

DELTA PETROLEUM CORPORATION

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For Immediate Release

DELTA PETROLEUM CORPORATION ANNOUNCES 2007 FINANCIAL RESULTS AND AGREEMENT TO JOINTLY DEVELOP ADDITIONAL RESERVES, PRODUCTION AND ACREAGE IN VEGA AREA OF THE PICEANCE BASIN

TOTAL ESTIMATED INCREASE IN PICEANCE BASIN RESOURCE POTENTIAL - 1.4 TCFE

REVISED DRILLING CAPITAL EXPENDITURE BUDGET FOR 2008 TO \$350 - \$370 MILLION

DENVER, Colorado (February 28, 2008) -- Delta Petroleum Corporation (NASDAQ Global Market: DPTR), an independent oil and gas exploration and development company ("Delta" or the "Company"), today announced its financial and operating results for the quarter and year ended December 31, 2007, as well as an agreement to develop additional reserves, production and acreage in the Vega Area of the southern Piceance Basin.

VEGA AREA AGREEMENT

The Company has closed a transaction with EnCana Oil & Gas (USA) Inc., ("EnCana") to jointly develop a portion of EnCana's leasehold in the Vega Area of the Piceance Basin. In addition, Delta has acquired over 1,700 drilling locations on approximately 18,250 gross acres with a 95% working interest. Delta also increased its interests in currently producing wells and will realize an addition of six million cubic feet ("MMcfd") of natural gas net per day. The transaction increases the Company's working interest in the North Vega project leasehold to 95% from an average 50%, with additional acquired acreage that includes the Buzzard Creek federal unit (4,300 acres) and approximately 6,000 acres immediately adjacent to the Buzzard Creek Unit. With this agreement, the Company's acreage position in the Vega Area totals over 20,250 net acres.

The Company estimates that the transaction's total resource potential is in excess of 1.4 trillion cubic feet equivalent ("Tcfe") giving the Company in excess of 2.0 Tcfe in the Piceance Basin. This also brings the Company's estimated total proved reserves to approximately 530 billion cubic feet equivalent ("Bcfe"). The effective date of the transaction is March 1, 2008. Under terms of the agreement the Company has committed to fund \$410.5 million with \$110.5 million at closing and three \$100 million installments over the next four years that have been guaranteed with a Letter of Credit.

Roger Parker, Delta's Chairman and CEO said, "This transaction more than doubles our position and drilling inventory in the southern Piceance Basin in one large contiguous acreage block. As previously demonstrated, we have significantly improved our drilling and operational efficiencies in the Vega Area thereby substantially enhancing our financial performance in the Piceance Basin. We are also announcing an increase in our 2008 drilling capital expenditure budget to a range of \$350 - \$370 million. The increase in our drilling capex budget allows us to accelerate our Vega Area drilling program and realize significant reserve growth and increases in the present value of our Piceance assets. We are running four rigs full time and expect to increase to eight rigs over the next 12 months in this area. Most importantly, this agreement provides Delta a significant drilling inventory for predictable, repeatable production and proved reserves per share growth for years to come."

RESULTS FOR THE FOURTH QUARTER 2007

For the quarter ended December 31, 2007, the Company reported total production of 5.03 Bcfe, which was in the mid range of previously stated guidance. Production increased 34% when compared with the fourth quarter of 2006 and 10% from third quarter 2007 levels. Total revenue increased 21% to \$45.1 million in the fourth quarter, compared with \$37.3 million in the quarter ended December 31, 2006. Revenue from oil and gas sales increased 57% to \$31.3 million, compared with \$19.9 million in the prior year quarter. The increase in oil and gas revenue when compared with the corresponding period of the previous year was primarily due to the significant increase in production from continuing operations. Revenue from contract drilling and trucking fees decreased 32% to \$11.5 million, versus \$16.9 million in the fourth quarter of 2006 due to an increase in DHS Drilling Company revenues from Delta which are eliminated in consolidation. EBITDAX totaled \$26.6 million during the three months ended December 31, 2007, compared with \$17.9 million in the three months ended December 31, 2006. Discretionary cash flow increased 61% to \$22.5 million, versus \$14.0 million in the comparable 2006 quarter. (Note: EBITDAX and Discretionary Cash Flow are non-GAAP measures and are described in greater detail below.)

The Company reported a fourth quarter net loss of (\$30.0 million), or (\$0.47) per share, compared with a net loss of (\$10.5 million), or (\$0.20) per share, in the fourth quarter of 2006. The fourth quarter 2007 loss included \$11.3 million of dry hole costs related to three exploratory wells, \$5.4 million of losses on ineffective derivative instruments, \$4.8 million of non-cash equity compensation expense and a \$4.2 million loss from DHS Drilling Company.

FOURTH QUARTER PRODUCTION VOLUMES, UNIT PRICES AND COSTS

Production volumes, average prices received and cost per equivalent thousand cubic feet (Mcf) for the three months ended December 31, 2007 and 2006 were as follows:

	Quarter Ended December 31,			
	2007		2006 ⁽¹⁾	
	Onshore	Offshore	Onshore	Offshore
Production volume –				
Total production (MMcfe)	4,812	216	3,522	231
Production from				
continuing operations:				
Oil (MBbls)	195	36	191	38
Natural Gas (MMcf)	2,908	-	1,358	-
Total (MMcfe)	4,078	216	2,501	231
Net average daily production-				
continuing operations:				
Oil (Bbl)	2,118	392	2,070	418
Natural Gas (Mcf)	31,616	-	14,761	-
Average sales price:				
Oil (per barrel)	\$ 82.79	\$ 66.93	\$ 58.03	\$ 41.15
Natural Gas (per Mcf)	\$ 4.38	\$ -	\$ 5.32	\$ -
Hedge effect (per Mcfe)	\$.57	\$ -	\$.23	\$ -
Lease operating costs -				
(per Mcfe)	\$ 1.18	\$ 5.16	\$ 1.44	\$ 2.49

⁽¹⁾Revised for operations discontinued in 2007.

Lease operating expense for the three months ended December 31, 2007 totaled \$5.9 million, compared with \$4.2 million in the comparable prior year quarter. Lease operating expense from continuing operations for onshore properties approximated \$1.18 per thousand cubic feet equivalents (Mcf) in the fourth quarter, compared with \$1.44 per Mcfe in the year earlier period.

Depreciation, depletion and amortization expense – oil and gas – was \$17.7 million for the three months ended December 31, 2007, versus \$16.2 million in the comparable year earlier period. Depletion expense decreased from a rate of \$5.77 per Mcfe in the fourth quarter 2006 to a rate of \$4.02 per Mcfe in the fourth quarter 2007.

Exploration expense consists of geological and geophysical costs and lease rentals. The Company's exploration costs for the three months ended December 31, 2007 totaled \$2.9 million, compared with \$1.3 million in the prior year period. Exploration expense for the fourth quarter 2007 primarily related to seismic projects in Utah, Wyoming and Texas.

General and administrative expense increased 39.4% to \$12.3 million during the fourth quarter of 2007, versus \$8.8 million in the three months ended December 31, 2006. The increase in general and administrative expense was primarily due to higher non-cash equity compensation costs of \$3.1 million.

RESULTS FROM THE FULL YEAR 2007

For the year ended December 31, 2007, the Company reported total production of 17.8 billion cubic feet of natural gas equivalents (Bcfe). Production for the year ended increased 10% when compared to the prior year. Total revenue increased 12% to \$164.2 million for the year ended December 31, 2007, compared with \$146.7 million in the year ended December 31, 2006.

The Company reported a net loss for the year ended December 31, 2007 of \$149.3 million, or (\$2.44) per diluted share, compared with net income of \$435,000, or \$0.01 per diluted share, for the year ended December 31, 2006. Net loss increased significantly due to a \$49.6 million increase in valuation allowance required to be recorded against the Company's deferred tax assets beginning in the second quarter of 2007, significant impairments and dry hole costs during 2007 which totaled \$85.1 million and non-cash equity compensation of \$15.9 million. EBITDAX totaled \$83.0 million for the year ended December 31, 2007, compared with \$76.4 million for the year ended December 31, 2006. Discretionary cash flow increased 24% to \$75.0 million, versus \$60.5 million in the comparable 2006 quarter.

FULL YEAR 2007 PRODUCTION VOLUMES, UNIT PRICES AND COSTS

Production volumes, average prices received and cost per equivalent Mcf for the twelve months ended December 31, 2007 and 2006.

	Years Ended December 31,			
	2007		2006 ⁽¹⁾	
	Onshore	Offshore	Onshore	Offshore
Production volume –				
Total production (MMcfe)	16,888	875	15,172	975
Production from				
continuing operations:				
Oil (MBbls)	703	146	856	162
Natural Gas (MMcfe)	8,601	-	5,438	-
Total (MMcfe)	12,818	875	10,576	975
Net average daily production-				
continuing operations:				
Oil (Bbl)	1,926	399	2,346	445
Natural Gas (Mcf)	23,563	-	14,899	-
Average sales price:				
Oil (per barrel)	\$ 68.85	\$ 52.96	\$ 64.37	\$ 46.75
Natural Gas (per Mcf)	\$ 4.47	\$ -	\$ 5.79	\$ -
Hedge effect (per Mcfe)	\$ 1.00	\$ -	\$ (.45)	\$ -
Lease operating costs -				
(per Mcfe)	\$ 1.29	\$ 4.09	\$ 1.32	\$ 3.75

⁽¹⁾Revised for operations discontinued in 2007.

Lease operating expense for the year ended December 31, 2007 was \$20.1 million compared with \$17.7 million in 2006. Lease operating expense for onshore properties approximated \$1.29 per Mcfe for the year ended December 31, 2007, versus \$1.32 per Mcfe in the comparable prior year.

Depreciation, depletion and amortization expense - oil and gas - increased 17% to \$63.4 million for the year ended December 31, 2007, compared with \$54.0 million in 2006. The increase in depletion expense was due to an increase in production from continuing operations.

Depreciation and amortization expense related to DHS Drilling Company increased to \$22.1 million for the year ended December 31, 2007, compared with \$16.4 million a year earlier, due to a greater number of rigs that DHS owned in 2007 compared to the prior year.

Exploration expense for the year ended December 31, 2007 increased to \$9.1 million, compared with \$4.7 million in the previous year. Exploration expense in 2007 related to seismic projects on the Company's Utah Hingeline, DJ Basin and Caballos Creek prospects.

General and administrative expense increased 39% to \$49.6 million for the year ended December 31, 2007, versus \$35.7 million in the previous year. Non-cash equity compensation expense increased by \$10.7 million from 2006 and technical and administrative staff and related personnel costs grew by 14%.

RESERVES AND RESERVE GROWTH

The following table presents information regarding the Company's primary oil and natural gas areas of operations as of December 31, 2007:

<u>Areas of Operations</u>	<u>Proved Reserves (Bcfe)</u> ⁽¹⁾	<u>% Natural Gas</u>	<u>% Proved Developed</u>	<u>2007 Production (MMcfe/d)</u> ⁽²⁾
Rocky Mountain Region	288.8	90.3%	25.8%	19.3
Gulf Coast Region	80.6	58.4%	49.7%	23.6
Offshore California	2.0	-%	100.0%	2.4
Other.....	<u>4.2</u>	<u>37.9%</u>	<u>72.7%</u>	<u>3.4</u>
Total	<u>375.6</u>	<u>82.4%</u>	<u>31.8%</u>	<u>48.7</u>

(1) Bcfe means billion cubic feet of gas equivalent

(2) MMcfe/d means million cubic feet of gas equivalent per day

	<u>GAS (MMcf)</u>	<u>Onshore OIL (MBbl)</u> (In thousands)	<u>Offshore OIL (MBbl)</u>
Estimated Proved Reserves: Balance at December 31, 2006	224,704	12,488	459
Revisions of quantity estimate	23,932	(2,126)	25
Extensions and discoveries	86,269	2,423	-
Purchase of properties	10,559	266	-
Sale of properties	(24,738)	(1,425)	-
Production	<u>(11,253)</u>	<u>(940)</u>	<u>(145)</u>
Estimated Proved Reserves: Balance at December 31, 2007	<u>309,473</u>	<u>10,686</u>	<u>339</u>

Total costs incurred in oil and gas operations during 2007, including acquisition, leasehold, drilling, completion, seismic, asset retirement obligations and all other capitalized oil and gas related costs, approximated \$347.7 million.

OPERATIONS UPDATE

Greentown Project, Paradox Basin, UT, 70% WI – The Company continues to complete and test the lower clastic intervals in the Greentown Federal 28-11 and Greentown State 36-24 wells with encouraging results. These activities have been focused on several lower intervals including the Cane Creek Formation. Further testing and completion operations will include the “O” zone, which has not yet been completed in either of the two wells. Completion activities to date have involved periods of shut-in and pressure build-up testing. The Company will report specific completion results once definitive production rates from individual intervals have been established and commingled production rates can be determined.

Additionally, the Company is currently drilling the Greentown Federal 26-43, which is located approximately one-half mile north of the Greentown State 36-11, and the Greentown State 31-36, which is located approximately two miles west of the Greentown State 32-42.

The Company has begun construction on the Greentown Pipeline and has designed a construction plan that anticipates environmental stipulations. The pipeline is projected to be operational by the end of the second quarter 2008.

Vega Unit and North Vega, Piceance Basin, CO, 95 – 100% WI – The Company continues to develop the Vega Unit area with four rigs and has 68 wells producing and 33 wells drilling and / or waiting on completion. The Company has begun construction of an additional compression facility that is projected to meet growing production needs from the Vega Area.

The Company has received approval from the Colorado Oil & Gas Conservation Commission for 10-acre infill development drilling.

Midway Loop Area, SE Gulf Coast, TX, ~ 10 – 55% WI – The Company completed the Best Kenneson Estes #2 for an initial gross rate of 14.0 Mmcf/d and 1,200 Bc/d and began production sales on February 8, 2008. The Company has drilled the Baxter A-141 which will begin producing within the next few weeks.

Howard Ranch, Wind River Basin, WY, 70 – 100% WI – The Company has completed the last well of a three well pilot program. Production rates from the wells average 1.1 Mmcf/d, 20 Bo/d and several hundred barrels of water per day. The Company is reviewing alternatives for more effective disposal of water which includes the possibility of obtaining surface discharge permits. Water disposal costs will affect the economics of ongoing drilling activity. The Company expects to drill at least four additional wells beginning in the second quarter 2008.

Central Utah Hingeline Project, UT, 65% WI – The Company and its partners have chosen a third drilling location on a seismically identified structural feature located approximately midway between the previously drilled Joseph prospect to the north and Parowan prospect to the south. An Application for Permit to Drill is expected to be filed within the next few weeks and it is anticipated that a well should be approved and spud by mid-summer.

Columbia River Basin, WA, 100% WI – The Company expects to begin drilling operations in the second quarter of 2008 with an industry partner.

2008 CAPITAL EXPENDITURES AND PRODUCTION GUIDANCE

The Company anticipates spending approximately \$350 to 370 million in drilling capital expenditures during 2008, of which approximately 88% will involve Rocky Mountain development and exploration projects. Included in the total, the Company expects to spend \$250 to \$260 million in the Piceance Basin, approximately \$40 million in the Paradox Basin and \$30 million in exploration activities.

To account for the above referenced transaction with EnCana, the Company is increasing its first quarter 2008 production guidance by 180,000 Mcfe from previously announced levels of 5.28 – 5.48 Bcfe, current expectations are for a range of 5.46 – 5.66 Bcfe. The Company is also increasing its full year 2008 production guidance to a 45% to 60% increase from 2007 production levels, for a range of 25.8 – 28.4 Bcfe.

COMMODITY HEDGES

From time to time, the Company enters into hedging agreements with other parties to mitigate the risk of commodity price volatility. The following table summarizes Delta's derivative contracts outstanding at February 26, 2008 and include new hedges for second and third quarter 2008 and first quarter 2009:

<u>Commodity</u>	<u>Volume</u>	<u>Price Floor / Price Ceiling</u>	<u>Term</u>	<u>Index</u>
Crude oil	1,200 Bbls / day	\$ 65.00 / \$ 80.03	Jan '08 - Mar '08	NYMEX – WTI
Crude oil	1,200 Bbls / day	\$ 65.00 / \$ 79.77	Apr '08 - June '08	NYMEX – WTI
Crude oil	1,200 Bbls / day	\$ 65.00 / \$ 79.86	July '08 - Sept '08	NYMEX – WTI
Crude oil	1,200 Bbls / day	\$ 65.00 / \$ 79.83	Oct '08 - Dec '08	NYMEX – WTI
Natural gas	15,000 MMBtu / day	\$ 6.50 / \$ 8.30	Jan '08 - Dec '08	CIG
Natural gas	5,000 MMBtu / day	\$ 6.50 / \$ 8.40	Jan '08 - Mar '08	CIG
Natural gas	10,000 MMBtu / day	\$ 6.00 / \$ 7.25	Apr '08 - Sept '08	CIG
Natural gas	10,000 MMBtu / day	\$ 6.50 / \$ 7.90	Oct '08 - Dec '08	CIG
Natural gas	10,000 MMBtu / day	\$ 6.50 / \$ 7.70	Apr '08 - June '08	CIG
Natural gas	10,000 MMBtu / day	\$ 6.50 / \$ 8.15	July '08 - Sept '08	CIG
Natural gas	35,000 MMBtu / day	\$ 7.50 / \$ 9.88	Jan '09 - Mar '09	CIG

The fair value of the Company's derivative instruments was a liability of \$3.4 million at December 31, 2007 and is a liability of \$15.2 million as of February 26, 2008.

EARNINGS RELEASE AND INVESTOR CONFERENCE CALL

The Company will host an investor conference call today, Thursday, February 28, 2008 at 12:00 noon EST to discuss operating results for the fourth quarter and full year 2007.

Shareholders and other interested parties may participate in the conference call by dialing 888-713-4209 (international participants dial 617-213-4863) and referencing the ID code 86892752 a few minutes before 12:00 noon Eastern time on February 28, 2008. The call will also be broadcast live and can be accessed through the Company's website at <http://www.deltapetro.com/eventscalendar.html>. A replay of the conference call will be available two hours after the completion of the conference call from February 28, 2008 until March 6, 2008 by dialing 888-286-8010 (international participants dial 617-801-6888) and entering the conference ID 70186831. Telephonic participants can reduce pre-call hold time by registering for the conference in advance through the following link:
<https://www.theconferencingservice.com/prereg/key.process?key=PHPCTY4QL>

ABOUT DELTA PETROLEUM CORPORATION

Delta Petroleum Corporation is an oil and gas exploration and development company based in Denver, Colorado. The Company's core areas of operations are the Gulf Coast and Rocky Mountain regions, which comprise the majority of its proved reserves, production and long-term growth prospects. The Company has a significant drilling inventory that consists of proved and unproved locations, the majority of which are located in its Rocky Mountain development projects. Its common stock is traded on the NASDAQ Global Market under the symbol "DPTR."

Forward-looking statements in this announcement are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Readers are cautioned that all forward-looking statements are based on management's present expectations, estimates and projections, but involve risks and uncertainty, including without limitation, uncertainties in the projection of future rates of production, unanticipated recovery or production problems, unanticipated results from wells being drilled or completed, the effects of delays in completion of gas gathering systems, pipelines and processing facilities, as well as general market conditions, competition and pricing. The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. In this press release we say that we estimate "that the transaction's total resource potential is approximately 1.4 Tcfe, which primarily consist of unproved resource potential." This is an estimate of reserve quantities that the SEC's guidelines strictly prohibit Delta from including in its filings with the SEC. This estimate is by its nature more speculative than an estimate of proved reserves and accordingly is subject to substantially greater risk of actually being realized by us. Please refer to the Company's report on Form 10-K for the year ended December 31, 2006 and subsequent reports on Forms 10-Q and 8-K as filed with the Securities and Exchange Commission for additional information. The Company is under no obligation (and expressly disclaims any obligation) to update or alter its forward-looking statements, whether as a result of new information, future events or otherwise.

For further information contact the Company at (303) 293-9133 or via email at info@deltapetro.com

or

RJ Falkner & Company, Inc., Investor Relations Counsel, at (800) 377-9893 or via email at info@rjfalkner.com

SOURCE: Delta Petroleum Corporation

**DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS**

	December 31, 2007	December 31, 2006
ASSETS	(In thousands)	
Current assets:		
Cash and cash equivalents	\$ 10,091	\$ 7,666
Assets held for sale	62,744	31,822
Trade accounts receivable, net of allowance for doubtful accounts, of \$664 and \$100, respectively	38,761	29,503
Prepaid assets	3,943	4,384
Inventory	4,236	2,851
Derivative instruments	2,930	10,799
Deferred tax asset	150	-
Other current assets	10,214	2,769
Total current assets	133,069	89,794
Property and equipment:		
Oil and gas properties, successful efforts method of accounting:		
Unproved	247,466	217,573
Proved	740,408	564,242
Drilling and trucking equipment	146,097	136,038
Pipeline and gathering system	22,140	14,909
Other	19,069	13,983
Total property and equipment	1,175,180	946,745
Less accumulated depreciation and depletion	(245,153)	(131,545)
Net property and equipment	930,027	815,200
Long-term assets:		
Marketable securities	6,268	-
Deferred financing costs	7,187	6,928
Goodwill	7,747	7,747
Other long-term assets	10,616	6,722
Investment in unconsolidated affiliates	10,281	2,932
Total long-term assets	42,099	24,329
Total assets	\$ 1,105,195	\$ 929,323
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of long-term debt	\$ 13	\$ 816
Accounts payable	119,783	84,439
Other accrued liabilities	17,105	10,818
Deferred tax liability	-	2,893
Derivative instruments	6,295	613
Total current liabilities	143,196	99,579
Long-term liabilities:		
7% Senior notes, unsecured	149,459	149,384
3 ¾% Senior convertible notes	115,000	-
Credit facility	73,600	118,000
Unsecured term loan	-	25,000
Credit facility/Term loan – DHS	75,000	74,050
Asset retirement obligation	4,154	4,013
Deferred tax liability	9,085	3,660
Other debt, net	-	14
Total long-term liabilities	426,298	374,121
Minority interest	27,296	27,390
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, \$.01 par value: authorized 3,000,000 shares, none issued	-	-
Common stock, \$.01 par value; authorized 300,000,000 shares, issued 66,429,000 shares at December 31, 2007, and 53,439,000 shares at December 31, 2006	664	534
Additional paid-in capital	664,733	430,479
Accumulated other comprehensive income	-	4,865
Accumulated deficit	(156,992)	(7,645)
Total stockholders' equity	508,405	428,233
Total liabilities and stockholders' equity	\$ 1,105,195	\$ 929,323

**DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS**

	<u>Years Ended December 31,</u>		<u>Three Months Ended December 31,</u>	
	<u>2007</u>	<u>2006</u>	<u>2007</u>	<u>2006</u>
	(In thousands, except per share amounts)			
Revenue:				
Oil and gas sales	\$ 94,559	\$ 94,223	\$ 31,287	\$ 19,865
Contract drilling and trucking fees	56,777	57,149	11,460	16,910
Gain (loss) on effective derivative instruments, net	<u>12,854</u>	<u>(4,712)</u>	<u>2,311</u>	<u>570</u>
Total revenue	164,190	146,660	45,058	37,345
Operating expenses:				
Lease operating expense	20,142	17,655	5,948	4,189
Transportation expense	3,684	978	1,360	(100)
Production taxes	5,559	4,784	2,083	945
Depreciation, depletion, accretion and amortization – oil and gas	63,373	53,980	17,661	16,205
Depreciation and amortization – drilling and trucking	22,052	16,404	5,534	5,303
Exploration expense	9,062	4,690	2,924	1,288
Dry hole costs and impairments	85,084	15,682	12,233	3,040
Drilling and trucking operations	36,954	34,163	7,283	9,990
General and administrative	49,621	35,696	12,332	8,847
Gain on sale of oil and gas properties	-	<u>(20,034)</u>	-	<u>(1,185)</u>
Total operating expenses	<u>295,531</u>	<u>163,998</u>	<u>67,358</u>	<u>48,522</u>
Operating income (loss)	(131,341)	(17,338)	(22,300)	(11,177)
Other income and (expense):				
Other income (expense)	376	(154)	(245)	(48)
Gain (loss) on ineffective derivative instruments, net	(2,902)	11,722	(5,381)	370
Gain on sale of investment in LNG	-	1,058	-	-
Minority interest	1,231	(2,595)	1,242	(1,020)
Losses from unconsolidated affiliates	(393)	-	(342)	-
Interest and financing costs	<u>(27,199)</u>	<u>(26,316)</u>	<u>(9,144)</u>	<u>(7,485)</u>
Total other expense	<u>(28,887)</u>	<u>(16,285)</u>	<u>(13,870)</u>	<u>(8,183)</u>
Loss from continuing operations before income taxes and discontinued operations	(160,228)	(33,623)	(36,170)	(19,360)
Income tax benefit (expense)	<u>(2,677)</u>	<u>12,623</u>	<u>2,025</u>	<u>7,233</u>
Income (loss) from continuing operations	(162,905)	(21,000)	(34,145)	(12,127)
Discontinued operations:				
Income from discontinued operations of properties sold, net of tax	17,556	9,163	3,934	1,797
Gain (loss) on sale of discontinued operations, net of tax	<u>(3,998)</u>	<u>6,712</u>	<u>231</u>	<u>23</u>
Income (loss) before extraordinary gain, net of tax	(149,347)	(5,125)	(29,980)	(10,307)
Extraordinary gain, net of tax	-	<u>5,560</u>	-	<u>(192)</u>
Net income (loss)	<u>\$ (149,347)</u>	<u>\$ 435</u>	<u>\$ (29,980)</u>	<u>\$ (10,499)</u>
Basic income (loss) per common share:				
Net loss from continuing operations	\$ (2.66)	\$ (.41)	\$ (.53)	\$ (.22)
Discontinued operations	.22	.31	.06	.03
Extraordinary gain, net of tax	-	.11	-	(.01)
Net income (loss)	<u>\$ (2.44)</u>	<u>\$.01</u>	<u>\$ (.47)</u>	<u>\$ (.20)</u>
Diluted income (loss) per common share:				
Net loss from continuing operations	\$ (2.66)	\$ (.39)	\$ (.53)	\$ (.22)
Discontinued operations	.22	.30	.06	.03
Extraordinary gain, net of tax	-	.10	-	(.01)
Net income (loss)	<u>\$ (2.44)</u>	<u>\$.01</u>	<u>\$ (.47)</u>	<u>\$ (.20)</u>

DELTA PETROLEUM CORPORATION
RECONCILIATION OF DISCRETIONARY CASH FLOW AND EBITDAX

(in thousands)
(unaudited)

THREE MONTHS ENDED:	December 31, <u>2007</u>	December 31, <u>2006</u>
CASH PROVIDED BY OPERATING ACTIVITIES	\$ 55,251	\$ 25,162
Changes in assets and liabilities	(35,654)	(15,125)
Exploration and dry hole costs	<u>2,924</u>	<u>3,979</u>
Discretionary Cash Flow*	<u>\$ 22,521</u>	<u>\$ 14,016</u>

TWELVE MONTHS ENDED:	December 31, <u>2007</u>	December 31, <u>2006</u>
CASH PROVIDED BY OPERATING ACTIVITIES	\$ 84,392	\$ 53,386
Changes in assets and liabilities	(19,486)	(1,336)
Exploration and dry hole costs	<u>10,055</u>	<u>8,475</u>
Discretionary Cash Flow*	<u>\$ 74,961</u>	<u>\$ 60,525</u>

* Discretionary cash flow represents net cash provided by operating activities before changes in assets and liabilities plus exploration costs. Discretionary cash flow is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Discretionary cash flow is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity.

THREE MONTHS ENDED:	December 31, <u>2007</u>	December 31, <u>2006</u>
Net income (loss)	\$ (29,980)	\$ (10,499)
Income tax expense (benefit)	(2,594)	(6,371)
Interest and financing costs	9,144	7,485
Depletion, depreciation and amortization	26,196	24,009
(Gain) loss on sale of oil and gas properties and other investments	334	(895)
Unrealized (gain) loss on derivative contracts	8,295	(179)
Exploration and dry hole costs	<u>15,157</u>	<u>4,328</u>
EBITDAX**	<u>\$ 26,552</u>	<u>\$ 17,878</u>

THREE MONTHS ENDED:	December 31, <u>2007</u>	December 31, <u>2006</u>
CASH PROVIDED BY OPERATING ACTIVITIES	\$ 55,251	\$ 25,162
Changes in assets and liabilities	(35,654)	(15,125)
Interest net of financing costs	6,835	6,646
Exploration and dry hole costs	2,924	3,979
Other non-cash items	<u>(2,804)</u>	<u>(2,784)</u>
EBITDAX**	<u>\$ 26,552</u>	<u>\$ 17,878</u>

TWELVE MONTHS ENDED:	December 31, <u>2007</u>	December 31, <u>2006</u>
Net income (loss)	\$ (149,347)	\$ 435
Income tax expense (benefit)	4,113	(502)
Interest and financing costs	27,199	26,316
Depletion, depreciation and amortization	98,415	82,596
(Gain) loss on sale of oil and gas properties and other investments	2,644	(40,643)
Unrealized (gain) loss on derivative contracts	5,816	(12,205)
Exploration and dry hole costs	<u>94,146</u>	<u>20,372</u>
EBITDAX**	<u>\$ 82,986</u>	<u>\$ 76,369</u>

TWELVE MONTHS ENDED:	December 31, <u>2007</u>	December 31, <u>2006</u>
CASH PROVIDED BY OPERATING ACTIVITIES	\$ 84,392	\$ 53,386
Changes in assets and liabilities	(19,486)	(1,336)
Interest net of financing costs	22,770	23,920
Exploration and dry hole costs	10,055	8,475
Other non-cash items	<u>(14,745)</u>	<u>(8,076)</u>
EBITDAX**	<u>\$ 82,986</u>	<u>\$ 76,369</u>

** EBITDAX represents net income before income tax expense (benefit), interest and financing costs, depreciation, depletion and amortization expense, gain on sale of oil and gas properties and other investments, unrealized gains (loss) on derivative contracts and exploration and impairment and dry hole costs. EBITDAX is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. EBITDAX is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit agreement and is used in the financial covenants in our bank credit agreement and our senior note indentures. EBITDAX is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations, or cash flow provided by operating activities prepared in accordance with GAAP.