DEVON ENERGY CORP/DE
Form 8-K
August 04, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 8-K
CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
Date of Report (Date of earliest event reported): August 4, 2010
DEVON ENERGY CORPORATION
(Exact Name of Registrant as Specified in its Charter)

DELAWARE	**001-32318**	**73-1567067**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(IRS Employer Identification Number)

20 NORTH BROADWAY, OKLAHOMA CITY, OK	**73102**
(Address of Principal Executive Offices)	(Zip Code)

Registrant s telephone number, including area code: **(405) 235-3611**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Information Regarding Forward-Looking Estimates

This report includes forward-looking statements as defined by the Securities and Exchange Commission. Such statements are those concerning, without limitation, strategic plans, expectations and objectives for future operations, including associated revenue, cost and financial position projections. In addition, forward-looking statements exclude statements of historical facts and generally can be identified by the use of forward-looking terminology such as may, will, expect, intend, project, estimate, anticipate, believe, or continue or similar terminology.

Our forward-looking statements included in this report are subject to a number of assumptions, risks and uncertainties that are discussed below. Many of these assumptions, risks and uncertainties are beyond our control. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Investors are cautioned that any forward-looking statements are not guarantees of future performance and actual results or developments may differ materially from those projected in the forward-looking statements. The forward-looking statements in this report are made as of the date of this report. We assume no duty to revise our forward-looking statements based on changes in internal estimates, expectations or otherwise.

Definitions

This report includes references to various abbreviations relating to volumetric production terms and other defined terms. These abbreviations and terms are defined as follows:

Measurements of Oil, Natural Gas and Natural Gas Liquids

NGL or NGLs means natural gas liquids.

Oil includes crude oil and condensate.

Bbl means barrel of oil. One barrel equals 42 U.S. gallons.

MBbls means thousand barrels.

MMBbls means million barrels.

MBbls/d means thousand barrels per day.

Mcf means thousand cubic feet of natural gas.

MMcf means million cubic feet.

Bcf means billion cubic feet.

MMcf/d means million cubic feet per day.

Boe means barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.

MBoe means thousand Boe.

MMBoe means million Boe.

MBoe/d means thousand Boe per day.

Btu means British thermal units, a measure of heating value.

MMBtu means million Btu.

MMBtu/d means million Btu per day.

Geographic Areas

Canada means the operations of Devon encompassing oil and gas properties located in Canada.

International means the discontinued operations of Devon that encompass oil and gas properties that lie outside the United States and Canada.

2

North America Onshore means the operations of Devon encompassing oil and gas properties in the continental United States and Canada.

U.S. Offshore means the operations of Devon encompassing oil and gas properties in the Gulf of Mexico.

U.S. Onshore means the properties of Devon encompassing oil and gas properties in the continental United States.

Other

Federal Funds Rate means the interest rate at which depository institutions lend balances at the Federal Reserve to other depository institutions overnight.

Inside FERC refers to the publication Inside F.E.R.C. s Gas Market Report.

LIBOR means London Interbank Offered Rate.

NYMEX means New York Mercantile Exchange.

SEC means United States Securities and Exchange Commission.

Item 8.01. Other Events

Our original 2010 forward-looking estimates are included in our 2009 Annual Report on Form 10-K. These estimates were based on our examination of historical operating trends, the information used to prepare our December 31, 2009 reserve reports and other data in our possession or available from third parties.

In November of 2009, we announced plans to strategically reposition Devon by divesting our U.S. Offshore and International assets. As a result of these divestitures, all revenues, expenses and capital related to our International operations are reported as discontinued operations in our financial statements. Accordingly, all forward-looking estimates in this document exclude amounts related to our International operations, unless otherwise noted. The operations related to our U.S. Offshore assets remain in our continuing operations.

Our original 2010 forward-looking estimates assumed all divestitures would close at the end of 2010. During the first half of 2010, we completed our exit from the Gulf of Mexico and divested our Panyu operations in China. We have also entered into agreements to sell our oil and gas properties in Azerbaijan and Brazil and our exploratory assets in China. As a result of these completed and announced divestitures, we are providing the 2010 U.S. Offshore actual results through the various divestiture dates and updating our 2010 estimates related to our International operations. The International estimates presented in this report assume the Azerbaijan transaction closes during the third quarter of 2010, the Brazil transaction closes at the end of the fourth quarter of 2010 and the China exploratory asset divestiture closes in the third quarter of 2010.

Furthermore, based on our examination of historical operating trends during the first half of 2010 and other data in our possession or available from third parties, we are also updating certain of our North America Onshore 2010 estimates.

This report includes all our 2010 forward-looking estimates, including both unchanged and updated estimates. Also, a summary of our forward-looking estimates is included at the end of this report.

General Assumptions and Risks Related to Our Estimates

We caution that our future oil, gas and NGL production, revenues and expenses are subject to all of the risks and uncertainties normally associated with exploring for, developing, producing and selling oil, gas and NGLs. These risks include, but are not limited to, price volatility, inflation or lack of availability of goods and services, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks discussed below.

Additionally, we caution that our future marketing and midstream revenues and expenses are subject to all of the risks and uncertainties normally associated with transporting oil, gas and NGLs and processing natural gas. These risks include, but are not limited to, price volatility, environmental risks, regulatory changes, the uncertainty inherent in estimating future processing volumes and pipeline throughput, cost of goods and services and other risks discussed below.

Also, the financial results of our foreign operations are subject to currency exchange rate risks. Unless otherwise noted, all of the following dollar amounts are expressed in U.S. dollars. Financial amounts related to our Canadian operations have been converted to U.S. dollars using an estimated average 2010 exchange rate of $0.97 dollar to $1.00 Canadian dollar. The actual 2010 exchange rate may vary materially from this estimate. Such variations could have a material effect on these forward-looking estimates.

Other specific risks associated with our price and production estimates are provided immediately below. Additional risks are discussed throughout this report in the context of line items most affected by such risks.

Specific Assumptions and Risks Related to Price and Production Estimates

Prices for oil, gas and NGLs are determined primarily by prevailing market conditions. Market conditions for these products are influenced by regional and worldwide economic conditions, weather and other local market conditions. These factors are beyond our control and are difficult to predict. In addition, volatility in general oil, gas and NGL prices may vary considerably due to differences between regional markets, differing quality of oil produced (i.e., sweet crude versus heavy or sour crude), differing Btu content of gas produced, transportation availability and costs and demand for the various products derived from oil, gas and NGLs. Substantially all of our revenues are attributable to sales, processing and transportation of these three commodities. Consequently, our financial results and resources are highly influenced by price volatility. We expect this volatility to continue throughout 2010.

Estimates for future production of oil, gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable discovery and production of these products. There can be no assurance of such stability. Most of our Canadian production of oil, gas and NGLs is subject to government royalties that fluctuate with prices. Thus, price fluctuations can affect reported production. Also, our production of oil related to our discontinued operations in Azerbaijan is governed by a payout agreement with the government. If the payout under this agreement is attained earlier than projected, our net production and proved reserves could be reduced.

Estimates for future processing and transport of oil, gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable processing and transport of these products. There can be no assurance of such stability.

The production, transportation, processing and marketing of oil, gas and NGLs are complex processes that are subject to disruption. These disruptions result from transportation and processing availability, mechanical failure, human error, hurricanes and other meteorological events, and numerous other factors. The 2010 forward-looking estimates in this report were prepared assuming demand, curtailment, producibility and general market conditions for our oil, gas and NGLs during 2010 will be substantially similar to 2009, unless otherwise noted.

North America Onshore Operating Items

The following 2010 estimates relate only to our North America Onshore assets that we are retaining subsequent to our offshore asset divestitures. Actual 2010 amounts related to our U.S. Offshore operations and 2010 estimates related to our discontinued International operations are provided following this section of estimates pertaining to our North America Onshore assets.

Oil, Gas and NGL Production

Set forth below are our estimates of oil, gas and NGL production for 2010. We estimate that our combined oil, gas and NGL production will total approximately 223 to 224 MMBoe.

	Oil (MMBbls)	Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe)
U.S. Onshore	14	704	28	159
Canada	26	213	3	65
North America Onshore	40	917	31	224

Oil and Gas Prices

We expect our 2010 average prices for the oil and gas production from each of our operating areas to differ from the NYMEX price as set forth in the following table. The expected ranges for prices are exclusive of the anticipated effects of the financial contracts presented in the Commodity Price Risk Management section below.

The NYMEX price for oil is determined using the monthly average of settled prices on each trading day for benchmark West Texas Intermediate crude oil delivered at Cushing, Oklahoma. The NYMEX price for gas is determined using the first-of-month South Louisiana Henry Hub price index as published monthly in *Inside FERC*.

	Expected Range of Prices as a % of NYMEX Price	
	Oil	Gas
U.S. Onshore	92% to 98%	79% to 85%
Canada	66% to 74%	85% to 93%
North America Onshore	74% to 82%	81% to 88%

Commodity Price Risk Management

From time to time, we enter into NYMEX related financial commodity collar and price swap contracts. Such contracts are used to manage the inherent uncertainty of future revenues due to oil and gas price volatility. Although these financial contracts do not relate to specific production from our operating areas, they will affect our overall revenues, earnings and cash flow in 2010.

As of August 2, 2010, our financial commodity contracts pertaining to 2010 consisted of oil and gas price collars, gas price swaps and gas basis swaps. The key terms of these contracts are presented in the following tables.

	Gas Price Swaps	
Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Quarter 1	1,265,000	$ 6.16
Quarter 2	1,471,044	$ 5.88
Quarter 3	1,265,000	$ 6.16
Quarter 4	1,265,000	$ 6.16
Total Year	1,316,370	$ 6.08

		Gas Price Collars			
		Floor Price		Ceiling Price	
Period	Volume (MMBtu/d)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)
Quarter 1	70,000	$ 4.10 - $5.40	$ 5.40	$ 4.35 - $6.30	$ 6.06
Quarter 2	132,912	$ 4.10 - $5.50	$ 5.10	$ 4.35 - $7.10	$ 6.24
Quarter 3	230,326	$ 4.50 - $5.50	$ 4.98	$ 5.40 - $7.10	$ 6.25
Quarter 4	355,000	$ 4.50 - $5.50	$ 4.85	$ 5.40 - $7.10	$ 6.12
Total Year	144,452	$ 4.10 - $5.50	$ 4.98	$ 4.35 - $7.10	$ 6.17

		Gas Basis Swaps	
Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Total Year	AECO	150,000	$ 0.33
Total Year	CIG	70,000	$ 0.37

		Oil Price Collars			
		Floor Price		Ceiling Price	
Period	Volume (Bbls/d)	Floor Range ($/Bbl)	Weighted Average Price ($/Bbl)	Ceiling Range ($/Bbl)	Weighted Average Price ($/Bbl)
Total Year	79,000	$ 65.00 - $70.00	$ 67.47	$ 90.35 - $103.30	$ 96.48

To the extent that monthly NYMEX prices in 2010 are outside of the ranges established by the collars or differ from those established by the swaps, we and the counterparties to the contracts will cash-settle the difference. Such settlements will either increase or decrease our revenues for the period. Also, we will mark-to-market the contracts based on their fair values throughout 2010. Changes in the contracts fair values will also be recorded as increases or decreases to our revenues. The expected ranges of our realized prices as a percentage of NYMEX prices, which are presented earlier in this report, do not include any estimates of the impact on our prices from monthly settlements or changes in the fair values of our price collars and swaps.

Marketing and Midstream Revenues and Expenses

Marketing and midstream revenues and expenses are derived primarily from our gas processing plants and gas pipeline systems. These revenues and expenses vary in response to several factors. The factors include, but are not limited to, changes in production from wells connected to the pipelines and related processing plants, changes in the absolute and relative prices of gas and NGLs, provisions of contractual agreements and the amount of repair and maintenance activity required to maintain anticipated processing levels and pipeline throughput volumes.

These factors increase the uncertainty inherent in estimating future marketing and midstream revenues and expenses. Given these uncertainties, we estimate that our 2010 marketing and midstream operating profit will be between $450 million and $525 million. We estimate that marketing and midstream revenues will be between $1.850 billion and $2.125 billion, and marketing and midstream expenses will be between $1.400 billion and $1.600 billion.

Production and Operating Expenses

These expenses, which include transportation costs, vary in response to several factors. Among the most significant of these factors are additions to or deletions from the property base, changes in the general price level of services and materials that are used in the operation of the properties, the amount of repair and workover activity required. Oil, gas and NGL prices also have an effect on lease operating expenses and impact the economic feasibility of planned workover projects.

Given these uncertainties, we expect that our 2010 lease operating expenses will be between $1.58 billion and $1.72 billion.

Taxes Other Than Income Taxes

Our taxes other than income taxes primarily consist of production taxes and ad valorem taxes that relate to our U.S. Onshore properties and are assessed by various government agencies. Production taxes are based on a percentage of production revenues that varies by property and government jurisdiction. Ad valorem taxes generally are based on property values as determined by the government agency assessing the tax. Over time, a certain property s assessed value will increase or decrease due to changes in commodity sales prices, production volumes and proved reserves. Therefore, ad valorem taxes will generally move in the same direction as our oil, gas and NGL sales but in a less predictable manner compared to production taxes. Additionally, both production and ad valorem taxes will increase or decrease due to changes in the rates assessed by the government agencies.

Given these uncertainties, we estimate that our taxes other than income taxes for 2010 will be between 5.00% and 6.00% of total oil, gas and NGL sales.

Depreciation, Depletion and Amortization (DD&A)

Our 2010 oil and gas property DD&A rate will depend on various factors. Most notable among such factors are the amount of proved reserves that will be added from drilling or acquisition efforts in 2010 compared to the costs incurred for such efforts, revisions to our year-end 2009 reserve estimates that, based on prior experience, are likely to be made during 2010, as well as potential carrying value reductions that result from full cost ceiling tests.

Given these uncertainties, we estimate that our oil and gas property related DD&A rate will be between $7.00 per Boe and $7.50 per Boe. Based on these DD&A rates and the production estimates set forth earlier, oil and gas property related DD&A expense for 2010 is expected to be between $1.57 billion and $1.68 billion.

Additionally, we expect that our depreciation and amortization expense related to non-oil and gas fixed assets will total between $240 million and $260 million in 2010.

Accretion of Asset Retirement Obligation

Accretion of asset retirement obligation in 2010 is expected to be between $80 million and $90 million.

General and Administrative Expenses (G&A)

Our G&A includes employee compensation and benefits costs and the costs of many different goods and services used in support of our business. G&A varies with the level of our operating activities and the related staffing and professional services requirements. In addition, employee compensation and benefits costs vary due to various market factors that affect the level and type of compensation and benefits offered to employees. Also, goods and services are subject to general price level increases or decreases. Therefore, significant variances in any of these factors from current expectations could cause actual G&A to vary materially from the estimate.

Given these limitations, we estimate our G&A for 2010 will be between $580 million and $600 million. This estimate includes approximately $105 million of non-cash, share-based compensation, net of related capitalization in accordance with the full cost method of accounting for oil and gas properties.

Reduction of Carrying Value of Oil and Gas Properties

Due to the volatile nature of oil and gas prices, it is not possible to predict whether we will incur full cost writedowns in 2010.

Interest Expense

Future interest rates and debt outstanding have a significant effect on our interest expense. We can only marginally influence the prices we will receive in 2010 from sales of oil, gas and NGLs and the resulting cash flow. This increases the margin of error inherent in estimating future outstanding debt balances and related interest expense. Other factors that affect outstanding debt balances and related interest expense, such as the amount and timing of capital expenditures are generally within our control.

As of June 30, 2010, we had total debt of $5.6 billion, which is exclusively fixed-rate debt at an overall weighted average rate of 7.2%. We don t anticipate any significant changes to our debt levels for the remainder of 2010.

Based on the factors above, we expect our 2010 interest expense to be between $350 million and $370 million. The estimated interest expense is exclusive of the anticipated effects of the interest rate swap contracts presented in the Interest Rate Risk Management section below.

The 2010 interest expense estimate above is comprised of four primary components interest related to outstanding debt, fees and issuance costs, capitalized interest and $19 million related to the early retirement of $350 million of 7.25% senior notes in June 2010. We expect interest expense in 2010 related to our outstanding debt, including net accretion of related discounts and the $19 million related to the 7.25% senior notes, to be between $415 million and $435 million. We expect interest expense in 2010 related to facility and agency fees, amortization of debt issuance costs and other miscellaneous items not related to outstanding debt balances to be between $5 million and $15 million. We also expect to capitalize between $70 million and $80 million of interest during 2010.

Interest Rate Risk Management

From time to time, we enter into interest rate swaps. Such contracts are used to manage our exposure to interest rate volatility.

As of June 30, 2010, our interest rate swaps pertaining to 2010 consisted of instruments with a total notional amount of $1.15 billion in which we receive a fixed rate and pay a variable rate. The key terms of these contracts are presented in the following table.

	Fixed-to-Floating Swaps		
Notional (In millions)	**Fixed Rate Received**	**Variable Rate Paid**	**Expiration**
$ 300	4.30%	Six month LIBOR	July 18, 2011
100	1.90%	Federal funds rate	August 3, 2012
500	3.90%	Federal funds rate	July 18, 2013
250	3.85%	Federal funds rate	July 22, 2013
$ 1,150	3.82%		

Income Taxes

Our financial income tax rate in 2010 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2010 will be significantly affected by the proportional share of consolidated pre-tax earnings generated by our United States and Canadian operations due to the different tax rates of each country. Also, certain tax deductions and credits will have a fixed impact on 2010 income tax expense regardless of the level of pre-tax earnings that are produced. Additionally, significant changes in estimated capital expenditures, production levels of oil, gas and NGLs, the prices of such products, marketing and midstream revenues, or any of the various expense items could materially alter the effect of these tax deductions and credits on 2010 financial income tax rates.

Given the uncertainty of pre-tax earnings, we expect that our total financial income tax rate in 2010 will be between 20% and 40%. The current income tax rate is expected to be between 5% and 15%. The deferred income tax rate is expected to be between 15% and 25%.

Offshore Divestitures

U.S. Offshore Operations

As previously discussed in this report, we divested all our Gulf of Mexico assets during the first half of 2010. The following table shows the actual 2010 production, pricing, expenses and capital associated with our U.S. Offshore operations prior to the various divestiture dates.

Under the provisions of the full cost method of accounting, no financial gain was recognized from our U.S. Offshore divestitures. Rather, the proceeds were recognized as an adjustment to capitalized oil and gas property and equipment. However, for federal and state income tax purposes, gains are recognized from these divestitures. Therefore, we expect to pay approximately $622 million of related income taxes in 2010. Because no gain from the divestitures is recognized for financial reporting purposes, the $622 million of current income tax expense will be offset by a like amount of deferred income tax benefit, resulting in no net impact on total income tax expense.

		($ in millions, except per Boe)
Oil production (MMBbls)		2
Gas production (Bcf)		17
Total production (MMBoe)		5
Average oil price as a % of NYMEX		101%
Average gas price as a % of NYMEX		115%
LOE	$	60
Oil & gas DD&A per Boe	$	6.10
Oil & gas DD&A	$	30
Taxes other than income taxes as % of revenue		2.00%
Accretion of asset retirement obligation	$	8
Development capital	$	204
Exploration capital	$	70
Total development & exploration	$	274
Other capital	$	100

Discontinued Operations

As previously discussed, we are in the process of divesting our International assets. As a result of these divestitures, all revenues, expenses and capital related to our International operations are reported as discontinued operations in our financial statements.

The following table shows the estimates for 2010 production, pricing, expenses and capital associated with our discontinued International operations for 2010. These estimates are based on the divestiture closing dates discussed previously in this report. As a result of the divestiture of our Panyu development in the second quarter of 2010, we recognized $110 million of current income tax expense and $37 million of deferred income tax benefit. These tax amounts are excluded from the income tax rate estimates presented in the table below. Pursuant to accounting rules for discontinued operations, the International assets are not subject to DD&A during 2010.

	Low	High
	($ in millions, except per Boe)	
Oil production (MMBbls)	9	11
Average oil price as a % of NYMEX	90%	100%
LOE	$ 145	$ 165
Taxes other than income taxes as % of revenue	12.00%	13.00%
Accretion of asset retirement obligation	$ 5	$ 5
Income tax rates:		
Current	10%	15%
Deferred	10%	15%
Total	20%	30%
Development capital	$ 170	$ 190
Exploration capital	$ 280	$ 300
Total development & exploration	$ 450	$ 490
Other capital	$ 55	$ 65

Restructuring Costs

In conjunction with the planned and completed 2010 asset divestitures, we estimate we will incur certain one-time restructuring costs totaling between $180 million and $200 million. This estimate includes $140 million of employee severance and termination costs and $40 million to $60 million of contract termination and other associated costs.

In the fourth quarter of 2009, we recognized $153 million of estimated employee severance costs associated with the planned divestitures. We decreased our estimate of employee severance costs in the second quarter of 2010 by $14 million to $139 million. The $14 million reduction consisted of $9 million related to our U.S. Offshore operations and $5 million related to our International discontinued operations. Until all divestitures are complete, it is uncertain whether we will recognize additional adjustments to the $139 million of estimated employee severance costs.

Considering the $14 million adjustment to employee severance costs and the estimate of contract termination and other costs, we estimate our 2010 restructuring costs will be approximately $30 million to $50 million.

Capital Resources, Uses and Liquidity

North America Onshore Capital Expenditures

Our capital expenditures budget is based on an expected range of future oil, gas and NGL prices as well as the expected costs of the capital additions. Should actual prices received differ materially from our price expectations for our future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2010 capital expenditures. In addition, if the actual material or labor costs of the budgeted items vary significantly from the anticipated amounts, actual capital expenditures could vary materially from our estimates.

Given the limitations discussed above, the following table shows expected ranges for drilling, development and facilities expenditures by geographic area. Development capital includes development activity related to reserves classified as proved and drilling that does not offset currently productive units and for which there is not a certainty of continued production from a known productive formation. Exploration capital includes exploratory drilling to

10

find and produce oil or gas in previously untested fault blocks or new reservoirs. Leasehold acquisition capital includes amounts related to proved and unproved property acquisitions.

	U.S. Onshore	Canada (In millions)	North America Onshore
Development capital	$ 2,570-$2,760	$ 1,140-$1,220	$ 3,710-$3,980
Exploration capital	$ 340-$360	$ 110-$120	$ 450-$480
Leasehold acquisition capital	$ 550-$600	$ 580-$620	$ 1,130-$1,220
Total	$ 3,460-$3,720	$ 1,830-$1,960	$ 5,290-$5,680

In addition to the expenditures presented in the table above, we expect to capitalize between $300 million and $320 million of G&A expenses in accordance with the full cost method of accounting and to capitalize between $10 million and $20 million of interest. We also expect to pay between $60 million and $65 million for plugging and abandonment charges. Additionally, we expect to spend between $250 million and $325 million on our midstream assets, which primarily include our oil pipelines, gas processing plants, and gas gathering and pipeline systems. We expect to spend between $375 million and $425 million for corporate and other fixed assets.

Other Cash Uses

Our management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.16 per share quarterly dividend rate and 439 million shares of common stock outstanding as of June 30, 2010, dividends are expected to approximate $282 million.

In May 2010, our Board of Directors approved a $3.5 billion share repurchase program. This program expires on December 31, 2011. Through July 2010, we had repurchased 11.9 million common shares for $761 million.

Capital Resources and Liquidity

Our estimated 2010 cash uses, including our capital activities, are expected to be funded primarily through a combination of our existing cash balances and operating cash flow. Another major source of liquidity is the proceeds from the divestiture of our offshore operations. Our performance and divestitures to date enabled us to end the second quarter of 2010 with a robust level of liquidity. As of June 30, 2010, we held $2.9 billion in cash and had $2.6 billion of available credit under our credit lines. This liquidity will allow us to continue repurchasing common shares and investing in the opportunities that exist across our North America Onshore portfolio of properties. The amount of operating cash flow to be generated during 2010 is uncertain due to the factors affecting revenues and expenses as previously cited.,We expect our combined capital resources to be adequate to fund our anticipated capital expenditures and other cash uses for 2010.

Summary of Forward-Looking Estimates

North America Onshore

The following tables summarize our 2010 forward-looking estimates related to our North America Onshore operations that will be retained following the U.S. Offshore and International divestitures.

Financial amounts related to our Canadian operations in the following tables have been converted to U.S. dollars using estimated average exchange rates of $0.97 dollar to $1.00 Canadian dollar for 2010.

	Oil (MMBbls)	Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe)
U.S. Onshore	14	704	28	159
Canada	26	213	3	65
North America Onshore	40	917	31	224

	As % of NYMEX Range[1]			
	Oil		Gas	
	Low	High	Low	High
U.S. Onshore	92%	98%	79%	85%
Canada	66%	74%	85%	93%
North America Onshore	74%	82%	81%	88%

1 The expected ranges for our operating area prices as a percentage of NYMEX prices do not include any estimates of the impact on our prices from monthly cash settlements or changes in the fair values of our hedging instruments as presented on pages 5 and 6.

	Low	High
	($ in millions, except per Boe)	
Marketing & midstream:		
Revenues	$ 1,850	$ 2,125
Expenses	$ 1,400	$ 1,600
Operating profit	$ 450	$ 525

LOE	$ 1,580	$ 1,720
Oil & gas DD&A per Boe	$ 7.00	$ 7.50
Oil & gas DD&A	$ 1,570	$ 1,680
Non-oil & gas DD&A	$ 240	$ 260
Taxes other than income taxes as % of revenue	5.00%	6.00%
Accretion of ARO	$ 80	$ 90
G&A	$ 580	$ 600
Interest	$ 350	$ 370
Income tax rates:		
Current	5%	15%
Deferred	15%	25%
Total	20%	40%

	Low	High
	(In millions)	
Development capital:		
U.S. Onshore	$ 2,570	$ 2,760
Canada	$ 1,140	$ 1,220
North America Onshore	$ 3,710	$ 3,980
Exploration capital:		
U.S. Onshore	$ 340	$ 360
Canada	$ 110	$ 120
North America Onshore	$ 450	$ 480
Leasehold acquisition capital:		
U.S. Onshore	$ 550	$ 600
Canada	$ 580	$ 620
North America Onshore	$ 1,130	$ 1,220
Total:		
U.S. Onshore	$ 3,460	$ 3,720
Canada	$ 1,830	$ 1,960
North America Onshore	$ 5,290	$ 5,680
Other capital:		
Capitalized G&A	$ 300	$ 320
Capitalized interest	$ 10	$ 20
Plugging & abandonment	$ 60	$ 65
Midstream	$ 250	$ 325
Corporate & other	$ 375	$ 425
Total other capital	$ 995	$ 1,155

U.S. Offshore

The following table summarizes the actual 2010 amounts associated with our U.S. Offshore operations prior to the various divestiture dates.

	($ in millions, except per Boe)
Oil production (MMBbls)	2
Gas production (Bcf)	17
Total production (MMBoe)	5
Average oil price as a % of NYMEX	101%
Average gas price as a % of NYMEX	115%
LOE	$ 60
Oil & gas DD&A per Boe	$ 6.10
Oil & gas DD&A	$ 30
Taxes other than income taxes as % of revenue	2.00%
Accretion of asset retirement obligation	$ 8
Development capital	$ 204
Exploration capital	$ 70
Total development & exploration	$ 274
Other capital	$ 100

Discontinued Operations

The following table summarizes our 2010 forward-looking estimates related to our discontinued International operations.

	Low	High
	($ in millions, except per Boe)	
Oil production (MMBbls)	9	11
Average oil price as a % of NYMEX	90%	100%
LOE	$ 145	$ 165
Taxes other than income taxes as % of revenue	12.00%	13.00%
Accretion of asset retirement obligation	$ 5	$ 5
Income tax rates:		
Current	10%	15%
Deferred	10%	15%

Total	20%	30%
Development capital	$ 170	$ 190
Exploration capital	$ 280	$ 300
Total development & exploration	$ 450	$ 490
Other capital	$ 55	$ 65

SIGNATURES

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

DEVON ENERGY CORPORATION

By: /s/ *Danny J. Heatly*
Danny J. Heatly
Senior Vice President Accounting and
Chief Accounting Officer

Date: August 4, 2010