DEVON ENERGY CORP/DE

FORM 10-K/A
(Amended Annual Report)

Filed 08/18/10 for the Period Ending 12/31/09

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 10-K/A

Amendment No. 1

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

or

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

Commission File Number 001-32318

DEVON ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Delaware *(State of other jurisdiction of incorporation or organization)*	**73-1567067** *(I.R.S. Employer identification No.)*
20 North Broadway, Oklahoma City, Oklahoma *(Address of principal executive offices)*	**73102-8260** *(Zip code)*

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock, par value $0.10 per share	The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act Yes ☐ No ☑

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2009, was approximately $24.0 billion, based upon the closing price of $54.50 per share as reported by the New York Stock Exchange on such date.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2010 annual meeting of stockholders — Part III

EXPLANATORY NOTE

We filed our Annual Report on Form 10-K for the year ended December 31, 2009 on February 25, 2010 (the “Original Report”). We are filing this Amendment No. 1 on Form 10-K/A (this “Amendment”) solely to revise Exhibits 99.1, 99.2 and 99.3 to the Original Report as follows:

- In the Original Report, each of these exhibits contained a statement limiting its use to Devon Energy Corporation. The exhibits in this Amendment do not include any such limitation.
- These exhibits omitted relevant benchmark prices and weighted average prices in the Original Report. The exhibits in this Amendment include the requisite pricing information.
- In the Original Report, Exhibit 99.1 omitted a statement that the third party engineer’s estimates and our estimates are within 10% of each other. The exhibit in this Amendment includes such a statement.
- Exhibit 99.1 included a reference to “generally accepted petroleum engineering and evaluation principles” in the Original Report. This exhibit has been modified to refer to “generally accepted petroleum engineering and evaluation methods and procedures” in this Amendment.

No other changes to the Original Report are included in this Amendment other than to provide currently dated consents of each engineering firm and certifications of our principal executive officer and principal financial officer.

This Amendment is being filed in response to comments we received from the staff of the Division of Corporation Finance of the Securities and Exchange Commission (the “SEC”) in connection with the staff’s review of the Original Report. We have made no attempt in this Amendment to modify or update the disclosures presented in the Original Report other than as noted above. Also, this Amendment does not reflect events occurring after the filing of the Original Report. Accordingly, this Amendment should be read in conjunction with the Original Report and our other filings with the SEC subsequent to the filing of the Original Report.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) *The following exhibits are filed as part of this report:*

Exhibit No.	Description
23.2	Consent of LaRoche Petroleum Consultants.
23.3	Consent of Ryder Scott Company, L.P.
23.4	Consent of AJM Petroleum Consultants.
31.1	Certification of principal executive office pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
99.1	Report of LaRoche Petroleum Consultants.
99.2	Report of Ryder Scott Company, L.P.
99.3	Report of AJM Petroleum Consultants.

The interactive data files of our financial statements and accompanying notes were provided as exhibits to our Annual Report on Form 10-K that was filed on February 25, 2010. Because no amendments have been made to such financial information, the interactive data files are not provided in this Form 10-K/A.

SIGNATURES

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

DEVON ENERGY CORPORATION

By: /s/ JOHN RICHELS
John Richels,
President and Chief Executive Officer

August 18, 2010

INDEX TO EXHIBITS

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99.3	Report of AJM Petroleum Consultants.

Exhibit 23.2

ENGINEER'S CONSENT

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-47672, 333-44702, 333-104922, 333-104933, 333-103679, 333-127630 and 333-159796) on Form S-8, and the Registration Statement (File No. 333-156025) on Form S-3 of Devon Energy Corporation of the references to our reports for Devon Energy Corporation, which appear in the Annual Report on Form 10-K of Devon Energy Corporation for the year ended December 31, 2009, and our report attached as Exhibit 99.1 to Amendment No. 1 to the Annual Report on Form 10-K of Devon Energy Corporation for the year ended December 31, 2009, filed on Form 10-K/A.

LaRoche Petroleum Consultants, Ltd.

By: */s/ William M. Kazman*
William M. Kazmann
Partner

August 18, 2010

Exhibit 23.3

CONSENT OF RYDER SCOTT COMPANY, L.P.

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-47672, 333-44702, 333-104922, 333-104933, 333-103679, 333-127630 and 333-159796) on Form S-8, and the Registration Statement (File No. 333-156025) on Form S-3 of Devon Energy Corporation of the references to our reports for Devon Energy Corporation, which appear in the Annual Report on Form 10-K of Devon Energy Corporation for the year ended December 31, 2009, and our report attached as Exhibit 99.2 to Amendment No. 1 to the Annual Report on Form 10-K of Devon Energy Corporation for the year ended December 31, 2009, filed on Form 10-K/A.

Ryder Scott Company, L.P.
TBPE Firm Registration No. F-1580

/s/ Ryder Scott Company, L.P.

Houston, Texas
August 18, 2010

Exhibit 23.4

ENGINEER'S CONSENT

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-47672, 333-44702, 333-104922, 333-104933, 333-103679, 333-127630 and 333-159796) on Form S-8, and the Registration Statement (File No. 333-156025) on Form S-3 of Devon Energy Corporation of the references to our reports for Devon Energy Corporation, which appear in the Annual Report on Form 10-K of Devon Energy Corporation for the year ended December 31, 2009, and our report attached as Exhibit 99.3 to Amendment No. 1 to the Annual Report on Form 10-K of Devon Energy Corporation for the year ended December 31, 2009, filed on Form 10-K/A.

AJM Petroleum Consultants

By: *_/s/ Robin G. Bertram_*
Robin G. Bertram, P.Eng.

August 18, 2010

Exhibit 31.1

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, John Richels, certify that:

1. I have reviewed this annual report on Form 10-K/A of Devon Energy Corporation; and

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report.

/s/ John Richels
John Richels
President and Chief Executive Officer

Date: August 18, 2010

Exhibit 31.2

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Jeffrey A. Agosta, certify that:

1. I have reviewed this annual report on Form 10-K/A of Devon Energy Corporation; and

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report.

/s/ Jeffrey A. Agosta
Jeffrey A. Agosta
Chief Financial Officer

Date: August 18, 2010

Exhibit 99.1

August 17, 2010

Mr. Bob Fant
Director Reserves and Economics
Devon Energy Corporation
1200 Smith Street
Houston, Texas 77002

Dear Mr. Fant:

At your request, LaRoche Petroleum Consultants, Ltd. (LPC) has audited the estimates of proved reserves and future net cash flow, as of December 31, 2009, to the Devon Energy Corporation (Devon) interest in certain properties located in Devon's Central, Western, and Southern Divisions in the United States as prepared and completed by Devon on January 15, 2010. The reserve estimates were prepared by Devon for public disclosure according to the United States Security and Exchange Commission (SEC) guidelines, and our audit is to confirm the accuracy of those estimates and classifications within the applicable SEC rules, regulations, and guidelines. It should be understood that our audit described herein does not constitute a complete reserve study of the oil and gas properties of Devon. It is our understanding that the properties audited by LPC comprise approximately ninety-three percent (93%) of Devon's aggregate reserves for the three Divisions set out above as estimated and reported by Devon. We prepared our own estimates of proved reserves and net cash flow for all of the properties audited, and compared our estimates to those prepared by Devon to complete our audit of such properties. We believe the assumptions, data, methods, and procedures used are appropriate for the purpose of this audit. Estimates by Devon and LPC are based on constant prices and costs as set forth in this letter and conform to our understanding of the SEC guidelines, reserves definitions, and applicable accounting rules.

It is our understanding that the properties audited by LPC and reflected in this audit report comprise sixty-four percent (64%) of Devon's aggregate, corporate reserves as estimated and reported by Devon.

The Central Division reserves are for the field areas designated by Devon's internal naming system as the Barnett Shale North Project Area, the Barnett Shale South Project Area, the Northridge Unconventional Field Group of the Eastern Oklahoma Project Area, the FWB Conventional Project Area, the FWB Conventional South Project Area, and the Cana Field Group of the Western Oklahoma Project Area.

The Southern Division reserves are for the areas designated by Devon's internal naming system as Field Groups consisting of the Agua Dulce Area, Bald Prairie, Bethany, Calhoun, Carthage Central, Carthage South, Dew, Maben, Montgomery County Area, Nan-Su-Gail, Oaks, Personville, Ruston North, Shady Grove, Stockman/Appleby, Waskom, and Zapata Area.

The Western Division reserves are for the following areas as designated by Devon’s internal naming system. For the Rocky Mountain District, the Bear Paw Uplift, Big Horn, Green River, Powder River Basin Conventional, San Juan, Uinta, Washakie, and Wind River Project Areas are included. For the Permian Basin District, the Ackerly Area, Anton Irish, Corbin, Deep Delaware, Fullerton Area, Gaucho, Keystone/Kermit, McKnight, Midland Basin, Odessa, Other PBTX, Outland, Ozona, Reeves, Slaughter, Townsend, Waddell North, Waddell South, Wasson, and Welch Area Field Groups are included.

The oil reserves include crude oil and condensate. Oil and natural gas liquid (NGL) reserves are expressed in barrels which are equivalent to 42 United States gallons. Gas volumes are expressed in thousands of standard cubic feet (Mcf) at the contract temperature and pressure bases.

The estimated reserves and future cash flow are for proved developed producing, proved developed non-producing, and proved undeveloped reserves. Devon’s estimates do not include any value for unproven reserves classified as probable or possible reserves that might exist for these properties, nor did it include any consideration that could be attributed to interests in undeveloped acreage beyond those tracts for which reserves have been estimated.

When compared on a field-by-field basis, some estimates determined by Devon are greater and some are lesser than the estimates determined by LPC. However, in our opinion, Devon’s estimates of proved oil and gas reserves and future cash flow as audited by LPC are in the aggregate reasonable, are within 10 percent of our numbers and have been prepared in accordance with generally accepted petroleum engineering and evaluation methods and procedures. These methods and procedures are set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers. We are satisfied with the methods and procedures used by Devon in preparing the December 31, 2009 reserve and future cash flow estimates. We saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by Devon.

The estimated reserves and future cash flow amounts in this audit of the Devon report are related to hydrocarbon prices. The price calculation methodology specified by the SEC regulations was used in the preparation of those estimates; however, actual future prices may vary significantly from the SEC-specified pricing. In addition, future changes in taxation affecting oil and gas producing companies and their products, and changes in environmental and administrative regulations may significantly affect the ability of Devon to operate and produce oil and gas at the projected levels. Therefore, volumes of reserves actually recovered and amounts of cash flow actually received may differ significantly from the estimated quantities presented in this audit.

Estimates of reserves for this audit were prepared using standard geological and engineering methods generally accepted by the petroleum industry. The reserves in this audit have been estimated using deterministic methods. The method or combination of methods utilized in the evaluation of each reservoir included consideration of the stage of development of the reservoir, quality and completeness of basic data, and production history. Recovery from various reservoirs and leases was estimated after consideration of the type of energy inherent in the reservoirs, the structural positions of the properties, and reservoir and well performance. In some instances, comparisons were made to similar properties where more complete data were available. We have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting rather than engineering or geosciences.

Prices used in this audit are based on the twelve-month unweighted arithmetic average of the first day of the month price for the period January through December 2009. Oil prices used by Devon are based on a Cushing West Texas Intermediate crude oil price of $61.18 per barrel, as published in Platts Oilgram, adjusted by lease for gravity, crude quality, transportation fees, and regional price differentials. Gas prices are based on a Henry Hub gas price of $3.87 per MMBTU, as published in Platts Gas Daily, adjusted by lease for energy content, transportation fees, and regional price differentials. NGL prices are based on a Mt. Belvieu composite product price of $28.89 per barrel, as published in the OPIS daily price bulletin, adjusted by area for composition, quality, transportation fees, and regional price differentials. Price differentials and adjustments to physical spot prices as of December 2009 were furnished by Devon and were accepted as presented. Oil and gas prices are held constant throughout the life of the properties. The weighted average prices over the life of the properties are $57.57/bbl for oil, $3.03/Mcf for gas, and $21.77/bbl for NGL.

Lease and well operating expenses are based on data obtained from Devon. As requested, expenses for the Devon-operated properties include only direct lease and field level costs. For properties operated by others, these expenses include the per-well overhead costs allowed under joint operating agreements along with direct lease and field level costs. Headquarters general and administrative overhead expenses of Devon are not included. Operating expenses are held constant throughout the life of the properties.

Capital costs and timing of all investments have been provided by Devon and are included as required for workovers, new development wells, and production equipment. Devon has represented to us that they have the ability and intent to implement their capital expenditure program as scheduled. Devon’s estimates of the cost to plug and abandon the wells net of salvage value are included and scheduled at the end of the economic life of individual properties. These costs are held constant.

LPC has made no investigation of possible gas volume and value imbalances that may have been the result of overdelivery or underdelivery to the Devon interest. Our projections are based on Devon receiving its net revenue interest share of estimated future gross oil, gas, and NGL production.

An on-site inspection of the properties has not been performed nor has the mechanical operation or condition of the wells and their related facilities been examined by LPC. The costs associated with the continued operation of uneconomic properties are not reflected in the cash flows.

The evaluation of potential environmental liability from the operation and abandonment of the properties is beyond the scope of this audit. In addition, no evaluation was made to determine the degree of operator compliance with current environmental rules, regulations, and reporting requirements. Therefore, no estimate of the potential economic liability, if any, from environmental concerns is included in our projections.

In our audit, we accepted without independent verification the accuracy and completeness of the information and data furnished by Devon with respect to ownership interest, oil and gas production, well test data, oil and gas prices, operating and development costs, and any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention which brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data.

The reserves estimated in our audit process and those presented by Devon are estimates only and should not be construed as exact quantities. They may or may not be recovered; if recovered, the revenues there from and the costs related thereto could be more or less than the estimated amounts. These estimates should be accepted with the understanding that future development, production history, changes in regulations, product prices, and operating expenses would probably cause us to make revisions in subsequent evaluations. A portion of these reserves are for behind-pipe zones, undeveloped locations, and producing wells that lack sufficient production history to utilize performance-related reserve estimates. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogies to similar production. These reserve estimates are subject to a greater degree of uncertainty than those based on substantial production and pressure data. It may be necessary to revise these estimates up or down in the future as additional performance data become available. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geological data; therefore, our conclusions represent informed professional judgments only, not statements of fact.

The results of our third party study were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Devon Energy Corporation.

Devon Energy Corporation makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Devon Energy Corporation has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Devon Energy Corporation of the references to our name as well as to the references to our third party audit for Devon Energy Corporation, which appears in the December 31, 2009 annual report on Form 10-K and/or 10-K/A of Devon Energy Corporation. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Devon Energy Corporation.

We have provided Devon Energy Corporation with a digital version of the original signed copy of this audit letter. In the event there are any differences between the digital version included in filings made by Devon Energy Corporation and the original signed audit letter, the original signed audit letter shall control and supersede the digital version.

LPC’s technical personnel responsible for preparing this audit meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers. We are independent petroleum engineers, geologists, and geophysicists and are not employed on a contingent basis. Data pertinent to the audit are maintained on file in our office.

Very truly yours,

LaRoche Petroleum Consultants, Ltd.
State of Texas Registration Number F-1360

William M. Kazmann
Licensed Professional Engineer
State of Texas No. 45012

Joe A. Young
Licensed Professional Engineer
State of Texas No. 62866

WMK:mk
09-400, 500, 700

cc: Bret Jameson
Ceci Leonard
Chad Shorre

Exhibit 99.2

DEVON ENERGY CORPORATION

OFFSHORE DIVISION

GULF PROPERTIES

Estimated

Future Proved Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

S. E. C.

Economic Parameters

As of

December 31, 2009

/s/ Fred W. Ziehe
Fred W. Ziehe, P.E.
TBPE License No. 63630
Managing Sr. Vice President
RYDER SCOTT COMPANY, L.P.
TBPE Firm License No. F-1580 [SEAL]

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5235 TELEPHONE (713) 651-9191

August 9, 2010

Devon Energy Corporation
20 North Broadway, Suite 1500
Oklahoma City, Oklahoma 73102-8260

Gentlemen:

At your request, Ryder Scott Company (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Devon Energy Corporation (Devon) as of December 31, 2009. The subject properties are located in Devon's Offshore Division in the state and federal waters of the Gulf of Mexico. The reserves and income data were estimated based on the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 18, 2010, and presented herein, was prepared for public disclosure by Devon in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. Based on information provided by Devon, the total proved reserves summarized in our report represent approximately 3 percent of Devon's reported total proved reserves on a barrel equivalent basis for their continuing operations.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2009, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
DEVON ENERGY CORPORATION
OFFSHORE DIVISION — GULF PROPERTIES
As of December 31, 2009

	Total Proved Developed and Undeveloped
Net Remaining Reserves	
Oil/Condensate — MBarrels	32,684.5
Plant Products — MBarrels	2,342.7
Gas — MMCF	341,994
Oil Equivalent — MBOE	*92,026.1*
Income Data — M$	
Future Gross Revenue	$ 3,421,296
Deductions	2,096,330
Future Net Income (FNI)	$ 1,324,966
Discounted FNI @ 10%	$ 966,866

Liquid hydrocarbons are expressed in thousands of standard 42 gallon barrels. All gas volumes are reported on an "as sold" basis expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The oil equivalent volumes shown above are calculated assuming a conversion of 6.0 MCF per 1.0 barrel oil and are expressed as thousands of equivalent barrels (MBOE). In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (M$).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package Merak Peep Petroleum Economic Evaluation and Decline Analysis Software, a copyrighted program of Schlumberger Limited. The program was used solely at the request of Devon. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The proved future gross revenue is before the deduction of production taxes. The deductions are comprised of the normal direct costs of operating the wells, ad valorem taxes, production taxes, certain transportation costs, recompletion costs, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 60 percent and gas reserves account for the remaining 40 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at three other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income — M$ As of December 31, 2009
Discount Rate Percent	Total Proved
5	$1,125,017
15	$ 840,154
20	$ 737,427

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10 (a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled “Petroleum Reserves Definitions” in this report. The developed proved non-producing reserves included herein consist of the shut-in and behind pipe categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes included herein do not attribute gas consumed in operations as reserves.

Reserves are those estimated remaining quantities of petroleum which are anticipated to be economically producible, as of a given date, from known accumulations under defined conditions. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Devon’s request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward. The proved reserves included herein were estimated using deterministic methods. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered”.

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease”. Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Devon’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which Devon owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. The reserve evaluator must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved". The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered". The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves". All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 50 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. The performance method included, but may not be limited to, decline curve analysis, which utilized extrapolations of historical monthly and/or daily production data and pressure data generally available through August 2009 in those cases where such data were considered to be definitive. The data utilized in this analysis were supplied to Ryder Scott by Devon or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 50 percent of the proved producing reserves were estimated by a combination of the performance and volumetric methods where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data alone as a basis for the reserve estimates was considered to be inappropriate.

All of the proved non-producing and undeveloped reserves included herein were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data supplied to Ryder Scott by Devon or which we have obtained from public data sources that were generally available through November 2009. The data utilized from the analogues, as well as seismic and well data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

It should be noted that the proved reserve volumes described herein consist of primary recovery, including both pressure depletion and natural water drive mechanisms.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Devon has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future production and income, we have relied upon data furnished by Devon with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data supplied by Devon. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations”. In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Devon. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Devon furnished us with the above mentioned average prices in effect on December 31, 2009. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the pricing reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials”. The differentials used in the preparation of this report were estimated by us based on information supplied by Devon.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices”. The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Benchmark Price Reference	Benchmark Price	Average Realized Price
Offshore Division —	**Oil/Cond**	**WTI Cushing**	**$61.18/ Bbl**	**$60.83/ Bbl**
Gulf Properties	**Gas**	**Henry Hub**	**$3.87/ MMBTU**	**$4.03/ Mcf**
	Ngl	**Mt. Belvieu**	**$28.89/Bbl**	**$24.06/Bbl**

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were provided by Devon and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. When applicable for operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The initial operating costs for each property, provided by Devon are based on current operating costs, but may include adjustments due to ongoing projects in certain fields which might affect future operating costs. In certain cases, a portion of the operating costs is considered “fixed” and remains constant as production declines. The remaining portion is considered “variable” and is reduced over time as variables such as production throughput and/or well counts decline. In addition, certain gathering and transportation fees, as provided by Devon, were included in this report and shown as “Transport Costs”. These costs and the related assumptions, provided by Devon, were accepted without independent verification. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Devon and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage, as provided by Devon, was significant. The estimates of the net abandonment costs furnished by Devon were accepted without independent verification. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Devon’s estimate.

The proved non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Devon’s plans to develop these reserves as of December 31, 2009. The implementation of Devon’s development plans as presented to us and incorporated herein is subject to the approval process adopted by Devon’s management. As the result of our inquires during the course of preparing this report, Devon has informed us that the development activities included herein have been subjected to and received the internal approvals required by Devon’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Devon. Additionally, Devon has assured us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

In certain instances, mainly in the Deep Water District, some proved undeveloped reserves are scheduled to be drilled beyond five years from the as of date of this report. This is largely due to the lack of well bore availability in these offshore properties. However, the senior management of Devon has provided us a letter that states "Even though Devon has announced intent to divest their assets in the offshore Gulf of Mexico, Devon is committed to development of their non-producing reserves" and "in the event Devon continues to own the assets when the non-producing reserves are to be developed, their approved 15-year Long Range Plan contains sufficient capital funding specifically designated for the development of . . . these reserves . . ."

Current costs used by Devon were held constant throughout the life of the properties, except as noted above.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any publicly traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Devon. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Devon.

Devon makes periodic filings on Form 10-K and/or 10-K/A with the SEC under the 1934 Exchange Act. Furthermore, Devon has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K and/or 10-K/A is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Devon of the references to our name as well as to the references to our third party report for Devon, which appears in the December 31, 2009 annual report on Form 10-K and/or 10-K/A of Devon. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Devon.

We have provided Devon with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Devon and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Fred W. Ziehe
Fred W. Ziehe, P.E.
TBPE License No. 63630
Managing Senior Vice President [SEAL]

FWZ/sm

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Fred W. Ziehe was the primary technical person responsible for overseeing the estimate of the reserves, future production and income presented herein.

Mr. Ziehe, an employee of Ryder Scott Company L.P. (Ryder Scott) since 1976, is a Managing Sr. Vice President and also serves as an Engineering Group Coordinator responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Ziehe was a Reservoir Engineer with Exxon Company U.S.A. For more information regarding Mr. Ziehe's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Ziehe earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1974, with Magna Cum Laude honors and is a registered Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Ziehe fulfills. As part of his 2009 continuing education hours, Mr. Ziehe attended sixteen hours of internally presented formalized training, as well as four hours at a public forum and at professional society presentations specifically on the new SEC regulations relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Ziehe attended an additional eighteen hours of formalized in-house training during 2009 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants. Mr. Ziehe served as a speaker at a public forum and as an in-house class instructor concerning the revised pricing criteria of the new SEC regulations.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Ziehe has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC Regulations". The SEC Regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions, as the following definitions, descriptions and explanations rely wholly or in part on excerpts from the original document (direct passages excerpted from the aforementioned SEC document are denoted in italics herein).

Reserves are those estimated remaining quantities of petroleum which are anticipated to be economically producible, as of a given date, from known accumulations under defined conditions. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC Regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the Commission. The SEC Regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the Commission unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (*i.e.* , *absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (* *i.e.* *, potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)

Sponsored and Approved by:

SOCIETY OF PETROLEUM ENGINEERS (SPE),

WORLD PETROLEUM COUNCIL (WPC)

AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)

SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing;

(2) wells which were shut-in for market conditions or pipeline connections; or

(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.3

DEVON CANADA CORPORATION

RESERVE AUDIT
OPINION

EXECUTIVE SUMMARY

Effective Date: December 31, 2009

January 15, 2010

Devon Canada Corporation
2000, 400 — 3 rd Avenue SW
Calgary, Alberta
T 2 P 4 H 4

Attention: Mr. Dean Curry

Re: Devon Canada Corporation
December 31, 2009 Reserve Audit Opinion

At your request and authorization, AJM Petroleum Consultants ("AJM") has audited the reserves management processes and practices of Devon Canada Corporation ("Devon Canada") and the resulting estimates as of December 31, 2009 that are detailed in the accompanying tables with respect to the reserves of your company. Our examination included such tests and procedures as we considered necessary under the circumstances to render our opinion.

During the course of our examination, we audited in excess of 91 percent of Devon Canada's total proved reserves. AJM's estimate for the audited properties varied from Devon Canada's estimates by two percent. When compared to Devon Canada's parent corporation, Devon Energy Corporation, AJM audited 25 percent of the company's total proved reserves.

The scope of the audit consisted of the independent preparation of our own estimates of the proved and proved plus probable reserves and the comparison of our proved reserve results to the estimates prepared by the company. When compared on a field by field basis, some estimates prepared by Devon Canada are greater than and some are less than those prepared by AJM. However, in our opinion, the estimates prepared by Devon Canada are in aggregate reasonable, are within the established audit tolerance of plus or minus 10 percent and the estimates have been prepared in accordance with generally accepted petroleum engineering practices and procedures. These practices and procedures are detailed within the Canadian Oil and Gas Evaluation Handbook ("COGEH"), set out by the Society of Petroleum Evaluation Engineers ("SPEE") as well as the Society of Petroleum Engineers' ("SPE") Standards Pertaining to the Estimation and Auditing of Oil and Gas Reserves. The proved and proved plus probable reserve estimates prepared by both Devon Canada and AJM conform to the reserve definitions as set forth in the SEC's Regulation S-X Part 210.4-10(a) and as clarified in subsequent Commission Staff Accounting Bulletins. We believe that such assumptions, data, methods, and procedures are appropriate for the purpose served by the report.

AJM was provided with Devon Canada's base hydrocarbon prices (oil, gas, condensate and natural gas liquids) as of December 31, 2009 in order to estimate the company's net after royalty reserves. In accordance with SEC requirements all prices and costs (capital and operating) were held constant. The effects of derivative instruments designated as price hedges of oil and gas quantities if any, are not reflected in AJM's individual property evaluations. An oil equivalent conversion factor of 6.0 Mcf per 1.0 barrel oil was used for sales gas.

In general terms, Devon Canada's corporate structure is such that lands are held within either Devon Canada Partnership ("DCP") or Devon ARL Corporation ("DRL"). For the purpose of this evaluation, properties which consist of both DCP and DRL lands are reported separately.

The Evaluation Procedure section included in this report details the reserves definitions, price and market demand forecasts and general procedure used by AJM in its reserve estimates. The extent and character of ownership and all factual data supplied by Devon Canada Corporation were accepted as presented. A field inspection and environmental/safety assessment of the properties was not made by AJM and the consultant makes no representations and accepts no responsibilities in this regard.

It should be understood that our audit does not constitute a complete reserves study of the oil and gas properties of your company. In the conduct of our examinations we have not independently verified the accuracy and completeness of all the information and data furnished by your company with respect to ownership interests, oil and gas production, historical costs of operations and development, product prices, and agreements relating to current and future operations and sales of production. We have, however, specifically identified to you the information and data upon which we relied so that you can subject it to procedures you consider necessary. Furthermore, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any of the information or data, we did not rely on that information or data until we had satisfactorily resolved our questions or independently verified it.

We are independent with respect to the company as provided in the standards pertaining to the estimating and auditing of oil and gas reserves information included in COGEH and the Association of Professional Engineers, Geologists and Geophysicists of Alberta ("APEGGA").

This audit is for the information of your company and for the information and assistance of its independent public accountants in connection with their review of, and report upon, the financial statements of your company. Supporting data documenting the audit, along with data provided by Devon Canada, are on file in our office. The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Devon Energy Corporation.

Devon Energy Corporation makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Devon Energy Corporation has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-X of Devon Energy Corporation to the references to our name as well as to the references to our third party report for Devon Energy Corporation, which appears in the December 31, 2009 annual report on Form 10-K and/or 10-K/A of Devon Energy Corporation. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Devon Energy Corporation.

Yours truly,

AJM Petroleum Consultants

Original signed by: *"Robin G. Bertram"*
Robin G. Bertram, P. Eng.
Vice President Engineering

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EVALUATION PROCEDURE

DEFINITIONS AND METHODOLOGY

Effective as of December 2009

Table of Contents

PROCEDURE

AJM Petroleum Consultants has prepared estimates of resources and reserves in accordance with the definitions published in The Canadian Oil and Gas Evaluation Handbook (COGEH), Volume 1, 2 nd Edition. The reader is referred to the Handbook for a complete description of the particular definitions quoted as follows.

Resources or Reserves Evaluation

A “Resources or Reserves Evaluation” is the process whereby a qualified reserves evaluator estimates the quantities and values of oil and gas resources or reserves by interpreting and assessing all available pertinent data. The value of an oil and gas asset is a function of the ability or potential ability of that asset to generate future net revenue, and it is measured using a set of forward-looking assumptions regarding resources or reserves, production, prices, and costs. Evaluations of oil and gas assets, in particular reserves, include a discounted cash flow analysis of estimated future net revenue.

Reserves Audit

A “Reserves Audit” is the process carried out by a qualified reserves auditor that results in a reasonable assurance, in the form of an opinion, that the reserves information has in all material respects been determined and presented according to the principles and definitions adopted by the Society of Petroleum Evaluation Engineers (“SPEE”) (Calgary Chapter), and Association of Professional Engineers, Geologists and Geophysicists of Alberta (“APEGGA”) and are, therefore free of material misstatement.

The reserves evaluations prepared by the Corporation have been audited, not for the purpose of verifying exactness, but the reserves information, company policies, procedures, and methods used in estimating the reserves will be examined in sufficient detail so that AJM Petroleum Consultants (“AJM”) can express an opinion as to whether, in the aggregate, the reserves information presented by the Corporation are reasonable.

AJM may require its own independent evaluation of the reserves information for a small number of properties, or for a large number of properties as tests for the reasonableness of the Corporation’s evaluations. The tests to be applied to the Corporation's evaluations insofar as their methods and controls and the properties selected to be re-evaluated will be determined by AJM, in its sole judgment, to arrive at an opinion as to the reasonableness of the Corporation's evaluations.

Reserves Review

A "Reserves Review" is the process whereby a reserves auditor conducts a high-level assessment of reserves information to determine if it is plausible. The steps consist primarily of enquiry, analytical procedure, analysis, review of historical reserves performance, and discussion with the Corporation's reserves management staff.

"Plausible" means the reserves data appear to be worthy of belief based on the information obtained by the independent qualified reserves auditor in carrying out the aforementioned steps. Negative assurance can be given by the independent reserves auditor, but an opinion cannot. For example, "Nothing came to my attention that would indicate the reserves information has not been prepared and presented in accordance with principles and definitions adopted by the SPEE (Calgary Chapter), and APEGGA (Practice Standard for the Evaluation of Oil and Gas Reserves for Public Disclosure).

Reviews do not require examination of the detailed document that supports the reserves information, unless this information does not appear to be plausible.

RESERVE DEFINITIONS

Reserve Classification: Proved and probable reserves are classified by AJM Petroleum Consultants in accordance with the following definitions that are the United States Securities and Exchange Commission Regulation S-X Part 210.4-10. These definitions are as follows:

Proved Oil And Gas Reserves : Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the “proved” classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(A) oil that may become available from known reservoirs but is classified separately as “indicated additional reserves”;

(B) crude oil, natural gas and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; and

(C) crude oil, natural gas and natural gas liquids, that may occur in undrilled prospects.

Proved Developed Oil And Gas Reserves: Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

The SEC does not further subdivide proved developed reserves. AJM further subdivides proved developed reserves between proved developed producing and proved developed non-producing reserves, as follows. The definition and guidelines are documented in the Petroleum Resources Management System (“PRMS”) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Proved Developed Producing Reserves: Proved developed producing reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Proved Developed Non-Producing Reserves: Proved developed non-producing reserves include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Proved Undeveloped Reserves: Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Probable Reserves: Probable reserves are those additional reserves which analysis of geoscience and engineering data indicates are less certain to be recovered than proved reserves but more certain to be recovered than possible reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves (2P).

The SEC does not further sub-divide probable reserves. AJM further sub-divides probable reserves into developed and undeveloped and producing and non-producing, as follows:

Probable Developed: Probable developed reserves are expected quantities to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Developed reserves may be subcategorized as producing or non-producing.

Producing: Probable reserves that are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-Producing: Probable reserves include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Probable Undeveloped: Probable undeveloped reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, or (3) where a relatively large expenditure (eg. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

RESOURCE AND RESERVE ESTIMATION

AJM generally assigns reserves to properties via deterministic methods. Probabilistic estimation techniques are typically used where there is a low degree of certainty in the information available and is generally used in resource evaluations. This will be stated within the detailed property reports.

Deterministic

Reserves and resources were estimated either by i) volumetric, ii) decline curve analysis, iii) material balance techniques, or iv) performance predictions.

Volumetric reserves were estimated using the wellbore net pay and an assigned drainage area or, where sufficient data was available, the reservoir volumes calculated from isopach maps. Reservoir rock and fluid data were obtained from available core analysis, well logs, PVT data, gas analysis, government sources, and other published information either on the evaluated pool or from a similar reservoir in the immediate area. In mature (producing) reservoirs decline curve analysis and/or material balance was utilized in all applicable evaluations.

Statistical Analysis

Whenever there is the need within an evaluation to assign reserves based on analogy or when volumetric reserves are being assigned, AJM utilizes a variety of different tools in support of. When evaluating Western Canadian prospects, typically AJM uses petroCUBE™.

The petroCUBE program is a web-based (www.petroCUBE.com) product co-developed by AJM Petroleum Consultants and geoLOGIC Systems Inc. petroCUBE provides geostatistical, technical, and financial information for conventional hydrocarbon plays throughout the Western Canadian Sedimentary Basin (“WCSB”).

The information provided by petroCUBE is an unbiased independent perspective into the historical performance of the conventional hydrocarbon activity in the WCSB. The statistical information is presented by commodity type (gas, oil) with each commodity further analyzed by geographic area and play type.

Analysis output includes cumulative frequency resource distribution curves, chance of success tables, production performance profiles for each play type and area, unrisked and risked resources, and initial production rates on a per well zone basis, and full cycle economic and play parameters.

Cumulative frequency curves show how the volumes for a play are distributed. These calculations include the average volumes for a play (P50), volumes for the best 10 percent of the wells (P_{10}), the minimum volumes developed by 90 percent of the wells (P_{90}).

Reserves assigned are compared to those volumes noted in the cumulative frequency curves for the corresponding area and play type. Typically an expected or proved plus probable reserve is a P_{50} volume.

Probabilistic

Because of the uncertainty inherent in reservoir parameters, probabilistic analysis, which is based on statistical techniques, provides a formulated approach by which to obtain a reasonable assessment of the petroleum initially in place (PUP) and/or the recoverable resource. Probabilistic analysis involves generating a range of possible outcomes for each unknown parameter and their associated probability of occurrence. When probabilistic analysis is applied to resource estimation, it provides a range of possible PIIPs or recoverable resources.

In preparing a resource estimate, AJM assesses the following volumetric parameters: areal extent, net pay thickness, porosity, hydrocarbon saturation, reservoir temperature, reservoir pressure, gas compressibility factor, recovery factor, and surface loss. A team of professional engineers and geologists experienced in probabilistic resource evaluation considered each of the parameters individually to estimate the most reasonable range of values. Working from existing data, the team discusses and agrees on the low (P_{90}) and high (P_{10}) values for each parameter. To help test the reasonableness of the proposed range, a minimum (P_{99}) and maximum (P1) value are also extrapolated from the low and high values. After ranges have been established for each parameter, these independent distributions are used to determine a P_{90}, P_{50}, and P_{10} result which comprise AJM's estimated range of PUP or recoverable resource.

It is important to note that the process used to determine the final P_{10}, P_{90}, and P_{50} results involves multiplying the various volumetric parameters together. This yields results which require adjustments to maintain an appropriate probability of occurrence. For example, when calculating total reservoir volume (Area x Pay), the chance of getting a volume greater than the P_{10} Area x P_{10} Pay is less than 10 percent — the chance of getting the calculated result is only 3.5 percent (p_{35}). As you multiply additional P_{10} values, the probability of achieving the calculated value becomes less likely. Similarly, multiplying P_{90} parameters together will yield a result that has a probability greater than P_{90}. As such, when multiplying independent distributions together the results must be adjusted via interpolation to determine final P_{90} and P_{10} values.

The results appearing in this report represent interpolated P_{90} and P_{10} values. As defined by COGEH (and the Petroleum Resource Management System "PRMS"), the P_{50} estimate is the "best estimate" for reporting purposes.

PRODUCTION FORECASTS

Production forecasts were based on historical trends or by comparison with other wells in the immediate area producing from similar reservoirs. Non-producing gas reserves were forecast to come on-stream within the first two years from the effective date under direct sales pricing and deliverability assumptions, if a tie-in point to an existing gathering system was in close proximity (approximately two miles). If the tie-in point was of a greater distance (and dependent on the reserve volume and risk) the reserves were forecast to come on-stream in years three or four from the effective date. If the reserves were located in a remote location and/or the reserve volume was of higher risk, the reserves were forecast to come on-stream beyond five years from the effective date. These on-stream dates were used when the company could not provide specific on-stream date information.

LAND SCHEDULE AND MAPS

The evaluated Corporation provided schedules of land ownership which included lessor and lessee royalty burdens. The land data was accepted as factual and no investigation of title by AJM was made to verify the records.

Well maps included within this report represent all of the Corporation's interests that were evaluated in the specified area.

GEOLOGY

An initial review of each property is undertaken to establish the produced maturity of the reservoir being evaluated. Where extensive production history exists a geologic analysis is not conducted since the remaining hydrocarbons can be determined by productivity analysis.

For properties that are not of a mature production nature a geologic review is conducted. This work consists of:

- developing a regional understanding of the play,
- assessing reservoir parameters from the nearest analogous production,
- analysis of all relevant well data including logs, cores, and tests to measure net formation thickness (pay), porosity, and initial water saturation,
- auditing of client mapping or developing maps to meet AJM's need to establish volumetric hydrocarbons-in-place.

Procedures specific to the project are discussed in the body of the report.

ROYALTIES AND TAXES

General

All royalties and taxes, including the lessor and overriding royalties, are based on government regulations, negotiated leases or farmout agreements, that were in effect as of the evaluation effective date. If regulations change, the net after royalty recoverable reserve volumes may differ materially.

AJM Petroleum Consultants utilizes a variety of reserves and valuation products in determining the result sets.

OPERATING AND CAPITAL CONSIDERATIONS

Operating and capital costs were based on current costs escalated to the date the cost was incurred, and are in current year dollars. The economic runs provide the escalated dollar costs as found in the Pricing Table 1 in the Price and Market Demand section.

Reserves estimated to meet the standards of NI 51-101 for constant prices and costs (optimal), are based on unescalated operating and capital costs.

Capital costs were either provided by the Corporation (and reviewed by AJM for reasonableness); or determined by AJM taking into account well capability, facility requirement, and distance to markets. Facility expenditures for shut-in gas are forecast to occur prior to the well's first production.

Operating costs were determined from historical data on the property as provided by the evaluated Corporation. If this data was not available or incomplete, the costs were based on AJM experience and historical database. Operating costs are defined into three types.

The first type, variable ($/Unit), covers the costs directly associated with the product production. Costs for processing, gathering and compression are based on raw gas volumes. Over the life of the project the costs are inflated in escalated runs to reflect the increase in costs overtime. In a constant dollar review the costs remain flat over the project life.

The second type, fixed plant or battery ($/year), is again a fixed component over the project life and reflects any gas plant or battery operating costs allocated back to the evaluated group. The plant or battery can also be run as a separate group and subsequently consolidated at the property level.

The third type takes the remaining costs that are not associated with the first two and assigns them to the well based on a fixed and variable component. A split of 65 percent fixed and 35 percent variable assumes efficiencies of operation over time, i.e.: the well operator can reduce the number of monthly visits as the well matures, workovers may be delayed, well maintenance can also be reduced. The basic assumption is that the field operator will continue to find efficiencies to reduce the costs over time to maintain the overall $/Boe cost. Thus as the production drops over time the 35 percent variable cost will account for these efficiencies. If production is flat all the costs will also remain flat. Both the fixed and variable costs in this type are inflated in the escalated case and held constant in the constant dollar review. These costs also include property taxes, lease rentals, government fees, and administrative overhead.

In evaluations conducted for purposes of Nl 51-101 well abandonment costs have been included. These costs were either provided by the Corporation (and reviewed by AJM for reasonableness) or estimated by AJM based on its experience. For undeveloped reserve estimates for undrilled locations, site reclamation costs are also included for the purpose of determining whether reserves should be attributed to that property in the first year in which the reserves are considered for attribution to the property.

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PRICE AND MARKET DEMAND FORECASTS

Pricing Overview

Devon provided AJM with hydrocarbon prices (oil, gas condensate, and natural gas liquids) appropriate for use in the preparation of a reserves report to be filed with the SEC with an effective date of December 31, 2009. These prices were calculated in accordance with the "Modernization of Oil and Gas Reporting: Final Rule" and were determined by taking the un-weighted average of the prices on the first day of the month for the preceding 12 months (January 1,2009 through to December 1,2009).

The effects of derivative instruments designated as price hedges of oil and gas quantities if any, are not reflected in AJM's individual property evaluations.

	Benchmark	Benchmark Price	Weighted Average Realized Report Price
Oil	NYMEX WTI @ Cushing	$61.18/bbl	$43.29/bbl
Gas	NYMEX Henry Hub	$3.87/MMbtu	$3.53/Mcf
NGL	Mt. Belvieu	$28.89/bbl	$28.40/bbl

GLOSSARY OF TERMS

AJM subscribes to the Glossary of Terms as defined by the Canadian Oil and Gas Evaluation Handbook, Volume 2.