DEVON ENERGY CORP/DE

FORM 8-K
(Current report filing)

Filed 02/16/11 for the Period Ending 02/16/11

Address	333 W. SHERIDAN AVENUE OKLAHOMA CITY, OK 73102
Telephone	4055528183
CIK	0001090012
Symbol	DVN
SIC Code	1311 - Crude Petroleum and Natural Gas
Fiscal Year	12/31

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): February 16, 2011

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 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 various abbreviations and terms that 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 in Brazil and Angola.

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

We are providing our 2011 forward-looking estimates in this report. These estimates were based on our examination of historical operating trends, the information used to prepare our December 31, 2010, reserve reports and other data in our possession or available from third parties. A summary of our forward-looking estimates is included at the end of this report.

During 2011, our operations are substantially comprised of our ongoing North America Onshore operations. We also have International operations in Brazil and Angola that we are divesting. We have entered into agreements to sell our assets in Brazil for $3.2 billion and our assets in Angola for $70 million, plus contingent consideration. 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. Additionally, all forward-looking estimates in this document exclude amounts related to our International operations, unless otherwise noted.

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 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 pipeline throughput, gas processing volumes and NGL content, 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 2011 exchange rate of $0.95 dollar to $1.00 Canadian dollar. The actual 2011 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 and political conditions, weather, supply disruptions and other local market conditions. These factors are beyond our control and are difficult to predict. In addition, volatility in 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 2011.

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.

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 2011 forward-looking estimates in this report were prepared assuming demand, curtailment, producibility and general market conditions for our oil, gas and NGLs during 2011 will be similar to 2010, unless otherwise noted.

North America Onshore Operating Items

The following 2011 estimates relate only to our North America Onshore assets.

Oil, Gas and NGL Production

Set forth below are our estimates of oil, gas and NGL production for 2011. We estimate that our combined oil, gas and NGL production will total approximately 236 to 240 MMBoe.

	Oil (MMBbls)	Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe)
U.S. Onshore	17	736	34	174
Canada	28	199	3	64
North America Onshore	45	935	37	238

Oil and Gas Prices

We expect our 2011 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	89% to 99%	80% to 90%
Canada	63% to 73%	82% to 92%
North America Onshore	73% to 83%	80% to 90%

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 2011.

As of February 10, 2011, our financial commodity contracts pertaining to 2011 consisted of oil and gas price collars, oil call options, gas price swaps, gas basis swaps and NGL 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)
Total year 2011	730,226	$5.49

Gas Basis Swaps

Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Total year 2011	Panhandle Eastern Pipeline	150,000	$0.33

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 2011	45,000	$75.00 - $75.00	$75.00	$105.00 - $116.10	$108.89

Oil Call Options Sold

Period	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Total year 2011	19,500	$95.00

NGL Basis Swaps

		Pay	Receive
Period	Volume (Bbls/d)	Natural Gasoline ($/Bbl)	Oil ($/Bbl)
Total year 2011	500	$70.77	$80.52

To the extent that monthly NYMEX prices in 2011 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 2011. 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 and NGL content 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 2011 marketing and midstream operating profit will be between $485 million and $535 million. We estimate that marketing and midstream revenues will be between $1.485 billion and $1.760 billion, and marketing and midstream expenses will be between $1.000 billion and $1.225 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, as well as 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 2011 lease operating expenses will be between $1.78 billion and $1.88 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 2011 will be between 5.20% and 6.20% of total oil, gas and NGL sales.

Depreciation, Depletion and Amortization ("DD&A")

Our 2011 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 2011 compared to the costs incurred for such efforts, revisions to our year-end 2010 reserve estimates that, based on prior experience, are likely to be made during 2011, 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 $7.40 per Boe and $8.00 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 $1.76 billion and $1.90 billion.

Additionally, we expect that our depreciation and amortization expense related to non-oil and gas fixed assets will total between $265 million and $295 million in 2011.

Accretion of Asset Retirement Obligation

Accretion of asset retirement obligation in 2011 is expected to be between $85 million and $95 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 2011 will be between $590 million and $630 million. This estimate includes approximately $110 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.

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 2011 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 December 31, 2010, we had total debt of $5.6 billion, which is exclusively fixed-rate debt at an overall weighted average rate of 7.2%. Our debt includes $1.75 billion that is scheduled to mature on September 30, 2011. We also have access to the commercial paper market and our credit lines. Any commercial paper or credit line borrowings would bear interest at variable rates.

Based on the factors above, we expect our 2011 interest expense to be between $300 million and $340 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 2011 interest expense estimate above is comprised of three primary components — interest related to outstanding debt, fees and issuance costs and capitalized interest. We expect interest expense in 2011 related to our outstanding debt, including net accretion of related discounts, to be between $380 million and $420 million. We expect interest expense in 2011 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. During 2011, we also expect to capitalize between $85 million and $95 million of interest, of which $45 to $55 million relates to our continuing oil and gas activities and the remainder relates to certain corporate construction projects and our discontinued operations.

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 December 31, 2010, our interest rate swaps pertaining to 2011 consisted of instruments with a total notional amount of $2.10 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, or sooner should we elect. The net settlement amount will be based upon us paying a weighted-average fixed rate of 3.92% 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 (In millions)	Fixed Rate Paid	Variable Rate Received	Expiration
$ 950	3.92%	Three month LIBOR	September 30, 2011

Income Taxes

Our financial income tax rate in 2011 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2011 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 2011 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 2011 financial income tax rates.

Given the uncertainty of pre-tax earnings, we expect that our total financial income tax rate in 2011 will be between 20% and 40%. The current income tax rate is expected to be between 0% and 10%. The deferred income tax rate is expected to be between 20% and 30%.

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 2011 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, we estimate that our 2011 oil and gas development and exploration capital expenditures will be between $4.500 billion and $4.900 billion. We estimate that our development capital will be between $3.875 billion and $4.175 billion. Development capital includes 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. Development capital also includes estimates for plugging and abandonment charges. We estimate that our exploration capital will be between $625 million and $725 million. Exploration capital includes exploratory drilling to find and produce oil or gas in previously untested fault blocks or new reservoirs. Exploration capital also includes purchases of proved and unproved leasehold acreage. In addition to the development and exploration expenditures, we expect to capitalize between $330 million and $350 million of G&A expenses and between $45 million and $55 million of interest related to our oil and gas activities.

In addition, we expect to spend between $225 million and $300 million on our midstream assets, which primarily include our oil pipelines, gas processing plants, and gas gathering and pipeline systems. We also expect total capital for corporate activities will be between $300 million and $395 million, including approximately $30 million of capitalized interest related to certain construction projects.

Other Cash Uses

In May 2010, our Board of Directors approved a $3.5 billion share repurchase program. This program expires on December 31, 2011. Through February 10, 2011, we had repurchased 23.5 million common shares for $1.6 billion, or $69.60 per share.

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 expected share repurchases, 2011 dividends are expected to approximate $264 million.

Capital Resources and Liquidity

Our estimated 2011 cash uses, including our capital activities, are expected to be funded primarily through a combination of our existing cash balances and operating cash flow, supplemented with commercial paper borrowings. At the beginning of 2011, we held $3.4 billion in cash and short-term investments. The amount of operating cash flow to be generated during 2011 is uncertain due to the factors affecting revenues and expenses as previously cited. However, if our operating cash flow were significantly less than our estimates, we would access the commercial paper market. Also, we have credit lines that we could access if deemed necessary. As of February 10, 2011, we had $2.0 billion of available credit under our credit lines.

Another major source of future liquidity will be the proceeds from the divestiture of our assets in Brazil and, to a lesser extent, the divestiture of our assets in Angola.

These sources of liquidity will allow us to continue repurchasing common shares and investing in the opportunities that exist across our North America Onshore portfolio of properties. We expect our combined capital resources to be adequate to fund our anticipated capital expenditures and other cash uses for 2011.

Summary of Forward-Looking Estimates

The following tables summarize our 2011 forward-looking estimates related to our North America Onshore operations. 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 dollar to $1.00 Canadian dollar for 2011.

	Oil (MMBbls)	Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe)
U.S. Onshore	17	736	34	174
Canada	28	199	3	64
North America Onshore	45	935	37	238

	As % of NYMEX Range [1]			
	Oil		Gas	
	Low	High	Low	High
U.S. Onshore	89%	99%	80%	90%
Canada	63%	73%	82%	92%
North America Onshore	73%	83%	80%	90%

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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	$ 1,485	$ 1,760
Expenses	$ 1,000	$ 1,225
Operating profit	$ 485	$ 535
LOE	$ 1,780	$ 1,880
Taxes other than income taxes as % of revenue	5.20%	6.20%
Oil & gas DD&A per Boe	$ 7.40	$ 8.00
Oil & gas DD&A	$ 1,760	$ 1,900
Non-oil & gas DD&A	$ 265	$ 295
Accretion of ARO	$ 85	$ 95
G&A	$ 590	$ 630
Interest	$ 300	$ 340
Income taxes — current	—%	10%
Income taxes — deferred	20%	30%
Total	20%	40%
Oil and gas capital:		
Development	$ 3,875	$ 4,175
Exploration	625	725
Subtotal	4,500	4,900
Capitalized G&A	330	350
Capitalized interest	45	55
Total oil and gas capital	4,875	5,305
Other capital:		
Midstream	225	300
Corporate & other	300	395
Total other capital	525	695
Total capital	$ 5,400	$ 6,000

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: February 16, 2011