to present loans held for resale and the related real estate at estimated fair value and as well as realized losses on loan payoffs, foreclosures and charge-offs. The decline in losses on loans in the first quarter of 2010 reflects a smaller portfolio and a slower decline in the valuations on the underlying loan and real estate collateral.

Other, net, includes $503 of charge - offs on the loans held by the securitization trusts offset by an increase of $138 in the fair value of an interest rate swap held by one of the trusts.

Six Months Ended June 30, 2010 versus 2009. Interest income is 28% higher in the first six months of 2010 than it was in the first six months of 2009 principally because of the effects of including the four securitization trusts in our consolidated financial statements beginning January 1, 2010. This effect was partially offset by lower interest income on loans held for sale because of a 23% decline in the UPB of the portfolio from June 2009 to June 2010. Interest expense declined largely because of the repayment in September 2009 of the facility used to finance our loans held for resale. Loss on loans held for resale, net decreased because of a smaller loan portfolio and a slowing of the declines seen in the valuation of the loan portfolio.

The following table shows selected assets and liabilities of our Loans and Residuals segment at:

	June 30, 2010		December 31, 2009	
Restricted cash – for securitization investors	$	1,012	$	—
Subordinate and residual trading securities (1)		—		3,634
Loans held for resale (2)		30,696		33,197
Advances on loans held for resale		4,088		4,321
Loans, net – restricted for securitization investors (3)		70,860		—
Real estate (4)		4,461		5,030
Other		1,774		2,508
Total assets	$	112,891	$	48,690
Secured borrowings – owed to securitization investors (5)		67,199		—
Other		1,807		1,164
Total liabilities	$	69,006	$	1,164

(1) As more fully described in Note 1 to our Interim Consolidated Financial Statements—Securitizations of Residential Mortgage Loans, effective January 1, 2010, we eliminated our investment in securities issued by the newly consolidated securitization trusts.
(2) Loans held for resale at June 30, 2010 and December 31, 2009 includes non-performing loans with a carrying value of $13,015 and $14,382, respectively. The UPB of nonperforming loans held for resale as a percentage of total UPB was 54% at June 30, 2010 compared to 56% at December 31, 2009. There were no loan sales during the first six months of 2010.
(3) Includes $74,245 of loans held by the newly consolidated securitization trusts, including $14,108 of nonperforming loans. The balance is net of an allowance for loan losses of $3,385. See Note 8 to the Interim Consolidated Financial Statements for additional information regarding these loans.
(4) Includes $3,830 and $5,030 at June 30, 2010 and December 31, 2009, respectively, of foreclosed properties from our portfolio of loans held for resale that are reported net of fair value allowances of $5,020 and $4,810, respectively. During the first six months of 2010, real estate sales more than offset transfers from loans held for resale. The balance at June 30, 2010 also includes $631 of foreclosed properties owned by the newly consolidated securitization trusts as of June 30, 2010, net of valuation allowances of $946.
(5) Represent certificates issued by the newly consolidated securitization trusts. See Note 13 to our Interim Consolidated Financial Statements for additional information regarding these borrowings.

Asset Management Vehicles

The following table presents selected results of operations of our Asset Management Vehicles segment for the periods ended June 30:

	Three months				Six months			
		2010		2009		2010		2009
Revenue (1)	$	176	$	460	$	364	$	997
Operating expenses		443		1,016		910		1,778
Loss from operations		(267)		(556)		(546)		(781)
Other income (expense)								
OSI		170		(379)		654		(106)
ONL and affiliates		(21)		(467)		17		(1,042)

Equity in earnings (losses) of unconsolidated entities	149	(846)	671	(1,148)
Other income (expense), net	149	(846)	671	(1,148)
Income (loss) from continuing operations before income taxes	$ (118)	$ (1,402)	$ 125	$ (1,929)

(1) Revenue consists of management fees earned from OSI and ONL and affiliates. In addition, our Servicing segment earns fees for servicing loans on behalf of these unconsolidated entities. In determining the amount of consolidated equity in earnings to recognize, we add back our share of the loan servicing and management fee expense recognized by OSI, ONL and affiliates. During the second quarter of 2010 and 2009, we earned total fees of $779 and $1,040, respectively, from OSI and ONL and affiliates. Year to date, we earned total fees of $1,631 and $2,367 for 2010 and 2009, respectively. On a consolidated basis, we have recognized approximately 75% of the loan servicing and management fee revenue.

Three and Six Months Ended June 2010 versus 2009. Management fee revenue continues to decline. The improvement in earnings of OSI and ONL and affiliates in the 2010 periods largely resulted from a reduction in losses on resolved loans, reflecting a slower decline in the valuations on the underlying loans and real estate collateral and an increase in the fair value of residual securities.

The following table shows selected assets and liabilities of our Asset Management Vehicles segment at:

	June 30, 2010	December 31, 2009
Receivables	$ 106	$ 334
OSI	8,539	7,885
ONL and affiliates (1)	4,915	7,044
Investments in unconsolidated entities	13,454	14,929
Other	2	8
Total assets	$ 13,562	$ 15,271

(1) During the first six months of 2010, we received distributions totaling $2,146 from ONL and its affiliates. At June 30, 2010, we had committed to invest up to an additional $33,840 in ONL and affiliated entities. The commitment expires in September 2010.

Mortgage Services, Financial Services and Technology Products

Mortgage Services, Financial Services and Technology Products were separated as of August 10, 2009 as part of the Separation of the Ocwen Solutions line of business, except for GSS and BMS Holdings which remain at Ocwen. As a separate, publicly-traded company, Altisource Portfolio Solutions S.A. (NASDAQ:ASPS) will file a Form 10-Q with the Securities and Exchange Commission.

Corporate Items and Other

The following table presents selected results of operations of Corporate Items and Other for the periods ended June 30:

	Three months		Six months	
	2010	2009	2010	2009
Revenue	$ 425	$ 112	$ 774	$ 365
Operating expenses	1,817	3,830	4,740	7,813
Loss from operations	(1,392)	(3,718)	(3,966)	(7,448)
Other income (expense)				
Gain (loss) on trading securities:				
Auction rate securities	(1,703)	6,024	(938)	5,984
Subordinates and residuals	(7)	(8)	(7)	(66)
	(1,710)	6,016	(945)	5,918
Gain on debt redemption	6	—	723	534
Other, net	(4,029)	739	(4,114)	595
Other income, net	(5,733)	6,755	(4,336)	7,047
Income (loss) from continuing operations before income taxes	$ (7,125)	$ 3,037	$ (8,302)	$ (401)

Three Months Ended June 2010 versus 2009. Operating expenses declined for the quarter primarily due to a reduction in professional service fees. In addition, we realized a loss of $1,675 from the sale of auction rate securities with a par value of $46,800 during the second quarter of 2010. Other, net includes a $3,000 charge to write-off our investment in a commercial real estate partnership during the second quarter of 2010. In the second quarter of 2009, we recorded $1,855 of professional service fees related to the Separation.

Six Months Ended June 30, 2010 versus 2009. Operating expenses for the first six months of 2010 declined as compared to the first six months of 2009 principally because we recorded $3,017 of expenses related to the Separation in 2009. We realized losses of $1,907 in the first six months of 2010 from sales of auction rate securities. Other, net includes the charge of $3,000 for the write-off of our investment in a commercial real estate partnership during the second quarter of 2010.

The following table shows selected assets and liabilities of Corporate Items and Other at:

	June 30, 2010	December 31, 2009
Cash	$ 143,225	$ 90,778
Trading securities, at fair value		
Auction rate (1)	78,073	247,464
Subordinates and residuals	52	58
Receivables, net	6,345	4,811
Income taxes receivable	19,312	17,865
Deferred tax assets, net	117,253	132,683
Premises and equipment, net	3,371	3,214
Interest-earning collateral deposits (2)	21,497	5,765
Other	11,717	11,539
Total assets	$ 400,845	$ 514,177
Lines of credit and other secured borrowings (1)	$ 56,153	$ —
Investment line (1)	—	156,968
Debt securities (3)	82,554	95,564
Fair value of derivatives (2)	11,787	—
Liability for selected tax items	6,978	15,326
Checks held for escheat	5,044	4,880
Payable to Altisource	3,574	10,606
Other (4)	15,582	18,909
Total liabilities	$ 181,672	$ 302,253

(1) In the first quarter of 2010, we liquidated $137,575 par value of securities as the result of the settlement of two of our auction rate securities litigation actions and the sale of certain auction rate securities. Furthermore, we sold $88,150 par value of securities with the option to repurchase the same securities at the same sales price until October 2012 and recognized the sale as a secured borrowing. We used these proceeds to repay the investment line. In the second quarter of 2010, we repurchased $46,800 par value of these securities at the initial sale price of $40,504, reduced the liability and sold the securities for cash proceeds of $44,460. Also in the second quarter of 2010, we sold auction rate securities with a par value of $35,000 under an agreement to repurchase and received proceeds of $21,704. We report repurchase agreements as collateralized financings and report the obligations to repurchase the assets sold as a secured borrowing.

(2) As disclosed in Note 18, we entered into interest rate swap agreements during the second quarter to hedge against our exposure to an increase in variable interest rates. At June 30, 2010, the counterparties to the swap agreements hold $15,732 of cash collateral.

(3) In January 2010, we repurchased $12,930 par value of our 10.875% Capital Trust Securities at a discount to par in the open market which generated a gain of $717, net of the write-off of unamortized issuance costs. In June 2010, we repurchased $80 par value of Capital Trust Securities which generated a net gain of $6.

(4) The decline in Other liabilities in the first six months of 2010 is primarily due to the payment of the 2009 annual bonus.

EQUITY

Total equity amounted to $899,930 at June 30, 2010 as compared to $865,863 at December 31, 2009. This increase of $34,067 is primarily due to net income of $36,898. In addition, as more fully described in Note 1—Securitizations of Residential Mortgage Loans, we recorded a $2,274 increase in the opening balance of retained earnings upon adoption of ASU 2009-17 (ASC 810, Consolidation) on January 1, 2010. The exercise of 217,775 stock options and the compensation in the form of employee share-based awards also contributed to the increase in equity in 2010. Partially offsetting these increases, we recognized $7,383 of unrealized losses, net of taxes, in Other comprehensive loss during the second quarter on interest rate swaps that we designated as cash flow hedges.

INCOME TAX EXPENSE (BENEFIT)

Income tax expense (benefit) was $(2,777) and $9,472 for the second quarter of 2010 and 2009, respectively. For the first six months, income tax expense was $7,797 and $17,509 for the 2010 and 2009 periods, respectively.

Our effective tax rate for first six months of 2010 was 17.4% as compared to 35.3% for the same period of 2009. Income tax expense on Income from continuing operations before income taxes differs from amounts that would be computed by applying the U.S. Federal corporate income tax rate of 35% primarily because of the effect of foreign taxes and foreign tax rates, foreign income with an indefinite deferral from U.S. taxation, losses from consolidated VIEs and state taxes. In addition, the effective rate reflects a benefit from the release of a reserve of $8,348 predominantly related to the wind down and liquidation of an advance financing structure. The reserve for this item had been recorded in 2009.

Our effective tax rate for first six months of 2010 and 2009 includes a non-cash benefit of approximately 6.1% and 3.8%, respectively, associated with the recognition of certain foreign deferred tax assets.

LIQUIDITY AND CAPITAL RESOURCES

We define liquidity as unencumbered cash balances plus unused, collateralized advance financing capacity. Our liquidity as of June 30, 2010, as measured by cash and available credit, was $229,874, a decrease of $62,241, or 21%, from December 31, 2009 to June 30, 2010. At June 30, 2010, our cash position was $143,386 compared to $90,919 at December 31, 2009. Our available credit on collateralized but unused advance financing capacity was $86,488 at June 30, 2010 compared to $201,200 at December 31, 2009.

Investment policy and funding strategy. Our primary sources of funds for near-term liquidity are:

Match funded liabilities	Payments received on loans held for resale
Lines of credit and other secured borrowings	Payments received on trading securities
Servicing fees and ancillary revenues	Debt securities

In addition to these near-term sources, additional long-term sources of liquidity include debt securities and equity capital.

Our primary uses of funds are the funding of servicing advances, the payment of interest and operating expenses, the purchase of servicing rights and the repayment of borrowings. We closely monitor our liquidity position and ongoing funding requirements.

Our investment policies emphasize principal preservation by limiting investments to include:

- Securities issued by the U.S. government, a U.S. agency or a U.S. government-sponsored enterprise
- Money market mutual funds
- Money market demand deposits

Currently, we are primarily invested in money market demand deposits. Furthermore, our investment policies are intended to minimize credit and counterparty risk by establishing risk limits based on each counterparty's equity size and long-term credit ratings. We regularly monitor and project cash flow timing in connection with our efforts to optimize the risk-adjusted yield of our portfolio of investments.

In assessing our liquidity outlook, our primary focus is on two measures:

- The relationship of dollars generated from maturing assets compared to dollars generated from maturing liabilities assuming no renewal of existing facilities and no new financings

- Unused borrowing capacity

At June 30, 2010, $752,828 of our total maximum borrowing capacity remained unused. The unused borrowing capacity in the Servicing business may be utilized in the future by pledging additional qualifying collateral to our facilities.

We maintain unused borrowing capacity for three reasons:

- As a protection should Advances increase due to increased delinquencies,
- To the extent that term financing is unavailable resulting in liabilities maturing faster than assets, as a protection should we be unable to either renew existing facilities or obtain new facilities and
- To provide capacity for the acquisition of additional servicing.

Outlook. In the second half of 2010, we expect to reduce up-front facility fees and execute at tighter spreads over LIBOR and commercial paper rates.

We also expect to benefit from the increase in the duration of our funding sources. Our $410,000 of TALF issuances increased the maturity for 49% of our advance financing needs at fixed interest rates.

Debt financing summary. During the six months ended June 30, 2010, we:

- Fully repaid $156,968 on our auction rate securities investment line;
- Repurchased Capital Trust Securities with a face value of $13,010;
- Repaid $12,000 on our original $60,000 fee reimbursement advance; and
- Repaid $1,400 on our original $7,000 term note;
- Renewed a $100,000 advance note;
- Renewed a $500,000 advance note;
- Renewed and extended a variable funding note with a maximum borrowing capacity of $300,000;
- Issued $200,000 of advance receivable backed notes under the TALF program; and
- Entered into financing arrangements collateralized by auction rate securities with a combined fair value and par value of $75,763 and $76,350, respectively, at June 30, 2010.

As a result of our ability to renew and increase advance facility notes before they entered their amortization period and to issue the TALF notes, maximum borrowing capacity for match funded advances increased by $228,000 from $1,360,000 at December 31, 2009 to $1,588,000 at June 30, 2010. When coupled with an increase in advances and match funded advances of $367,192, we decreased our unused advance borrowing capacity from $894,309 at December 31, 2009 to $752,828 at June 30, 2010. The primary reason for the net increase in advances in 2010 was the acquisition of the $6.9 billion servicing portfolio during the second quarter. Our prospects for advance financing improved due to the inclusion of servicer advances in TALF which was announced by the Federal Reserve Bank of New York in on March 19, 2009. Although the TALF window closed in March 2010, we were able to establish relations with many cash and TALF investors during our December 2009 and February 2010 issuances, and thus have generated significant interest for future medium-term note issuances.

In order for us to maintain liquidity and the ability to finance new advances, we repay borrowings under facilities that have entered their amortization period and pledge them to another facility. Our new advance facility structure, which has four notes outstanding as of June 30, 2010, permits collateral to be apportioned between notes when one or more notes are in amortization. This feature permits us to continue to finance new advances provided there is sufficient capacity on other revolving notes in the structure that are not in amortization.

Our ability to finance servicing advances continues to be a significant factor that affects our liquidity. Three of our match funded advance facilities that are rated are subject to increases in the financing discount if deemed necessary by the rating agencies in order to maintain the minimum rating required for the facility. While several rating agencies have adjusted their methodology for rating servicer advances and advance rates for newly issued notes are lower than in the past, we do not expect future advance rate changes to have a material effect on our liquidity. Our ability to continue to pledge collateral under each advance facility depends on the performance of the collateral. Currently, the majority of our collateral qualifies for financing under the advance facility to which it is pledged.

Some of our existing debt covenants limit our ability to incur additional debt in relation to our equity, require that we do not exceed maximum levels of delinquent loans and require that we maintain minimum levels of liquid assets and earnings. Failure to comply with these covenants could result in restrictions on new borrowings or the early termination of our borrowing facilities. We are currently in compliance with these covenants and do not expect them to restrict our activities.

Cash flows for the six months ended June 30, 2010. Our operating activities provided $360,795 of cash primarily due to our liquidation of auction rate securities and net collections of servicing advances. Trading activities provided $168,453 of cash from sales, settlements and redemptions of auction rate securities. Excluding the advances acquired in connection with the $6.9 billion residential servicing portfolio we acquired in the second quarter, advances declined $153,997. Also, servicing liabilities declined by $36,702.

Our investing activities used $547,351 of cash during the first six months of 2010. During the second quarter of 2010, we paid $23,425 to purchase MSRs and acquired $528,882 of advances and other assets in connection with the acquisition of a $6.9 billion servicing portfolio. We also received $2,146 of distributions from our asset management entities.

Our financing activities provided $239,023 of cash primarily consisting of $369,481 of net proceeds from match funded liabilities of our Servicing business. We also received proceeds of $96,657 from collateralized financing transactions involving auction rate securities and recognized these transactions as secured borrowings. This was partially offset, as we repaid the investment line of $156,968, reduced the borrowings collateralized by auction rate securities by $40,504 and purchased Capital Trust Securities with a face value of $13,010 for $11,659. We also paid the first annual installment of $12,000 on our $60,000 fee reimbursement advance.

Cash flows for the six months ended June 30, 2009. Our operating activities provided $193,119 reflecting a decline in the funding requirements of our Servicing operations and a decline in net cash used by trading activities. We collected net cash of $164,979 on advances and match funded advances while servicing liabilities declined by $57,977.

Our investing activities used $6,387 net cash primarily due to the purchase of MSRs for $10,241offset by $3,246 of distributions we received from our asset management entities.

Our financing activities used $173,846 of cash as we made $195,226 of net repayments of borrowings under our match funded advance facilities as a result of declines in servicing advances. Net proceeds of $67,000 from two new secured borrowings were largely offset by repayments on the investment line and repurchases of our 3.25% Convertible Notes. Cash flows from financing activities for the first six months of 2009 include $49,187 of net proceeds from sales and repurchases of our common stock.

CONTRACTUAL OBLIGATIONS AND OFF BALANCE SHEET ARRANGEMENTS

Contractual Obligations

We believe that we have adequate resources to fund all unfunded commitments to the extent required and meet all contractual obligations as they come due. Such contractual obligations include our Convertible Notes, Capital Trust Securities, lines of credit and other secured borrowings, interest payments and operating leases. See Note 25 to the Interim Consolidated Financial Statements for additional information regarding commitments and contingencies.

Off-Balance Sheet Arrangements

In the normal course of business, we engage in transactions with a variety of financial institutions and other companies that are not reflected on our Consolidated Balance Sheet. We are subject to potential financial loss if the counterparties to our off-balance sheet transactions are unable to complete an agreed upon transaction. We seek to limit counterparty risk through financial analysis, dollar limits and other monitoring procedures. In addition, through our investment in subordinate and residual securities, we provide credit support to the senior classes of securities. We have also entered into non-cancelable operating leases and have committed to invest up to an additional $33,840 in ONL and related entities.

Derivatives. We record all derivative transactions at fair value on our Consolidated Balance Sheets. We currently use these derivatives principally to manage our interest rate risk. The notional amounts of our derivative contracts do not reflect our exposure to credit loss. See Note 18 to our Interim Consolidated Financial Statements for additional information regarding derivatives.

Involvement with SPEs. We use SPEs for a variety of purposes but principally in the financing of our servicing advances and in the securitization of mortgage loans.

Our securitizations of mortgage loans were structured as sales. The SPEs to which we transferred the mortgage loans were qualifying special purpose entities (QSPEs) and, therefore, were not subject to consolidation through 2009. We have retained both subordinated and residual interests in these SPEs. Where we are the servicer of the securitized loans, we generally have the right to repurchase the mortgage loans from the SPE when the costs exceed the benefits of servicing the remaining loans. As disclosed in the Recent Accounting Developments below, ASC 860 amended the current accounting standards primarily to eliminate the concept of a QSPE. Effective January 1, 2010, ASC 810 required that we reevaluate these QSPEs as well as all other potentially significant interests in other unconsolidated entities to determine if we should include them in our consolidated financial statements. We have determined that these QSPEs are VIEs and that we are the primary beneficiary of four of these QSPEs and have included them in our consolidated financial statements effective January 1, 2010.

We generally use match funded securitization facilities to finance our servicing advances. The SPEs to which the advances are transferred in the securitization transaction are included in our consolidated financial statements either because the transfer did not qualify for sales accounting treatment or because we are the primary beneficiary where the SPE is also a VIE. The holders of the debt of these SPEs can look only to the assets of the SPEs for satisfaction of the debt and have no recourse against OCN. However, OLS has guaranteed the payment of the obligations of the issuer under a match funded facility that closed in April 2008. The maximum amount payable under the guarantee is limited to 10% of the notes outstanding at the end of the facility’s revolving period.

VIEs. In addition to certain of our financing SPEs, we have invested in several other VIEs primarily in connection with purchases and securitizations of whole loans. If we determine that we are the primary beneficiary of a VIE, we report the VIE in our consolidated financial statements.

RECENT ACCOUNTING DEVELOPMENTS

Recent Accounting Pronouncements

Listed below are recent accounting pronouncements which did or are expected to have a significant impact upon adoption. For additional information regarding these and other recent accounting pronouncements, see Note 2 to our Interim Consolidated Financial Statements.

ASU 2009-16 (ASC 860, Transfers and Servicing). This statement eliminates the exceptions for qualifying special purpose entities (QSPE) from the consolidation guidance (ASC 810) and clarifies that the objective of the standard is to determine whether a transferor and all of the entities included in the transferor’s financial statements being presented have surrendered control over transferred financial assets. That determination must consider the transferor’s continuing involvements in the transferred financial asset, including all arrangements or agreements made contemporaneously with, or in contemplation of, the transfer, even if they were not entered into at the time of the transfer. This statement modifies the financial-components approach currently used and limits the circumstances in which a financial asset, or portion of a financial asset, should be derecognized when the transferor has not transferred the entire original financial asset to an entity that is not consolidated with the transferor in the financial statements being presented and/or when the transferor has continuing involvement with the transferred financial asset.

This statement defines the term participating interest to establish specific conditions for reporting a transfer of a portion of a financial asset as a sale. If the transfer does not meet those conditions, a transferor should account for the transfer as a sale only if it transfers an entire financial asset or a group of entire financial assets and surrenders control over the entire transferred asset(s). This statement requires that a transferor recognize and initially measure at fair value all assets obtained (including a transferor’s beneficial interest) and liabilities incurred as a result of a transfer of financial assets accounted for as a sale. Enhanced disclosures are required to provide financial statement users with greater transparency about transfers of financial assets and a transferor’s continuing involvement with transferred financial assets.

The provisions for guaranteed mortgage securitizations are removed to require those securitizations to be treated the same as any other transfer of financial assets within the scope of the standard. If such a transfer does not meet the requirements for sale accounting, the securitized mortgage loans should continue to be classified as loans in the transferor’s statement of financial position.

We adopted this standard effective January 1, 2010 as a result of which, we reevaluated certain QSPEs with which we had ongoing relationships as further described under ASU 2009-17, below, and reassessed the adequacy of our disclosures with regard to our servicing assets and servicing liabilities.

ASC 810, Consolidation. This standard requires an enterprise to perform ongoing periodic assessments to determine whether the enterprise’s variable interest or interests give it a controlling financial interest in a VIE. We adopted this standard effective January 1, 2010. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both of the following characteristics:

(a) The power to direct the activities of a variable interest entity that most significantly impact the entity’s economic performance

(b) The obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

In addition to reintroducing the concept of control into the determination of the primary beneficiary of a VIE, this statement makes numerous other amendments to the current standards primarily to reflect the elimination of the concept of a QSPE under ASC 860 (above). This statement also amends the current standards to require enhanced disclosures that will provide users of financial statements with more transparent information about an enterprise's involvement in a variable interest entity. The enhanced disclosures are required for any enterprise that holds a variable interest in a VIE. The additional disclosures required by this statement are included in Note 1—Summary of Significant Accounting Policies.

As also disclosed in Note 1—Summary of Significant Accounting Policies, we previously excluded certain loan securitization trusts from our consolidated financial statements because each was a QSPE. Effective January 1, 2010, we reevaluated these QSPEs as well as all other potentially significant interests in other unconsolidated entities to determine if we should include them in our consolidated financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK (DOLLARS IN THOUSANDS)

Market risk includes liquidity risk, interest rate risk and foreign currency exchange rate risk. Market risk also reflects the risk of declines in the valuation of financial instruments and the collateral underlying loans. Our Investment Committee reviews significant transactions that may impact market risk and is authorized to utilize a wide variety of techniques and strategies to manage market risk including, in particular, interest rate risk.

Liquidity Risk

We are exposed to liquidity risk primarily because of the cash required to support the Servicing business including the requirement to make advances pursuant to servicing contracts. In general, we finance our operations through operating cash flow, match funding agreements and secured borrowings. See the Liquidity Summary and Liquidity and Capital Resources sections for additional discussion of liquidity.

Interest Rate Risk

Interest rate risk is a function of (i) the timing and (ii) the dollar amount of assets and liabilities that re-price at each point in time. We are exposed to interest rate risk to the extent that our interest-bearing liabilities mature or re-price at different speeds, or different bases, than interest-earning assets.

If interest rates increase by 1% on our variable rate advance financing and interest earning cash and float balances, we estimate a net positive impact of approximately $355 resulting from an increase of $4,663 in annual interest income compared to an increase of $4,308 in annual interest expense. This outcome is due in large part to our hedging activities. See below and Note 18 to our Interim Consolidated Financial Statements for additional information regarding our use of derivatives.

At June 30, 2010, we had interest rate caps with a notional amount of $308,333 to hedge our exposure to rising interest rates on variable-rate match funded notes with a combined maximum borrowing capacity of $350,000. In addition, during the second quarter of 2010 we entered into interest rate swaps with a notional amount of $250,000 to hedge a portion of a $500,000 variable-rate advance funding facility of which we were borrowing $250,000 at June 30, 2010. Also during the second quarter of 2010, we entered into interest rate swaps with a notional amount of $637,201 to hedge the variable-rate debt anticipated to be used to fund advances that will be acquired as part of the HomEq Servicing acquisition.

		June 30, 2010
Total borrowings outstanding (1)(2)	$	1,027,479
Fixed rate borrowings		540,554
Variable rate borrowings		486,925
Float balances (held in custodial accounts, excluded from our Consolidated Balance Sheet)		322,985
Notional balance of interest rate caps		308,333
Notional balance of interest rate swaps (3)		887,201

(1) Borrowing amounts are exclusive of any related discount.

(2) Excluding Secured borrowings – owed to securitization investors of $67,199, the holders of which have no recourse against the assets of Ocwen.

(3) Excluding an interest rate swap held by one of the securitization trusts that we began to include in our consolidated financials statements effective January 1, 2010.

Excluding Loans, net – restricted for securitization investors of $70,860, our Consolidated Balance Sheet at June 30, 2010 included interest-earning assets totaling $225,515 including $42,743 of interest-earning cash accounts, $78,073 of auction rate securities, $42,445 of debt service accounts, $30,696 of loans held for resale and $23,408 of interest-earning collateral accounts.

Foreign Currency Exchange Rate Risk

We are exposed to foreign currency exchange rate risk in connection with our investment in non-U.S. dollar functional currency operations to the extent that our foreign exchange positions remain unhedged. Our operations in Uruguay and India expose us to foreign currency exchange rate risk, but we do not consider this risk significant. During the second quarter of 2010, we entered into foreign exchange forward contracts to hedge against the effect of changes in the value of the India Rupee on recurring amounts payable to our subsidiary in India, OFSPL, for services rendered to U.S. affiliates. The notional balance of these contracts was $16,000 at June 30, 2010. We did not designate these contracts as hedges.

ITEM 4. CONTROLS AND PROCEDURES

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act) as of June 30, 2010. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2010, our disclosure controls and procedures (1) were designed and functioning effectively to ensure that material information relating to Ocwen, including its consolidated subsidiaries, is made known to our Chief Executive Officer and Chief Financial Officer by others within those entities, particularly during the period in which this report was being prepared and (2) were operating effectively in that they provided reasonable assurance that information required to be disclosed by Ocwen in the reports that it files or submits under the Securities Exchange Act of 1934 (i) is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and (ii) accumulated and communicated to management, including the Chief Executive Officer or Chief Financial Officer, as appropriate, to allow timely decisions regarding disclosure.

No change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act) occurred during the fiscal quarter ended June 30, 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

See Note 25—Commitments and Contingencies to the Interim Consolidated Financial Statements for information regarding legal proceedings.

ITEM 1A. RISK FACTORS

The following supplements the discussion of the principal risks and uncertainties that affect or could affect our business operations that was included under Item 1A on pages 11 through 18 of our Annual Report on Form 10-K for the year ended December 31, 2009 and should be read in conjunction with such disclosures.

Our business may be affected by the enactment of the Dodd-Frank Wall Street Reform and Consumer Protection Act. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was signed into law on July 21, 2010. Certain provisions of the Dodd-Frank Act may impact our business. For example, we may be required to clear and exchange trade some or all of the swap transactions that we enter into which could result in higher cost, less transaction flexibility and price disclosure. Because many provisions of the Dodd-Frank Act require rule making by governmental agencies to implement, we cannot predict the impact of the Dodd-Frank Act on Ocwen and its business.

ITEM 5. OTHER INFORMATION

On July 29, 2010, Ocwen Financial Corporation (“Ocwen”) and certain subsidiaries of Ocwen entered into a senior secured term loan facility agreement (the “Credit Agreement”) with Barclays Bank PLC and the other lenders that are parties thereto, and Ocwen borrowed thereunder term loans in an aggregate principal amount equal to $350 million (the “Proceeds”). The Proceeds will be used (a) to fund a portion of the acquisition of the non-prime mortgage servicing business known as “HomEq Servicing” by Ocwen Loan Servicing, LLC (“OLS”) in accordance with the provisions of the Asset Purchase Agreement, dated May 28, 2010, among Barclays Bank PLC, Barclays Capital Real Estate Inc., OLS and Ocwen (the “HomEq Acquisition”), (b) to pay fees and expenses incurred in connection with the HomEq Acquisition and the transactions contemplated by the Credit Agreement and (c) for general corporate purposes of Ocwen and its subsidiaries.

Borrowings under the Credit Agreement will bear interest, at the election of Ocwen, at a rate per annum equal to either (a) the greatest of (i) the prime rate of Barclays Bank PLC in effect on such day, (ii) the federal funds effective rate in effect on such day plus 0.50% and (iii) the one-month Eurodollar rate (1-Month LIBOR), in each case plus the applicable margin of 6.00% and a floor of 3.00% or (b) 1-Month LIBOR, plus the applicable margin of 7.00% with a 1-Month LIBOR floor of 2.00%.

The Credit Agreement has been guaranteed by OLS and Real Estate Servicing Solutions Inc. The Credit Agreement is and will be guaranteed by each of Ocwen’s current and future domestic subsidiaries that is not a securitization entity and that represents (a) 5% or more of Ocwen’s consolidated adjusted EBITDA, (b) 5% or more of Ocwen’s consolidated total assets or (c) 5% or more of Ocwen’s consolidated total revenues. If at any time the subsidiaries (excluding foreign subsidiaries and securitization entities) that do not meet the thresholds set forth in the immediately preceding sentence comprise in the aggregate more than (i) 6% of Ocwen’s consolidated adjusted EBITDA, (ii) 6% of Ocwen’s consolidated total assets or (iii) 6% of Ocwen’s consolidated total revenues (excluding from each such calculation the contribution of securitization entities and foreign subsidiaries), then Ocwen is required to cause additional subsidiaries to provide guaranties under the Credit Agreement to the extent required such that the foregoing condition ceases to be true. The Credit Agreement is secured by a first priority security interest in substantially all of the tangible and intangible assets of Ocwen and the guarantors, as well as by a pledge of the equity of certain of the subsidiaries of Ocwen and each guarantor.

$150 million of the Proceeds has been deposited into escrow pending the closing of the HomEq Acquisition. If the closing of the HomEq Acquisition has not occurred by December 31, 2010, Ocwen is required to prepay the term loans under the Credit Agreement in an aggregate amount equal to $150 million and the escrowed funds will be applied to effect such prepayment. If the closing of the HomEq Acquisition occurs prior to December 31, 2010, then the escrowed funds may be used by Ocwen to pay the acquisition price in connection therewith, unless a payment default or bankruptcy default exists under the Credit Agreement.

Ocwen is required to prepay the principal amount of the term loans in consecutive quarterly installments of $8.75 million per quarter commencing September 30, 2010, with the balance of the term loans becoming due on July 29, 2015.

Ocwen is permitted to prepay the term loans at any time, without premium or penalty, other than LIBOR breakage costs; provided, that if all or any portion of the term loans are repaid prior to the one year anniversary of the closing of the Credit Agreement through voluntary or mandatory repayments from the incurrence of indebtedness having a lower effective yield than the term loans (whether by reason of the interest rate applicable to such indebtedness or by reason of the issuance of such indebtedness at a discount), Ocwen must pay a premium equal to 1.0% of the amount of term loans repaid.

Ocwen is required to make mandatory prepayments of the term loans in certain instances, including with the proceeds of certain material asset sales, insured casualties and condemnation events, in each case, subject to a 9-month reinvestment provision. Ocwen is also required to make mandatory prepayments of the term loans if there is positive consolidated excess cash flow (as defined in the Credit Agreement) for any fiscal year (commencing with the fiscal fear ending December 31, 2011), in an amount equal to (a) 50% of such consolidated excess cash flow minus (b) voluntary repayments of the loans during such fiscal year; provided, that if, as of the last day of the most recently ended fiscal year, the corporate leverage ratio (as defined in the Credit Agreement) is 1.25 to 1.00 or less, Ocwen shall only be required to make the prepayments and/or reductions otherwise required under the Credit Agreement in an amount equal to (i) 25% of such consolidated excess cash flow minus (ii) voluntary repayments of the loans during such fiscal year.

Under specified terms and conditions, the amount available under the Credit Agreement may be increased by up to $300 million of incremental term loan facilities so long as, after giving effect to the incremental facilities, Ocwen is in pro forma compliance with each of the financial covenants under the Credit Agreement as of the last day of the most recently ended fiscal quarter after giving effect to such incremental facilities; provided, that the loan-to-value ratio (as defined in the Credit Agreement) shall not exceed a percentage equal to 0.9 times the percentage that was otherwise required.

The Credit Agreement contains provisions that limit Ocwen’s ability to incur debt, make investments, sell assets, create liens, engage in transactions with affiliates, engage in mergers and acquisitions, pay dividends and other restricted payments, grant negative pledges, engage in sale-leaseback transactions and change its business activities.

The Credit Agreement requires Ocwen to comply with certain financial covenants, including an interest coverage ratio, a corporate leverage ratio, a ratio of consolidated total debt to consolidated tangible net worth and a loan-to-value ratio.

In addition, the Credit Agreement contains events of default, including (subject to certain materiality thresholds and grace periods) payment default, failure to comply with covenants, material inaccuracy of representation or warranty, default under the Guaranty, dated June 28, 2005, from Ocwen in favor of the Office of Thrift Supervision and the other guaranteed parties named therein, bankruptcy or insolvency proceedings, material unsatisfied judgments, certain ERISA events, change of control, cross-default to other debt and credit agreements and the occurrence of an early amortization event under the indenture to be executed in connection with the securitization of certain of the servicer advances acquired in connection with the HomEq Acquisition. The remedies for events of default contained in the Credit Agreement are customary for this type of loan facility.

Ocwen paid to each lender a closing fee as compensation for the funding of such lender’s term loan. In addition, Ocwen will pay administrative fees to the administrative agent, collateral agent, syndication agent, arranger and joint bookrunner.

ITEM 6. EXHIBITS

(3) Exhibits.

2.1	Separation Agreement, dated as of August 10, 2009, by and between Ocwen Financial Corporation and Altisource Portfolio Solutions S.A. (1)
2.2	Asset Purchase Agreement dated as of May 28, 2010, among Barclays Bank PLC, Barclays Capital Real Estate, Inc., Ocwen Loan Servicing, LLC and Ocwen Financial Corporation (2)
3.1	Amended and Restated Articles of Incorporation (3)
3.2	Amended and Restated Bylaws (4)
4.0	Form of Certificate of Common Stock (3)
4.1	Certificate of Trust of Ocwen Capital Trust I (5)
4.2	Amended and Restated Declaration of Trust of Ocwen Capital Trust I (5)
4.3	Form of Capital Security of Ocwen Capital Trust I (included in Exhibit 4.4) (5)
4.4	Form of Indenture relating to 10.875% Junior Subordinated Debentures due 2027 of OCN (5)
4.5	Form of 10.875% Junior Subordinated Debentures due 2027 of OCN (included in Exhibit 4.6) (5)
4.6	Form of Guarantee of OCN relating to the Capital Securities of Ocwen Capital Trust I (5)
4.7	Indenture dated as of July 28, 2004, between OCN and the Bank of New York Trust Company, N.A., as trustee (6)
10.1	Tax Matters Agreement, dated as of August 10, 2009, by and between Ocwen Financial Corporation and Altisource Solutions S.à r.l. (1)
10.2	Transition Services Agreement, dated as of August 10, 2009, by and between Ocwen Financial Corporation and Altisource Solutions S.à r.l. (1)
10.3	Employee Matters Agreement, dated as of August 10, 2009, by and between Ocwen Financial Corporation and Altisource Solutions S.à r.l. (1)
10.4	Technology Products Services Agreement, dated as of August 10, 2009, by and between Ocwen Financial Corporation and Altisource Solutions S.à r.l. (1)
10.5	Services Agreement, dated as of August 10, 2009, by and between Ocwen Financial Corporation and Altisource Solutions S.à r.l. (1)
10.6	Data Center and Disaster Recovery Agreement, dated as of August 10, 2009, by and between Ocwen Financial Corporation and Altisource Solutions S.à r.l. (1)
10.7	Intellectual Property Agreement, dated as of August 10, 2009, by and between Ocwen Financial Corporation and Altisource Solutions S.à r.l. (1)
10.8	Senior Secured Term Loan Facility Agreement, dated as of July 29, 2010, by and among Ocwen Financial Corporation, certain subsidiaries of Ocwen Financial Corporation, the lenders that are parties to the agreement from time to time and Barclays Bank PLC (filed herewith)
10.9	Pledge and Security Agreement, dated as of July 29, 2010, by and between Ocwen Financial Corporation, Ocwen Loan Servicing, LLC and each of the other subsidiaries of Ocwen Financial Corporation that is a party to the agreement from time to time and Barclays Bank PLC (filed herewith)
31.1	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith)
31.2	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith)
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith)
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith)

(1) Incorporated by reference from the similarly described exhibit included with the Registrant's Form 8-K filed with the Commission on August 12, 2009.
(2) Incorporated by reference from the similarly described exhibit included with the Registrant's Form 8-K filed with the Commission on June 2, 2010.
(3) Incorporated by reference from the similarly described exhibit filed in connection with the Registrant's Registration Statement on Form S-1 (File No. 333-5153) as amended, declared effective by the commission on September 25, 1996.
(4) Incorporated by reference from the similarly described exhibit included with the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007.
(5) Incorporated by reference from the similarly described exhibit filed in connection with our Registration Statement on Form S-1 (File No. 333-28889), as amended, declared effective by the Commission on August 6, 1997.
(6) Incorporated by reference from the similarly described exhibit included with Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

OCWEN FINANCIAL CORPORATION

Date: August 4, 2010 By: /s/ David J. Gunter
David J. Gunter,
Executive Vice President, Chief Financial Officer and
Chief Accounting Officer
(On behalf of the Registrant and as its principal financial officer)

RIGHT: 0pt" align="left">Net earnings per common share – basic and diluted (1)

$	1.56
$	1.46
$	4.61

(1) Restated to reflect two-for-one common share split in May 2010.

12. FINANCIAL INSTRUMENTS

The carrying values of the Company’s financial instruments by category are as follows:

	2010		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ –	$ 22	$ –
Accounts receivable	1,481	–	–
Accounts payable	–	–	(274)
Accrued liabilities	–	–	(2,163)
Other long-term liabilities	–	(451)	(91)
Long-term debt	–	–	(8,499)
	$ 1,481	$ (429)	$ (11,027)

	2009		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at

			amortized cost
Cash and cash equivalents	$ –	$ 13	$ –
Accounts receivable	1,148	–	–
Accounts payable	–	–	(240)
Accrued liabilities	–	–	(1,522)
Other long-term liabilities	–	(309)	(167)
Long-term debt	–	–	(9,658)
	$ 1,148	$ (296)	$ (11,587)

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The carrying value of the Company's financial instruments approximates their fair value, except for fixed-rate long-term debt as noted below. The fair values of the Company's financial assets and liabilities are outlined below:

	2010		
	Carrying value	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term liabilities	$ (451)	$ –	$(451)
Fixed-rate long-term debt(2) (3)	(7,063)	(7,835)	–
	$ (7,514)	$ (7,835)	$(451)

	2009		
	Carrying value	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term liabilities	$ (309)	$ –	$(309)
Fixed-rate long-term debt(2) (3)	(7,761)	(8,212)	–
	$ (8,070)	$ (8,212)	$(309)

(1) Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $61 million (2009 – $38 million) to reflect the fair value impact of hedge accounting.

(3) The fair value of fixed-rate long-term debt has been determined based on quoted market prices.

Risk Management

The changes in estimated fair values of derivative financial instruments included in the net risk management asset (liability) were recognized in the financial statements as follows:

Asset (liability)	2010 Risk management mark-to-market	2009 Risk management mark-to-market
Balance – beginning of year	$ (309)	$ 2,119
Net cost of outstanding put options	106	–
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	25	(1,991)
Interest expense	30	(25)
Foreign exchange	(101)	(338)
Other comprehensive income	(41)	(78)
Settlement of interest rate swaps and other	(55)	4
	(345)	(309)
Add: put premium financing obligations (1)	(106)	–

Balance – end of year		(451)		(309)
Less: current portion		(222)		(182)
	$	(229)	$	(127)

(1)The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations have been reflected in the net risk management asset (liability).

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Net (gains) losses from risk management activities for the years ended December 31 were as follows:

		2010		2009		2008
Net realized risk management (gain) loss	$	(96)	$	(1,253)	$	1,860
Net unrealized risk management (gain) loss		(25)		1,991		(3,090)
	$	(121)	$	738	$	(1,230)

Financial Risk Factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At December 31, 2010, the Company had the following derivative financial instruments outstanding to manage its commodity price exposures:

i) Sales Contracts

	Remaining term		Volume	Weighted average price		Index
Crude oil						
Crude oil price collars	Jan 2011	–Dec 2011	50,000 bbl/d	US$70.00	–US$102.23	WTI
Crude oil puts (1)	Jan 2011	–Dec 2011	100,000 bbl/d		US$70.00	WTI

(1) Crude oil put options have a cost of US$106 million.

ii) Purchase Contracts

	Remaining term		Volume	Weighted average fixed rate	Floating index
Natural gas					
Swaps – floating to fixed	Jan 2011	–Dec 2011	125,000 GJ/d	C$4.87	AECO

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

The natural gas derivative financial instruments designated as hedges as at December 31, 2010 were classified as cash flow hedges.

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Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2010, the Company had the following interest rate swap contracts outstanding:

	Remaining term	Amount ($ millions)	Fixed rate	Floating rate
Interest rate (1) (2)				
Swaps – floating to fixed	Jan 2011 – Feb 2012	C$200	1.4475%	3 month CDOR (3)

(1) During 2010, the Company unwound US$350 million of 4.9% interest rate swaps for proceeds of US$54 million.

(2) During 2010, the Company unwound C$300 million of 1.0680% interest rate swaps for nominal consideration.

(3) Canadian Dealer Offered Rate

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At December 31, 2010, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency					
Swaps (1)	Jan 2011 – Jul 2011	US$150	0.999	6.70%	7.70%
	Jan 2011 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2011 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2011 – Mar 2038	US$550	1.170	6.25%	5.76%

(1) Subsequent to December 31, 2010, the Company entered into cross currency swap contracts for US$50 million with an exchange rate of $0.994 (US$/C$) and average interest rates of 6.70% (US$) and 7.88% (C$) for the period January to July 2011.

All cross currency swap derivative financial instruments designated as hedges at December 31, 2010 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2010, the Company had US$1,162 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

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Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2010, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents, and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	2010	
	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase WTI US$1.00/bbl	$ (7)	$ –
Decrease WTI US$1.00/bbl	$ 7	$ –
Increase AECO C$0.10/Mcf	$ –	$ 3
Decrease AECO C$0.10/Mcf	$ –	$ (3)
Interest rate risk		
Increase interest rate 1%	$ (8)	$ 22
Decrease interest rate 1%	$ 8	$ (31)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (27)	$ –
Decrease exchange rate by US$0.01	$ 27	$ –

b) Credit Risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2010, substantially all of the Company's accounts receivables were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2010, the Company had net risk management assets of $nil with specific counterparties related to derivative financial instruments (December 31, 2009 – $7 million).

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c) Liquidity Risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, and access to debt capital markets, to meet obligations as they become due. Due to fluctuations in the timing of the receipt and/or disbursement of operating cash flows, the Company believes it has adequate bank credit facilities to provide liquidity.

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 274	$ –	$ –	$ –
Accrued liabilities	$ 2,163	$ –	$ –	$ –
Risk management	$ 222	$ 32	$ 96	$ 101
Other long-term liabilities	$ 25	$ 25	$ 41	$ –
Long-term debt (1)	$ 398	$ 348	$ 1,546	$ 4,774

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities.

13. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 228	$ 199	$ 172	$ 164	$ 152	$ 932
Offshore equipment operating leases	$ 141	$ 98	$ 97	$ 97	$ 81	$ 168
Offshore drilling	$ 7	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 18	$ 17	$ 19	$ 28	$ 27	$ 7,123
Office leases	$ 27	$ 27	$ 28	$ 28	$ 32	$ 339
Other	$ 102	$ 66	$ 19	$ 16	$ 24	$ 10

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2011 – 2015 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

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14. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

	2010		2009		2008	
Changes in non-cash working capital						
Accounts receivable, inventory, prepaids and other	$	(340)	$	(276)	$	111
Accounts payable		37		(151)		(4)
Accrued liabilities		576		(429)		(15)
Net changes in non-cash working capital	$	273	$	(856)	$	92
Relating to:						
Operating activities	$	149	$	(235)	$	(189)
Financing activities		(5)		(12)		46
Investing activities		129		(609)		235
	$	273	$	(856)	$	92

Other cash flow information:		2010		2009		2008
Interest paid	$	471	$	516	$	574
Taxes other than income tax paid	$	102	$	52	$	300
Current income tax paid	$	111	$	216	$	258

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15. SEGMENTED INFORMATION

The Company’s Exploration and Production activities are conducted in three geographic segments: North America, North Sea and Offshore West Africa. These activities include the exploration, development, production and marketing of crude oil, natural gas liquids and natural gas.

The Company’s Oil Sands Mining and Upgrading is a separate segment from Exploration and Production activities as the bitumen is recovered through mining operations.

Midstream activities include the Company’s pipeline operations and an electricity co-generation system. Activities that are not included in the above segments are reported in the segmented information as other. Inter-segment eliminations include internal transportation, electricity charges and natural gas sales.

	Exploration and Production										
	North America			North Sea			Offshore West Africa			T	
	2010	2009	2008	2010	2009	2008	2010	2009	2008	2010	20
Segmented revenue	$ 9,713	$ 7,973	$ 13,496	$ 1,058	$ 961	$ 1,769	$ 884	$ 913	$ 944	$ 11,655	$ 9
Less: royalties	(1,267)	(825)	(1,876)	(2)	(2)	(4)	(62)	(81)	(143)	(1,331)	(
Segmented revenue, net of royalties	8,446	7,148	11,620	1,056	959	1,765	822	832	801	10,324	8
Segmented expenses											
Production	1,675	1,748	1,881	385	376	457	167	179	102	2,227	2
Transportation and blending	1,761	1,213	1,975	8	8	10	1	1	1	1,770	
Depletion, depreciation and amortization	2,336	2,060	2,236	303	261	317	1,023	335	132	3,662	2
Asset retirement obligation accretion	46	41	42	33	24	27	6	4	2	85	6
Realized risk management activities	(96)	(880)	1,861	–	(373)	(1)	–	–	–	(96)	(
Total segmented expenses	5,722	4,182	7,995	729	296	810	1,197	519	237	7,648	4
Segmented earnings (loss) before the	$ 2,724	$ 2,966	$ 3,625	$ 327	$ 663	$ 955	$ (375)	$ 313	$ 564	$ 2,676	$ 3

following
Non–segmented expenses
Administration
Stock-based compensation expense (recovery)
Interest, net
Unrealized risk management activities
Foreign exchange (gain) loss
Total non-segmented expenses
Earnings before taxes
Taxes other than income tax
Current income tax expense
Future income tax expense (recovery)
Net earnings

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	Oil Sands Mining and Upgrading			Midstream			Inter–segment elimination and other			Total		
	2010	2009	2008	2010	2009	2008	2010	2009	2008	2010	2009	2008
Segmented revenue	$ 2,649	$ 1,253	$ –	$ 79	$ 72	$ 77	$ (61)	$ (94)	$ (113)	$ 14,322	$ 11,078	$ 16,173
Less: royalties	(90)	(36)	–	–	–	–	–	8	6	(1,421)	(936)	(2,017)
Segmented revenue, net of royalties	2,559	1,217	–	79	72	77	(61)	(86)	(107)	12,901	10,142	14,156
Segmented expenses												
Production	1,208	683	–	22	19	25	(10)	(18)	(14)	3,447	2,987	2,451
Transportation and blending	61	41	–	–	–	–	(48)	(45)	(50)	1,783	1,218	1,936
Depletion, depreciation and amortization	366	187	–	8	9	8	–	(33)	(10)	4,036	2,819	2,683
Asset retirement obligation accretion	22	21	–	–	–	–	–	–	–	107	90	71
Realized risk management activities	–	–	–	–	–	–	–	–	–	(96)	(1,253)	1,860
Total segmented expenses	1,657	932	–	30	28	33	(58)	(96)	(74)	9,277	5,861	9,001
Segmented earnings (loss) before the following	$ 902	$ 285	$ –	$ 49	$ 44	$ 44	$ (3)	$ 10	$ (33)	3,624	4,281	5,155
Non–segmented expenses												
Administration										210	181	180
Stock-based compensation expense (recovery)										294	355	(52)
Interest, net										449	410	128
Unrealized risk management activities										(25)	1,991	(3,090)
										(182)	(631)	718

Foreign exchange (gain) loss			
Total non–segmented expenses	746	2,306	(2,116)
Earnings before taxes	2,878	1,975	7,271
Taxes other than income tax	119	106	178
Current income tax expense	698	388	501
Future income tax expense (recovery)	364	(99)	1,607
Net earnings	$ 1,697	$ 1,580	$ 4,985

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Capital Expenditures

	2010			2009		
	Net expenditures	Non cash and fair value changes(1)	Capitalized costs	Net expenditures	Non cash and fair value changes(1)	Capitalized costs
Exploration and Production						
North America	$ 4,369	$ 386	$ 4,755	$1,663	$ 65	$ 1,728
North Sea	149	(41)	108	168	146	314
Offshore West Africa	246	(10)	236	544	111	655
Other	3	–	3	2	–	2
	4,767	335	5,102	2,377	322	2,699
Oil Sands Mining and Upgrading(2)	535	(59)	476	553	355	908
Midstream	7	–	7	6	–	6
Head office	18	–	18	13	–	13
	$ 5,327	$ 276	$ 5,603	$2,949	$ 677	$ 3,626

(1) Asset retirement obligations, future income tax adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest, stock-based compensation, and the impact of intersegment eliminations.

Segmented Assets

	2010	2009
Exploration and Production		
North America	$ 25,499	$ 22,994
North Sea	1,674	1,968
Offshore West Africa	1,186	2,033
Other	46	42
Oil Sands Mining and Upgrading	13,865	13,621
Midstream	338	306
Head office	61	60
	$ 42,669	$ 41,024

16. Subsequent Events

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

The Company believes that it has adequate insurance coverage to mitigate all significant property damage related losses. The Company also maintains business interruption coverage, subject to a waiting period, which it believes will mitigate operating losses related to on-going operations.

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17. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company's consolidated financial statements have been prepared in accordance with Canadian GAAP. These principles conform in all material respects with US GAAP except as noted below. Certain differences arising from US GAAP disclosure requirements are not addressed.

The application of US GAAP would have the following effects on consolidated net earnings (loss) as reported:

(millions of Canadian dollars, except per common share amounts)	Notes		2010		2009		2008
Net earnings – Canadian GAAP		$	1,697	$	1,580	$	4,985
Adjustments							
Depletion, net of taxes of $365 million (2009 – $7 million, 2008 – $2,503 million)	(A,B,C,D)		1,128		(273)		(6,169)
Stock-based compensation, net of taxes of $107 million (2009 – $51 million, 2008 – $32 million)	(B)		(41)		(154)		(76)
Future income taxes	(F)		–		–		234
Net earnings (loss) – US GAAP		$	2,784	$	1,153	$	(1,026)
Net earnings (loss) – US GAAP per common share (1)							
Basic		$	2.56	$	1.06	$	(0.95)
Diluted	(E)	$	2.54	$	1.06	$	(0.95)

(1) Restated to reflect two-for-one common share split in May 2010.

Comprehensive income (loss) under US GAAP would be as follows:

(millions of Canadian dollars)		2010		2009		2008
Comprehensive income – Canadian GAAP	$	1,634	$	1,214	$	5,175
US GAAP earnings adjustments		1,087		(427)		(6,011)
Comprehensive income (loss) – US GAAP	$	2,721	$	787	$	(836)

The application of US GAAP would have the following effects on the consolidated balance sheets as reported:

			2010				
(millions of Canadian dollars)	Notes		Canadian GAAP		Increase (Decrease)		US GAAP
Current assets		$	2,172	$	–	$	2,172
Property, plant and equipment	(A,B,C,D)		40,472		(7,324)		33,148
Other long-term assets	(G)		25		44		69
		$	42,669	$	(7,280)	$	35,389
Current liabilities	(B)	$	3,156	$	354	$	3,510
Long-term debt	(G)		8,499		44		8,543
Other long-term liabilities	(B)		2,130		9		2,139
Future income tax	(A,B,C,D)		7,899		(2,105)		5,794
Share capital			3,147		–		3,147

Retained earnings		18,005		(5,582)		12,423
Accumulated other comprehensive income		(167)		–		(167)
	$	42,669	$	(7,280)	$	35,389

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(millions of Canadian dollars)	Notes	2009 Canadian GAAP	2009 Increase (Decrease)	2009 US GAAP
Current assets		$ 1,891	$ 103	$ 1,994
Property, plant and equipment	(A,B,C,D)	39,115	(8,824)	30,291
Other long-term assets	(G)	18	49	67
		$ 41,024	$(8,672)	$ 32,352
Current liabilities	(B)	$ 2,405	$ 387	$ 2,792
Long-term debt	(G)	9,658	49	9,707
Other long-term liabilities	(B)	1,848	35	1,883
Future income tax	(A,B,C,D)	7,687	(2,474)	5,213
Share capital		2,834	–	2,834
Retained earnings		16,696	(6,669)	10,027
Accumulated other comprehensive income		(104)	–	(104)
		$ 41,024	$(8,672)	$ 32,352

Notes:

(A) Under Canadian full cost accounting guidance, costs capitalized in each country cost centre are limited to an amount equal to the future net revenues from proved plus probable reserves using estimated future prices and costs discounted at the risk-free rate, plus the carrying amount of unproved properties and major development projects (the "ceiling test") as described in note 1(I). Under the full cost method of accounting as set forth by the US Securities and Exchange Commission, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on prices using the average first-day-of-the-month price during the previous twelve-month period and costs as at the balance sheet date, and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. In addition, beginning in 2009, the Company's Oil Sands Mining and Upgrading activities would have been included in the Company's US GAAP full cost oil and gas cost centre for Canada for ceiling test purposes. These differences in applying the ceiling test to current and prior years would have resulted in the recognition of ceiling test impairments under US GAAP, which would have reduced property, plant and equipment by $8,396 million in 2010 (2009 – $8,951 million, 2008 – $8,697 million).

For the year ended December 31, 2010, US GAAP net earnings would have increased by $66 million (2009 – decreased by $815 million, 2008 – decreased by $6,164 million), net of income taxes of $24 million (2009 – $178 million, 2008 – $2,501 million) to reflect the impact of a current year ceiling test impairment. In addition, the impact of prior ceiling test impairments would have increased US GAAP net earnings by $359 million (2009 – $551 million, 2008 – $3 million), net of income taxes of $154 million (2009 – $188 million, 2008 – $1 million) to reflect the impact of lower depletion charges.

During 2009, the US Securities and Exchange Commission adopted revisions to its oil and gas reporting disclosures contained in Regulation S-K and Topic 932 "Extractive Activities – Oil and Gas" (a summary of the requirements included in Regulation S-X). These revisions impacted the reserves used in the Company's calculation of the ceiling test under US GAAP at December 31, 2009 and 2010 and the calculation of depletion in 2010. In addition, oil and gas activities were determined based on the end product, rather than the method of extraction. As a result, the Company's Oil Sands Mining and Upgrading operations were included in its full cost oil and gas cost center for Canada. These revisions were effective for filings made on or after January 1, 2010, and were applied prospectively with no retroactive restatement. For the year ended December 31, 2010, US GAAP net earnings would have increased by $708 million, net of income taxes of $237 million, to reflect the impact of lower depletion charges.

(B) The Company accounts for its stock-based compensation liability under Canadian GAAP using the intrinsic value method, as described in note 1(P). Under US GAAP, effective January 1, 2006, the Company would have adopted Financial Accounting Standards Board Statement (FASB) Topic 718 “Compensation – Stock Compensation” (previously FAS 123(R)), which requires companies to account for all stock-based compensation liabilities using the fair value method, where fair value is measured using an option pricing model. The Company uses the Black Scholes option pricing model to determine the fair value of its stock-based compensation liability for US GAAP purposes. The previous US GAAP standard, FAS 123, required companies to account for cash settled stock-based compensation liabilities using the intrinsic value method. For the year ended December 31, 2010, US GAAP net earnings would have increased by $66 million (2009 – decreased by $154 million, 2008 – decreased by $76 million), net of income taxes of $nil (2009 – $51 million, 2008 – $32 million) related to the different valuation methodologies. In addition, US GAAP net earnings would have decreased by $1 million (2009 – $1 million, 2008 – $nil), net of income taxes of $nil (2009 and 2008 – $nil) related to the impact of the change in capitalized stock-based compensation on depletion, depreciation and amortization expenses.

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Future income tax expense would have included a charge of $107 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.

(C)Under US GAAP, the foreign currency component of a business combination is not eligible for cash flow hedging. The impact of prior year adjustments would have decreased US GAAP net earnings by $3 million for the year ended December 31, 2010 (2009 – $7 million, 2008 – $8 million), net of income taxes of $2 million (2009 and 2008 – $3 million), to reflect the impact of higher depletion charges.

(D)Under Canadian GAAP, the Company began capitalizing interest on the Horizon Project when the Board of Directors approval was received in 2005. For US GAAP, capitalization of interest on projects constructed over time is mandatory and interest would have been capitalized to the costs of construction beginning in 2004. As a result of applying US GAAP, an additional $27 million would have been capitalized to property, plant and equipment in 2004. During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest ceased anddepletion, depreciation and amortization of these assets commenced. For the year ended December 31, 2010, US GAAP net earnings would have decreased by $1 million (2009 – $1 million, 2008 – $nil), net of income taxes of $nil (2009 and 2008 – $nil).

(E)Under Canadian GAAP, the Company is not required to include potential common shares related to stock options in the calculation of diluted earnings per share as the Company has recorded the potential settlement of the stock options as a liability. Under US GAAP Topic 260 “Earnings Per Share” (previously FAS 128 “Earnings Per Share”), the Company would have included potential common shares related to stock options in the calculation of diluted earnings per share. For the year ended December 31, 2010, 8 million additional shares would have been included in the calculation of diluted earnings per share for US GAAP (2009 and 2008 – nil additional shares).

(F)Under Canadian GAAP, the effects of income tax changes are recognized when the changes are considered substantively enacted. Under US GAAP, the income tax changes would not be recognized until the changes are enacted into law. For the year ended December 31, 2008, the differences between substantively enacted and enacted tax legislation resulted in a difference in timing of the recognition of a $234 million future income tax recovery.

(G)Under Canadian GAAP, debt issue costs on long-term debt must be included in the carrying value of the related debt. Under US GAAP, these items must be recorded as a deferred charge. Application of US GAAP would have resulted in the balance sheet reclassification of $44 million of debt issue costs from long-term debt to deferred charges in 2010 (2009 – $49 million, 2008 – $55 million).

(H)In December 2007, the FASB issued Topic 805 “Business Combinations” (previously FAS 141(R) “Business Combinations”), which replaced FAS 141 effective for fiscal years beginning after December 15, 2009. Topic 805 retains the purchase method of accounting and requires assets acquired and liabilities assumed in a business combination to be measured at fair value at the date of acquisition. The standard also requires acquisition-related costs and restructuring costs to be recognized separately from the business combination. This standard is to be applied prospectively to all business combinations subsequent to the effective date and does not require restatement of previously completed business combinations. The adoption of this standard did not result in a US GAAP reconciling item.

(I)Effective January 1, 2011 the Company will be preparing consolidated financial statements in accordance with IFRS and a reconciliation to US GAAP will not be required. As a result, SAB Topic 11M, “Disclosure of the Impact that Recently Issued Accounting Standards Will Have on the Financial Statements of the Registrant When Adopted in a Future Period” was not provided for 2010.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "int "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "se expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, and other guidance provided throughout this Management's Discussion and Analysis ("MD&A") including the information in the "Outlook" section and the sensitivity analysis constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands resumption of production and future expansion, Primrose, Pelican Lake, Olowi Field (Offshore Gabon), the Kirby Thermal Oil Sands Project, the Keystone Pipeline US Gulf Coast expansion, and the construction and operation of the North West Redwater bitumen refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year if necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and natural gas liquids ("NGLs") not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available. For additional information refer to the "Risks and Uncertainties" section of this MD&A.

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Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

Management's Discussion and Analysis includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, cash production costs and net asset value. These financial measures are not defined by generally accepted accounting principles in Canada ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with Canadian GAAP, in the "Financial Highlights" section of this MD&A. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2010. The Company's consolidated financial statements and this MD&A have been prepared in accordance with Canadian GAAP in effect as at and for the year ended December 31, 2010. Effective January 1, 2011, the Company will adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board. Unless otherwise stated, references to Canadian GAAP do not incorporate the impact of any changes to accounting standards that will be required due to changes required by IFRS. A reconciliation of Canadian GAAP to generally accepted accounting principles in the United States ("US GAAP") is included in note 17 to the consolidated financial statements. All dollar amounts are referenced in millions of Canadian dollars, except where otherwise noted. Common share data has been restated to reflect the two-for-one share split in May 2010. The calculation of barrels of oil equivalent ("BOE") is based on a conversion ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent the value equivalency at the wellhead. Production volumes and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of transportation and blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only. The following discussion and analysis refers primarily to the Company's 2010 financial results compared to 2009 and 2008, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2011. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2010, its Annual Information Form for the year ended December 31, 2010, and its audited consolidated financial statements for the year ended December 31, 2010 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 1, 2011.

ABBREVIATIONS

AECO	Alberta natural gas reference location
AIF	Annual Information Form
API	Specific gravity measured in degrees on the American Petroleum Institute scale
ARO	Asset retirement obligations
bbl	barrels
bbl/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
Bitumen	Solid or semi-solid with viscosity greater than 10,000 centipoise
Brent	Dated Brent

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C$	Canadian dollars
CAPEX	Capital expenditures
CBM	Coal Bed Methane
CICA	Canadian Institute of Chartered Accountants
CO2	Carbon dioxide
CO2e	Carbon dioxide equivalents
Canadian GAAP	Generally accepted accounting principles in Canada
CSS	Cyclic steam stimulation
EOR	Enhanced oil recovery
E&P	Exploration and Production
FPSO	Floating Production, Storage and Offloading Vessel
GHG	Greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Horizon	Horizon Oil Sands
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
Mbbl	thousand barrels
Mbbl/d	thousand barrels per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMcfe	millions of cubic feet equivalent
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
PRT	Petroleum Revenue Tax
SAGD	Steam-Assisted gravity drainage
SCO	Synthetic crude oil
SEC	United States Securities and Exchange Commission
Tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US GAAP	Generally accepted accounting principles in the United States
US$	United States dollars
WCS	Western Canadian Select
WCSB	Western Canadian Sedimentary Basin
WCS Heavy Differential	WCS Heavy Differential from WTI
WTI	West Texas Intermediate

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OBJECTIVES AND STRATEGY

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value (1) on a per common share basis through the development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

- § Balance among its products, namely natural gas, light and medium crude oil and NGLs, Pelican Lake heavy crude oil (2), primary heavy crude oil, bitumen (thermal oil) and SCO;
- § Balance among near-, mid- and long-term projects;
- § Balance among acquisitions, exploitation and exploration; and
- § Balance between sources and terms of debt financing and maintenance of a strong balance sheet.

(1) Discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt.

(2) Pelican Lake heavy crude oil is 14–17° API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates.

The Company's three-phase crude oil marketing strategy includes:

- § Blending various crude oil streams with diluents to create more attractive feedstock;
- § Supporting and participating in pipeline expansions and/or new additions; and
- § Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil.

Operational discipline and cost control are fundamental to the Company. By consistently controlling costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Cost control is attained by developing area knowledge, by dominating core areas and by maintaining high working interests and operator status in its properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete all of its growth projects. Additionally, the Company's risk management hedge program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt financing to selectively acquire properties generating future cash flows in its core regions.

Highlights for the year ended December 31, 2010 include the following:

- § Achieved net earnings of $1.7 billion, adjusted net earnings from operations of $2.6 billion, and cash flow from operations of $6.3 billion;
- § Achieved record yearly production of 632,191 BOE/d;
- § Achieved annual crude oil and natural gas production guidance;
- § Drilled a record 654 net primary heavy crude oil wells;
- § Received Board of Directors sanction and commenced construction of Phase 1 of the Kirby In Situ Oil Sands project;
- §

Acquired approximately $1.9 billion of crude oil and natural gas properties in the Company’s core regions in Western Canada;

- § Submitted a joint proposal to the Government of Alberta to construct and operate a bitumen upgrading and refining facility;
- § Reduced long-term debt by $1.2 billion to $8.5 billion in 2010 from $9.7 billion in 2009;
- § Completed the subdivision of the Company’s common shares on a two for one basis;
- § Purchased 2,000,000 common shares for a total cost of $68 million under a Normal Course Issuer Bid; and
- § Increased annual per share dividend payment to $0.30 from $0.21, our 10th consecutive year of dividend increases.

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NET EARNINGS AND CASH FLOW FROM OPERATIONS

Financial Highlights ($ millions, except per common share amounts)		2010		2009(1)		2008(1)
Revenue, before royalties	$	14,322	$	11,078	$	16,173
Net earnings	$	1,697	$	1,580	$	4,985
Per common share – basic and diluted	$	1.56	$	1.46	$	4.61
Adjusted net earnings from operations (2)	$	2,570	$	2,689	$	3,492
Per common share – basic and diluted	$	2.36	$	2.48	$	3.23
Cash flow from operations (3)	$	6,321	$	6,090	$	6,969
Per common share – basic and diluted	$	5.81	$	5.62	$	6.45
Dividends declared per common share	$	0.30	$	0.21	$	0.20
Total assets	$	42,669	$	41,024	$	42,650
Total long-term liabilities	$	18,528	$	19,193	$	20,856
Capital expenditures, net of dispositions	$	5,506	$	2,997	$	7,451

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

(2) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presented below lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(3) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presented below lists the effects of certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations ($ millions)		2010	2009		2008
Net earnings as reported	$	1,697$	1,580	$	4,985
Stock-based compensation expense (recovery), net of tax (a)(e)		294	261		(38)
Unrealized risk management (gain) loss, net of tax (b)		(16)	1,437		(2,112)
Unrealized foreign exchange (gain) loss, net of tax (c)		(160)	(570)		698
Gabon, Offshore West Africa ceiling test impairment (d)		672	–		–
Effect of statutory tax rate and other legislative changes on future income tax liabilities (e)		83	(19)		(41)
Adjusted net earnings from operations	$	2,570$	2,689	$	3,492

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.

(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

(c) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, offset by the impact of cross currency swap hedges, and are recognized in net earnings.

(d) Performance from the Olowi Field continues to be below expectations. As a result, the Company recognized a pre-tax ceiling test impairment charge of $726 million ($672 million after-tax) at December 31, 2010.

(e) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted or enacted. During 2010, the Canadian Federal Government enacted changes to the taxation of stock options surrendered by employees for cash payments. As a result of the changes, the Company anticipates that Canadian based employees will no longer surrender their options for cash payments, resulting in a loss of future income tax deductions for the Company. The impact of this change was an $83 million charge to future income tax expense. Income tax rate changes during 2009 resulted in a reduction of future income tax liabilities of approximately $19 million in North America. Income tax rate changes during 2008 resulted in a reduction of future income tax liabilities of approximately $19 million in North America and $22 million in Côte d'Ivoire, Offshore West Africa.

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Cash Flow from Operations ($ millions)	2010	2009	2008
Net earnings	$ 1,697	$ 1,580	$ 4,985
Non-cash items:			
Depletion, depreciation and amortization	4,036	2,819	2,683
Asset retirement obligation accretion	107	90	71
Stock-based compensation expense (recovery)	294	355	(52)
Unrealized risk management (gain) loss	(25)	1,991	(3,090)
Unrealized foreign exchange (gain) loss	(180)	(661)	832
Deferred petroleum revenue tax expense (recovery)	28	15	(67)
Future income tax expense (recovery)	364	(99)	1,607
Cash flow from operations	$ 6,321	$ 6,090	$ 6,969

For 2010, the Company reported net earnings of $1,697 million compared to net earnings of $1,580 million for 2009 (2008 – $4,985 million). Net earnings for the year ended December 31, 2010 included net unrealized after-tax expenses of $873 million related to the effects of stock-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of a ceiling test impairment charge at Gabon, Offshore West Africa and the impact of statutory tax rate and other legislative changes on future income tax liabilities (2009 – $1,109 million after-tax expenses; 2008 – $1,493 million after-tax income). Excluding these items, adjusted net earnings from operations for the year ended December 31, 2010 decreased to $2,570 million from $2,689 million for 2009 (2008 – $3,492 million).

The decrease in adjusted net earnings from the year ended December 31, 2009 was primarily due to:

§ lower realized risk management gains;

§ higher depletion, depreciation and amortization expense;

§ lower natural gas sales volumes and netbacks; and

§ the impact of the stronger Canadian dollar, partially offset by

§ the impact of higher crude oil and NGL sales volumes and netbacks.

The impacts of stock-based compensation, unrealized risk management activities and changes in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the year ended December 31, 2010 increased to $6,321 million ($5.81 per common share) from $6,090 million ($5.62 per common share) for 2009 (2008 – $6,969 million; $6.45 per common share). The increase in cash flow from operations from 2009 was primarily due to:

§ the impact of higher crude oil and NGL sales volumes and netbacks, partially offset by

§ lower realized risk management gains;

§ lower natural gas sales volumes and netbacks;

§ higher cash taxes; and

§ the impact of the stronger Canadian dollar.

For the Company’s Exploration and Production activities, the 2010 average sales price per bbl of crude oil and NGLs increased 14% to average $65.81 per bbl from $57.68 per bbl in 2009 (2008 – $82.41 per bbl), and the average natural gas price decreased 10% to average $4.08 per Mcf from $4.53 per Mcf for 2009 (2008 – $8.39 per Mcf). The Company’s average sales price of SCO increased 10% to average $77.89 per bbl from $70.83 per bbl in 2009 (2008 – nil).

Total production of crude oil and NGLs before royalties increased 20% to 424,985 bbl/d from 355,463 bbl/d for 2009 (2008 – 315,667 bbl/d). The increase in crude oil and NGLs production was primarily due to higher volumes from the Company’s bitumen (thermal oil) and Horizon operations.

Total natural gas production before royalties decreased 5% to average 1,243 MMcf/d from 1,315 MMcf/d for 2009 (2008 – 1,495 MMcf/d). The decrease in natural gas production primarily reflected natural production declines and the Company’s strategic reduction in natural gas drilling activity in North America, partially offset by new production volumes from the Septimus facility in Northeast British Columbia and from production volumes from natural gas properties acquired during the year.

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Total crude oil and NGLs and natural gas production volumes before royalties increased 10% to average 632,191 BOE/d from 574,730 BOE/d for 2009 (2008 – 564,845 BOE/d). Total production for 2010 was within the Company's previously issued guidance.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)

2010		Total	Dec 31	Sep 30	Jun 30	Mar 31(1)
Revenue, before royalties	$	14,322	$ 3,787	$ 3,341	$ 3,614	$ 3,580
Net earnings (loss)	$	1,697	$(416)	$ 580	$ 667	$ 866
Net earnings (loss) per common share						
– basic and diluted	$	1.56	$(0.38)	$ 0.53	$ 0.61	$ 0.80
2009		Total(1)	Dec 31(1)	Sep 30(1)	Jun 30(1)	Mar 31(1)
Revenue, before royalties	$	11,078	$ 3,319	$ 2,823	$ 2,750	$ 2,186
Net earnings	$	1,580	$ 455	$ 658	$ 162	$ 305
Net earnings per common share						
– basic and diluted	$	1.46	$ 0.42	$ 0.61	$ 0.15	$ 0.28

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

Volatility in quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

§ Crude oil pricing – The impact of fluctuating demand, inventory storage levels and geopolitical uncertainties on worldwide benchmark pricing, and the impact of the WCS Heavy Differential from WTI ("WCS Differential") in North America.

§ Natural gas pricing – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into the US.

§ Crude oil and NGLs sales volumes – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the commencement and ramp up of operations at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore West Africa.

§ Natural gas sales volumes – Fluctuations in production due to the Company's strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates and the impact of acquisitions.

§ Production expense – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America and the commencement of operations at Horizon and the Olowi Field in Offshore Gabon.

§ Depletion, depreciation and amortization – Fluctuations due to changes in sales volumes, proved reserves, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company’s proved undeveloped reserves, the impact of the commencement of operations at Horizon and the Olowi Field and the impact of ceiling test impairments at the Olowi Field.

§ Stock-based compensation – Fluctuations due to the mark-to-market movements of the Company’s stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company’s share price.

§ Risk management – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company’s risk management activities.

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§ Foreign exchange rates – Changes in the Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Fluctuations in unrealized foreign exchange gains and losses are recorded with respect to US dollar denominated debt and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swap hedges.

§ Income tax expense – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

(Yearly average)		2010		2009	2008
WTI benchmark price (US$/bbl)	$	79.55	$	61.93$	99.65
Dated Brent benchmark price (US$/bbl)	$	79.50	$	61.61$	96.99
WCS blend differential from WTI (US$/bbl)	$	14.26	$	9.64$	20.03
WCS blend differential from WTI (%)		18%		16%	20%
SCO price (US$/bbl)	$	78.56	$	61.51$	102.48
Condensate benchmark price (US$/bbl)	$	81.81	$	60.60$	100.10
NYMEX benchmark price (US$/MMBtu)	$	4.42	$	4.03$	8.95
AECO benchmark price (C$/GJ)	$	3.91	$	3.91$	7.71
US / Canadian dollar average exchange rate	$	0.9709	$	0.8760$	0.9381
US / Canadian dollar year end exchange rate	$	1.0054	$	0.9555$	0.8166

Commodity Prices

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized price is also highly sensitive to fluctuations in foreign exchange rates. The average value of the Canadian dollar in relation to the US dollar fluctuated significantly throughout 2010, with a high of approximately $1.01 in December 2010 and a low of approximately $0.93 in May 2010.

WTI pricing was reflective of the slow overall economic recovery in the United States and Europe, with offsetting strong Asian demand mitigating the decline. The relative weakness of the US dollar also contributed to higher WTI pricing. For 2010, WTI averaged US$79.55 per bbl, an increase of 28% compared to US$61.93 per bbl for 2009 (2008 – US$99.65 per bbl).

Brent averaged US$79.50 per bbl for 2010, an increase of 29% compared to US$61.61 per bbl for 2009 (2008 – US$96.99 per bbl). Crude oil sales contracts for the North Sea and Offshore West Africa are typically based on Brent pricing, which is more reflective of international markets and the overall supply and demand balance. Brent pricing was reflective of continued strong demand from Asian markets. The increase in Brent pricing relative to WTI was due to logistical constraints and high inventory levels of crude at Cushing during portions of 2010.

The WCS Differential averaged 18% of WTI for 2010 compared to 16% for 2009 (2008 – 20%). The widening WCS Differential was partially due to pipeline disruptions in the last half of 2010 that forced the temporary shutdown and apportionment of major oil pipelines to Midwest refineries in the United States.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events and the timing and extent of the continuing economic recovery. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery margins.

NYMEX natural gas prices averaged US$4.42 per MMBtu for 2010, an increase of 10% from US$4.03 per MMBtu for 2009 (2008 – US$8.95 per MMBtu). Alberta based AECO natural gas pricing for 2010 averaged $3.91 per GJ and was comparable to average prices in 2009 (2008 – $7.71 per GJ). Natural gas prices continue to be depressed due to strong US shale gas production limiting the upside to natural gas price recovery.

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Operating, Royalty and Capital Costs

Strong commodity prices in recent years have resulted in increased demand for oilfield services worldwide. This has led to inflationary operating and capital cost pressures throughout the crude oil and natural gas industry, particularly related to drilling activities and oil sands developments.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. The Federal Government will also be developing a comprehensive management system for air pollutants. In the province of Alberta, GHG regulations came into effect July 1, 2008, affecting facilities emitting more than 100 kilotonnes of CO2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in situ heavy crude oil facilities and the Hays sour natural gas plant, face compliance obligations under the regulations. In the province of British Columbia, carbon tax is currently being assessed at $20/tonne of CO2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $25/tonne on July 1, 2011, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that eight facilities in British Columbia will be included under the cap and trade system, based on a proposed requirement of 25 kilotonne CO2e annually. The province of Saskatchewan is expected to release GHG regulations in 2011 that would likely require the North Tangleflags in situ heavy oil facility to meet a reduction target for its GHG emissions. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2008) of the UK National Allocation Plan, the Company operated below its CO2 allocation. In Phase 2 (2009 – 2012) the Company's CO2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Legislation to regulate GHGs in the United States through a cap and trade system is pending. In the absence of legislation, the United States Environmental Protection Agency ("EPA") is intending to regulate GHGs under the Clean Air Act. This EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

Continued cost pressures and the final outcome of changes to environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects. For additional details, refer to the "Greenhouse Gas and Other Air Emissions" section of this MD&A.

The Alberta Government implemented changes to the Alberta Royalty Framework ("ARF") effective January 1, 2009. The ARF includes a number of changes to royalty rates for natural gas, crude oil, and oil sands production. Under the ARF, royalties payable vary according to commodity prices and the productivity of wells. Initial changes to the Alberta royalty regime under the ARF included the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout, depending on benchmark crude oil pricing.

During 2010, the Government of Alberta modified crude oil and natural gas royalty rates. These changes included:

§ Effective May 1, 2010, an extension of the period subject to the 5% maximum royalty rate for coalbed methane and shale gas wells to the first 36 months after start of production, subject to volume limits of 750 MMcfe for coalbed methane and no volume limits for shale gas.

§ Effective May 1, 2010, an extension of the period subject to the 5% maximum royalty rate for horizontal natural gas and crude oil wells. The period for horizontal natural gas wells has been extended to the first 18 months after start of production, and volumes of 500 MMcfe. Limits on production months and volumes for crude oil will be set according to the measured depth of the wells.

§ Effective January 1, 2011, a reduction in the maximum royalty rate to 5% on new natural gas and crude oil wells for the first 12 months after the start of production, subject to volume limits of 500 MMcfe and 50,000 BOE respectively.

§ Effective January 1, 2011, a reduction in the maximum royalty rate for crude oil from 50% to 40% and a reduction in the maximum royalty rate for conventional and unconventional natural gas from 50% to 36%.

Modifications were also made to the natural gas deep drilling program, including changes to depth requirements. The Government of Alberta also announced changes to the price components of oil and gas royalty formulas to reduce the royalty rate at prices higher than $85.00 per bbl and $5.25 per GJ respectively.

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ANALYSIS OF CHANGES IN REVENUE, BEFORE ROYALTIES AND RISK MANAGEMENT ACTIVITIES

		Changes due to				Changes due to			
($ millions)	2008	Volumes	Prices	Other	2009	Volumes	Prices	Other	2010
North America									
Crude oil and NGLs	$ 8,811	$ (424)	$(2 ,649)	$ –	$ 5,738	$ 938	$ 1,127	$ 2	$ 7,805
Natural Gas	4,685	(598)	(1,852)	–	2,235	(121)	(206)	–	1,908
	13,496	(1,022)	(4,501)	–	7,973	817	921	2	9,713
North Sea									
Crude oil and NGLs	1,753	(344)	(465)	–	944	(71)	171	(1)	1,043
Natural gas	16	–	1	–	17	–	(2)	–	15
	1,769	(344)	(464)	–	961	(71)	169	(1)	1,058
Offshore West Africa									
Crude oil and NGLs	895	413	(436)	–	872	(130)	104	–	846
Natural gas	49	18	(26)	–	41	(6)	3	–	38
	944	431	(462)	–	913	(136)	107	–	884
Subtotal									
Crude oil and NGLs	11,459	(355)	(3,550)	–	7,554	737	1,402	1	9,694
Natural gas	4,750	(580)	(1,877)	–	2,293	(127)	(205)	–	1,961
	16,209	(935)	(5,427)	–	9,847	610	1,197	1	11,655
Oil Sands Mining and Upgrading	–	1,253	–	–	1,253	1,175	221	–	2,649
Midstream	77	–	–	(5)	72	–	–	7	79
Intersegment eliminations and other (1)	(113)	–	–	19	(94)	–	–	33	(61)
Total	$ 16,173	$ 318	$ (5,427)	$ 14	$ 11,078	$ 1,785	$ 1,418	$ 41	$ 14,322

(1) Eliminates internal transportation, electricity charges, and natural gas sales.

Revenue increased 29% to $14,322 million for 2010 from $11,078 million for 2009 (2008 – $16,173 million). The increase was primarily due to an increase in realized crude oil and NGL prices and volumes, partially offset by a decrease in realized natural gas prices and volumes.

For 2010, 13% of the Company's crude oil and natural gas revenue was generated outside of North America (2009 – 17%; 2008 – 17%). North Sea accounted for 7% of crude oil and natural gas revenue for 2010 (2009 – 9%; 2008 – 11%), and Offshore West Africa accounted for 6% of crude oil and natural gas revenue for 2010 (2009 – 8%; 2008 – 6%).

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ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2010	2009	2008
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	270,562	234,523	243,826
North America – Oil Sands Mining and Upgrading	90,867	50,250	–
North Sea	33,292	37,761	45,274
Offshore West Africa	30,264	32,929	26,567
	424,985	355,463	315,667
Natural gas (MMcf/d)			
North America	1,217	1,287	1,472
North Sea	10	10	10
Offshore West Africa	16	18	13
	1,243	1,315	1,495
Total barrels of oil equivalent (BOE/d)	632,191	574,730	564,845
Product mix			
Light and medium crude oil and NGLs	18%	21%	22%
Pelican Lake heavy crude oil	6%	6%	6%
Primary heavy crude oil	15%	15%	16%
Bitumen (thermal oil)	14%	11%	12%
Synthetic crude oil	14%	9%	–
Natural gas	33%	38%	44%
Percentage of gross revenue (1)			
(excluding midstream revenue)			
Crude oil and NGLs	85%	78%	68%
Natural gas	15%	22%	32%

(1) Net of transportation and blending costs and excluding risk management activities.

ANALYSIS OF DAILY PRODUCTION, NET OF ROYALTIES

	2010	2009	2008
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	219,736	201,873	207,933
North America – Oil Sands Mining and Upgrading	87,763	48,833	–
North Sea	33,227	37,683	45,182
Offshore West Africa	28,288	29,922	22,641
	369,014	318,311	275,756
Natural gas (MMcf/d)			
North America	1,168	1,214	1,225
North Sea	10	10	10
Offshore West Africa	15	17	11
	1,193	1,241	1,246
Total barrels of oil equivalent (BOE/d)	567,743	525,103	483,541

The Company’s business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely natural gas, light and medium crude oil and NGLs, Pelican Lake heavy crude oil, primary heavy crude oil, bitumen (thermal oil), and SCO.

Total production averaged 632,191 BOE/d for 2010, a 10% increase from 574,730 BOE/d for 2009 (2008 – 564,845 BOE/d).

Total production of crude oil and NGLs before royalties increased 20% to 424,985 bbl/d for 2010 from 355,463 bbl/d for 2009 (2008 – 315,667 bbl/d). The increase in crude oil and NGLs production from 2009 was primarily due to higher volumes from the Company's bitumen (thermal oil) and Horizon operations. Crude oil and NGLs production for 2010 was within the Company's previously issued guidance of 423,000 to 430,000 bbl/d.

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Natural gas production continued to represent the Company's largest product offering, accounting for 33% of the Company's total production in 2010. Total natural gas production before royalties decreased 5% to 1,243 MMcf/d for 2010 from 1,315 MMcf/d for 2009 (2008 – 1,495 MMcf/d). The decrease in natural gas production from 2009 primarily reflected natural production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects, partially offset by new production volumes from the Septimus facility in Northeast British Columbia and natural gas producing properties acquired during the year. Natural gas production for 2010 was within the Company's previously issued guidance of 1,242 to 1,250 MMcf/d.

For 2011, annual production is forecasted to average between 385,000 and 427,000 bbl/d of crude oil and NGLs and between 1,177 and 1,246 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for 2010 increased 15% to average 270,562 bbl/d from 234,523 bbl/d for 2009 (2008 – 243,826 bbl/d). The increase in production from 2009 was primarily due to the cyclic nature of the Company's bitumen (thermal oil) production and the results of the impact of a record heavy oil drilling program.

North America natural gas production for 2010 decreased 5% to average 1,217 MMcf/d from 1,287 MMcf/d for 2009 (2008 –1,472 MMcf/d). The decrease in natural gas production from 2009 reflected production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects, partially offset by results of new production from the Septimus facility in Northeast British Columbia and natural gas producing properties acquired during the year.

North America – Oil Sands Mining and Upgrading

Horizon Phase 1 commenced production of synthetic crude oil during 2009. Production averaged 90,867 bbl/d for 2010, an increase of 81% from 50,250 bbl/d for 2009. The increase in production of synthetic crude oil from 2009 reflected the Company's focus on reliability improvements and ramping up of production.

North Sea

North Sea crude oil production for 2010 was 33,292 bbl/d, a decrease of 12% from 37,761 bbl/d for 2009 (2008 – 45,274 bbl/d). The decrease in production volumes from 2009 was due to natural field declines and timing of scheduled maintenance shut downs in 2010.

Offshore West Africa

Offshore West Africa crude oil production for 2010 decreased 8% to 30,264 bbl/d from 32,929 bbl/d for 2009 (2008 – 26,567 bbl/d), due to natural field declines.

Performance from the Olowi Field continues to be below expectations and, as a result, the Company recognized a pre-tax ceiling test impairment of $726 million ($672 million after-tax) at December 31, 2010.

CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized on crude oil volumes that were stored in various tanks, pipelines, or floating production, storage and offloading vessels as follows:

(bbl)	2010	2009	2008
North America – Exploration and Production	761,351	1,131,372	761,351
North America – Oil Sands Mining and Upgrading (SCO)	1,172,200	1,224,481	–

North Sea	264,995	713,112	558,904
Offshore West Africa	404,197	51,103	1,113,156
	2,602,743	3,120,068	2,433,411

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OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	2010	2009	2008
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	$ 65.81	$ 57.68	$ 82.41
Royalties	10.09	6.73	10.48
Production expense	14.16	15.92	16.26
Netback	$ 41.56	$ 35.03	$ 55.67
Natural gas ($/Mcf) (1)			
Sales price (2)	$ 4.08	$ 4.53	$ 8.39
Royalties (3)	0.20	0.32	1.46
Production expense	1.09	1.08	1.02
Netback	$ 2.79	$ 3.13	$ 5.91
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	$ 49.90	$ 44.87	$ 68.62
Royalties	6.72	4.72	9.78
Production expense	11.25	11.98	11.79
Netback	$ 31.93	$ 28.17	$ 47.05

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts

ANALYSIS OF PRODUCT PRICES – EXPLORATION AND PRODUCTION

	2010	2009	2008
Crude oil and NGLs ($/bbl) (1) (2)			
North America	$ 62.28	$ 54.70	$ 77.42
North Sea	$ 82.49	$ 68.84	$ 100.31
Offshore West Africa	$ 78.93	$ 65.27	$ 97.96
Company average	$ 65.81	$ 57.68	$ 82.41
Natural gas ($/Mcf) (1) (2)			
North America	$ 4.05	$ 4.51	$ 8.41
North Sea	$ 3.83	$ 4.66	$ 4.09
Offshore West Africa	$ 6.63	$ 6.11	$ 10.03
Company average	$ 4.08	$ 4.53	$ 8.39
Company average ($/BOE) (1) (2)	$ 49.90	$ 44.87	$ 68.62

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

Realized crude oil and NGLs prices increased 14% to average $65.81 per bbl for 2010 from $57.68 per bbl for 2009 (2008 – $82.41 per bbl). The increase in 2010 was primarily a result of higher WTI and Brent benchmark crude oil prices during the year, partially offset by the impact of a widening WCS Differential and the stronger Canadian dollar relative to the US dollar during 2010.

The Company’s realized natural gas price decreased 10% to average $4.08 per Mcf for 2010 from $4.53 per Mcf for 2009 (2008 – $8.39 per Mcf). The decrease in 2010 was primarily due to lower benchmark prices resulting from lower demand and high storage levels, strong incremental production from shale gas plays, the widening NYMEX and AECO differential and the impact of a stronger Canadian dollar relative to the US dollar.

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North America

North America realized crude oil prices increased 14% to average $62.28 per bbl for 2010 from $54.70 per bbl for 2009 (2008 – $77.42 per bbl). The increase in 2010 was primarily due to higher WTI benchmark pricing, partially offset by the impact of the widening WCS Differential and the stronger Canadian dollar relative to the US dollar.

The Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During 2010, the Company contributed approximately 165,000 bbl/d of heavy crude oil blends to the WCS stream. The Company has entered into a 20 year transportation agreement to commit to ship 120,000 bbl/d of heavy sour crude oil blend on the proposed 500,000 bbl/d Keystone Pipeline US Gulf Coast expansion from Hardisty, Alberta to the US Gulf Coast. Contemporaneously, the Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy sour crude oil to a major US refiner. Deliveries under the agreements are expected to commence in 2013 upon completion of the pipeline expansion and are subject to receipt of regulatory approval of the pipeline expansion.

Subsequent to December 31, 2010, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen refinery near Redwater, Alberta. In addition, the partnership has entered into an agreement to process bitumen supplied by the Government of Alberta under the Alberta Royalty Framework's Bitumen Royalty In Kind initiative. Project development is dependent upon completion of this detailed engineering and final project sanction by the respective parties.

North America realized natural gas prices decreased 10% to average $4.05 per Mcf for 2010 from $4.51 per Mcf for 2009 (2008 – $8.41 per Mcf), primarily related to lower benchmark prices due to lower demand and high storage levels, the widening NYMEX and AECO differential, strong incremental production from shale gas plays, the impact of natural gas physical sales contracts in 2009 and the impact of a stronger Canadian dollar relative to the US dollar.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Yearly average)		2010		2009		2008
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs (C$/bbl)	$	68.02	$	57.02	$	89.04
Pelican Lake heavy crude oil (C$/bbl)	$	61.69	$	55.52	$	76.91
Primary heavy crude oil (C$/bbl)	$	62.04	$	55.66	$	74.91
Bitumen (thermal oil) (C$/bbl)	$	59.55	$	51.18	$	71.89
Natural gas (C$/Mcf)	$	4.05	$	4.51	$	8.41

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation and blending costs and excluding risk management activities.

North Sea

North Sea realized crude oil prices increased 20% to average $82.49 per bbl for 2010 from $68.84 per bbl for 2009 (2008 – $100.31 per bbl). Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. The increase in realized crude oil prices in the North Sea from 2009 reflected increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 21% to average $78.93 per bbl for 2010 from $65.27 per bbl for 2009 (2008 – $97.96 per bbl). Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. The increase in realized crude oil prices in Offshore West Africa from 2009 reflected increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

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ROYALTIES – EXPLORATION AND PRODUCTION

		2010		2009		2008
Crude oil and NGLs ($/bbl) (1)						
North America	$	11.85	$	7.93	$	11.99
North Sea	$	0.16	$	0.14	$	0.21
Offshore West Africa	$	5.54	$	5.79	$	14.81
Company average	$	10.09	$	6.73	$	10.48
Natural gas ($/Mcf) (1)						
North America (2)	$	0.20	$	0.32	$	1.47
Offshore West Africa	$	0.53	$	0.53	$	1.52
Company average	$	0.20	$	0.32	$	1.46
Company average ($/BOE) (1)	$	6.72	$	4.72	$	9.78
Percentage of revenue (3)						
Crude oil and NGLs		15%		12%		13%
Natural gas (2)		5%		7%		17%
BOE		13%		11%		14%

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

(3) Net of transportation and blending costs and excluding risk management activities.

North America

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs ("net profit"). For 2008 and prior years, royalties were calculated as 1% of gross revenues until the Company's capital investments in the applicable project were fully recovered, at which time the royalty increased to 25% of net profit. Effective January 1, 2009, changes to the Alberta royalty regime under the ARF include the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout depending on benchmark crude oil pricing.

Crude oil and NGLs royalties for 2010 compared to 2009 reflected higher realized crude oil prices and averaged approximately 19% of gross revenues for 2010 compared to 14% for 2009 (2008 – 15%). North America crude oil and NGLs royalties per bbl are anticipated to average 16% to 20% of gross revenue for 2011.

Natural gas royalties averaged approximately 5% of gross revenues for 2010 compared to 7% for 2009 (2008 – 18%), primarily due to lower benchmark natural gas prices. North America natural gas royalties per Mcf are anticipated to average 4% to 6% of gross revenue for 2011.

North Sea

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining royalty is a gross overriding royalty on the Ninian Field.

Offshore West Africa

Under the terms of the Production Sharing Contracts (“PSCs”), royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of revenue averaged approximately 7% for 2010 compared to 9% for 2009 (2008 – 15%). Offshore West Africa royalty rates are anticipated to average 13% to 15% of gross revenue for 2011, as a result of the expected payout of the Baobab Field.

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PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

		2010		2009		2008
Crude oil and NGLs ($/bbl) (1)						
North America	$	12.14	$	14.63	$	14.96
North Sea	$	29.73	$	26.98	$	26.29
Offshore West Africa	$	14.64	$	12.83	$	10.29
Company average	$	14.16	$	15.92	$	16.26
Natural gas ($/Mcf) (1)						
North America	$	1.06	$	1.07	$	1.00
North Sea	$	2.91	$	2.16	$	2.51
Offshore West Africa	$	1.76	$	1.23	$	1.61
Company average	$	1.09	$	1.08	$	1.02
Company average ($/BOE) (1)	$	11.25	$	11.98	$	11.79

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and NGLs production expense for 2010 decreased 17% to $12.14 per bbl from $14.63 per bbl for 2009 (2008 – $14.96 per bbl). The decrease in production expense per bbl from 2009 was primarily a result of higher production volumes and lower cost of natural gas for fuel for the Company's bitumen (thermal oil) operations.

North America natural gas production expense for 2010 was $1.06 per Mcf, comparable to 2009 production expense at $1.07 per Mcf (2008 – $1.00 per Mcf), as lower service costs offset the effects of lower production volumes.

North Sea

North Sea crude oil production expense for 2010 increased 10% to $29.73 per bbl from $26.98 per bbl for 2009 (2008 - $26.29 per bbl). Production expense increased on a per barrel basis due to lower volumes on relatively fixed costs.

Offshore West Africa

Offshore West Africa crude oil production expense for 2010 increased 14% to $14.64 per bbl from $12.83 per bbl for 2009 (2008 - $10.29 per bbl). Production expense increased on a per barrel basis due to the timing of liftings for each field, including the impact of costs associated with the Olowi Field which has higher production expenses than the Espoir and Baobab fields.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts) (1)		2010		2009		2008
North America	$	2,336	$	2,060	$	2,236
North Sea		303		261		317
Offshore West Africa		1,023		335		132
Expense	$	3,662	$	2,656	$	2,685
$/BOE	$	18.49	$	13.82	$	12.97

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, Depreciation and Amortization (“DD&A”) expense for 2010 increased to $3,662 million from $2,656 million for 2009 (2008 – $2,685 million), primarily due to higher production in North America, an increase in the estimated future costs to develop the Company’s proved undeveloped reserves in the North Sea and the impact of a ceiling test impairment related to Gabon, Offshore West Africa at December 31, 2010.

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ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts) (1)		2010		2009		2008
North America	$	46	$	41	$	42
North Sea		33		24		27
Offshore West Africa		6		4		2
Expense	$	85	$	69	$	71
$/BOE	$	0.43	$	0.36	$	0.34

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Accretion expense for 2010 increased from 2009 primarily due to higher asset retirement obligations recognized in the North Sea in 2009.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

FINANCIAL METRICS

($/bbl) (1)		2010		2009		2008
SCO sales price (2)	$	77.89	$	70.83	$	–
Bitumen value for royalty purposes (3)	$	56.14	$	56.57	$	–
Bitumen royalties (4)	$	2.72	$	2.15	$	–

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation.

(3) Calculated as the simple average of the monthly bitumen valuation methodology price.

(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices increased 10% to average $77.89 per bbl for the year ended December 31, 2010 from $70.83 per bbl for the year ended December 31, 2009. The increase in SCO prices from 2009 was primarily due to the increase in the WTI benchmark price, offset by the impact of the strengthening Canadian dollar. There is an active market for SCO throughout North America.

PRODUCTION COSTS

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 15 to the Company’s consolidated financial statements.

($ millions)		2010		2009		2008
Cash costs, excluding natural gas costs	$	1,082	$	599	$	–
Natural gas costs		126		84		–
Total cash production costs	$	1,208	$	683	$	–

($/bbl) (1)	2010	2009	2008

Cash costs, excluding natural gas costs	$	32.58	$	34.97	$	–
Natural gas costs		3.78		4.92		–
Total cash production costs	$	36.36	$	39.89	$	–
Sales (bbl/d)		91,010		46,896		–

(1) Amounts expressed on a per unit basis are based on sales volumes.

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First sales from Horizon occurred in the second quarter of 2009.

Total cash production costs averaged $36.36 per bbl for 2010 compared to $39.89 per bbl for 2009. The decrease in cash production costs was primarily due to the Company's ongoing focus on planned maintenance, reliability improvements and the stabilization of production volumes at levels approaching plant capacity.

($ millions)		2010		2009		2008
Depreciation, depletion and amortization	$	366	$	187	$	–
Asset retirement obligation accretion		22		21		–
Total	$	388	$	208	$	–

($/bbl) (1)		2010		2009		2008
Depreciation, depletion and amortization	$	11.02	$	10.95	$	–
Asset retirement obligation accretion		0.67		1.22		–
Total	$	11.69	$	12.17	$	–

(1) Amounts expressed on a per unit basis are based on sales volumes.

During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs ceased, and depletion, depreciation and amortization of these assets commenced. Depletion, depreciation and amortization increased in 2010 compared to 2009 primarily due to higher sales volumes and the impact of certain assets depreciated on a straight-line basis.

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

MIDSTREAM

($ millions)		2010		2009		2008
Revenue	$	79	$	72	$	77
Production expense		22		19		25
Midstream cash flow		57		53		52
Depreciation		8		9		8
Segment earnings before taxes	$	49	$	44	$	44

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to control the transport of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts) (1)		2010		2009		2008
Expense	$	210	$	181	$	180
$/BOE	$	0.91	$	0.87	$	0.87

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for 2010 increased from 2009 due to higher staffing and general corporate costs.

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STOCK-BASED COMPENSATION

($ millions)		2010		2009		2008
Expense (recovery)	$	294	$	355	$	(52)

The Company's Stock Option Plan (the "Option Plan") was designed to provide current employees with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. As a result of enacted changes to Canadian income tax legislation in 2010 related to the cash surrender of options, the Company anticipates that Canadian based employees will now choose to exercise their options to receive newly issued common shares rather than surrender their options for cash payment.

The Company recorded a $294 million stock-based compensation expense during 2010 primarily as a result of normal course graded vesting of options granted in prior periods, the impact of vested options exercised or surrendered during the year, and the 17% increase in the Company's share price for the year ended December 31, 2010 (December 31, 2010 – $44.35; December 31, 2009 – $38.00; December 31, 2008 – $24.38; December 31, 2007 – $36.29). The Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. For the year ended December 31, 2010, the Company capitalized $24 million in stock-based compensation to Oil Sands Mining and Upgrading (2009 – $2 million capitalized; 2008 – $23 million recovery).

The stock-based compensation liability at December 31, 2010 reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price. In periods when substantial stock price changes occur, the Company's net earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

For the year ended December 31, 2010, the Company paid $45 million for stock options surrendered for cash settlement (2009 – $94 million; 2008 – $207 million).

INTEREST EXPENSE

($ millions, except per BOE amounts and interest rates) (1)		2010		2009		2008
Expense, gross	$	477	$	516	$	609
Less: capitalized interest, Oil Sands Mining and Upgrading		28		106		481
Expense, net	$	449	$	410	$	128
$/BOE	$	1.94	$	1.96	$	0.62
Average effective interest rate		5.0%		4.3%		5.1%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest expense for 2010 decreased from 2009 due to lower debt levels and the impact of a stronger Canadian dollar on US dollar denominated debt partially offset by the impact of higher variable interest rates. The Company's average effective interest rate increased from 2009 primarily due to an increased weighting of fixed versus floating rate debt and higher variable interest rates.

During 2009, interest capitalization ceased on Horizon Phase 1 as the Phase 1 assets were completed and available for their intended use, increasing net interest expense accordingly.

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RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

($ millions)		2010		2009		2008
Crude oil and NGLs financial instruments	$	84	$	(1,330)	$	2,020
Natural gas financial instruments		(234)		(33)		(21)
Foreign currency contracts and interest rate swaps		54		110		(139)
Realized (gain) loss	$	(96)	$	(1,253)	$	1,860
Crude oil and NGLs financial instruments	$	(108)	$	2,039	$	(3,104)
Natural gas financial instruments		71		(58)		16
Foreign currency contracts and interest rate swaps		12		10		(2)
Unrealized (gain) loss	$	(25)	$	1,991	$	(3,090)
Net (gain) loss	$	(121)	$	738	$	(1,230)

Complete details related to outstanding derivative financial instruments at December 31, 2010 are disclosed in note 12 to the Company's consolidated financial statements.

The cash settlement amount of commodity derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement, as compared to their mark-to-market value at December 31, 2010.

Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized gain of $25 million ($16 million after-tax) on its risk management activities for the year ended December 31, 2010 (2009 – $1,991 million unrealized loss, $1,437 million after-tax; 2008 – $3,090 million unrealized gain, $2,112 million after-tax).

FOREIGN EXCHANGE

($ millions)		2010		2009		2008
Net realized (gain) loss	$	(2)	$	30	$	(114)
Net unrealized (gain) loss (1)		(180)		(661)		832
Net (gain) loss	$	(182)	$	(631)	$	718

(1) Amounts are reported net of the hedging effect of cross currency swap hedges.

As a result of foreign currency translation, the Company's operating results are affected by the fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. The majority of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in decreased revenue from the sale of the Company's production. Conversely a decrease in the value of the Canadian dollar in relation to the US dollar results in increased revenue from the sale of the Company's production. Production expenses and future income tax liabilities in the North Sea are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The net unrealized foreign exchange gain in 2010 was primarily related to the strengthening Canadian dollar in relation to the US dollar with respect to the US dollar denominated debt, together with the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling. Included in the net unrealized gain for the year ended December 31, 2010 was an unrealized loss of $101 million (2009 – $338 million unrealized loss, 2008 – $449 million unrealized gain) related to the impact of cross currency swap hedges. The net realized foreign exchange gain for 2010 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the year at US$1.0054 compared to US$0.9555 at December 31, 2009 (December 31, 2008 – US$0.8166).

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TAXES

($ millions, except income tax rates)		2010		2009		2008
Current	$	91	$	91	$	245
Deferred		28		15		(67)
Taxes other than income tax	$	119	$	106	$	178
North America (1)	$	432	$	28	$	33
North Sea		203		278		340
Offshore West Africa		63		82		128
Current income tax		698		388		501
Future income tax		364		(99)		1,607
		1,062		289		2,108
Income tax rate and other legislative changes (2) (3) (4)		(83)		19		41
	$	979	$	308	$	2,149
Effective income tax rate before income tax rate and other legislative changes		28.1%		24.3%		27.8%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.

(2) During 2010, future income tax expense included a charge of $83 million related to enacted changes to the taxation of stock options surrendered by employees in Canada for cash.

(3) Includes the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions enacted during 2009.

(4) Includes the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions and $22 million due to Côte d'Ivoire corporate income tax rate reductions enacted during 2008.

Taxes other than income tax primarily includes current and deferred PRT, which is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including related capital and abandonment expenditures.

Taxable income from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities that may ultimately arise from these reassessments will be material.

For 2011, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $350 million to $450 million in Canada and $280 million to $320 million in the North Sea and Offshore West Africa.

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NET CAPITAL EXPENDITURES (1)

($ millions)	2010	2009	2008
Expenditures on property, plant and equipment			
Net property acquisitions	$ 1,904	$ 6	$ 336
Land acquisition and retention	141	77	86
Seismic evaluations	100	73	107
Well drilling, completion and equipping	1,500	1,244	1,664
Production and related facilities	1,122	977	1,282
Total net reserve replacement expenditures	4,767	2,377	3,475
Oil Sands Mining and Upgrading:			
Horizon Phase 1 construction costs	–	69	2,732
Horizon Phase 1 commissioning costs and other	–	202	364
Horizon Phases 2/3 construction costs	319	104	336
Capitalized interest, stock-based compensation and other	88	98	480
Sustaining capital	128	80	–
Total Oil Sands Mining and Upgrading (2)	535	553	3,912
Midstream	7	6	9
Abandonments (3)	179	48	38
Head office	18	13	17
Total net capital expenditures	$ 5,506	$ 2,997	$ 7,451
By segment			
North America	$ 4,369	$ 1,663	$ 2,344
North Sea	149	168	319
Offshore West Africa	246	544	811
Other	3	2	1
Oil Sands Mining and Upgrading	535	553	3,912
Midstream	7	6	9
Abandonments (3)	179	48	38
Head office	18	13	17
Total	$ 5,506	$ 2,997	$ 7,451

(1) Net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.

(3) Abandonments represent expenditures to settle ARO and have been reflected as capital expenditures in this table.

The Company's operating strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core regions where it can dominate the land base and infrastructure. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for 2010 were $5,506 million compared to $2,997 million for 2009 (2008 – $7,451 million). The increase in capital expenditures from the prior year was primarily due to the purchase of crude oil and natural gas producing properties and unproved land in the Company's core regions in Western Canada and the increase in the Company's abandonment program.

Drilling Activity (number of wells)

	2010	2009	2008
Net successful natural gas wells	92	109	269
Net successful crude oil wells	934	644	682
Dry wells	33	46	39
Stratigraphic test / service wells	491	329	131
Total	1,550	1,128	1,121
Success rate (excluding stratigraphic test / service wells)	97%	94%	96%

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North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 83% of the total capital expenditures for the year ended December 31, 2010 compared to approximately 58% for 2009 (2008 – 32%).

During 2010, the Company targeted 98 net natural gas wells, including 26 wells in Northeast British Columbia, 21 wells in the Northern Plains region, 46 wells in Northwest Alberta, and 5 wells in the Southern Plains region. The Company also targeted 953 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 654 primary heavy crude oil wells, 175 Pelican Lake heavy crude oil wells, 17 bitumen (thermal oil) wells and 15 light crude oil wells were drilled. Another 92 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in recent years, a low natural gas price, and as a result of royalty changes under the ARF, natural gas drilling activities have been reduced. Deferred natural gas well locations have been retained in the Company's prospect inventory.

As part of the phased expansion of its In situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. During 2010, the Company drilled 17 thermal oil wells, and 58 stratigraphic test wells and observation wells. Overall Primrose thermal production for 2010 was approximately 90,000 bbl/d (2009 – 64,000 bbl/d; 2008 – 65,000 bbl/d). The Primrose East Expansion was completed and first steaming commenced in September 2008, with first production achieved in the first quarter of 2009. During 2009, operational issues on one of the pads caused steaming to cease on all well pads in the Primrose East project area. The Company received approval from regulators to commence steaming on the next cycle in the third quarter of 2010.

The next planned phase of the Company's In Situ Oil Sands Assets expansion is the Kirby Project. Currently the Company is proceeding with the detailed engineering and design work. During the third quarter of 2010, the Company received final regulatory approval for Phase 1 of the Project. During the fourth quarter, the Company's Board of Directors sanctioned Kirby Phase 1. Construction commenced in the fourth quarter of 2010, with first steam targeted in 2013.

Development of new pads and tertiary recovery conversion projects at Pelican Lake continued as expected throughout 2010. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 38,000 bbl/d in 2010 (2009 – 37,000 bbl/d; 2008 – 37,000 bbl/d).

For 2011, the Company's overall drilling activity in North America is expected to comprise approximately 72 natural gas wells and 1,186 crude oil wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 spending during 2010 continued to be focused on construction of the third Ore Preparation Plant, additional product tankage, the butane treatment unit, the sulphur recovery unit, and hydro-transport.

On January 6, 2011, a fire occurred at the Company's primary upgrading coking plant. The fire was confined to one of the coke drums. Production capacity at Horizon has been suspended during the investigation and repair/rebuild to plant equipment damaged by the fire.

A preliminary assessment of the extent of damage and timelines to repair/rebuild indicate that the coke drums are serviceable. The procurement process for all necessary replacement components and parts for the damage caused by the fire has been initiated. Based on preliminary estimates, the first set of coke drums is targeted to resume production in the second quarter of 2011 with production rates of approximately 55,000 bbl/d. The second set of coke drums is currently targeted to be on production in the third quarter of 2011.

The Company believes that it has adequate insurance coverage to mitigate all significant property damage related losses. The Company also maintains business interruption coverage, subject to a waiting period, which it believes will mitigate operating losses related to on-going operations.

North Sea

During 2010, the Company drilled 0.9 net oil wells and 0.9 net injection wells at Ninian following commencement of drilling in the second quarter of the year. The Company also successfully completed planned maintenance shutdowns at all of its production facilities in the year.

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The Company plans to continue drilling at Ninian during 2011 and commence drilling at Murchison in the second quarter of 2011. The Company also continues to focus on developing and high grading its inventory of drilling locations for future execution.

Offshore West Africa
The Company drilled 7.1 wells during 2010. First crude oil was achieved on the Olowi Field on Platform B in the second quarter of the year, and on Platform A in the fourth quarter of the year. At Espoir, facilities upgrades were competed and incremental production volumes delivered during 2010.

Performance from the Olowi Field continues to be below expectations and, as a result, the Company recognized a pre-tax ceiling test impairment of $726 million ($672 million after-tax) at December 31, 2010.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		2010		2009		2008
Working capital (deficit) (1)	$	(984)	$	(514)	$	392
Long-term debt (2) (3)	$	8,499	$	9,658	$	13,016
Shareholders' equity						
Share capital	$	3,147	$	2,834	$	2,768
Retained earnings		18,005		16,696		15,344
Accumulated other comprehensive (loss) income		(167)		(104)		262
Total	$	20,985	$	19,426	$	18,374
Debt to book capitalization (3) (4)		29%		33%		41%
Debt to market capitalization (3) (5)		15%		19%		33%
After-tax return on average common shareholders' equity (6)		8%		8%		33%
After-tax return on average capital employed (3) (7)		7%		6%		19%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Includes the current portion of long-term debt (2010 – $nil; 2009 – $nil; 2008 – $420 million).

(3) Long-term debt at December 31, 2010, 2009 and 2008 is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.

(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.

(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.

(6) Calculated as net earnings for the year; as a percentage of average common shareholders' equity for the year.

(7) Calculated as net earnings plus after-tax interest expense for the year; as a percentage of average capital employed.

At December 31, 2010, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. The Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon these factors, as well as maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its on-going hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

The Company believes that its capital resources are sufficient to compensate for any short term cash flow reductions arising from Horizon, and accordingly, the Company's targeted capital program currently remains unchanged for 2011. At December 31, 2010, the Company had $2,444 million of available credit under its bank credit facilities. During 2010, the Company repaid $400 million of the medium term notes bearing interest at 5.50%. Long-term debt was $8,499 million at December 31, 2010, resulting in a debt to book capitalization ratio of 29% (December 31, 2009 – 33%; December 31, 2008 – 41%). This ratio is below the 35% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, and lower commodity prices occur. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet and flexible capital structure. Further details related to the Company's long-term debt at December 31, 2010 are discussed below and in note 5 to the Company's consolidated financial statements.

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During 2009, the Company filed new base shelf prospectuses that allowed for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this program, the purchase of put options is in addition to the above parameters. As at December 31, 2010, in accordance with the policy, approximately 11% of budgeted crude oil volumes were hedged using collars for 2011. Further details related to the Company's commodity related derivative financial instruments outstanding at December 31, 2010 are discussed in note 12 to the Company's consolidated financial statements.

Share Capital

The Company's shareholders passed a Special Resolution subdividing the common shares of the Company on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2010, with such subdivision taking effect in May 2010. All common share, per common share, and stock option amounts have been restated to reflect the share split.

As at December 31, 2010, there were 1,090,848,000 common shares outstanding and 66,844,000 stock options outstanding. As at March 1, 2011, the Company had 1,093,711,000 common shares outstanding and 63,029,000 stock options outstanding.

On March 1, 2011, the Company's Board of Directors approved an increase in the annual dividend declared by the Company to $0.36 per common share for 2011. The increase represents a 20% increase from the prior year, recognizing the stability of the Company's cash flow and providing a return to Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change. In March 2010, an increase in the annual dividend paid by the Company to $0.30 per common share was approved for 2010. The increase represented a 43% increase from 2009.

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), during the 12-month period commencing April 6, 2010 and ending April 5, 2011, up to 27,163,940 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. As at March 1, 2011, 2,000,000 common shares had been purchased for cancellation at an average price of $33.77 per common share, for a total cost of $68 million.

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COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. As at December 31, 2010, no entities were consolidated under CICA Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2010:

($ millions)	2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 228	$ 199	$ 172	$ 164	$ 152	$ 932
Offshore equipment operating lease	$ 141	$ 98	$ 97	$ 97	$ 81	$ 168
Offshore drilling	$ 7	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 18	$ 17	$ 19	$ 28	$ 27	$ 7,123
Long-term debt (2)	$ 398	$ 348	$ 798	$ 348	$ 400	$ 4,774
Interest expense (3)	$ 438	$ 400	$ 353	$ 333	$ 307	$ 4,236
Office leases	$ 27	$ 27	$ 28	$ 28	$ 32	$ 339
Other	$ 102	$ 66	$ 19	$ 16	$ 24	$ 10

(1) Amounts represent management's estimate of the future undiscounted payments to settle ARO related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2011 – 2015 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates as of December 31, 2010.

LEGAL PROCEEDINGS

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

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RESERVES

For the year ended December 31, 2010, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's proved, as well as proved plus probable crude oil, NGLs and natural gas reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

In previous years, the Company had been granted an exemption order from the securities regulators in Canada that allowed substitution of United States SEC requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2010 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

The following tables summarize the Company's gross proved and proved plus probable reserves as at December 31, 2010, prepared in accordance with NI 51-101 reserves disclosures:

Proved Reserves	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	501	116	251	732	1,871	3,902	46	4,167
Discoveries	-	1	-	-	-	69	2	15
Extensions	1	20	2	47	-	217	5	111
Infill Drilling	3	25	-	-	-	21	1	33
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	12	2	-	109	-	446	7	204
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	1(94)		(1)(16)	
Technical Revisions	-	30	(1)	64	93	153	6	218
Production	(35)	(34)	(14)	(33)	(33)(454)		(6)(231)	
December 31, 2010	482	160	239	919	1,932	4,262	63	4,505

Proved plus Probable Reserves	Light and Medium Crude Oil	Primary Heavy Crude Oil	Pelican Lake Heavy Crude	Bitumen (Thermal Oil)	Synthetic Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent

			Oil					
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2009	732	155	357	1,327	2,840	5,242	61	6,346
Discoveries	-	1	-	-	-	88	3	19
Extensions	1	28	4	108	-	315	7	200
Infill Drilling	6	35	1	-	-	35	1	49
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	16	3	-	272	-	556	8	391
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	(2)	(120)	(1)	(23)
Technical Revisions	(17)	29	(1)	28	83	104	7	147
Production	(35)	(34)	(14)	(33)	(33)	(454)	(6)	(231)
December 31, 2010	703	217	348	1,702	2,888	5,767	83	6,902

At December 31, 2010, the Company’s gross proved crude oil and NGLs reserves totaled 3,795 MMbbl, and gross proved plus probable crude oil and NGLs reserves totaled 5,941 MMbbl. Proved reserve additions and revisions replaced 279% of 2010 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 241 MMbbl, and additions to proved plus probable reserves amounted to 498 MMbbl. Net positive revisions amounted to 192 MMbbl for proved reserves and 126 MMbbl for proved plus probable reserves. The net gains were primarily due to technical revisions to prior estimates based on improved or better than expected reservoir performance.

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At December 31, 2010, the Company's gross proved natural gas reserves totaled 4,262 Bcf, and gross proved plus probable natural gas reserves totaled 5,767 Bcf. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 755 Bcf, and additions to proved plus probable reserves amounted to 996 Bcf. Net positive revisions for proved reserves amounted to 59 Bcf primarily due to technical revisions to prior estimates based on improved or better than expected reservoir performance partially offset by economic factors. Net negative revisions for proved plus probable reserves amounted to 16 Bcf primarily due to lower benchmark natural gas pricing.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and net present value of remaining reserves.

Information with respect to estimated benchmark future pricing is included in note 4 to the Company's consolidated financial statements. The crude oil, NGL and natural gas reference pricing and inflation and exchange rates used in the preparation of reserves are as per the Sproule price forecast dated December 31, 2010. Additional reserves disclosure is annually disclosed in the AIF and the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

RISKS AND UNCERTAINTIES

The Company is exposed to various operational risks inherent in exploring, developing, producing and marketing crude oil and natural gas and the mining and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following items:

— The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserve revisions due to economic and technical factors. Reserve revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
— Reservoir quality and uncertainty of reserve estimates;
— Prevailing prices of crude oil and NGLs, and natural gas;
— Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
— Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
— Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas;
— Success of exploration and development activities;
— Timing and success of integrating the business and operations of acquired companies;
— Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
— Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
— Foreign exchange risk due to fluctuating exchange rates on the Company's US dollar denominated debt and as the majority of sales are based in US dollars;
— Environmental impact risk associated with exploration and development activities, including GHG;
— Mechanical or equipment failure of facilities and infrastructure.
— Risk of catastrophic loss due to fire, explosion or acts of nature;
— Geopolitical risks associated with changing governmental policies, social instability and other political, economic or diplomatic developments in the Company's operations;
— Future legislative and regulatory developments related to environmental regulation;

— Potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdictions where the Company has operations;
— Changing royalty regimes;
— Business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting the Company or other parties whose operations or assets directly or indirectly affect the Company and that may or may not be financially recoverable; and
— Other circumstances affecting revenue and expenses.

The Company uses a variety of means to help mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk to an acceptable level. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity.

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Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. Substantially all of the Company's accounts receivables are due within normal trade terms. Derivative financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with substantially all investment grade financial institutions and other entities. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional detail regarding the Company's risks and uncertainties, refer to the Company's AIF.

ENVIRONMENT

The Company continues to invest in people, technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner.

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation, particularly in North America and the North Sea. Existing and expected legislation and regulations require the Company to address and mitigate the effect of its activities on the environment. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings and cash flow from operations.

The Company's associated environmental risk management strategies focus on working with legislators and regulators to ensure that any new or revised policies, legislation or regulations properly reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, released water quality, reduced fresh water use and the minimization of the impact on the landscape. Training and due diligence for operators and contractors are key to the effectiveness of the Company's environmental management programs and the prevention of incidents. The Company's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

The Company's Plan and operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements, regional management frameworks, industry operating standards and guidelines, and internal corporate standards. The Company, as part of this Plan, has implemented a proactive program that includes:

— An internal environmental compliance audit and inspection program of the Company's operating facilities;
— A suspended well inspection program to support future development or eventual abandonment;
— Appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment;
— An effective surface reclamation program;
— A due diligence program related to groundwater monitoring;
— An active program related to preventing and reclaiming spill sites;
— A solution gas conservation program;
— A program to replace the majority of fresh water for steaming with brackish water;
— Water programs to improve efficiency of use, recycle rates and water storage;

— Environmental planning for all projects to assess impacts and to implement avoidance and mitigation programs;
— Reporting for environmental liabilities;
— A program to optimize efficiencies at the Company's operated facilities;
— Continued evaluation of new technologies to reduce environmental impacts;
— Implementation of a tailings management plan; and
— CO2 reduction programs including the injection of CO2 into tailings and for use in enhanced oil recovery.

For 2010, the Company's capital expenditures included $179 million for abandonment expenditures (2009 – $48 million; 2008 – $38 million).

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The Company’s estimated undiscounted ARO at December 31, 2010 was as follows:

Estimated ARO, undiscounted ($ millions)		2010		2009
North America, Exploration and Production	$	4,125	$	3,346
North America, Oil Sands Mining and Upgrading		1,479		1,485
North Sea		1,396		1,522
Offshore West Africa		232		253
		7,232		6,606
North Sea PRT recovery		(423)		(568)
	$	6,809	$	6,038

The estimate of ARO was based on estimates of future costs to abandon and restore wells, production facilities and offshore production platforms. Factors that affect costs include number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs in accordance with present legislation and industry operating practice. The Company’s strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates. The future abandonment costs incurred in the North Sea are estimated to result in a PRT recovery of $423 million (2009 – $568 million), as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The expected PRT recovery reduces the Company’s net undiscounted abandonment liability to $6,809 million (2009 – $6,038 million).

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company, through the Canadian Association of Petroleum Producers (“CAPP”), is working with legislators and regulators as they develop and implement new GHG emission laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage technological innovation, energy efficiency, targeted research and development while not impacting competitiveness.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. The Federal Government will also be developing a comprehensive management system for air pollutants.

In the province of Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO2e annually. Two of the Company’s facilities, the Primrose/Wolf Lake in situ heavy crude oil facilities and the Hays sour natural gas plant face compliance obligations under the regulations. In the province of British Columbia, carbon tax is currently being assessed at $20/tonne of CO2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $25/tonne on July 1, 2011, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that eight facilities in British Columbia will be included under the cap and trade system, based on a proposed requirement of 25 kilotonne CO2e annually. The province of Saskatchewan is expected to release GHG regulations in 2011 that may likely require the North Tangleflags in situ heavy oil facility to meet a reduction target for its GHG emissions. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its CO2 allocation. In Phase 2 (2008 – 2012) the Company’s CO2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Legislation to regulate GHGs in the United States through a cap and trade system is pending. In the absence of legislation, the United States Environmental Protection Agency ("EPA") is intending to regulate GHGs under the Clean Air Act. This EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

There are a number of unresolved issues in relation to Canadian Federal and Provincial GHG regulatory requirements. Key among them is the form of regulation, an appropriate common facility emission level, availability and duration of compliance mechanisms, and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emission reduction initiatives including solution gas conservation, compressor optimization to improve fuel gas efficiency, CO2 capture and sequestration in oil sands tailings, CO2 capture and storage in association with enhanced oil recovery, and participation in an industry initiative to promote an integrated CO2 capture and storage network.

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The additional requirements of enacted or proposed GHG regulations on the Company's operations will increase capital expenditures and operating expenses, especially those related to the Horizon Project and the Company's other existing and planned large oil sands projects. This may have an adverse effect on the Company's net earnings and cash flow from operations.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through Company and industry participation with stakeholders, guidelines have been developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

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CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make judgments, assumptions and estimates in the application of Canadian GAAP that have a significant impact on the financial results of the Company. Actual results may differ from those estimates, and those differences may be material. Effective January 1, 2011, the Company will adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board. Unless otherwise stated, references to Canadian GAAP do not incorporate the impact of any changes to accounting standards that will be required due to changes required by IFRS. Critical accounting estimates are reviewed by the Company's Audit Committee annually. The Company believes the following are the most critical accounting estimates in preparing its consolidated financial statements.

Exploration and Production Property, Plant and Equipment / Depletion, Depreciation and Amortization

Under Canadian GAAP, the Company follows the full cost method of accounting for its Exploration and Production properties and equipment as prescribed by CICA Accounting Guideline 16 ("AcG 16"). Accordingly, all costs relating to the exploration for and development of crude oil and natural gas reserves, whether successful or not, are capitalized and accumulated in country-by-country cost centres. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of a gain or loss except where such dispositions result in a change in the depletion rate of the specific cost centre of 20% or more. Under Canadian GAAP, substantially all of the capitalized costs and estimated future capital costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country using estimated future prices and costs, rather than constant prices and costs as required by the SEC for US GAAP purposes.

Under Canadian GAAP, the carrying amount of crude oil and natural gas properties in each cost centre may not exceed their recoverable amount ("the ceiling test"). The recoverable amount is calculated as the undiscounted cash flow using proved reserves and estimated future prices and costs. If the carrying amount of a cost centre exceeds its recoverable amount, an impairment loss equal to the amount by which the carrying amount of the properties exceeds their estimated fair value is charged against net earnings. Fair value is calculated as the cash flow from those properties using proved plus probable reserves and estimated future prices and costs, discounted at a risk-free interest rate. At December 31, 2010, a pre-tax ceiling test impairment of $726 million (2009 – $115 million) was recognized under Canadian GAAP related to the Olowi Field in Offshore Gabon. As net revenues exceeded capitalized costs for all other cost centres, no other impairments were required under Canadian GAAP. Under US GAAP, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on prices and costs using the average first-day-of-the-month price during the previous 12-month period and costs as at the balance sheet date and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. These differences in applying the ceiling test in the current year would not have resulted in the recognition of any incremental after-tax ceiling test impairment (2009 –incremental ceiling test impairment of $815 million) under US GAAP.

The alternate acceptable method of accounting for Exploration and Production properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment. In addition, under this method, cost centres are defined based on reserve pools rather than by country. The use of the full cost method usually results in higher capitalized costs and increased DD&A rates compared to the successful efforts method.

Crude Oil and Natural Gas Reserves

The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserve estimates would result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates may also result in an impairment of crude oil and natural gas property, plant and equipment carrying amounts under the ceiling test.

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Asset Retirement Obligations

Under CICA Handbook Section 3110, “Asset Retirement Obligations”, the Company is required to recognize a liability for the future retirement obligations associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company’s total ARO amount. These individual assumptions can be subject to change.

The estimated fair values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. Retirement costs equal to the estimated fair value of the ARO are capitalized as part of the cost of associated capital assets and are amortized to expense through depletion over the life of the asset. The fair value of the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company’s average credit-adjusted risk-free interest rate, which is currently 6.6%. In subsequent periods, the ARO is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. The estimates described impact earnings by way of depletion on the retirement cost and accretion on the asset retirement liability. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted or enacted as of the consolidated balance sheet date. Accounting for income taxes is a complex process that requires management to interpret frequently changing laws and regulations (e.g. changing income tax rates) and make certain judgments with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. These interpretations and judgments impact the current and future income tax provisions, future income tax assets and liabilities, and net earnings.

Risk Management Activities

The Company utilizes various derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company has relied primarily on external readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

Purchase Price Allocations

The purchase prices of business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future DD&A expense and impairment tests.

The Company has made various assumptions in determining the fair values of the acquired assets and liabilities. The most significant assumptions and judgments relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates (a) crude oil and natural gas reserves, and (b) future prices of crude oil and natural gas. Reserve estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgments associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

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CONTROL ENVIRONMENT

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2010, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management also performed an assessment of internal control over financial reporting as at December 31, 2010, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2010 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises will be required to adopt IFRS as promulgated by the IASB in place of Canadian GAAP effective January 1, 2011.

The Company has established a formal IFRS project governance structure. The structure includes a Steering Committee, which consists of senior levels of management from finance and accounting, operations and information technology ("IT"). The Steering Committee provides regular updates to the Company's Management and the Audit Committee of the Board of Directors.

The Company's IFRS conversion project was broken down into the following phases:

§ Phase 1 Diagnostic – identification of potential accounting and reporting differences between Canadian GAAP and IFRS.

§ Phase 2 Planning – establishment of project governance, processes, resources, budget and timeline.

§ Phase 3 Policy Delivery and Documentation – establishment of accounting policies under IFRS.

§ Phase 4 Policy Implementation – establishment of processes for accounting and reporting, IT change requirements, and education.

§ Phase 5 Sustainment – ongoing compliance with IFRS after implementation.

The Company has substantially completed its IFRS conversion project. Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, capitalized interest, impairment testing, and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. A summary of the significant differences identified is included below. As certain IFRS standards may change during 2011, the Company may be required to adopt additional new and /or amended accounting standards in the preparation of its December 31, 2011 consolidated financial statements prepared in accordance with IFRS.

The Company has identified, developed and tested accounting and reporting systems and processes to capture data required for IFRS accounting and reporting, including 2010 requirements to capture both Canadian GAAP and IFRS data. IT system changes are complete and implemented.

Summary of Identified IFRS Accounting Policy Differences

Property, Plant & Equipment

Adoption of IFRS will significantly impact the Company's accounting policies for PP&E. For Canadian GAAP purposes, the Company followed the full cost method of accounting for its Exploration and Production properties and equipment as prescribed by AcG 16. Application of the full cost method of accounting is discussed in the "Critical Accounting Estimates" section of this MD&A. Significant differences in accounting for PP&E under IFRS include:

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§ Pre-exploration costs must be expensed. Under full cost accounting, these costs are currently included in the country cost centre.

§ Exploration and evaluation costs are initially capitalized as exploration and evaluation assets. In areas where the Company has existing operations, costs associated with reserves that are found to be technically feasible and commercially viable will be transferred to PP&E. If technically feasible and commercially viable reserves are not established in an area and if no further activity is planned in that area, the costs are expensed. Under full cost accounting, exploration and evaluation costs are currently disclosed as PP&E but withheld from depletion. Costs are transferred to the depletable assets when proved reserves are assigned or when it is determined that the costs are impaired.

§ PP&E for producing properties is depleted at an asset level. Under full cost accounting, PP&E is depleted on a country cost centre basis.

§ Interest directly attributable to the acquisition or construction of a qualifying asset must be capitalized to the cost of the asset. Under Canadian GAAP, capitalization of interest is not required.

§ Impairment of PP&E is tested at a cash generating unit level (the lowest level at which cash inflows can be separately identified). Under full cost accounting, impairment is tested at the country cost centre level.

IFRS 1 "First-time Adoption of International Financial Reporting Standards" issued by the IASB includes a transition exemption for oil and gas companies following full cost accounting under their previous GAAP. The transition exemption allows full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes to IFRS compliant units of account without requiring retroactive adjustment, subject to an initial impairment test. The Company has adopted this transition exemption. After initial adoption, future impairment charges may be reversed.

Asset Retirement Obligations

Canadian GAAP accounting requirements for asset retirement obligations ("ARO") are discussed in the "Critical Accounting Estimates" section of this MD&A. A significant difference in accounting for ARO under IFRS is that the liability must be re-measured at each balance sheet date using current discount rates, whereas under Canadian GAAP the discount rates do not change once the liability is recorded. On transition to IFRS, the increase in ARO liability on PP&E for which the full cost exemption above is applied must be recorded in retained earnings. For the change in ARO liability on other non-full cost PP&E, the increase is adjusted to PP&E in accordance with the general exemption for decommissioning liabilities included in IFRS 1. In future periods, the impact of changes in discount rates on the ARO liability for all PP&E is adjusted to PP&E.

Stock-based Compensation

Under Canadian GAAP, the Company's stock option plan liability is valued using the intrinsic value method, calculated as the amount by which the market price of the Company's shares exceeds the exercise price of the option for vested options. Under IFRS, the stock option plan liability must be measured using a fair value option pricing model such as the Black-Scholes model. The Company has utilized the exemption in IFRS 1 under which options that were settled prior to January 1, 2010 will not have to be retrospectively restated. On transition to IFRS, the increase in stock-based compensation liability must be recorded in retained earnings.

Petroleum Revenue Tax

Under Canadian GAAP, the liability for the UK PRT is estimated using proved plus probable reserves and future prices and costs, and apportioned to accounting periods over the life of the field on the basis of total estimated future operating income. Under IFRS, the PRT liability is estimated using the balance sheet method in accordance with IAS 12 “Income Taxes”, where the liability is based on temporary differences in balance sheet assets and liabilities versus their tax basis. On transition to IFRS, the increase in PRT liability must be recorded in retained earnings.

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Income Taxes

Both Canadian GAAP and IFRS follow the liability method of accounting for income taxes, where tax liabilities and assets are recognized on temporary differences. However, there are certain exceptions to the treatment of temporary differences under IFRS that result in an adjustment to the Company's future tax liability under IFRS. In addition, the Company's future tax liability will be impacted by the tax effects of any changes noted in the above areas. On transition to IFRS, the decrease in the net future income tax liability must be recorded in retained earnings.

Other IFRS 1 Exemptions

The Company has adopted the following IFRS 1 transition exemptions:

§ The Company has elected to reset the foreign currency translation adjustment to $nil by transferring the Canadian GAAP balance to retained earnings on January 1, 2010, rather than retrospectively restating the balance.

§ The Company has adopted the IFRS 1 election to not restate business combinations entered into prior to January 1, 2010.

IFRS Transitional Impacts

Giving effect to the above-noted transitional impacts, the Company estimates that on adoption of IFRS, total Shareholders' Equity as at January 1, 2010 decreased by less than 4% compared to the balance previously determined under Canadian GAAP, resulting in a marginal increase in the Company's reported debt to book capitalization to 34% from 33%. After the adoption of IFRS, the Company expects that 2010 net earnings decreased by an amount estimated to be between $100 million to $200 million, primarily due to higher depletion, depreciation and amortization, offset by lower UK PRT expense. Further, on adoption of IFRS, the Company does not anticipate any significant differences in cash flow from operations as would have been previously reported. Readers are cautioned that these estimates are subject to change, should underlying IFRS standards and/or the interpretations thereof be revised, prior to the final release of the Company's December 31, 2011 annual consolidated financial statements.

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OUTLOOK

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas. The Company expects production levels in 2011 to average between 385,000 bbl/d and 427,000 bbl/d of crude oil and NGLs and between 1,177 MMcf/d and 1,246 MMcf/d of natural gas.

Capital expenditures in 2011 are currently expected to be as follows:

($ millions)		2011 Guidance
Exploration and Production		
North America natural gas	$	600
North America crude oil and NGLs		1,895
North America bitumen (thermal oil)		
Primrose and future		830
Kirby Phase 1		515
Redwater Upgrading and Refining		340
North Sea		370
Offshore West Africa		135
Property acquisitions, dispositions and midstream		350
	$	5,035
Oils Sands Mining and Upgrading		
Sustaining and reclamation capital	$	220
Project capital		
Reliability – Tranche 2		370
Directive 74 and Technology		130
Phase 2A		200 – 230
Phase 2B		10 – 295
Phase 3		90 – 150
Phase 4		0 – 25
Total capital projects	$	800 – 1,200
Capitalized interest and other costs	$	100
	$	1,120 – 1,520
Total	$	6,155 – 6,555

The above capital expenditure budget incorporates the following levels of drilling activity:

(Number of wells)	2011 Guidance
Targeting natural gas	72
Targeting crude oil	1,190
Stratigraphic test / service wells – Exploration and Production	520
Stratigraphic test wells – Oil Sands Mining and Upgrading	280
Total	2,062

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North America Natural Gas

The 2011 North America natural gas drilling program is highlighted by the continued high-grading of the Company's natural gas asset base as follows:

(Number of wells)	2011 Guidance
Coal bed methane and shallow natural gas	4
Conventional natural gas	24
Cardium natural gas	4
Deep natural gas	39
Foothills natural gas	1
Total	72

North America Crude Oil and NGLs

The 2011 North America crude oil drilling program is highlighted by continued development of the Primrose thermal projects, Pelican Lake, and a strong primary heavy crude oil program, as follows:

(Number of wells)	2011 Guidance
Primary heavy crude oil	791
Bitumen (thermal oil)	217
Light and medium crude oil	138
Pelican Lake heavy crude oil	40
Total	1,186

Oil Sands Mining and Upgrading
Construction and commissioning of the third Ore Preparation Plant, along with the associated hydro-transport pipeline is on schedule for 2011. Engineering work as originally targeted for 2011 also continues on schedule. The Company is targeting additional cost estimate information for the Horizon expansion to be complete in the second quarter of 2011.

North Sea
During 2011, the majority of capital expenditures will be incurred to complete necessary sustaining capital activities on North Sea platforms.

Offshore West Africa
During 2011, the majority of capital expenditures will be incurred on drilling and completions.

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SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2010, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl (1)				
Excluding financial derivatives	$ 128	$ 0.12	$ 99	$ 0.09
Including financial derivatives	$ 128	$ 0.12	$ 99	$ 0.09
Natural gas – AECO C$0.10/Mcf (1)				
Excluding financial derivatives	$ 34	$ 0.03	$ 25	$ 0.02
Including financial derivatives	$ 38	$ 0.04	$ 29	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 175	$ 0.16	$ 104	$ 0.10
Natural gas – 10 MMcf/d	$ 9	$ 0.01	$ 1	$ –
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 101 – 103	$ 0.09	$ 40 – 41	$ 0.04
Interest rate change – 1%	$ 9	$ 0.01	$ 9	$ 0.01

(1) For details of financial instruments in place, refer to note 12 to the Company's consolidated financial statements as at December 31, 2010.

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DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2010	2009	2008
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	252,450	275,584	267,177	286,698	270,562	234,523	243,826
North America – Oil Sands Mining and Upgrading	86,995	99,950	83,809	92,730	90,867	50,250	–
North Sea	36,879	37,669	27,045	31,701	33,292	37,761	45,274
Offshore West Africa	29,942	29,842	33,554	27,706	30,264	32,929	26,567
Total	406,266	443,045	411,585	438,835	424,985	355,463	315,667
Natural gas (MMcf/d)							
North America	1,193	1,219	1,234	1,223	1,217	1,287	1,472
North Sea	15	9	8	9	10	10	10
Offshore West Africa	18	9	16	20	16	18	13
Total	1,226	1,237	1,258	1,252	1,243	1,315	1,495
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	451,269	478,770	472,850	490,470	473,447	449,054	489,081
North America – Oil Sands Mining and Upgrading	86,995	99,950	83,809	92,730	90,867	50,250	–
North Sea	39,352	39,175	28,321	33,186	34,973	39,444	46,956
Offshore West Africa	32,940	31,300	36,304	31,055	32,904	35,982	28,808
Total	610,556	649,195	621,284	647,441	632,191	574,730	564,845

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PER UNIT RESULTS – EXPLORATION AND PRODUCTION (1)

	Q1	Q2	Q3	Q4	2010	2009	2008
Crude oil and NGLs ($/bbl)							
Sales price (2)	$ 68.76	$ 63.62	$ 63.21	$ 67.74	$ 65.81	$ 57.68	$ 82.41
Royalties	10.08	8.95	9.05	12.14	10.09	6.73	10.48
Production expense	14.56	13.19	15.37	13.59	14.16	15.92	16.26
Netback	$ 44.12	$ 41.48	$ 38.79	$ 42.01	$ 41.56	$ 35.03	$ 55.67
Natural gas ($/Mcf)							
Sales price (2)	$ 5.19	$ 3.86	$ 3.75	$ 3.56	$ 4.08	$ 4.53	$ 8.39
Royalties (3)	0.41	0.25	0.11	0.07	0.20	0.32	1.46
Production expense	1.20	1.05	1.05	1.05	1.09	1.08	1.02
Netback	$ 3.58	$ 2.56	$ 2.59	$ 2.44	$ 2.79	$ 3.13	$ 5.91
Barrels of oil equivalent ($/BOE)							
Sales price (2)	$ 53.88	$ 47.97	$ 47.44	$ 50.41	$ 49.90	$ 44.87	$ 68.62
Royalties	7.07	6.10	5.83	7.83	6.72	4.72	9.78
Production expense	11.67	10.55	11.89	10.91	11.25	11.98	11.79
Netback	$ 35.14	$ 31.32	$ 29.72	$ 31.67	$ 31.93	$ 28.17	$ 47.05

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation and blending costs and excluding risk management activities.

(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING (1)

	Q1	Q2	Q3	Q4	2010	2009	2008
Crude oil and NGLs ($/bbl)							
SCO sales price (2)	$ 78.76	$ 75.97	$ 75.31	$ 81.51	$ 77.89	$ 70.83	$ –
Bitumen royalties (3)	2.83	2.69	2.57	2.77	2.72	2.15	–
Production expense	43.12	32.27	34.35	36.13	36.36	39.89	–
Netback	$ 32.81	$ 41.01	$ 38.39	$ 42.61	$ 38.81	$ 28.79	$ –

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation.

(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

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TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2010	2009(1)
TSX – C$						
Trading volume (thousands)					661,832	1,040,320
Share price ($/share)						
High	$ 38.70	$ 40.08	$ 37.35	$ 45.00	$ 45.00	$ 39.50
Low	$ 33.81	$ 33.09	$ 31.97	$ 35.80	$ 31.97	$ 17.93
Close	$ 37.59	$ 35.33	$ 35.59	$ 44.35	$ 44.35	$ 38.00
Market capitalization as at December 31 ($ millions)					$ 48,379	$ 41,217
Shares outstanding (thousands)					1,090,848	1,084,654
NYSE – US$						
Trading volume (thousands)					759,327	1,514,614
Share price ($/share)						
High	$ 37.33	$ 40.12	$ 36.47	$ 44.77	$ 44.77	$ 38.26
Low	$ 31.42	$ 30.51	$ 30.00	$ 34.64	$ 30.00	$ 13.85
Close	$ 37.02	$ 33.23	$ 34.60	$ 44.42	$ 44.42	$ 35.98
Market capitalization as at December 31($ millions)					$ 48,455	$ 39,020
Shares outstanding (thousands)					1,090,848	1,084,654

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

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ADDITIONAL DISCLOSURE

Certifications

The required disclosure is included in Exhibits 2, 3, 4 and 5 of the Annual Report on Form 40-F

Disclosure Controls and Procedures

As of the end of the registrant’s fiscal year ended December 31, 2010, an evaluation of the effectiveness of Canadian Natural’s “disclosure controls and procedures” (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”) was carried out by Canadian Natural’s management with the participation of Canadian Natural’s principal executive officer and principal financial officer. Based upon the evaluation, Canadian Natural’s principal executive officer and principal financial officer have concluded that as of the end of the fiscal year, Canadian Natural’s disclosure controls and procedures are effective to ensure that information required to be disclosed by the registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (ii) accumulated and communicated to the registrant’s management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

It should be noted that while Canadian Natural’s principal executive officer and principal financial officer believe that Canadian Natural’s disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect Canadian Natural’s disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Management’s Annual Report on Internal Control Over Financial Reporting

The required disclosure is included in the “Management’s Assessment of Internal Control Over Financial Reporting” that accompanies Canadian Natural’s audited consolidated financial statements for the fiscal year ended December 31, 2010, filed as part of this Annual Report on Form 40-F.

Attestation Report of the Registered Public Accounting Firm

The required disclosure is included in the “Independent Auditors’ Report” that accompanies Canadian Natural’s audited consolidated financial statements for the fiscal year ended December 31, 2010, filed as part of this Annual Report on Form 40-F.

Changes in Internal Control Over Financial Reporting

During the fiscal year ended December 31, 2010, there were no changes in Canadian Natural’s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, Canadian Natural’s internal control over financial reporting.

Notices Pursuant to Regulation BTR

None.

Audit Committee Financial Expert

The Board of Directors of Canadian Natural has determined that Ms. C.M. Best qualifies as an “audit committee financial expert” (as defined in paragraph 8(b) of General Instruction B to the Form 40-F) serving on its Audit Committee. Ms. C.M. Best is, as are all members of the Audit Committee of the Board of Directors of Canadian Natural, “independent” as such term is defined in the rules of the New York Stock Exchange.

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Code of Ethics

Canadian Natural has a long-standing Code of Integrity, Business Ethics and Conduct (the "Code of Ethics"), which covers such topics as employment standards, conflict of interest, the treatment of confidential information and trading in Canadian Natural's shares and is designed to ensure that Canadian Natural's business is consistently conducted in a legal and ethical manner. Each director and all employees, including each member of senior management and more specifically the principal executive officer, the principal financial officer and the principal accounting officer, are required to abide by the Code of Ethics. The Nominating and Corporate Governance Committee periodically reviews the Code of Ethics to ensure it addresses appropriate topics and complies with regulatory requirements and recommends any appropriate changes to the Board for approval.

Any waivers of or amendments to the Code of Ethics must be approved by the Board of Directors and will be appropriately disclosed. In the past fiscal year, there have not been any waivers, including implicit waivers, from any provisions of the Code of Ethics and there have been no substantive amendments.

The Code of Ethics is available through the System for Electronic Document and Analysis and Retrieval (SEDAR) at www.sedar.com. Requests for copies can also be made by contacting: Bruce E. McGrath, Corporate Secretary, Canadian Natural Resources Limited, 2500-855 2nd Street, S.W., Calgary, Alberta, Canada T2P 4J8.

Principal Accountant Fees and Services

PricewaterhouseCoopers LLP ("PwC") has been the auditor of Canadian Natural since Canadian Natural's inception. The aggregate amounts billed by PwC for each of the last two fiscal years for audit fees, audit-related fees, tax fees and all other fees, excluding expenses, are set forth below.

Audit Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural ending December 31, 2010 and December 31, 2009, for professional services rendered by PwC for the audit of its internal controls and annual consolidated financial statements in connection with statutory and regulatory filings or engagements for those fiscal years, unaudited reviews of the first, second and third quarters of its interim consolidated financial statements and audits of certain of Canadian Natural's subsidiary companies' annual financial statements and assistance related to Canadian Natural's conversion to International Financial Reporting Standards were $3,001,500 for 2010 and were $2,710,110 for 2009.

Audit-Related Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2010 and December 31, 2009, for audit-related services by PwC including debt covenant compliance and Crown Royalty Statements, were $169,000 for 2010 and were $154,302 for 2009. Canadian Natural's Audit Committee approved all of these audit-related services.

Tax Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2010 and December 31, 2009, for professional services rendered by PwC for tax services related to expatriate personal tax compliance, other corporate tax return matters and participation in a global taxation study were $149,000 for 2010 and were $131,653 for 2009. Canadian Natural's Audit Committee approved all of these tax-related services.

All Other Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2010 and December 31, 2009 for other services were $54,100 for 2010 and were $9,500 for 2009. The fees for other services paid in 2010 related to the design of crown royalty compliance program and accessing resource materials through PwC's accounting literature library. Canadian Natural's Audit Committee approved all of the noted services.

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Audit Committee Pre-Approval Policies and Procedures

The Audit Committee's duties and responsibilities include the review and approval of fees to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors. The Audit Committee also reviews and approves the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department prior to the commencement of the audit and reviews and approves proposed non-audit services to be provided by the independent auditors, except those non-audit services prohibited by legislation. Canadian Natural did not rely on the de minimis exemption provided by paragraph (c)(7)(i)(c) of Rule 2.01 of Regulation S-X in 2010.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. As at December 31, 2010, no entities were consolidated under CICA Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2010:

($ millions)	2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 228	$ 199	$ 172	$ 164	$ 152	$ 932
Offshore equipment operating lease	$ 141	$ 98	$ 97	$ 97	$ 81	$ 168
Offshore drilling	$ 7	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 18	$ 17	$ 19	$ 28	$ 27	$ 7,123
Long-term debt (2)	$ 398	$ 348	$ 798	$ 348	$ 400	$ 4,774
Interest expense (3)	$ 438	$ 400	$ 353	$ 333	$ 307	$ 4,236
Office leases	$ 27	$ 27	$ 28	$ 28	$ 32	$ 339
Other	$ 102	$ 66	$ 19	$ 16	$ 24	$ 10

(1) Amounts represent management's estimate of the future undiscounted payments to settle ARO related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2011 – 2015 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates as of December 31, 2010.

Identification of the Audit Committee

Canadian Natural has a separately designated standing audit committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The members of the Audit Committee are Messrs. T. W. Faithfull, G. A. Filmon, G. D. Giffin, D. A. Tuer and Ms. C.M. Best, who chairs the Audit Committee.

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UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

Undertaking

Canadian Natural undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

Consent to Service of Process

Canadian Natural has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the agent for service of process of Canadian Natural shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the relevant registration statement.

SIGNATURES

Pursuant to the requirements of the Exchange Act, Canadian Natural certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereto duly authorized.

Dated this 25th day of March, 2011.

CANADIAN NATURAL RESOURCES LIMITED

By: SIGNED “STEVE W. LAUT”
Name: Steve W. Laut
Title: President

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Documents filed as part of this report:

EXHIBIT INDEX

Exhibit No.	Description
1.	Supplementary Oil & Gas Information for the fiscal year ended December 31, 2010.
2.	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
3.	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
4.	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
5.	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
6.	Consent of PricewaterhouseCoopers LLP, independent chartered accountants.
7.	Consent of Sproule Associates Limited, independent petroleum engineering consultants.
8.	Consent of Sproule International Limited, independent petroleum engineering consultants.
9.	Consent of GLJ Petroleum Consultants Ltd., independent petroleum engineering consultants.

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QUICKLINKS

Exhibit No. Description

1. Supplementary Oil & Gas Information for the fiscal year ended December 31, 2010.

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