DEVON ENERGY CORP/DE

FORM 8-K
(Current report filing)

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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): November 16, 2009

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:

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

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

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

☐ 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 the control of Devon. 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.

Item 2.05 Costs Associated With Exit or Disposal Activities

In a news release issued on November 16, 2009, we unveiled our plan to strategically reposition Devon as a high-growth North American onshore exploration and production company. We intend to divest all of our U.S. Offshore and International assets. We plan to direct the proceeds to our high-return North America Onshore portfolio and to retire debt. We expect to complete the divestitures throughout 2010 and to have finished the process by year-end.

We estimate that we will incur approximately $200 million to $275 million of total one-time restructuring costs in connection with the planned 2010 divestitures. This estimate includes $175 million to $225 million of employee severance costs and $25 million to $50 million of contract termination and other costs. We expect to recognize the employee severance costs during the fourth quarter of 2009. We expect the majority of the remaining restructuring costs will be recognized during 2010.

We estimate that approximately $125 million to $175 million of the estimated total costs will result in future cash expenditures. The majority of the costs that will not result in future cash expenditures consist of employee severance costs related to accelerated vesting of stock awards.

Item 8.01. Other Events

We are providing our 2010 forward-looking estimates in this report. These estimates are based on our examination of historical operating trends, the information being used to prepare our forthcoming December 31, 2009 reserve reports and other data in our possession or available from third parties.

As mentioned above, we announced plans to strategically reposition Devon by divesting our U.S. Offshore and International assets. Although we expect to complete the divestitures throughout 2010, all estimates in this report assume the divestitures close at the end of 2010. The assets to be divested represent approximately 11% of our estimated 2009 production and 7% of our forecasted December 31, 2009 proved reserves.

As a result of these planned divestitures, all revenues, expenses and capital related to our International operations will be 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 will remain in our continuing operations.

A summary of our 2010 forward-looking estimates is included at the end of this report. Because the 2009 estimates we have previously provided include amounts related to our International operations, the summary also includes 2009 estimates that present our International operations separately as discontinued.

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:

"Bbl" or "Bbls" means barrel or barrels.

"Bbls/d" means barrels per day.

"Bcf" means billion cubic feet.

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

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

"Canada" means our operations encompassing oil and gas properties located in Canada.

"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* .

"International" means our operations encompassing oil and gas properties that lie outside the United States and Canada.

"LIBOR" means London Interbank Offered Rate.

"MMBbls" means million Bbls.

"MMBoe" means million Boe.

"MMBtu" means million Btu.

"MMBtu/d" means million Btu per day.

"Mcf" means thousand cubic feet.

"MMcf" means million cubic feet.

"NGL" or "NGLs" means natural gas liquids.

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

"NYMEX" means New York Mercantile Exchange.

"Oil" includes crude oil and condensate.

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

"U.S. Onshore" means our operations encompassing oil and gas properties in the continental United States.

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 $0.95 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 and China is governed by payout agreements with the governments of these countries. If the payout under these agreements is attained earlier than projected, our net production and proved reserves in such areas 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.

Operating Items

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 229 to 233 MMBoe. The following estimates for oil, gas and NGL production are calculated at the midpoint of the estimated range for total production.

	Oil (MMBbls)	Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe)
U.S. Onshore	13	686	27	154
Canada	28	204	3	65
North America Onshore	41	890	30	219
U.S. Offshore	4	46	—	12
Total	45	936	30	231

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	90% to 100%	75% to 85%
Canada	65% to 75%	85% to 95%
North America Onshore	72% to 82%	77% to 87%
U.S. Offshore	95% to 105%	100% to 110%

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 November 10, 2009, our financial commodity contracts pertaining to 2010 consisted of oil price collars and gas price swaps. The key terms of these contracts are presented in the following tables.

	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	71,000	$65.00 - $70.00	$ 67.18	$90.35 - $103.30	$ 96.23

	Gas Price Swaps	
Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Total year	1,085,000	$ 6.18

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 $500 million. We estimate that marketing and midstream revenues will be between $1.85 billion and $2.10 billion, and marketing and midstream expenses will be between $1.40 billion and $1.60 billion.

Production and Operating Expenses

Our production and operating expenses include lease operating expenses, transportation costs and production taxes. These expenses 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 and changes in production tax rates. 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 $1.86 billion and $2.01 billion. This estimated range includes $1.69 billion to $1.82 billion related to our North America Onshore business and $0.17 to $0.19 billion associated with our U.S. Offshore operations.

Additionally, we estimate that our production taxes for 2010 will be between 2.75% and 3.25% of total oil, gas and NGL revenues, excluding the effect on revenues from derivative contracts upon which production taxes are not assessed. We estimate our 2010 production tax rates for our North America Onshore operations will range from 2.75% to 3.25% of revenues. We estimate the U.S. Offshore rates will range from 1.25% to 1.75% of revenues.

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 reductions of carrying value resulting from full cost ceiling tests.

Given these uncertainties, we estimate that our oil and gas property related DD&A rate will be between $7.75 per Boe and $8.25 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 $1.79 billion and $1.91 billion. For our North America Onshore assets, we estimate the DD&A rate will range from $7.75 to $8.25 per Boe, resulting in estimated DD&A expense of $1.70 billion to $1.81 billion. Our U.S. Offshore DD&A rate is estimated to be between $6.75 and $7.25 per Boe, resulting in estimated DD&A expense of $0.09 billion to $0.10 billion.

Additionally, we expect that our depreciation and amortization expense related to non-oil and gas property fixed assets will total between $270 million and $300 million in 2010. This estimate relates entirely to our North America Onshore assets.

Accretion of Asset Retirement Obligation

Accretion of asset retirement obligation in 2010 is expected to be between $95 million and $105 million. This estimated range includes $70 million to $80 million related to our North America Onshore business and $25 million associated with our U.S. Offshore operations.

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 $620 million. This estimate includes approximately $115 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.

Restructuring Costs

In conjunction with the planned 2010 asset divestitures, we estimate we will incur certain one-time restructuring costs totaling between $200 million and $275 million. Such costs will consist of employee severance and termination costs, contract termination costs and other associated costs. We expect to recognize the employee severance costs during the fourth quarter of 2009. We expect the majority of the remaining restructuring costs will be recognized during 2010.

Reduction of Carrying Value of Oil and Gas Properties

We follow the full cost method of accounting for our oil and gas properties. Under the full cost method, our net book value of oil and gas properties, less related deferred income taxes (the "costs to be recovered"), may not exceed a calculated "full cost ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from oil and gas properties plus the cost of unevaluated properties.

The ceiling is imposed separately by country. The costs to be recovered are compared to the ceiling on a quarterly basis. If the costs to be recovered exceed the ceiling, the excess is written off as an expense. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Future net revenues are calculated using prices that represent the average of the first-day-of-the-month price for the 12-month period prior to the end of each quarterly period. These prices are held constant indefinitely and are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Costs included in future net revenues are determined in a similar manner.

Because the ceiling calculation dictates the use of prices that are not representative of future prices and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and gas prices have historically been cyclical and, for any particular 12-month period, can be either higher or lower than our long-term price forecast, which is a more appropriate input for estimating fair value. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

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 September 30, 2009, we had total debt of $7.4 billion. This included $6.0 billion of fixed-rate debt and $1.4 billion of variable-rate commercial paper borrowings. The fixed-rate debt bears interest at an overall weighted average rate of 7.24%. The commercial paper borrowings bear interest at variable rates based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. As of September 30, 2009, the weighted average variable rate for our commercial paper borrowings was 0.32%. Additionally, any future borrowings under our credit facilities would bear interest at various fixed-rate options for periods up to twelve months and are generally less than the prime rate.

Based on the factors above, we expect our 2010 interest expense to be between $375 million and $415 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 three primary components — interest related to outstanding debt, fees and issuance costs, and capitalized interest. We expect the interest expense in 2010 related to our fixed-rate and floating-rate debt, including net accretion of related discounts, to be between $455 million and $495 million. We expect the 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 $10 million and $20 million. We also expect to capitalize between $90 million and $100 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 November 10, 2009, our interest rate swaps pertaining to 2010 consisted of instruments with a total notional amount of $1.85 billion. These consist of instruments with a notional amount of $1.15 billion in which we receive a fixed rate and pay a variable rate. The remaining instruments consist of forward starting swaps. Under the terms of the forward starting swaps, we will net settle these contracts in September 2011. The net settlement amount will be based upon us paying a weighted-average fixed rate of 3.99% and receiving a floating rate that is based upon the three-month LIBOR. The difference between the fixed and floating rate will be applied to the notional amount for the 30-year period from September 30, 2011 to September 30, 2041. The key terms of these contracts are presented in the following tables.

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%		

Forward Starting Swaps

Notional	Fixed Rate Paid	Variable Rate Received	Expiration
(In millions)			
$700	3.99%	Three month LIBOR	September 30, 2011

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 10% and 20%. The deferred income tax rate is expected to be between 10% and 20%. These ranges do not include the impact of current and deferred income taxes that will be recognized upon the completion of the 2010 asset divestitures.

Discontinued Operations

As previously discussed, we intend to divest our U.S. Offshore and International assets. As a result of these planned divestitures, all revenues, expenses and capital related to our International operations will be reported as discontinued operations in our financial statements. The operations related to our U.S. Offshore assets will remain in our continuing operations.

The following table shows the estimates for 2010 production, pricing, expenses and capital associated with our discontinued International operations for 2010. These estimates assume the sales will occur at the end of 2010. Pursuant to accounting rules for discontinued operations, the International assets will not be subject to DD&A during 2010.

	Low	High
	($ in millions, except per Boe)	
Oil production (MMBbls)	14	16
Oil area price as a % of NYMEX	90%	100%
LOE	$ 190	$ 210
Production tax as % of revenue	10.25%	10.75%
Accretion of ARO	$ 5	$ 5
Income tax rates:		
Current	20%	30%
Deferred	(5%)	—%
Total	15%	30%
Development capital	$ 220	$ 260
Exploration capital	$ 240	$ 280
Total development & exploration	$ 460	$ 540
Other capital	$ 80	$ 90

Capital Resources, Uses and Liquidity

Capital Expenditures

Though we have completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, we do not forecast, nor can we reasonably predict, the timing or size of such possible acquisitions.

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 find and produce oil or gas in previously untested fault blocks or new reservoirs.

	U.S. Onshore	Canada	North America Onshore	U.S. Offshore	Total
			(In millions)		
Development capital	$2,210-$2,470	$1,010-$1,140	$3,220-$3,610	$ 820-$900	$4,040-$4,510
Exploration capital	$ 520-$560	$ 20-$30	$ 540-$590	$ 100-$120	$ 640-$710
Total	$2,730-$3,030	$1,030-$1,170	$3,760-$4,200	$920-$1,020	$4,680-$5,220

In addition to the above expenditures for drilling, development and facilities, we expect to capitalize between $330 million and $350 million of G&A expenses in accordance with the full cost method of accounting and to capitalize between $65 million and $75 million of interest. We also expect to pay between $80 million and $90 million for plugging and abandonment charges. Additionally, we expect to spend between $380 million and $430 million on our marketing and midstream assets, which primarily include our oil pipelines, gas processing plants, and gas 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 444 million shares of common stock outstanding as of September 30, 2009, dividends are expected to approximate $285 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. Any remaining cash uses could be funded by increasing our borrowings under our commercial paper program or with borrowings from the available capacity under our credit facilities, which was approximately $2.0 billion as of November 2, 2009. The amount of operating cash flow to be generated during 2010 is uncertain due to the factors affecting revenues and expenses as previously cited. However, we expect our combined capital resources to be adequate to fund our anticipated capital expenditures and other cash uses for 2010.

If significant other acquisitions or other unplanned capital requirements arise during the year, we could utilize our existing credit facilities and/or seek to establish and utilize other sources of financing.

Summary of Forward-Looking Estimates

The following tables summarize our 2010 forward-looking estimates related to our continuing operations. As previously discussed, on November 16, 2009, we announced plans to divest our U.S. Offshore and International assets.

As a result of the planned divestitures, the following tables include separate United States Offshore estimates for production, pricing, LOE, production taxes, oil and gas property DD&A, ARO accretion and capital. Also, all revenues, expenses and capital related to our International operations will be reported as discontinued operations in our financial statements. Accordingly, the forward-looking estimates in the following tables exclude amounts related to our International operations. Because the 2009 estimates we have previously provided include amounts related to our International operations, the following tables also include 2009 estimates that present our International operations separately as discontinued.

Financial amounts related to our Canadian operations in the following tables have been converted to U.S. dollars using estimated average exchange rates of $0.95 and $0.86 dollar to $1.00 Canadian dollar for 2010 and 2009, respectively.

	2010	2009
Oil production (MMBbls):		
U.S. Onshore	13	11
Canada	28	25
North America Onshore	41	36
U.S. Offshore	4	6
Total	45	42
Gas production (Bcf):		
U.S. Onshore	686	701
Canada	204	225
North America Onshore	890	926
U.S. Offshore	46	42
Total	936	968
NGL production (MMBbls):		
U.S. Onshore	27	25
Canada	3	4
North America Onshore	30	29
U.S. Offshore	—	—
Total	30	29
Combined production (MMBoe):		
U.S. Onshore	154	153
Canada	65	66
North America Onshore	219	219
U.S. Offshore	12	13
Total	231	232

	As % of NYMEX Range			
	2010		2009	
	Low	High	Low	High
Oil operating area prices [1] :				
U.S. Onshore	90%	100%	85%	95%
Canada	65%	75%	65%	75%
North America Onshore	72%	82%	70%	80%
U.S. Offshore	95%	105%	95%	105%
Gas operating area prices [1] :				
U.S. Onshore	75%	85%	75%	85%
Canada	85%	95%	83%	93%
North America Onshore	77%	87%	77%	87%
U.S. Offshore	100%	110%	100%	110%

[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.

	2010						2009	
	North America Onshore		U.S. Offshore		Total		Total	
	Low	High	Low	High	Low	High	Low	High
	($ in millions, except per Boe)							
Marketing & midstream:								
Revenues					$ 1,850	$ 2,100	$ 1,180	$ 1,400
Expenses					$ 1,400	$ 1,600	$ 750	$ 900
Operating profit					$ 450	$ 500	$ 430	$ 500
LOE	$ 1,690	$ 1,820	$ 170	$ 190	$ 1,860	$ 2,010	$ 1,740	$ 2,060
Production tax as % of revenue	2.75%	3.25%	1.25%	1.75%	2.75%	3.25%	2.25%	2.75%
Oil & gas DD&A per Boe	$ 7.75	$ 8.25	$ 6.75	$ 7.25	$ 7.75	$ 8.25	$ 7.60	$ 8.10
Oil & gas DD&A	$ 1,700	$ 1,810	$ 90	$ 100	$ 1,790	$ 1,910	$ 1,750	$ 1,850
Non-oil & gas DD&A					$ 270	$ 300	$ 280	$ 300
Accretion of ARO	$ 70	$ 80	$ 25	$ 25	$ 95	$ 105	$ 80	$ 90
G&A					$ 580	$ 620	$ 650	$ 680
Interest					$ 375	$ 415	$ 345	$ 355
Income tax rates:								
Current					10%	20%	10%	20%
Deferred					10%	20%	10%	20%
Total					20%	40%	20%	40%

	2010		2009	
	Low	High	Low	High
	(In millions)			
Development capital:				
U.S. Onshore	$ 2,210	$ 2,470	$ 1,520	$ 1,790
Canada	$ 1,010	$ 1,140	$ 740	$ 870
North America Onshore	$ 3,220	$ 3,610	$ 2,260	$ 2,660
U.S. Offshore	$ 820	$ 900	$ 460	$ 540
Total development	$ 4,040	$ 4,510	$ 2,720	$ 3,200
Exploration capital:				
U.S. Onshore	$ 520	$ 560	$ 150	$ 170
Canada	$ 20	$ 30	$ 40	$ 50
North America Onshore	$ 540	$ 590	$ 190	$ 220
U.S. Offshore	$ 100	$ 120	$ 130	$ 150
Total exploration	$ 640	$ 710	$ 320	$ 370
Total development & exploration:				
U.S. Onshore	$ 2,730	$ 3,030	$ 1,670	$ 1,960
Canada	$ 1,030	$ 1,170	$ 780	$ 920
North America Onshore	$ 3,760	$ 4,200	$ 2,450	$ 2,880
U.S. Offshore	$ 920	$ 1,020	$ 590	$ 690
Total development & exploration	$ 4,680	$ 5,220	$ 3,040	$ 3,570
Other capital:				
Capitalized G&A	$ 330	$ 350	$ 350	$ 360
Capitalized interest	$ 65	$ 75	$ 80	$ 90
Plugging & abandonment	$ 80	$ 90	$ 100	$ 110
Marketing & midstream	$ 380	$ 430	$ 280	$ 330
Corporate & other	$ 375	$ 425	$ 215	$ 225
Total other capital	$ 1,230	$ 1,370	$ 1,025	$ 1,115

The following table summarizes our 2010 and 2009 forward-looking estimates related to our discontinued International operations.

	2010		2009	
	Low	High	Low	High
	($ in millions, except per Boe)			
Oil production (MMBbls)	14	16	16	16
Oil area price as a % of NYMEX	90%	100%	90%	100%
LOE	$ 190	$ 210	$ 190	$ 210
Production tax as % of revenue	10.25%	10.75%	8.25%	8.75%
Accretion of ARO	$ 5	$ 5	$ 5	$ 5
Income tax rates:				
Current	20%	30%	10%	20%
Deferred	(5%)	—%	5%	10%
Total	15%	30%	15%	30%
Development capital	$ 220	$ 260	$ 160	$ 200
Exploration capital	$ 240	$ 280	$ 240	$ 280
Total development & exploration	$ 460	$ 540	$ 400	$ 480
Other capital	$ 80	$ 90	$ 70	$ 80

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: November 16, 2009