DEVON ENERGY CORP/DE
Form 8-K
August 06, 2008

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 6, 2008
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))

Item 8.01. Other Events

We reported our original 2008 forward-looking estimates in a Current Report on Form 8-K dated February 6, 2008, and also in our 2007 Annual Report on Form 10-K/A. In this document, we are updating certain of these 2008 forward-looking estimates. The updated estimates and the reasons therefore, along with the estimates that have not changed, are presented in the following pages.

Definitions

The following discussion includes references to various abbreviations relating to volumetric production terms and other defined terms. These definitions are 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.

Federal Funds Rate means the interest rate that financial institutions charge each other for the use of United States Treasury funds.

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

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.

NYMEX means New York Mercantile Exchange.

Oil includes crude oil and condensate.

Forward-Looking Estimates

The forward-looking statements provided in this discussion are based on our examination of historical operating trends, the information which was used to prepare the December 31, 2007 Devon reserve reports and other data in our possession or available from third parties. We caution that future oil, gas and NGL production, revenues and expenses are subject to all of the risks and uncertainties normally incident to the exploration for and development, production and sale of 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 would caution that future marketing and midstream revenues and expenses are subject to all of the risks and uncertainties normally incident to the marketing and midstream business. 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.

In January 2007, we announced our intent to divest our West African oil and gas assets and terminate our operations in West Africa. During the second quarter of 2008, we sold our assets and terminated our operations in certain West African countries and received proceeds of $2.4 billion ($1.7 billion net of income taxes and purchase price adjustments). These sales consisted primarily of our assets in Gabon and Equatorial Guinea the largest individual transaction in the divestiture program. We have also entered into agreements to sell our assets in Cote D Ivoire and other less significant countries located in West Africa for approximately $250 million. We are obtaining the necessary partner and government approvals for these properties and expect to complete these sales during the third quarter of 2008.

All West African related revenues, expenses and capital are reported as discontinued operations in our 2008 financial statements. Accordingly, all forward-looking estimates in this document exclude amounts related to our operations in West Africa, unless otherwise noted.

Though we have completed several major property acquisitions and dispositions in recent years, these transactions are opportunity driven. Thus, the following forward-looking estimates do not include any financial and operating effects of potential property acquisitions or divestitures which may occur during 2008, except for West Africa as previously discussed.

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. Amounts related to Canadian operations have been converted to U.S. dollars using a projected average 2008 exchange rate of $0.99 dollar to $1.00 Canadian dollar. The actual 2008 exchange rate may vary materially from this estimate. Such variations could have a material effect on these forward-looking estimates.

Additional risks are discussed below in the context of line items most affected by such risks. A summary of these forward-looking estimates is included at the end of this document.

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 contents 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.

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 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 international production of oil and gas is governed by payout agreements with the governments of the countries in which we operate. 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 which are subject to disruption due to transportation and processing availability, mechanical failure, human error, meteorological events including, but not limited to, hurricanes, and numerous other factors. The following forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for our oil, gas and NGLs during 2008 will be substantially similar to those of 2007, unless otherwise noted.

Geographic Reporting Areas

The following estimates of production, average price differentials compared to industry benchmarks and capital expenditures are provided separately for each of the following geographic areas:

- the United States Onshore;
- the United States Offshore, which encompasses all oil and gas properties in the Gulf of Mexico;
- Canada; and
- International, which encompasses all oil and gas properties that lie outside of the United States and Canada. As previously discussed, all West African related revenues, expenses and capital will be reported as discontinued operations in our 2008 financial statements. Accordingly, all forward-looking estimates in this document exclude amounts related to our operations in West Africa, unless otherwise noted.

Year 2008 Potential Operating Items

Oil, Gas and NGL Production

Set forth below are our estimates of oil, gas and NGL production for 2008. Our original estimate was that, on a combined basis, our 2008 oil, gas and NGL production would total approximately 240 to 247 MMBoe. Based on increased drilling activity in our United States Onshore business and better than expected performance in our Canadian operations offset by slower than anticipated development in certain of our international projects, we now estimate that production will total approximately 240 to 244 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)
United States Onshore	12	664	24	147
United States Offshore	7	60	1	18
Canada	24	207	4	62
International	15	2		15
Total	58	933	29	242

Oil and Gas Prices

Oil and Gas Operating Area Prices

We expect our 2008 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. These expected ranges are exclusive of the anticipated effects of the oil and gas financial contracts presented in the Commodity Price Risk Management section below.

The NYMEX price for oil is 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 to be 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
United States Onshore	90% to 100%	80% to 90%
United States Offshore	95% to 105%	97% to 107%
Canada	70% to 80%	85% to 95%
International	90% to 100%	95% to 105%

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 and average realized oil and gas prices in 2008.

The key terms of our 2008 oil and gas financial collar and price swap contracts are presented in the following tables. The tables include contracts entered into as of June 30, 2008.

Oil Financial Contracts

		Price Collar Contracts		
		Floor Price	Ceiling Price	
Period	**Volume (Bbls/d)**	**Floor Price ($/Bbl)**	**Ceiling Range ($/Bbl)**	**Weighted Average Price ($/Bbl)**
First Quarter	21,011	$70.00	$ 132.50 - $148.00	$140.31
Second Quarter	22,000	$70.00	$ 132.50 - $148.00	$140.20
Third Quarter	22,000	$70.00	$ 132.50 - $148.00	$140.20
Fourth Quarter	22,000	$70.00	$ 132.50 - $148.00	$140.20
2008 Average	21,754	$70.00	$ 132.50 - $148.00	$140.23

Gas Financial Contracts

	Price Collar Contracts				Price Swap Contracts	
		Floor Price	Ceiling Price			
Period	**Volume (MMBtu/d)**	**Floor Price ($/MMBtu)**	**Ceiling Range ($/MMBtu)**	**Weighted Average Price ($/MMBtu)**	**Volume (MMBtu/d)**	**Weighted Average Price ($/MMBtu)**
First Quarter	634,011	$ 7.50	$ 9.00 - $10.25	$ 9.43	364,670	$ 8.23
Second Quarter	1,080,000	$ 7.50	$ 9.00 - $10.25	$ 9.43	620,000	$ 8.24
Third Quarter	1,080,000	$ 7.50	$ 9.00 - $10.25	$ 9.43	620,000	$ 8.24
Fourth Quarter	1,080,000	$ 7.50	$ 9.00 - $10.25	$ 9.43	620,000	$ 8.24
2008 Average	969,112	$ 7.50	$ 9.00 - $10.25	$ 9.43	556,516	$ 8.24

To the extent that monthly NYMEX prices in 2008 differ from those established by the gas price swaps, or are outside of the ranges established by the oil and natural gas collars, we and the counterparties to the contracts will cash-settle the difference. Such settlements will either increase or decrease our oil and gas revenues for the period. Also, we will mark-to-market the contracts based on their fair values throughout 2008. Changes in the contracts fair values will also be recorded as increases or decreases to our oil and gas revenues. The expected ranges of our realized oil and gas prices as a percentage of NYMEX prices, which are presented earlier in this document, do not include any estimates of the impact on our oil and gas prices from monthly settlements or changes in the fair values of our oil and gas price swaps and collars.

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. Our original estimate for 2008 operating profit was between $510 million and $550 million. Due to higher natural gas and natural gas liquids prices and higher volumes, we now expect our operating profit for 2008 to total between $700 million and $760 million. We estimate that marketing and midstream revenues will be between $2.21 billion and $2.62 billion, and marketing and midstream expenses will be between $1.51 billion and $1.86 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 continue to expect that our 2008 lease operating expenses will be between $2.17 billion to $2.24 billion. Additionally, we continue to estimate that our production taxes for 2008 will be between 3.5% and 4.0% of total oil, gas and NGL revenues, excluding the effect on revenues from financial collars and price swap contracts upon which production taxes are not assessed.

Depreciation, Depletion and Amortization (DD&A)

Our 2008 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 2008 compared to the costs incurred for such efforts, and the revisions to our year-end 2007 reserve estimates that, based on prior experience, are likely to be made during 2008.

Given these uncertainties, we continue to estimate that our oil and gas property related DD&A rate will be between $12.75 per Boe and $13.25 per Boe. Based on these DD&A rates and the production estimates set forth earlier, oil and gas property related DD&A expense for 2008 is expected to be between $3.09 billion and $3.20 billion.

Additionally, we continue to expect that our depreciation and amortization expense related to non-oil and gas property fixed assets will total between $260 million and $270 million in 2008.

Accretion of Asset Retirement Obligation

Accretion of asset retirement obligation in 2008 is expected to be between $75 million and $85 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.

Our original estimate was that our 2008 G&A would be between $590 million and $610 million. Due to increases in employee compensation and benefits costs, we now estimate our 2008 G&A to be between $660 million and $680 million. This estimate includes approximately $145 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

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 properties not subject to amortization. The ceiling is imposed separately by country. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. These prices are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. 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.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, 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, on any particular day at the end of a quarter, can be either substantially higher or lower than our long-term price forecast that is a barometer for true 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.

Because of the volatile nature of oil and gas prices, it is not possible to predict whether we will incur full cost writedowns in 2008.

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 2008 from sales of oil, gas and NGLs and the resulting cash flow. Likewise, we can only marginally influence the timing of the closing of our West African divestitures and the attendant cash receipts. These factors increase the margin of error inherent in estimating future outstanding debt balances and related interest expense. Other factors which affect outstanding debt balances and related interest expense, such as the amount and timing of capital expenditures are generally within our control.

Our original estimate for 2008 interest expense was between $340 million and $350 million. Based primarily on lower than anticipated commercial paper and credit facility borrowings, we now expect our 2008 interest expense to be between $330 million and $340 million.

The interest expense in 2008 related to our fixed-rate and floating-rate debt, including net accretion of related discounts, is now expected to be between $430 million and $440 million. As of June 30, 2008, all of our debt bears interest at fixed rates. However, any commercial paper or credit facility borrowings would bear interest at variable rates. The interest rate for our commercial paper borrowings is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. Our credit facility borrowings bear interest at various fixed-rate options for periods up to twelve months and are generally less than the prime rate.

Our outstanding debt as of June 30, 2008 included $4.8 billion of long-term debt. All of this long-term debt bears interest at fixed rates with an overall weighted-average rate of 7.6%. In July 2008, we entered into interest rate swaps to mitigate a portion of the fair value effects of interest rate fluctuations on our fixed-rate debt. Under the terms of these swaps, we receive a fixed rate and pay a variable rate on a total notional amount of $1.05 billion. The key terms of these interest rate swaps are presented in the table below.

Notional (In millions)	Fixed Rate Received	Variable Rate Paid	Expiration
$ 500	3.90%	Federal funds rate	July 18, 2013
$ 300	4.30%	Six month LIBOR	July 18, 2011
$ 250	3.85%	Federal funds rate	July 22, 2013
$ 1,050	4.00%		

Including the effects of these swaps, the weighted-average interest rate related to our fixed-rate debt was 7.2% as of July 31, 2008.

Our interest expense totals include payments of facility and agency fees, amortization of debt issuance costs and other miscellaneous items not related to the debt balances outstanding. We continue to expect between $5 million and $15 million of such items to be included in our 2008 interest expense. Also, we now expect to capitalize between $105 million and $115 million of interest during 2008, including amounts related to our discontinued operations.

Other Income

We continue to estimate that our other income in 2008 will be between $55 million and $75 million.

As of the June 30, 2008, we had received insurance claim settlements related to the 2005 hurricanes which were $92 million in excess of amounts incurred to repair related damages. None of this $92 million excess has been recognized as income, pending the resolution of the amount of future necessary repairs and the settlement of certain claims that have been filed with secondary insurers. Based on the most recent estimates of our costs for repairs, we believe that some amount will ultimately be recorded as other income. However, the timing and amount that would be recorded as other income are uncertain. Therefore, the 2008 estimate for other income above does not include any amount related to hurricane proceeds.

Income Taxes

Our financial income tax rate in 2008 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2008 will be significantly affected by the proportional share of consolidated pre-tax earnings generated by U.S., Canadian and International operations due to the different tax rates of each country. There are certain tax deductions and credits that will have a fixed impact on 2008 income tax expense regardless of the level of pre-tax earnings that are produced.

Given the uncertainty of pre-tax earnings, we expect that our consolidated financial income tax rate in 2008 will be between 20% and 40%. The current income tax rate is expected to be between 10% and 15%. The deferred income tax rate is expected to be between 10% and 25%. 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 the aforementioned tax deductions and credits on 2008 financial income tax rates.

Discontinued Operations

As previously discussed, during the second quarter of 2008, we sold our assets and terminated our operations in certain West African countries and received proceeds of $2.4 billion ($1.7 billion net of income taxes and purchase price adjustments). These sales consisted primarily of our assets in Gabon and Equatorial Guinea the largest individual transaction in the divestiture program. As a result of these sales, we recognized after-tax gains totaling $647 million. We have also entered into agreements to sell our assets in Cote D Ivoire and other less significant countries located in West Africa for approximately $250 million. We are obtaining the necessary partner and government approvals for these properties and expect to complete these sales during the third quarter of 2008.

The following table presents the 2008 estimates for production, production and operating expenses and capital expenditures associated with these discontinued operations. These estimates include amounts related to all assets in the West African divestiture package for the first half of 2008. Pursuant to accounting rules for discontinued operations, the West African assets are not subject to DD&A during 2008.

Oil production (MMBbls)	3
Gas production (Bcf)	3
Total production (MMBoe)	4
Production and operating expenses (In millions)	$25
Capital expenditures (In millions)	$28

Year 2008 Potential 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 budget, nor can we reasonably predict, the timing or size of such possible acquisitions.

Our capital expenditures budget for drilling, development and facilities expenditures 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 2008 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, our original estimate for 2008 capital expenditures for drilling, development and facilities expenditures was between $5.585 billion and $5.900 billion. We now estimate these capital expenditures will be between $7.185 billion and $7.475 billion. A significant portion of this incremental capital is directed to additional acreage capture in North America and increased investment in the Lower Tertiary trend.

The following table shows expected drilling, development and facilities expenditures by geographic area. Development capital includes development activity related to reserves classified as proved as of year-end 2007 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.

	United States Onshore	United States Offshore	Canada	International	Total
			(In millions)		
Development capital	$ 3,660-$3,785	$ 640-$670	$ 1,090-$1,140	$ 230-$255	$ 5,620-$5,850
Exploration capital	$ 540-$560	$ 550-$570	$ 235-$245	$ 240-$250	$ 1,565-$1,625
Total	$ 4,200-$4,345	$ 1,190-$1,240	$ 1,325-$1,385	$ 470-$505	$ 7,185-$7,475

In addition to the above expenditures for drilling, development and facilities, we expect to spend between $490 million to $550 million on our marketing and midstream assets, which primarily include our oil pipelines, gas processing plants, and gas pipeline systems. We also expect to capitalize between $365 million and $375 million of G&A expenses in accordance with the full cost method of accounting and to capitalize between $95 million and $105 million of interest. We also expect to pay between $70 million and $80 million for plugging and abandonment charges, and to spend between $220 million and $230 million for other non-oil and gas property 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 June 30, 2008, dividends are expected to approximate $283 million. Also, prior to the redemption of our 6.49% cumulative preferred stock in June 2008, we paid $5 million of preferred stock dividends.

Capital Resources and Liquidity

Our estimated 2008 cash uses, including our drilling and development activities, retirement of debt and repurchase of common stock, are expected to be funded primarily through a combination of existing cash balances, operating cash flow and proceeds from the sale of our assets in West Africa. 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 facility, which was approximately $2.4 billion at August 5, 2008. The amount of operating cash flow to be generated during 2008 is uncertain due to the factors affecting revenues and expenses as previously cited. However, we expect our combined capital resources to be more than adequate to fund our anticipated capital expenditures and other cash uses for 2008.

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

Summary of 2008 Forward-Looking Estimates

The tables below summarize our 2008 forward-looking estimates related to our continuing operations. As previously discussed, all West African related revenues, expenses and capital will be reported as discontinued operations in our 2008 financial statements. Accordingly, all forward-looking estimates in this document exclude amounts related to our operations in West Africa, unless otherwise noted.

Oil production (MMBbls)	
U.S. Onshore	12
U.S. Offshore	7
Canada	24
International	15
Total	58

Gas production (Bcf)	
U.S. Onshore	664
U.S. Offshore	60
Canada	207
International	2
Total	933

NGL production (MMBbls)	
U.S. Onshore	24
U.S. Offshore	1
Canada	4
Total	29

Total production (MMBoe)	
U.S. Onshore	147
U.S. Offshore	18
Canada	62
International	15
Total	242

	As % of NYMEX Range	
	Low	**High**
Oil Operating Area Prices [1]		
U.S. Onshore	90%	100%
U.S. Offshore	95%	105%
Canada	70%	80%
International	90%	100%

Gas Operating Area Prices [1]		
U.S. Onshore	80%	90%
U.S. Offshore	97%	107%
Canada	85%	95%
International	95%	105%

[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 oil and gas prices from monthly settlements or changes in the fair values of our oil and gas price swaps and collars as presented on page 5.

	Range	
	Low	**High**
Marketing and midstream (In millions)		
Revenues	$ 2,210	$ 2,620
Expenses	$ 1,510	$ 1,860
Operating profit	$ 700	$ 760
Production and operating expenses ($ in millions)		
LOE	$ 2,170	$ 2,240
Production taxes	3.5%	4.0%
DD&A (In millions, except per Boe)		
Oil and gas DD&A	$ 3,090	$ 3,200
Non-oil and gas DD&A	$ 260	$ 270
Total DD&A	$ 3,350	$ 3,470
Oil and gas DD&A per Boe	$ 12.75	$ 13.25
Other (In millions)		
Accretion of ARO	$ 75	$ 85
G&A	$ 660	$ 680
Interest expense	$ 330	$ 340
Other income	$ 55	$ 75
Income tax rates		
Current	10%	15%
Deferred	10%	25%
Total tax rate	20%	40%

	Range Low	Range High
	(In millions)	
Development capital		
U.S. Onshore	$ 3,660	$ 3,785
U.S. Offshore	$ 640	$ 670
Canada	$ 1,090	$ 1,140
International	$ 230	$ 255
Total	$ 5,620	$ 5,850
Exploration capital		
U.S. Onshore	$ 540	$ 560
U.S. Offshore	$ 550	$ 570
Canada	$ 235	$ 245
International	$ 240	$ 250
Total	$ 1,565	$ 1,625
Total drilling and facility capital		
U.S. Onshore	$ 4,200	$ 4,345
U.S. Offshore	$ 1,190	$ 1,240
Canada	$ 1,325	$ 1,385
International	$ 470	$ 505
Total	$ 7,185	$ 7,475
Other capital		
Marketing & midstream	$ 490	$ 550
Capitalized G&A	$ 365	$ 375
Capitalized interest	$ 95	$ 105
Plugging and abandonment	$ 70	$ 80
Non-oil and gas	$ 220	$ 230
Total	$ 1,240	$ 1,340

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
Vice President Accounting and
Chief Accounting Officer

Date: August 6, 2008