UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): February 22, 2007

The Williams Companies, Inc.
(Exact name of registrant as specified in its charter)

Delaware	1-4174	73-0569878
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

One Williams Center, Tulsa, Oklahoma	74172
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 918/573-2000

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

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

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240-14a-12)

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

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 2.02. Results of Operations and Financial Condition.

On February 22, 2007, The Williams Companies, Inc. ("Williams" or the "Company") issued a press release announcing its financial results for the quarter and year ended December 31, 2006. A copy of the press release and its accompanying financial highlights and reconciliation schedules are furnished as a part of this current report on Form 8-K as Exhibit 99.1 and is incorporated herein in its entirety by reference.

The press release and accompanying financial highlights and reconciliation schedules are being furnished pursuant to Item 2.02, Results of Operations and Financial Condition. The information furnished is not deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended.

Item 7.01. Regulation FD Disclosure.

Williams wishes to disclose for Regulation FD purposes its slide presentation, furnished herewith as Exhibit 99.2, to be utilized during a public conference call and webcast on the morning of February 22, 2007.

On February 22, 2007, Williams also announced that its domestic and international proved natural gas reserves as of December 31, 2006, increased to 3.9 trillion cubic feet equivalent. Williams replaced its 2006 U.S. wellhead production of 276 billion cubic feet equivalent (Bcfe) at a ratio of 216 percent. A copy of the press release announcing the same is furnished as Exhibit 99.3 to this Current Report on Form 8-K and is incorporated herein.

On February 22, 2007, Williams also announced the sale of dispatch and tolling rights and natural gas supply arrangements to Southern California Edison, a subsidiary of Edison International. The seven contracts "mirror" Williams' rights under its tolling agreement with certain subsidiaries of the AES Corporation and represent up to 1,920 megawatts of power.

The slide presentation and press releases are being furnished pursuant to Item 7.01, Regulation FD Disclosure. The information furnished is not deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended.

Item 9.01. Financial Statements and Exhibits.

(a) None

(b) None

(c) None

(d) Exhibits

Exhibit 99.1	Copy of Williams' press release dated February 22, 2007, publicly announcing its fourth quarter and year-end 2006 financial results.
Exhibit 99.2	Copy of Williams' slide presentation to be utilized during the February 22, 2007, public conference call and webcast.
Exhibit 99.3	Copy of Williams' press release dated February 22, 2007, publicly announcing its replacement of 2006 U.S. natural gas production.
Exhibit 99.4	Copy of Williams' press release dated February 22, 2007, publicly announcing the sale of dispatch and tolling rights and natural gas supply arrangements to Southern California Edison.

Pursuant to the requirements of the Securities Exchange Act of 1934, Williams has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

THE WILLIAMS COMPANIES, INC.

Date: February 22, 2007

/s/ Donald R. Chappel

Name: Donald R. Chappel
Title: Senior Vice President and Chief Financial Officer

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INDEX TO EXHIBITS

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Exhibit 99.1

News Release

NYSE:WMB

Date: Feb. 22, 2007

Williams Reports Fourth-Quarter and Full-Year 2006 Financial Results

- *Record-High NGL Margins Drive 2006 Performance*
- *Natural Gas Production Rises 21% for Full Year; Fourth Consecutive Year to Replace More Than 200% of Production*
- *Net Income $308.5 Million for Full Year*
- *Recurring Adjusted Income Increases 38% to $707.8 Million for Full Year; Up 17% for Fourth Quarter*
- *Cash Flow From Operations Rises 30% to $1.9 Billion for Full Year*

Year-End Summary Financial Information *Per share amounts are reported on a fully diluted basis*	2006 millions	2006 per share	2005 millions	2005 per share
Income from continuing operations	$ 332.8	$ 0.55	$ 317.4	$ 0.53
Loss from discontinued operations	$ (24.3)	$ (0.04)	$ (2.1)	—
Cumulative effect of change in accounting principle	—	—	$ (1.7)	—
Net income	$ 308.5	$ 0.51	$ 313.6	$ 0.53
Recurring income from continuing operations*	$ 520.3	$ 0.86	$ 427.8	$ 0.72
After-tax mark-to-market adjustments	$ 187.5	$ 0.31	$ 85.0	$ 0.14
Recurring income from continuing operations — after mark-to-market adjustment*	$ 707.8	$ 1.17	$ 512.8	$ 0.86

* A schedule reconciling income (loss) from continuing operations to recurring income (loss) from continuing operations and mark-to-market adjustments (non-GAAP measures) is available on Williams' Web site at www.williams.com and as an attachment to this press release.

Quarterly Summary Financial Information *Per share amounts are reported on a fully diluted basis*	4Q 2006 millions	4Q 2006 per share	4Q 2005 millions	4Q 2005 per share
Income from continuing operations	$ 155.5	$ 0.25	$ 68.8	$ 0.11
Loss from discontinued operations	$ (9.1)	$ (0.01)	$ (0.3)	—
Cumulative effect of change in accounting principle	—	—	$ (1.7)	—
Net income	$ 146.4	$ 0.24	$ 66.8	$ 0.11
Recurring income from continuing operations*	$ 158.4	$ 0.26	$ 168.1	$ 0.28
After-tax mark-to-market adjustments	$ 22.0	$ 0.04	$ (13.8)	$ (0.02)
Recurring income from continuing operations — after mark-to-market adjustment*	$ 180.4	$ 0.30	$ 154.3	$ 0.26

TULSA, Okla. — Williams (NYSE:WMB) announced 2006 unaudited net income of $308.5 million, or 51 cents per share on a diluted basis, compared with net income of $313.6 million, or 53 cents per share on a diluted basis, for 2005.

Results for 2006 reflect record-high natural gas liquids (NGL) margins for the year, as well as the company's continued strong growth in natural gas production. Williams' average daily production from domestic and international interests increased 21 percent in 2006, surpassing 800 million cubic feet of gas equivalent (MMcfe).

These benefits were partially offset by lower net realized prices for natural gas, a $167.3 million charge associated with a securities litigation settlement, and higher operations and maintenance costs.

Results for 2006 also include unrealized mark-to-market losses of $22 million from the Power business, compared with $172 million of unrealized gains in 2005.

For fourth-quarter 2006, the company reported net income of $146.4 million, or 24 cents per share on a diluted basis, compared with net income of $66.8 million, or 11 cents per share on a diluted basis, for fourth-quarter 2005.

The net income improvement in the fourth quarter is primarily due to the absence of litigation accruals and certain impairments that occurred during the 2005 period, as well as the benefit of record-high NGL margins. Fourth-quarter 2006 also includes a $40 million favorable impact from the resolution of a federal income tax litigation matter, partially offset by a $16 million after-tax impairment charge related to an international Exploration & Production investment.

The company reported 2006 income from continuing operations of $332.8 million, or 55 cents per share on a diluted basis, compared with $317.4 million, or 53 cents per share on a diluted basis, in 2005.

For fourth-quarter 2006, the company reported income from continuing operations of $155.5 million, or 25 cents per share on a diluted basis, compared with $68.8 million, or 11 cents per share on a diluted basis, for fourth-quarter 2005.

Recurring Results Adjusted for Effect of Mark-to-Market Accounting

To provide an added level of disclosure and transparency, Williams continues to provide an analysis of recurring earnings adjusted to remove all mark-to-market effects from its Power business unit. Recurring earnings exclude items of income or loss that the company characterizes as unrepresentative of its ongoing operations.

Recurring income from continuing operations — after adjusting for the mark-to-market effect to reflect income as though mark-to-market accounting had never been applied to Power's designated hedges and other derivatives — was $707.8 million, or $1.17 per share, for 2006. In 2005, the adjusted recurring income from continuing operations was $512.8 million, or 86 cents per share.

For the fourth quarter of 2006, recurring income from continuing operations — after adjusting for the mark-to-market effect — was $180.4 million, or 30 cents per share, compared with $154.3 million, or 26 cents per share, for the same period in 2005.

A reconciliation of the company's income from continuing operations to recurring income from continuing operations and mark-to-market adjustments accompanies this news release.

CEO Perspective

"Our portfolio of natural gas businesses continues to deliver strong performance," said Steve Malcolm, chairman, president and chief executive officer. "Record-level NGL margins in our Midstream business contributed significantly to our results. While natural gas prices were lower during 2006, oil and natural gas liquids prices were stronger. That helped to balance and strengthen our financial performance.

"We expect strong NGL margins once again will help support the company's performance, but at levels that are likely to be less than the record-high margins we experienced last year.

"We have a strong track record of growing our natural gas production while making significant additions to our reserves. For the fourth year in a row, we've replaced our reserves at a rate in excess of 200 percent. In the Piceance Basin, we are continuing to deploy high-tech, high-efficiency equipment and practices to support our accelerated development of production.

"For us, growing our segment profit and our natural gas reserves and production are major catalysts to deliver additional shareholder value. Other significant value drivers are higher rates for our interstate gas pipelines; more deals to sell power beyond 2010; additional midstream expansions; and the opportunity to raise more low-cost capital through dropdowns to Williams Partners."

Business Segment Performance

Consolidated results include segment profit for Williams' primary businesses — Exploration & Production, Midstream Gas & Liquids, Gas Pipeline and Power — as well as results reported in the Other segment.

For 2006, Williams' businesses reported consolidated segment profit of $1.47 billion, compared with $1.28 billion for 2005.

Higher results for 2006 were driven by extraordinary results in Midstream, along with the absence of certain impairment charges and litigation accruals in 2005. These benefits were partially offset by lower segment profit in Exploration & Production and Gas Pipeline.

Williams' businesses reported consolidated segment profit of $367.3 million in the fourth quarter of 2006, compared with $311.9 million in the fourth quarter of 2005.

The fourth-quarter 2006 results are primarily attributable to strong profitability in Midstream, as well as the absence of certain impairment charges and litigation accruals recorded in fourth-quarter 2005. These benefits were offset by a segment profit decrease in Exploration & Production.

On a basis adjusted to remove the effect of nonrecurring items and mark-to-market accounting, Williams had recurring consolidated segment profit of approximately $1.84 billion in 2006, compared with $1.58 billion for 2005 — an increase of 16 percent. The improvement in 2006 on an adjusted basis is primarily due to Midstream's extraordinary results, along with significant improvement in Power's recurring after-mark-to-market adjustment results.

On a basis adjusted to remove the effect of nonrecurring items and market-to-market accounting, Williams had recurring consolidated segment profit of $407 million in fourth-quarter 2006, compared with $448 million in fourth-quarter 2005. The reduction in consolidated segment profit on an adjusted basis is attributed to lower segment profit in Exploration & Production and Gas Pipeline, partially offset by improved Midstream results.

For 2006, net cash provided by operating activities was approximately $1.9 billion, compared with approximately $1.45 billion for the same period in 2005. Net cash generated in 2006 was primarily reinvested in the form of capital expenditures, which totaled approximately $2.5 billion in 2006.

Exploration & Production: U.S. Production Up 23% in 2006 From Development Activities

Exploration & Production, which includes natural gas production and development in the U.S. Rocky Mountains, San Juan Basin and Mid-Continent, and oil and gas development in South America, reported 2006 segment profit of $551.5 million. A year ago, the business reported segment profit of $587.2 million.

The substantially higher production volumes in 2006 were more than offset by lower average realized prices, higher operating costs, and the absence of $29.6 million of gains from the sale of certain properties in 2005. Higher operating costs reflect an increased number of producing wells and higher well service and industry costs.

For 2006, combined average daily production from U.S. and international interests was up 21 percent to approximately 803 million cubic feet of gas equivalent (MMcfe), compared with 662 MMcfe for the same period in 2005.

Daily production solely from interests in the United States increased 23 percent to approximately 752 MMcfe in 2006 from 612 MMcfe in 2005.

For the fourth quarter of 2006, Exploration & Production reported segment profit of $139.6 million, compared with $206.4 million for the same period last year.

The significant increases in production volumes in the fourth quarter were more than offset by lower average realized prices and higher operating costs.

During the fourth quarter of 2006, Williams' U.S. production realized net average prices of $4.45 per thousand cubic feet of gas equivalent (Mcfe) — 21 percent lower than the $5.66 per Mcfe realized in the same period a year ago.

In a separate announcement today, Williams reported year-end 2006 proved U.S. natural gas reserves of 3.7 trillion cubic feet equivalent, up 9.5 percent from year-end 2005 reserves. Including its international interests, Williams had total proved natural gas and oil reserves of 3.9 trillion cubic feet equivalent at year-end 2006.

Williams' activities in 2006 resulted in the total addition of 597 billion cubic feet equivalent in net reserves. Over the past three years, Williams has added over 1.6 trillion cubic feet equivalent in domestic net reserves from drilling activity. For the fourth consecutive year, Williams has replaced more than 200 percent of its reserves.

U.S. Proved Reserves Reconciliation

Figures in billion cubic feet equivalent of natural gas. May not add due to rounding.

Proved reserves Dec. 31, 2005	3,382
Acquisitions	41
Divestitures	(1)
Additions and revisions	557
Production	(277)
Proved reserves Dec. 31, 2006	3,701

In 2006, Williams continued to have a drilling success rate of approximately 99 percent. The company drilled 1,783 gross wells, of which 1,770 were successful. In 2005, Williams also achieved a 99 percent success rate, drilling 1,629 gross wells.

Williams currently has 25 rigs operating in the Piceance Basin of western Colorado — the company's cornerstone for production and reserves growth.

Within that fleet are 10 new-generation, high-efficiency drilling rigs specifically designed for conditions in the Piceance Basin. Williams deployed those rigs during 2006.

Williams plans to invest $1.3 billion to $1.4 billion of capital in Exploration & Production this year. These investments focus primarily on activity designed to increase domestic production by 15 to 20 percent during the year.

For 2007, Williams expects $700 million to $975 million in segment profit from Exploration & Production. The wide range in guidance reflects the potential volatility of natural gas prices and an assumption of unhedged natural gas prices ranging from $7 to $8.30 (Henry Hub), adjusted for basis differential.

Midstream Gas & Liquids: Segment Profit Jumps 40% for Year, 46% in Fourth Quarter

Midstream, which provides natural gas gathering and processing services, along with natural gas liquids fractionation and storage services and olefins production, reported 2006 segment profit of $658.3 million, compared with $471.2 million in 2005, an increase of 40 percent.

For the fourth quarter of 2006, Midstream reported segment profit of $163.9 million, compared with $112.4 million for the same period in 2005, an increase of 46 percent.

The improvement in both year-over-year and quarter-over-quarter results in 2006 primarily reflects increased NGL sales margins; significantly higher production handling volumes and revenues in the deepwater Gulf of Mexico; and higher fee-based gathering and processing revenues. The year-over-year increases were partially offset by approximately $72.7 million in litigation accruals related to a contractual dispute surrounding certain natural gas processing facilities known as Gulf Liquids.

During 2006, Williams' sales of NGL equity volumes in the United States generated margins of $441.5 million — 121 percent higher than margins of $199.9 million for 2005. The extraordinary margins during 2006 primarily reflect the gap between higher liquids prices — which typically track closely to crude oil prices — and lower natural gas prices.

Also for the year, Midstream sold 1.35 billion gallons of NGL equity volumes, compared with equity sales of 1.27 billion gallons in 2005. These equity volumes are retained and subsequently marketed by Williams as payment-in-kind under the terms of certain processing contracts. Total production of NGLs from operated domestic plants also reached record levels, moving from 2.35 billion gallons in 2005 to 2.60 billion gallons in 2006.

During 2006, Williams installed the fifth cryogenic processing train at our existing gas plant in Opal, Wyo. The plant is currently being commissioned and should be in full operating mode in March 2007. The expansion is designed to boost the plant's processing capacity by more than 30 percent to 1.45 billion cubic feet per day and produce approximately 67,000 barrels per day of NGLs.

Williams plans to invest $430 million to $470 million of capital in Midstream in 2007. These investments focus primarily on expanding Williams' gathering and processing systems in the deepwater Gulf of Mexico and in the western United States. We will continue construction on the extension of our Discovery system to the Tahiti prospect and the 37-mile extension of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon. In 2007, we will continue working on our Perdido Norte project, which includes oil and gas lines that expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico.

For 2007, Williams expects $450 million to $750 million in segment profit from Midstream. The wide range in guidance reflects the potential market volatility in both natural gas and NGL prices during the year and assumptions of NGL margins consistent with an oil-to-gas price ratio of 7.4 to 9.6 (West Texas Intermediate crude to Henry Hub gas).

Gas Pipeline: Earnings Expected to Increase as New Rates Go Into Effect

Gas Pipeline, which primarily delivers natural gas to markets along the Eastern Seaboard, in Florida and in the Northwest, reported 2006 segment profit of $467.4 million, compared with the $585.8 million for 2005.

Results for 2006 were reduced by approximately $77 million in selling, general and administrative cost increases, which stemmed primarily from higher costs for personnel, property insurance and information systems support. In addition, 2005 benefited by $14 million from the resolution of Transco's fuel-tracker filings.

For the fourth quarter of 2006, Gas Pipeline reported segment profit of $101 million compared with $92.8 million for the same period in 2005. The increase is primarily due to the absence of fourth-quarter 2005 prior-period accounting and valuation corrections related to inventories, though that benefit was offset somewhat by higher selling, general and administrative expenses in the most recent quarter.

Northwest Pipeline's new, higher rates went into effect, subject to refund, on Jan. 1, 2007. During the first quarter of 2007, Williams announced that Northwest Pipeline had filed a stipulation and settlement agreement that resolves all outstanding issues in its pending rate case, subject to Federal Energy Regulatory Commission (FERC) approval.

The settlement between Northwest Pipeline and the intervening parties in the case, including Northwest's customers, is supported by the FERC staff and is expected to be uncontested. Williams anticipates the process will be concluded by mid-2007.

Williams' Transco system also will benefit from new, higher rates, which go into effect, subject to refund, on March 1, 2007. Transco filed its rate case with the FERC on Aug. 31, 2006. The filing reflects, among other things, current levels of operating costs and rate base.

Since the beginning of the fourth quarter 2006, Williams has announced the status of a variety of Gas Pipeline projects — most significantly the completion and placement into service of its capacity replacement project in Washington state.

Williams plans to invest $425 million to $535 million of capital in Gas Pipeline in 2007. About half of these investments are planned for expansion projects, with the majority dedicated to the Leidy-to-Long Island and Potomac projects on the Transco system and the Parachute project on the Northwest Pipeline system. The majority of our non-expansion investments are tied to pipeline integrity projects.

For 2007, Williams expects $585 million to $655 million in segment profit from Gas Pipeline. The projected increase over 2006 results is principally because of new, higher rates for both the Northwest Pipeline and Transco systems.

Power: Contracting Megawatts Past 2010

Power manages a portfolio of more than 7,000 megawatts and provides services that support Williams' natural gas businesses.

Power Recurring Segment Profit (Loss) Adjusted for Mark-to-Market Effect

Amounts are reported in millions	YTD 2006	YTD 2005
Segment loss	$ (210.8)	$ (256.7)
Nonrecurring adjustments	$ (7.9)	$ 116.6
Recurring segment loss	$ (218.7)	$ (140.1)
Mark-to-market adjustments — net	$ 303.6	$ 137.7
Recurring segment profit (loss) after MTM adjustments	$ 84.9	$ (2.4)

	4Q 2006	4Q 2005
Segment loss	$ (39.0)	$ (69.4)
Nonrecurring adjustments	$ 1.3	$ 91.7
Recurring segment profit (loss)	$ (37.7)	$ 22.3
Mark-to-market adjustments — net	$ 35.6	$ (22.4)
Recurring segment loss after MTM adjustments	$ (2.1)	$ (0.1)

Power reported a 2006 segment loss of $210.8 million, compared with a segment loss of $256.7 million in 2005. These unadjusted results include the non-cash effect of forward unrealized mark-to-market gains and losses.

The improvement in 2006 is primarily the result of $99 million in increased accrual earnings, a $15 million higher gain on the sale of certain accounts receivable, and a $125 million increase due primarily to the absence of litigation and impairment accruals that occurred in 2005. These items were partially offset by a $194.3 million unfavorable change in unrealized earnings. The decline in unrealized earnings results primarily from power price decreases on a net long power position in 2006, compared to power price increases on a net long power position in 2005.

For the key performance measure of recurring segment profit adjusted for the effect of mark-to-market accounting, Power reported $84.9 million in 2006, compared with a loss of $2.4 million in 2005.

The year-over-year improvement on the adjusted basis primarily reflects the benefit of structured power hedges in 2006 along with the sale of certain accounts receivable; those benefits were offset partially by the impact of lower fourth quarter 2006 natural gas inventory withdrawals.

Power reported a fourth-quarter 2006 segment loss of $39 million, compared with a segment loss of $69.4 million in fourth-quarter 2005. These unadjusted results include the non-cash effect of forward unrealized mark-to-market results.

The improvement in the fourth quarter of 2006 is primarily the result of the absence of litigation accruals and an impairment charge that occurred during the fourth quarter of 2005, as well as an increase in accrual earnings. These benefits were partially offset by lower unrealized mark-to-market gains and the sale during the fourth-quarter of 2005 of certain accounts receivable.

For the fourth quarter of 2006, Power reported a recurring segment loss adjusted for the effect of mark-to-market accounting of $2.1 million, compared with a loss of $0.1 million in 2005.

In 2006, Power generated approximately $93 million in cash flow from operations, largely reflecting positive portfolio cash flows net of selling, general and administrative expenses. In 2005, Power generated approximately $188 million in cash flow from operations, largely the result of positive portfolio cash flows and the return of margin dollars.

Power also completed a significant number of new power sales contracts in 2006. These contracts increase value and cash-flow certainty and reduce the portfolio’s future exposures to fuel-price and weather volatility.

In a separate announcement today, Williams announced that its Power business has reached agreements with Southern California Edison that lock in certain of Williams’ future power sales and natural gas purchases beyond 2010.

For 2007, Williams expects segment results from its Power business to range from a loss of $75 million to break-even, absent the effect of any future unrealized mark-to-market gains or losses.

On a basis adjusted for the effect of mark-to-market accounting, Williams is lowering the high end of its expectation for Power’s 2007 recurring segment profit by $25 million. The updated range — $50 million to $125 million — is designed to more accurately reflect the ongoing effects of price mitigation on our West portfolio and a less favorable outlook for Northeast heat rates.

Guidance Through 2008

In 2007, Williams expects $1.9 billion to $2.4 billion in consolidated segment profit and earnings per share of $1.10 to $1.50. Both ranges are presented on a recurring basis adjusted for the effect of mark-to-market accounting and assume natural gas prices and NGL margins as previously referenced for Exploration & Production and Midstream. The ranges also contain an assumption for crude oil pricing in the range of $53 to $73 per barrel. Actual 2006 average market price for crude oil was approximately $66.

The updated consolidated segment profit guidance is approximately $75 million lower than what the company shared in November 2006. The change reflects Williams' expectation that NGL margins will be stronger than historical levels, but lower than record-high levels in 2006. Also, the change reflects the company's expectation that the Exploration & Production business will continue to experience costs that are higher, but that remain more favorable than industry averages.

In 2008, Williams expects consolidated segment profit of $2.20 billion to $2.88 billion on a recurring basis adjusted for the effect of mark-to-market accounting. The projected improvement over 2007 is primarily the result of expected increases in natural gas production.

Guidance for consolidated segment profit includes results for the four primary businesses, as well as the Other segment.

The company's overall capital budget is $2.23 to $2.43 billion for 2007 and $1.85 billion to $2.13 billion for 2008.

Today's Analyst Call

Williams' management will discuss the company's 2006 financial results and outlook through 2008 during an analyst presentation to be webcast live beginning at 10 a.m. Eastern today.

Participants are encouraged to access the presentation and corresponding slides via www.williams.com.

A limited number of phone lines also will be available at (800) 811-0667. International callers should dial (913) 981-4901. Callers should dial in at least 10 minutes prior to the start of the discussion.

Replays of the webcast will be available for two weeks at www.williams.com following the event.

Form 10-K

The company expects to file its Form 10-K with the Securities and Exchange Commission during the week of Feb. 26. The document will be available on both the SEC and Williams websites.

About Williams (NYSE:WMB)

Williams, through its subsidiaries, primarily finds, produces, gathers, processes and transports natural gas. The company also manages a wholesale power business. Williams' operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, Southern California and Eastern Seaboard. More information is available at www.williams.com.

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Williams' reports, filings, and other public announcements might contain or incorporate by reference statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of Private Securities Litigation Reform Act of 1995. You typically can identify forward-looking statements by the use of forward-looking words, such as "anticipate," believe," "could," "continue," "estimate," "expect," "forecast," "may," "plan," "potential," "project," "schedule," "will," and other similar words. These statements are based on our intentions, beliefs, and assumptions about future events and are subject to risks, uncertainties, and other factors. Actual results could differ materially from those contemplated by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such statements, other factors could cause our actual results to differ materially from the results expressed or implied in any forward-looking statements. Those factors include, among others: changes in general economic conditions and changes in the industries in which Williams conducts business; changes in federal or state laws and regulations to which Williams is subject, including tax, environmental and employment laws and regulations; the cost and outcomes of legal and administrative claims proceedings, investigations, or inquiries; the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including our credit ratings and general economic conditions; the level of creditworthiness of counterparties to our transactions; the amount of collateral required to be posted from time to time in our transactions; the effect of changes in accounting policies; the ability to control costs; the ability of each business unit to successfully implement key systems, such as order entry systems and service delivery systems; the impact of future federal and state regulations of business activities, including allowed rates of return, the pace of deregulation in retail natural gas and electricity markets, and the resolution of other regulatory matters; changes in environmental and other laws and regulations to which Williams and its subsidiaries are subject or other external factors over which we have no control; changes in foreign economies, currencies, laws and regulations, and political climates, especially in Canada, Argentina, Brazil, and Venezuela, where Williams has direct investments; the timing and extent of changes in commodity prices, interest rates, and foreign currency exchange rates; the weather and other natural phenomena; the ability of Williams to develop or access expanded markets and product offerings as well as their ability to maintain existing markets; the ability of Williams and its subsidiaries to obtain governmental and regulatory approval of various expansion projects; future utilization of pipeline capacity, which can depend on energy prices, competition from other pipelines and alternative fuels, the general level of natural gas and petroleum product demand, decisions by customers not to renew expiring natural gas transportation contracts; the accuracy of estimated hydrocarbon reserves and seismic data; and global and domestic economic repercussions from terrorist activities and the government's response to such terrorist activities. In light of these risks, uncertainties, and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time that we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

In regard to the company's reserves in Exploration & Production, the SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves. We have used certain terms in this news release, such as "probable" reserves and "possible" reserves and "new opportunities potential" reserves that the SEC's guidelines strictly prohibit us from including in filings with the SEC. The SEC defines proved reserves as estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under the assumed economic conditions. Probable and possible reserves are estimates of potential reserves that are made using accepted geological and engineering analytical techniques, but which are estimated with reduced levels of certainty than for proved reserves. Possible reserve estimates are less certain than those for probable reserves. New opportunities potential is an estimate of reserves for new areas for which we do not have sufficient information to date to raise the reserves to either the probable category or the possible category. New opportunities potential estimates are even less certain that those for possible reserves. Reference to "total resource portfolio" include proved, probable and possible reserves as well as new opportunities potential.

Investors are urged to closely consider the disclosures and risk factors in our annual report on Form 10-K filed with the Securities and Exchange Commission on March 9, 2006, and our quarterly reports on Form 10-Q available from our offices or from our website at <u>*www.williams.com.*</u>

Financial Highlights and Operating Statistics

(UNAUDITED)

Final

December 31, 2006

Reconciliation of Income (Loss) from Continuing Operations to Recurring Earnings (Loss)

(UNAUDITED)

(Dollars in millions, except per-share amounts)	2005 *1st Qtr*	2005 *2nd Qtr*	2005 *3rd Qtr*	2005 *4th Qtr*	2005 *Year*	2006 *1st Qtr*	2006 *2nd Qtr*	2006 *3rd Qtr*	2006 *4th Qtr*	2006 *Year*
Income (loss) from continuing operations available to common stockholders	$ 202.2	$ 40.7	$ 5.7	$ 68.8	$ 317.4	$ 131.1	($63.9)	$ 110.1	$ 155.5	$ 332.8
Income (loss) from continuing operations — diluted earnings (loss) per common share	$ 0.34	$ 0.07	$ 0.01	$ 0.11	$ 0.53	$ 0.22	($0.11)	$ 0.19	$ 0.25	$ 0.55
Nonrecurring items:										
Exploration & Production										
Gains on sales of E&P properties	(7.9)	—	(21.7)	—	(29.6)	—	—	—	—	—
Loss provision related to an ownership dispute	0.3	—	—	—	0.3	—	—	—	—	—
Total Exploration & Production nonrecurring items	(7.6)	—	(21.7)	—	(29.3)	—	—	—	—	—
Gas Pipeline										
Prior period liability corrections — TGPL	(13.1)	(4.6)	—	—	(17.7)	—	—	—	—	—
Prior period pension adjustment — TGPL	—	(17.1)	—	—	(17.1)	—	—	—	—	—
Income from favorable ruling on FERC appeal (1999 Fuel Tracker)	—	—	(14.2)	—	(14.2)	—	—	—	—	—
Prior period inventory corrections — TGPL	—	—	—	32.1	32.1	—	—	—	—	—
Accrual of contingent refund obligation — TGPL	—	—	—	5.2	5.2	—	—	—	—	—
Reversal of litigation contigency due to favorable ruling — TGPL	—	—	—	—	—	(2.0)	—	—	—	(2.0)
Total Gas Pipeline nonrecurring items	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)	—	—	—	(2.0)
Midstream Gas & Liquids										
Gains on sales of MGL properties	—	—	—	—	—	—	—	(7.9)	—	(7.9)
Adjustment of accounts payable accrual	—	—	—	—	—	—	—	10.6	—	10.6
Losses on asset retirements and abandonments	—	—	—	—	—	—	—	5.2	—	5.2
Accrual for Gulf Liquids litigation contingency	—	—	—	—	—	—	68.0	2.4	2.3	72.7
Settlement of an international contract dispute	—	—	—	—	—	(6.3)	—	—	—	(6.3)
Total Midstream Gas & Liquids nonrecurring items	—	—	—	—	—	(6.3)	68.0	10.3	2.3	74.3
Power										
Reduction of contingent obligations associated with our former distributive power generation business	—	—	—	—	—	—	—	(12.7)	—	(12.7)
Accrual for a regulatory settlement (1)	4.6	—	—	—	4.6	—	—	—	—	—
Accrual for litigation contingencies (1)	—	13.1	0.4	68.7	82.2	—	—	3.5	1.3	4.8
Impairment of Aux Sable	—	—	—	23.0	23.0	—	—	—	—	—
Prior period correction	6.8	—	—	—	6.8	—	—	—	—	—
Total Power nonrecurring items	11.4	13.1	0.4	91.7	116.6	—	—	(9.2)	1.3	(7.9)
Other										
Impairment of Longhorn	—	49.1	—	38.1	87.2	—	—	—	—	—
Write-off of capitalized project development costs	—	4.0	—	—	4.0	—	—	—	—	—
Gain on sale of real property	—	—	—	(9.0)	(9.0)	—	—	—	—	—
Total Other nonrecurring items	—	53.1	—	29.1	82.2	—	—	—	—	—
Nonrecurring items included in segment profit (loss)	(9.3)	44.5	(35.5)	158.1	157.8	(8.3)	68.0	1.1	3.6	64.4
Nonrecurring items below segment profit (loss)										
Gain on sale of remaining interests in Seminole Pipeline and MAPL (Investing income / loss — Midstream)	—	(8.6)	—	—	(8.6)	—	—	—	—	—
Impairment of cost-based investment — Petrowayu (Investing income / loss — Exploration & Production)	—	—	—	—	—	—	—	—	16.4	16.4
Loss provision related to an ownership dispute — interest component (Interest accrued — Exploration & Production)	2.7	—	—	—	2.7	—	—	—	—	—
Directors and officers insurance policy adjustment (General corporate expenses — Corporate)	—	—	13.8	—	13.8	—	—	—	—	—
Loss provision related to ERISA litigation settlement (Other income (expense) — net — Corporate)	—	—	5.0	—	5.0	—	—	—	—	—
Securities litigation settlement and related costs (1)	—	—	—	9.4	9.4	1.2	160.7	3.4	2.0	167.3
Reversal of interest accrual related to reversal of litigation contingency noted above (Interest accrued — Gas Pipeline — TGPL)	—	—	—	—	—	(5.0)	—	—	—	(5.0)
Early debt retirement costs (Corporate and Exploration & Production)	—	—	—	—	—	27.0**(1)**	4.4	—	—	31.4
Gain on sale of Algar/Triangulo shares (Investing income / loss — Other)	—	—	—	—	—	(6.7)	—			(6.7)
Interest related to Gulf Liquids litigation contingency (Interest accrued — Midstream)	—	—	—	—	—	—	20.0	0.6	1.4	22.0
	2.7	(8.6)	18.8	9.4	22.3	16.5	185.1	4.0	19.8	225.4
Total nonrecurring items	(6.6)	35.9	(16.7)	167.5	180.1	8.2	253.1	5.1	23.4	289.8
Tax effect for above items (1)	(2.8)	10.7	(6.4)	48.0	49.5	3.4	76.6	1.8	2.8	84.6
Adjustment for nonrecurring excess deferred tax (benefit) provision	—	—	—	(20.2)	(20.2)	—	—	—	7.4	7.4
Adjustment for tax benefit related to federal income tax litigation	—	—	—	—	—	—	—	—	(25.1)	(25.1)
Recurring income (loss) from continuing operations available to common stockholders	$ 198.4	$ 65.9	($4.6)	$ 168.1	$ 427.8	$ 135.9	$ 112.6	$ 113.4	$ 158.4	$ 520.3
Recurring diluted earnings (loss) per common share	$ 0.33	$ 0.11	($0.01)	$ 0.28	$ 0.72	$ 0.23	$ 0.19	$ 0.19	$ 0.26	$ 0.86
Weighted-average shares — diluted (thousands)	599,422	578,902	580,735	609,106	605,847	607,073	595,561	609,062	610,352	608,627

(1) No tax effect on $.6 million of the accrual for a regulatory settlement in 1st quarter 2005 and $8 million and $42 million of the accrual for litigation contingencies in 2nd quarter 2005 and 4th quarter 2005, respectively. The tax rate applied to Midstream's international contract dispute settlement in 1st quarter 2006 is 34%. The tax rate applied to nonrecurring items for 2nd quarter 2006 has been adjusted for the effect of nondeductible expenses associated with securities litigation settlement and related costs and early debt retirement costs related to our convertible debt. The tax rate applied to 3rd and 4th quarter 2006 has been adjusted for the effect of nondeductible expenses associated with the securities litigation settlement and related costs. The tax rate applied to 4th quarter 2006 has also been adjusted for the effect of a nondeductible international impairment.

Note: The sum of earnings (loss) per share for the quarters may not equal the total earnings (loss) per share for the year due to changes in the weighted-average number of common shares outstanding.

Consolidated Statement of Operations
(UNAUDITED)

	2005					2006				
(Dollars in millions, except per-share amounts)	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*
Revenues	$ 2,954.0	$ 2,871.2	$ 3,082.3	$ 3,676.1	$ 12,583.6	$ 3,027.5	$ 2,715.1	$ 3,300.0	$ 2,770.3	$ 11,812.9
Segment costs and expenses:										
Costs and operating expenses	2,390.3	2,491.6	2,826.2	3,162.9	10,871.0	2,588.7	2,273.8	2,822.4	2,288.7	9,973.6
Selling, general and administrative expenses	73.5	62.7	90.6	98.6	325.4	71.0	109.3	128.0	140.9	449.2
Other (income) expense — net	(1.8)	21.9	(21.4)	62.5	61.2	(22.3)	61.7	(15.8)	(2.9)	20.7
Total segment costs and expenses	2,462.0	2,576.2	2,895.4	3,324.0	11,257.6	2,637.4	2,444.8	2,934.6	2,426.7	10,443.5
Equity earnings	17.7	9.8	17.6	20.5	65.6	22.2	23.1	29.9	23.7	98.9
Income (loss) from investments	—	(48.4)	—	(60.7)	(109.1)	—	(0.5)	0.5	—	—
Total segment profit	**509.7**	**256.4**	**204.5**	**311.9**	**1,282.5**	**412.3**	**292.9**	**395.8**	**367.3**	**1,468.3**
Reclass equity earnings	(17.7)	(9.8)	(17.6)	(20.5)	(65.6)	(22.2)	(23.1)	(29.9)	(23.7)	(98.9)
Reclass income (loss) from investments	—	48.4	—	60.7	109.1	—	0.5	(0.5)	—	—
General corporate expenses	(28.0)	(35.5)	(42.8)	(48.6)	(154.9)	(30.6)	(33.7)	(35.0)	(32.8)	(132.1)
Securities litigation settlement and related fees	—	—	—	—	—	(1.2)	(160.7)	(3.4)	(2.0)	(167.3)
Operating income	464.0	259.5	144.1	303.5	1,171.1	358.3	75.9	327.0	308.8	1,070.0
Interest accrued	(164.7)	(164.6)	(166.0)	(176.4)	(671.7)	(162.8)	(181.5)	(162.7)	(169.1)	(676.1)
Interest capitalized	1.1	1.4	1.8	2.9	7.2	3.0	4.0	4.8	5.4	17.2
Investing income (loss)	31.0	(17.2)	31.1	(21.2)	23.7	46.9	43.3	50.7	32.1	173.0
Early debt retirement costs	—	—	—	(0.4)	(0.4)	(27.0)	(4.4)	—	—	(31.4)
Minority interest in income of consolidated subsidiaries	(5.2)	(4.8)	(6.8)	(8.9)	(25.7)	(7.1)	(8.3)	(12.1)	(12.5)	(40.0)
Other income (expense) — net	5.5	8.1	(1.1)	14.6	27.1	8.1	8.0	2.8	7.5	26.4
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle	331.7	82.4	3.1	114.1	531.3	219.4	(63.0)	210.5	172.2	539.1
Provision (benefit) for income taxes	129.5	41.7	(2.6)	45.3	213.9	88.3	0.9	100.4	16.7	206.3
Income (loss) from continuing operations	**202.2**	**40.7**	**5.7**	**68.8**	**317.4**	**131.1**	**(63.9)**	**110.1**	**155.5**	**332.8**
Income (loss) from discontinued operations	(1.1)	0.6	(1.3)	(0.3)	(2.1)	0.8	(12.1)	(3.9)	(9.1)	(24.3)
Income (loss) before cumulative effect of change in accounting principle	201.1	41.3	4.4	68.5	315.3	131.9	(76.0)	106.2	146.4	308.5
Cumulative effect of change in accounting principle	—	—	—	(1.7)	(1.7)	—	—	—	—	—
Net income (loss)	**$ 201.1**	**$ 41.3**	**$ 4.4**	**$ 66.8**	**$ 313.6**	**$ 131.9**	**$ (76.0)**	**$ 106.2**	**$ 146.4**	**$ 308.5**
Diluted earnings per common share:										
Income (loss) from continuing operations	**$ 0.34**	**$ 0.07**	**$ 0.01**	**$ 0.11**	**$ 0.53**	**$ 0.22**	**$ (0.11)**	**$ 0.19**	**$ 0.25**	**$ 0.55**
Loss from discontinued operations	—	—	—	—	—	—	**(0.02)**	(0.01)	(0.01)	**(0.04)**
Net income (loss)	**$ 0.34**	**$ 0.07**	**$ 0.01**	**$ 0.11**	**$ 0.53**	**$ 0.22**	**$ (0.13)**	**$ 0.18**	**$ 0.24**	**$ 0.51**
Weighted-average number of shares used in computation (thousands)	599,422	578,902	580,735	609,106	605,847	607,073	595,561	609,062	610,352	608,627
Common shares outstanding at end of period (thousands)	570,501	571,502	572,922	573,592	573,592	595,007	595,562	596,130	597,147	597,147
Market price per common share (end of period)	$ 18.81	$ 19.00	$ 25.05	$ 23.17	$ 23.17	$ 21.39	$ 23.36	$ 23.87	$ 26.12	$ 26.12
Common dividends per share	$ 0.05	$ 0.05	$ 0.075	$ 0.075	$ 0.25	$ 0.075	$ 0.09	$ 0.09	$ 0.09	$ 0.345

Note: The sum of earnings (loss) per share for the quarters may not equal the total earnings (loss) per share for the year due to changes in the weighted-average number of common shares outstanding. Certain amounts have been reclassified to conform to current classifications.

Reconciliation of Segment Profit to Recurring Segment Profit
(UNAUDITED)

	2005					2006				
(Dollars in millions)	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*
Segment profit (loss):										
Exploration & Production	$ 103.7	$ 118.3	$ 158.8	$ 206.4	$ 587.2	$ 147.6	$ 119.8	$ 144.5	$ 139.6	$ 551.5
Gas Pipeline	167.4	164.5	161.1	92.8	585.8	134.7	122.7	109.0	101.0	467.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	151.5	130.7	212.2	163.9	658.3
Power	114.1	(75.0)	(226.4)	(69.4)	(256.7)	(22.5)	(79.6)	(69.7)	(39.0)	(210.8)
Other	(4.1)	(60.5)	(10.1)	(30.3)	(105.0)	1.0	(0.7)	(0.2)	1.8	1.9
Total segment profit	**$ 509.7**	**$ 256.4**	**$ 204.5**	**$ 311.9**	**$ 1,282.5**	**$ 412.3**	**$ 292.9**	**$ 395.8**	**$ 367.3**	**$ 1,468.3**
Nonrecurring adjustments:										
Exploration & Production	$ (7.6)	$ —	$ (21.7)	$ —	$ (29.3)	$ —	$ —	$ —	$ —	$ —
Gas Pipeline	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)	—	—	—	(2.0)
Midstream Gas & Liquids	—	—	—	—	—	(6.3)	68.0	10.3	2.3	74.3
Power	11.4	13.1	0.4	91.7	116.6	—	—	(9.2)	1.3	(7.9)
Other	—	53.1	—	29.1	82.2	—	—	—	—	—
Total segment nonrecurring adjustments	**$ (9.3)**	**$ 44.5**	**$ (35.5)**	**$ 158.1**	**$ 157.8**	**$ (8.3)**	**$ 68.0**	**$ 1.1**	**$ 3.6**	**$ 64.4**
Recurring segment profit (loss):										
Exploration & Production	96.1	118.3	137.1	206.4	557.9	147.6	119.8	144.5	139.6	551.5
Gas Pipeline	154.3	142.8	146.9	130.1	574.1	132.7	122.7	109.0	101.0	465.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	145.2	198.7	222.5	166.2	732.6
Power	125.5	(61.9)	(226.0)	22.3	(140.1)	(22.5)	(79.6)	(78.9)	(37.7)	(218.7)
Other	(4.1)	(7.4)	(10.1)	(1.2)	(22.8)	1.0	(0.7)	(0.2)	1.8	1.9
Total recurring segment profit	**$ 500.4**	**$ 300.9**	**$ 169.0**	**$ 470.0**	**$ 1,440.3**	**$ 404.0**	**$ 360.9**	**$ 396.9**	**$ 370.9**	**$ 1,532.7**

Note: Segment profit (loss) includes equity earnings (loss) and certain income (loss) from investments reported in Investing income (loss) in the Consolidated Statement of Income. Equity earnings (loss) results from investments accounted for under the equity method. Income (loss) from investments results from the management of certain equity investments.

Exploration & Production
(UNAUDITED)

(Dollars in millions)	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year	2006 1st Qtr	2006 2nd Qtr	2006 3rd Qtr	2006 4th Qtr	2006 Year
Revenues:										
Production	$ 210.2	$ 234.8	$ 283.0	$ 344.4	$ 1,072.4	$ 286.8	$ 287.9	$ 316.1	$ 347.0	$ 1,237.8
Gas management	28.2	32.6	32.1	52.0	144.9	41.2	28.3	25.3	39.3	134.1
Net nonqualified hedge derivative income (loss)	(0.1)	0.6	(15.9)	9.8	(5.6)	12.8	(1.6)	1.8	11.0	24.0
International	10.8	11.6	16.3	14.7	53.4	16.0	15.1	16.8	15.8	63.7
Other	(0.1)	1.9	2.9	(0.7)	4.0	(0.8)	12.6	11.1	5.1	28.0
Total revenues	249.0	281.5	318.4	420.2	1,269.1	356.0	342.3	371.1	418.2	1,487.6
Segment costs and expenses:										
Depreciation, depletion and amortization (including International)	58.5	59.5	66.4	69.6	254.0	73.1	84.5	95.3	108.6	361.5
Lease and other operating expenses *	23.8	23.9	28.5	29.0	105.2	30.1	43.8	39.0	46.4	159.3
Operating taxes	21.1	23.9	26.7	29.4	101.1	31.8	28.1	31.1	28.7	119.7
Exploration expenses *	0.9	1.1	1.5	4.1	7.6	4.4	2.4	2.6	7.2	16.6
Gathering expense	5.6	6.0	5.0	8.1	24.7	6.4	7.5	7.6	8.6	30.1
Selling, general and administrative expenses (including International)	17.0	17.7	20.3	24.6	79.6	21.5	28.2	28.2	34.4	112.3
Gas management expenses	28.2	32.6	32.1	52.0	144.9	41.2	28.3	25.3	39.3	134.1
International (excluding DD&A and SG&A)	3.3	3.3	4.7	3.6	14.9	5.5	4.9	5.0	5.9	21.3
Other (income) expense — net	(9.6)	(1.2)	(19.8)	(0.7)	(31.3)	(0.6)	0.7	(1.9)	4.8	3.0
Total segment costs and expenses	148.8	166.8	165.4	219.7	700.7	213.4	228.4	232.2	283.9	957.9
Equity earnings — International	3.5	3.6	5.8	5.9	18.8	5.0	5.9	5.6	5.3	21.8
Reported segment profit	**103.7**	**118.3**	**158.8**	**206.4**	**587.2**	**147.6**	**119.8**	**144.5**	**139.6**	**551.5**
Nonrecurring adjustments	(7.6)	—	(21.7)	—	(29.3)	—	—	—	—	—
Recurring segment profit, pre-tax	**$ 96.1**	**$ 118.3**	**$ 137.1**	**$ 206.4**	**$ 557.9**	**$ 147.6**	**$ 119.8**	**$ 144.5**	**$ 139.6**	**$ 551.5**

* Amounts have been reclassified to the current classifications.

Operating statistics

	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year	2006 1st Qtr	2006 2nd Qtr	2006 3rd Qtr	2006 4th Qtr	2006 Year
Domestic:										
Total domestic net volumes (Bcfe)	51.1	55.0	57.9	59.5	223.5	59.5	67.1	71.8	76.0	274.4
Net domestic volumes per day (MMcfe/d)	568	604	629	646	612	661	738	780	826	752
Net domestic realized price ($/Mcfe)(1)	$ 4.001	$ 4.164	$ 4.801	$ 5.655	$ 4.688	$ 4.712	$ 4.177	$ 4.300	$ 4.450	$ 4.401
Production taxes per Mcfe	$ 0.413	$ 0.435	$ 0.462	$ 0.493	$ 0.452	$ 0.534	$ 0.420	$ 0.433	$ 0.377	$ 0.436
Lease and other operating expense per Mcfe	$ 0.466	$ 0.436	$ 0.492	$ 0.486	$ 0.471	$ 0.505	$ 0.653	$ 0.544	$ 0.610	$ 0.581

(1) Net realized price is calculated the following way: production revenues (including hedging activities and incremental margins related to gas management activities) divided by net volumes.

	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year	2006 1st Qtr	2006 2nd Qtr	2006 3rd Qtr	2006 4th Qtr	2006 Year
International:										
Total volumes including Equity Investee (Bcfe)	5.3	5.5	6.1	6.0	22.9	6.0	5.6	6.0	6.1	23.7
Volumes per day (MMcfe/d)	59	61	67	65	63	67	61	65	67	65
Volumes net to Williams (after minority interest) (Bcfe)	4.1	4.3	4.8	4.8	18.0	4.7	4.4	4.7	4.8	18.6
Volumes net to Williams per day (MMcfe/d)	46	48	53	51	49	53	48	51	53	51
Total Domestic and International:										
Volumes net to Williams (after minority interest) (Bcfe)	55.3	59.3	62.7	64.2	241.5	64.2	71.5	76.5	80.9	293.1
Volumes net to Williams per day (MMcfe/d)	614	652	682	697	662	714	786	831	879	803

Gas Pipeline
(UNAUDITED)

(Dollars in millions)	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year	2006 1st Qtr	2006 2nd Qtr	2006 3rd Qtr	2006 4th Qtr	2006 Year
Revenues:										
Northwest Pipeline	$ 80.3	$ 78.9	$ 79.6	$ 82.7	$ 321.5	$ 79.6	$ 80.0	$ 81.0	$ 83.7	$ 324.3
Transcontinental Gas Pipe Line	254.9	278.1	266.0	292.0	1,091.0	254.3	257.2	253.0	258.1	1,022.6
Other	0.1	—	0.2	—	0.3	0.1	0.1	0.2	0.4	0.8
Total revenues	335.3	357.0	345.8	374.7	1,412.8	334.0	337.3	334.2	342.2	1,347.7
Segment costs and expenses:										
Costs and operating expenses	160.4	193.3	177.6	250.7	782.0	177.2	192.8	192.2	203.2	765.4
Selling, general and administrative expenses	18.6	6.8	23.6	35.1	84.1	31.0	35.4	45.1	50.0	161.5
Other (income) expense — net	0.3	0.3	0.5	3.4	4.5	(1.4)	(3.4)	(2.4)	(2.3)	(9.5)
Total segment costs and expenses	179.3	200.4	201.7	289.2	870.6	206.8	224.8	234.9	250.9	917.4
Equity earnings	11.4	7.9	17.0	7.3	43.6	7.5	10.7	9.2	9.7	37.1
Income (loss) from investments	—	—	—	—	—	—	(0.5)	0.5	—	—
Reported segment profit:										
Northwest Pipeline	39.7	36.5	39.1	37.2	152.5	33.3	32.8	31.8	29.0	126.9
Transcontinental Gas Pipe Line	117.9	121.8	107.0	50.1	396.8	95.8	81.3	69.5	63.7	310.3
Other	9.8	6.2	15.0	5.5	36.5	5.6	8.6	7.7	8.3	30.2
Total reported segment profit	**167.4**	**164.5**	**161.1**	**92.8**	**585.8**	**134.7**	**122.7**	**109.0**	**101.0**	**467.4**
Nonrecurring adjustments:										
Northwest Pipeline	—	—	—	—	—	—	—	—	—	—
Transcontinental Gas Pipe Line	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)	—	—	—	(2.0)
Other	—	—	—	—	—	—	—	—	—	—
Total nonrecurring adjustments	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)	—	—	—	(2.0)
Recurring segment profit:										
Northwest Pipeline	39.7	36.5	39.1	37.2	152.5	33.3	32.8	31.8	29.0	126.9
Transcontinental Gas Pipe Line	104.8	100.1	92.8	87.4	385.1	93.8	81.3	69.5	63.7	308.3
Other	9.8	6.2	15.0	5.5	36.5	5.6	8.6	7.7	8.3	30.2
Total recurring segment profit, pre-tax	**$ 154.3**	**$ 142.8**	**$ 146.9**	**$ 130.1**	**$ 574.1**	**$ 132.7**	**$ 122.7**	**$ 109.0**	**$ 101.0**	**$ 465.4**
Operating statistics										
Northwest Pipeline										
Throughput (TBtu)	181.2	146.2	152.9	192.6	672.9	179.7	142.7	156.6	196.5	675.5
Average daily transportation volumes (TBtu)	2.0	1.6	1.7	2.1	1.9	2.0	1.6	1.7	2.1	1.9
Average daily firm reserved capacity (TBtu)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Transcontinental Gas Pipe Line										
Throughput (TBtu)	537.7	427.9	453.6	466.6	1,885.8	502.8	427.0	471.3	457.7	1,858.8
Average daily transportation volumes (TBtu)	6.0	4.7	4.9	5.1	5.2	5.6	4.6	5.1	5.0	5.1
Average daily firm reserved capacity (TBtu)	6.9	6.5	6.4	6.8	6.7	7.0	6.4	6.4	6.7	6.6

Midstream Gas & Liquids
(UNAUDITED)

	2005					2006				
(Dollars in millions)	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*
Revenues:										
Gathering	$ 70.6	$ 74.2	$ 74.0	$ 75.8	$ 294.6	$ 76.8	$ 79.0	$ 79.2	$ 79.7	$ 314.7
Processing	23.5	24.3	25.5	22.9	96.2	24.9	27.4	27.6	29.2	109.1
Venezuela fee revenue	36.5	37.8	40.4	38.8	153.5	38.9	38.0	40.6	36.3	153.8
NGL sales from gas processing	285.1	247.0	244.2	259.0	1,035.3	263.7	292.6	296.6	262.9	1,115.8
Production handling and transportation	18.6	20.4	14.7	20.6	74.3	37.2	33.2	33.0	30.4	133.8
Olefins sales (including Gulf and Canada)	146.6	114.2	121.4	185.3	567.5	148.9	131.4	175.9	155.7	611.9
Trading/marketing sales	588.0	574.4	522.0	578.1	2,262.5	709.0	806.1	863.9	757.9	3,136.9
Other revenues	23.7	33.2	31.7	39.1	127.7	34.4	30.7	28.8	29.5	123.4
	1,192.6	1,125.5	1,073.9	1,219.6	4,611.6	1,333.8	1,438.4	1,545.6	1,381.6	5,699.4
Intrasegment eliminations	(385.6)	(345.4)	(319.2)	(328.7)	(1,378.9)	(354.4)	(394.9)	(428.6)	(396.8)	(1,574.7)
Total revenues	807.0	780.1	754.7	890.9	3,232.7	979.4	1,043.5	1,117.0	984.8	4,124.7
Segment costs and expenses:										
NGL cost of goods sold	225.1	202.4	189.6	218.3	835.4	199.9	172.7	156.9	144.8	674.3
Olefins cost of goods sold	118.7	104.0	102.2	163.5	488.4	132.8	108.1	141.2	127.8	509.9
Trading/marketing cost of goods sold	584.0	574.7	510.1	575.8	2,244.6	716.7	799.1	863.4	765.8	3,145.0
Venezuela operating costs	16.1	16.0	17.4	17.6	67.1	16.8	18.1	17.1	19.0	71.0
Operating costs	101.6	101.5	112.8	113.9	429.8	120.6	120.7	134.2	135.4	510.9
Other										
Selling, general and administrative expenses	22.9	21.0	23.1	29.3	96.3	23.3	25.2	31.1	31.4	111.0
Other (income) expense — net	2.6	1.7	0.8	(1.7)	3.4	(17.9)	70.0	(3.2)	(2.9)	46.0
Intrasegment eliminations	(385.5)	(345.5)	(319.2)	(328.7)	(1,378.9)	(354.4)	(394.9)	(428.6)	(396.8)	(1,574.7)
Total segment costs and expenses	685.5	675.8	636.8	788.0	2,786.1	837.8	919.0	912.1	824.5	3,493.4
Equity earnings	7.1	4.1	3.2	9.2	23.6	9.9	6.2	7.3	3.6	27.0
Income from investments	—	0.7	—	0.3	1.0	—	—	—	—	—
Reported segment profit	**128.6**	**109.1**	**121.1**	**112.4**	**471.2**	**151.5**	**130.7**	**212.2**	**163.9**	**658.3**
Nonrecurring adjustments	—	—	—	—	—	(6.3)	68.0	10.3	2.3	74.3
Recurring segment profit, pre-tax	**$ 128.6**	**$ 109.1**	**$ 121.1**	**$ 112.4**	**$ 471.2**	**$ 145.2**	**$ 198.7**	**$ 222.5**	**$ 166.2**	**$ 732.6**
Operating statistics										
Gathering volumes (TBtu)	315.5	323.6	310.3	303.9	1,253.3	296.9	300.1	292.5	291.9	1,181.4
Gathering rate ($/MMBtu)	$ 0.2237	$ 0.2292	$ 0.2386	$ 0.2496	$ 0.2351	$ 0.2590	$ 0.2634	$ 0.2708	$ 0.2730	$ 0.2664
Processing volumes (TBtu)	181.0	184.5	190.3	165.6	721.4	191.8	204.8	210.0	226.5	833.1
Processing rate ($/MMBtu)	$ 0.1299	$ 0.1316	$ 0.1342	$ 0.1381	$ 0.1334	$ 0.1298	$ 0.1340	$ 0.1314	$ 0.1289	$ 0.1310
NGL equity sales (million gallons)	398.7	338.3	276.4	255.8	1,269.2	333.7	361.3	334.0	325.8	1,354.8
NGL margin ($/gallon)	$ 0.1503	$ 0.1318	$ 0.1976	$ 0.1565	$ 0.1569	$ 0.1900	$ 0.3319	$ 0.4183	$ 0.3625	$ 0.3259
Olefins sales (Ethylene & Propylene) (million lbs)	266.5	265.6	258.1	275.9	1,066.1	259.2	196.8	268.1	263.8	987.9

Power
(UNAUDITED)

(Dollars in millions)	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year	2006 1st Qtr	2006 2nd Qtr	2006 3rd Qtr	2006 4th Qtr	2006 Year
Revenues:										
Natural gas & power	$ 2,066.3	$ 1,998.6	$ 2,244.3	$ 2,787.0	$ 9,096.2	$ 2,053.3	$ 1,606.6	$ 2,104.1	$ 1,698.1	$ 7,462.1
Crude & refined products	(1.1)	(0.2)	(1.6)	0.1	(2.8)	—	—	—	—	—
Other	(0.3)	1.0	0.2	(0.4)	0.5	(0.1)	0.4	—	—	0.3
Total revenues	2,064.9	1,999.4	2,242.9	2,786.7	$ 9,093.9	2,053.2	1,607.0	2,104.1	1,698.1	$ 7,462.4
Segment costs and expenses:										
Costs and operating expenses	1,930.3	2,041.1	2,450.9	2,750.2	9,172.5	2,082.1	1,671.4	2,167.6	1,716.8	7,637.9
Selling, general and administrative expenses	16.0	16.9	21.1	10.5	64.5	(4.5)	18.9	22.2	25.6	62.2
Other (income) expense — net	5.6	17.3	(1.7)	95.5	116.7	(2.1)	(3.4)	(8.4)	—	(13.9)
Total segment costs and expenses	1,951.9	2,075.3	2,470.3	2,856.2	9,353.7	2,075.5	1,686.9	2,181.4	1,742.4	7,686.2
Equity Earnings	1.1	0.9	1.0	0.1	3.1	(0.2)	0.3	7.6	5.3	13.0
Reported segment profit (loss)	**114.1**	**(75.0)**	**(226.4)**	**(69.4)**	**(256.7)**	**(22.5)**	**(79.6)**	**(69.7)**	**(39.0)**	**(210.8)**
Nonrecurring adjustments	11.4	13.1	0.4	91.7	116.6	—	—	(9.2)	1.3	(7.9)
Recurring segment profit (loss), pre-tax	**$ 125.5**	**$ (61.9)**	**$ (226.0)**	**$ 22.3**	**$ (140.1)**	**$ (22.5)**	**$ (79.6)**	**$ (78.9)**	**$ (37.7)**	**$ (218.7)**
Operating statistics										
Volumes										
Natural gas (Bcfd)										
Sales to third parties	1.7	1.8	1.7	1.7	1.7	1.7	1.5	1.7	1.7	1.7
Sales to other segments	0.6	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
For use in tolling agreements and by owned generation	0.2	0.2	0.3	0.1	0.2	0.1	0.2	0.4	0.1	0.2
Total managed	2.5	2.4	2.3	2.1	2.3	2.2	2.1	2.5	2.2	2.3
Crude & refined products (MBPD)	—	—	—	—	—	—	—	—	—	—
Power (GWh)	14,832	15,906	21,690	14,559	66,987	11,505	12,949	17,430	11,982	53,866

Additional statistics

Value at risk

	Quarter ended 12/31/2006 (in Millions)
One day VaR - 95% confidence level	
Trading	$ 1.4MM
Non-Trading	$ 12.2MM
Aggregate Earnings VaR	$ 3.0MM

	Quarter ended 9/30/2006 (in Millions)
One day VaR - 95% confidence level	
Trading	$ 1.8MM
Non-Trading	$16.3MM
Aggregate Earnings VaR	$ 5.2MM

	Quarter ended 6/30/2006 (in Millions)
One day VaR - 95% confidence level	
Trading	$ 3.1MM
Non-Trading	$24.9MM
Aggregate Earnings VaR	$ 5.6MM

	Quarter ended 3/31/2006 (in Millions)
One day VaR - 95% confidence level	
Trading	$3.8MM
Non-Trading	$6.0MM
Aggregate Earnings VaR	$9.2MM

Net Credit Exposure (in Millions)

	Investment Grade	Total
Gas and electric utilities	$ 120.4	$ 120.5
Energy marketers and traders	209.0	455.4
Financial institutions	325.5	325.5
Other	20.4	20.4
	$ 675.3	$ 921.8
Credit Reserves		(20.3)
Net Credit Exposure from Derivative Contracts		$ 901.5

Fair Value Of Mark-to-Market Derivatives (in Millions)

Period the value of mark-to-market derivatives is expected to be realized:	
1-12 months	$ 3.4

13-36 months	(0.4)
37-60 months	0.2
61-120 months	—
121+ months	0.1
Total Fair Value	3.3
Non-Trading MTM Derivatives and SFAS 133 Hedges	412.6
Non-Power Business Unit Hedges	20.5
Total Net Derivative Assets and Liabilities	$ 436.4

Power Portfolio
(Megawatts)

	Quarter Ended	
	12/31/06	12/31/05
Owned	207	207
Contracted	9,708	9,616
Total	9,915	9,823

Credit Support (in Millions)

As of December 31, 2006	
Prepays	$ 7
Margins	$(77)
Adequate Assurance	$ 8

Capital Expenditures and Investments
(UNAUDITED)

(Dollars in millions)	2005 *1st Qtr*	2005 *2nd Qtr*	2005 *3rd Qtr*	2005 *4th Qtr*	2005 *Year*	2006 *1st Qtr*	2006 *2nd Qtr*	2006 *3rd Qtr*	2006 *4th Qtr*	2006 *Year*
Capital expenditures:										
Exploration & Production	$ 158.6	$ 182.8	$ 211.1	$ 230.8	$ 783.3	$ 310.3	$ 283.9	$ 384.9	$ 442.9	$ 1,422.0
Gas Pipeline:										
Northwest Pipeline	12.0	29.6	43.2	52.2	137.0	40.3	96.0	177.4	159.1	472.8
Transcontinental Gas Pipe Line	35.7	55.0	80.7	83.1	254.5	46.4	106.7	109.4	75.6	338.1
Other	—	—	—	2.2	2.2	—	—	—	—	—
Total	47.7	84.6	123.9	137.5	393.7	86.7	202.7	286.8	234.7	810.9
Midstream Gas & Liquids	16.3	25.5	32.7	40.7	115.2	70.7	39.3	83.5	63.5	257.0
Power	1.0	0.7	0.4	0.1	2.2	0.6	0.6	(0.1)	0.1	1.2
Other	(0.7)*	0.1	1.2	4.0	4.6	—	7.8	1.2	9.1	18.1
Total	**$ 222.9**	**$ 293.7**	**$ 369.3**	**$ 413.1**	**$ 1,299.0**	**$ 468.3**	**$ 534.3**	**$ 756.3**	**$ 750.3**	**$ 2,509.2**
Purchase of investments:										
Exploration & Production	$ 6.3	$ —	$ 0.3	$ —	$ 6.6	$ —	$ —	$ —	$ —	$ —
Gas Pipeline	—	—	—	—	—	—	—	4.5	0.7	5.2
Midstream Gas & Liquids	—	35.0	11.5	—	46.5	(3.4)	0.8	—	2.4	(0.2)
Other	20.0	20.6	4.5	17.9	63.0	13.1	26.0	4.6	0.2	43.9
Total	**$ 26.3**	**$ 55.6**	**$ 16.3**	**$ 17.9**	**$ 116.1**	**$ 9.7**	**$ 26.8**	**$ 9.1**	**$ 3.3**	**$ 48.9**
Summary:										
Exploration & Production	$ 164.9	$ 182.8	$ 211.4	$ 230.8	$ 789.9	$ 310.3	$ 283.9	$ 384.9	$ 442.9	$ 1,422.0
Gas Pipeline	47.7	84.6	123.9	137.5	393.7	86.7	202.7	291.3	235.4	816.1
Midstream Gas & Liquids	16.3	60.5	44.2	40.7	161.7	67.3	40.1	83.5	65.9	256.8
Power	1.0	0.7	0.4	0.1	2.2	0.6	0.6	(0.1)	0.1	1.2
Other	19.3	20.7	5.7	21.9	67.6	13.1	33.8	5.8	9.3	62.0
Total	**$ 249.2**	**$ 349.3**	**$ 385.6**	**$ 431.0**	**$ 1,415.1**	**$ 478.0**	**$ 561.1**	**$ 765.4**	**$ 753.6**	**$ 2,558.1**
Cumulative summary:										
Exploration & Production	$ 164.9	$ 347.7	$ 559.1	$ 789.9	$ 789.9	$ 310.3	$ 594.2	$ 979.1	$ 1,422.0	$ 1,422.0
Gas Pipeline	47.7	132.3	256.2	393.7	393.7	86.7	289.4	580.7	816.1	816.1
Midstream Gas & Liquids	16.3	76.8	121.0	161.7	161.7	67.3	107.4	190.9	256.8	256.8
Power	1.0	1.7	2.1	2.2	2.2	0.6	1.2	1.1	1.2	1.2
Other	19.3	40.0	45.7	67.6	67.6	13.1	46.9	52.7	62.0	62.0
Total	**$ 249.2**	**$ 598.5**	**$ 984.1**	**$ 1,415.1**	**$ 1,415.1**	**$ 478.0**	**$ 1,039.1**	**$ 1,804.5**	**$ 2,558.1**	**$ 2,558.1**

* Reflects the transfer of property from the corporate parent to various segments.

Depreciation, Depletion and Amortization and Other Selected Financial Data
(UNAUDITED)

	2005					2006				
(Dollars in millions)	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*
Depreciation, depletion and amortization:										
Exploration & Production	$ 58.6	$ 59.4	$ 66.4	$ 69.8	$ 254.2	$ 73.0	84.2	94.8	108.2	360.2
Gas Pipeline:										
Northwest Pipeline	17.3	17.0	17.9	18.4	70.6	18.5	18.8	19.1	20.2	76.6
Transcontinental Gas Pipe Line	49.4	48.6	49.3	49.4	196.7	50.0	51.7	51.2	52.2	205.1
Total	66.7	65.6	67.2	67.8	267.3	68.5	70.5	70.3	72.4	281.7
Midstream Gas & Liquids	46.0	46.4	49.5	50.1	192.0	49.4	49.9	49.9	52.0	201.2
Power	3.9	3.7	3.6	3.7	14.9	3.2	3.2	2.3	2.0	10.7
Other	3.0	3.0	2.9	2.7	11.6	2.9	2.7	3.1	3.0	11.7
Total	$ 178.2	$ 178.1	$ 189.6	$ 194.1	$ 740.0	$ 197.0	$ 210.5	$ 220.4	$ 237.6	$ 865.5
Other selected financial data:										
Cash and cash equivalents	$ 1,210.0	$ 1,297.2	$ 1,360.5	$ 1,597.2	$ 1,597.2	$ 1,115.0	$ 980.4	$ 1,074.6	$ 2,268.6	$ 2,268.6
Total assets	$ 26,434.1	$ 26,399.7	$ 33,655.8	$ 29,442.6	$ 29,442.6	$ 26,029.0	$ 25,617.2	$ 24,821.5	$ 25,402.4	$ 25,402.4
Capital structure:										
Debt										
Current	$ 99.5	$ 98.6	$ 122.4	$ 122.6	$ 122.6	$ 175.7	$ 170.7	$ 142.3	$ 392.1	$ 392.1
Noncurrent	$ 7,650.4	$ 7,645.7	$ 7,598.7	$ 7,590.5	$ 7,590.5	$ 7,252.8	$ 7,292.6	$ 7,275.2	$ 7,622.0	$ 7,622.0
Stockholders' equity	$ 5,261.1	$ 5,353.6	$ 5,154.4	$ 5,427.5	$ 5,427.5	$ 5,925.5	$ 5,882.3	$ 6,071.2	$ 6,073.2	$ 6,073.2
Debt to debt-plus-equity ratio	59.6%	59.1%	60.0%	58.7%	58.7%	55.6%	55.9%	55.0%	56.9%	56.9%

Adjustment to remove MTM effect

Dollars in millions except for per share amounts	2006 1Q	2006 2Q	2006 3Q	2006 4Q	2006 Year	2005 1Q	2005 2Q	2005 3Q	2005 4Q	2005 Year
Recurring income from cont. ops available to common shareholders	**$ 136**	**$ 113**	**$ 113**	**$ 158**	**$ 520**	**$ 198**	**$ 66**	**$ (5)**	**$ 168**	**$ 428**
Recurring diluted earnings per common share	**$ 0.23**	**$ 0.19**	**$ 0.19**	**$ 0.26**	**$ 0.86**	**$ 0.33**	**$ 0.11**	**$ (0.01)**	**$ 0.28**	**$ 0.72**
Mark-to-Market (MTM) adjustments:										
Reverse forward unrealized MTM gains/losses	(43)	38	16	11	22	(221)	(22)	141	(70)	(172)
Add realized gains/losses from MTM previously recognized	77	100	80	25	282	113	77	72	48	310
Total MTM adjustments	34	138	96	36	304	(108)	55	213	(22)	138
Tax effect of total MTM adjustments (at 39%)	13	53	37	14	116	(42)	21	83	(8)	53
After tax MTM adjustments	21	85	59	22	188	(66)	34	130	(14)	85
Recurring income from cont. ops available to common shareholders after MTM adjust.	**$ 157**	**$ 198**	**$ 172**	**$ 180**	**$ 708**	**$ 132**	**$ 100**	**$ 125**	**$ 154**	**$ 513**
Recurring diluted earnings per share after MTM adj.	**$ 0.26**	**$ 0.33**	**$ 0.28**	**$ 0.30**	**$ 1.17**	**$ 0.22**	**$ 0.17**	**$ 0.22**	**$ 0.26**	**$ 0.86**
weighted average shares — diluted (thousands)	607,073	595,561	609,062	610,352	608,627	599,422	578,902	580,735	609,106	605,847

Adjustments have been made to reverse estimated forward unrealized MTM gains/losses and add estimated realized gains/losses from MTM previously recognized, i.e. assumes MTM accounting had never been applied to designated hedges and other derivatives.

Some annual figures may differ from sum of quarterly figures due to rounding.

Non-GAAP Utility Statement:

This press release includes certain financial measures, EBITDA, operating free cash flow, recurring earnings and recurring segment profit, that are non-GAAP financial measures as defined under the rules of the Securities and Exchange Commission. EBITDA represents the sum of net income (loss), net interest expense, income taxes, depreciation and amortization of intangible assets, less income (loss) from discontinued operations. Operating free cash flow is defined as cash flow from continuing operations less capital expenditures before dividends or principal payments. Recurring earnings exclude items of income or loss that the company characterizes as unrepresentative of its ongoing operations. Recurring earnings and recurring segment profit provide investors meaningful insight into the Company’s results from ongoing operations. This press release is accompanied by a reconciliation of these non-GAAP financial measures to their nearest GAAP financial measures. Management uses these financial measures because they are widely accepted financial indicators used by investors to compare company performance. In addition, management believes that these measures provide investors an enhanced perspective of the operating performance of the Company’s assets and the cash that the business is generating. Neither EBITDA nor recurring earnings, operating free cash flow and recurring segment profit are intended to represent cash flows for the period, nor are they presented as an alternative to net income or cash flow from operations. They should not be considered in isolation or as substitutes for a measure of performance prepared in accordance with United States generally accepted accounting principles.

Certain financial information in this press release is also shown including Power mark-to-market adjustments. This press release is accompanied by a reconciliation of these non-GAAP financial measures to their nearest GAAP financial measures. Prior to the third quarter 2004, the Company did not qualify for hedge accounting with respect to its Power segment. In September 2004, we announced our decision to continue operating the Power business. As a result of that decision, Power’s derivative contracts became eligible for hedge accounting. Hedge accounting reduces earnings volatility associated with Power’s portfolio of certain derivative hedging instruments. Prior to the adoption of hedge accounting, these derivative hedging instruments were accounted for on a mark-to-market basis with the change in fair value recognized in earnings each period. Management uses the mark-to-market adjustments to better reflect Power’s results on a basis that is more consistent with Power’s portfolio cash flows and to aid investor understanding. The adjustments reverse forward unrealized mark-to-market gains or losses from derivatives and add realized gains or losses from derivatives for which mark-to-market income has been previously recognized, with the effect that the resulting adjusted segment profit is presented as if mark-to-market accounting had never been applied to designated hedges or other derivatives. The measure is limited by the fact that it does not reflect potential unrealized future losses or gains on derivative contracts. However, management compensates for this limitation since derivative assets and liabilities do reflect unrealized gains and losses of derivative contracts. Overall, management believes the mark-to-market adjustments provide an alternative measure that more closely matches realized cash flows for the Power segment but does not substitute for actual cash flows. We also apply the mark-to-market adjustment and the recurring adjustments to present a measure referred to as recurring income from continuing operations after mark-to-market adjustments.

Exhibit 99.2

Williams 2006
4th Quarter Earnings

February 22, 2007

Forward Looking Statements

Our reports, filings, and other public announcements might contain or incorporate by reference statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You typically can identify forward-looking statements by the use of forward-looking words, such as "anticipate," believe," "could," "continue," "estimate," "expect," "forecast," "may," "plan," "potential," "project," "schedule," "will," and other similar words. These statements are based on our intentions, beliefs, and assumptions about future events and are subject to risks, uncertainties, and other factors. Actual results could differ materially from those contemplated by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such statements, other factors could cause our actual results to differ materially from the results expressed or implied in any forward-looking statements. Those factors include, among others:

- Our businesses are subject to complex government regulations that are subject to changes in the regulations themselves or in their interpretation or implementation;
- Our ability to gain adequate, reliable and affordable access to transmission and distribution assets due to the FERC and regional regulation of wholesale market transactions for electricity and gas;
- Our gas sales, transmission and storage operations are subject to government regulations and rate proceedings that could have an adverse impact on our ability to recover the costs of operating our pipeline facilities;
- The different regional power markets in which we compete or will compete in the future have changing regulatory structures;
- Our risk measurement and hedging activities might not prevent losses;
- Electricity, natural gas liquids and gas prices are volatile and this volatility could adversely affect our financial results, cash flows, access to capital and ability to maintain existing businesses;
- We might not be able to successfully manage the risks associated with selling and marketing products in the wholesale energy markets;
- Our operating results might fluctuate on a seasonal and quarterly basis;
- Risks related to laws of other countries, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments;
- Legal proceedings and governmental investigations related to our business;
- Recent developments affecting the wholesale power and energy trading industry sector that have reduced market activity and liquidity;
- Because we no longer maintain investment grade credit ratings, our counterparties have required us to provide higher amounts of credit support;
- Despite our restructuring efforts, we may not attain investment grade ratings;
- Institutional knowledge represented by our former employees now employed by our outsourcing service provider might not be adequately preserved;
- Failure of the outsourcing relationship might negatively impact our ability to conduct our business;

Forward Looking Statements (cont.)

- Our ability to receive services from outsourcing provider locations outside the United States might be impacted by cultural differences, political instability, or unanticipated regulatory requirements in jurisdictions outside the United States;
- We could be held liable for the environmental condition of any of our assets, which could include losses or costs of compliance that exceed our current expectations;
- Environmental regulation and liability relating to our business will be subject to environmental legislation in all jurisdictions in which it operates, and such legislation may be subject to change;
- Potential changes in accounting standards that might cause us to revise our financial disclosure in the future, which might change the way analysts measure our business or financial performance;
- The continued availability of natural gas reserves to our natural gas transmission and midstream businesses;
- Our drilling, production, gathering, processing and transporting activities involve numerous risks that might result in accidents and other operating risks and costs;
- Compliance with the Pipeline Improvement Act may result in unanticipated costs and consequences;
- Estimating reserves and future net revenues involves uncertainties and negative revisions to reserve estimates and oil and gas price declines may lead to impairment of oil and gas assets;
- The threat of terrorist activities and the potential for continued military and other actions;
- The historic drilling success rate of our exploration and production business is no guarantee of future performance; and
- Our assets and operations can be affected by weather and other phenomena.

In light of these risks, uncertainties, and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time that we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise

Investors are urged to closely consider the disclosures and risk factors in our annual report on Form 10-K filed with the Securities and Exchange Commission on March 9, 2006, and our quarterly reports on Form 10-Q available from our offices or from our website at www.williams.com.

Oil and Gas Reserves Disclaimer

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves. We use certain terms in this presentation, such as "probable" reserves and "possible" reserves and "new opportunities potential" reserves that the SEC's guidelines strictly prohibit us from including in filings with the SEC.

The SEC defines proved reserves as estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under the assumed economic conditions. Probable and possible reserves are estimates of potential reserves that are made using accepted geological and engineering analytical techniques, but which are estimated with reduced levels of certainty than for proved reserves. Possible reserve estimates are less certain than those for probable reserves. New opportunities potential is an estimate of reserves for new areas for which we do not have sufficient information to date to raise the reserves to either the probable category or the possible category. New opportunities potential estimates are even less certain that those for possible reserves.

Reference to "total resource portfolio" include proved, probable and possible reserves as well as new opportunities potential.

Investors are urged to closely consider the disclosures and risk factors in our Forms 10-K and 10-Q, available from our offices or from our Web site at www.williams.com.

2006 Review

Steve Malcolm
Chairman, President & CEO

Headlines

- Key earnings measure* jumps 38% for year
- Record-high margins fuel extraordinary Midstream performance
- Development activity boosts natural gas production and reserves
  - Production from U.S. assets rises 23%
  - Reserves replaced at rate of 216%
- $1.6 billion midstream asset dropped down to Williams Partners L.P.
- New, higher rates for Transco, Northwest
- Power business captures megawatt sales beyond 2010
- Operations garner recognition and rewards
- Shareholders earn 65% total return in last 8 quarters

* Recurring income from continuing operations after mark-to-market adjustments

Well-positioned for near- to long-term value creation

Prime assets deliver growth

- **E&P – our primary growth:** long-lived natural gas assets; development costs among lowest
- **Midstream –** significant growth potential; **strong free cash flow** from ops; drop-downs are source of cash; delivers big benefit when NGL margins are strong
- **Gas Pipeline – anchors credit**: expansions support stable and growing cash flows to reinvest in high-return E&P and midstream growth
- **Power –** market for **2010-and-beyond** power becoming a reality; continues to deliver on strategy to generate cash and reduce risk

Pursuing growth with discipline

- **Portfolio** – provides **inherent commodity hedge**
- **EVA-based investments**
- Committed to **maintaining or improving credit** ratios/ratings
- Access to **low-cost capital** via Williams Partners L.P.

Solid record of delivering results

- **>100% increase in recurring segment profit** after mark-to-market effect 2003-2006
- Virtually all **secured debt eliminated**
- **Resolved** significant legacy issues
- **65% return** to shareholders in last 8 quarters; **increased dividend 20%** in 2006 alone

Taking action to drive value creation

- **Deep bench** of qualifying assets – potential annual dropdowns of $1B-$2B in '07 and '08
- Acceleration yielded $1.6 billion in drop-downs in '06; moved GP into higher returns
- E&P **production sharply increased**, future prospects good; expanding activity to new areas with high potential for success
- **New projects and rate cases** expected to support significantly **higher pipeline profits** in 2007 and beyond

Value-growth catalysts to watch

- Growing segment profit
- Growing natural gas reserves and production
- New, higher rates for Northwest and Transco
- More megawatts contracted into market beyond 2010
- Capture of additional midstream projects
- More potential dropdowns to Williams Partners

Financial Results

Don Chappel
Chief Financial Officer

Financial Results

Dollars in millions (except per share amounts)	4th Quarter 2006	4th Quarter 2005	Year 2006	Year 2005
Income from Continuing Operations	$ 155	$ 69	$ 333	$ 318
(Loss) from Discontinued Operations	(9)	-	(24)	(2)
Cumulative effect of change in accounting principle	-	(2)	-	(2)
Net Income	$ 146	$ 67	$ 309	$ 314
Net Income/Share	$ 0.24	$ 0.11	$ 0.51	$ 0.53
Recurring Income from Cont. Ops./Share	$ 0.26	$ 0.28	$ 0.86	$ 0.72
Recurring Income from Continuing Operations After MTM Adjustments/Share	**$ 0.30**	**$ 0.26**	**$ 1.17**	**$ 0.86**

A more detailed schedule reconciling income from continuing operations to recurring income from continuing operations is available on Williams' website at www.williams.com and at the end of this presentation.

Financial Results

Recurring Income from Continuing Operations

Dollars in millions (except per share amounts)	4th Quarter 2006	4th Quarter 2005	Year 2006	Year 2005
Income from Continuing Operations	$ 155	$ 69	$ 333	$ 318
Nonrecurring Items				
Regulatory & Litigation Contingencies				
Settlements & Related Costs	7	87	260	106
Debt Retirement Expense	-	-	31	-
Impairments/Losses/Write-offs/Contingency Adj.	16	61	9	133
(Income)/expense related to prior periods	-	28	4	(15)
Gains on sale of assets	-	(9)	(15)	(47)
Other – Net	1	-	1	3
Total Nonrecurring Items	24	167	290	180
Tax effects of adjustments	(3)	(48)	(85)	(50)
Adjustment for tax benefit related to fed. inc. tax lit.	(25)	-	(25)	-
Adjustment for nonrecurring excess deferred tax benefit	7	(20)	7	(20)
Recurring Income from Cont. Ops. Avail to Com.	$ 158	$ 168	$ 520	$ 428
Recurring Income from Continuing Ops./Share	$ 0.26	$ 0.28	$ 0.86	$ 0.72

A more detailed schedule reconciling income from continuing operations to recurring income from continuing operations after mark-to-market adjustments is available on Williams' Web site at www.williams.com and at the end of this presentation.

Recurring Income from Cont. Ops. After MTM Adjustment

Williams

Dollars in millions (except per share amounts)	4th Quarter 2006	4th Quarter 2005	Year 2006	Year 2005
Recurring Inc. from Cont. Ops. Avail. to Common	$ 158	$ 168	$ 520	$ 428
Recurring Diluted Earnings per Common Share	$ 0.26	$ 0.28	$ 0.86	$ 0.72
Mark-to-Market (MTM) adjustments for Power:				
Reverse forward unrealized MTM (gains)/losses	$ 11	$ (70)	$ 22	$ (172)
Add realized gains from MTM previously recognized	25	48	282	310
Total MTM Adjustments	36	(22)	304	138
Tax Effect of Total MTM Adjustments	(14)	8	(116)	(53)
After-Tax MTM Adjustments	$ 22	$ (14)	$ 188	$ 85
Recurring Inc. from Cont. Ops. Avail. to Common Shareholders after MTM adjustments	$ 180	$ 154	$ 708	$ 513
Recurring Diluted Earnings Per Share after MTM adjustments	$ 0.30	$ 0.26	$ 1.17	$ 0.86

Note: Adjustments have been made to reverse estimated forward unrealized mark-to-market ("MTM") (gains)/losses and add estimated realized gains from MTM previously recognized, i.e. assumes MTM accounting had never been applied to designated hedges and other derivatives.

A more detailed schedule reconciling income from continuing operations to recurring income from continuing operations after mark-to-market adjustments is available on Williams' Web site at www.williams.com and at the end of this presentation.

Fourth Quarter Segment Profit

Dollars in millions	Reported 2006	Reported 2005	Recurring 2006	Recurring 2005
Exploration & Production (see slide 72)	$ 140	$ 206	$ 140	$ 206
Midstream Gas & Liquids (see slide 85)	164	112	166	112
Gas Pipeline (see slide 92)	101	93	101	130
Power (see slide 95)	(39)	(69)	(38)	22
Other	1	(30)	2	-
Segment Profit	$ 367	$ 312	$ 371	$ 470
MTM Adjustments - Power			36	(22)
Segment Profit after MTM Adjustments			**$ 407**	**$ 448**
Memo:				
Power after MTM Adjustments			$ (2)	-

A more detailed schedule reconciling income (loss) from continuing operations to recurring income from continuing operations is available on Williams' Web site at www.williams.com and at the end of this presentation.

2006 Segment Profit

Dollars in millions	Reported 2006	Reported 2005	Recurring 2006	Recurring 2005
Exploration & Production (see slide 72)	$ 552	$ 587	$ 552	$ 558
Midstream Gas & Liquids (see slide 85)	658	471	733	471
Gas Pipeline (see slide 92)	467	586	465	574
Power (see slide 95)	(211)	(257)	(219)	(140)
Other	2	(104)	2	(23)
Segment Profit	$ 1,468	$ 1,283	$ 1,533	$ 1,440
MTM Adjustments - Power			304	138
Segment Profit after MTM Adjustments			**$ 1,837**	**$ 1,578**
Memo:				
Power after MTM Adjustments			$ 85	$ (2)

A more detailed schedule reconciling income (loss) from continuing operations to recurring income from continuing operations is available on Williams' Web site at www.williams.com and at the end of this presentation.

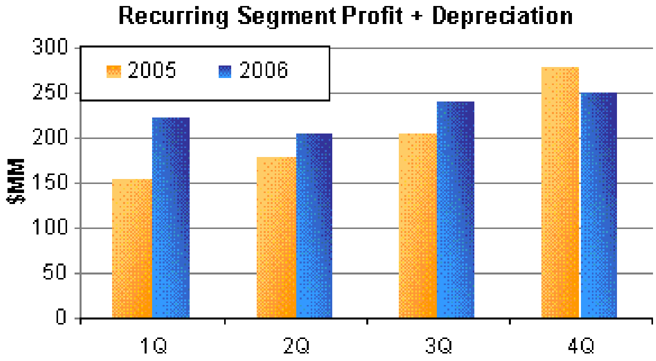
Business Unit Results

Exploration & Production

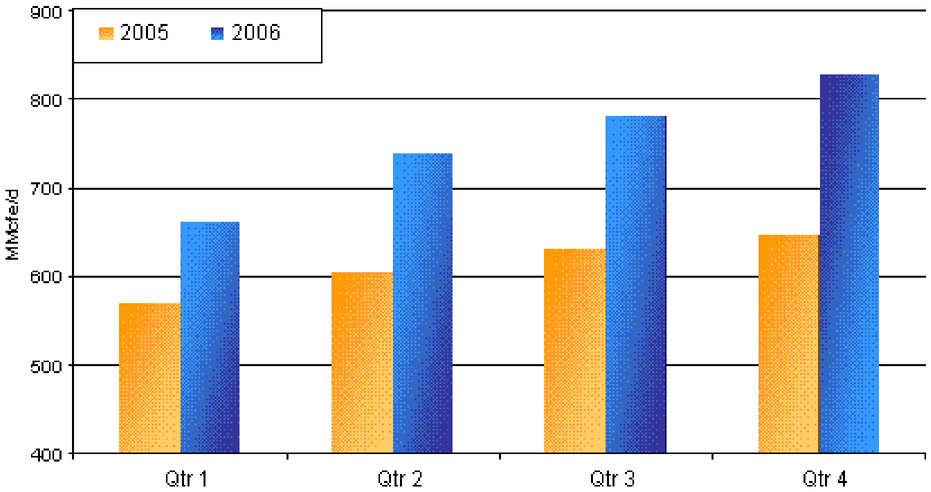
Ralph Hill
President

2006 Accomplishments

- Impressive drill bit volume growth of 21%
- Domestic reserves replacement of 216%
- 4Q06 production 879 MMcfed, up 26%, 181 MMcfed increase since 4Q05
- Powder River volumes continue strong growth
- Piceance Highlands: Barcus Creek farm-in deal
- Expanded Barnett Shale position
- San Juan team awarded Oil & Gas Investor Best Field Rejuvenation
- 2006 Hydrocarbon Producer of the year at Global Energy Awards



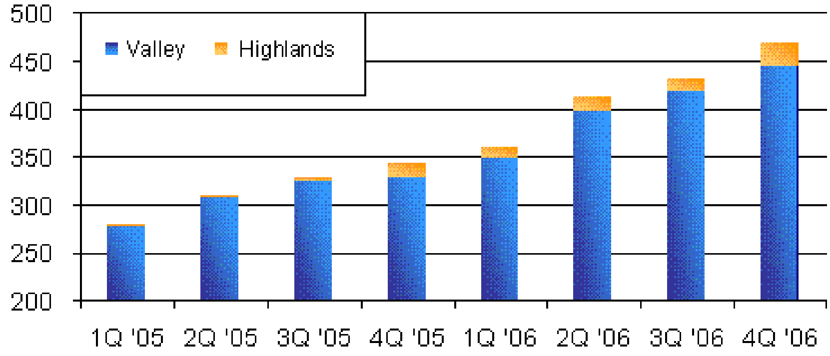
Strong domestic production growth of 23%



- 2006 Domestic production grew 23% or 140 MMcfe/d over 2005

Piceance Production Growth

- Up 126 MMcfed or 37% over a year ago
- 25 Total rigs currently operating in Piceance compared to 19 a year ago
- BLM/DOW awarded Williams first ever Piceance year round drilling pilot
- All 10 H&P FlexRigs in operation
- 4 Nabors Super Sundowner rigs scheduled
- Williams in process of high-grading fleet

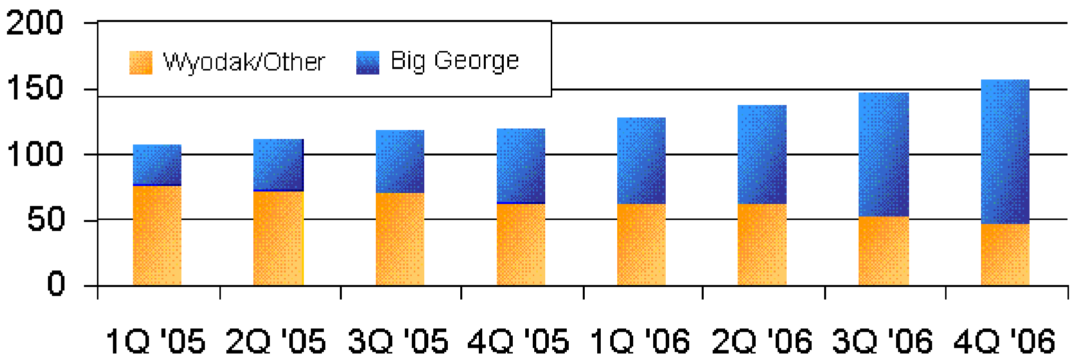


Piceance Highlands – Momentum Continues

- 43 wells spud in 2006
- 26 MMcfed current net production, up from 15 MMcfed year ago
- Major road, pipeline, and facilities construction nearing completion
- Winter drilling pilot under way

Powder River Production Growth

- Up 36 MMcfed or 30% over a year ago
- Big George coals driving basin growth
  - Up 88% year over year
  - Sequential quarter volumes up 15%



An Industry Leader in 2006 Cost Performance

- Lease operating expense of $0.46 / Mcfe
- 3-year average F&D cost of $1.55 / Mcfe
- Depletion, depreciation & amortization cost of $1.28 / Mcfe

Strong 2006 Reserves Performance

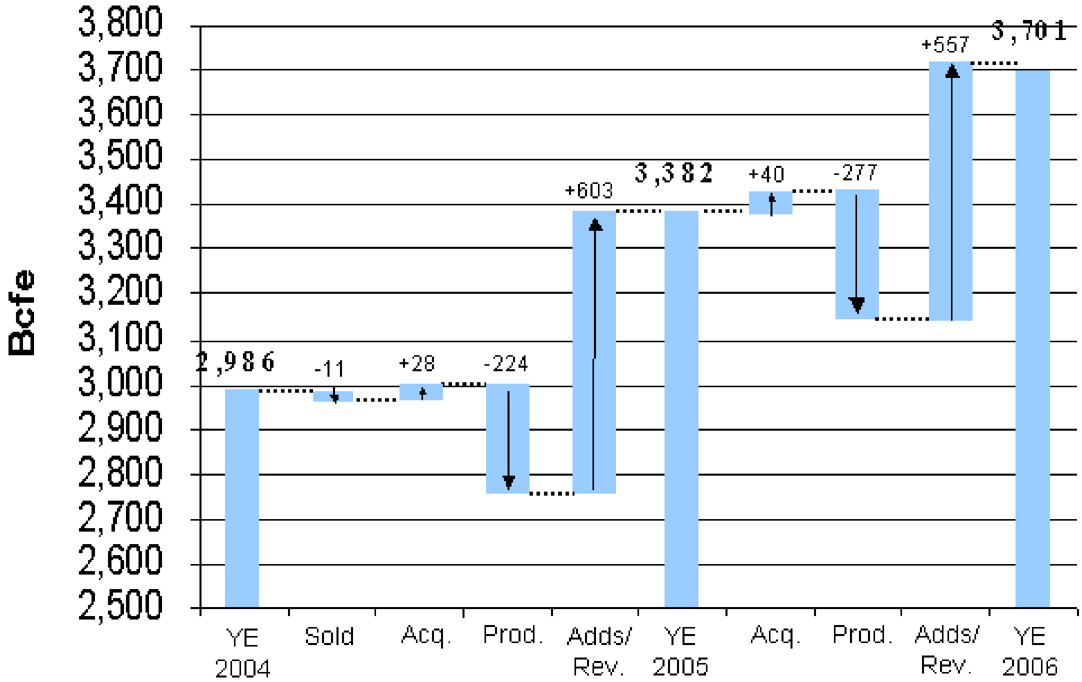
- Total U.S. proved reserves 3.7 Tcfe, up 9.5%
- U.S. and International proved reserves 3.9 Tcfe
- 216% domestic reserves replacement
- 99% drilling success rate
- Added 597 Bcfe to proved

	2004	2005	2006	Total
Probable to Proved Transfers (Bcfe)	451	603	557	1,611

Exploration & Production

Domestic Proved Reserves Reconciliation

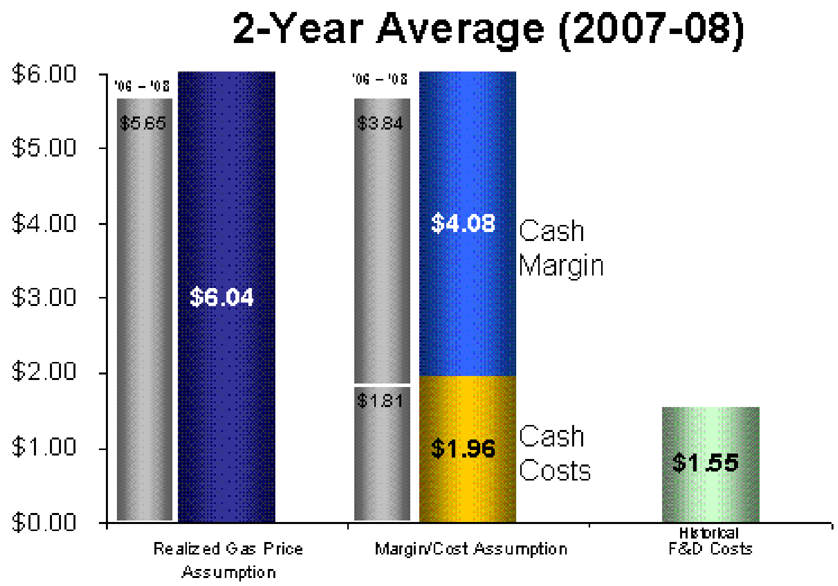
Williams



Note: May not add due to rounding

Exploration & Production

Cash Margin Analysis



Reflective of core basins

- *$6.04 is after hedging and includes average basin market price of $6.38 before hedging*
- *Cash costs include LOE, G&A, taxes and gathering*
- *F&D costs include capital and exploration costs/proved reserves ('04-'06 average)*

Guidance Updates

$MM	2007			2008		
11/2/06 Capital Guidance	**$1,150**		**$1,250**	**$1,150**		**$1,300**
Increased Costs & Facilities		90			40	
Additional Ft. Worth		30			20	
Other Opportunities		30			40	
		150			**100**	
2/22/07 Capital Guidance	**$1,300**		**$1,400**	**$1,250**		**$1,400**
11/2/06 Segment Profit Guidance	**$825**		**$950**	**$1,025**		**$1,175**
Gas Price Range	(75)		75	(75)		75
Increased Operating Expenses	(50)		(50)	-		-
2/22/07 Segment Profit Guidance	**$700**		**$975**	**$950**		**$1,250**

2007-08 Guidance

Dollars in millions	2007	2008
Segment Profit	$700 - 975	$950 - 1,250
	$825 - 950	*$1,025 - 1,175*
Annual DD&A	485 - 535	575 - 625
	455 - 505	*500 – 550*
Segment Profit + DD&A	$1,185 - 1,510	$1,525 - 1,875
	$1,280 - 1,455	*$1,725*
Capital Spending	$1,300 - 1,400	$1,250 - 1,400
	$1,150 - 1,250	*$1,150 - 1,300*
Production (MMcfe/d)	905 - 1,005	990 - 1,140

Note: 2006-08 hedge information included in Appendix.

Note: If guidance has changed, previous guidance from 11/2006 is shown in italics directly below.

Key Points – Value Creation Continues

- An industry leader in production growth and cost efficiencies
- Continued strong reserves replacement through the drill bit
- Award winning 2006 performance
- Long-term repeatable drilling inventory of significant proved undeveloped, probables, and possibles
- Strategy remains rapid development of our premier drilling inventory
- Long history of high drilling success, low finding costs
- Short time cycle investments, fast cash returns
- New areas significantly contributing
- Experienced and talented work force
- Exciting new opportunities
  - Barcus Creek, Paradox Basin, Ft. Worth Basin, Other

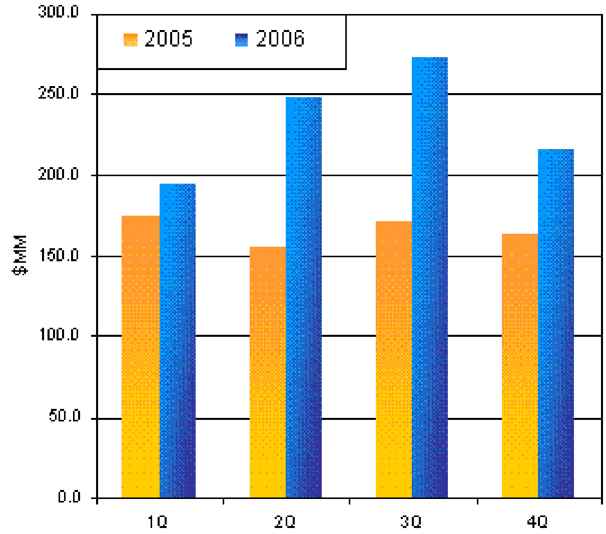
Midstream

Alan Armstrong
President

2006 Accomplishments

- Record annual recurring segment profit
- NGL unit margins set new annual record – over 2 times 5 year average
- Total NGL production record for Midstream operated plants
- Deepwater fee revenue grew by 49%
- Great performance by WPZ
- Gulf Deepwater Expansions
- Western Basin Progress
  - Opal TXP-V construction completed
- Hurricane recovery efforts: Cameron Meadows capacity restored
- Secured NGL take-away through Overland Pas Pipeline

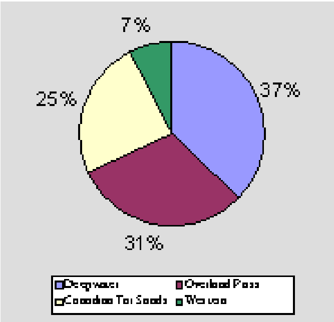
Recurring Segment Profit + Depreciation

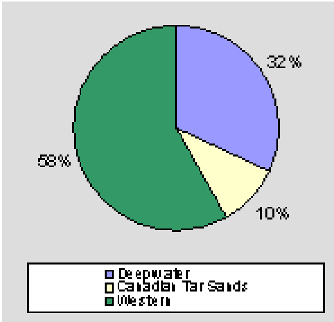


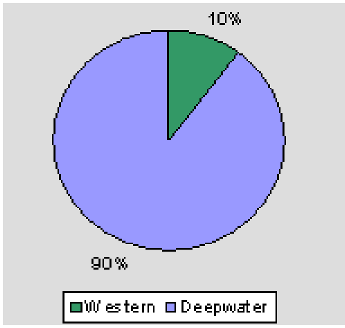
Midstream

Significant Progress Made on Growth Projects

In Development/Proposal 2007 & 2008+ Spending $900MM–1,500MM	Under Negotiation 2007 & 2008+ Spending $300MM–500MM	In Guidance 2007 & 2008+ Spending $800-900MM





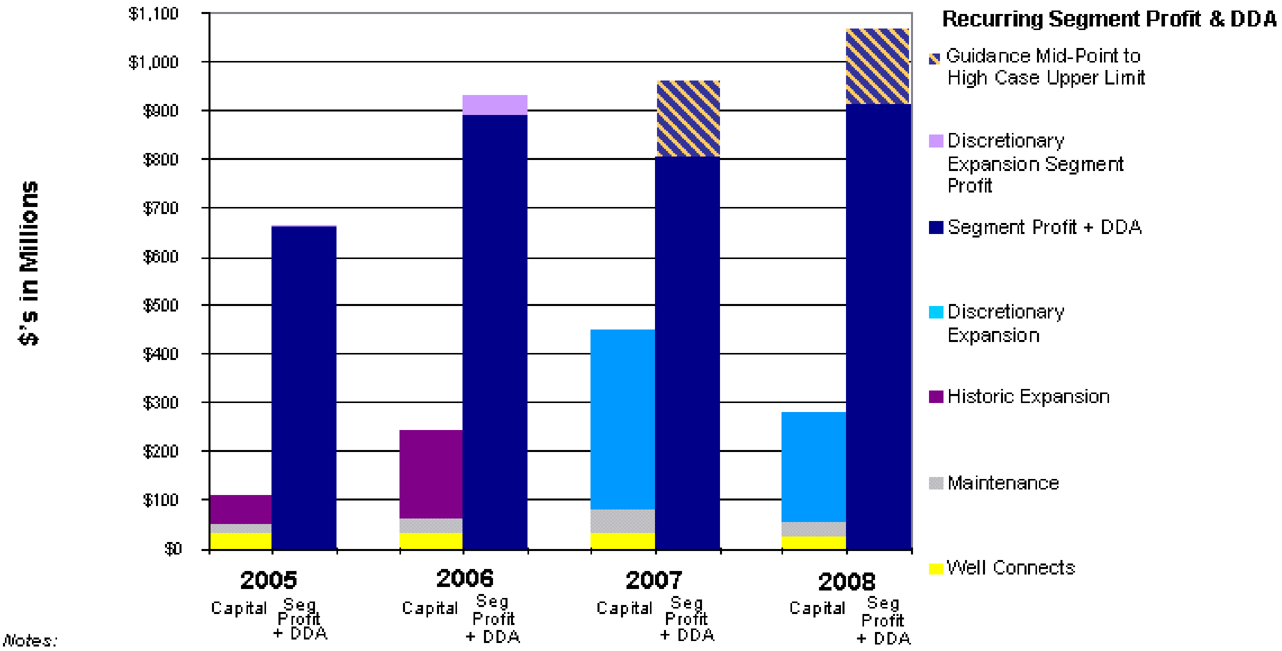


Major Growth Projects Included in Guidance ($ Millions)

Project Name – In Service Date	2007	2008	Segment Profit*
Opal TXP V (1Q 2007)	$10	-	$50
Blind Faith (2Q 2008)	$94	$42	$19
Other Wyoming G&P (4Q '07 & Various)	$50	$10	$8
Western Gulf Deepwater Expansion (3Q '09)	$185	$180	$82

* Segment Profit – Segment profit generated in first full calendar year of operation.

Free Cash Flow - Forecast



Notes:
- Segment Profit is stated on a recurring basis.
- Segment Profit + DDA and Capital Spending reflect midpoint of ranges.

Key Points

- Annual NGL margins reach historic levels – cushioning enterprise impact of lower gas prices
- Well positioned for growth
  - WPZ lower cost of capital
  - Deepwater expansions progress
  - Western opportunities abound
  - Canadian Tar Sands off-gas
- Forecast margins in line with current gas/crude pricing relationship
- Differentiating our business on reliability
- Base business continues to generate healthy returns and free cash flows

Gas Pipeline

Phil Wright
President

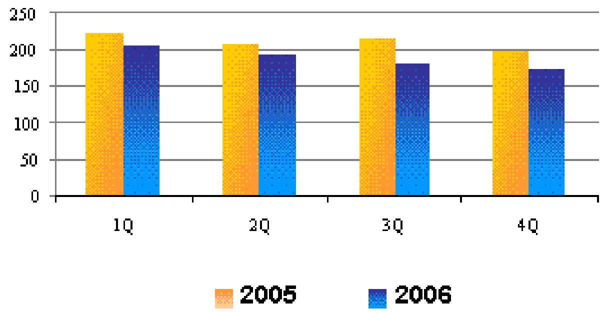
2006 Accomplishments and Current Update

Northwest
- Completion of 26" line replacement project on time, within budget
- Contract terms extended with various shippers
- Higher results in new customer satisfaction survey
- Filed rate case June 30, effective Jan 1, 2007; Unopposed settlement filed with FERC on Jan 31 2007

Transco
- Leidy to Long Island project receives FERC approval
- Sentinel project agreements executed with shippers
- Favorable Environmental Assessment received for Potomac project
- Higher results in new customer satisfaction survey
- Filed rate case August 31, effective March 1, 2007

Gulfstream
- FERC certificate application filed for Phase IV Expansion
- Florida approves FP&L's West County Energy Center - Gulfstream's Phase III expansion

Recurring Segment Profit + Depreciation



NWP Rate Case Update

- Quick rate case resolution is a testament to a quality customer relationship
- Provide customers with rate certainty for the next several years
- 10 years since previous rate case
- Settlement based on an annual cost of service of $404 million
  - Recovery of the 26” line replacement project’s cost
- “Black Box” negotiation basis
  - No stated ROE

Gas Pipeline

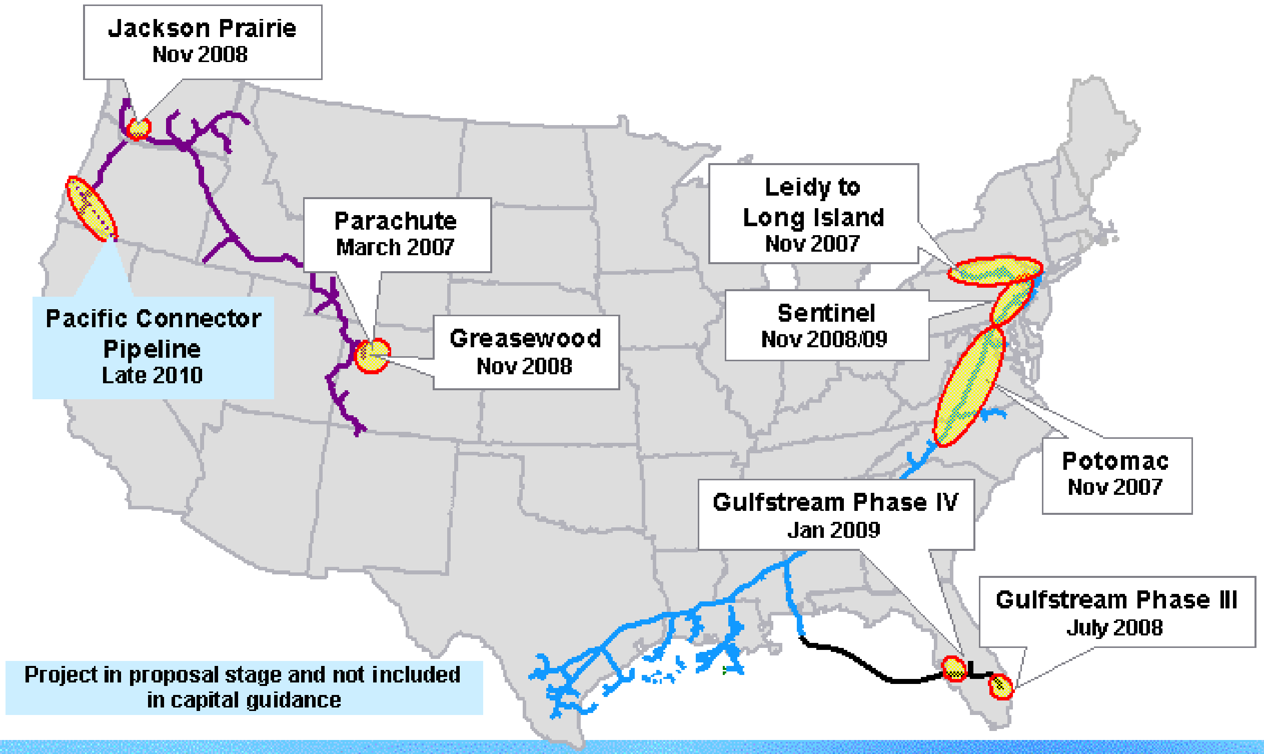
2007-08 Capital Spending Detail

Dollars in millions	2007	2008
Normal Maintenance/Compliance[1]	$215 -270	$180 - 260
Expansion[2]	210 - 265 *160 - 200*	105 - 150 *160 - 180*
Total	$425 - 535 *370 - 470*	$285 - 410 *340 - 440*

[1]The Normal Maintenance/Compliance line includes the 26" replacement project previously shown separately
Note: Sum of ranges may not necessarily match total range
Note: If guidance has changed, previous guidance from 11/02/06 is shown in italics directly below.

[2]**Major Growth Projects (in guidance):**	**2007**	**2008**	**1st full yr Seg. Profit**
Parachute (In Service 3/07)	$35 - 40		$7
Leidy to Long Island (In Service 11/07)	85 - 115	1 - 5	23
Potomac (In Service 11/07)	55 - 65	1 - 5	13
Sentinel (In Service Ph1 11/08, Ph2 11/09)	5 - 15	70 - 80	25
Greasewood (In Service 11/08)	0 - 5	20 - 40	3
Jackson Prairie Deliverability (In Service 11/08)	5 - 10	5 - 15	2

Growth Projects and Opportunities



Key Points

- Completion of 26” line replacement project on time, within budget
- Growth projects progressing with in service dates approaching
- Rate cases making headway with settlements forthcoming
- 2007 supported by new rate cases and lower capital
- Return to cash generator in 2007

Power

Bill Hobbs
President

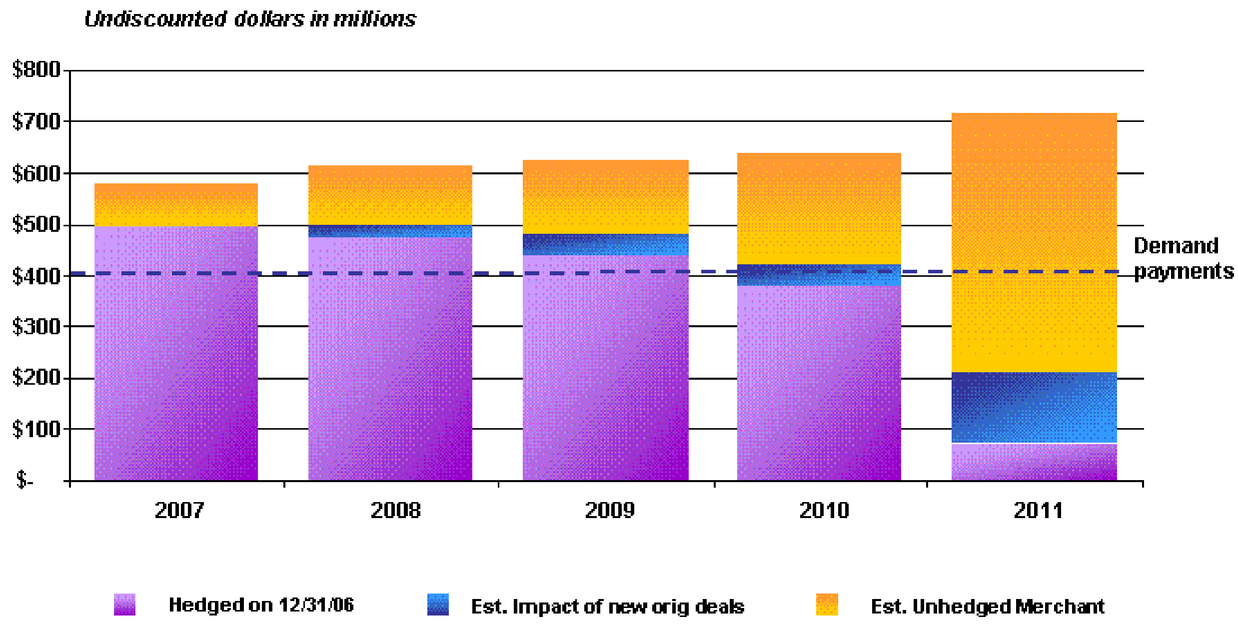
Successful 2006

- Commercial operations generated strong results
  - Originated new transactions across all regions
    - Efforts improved cash-flow certainty and expected to provide approximately $120 million in cash flows from 2007 to 2010
  - $87 million increase in year-over-year recurring segment profit after MTM adjustment
  - Transacted with new customers in both power and natural gas businesses
  - Continued high level of service to Midstream and E&P
- Fourth consecutive year of positive cash flow from operations
- Power market fundamentals continue to gain momentum
- Now marketing 1 Bcf/d of equity and certain third-party natural gas production
- Strong, customer-focused organization

Strong Start to 2007

- West: Executed multi-unit tolling re-sales for up to 4 years with Southern California Edison
  - First sale beyond 2010
  - Currently sold out through 2010
  - 60 percent sold out in 2011
- Northeast: Transacted seven incremental capacity sales approximating 20 percent of available capacity over four years
  - First sale beyond 2010
  - Market-driven PJM capacity market enhancing value
  - Energy (spark spread) upside opportunities remain
- Expect additional sales beyond 2010 by year-end

YTD Origination Success Adds Approx. $250MM to Hedged Cash Flows



Note: Cash flows presented here are forecasts and do not include the Natural Gas portfolio.

2007-08 Consolidated Outlook

Don Chappel
Chief Financial Officer

Consolidated

2007 Forecast Guidance

Dollars in millions, except per-share amounts	Feb 22 Guidance
Segment profit before MTM adjustment	$1,775 - $2,275
Net Interest Expense	(640) - (700)
Other (Primarily General Corp. Costs)	(140) - (170)
Pretax Income	995 - 1,405
Provision for Income Tax	(395) - (560)
Recurring Income from Continuing Operations	$600 - $845
Diluted EPS – Recurring	$0.98 - $1.37
Diluted EPS – Recurring After MTM Adj. [1]	**$1.10 - $1.50**

[1] *Includes MTM adjustment of $125 million (pretax) in Feb. 22 guidance*
Note: Fully diluted shares of 615 million

Note: See slide 48 for commodity price assumptions

Consolidated

2007-08 Segment Profit

Dollars in millions	**2007**	**2008**
Exploration & Production	$700 - 975 *825 - 950*	$950 - 1,250 *1,025 - 1,175*
Midstream	450 - 750 *500*	550 - 825 *800*
Gas Pipeline	585 - 655	590 - 665
Power	(75) - 0 *25*	(130) - 20 *(150) - 0*
Other / Corp. / Rounding	15 - (30) *10*	(15) - 35
Total Reported Before MTM Adj. [1]	$1,775 - 2,275 *1,845 - 2,350*	$1,945 - 2,795 *2,000 - 2,675*
MTM Adjustment	125	180 *200*
Total Reported After MTM Adj. [1]	$1,900 - 2,400 *1,970 - 2,475*	$2,125 - 2,975 *2,200 - 2,875*
Nonrecurring Items	-	-
Total Recurring After MTM Adj. [1]	**$1,900 - 2,400** *1,970 - 2,475*	**$2,125 - 2,975** *2,200 - 2,875*

Power After MTM Adj.	$50 - 125 *150*	$50 - 200

Note: If guidance has changed, previous guidance from 11/2/06 is shown in italics directly below

[1] Sum of the ranges for the business units does not match the consolidated total due to the offsetting effect of natural gas prices within our business units

See slide 48 for commodity price assumptions

2007 Segment Profit [1] Forecast Guidance Change

Dollars in millions	2007 Guidance
Previous Segment Profit Guidance Nov. 2	$1,970 - $2,475
Change in Natural Gas Prices (Consolidated)	-
Change in NGL Margins (Midstream)	(25)
Additional Costs (E&P)	(50)
Other / Rounding	5 - 0
New Segment Profit Guidance	**$1,900 - $2,400**

[1] Recurring Segment Profit After MTM Adjustment

Commodity Price Summary

Un-hedged Commodity Price Assumptions	2007	2008
Exploration & Production:		
Natural Gas:		
Basin Prices		
Average Rockies	$5.10 - $6.40	$5.10 - $6.40
Average San Juan / Mid-Continent	$6.10 - $7.40	$6.10 - $7.40
NYMEX (reference only)	$7.00 - $8.30	$7.00 - $8.30
Midstream:		
Crude Oil to Natural Gas Ratio [1]	7.4x - 9.6x	7.4x - 9.6x
Crude Oil – WTI (reference only)	$53 - $73	$53 - $73

[1] Oil = WTI and Natural Gas = Henry Hub

2007-08 Hedge Update

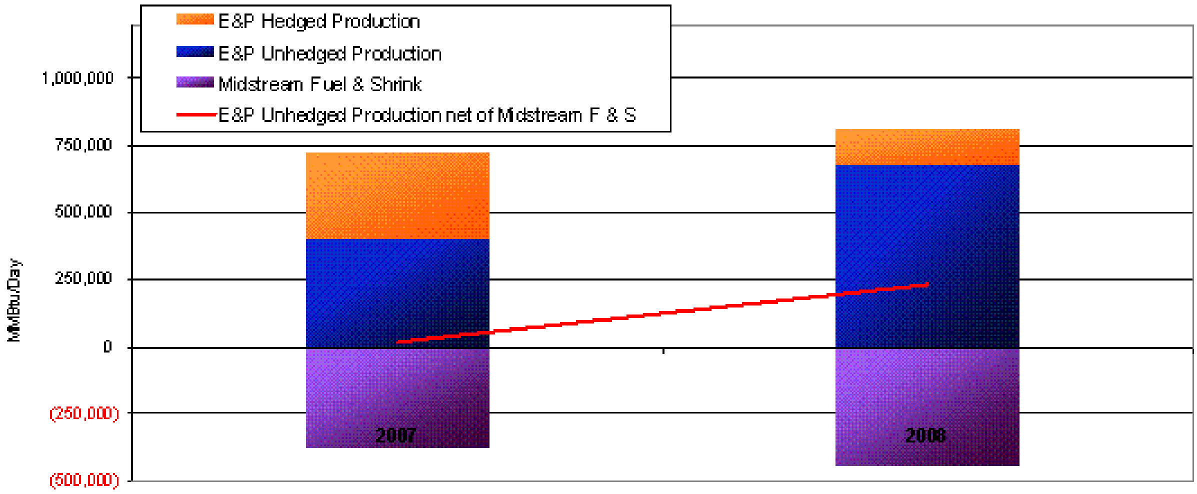
Dollars in millions	2007	2008
Fixed Price at the basin:		
Volume (MMcf/d)	172	73
Average Price ($/Mcf)	$3.90	$3.96
NYMEX Collars:		
Volume (MMcf/d)	15	-
Average Price ($/Mcf)	$6.50 - $8.25	
At the Basin Collars:[1]		
NWPL Rockies		
Volume (MMcf/d)	50	105
Price ($/Mcf)	$5.65 - $7.45	$6.02 - $9.07
EPNG San Juan		
Volume (MMcf/d)	130	75
Average Price ($/Mcf)	$5.98 - $9.63	$6.20 - 9.16
Mid-Continent		
Volume (MMcf/d)	75	5
Price ($/Mcf)	$6.82 - $10.80	$7.23 - $8.62

[1] *Please note basin locations are not NYMEX*

Note: The only remaining legacy fixed price hedges are in 2009 of 129MMcfd @ $3.67 and in 2010 of 70MMcfd @ $3.73

Natural hedges in our commodity businesses

Economic Natural Gas Exposure for E&P and Midstream (2007-2008)



*All values are undiscounted
* International E&P volumes are not included
* Projected E&P volumes are reduced by 20% for fuel & shrink and production taxes
* Hedges are presented in terms of price exposure. Because some hedges have option characteristics, this volume may be different from notional hedge volumes

Consolidated

2007-08 Capital Expenditures

Dollars in millions	2007	2008
Exploration & Prod.	$1,300 - 1,400 *1,150 - 1,250*	$1,250 - 1,400 *1,150 - 1,300*
Midstream	430 - 470 *420 - 460*	260 - 300
Gas Pipeline	425 - 535 *370 - 470*	285 - 410 *340 - 440*
Power	-	-
Other/Corporate	10 - 30	10 - 30
Total	$2,225 - 2,425 *$2,000 - 2,200*	$1,850 - 2,125 *$1,800 - 2,050*

Notes:
- Sum of ranges for each business line does not necessarily match total range

2007-08 Outlook

Dollars in millions	2007	2008
Segment Profit		
Reported After MTM Adj.	$ 1,900 - 2,400 *1,970 - 2,475*	$2,125 - 2,975 *2,200 - 2,875*
Recurring After MTM Adj.	1,900 - 2,400 *1,970 - 2,475*	2,125 - 2,975 *2,200 - 2,875*
DD&A	970 - 1,070 *960 - 1,060*	1,110 - 1,210 *1,050 - 1,150*
Cash Flow from Ops.[1]	2,000 - 2,300	2,425 - 2,825
Capital Expenditures	2,225 - 2,425 *2,000 - 2,200*	1,850 - 2,125 *1,800 - 2,050*
Operating Free Cash Flow[2]	(225) - (125) *0 - 100*	575 - 700 *625 - 775*

[1] Cash flow from continuing operations.
[2] Operating free cash flow is defined as cash flow from continuing operations less capital expenditures, before dividend or principal payments

Note: If guidance has changed, previous guidance from 11/2/06 is shown in italics directly below

Allocation of 2007 Available Cash

Dollars in billions	2007
Cash Sources:	
Available Cash and Cash Equivalents	$1.9
Cash Flow from Operations	2.0 - 2.3
Total Available Cash	3.9 - 4.2
Cash Uses:	
Capital Spending	(2.2) - (2.4)
Dividends / Minority Interest Payments	(0.3)
Corporate Debt Maturities	(0.1)
Settlement of Prior Contingent Obligations	(0.2)
Normalized Cash Balance	(0.5)
Total Cash Uses	(3.3) - (3.5)
Expected Surplus Cash	$0.6 - $0.7

Consolidated

Financial Strategy/Key Points

- Drive/enable sustainable growth in EVA® / shareholder value
- MLP continues to provide benefits to WMB
  - Low-cost equity capital funding source for growth
  - Growing incentive distributions and GP value
- Continue to maintain and/or improve credit ratios/ratings
- Reduce risk in Power segment
- Opportunity rich
  - Continued focus and disciplined EVA®-based investments in natural gas businesses
  - Combination of growth in operating cash flows and EVA® drives value creation

Summary

Steve Malcolm
Chairman, President & CEO

Value-growth catalysts to watch

- Growing segment profit
- Growing natural gas reserves and production
- New, higher rates for Northwest and Transco
- More megawatts contracted into market beyond 2010
- Capture of additional midstream projects
- More potential dropdowns to Williams Partners

Well-positioned for near- to long-term value creation

Williams

- Prime assets deliver growth
- Pursuing growth with discipline
- Solid record of delivering results
- Taking action to drive value creation

Q&A

Non-GAAP Reconciliations

Non-GAAP Disclaimer

This presentation includes certain financial measures, EBITDA, recurring earnings, operating free cash flow and recurring segment profit, that are non-GAAP financial measures as defined under the rules of the Securities and Exchange Commission. EBITDA represents the sum of net income (loss), net interest expense, income taxes, depreciation and amortization of intangible assets, less income (loss) from discontinued operations. Operating free cash flow is defined as cash flow from continuing operations less capital expenditures before dividends or principal payments. Recurring earnings exclude items of income or loss that the company characterizes as unrepresentative of its ongoing operations. Recurring earnings and recurring segment profit provide investors meaningful insight into the Company's results from ongoing operations. This presentation is accompanied by a reconciliation of these non-GAAP financial measures to their nearest GAAP financial measures. Management uses these financial measures because they are widely accepted financial indicators used by investors to compare company performance. In addition, management believes that these measures provide investors an enhanced perspective of the operating performance of the Company's assets and the cash that the business is generating. Neither EBITDA nor recurring earnings, operating free cash flow and recurring segment profit are intended to represent cash flows for the period, nor are they presented as an alternative to net income or cash flow from operations. They should not be considered in isolation or as substitutes for a measure of performance prepared in accordance with United States generally accepted accounting principles.

Certain financial information in this presentation is also shown including Power mark-to-market adjustments. This presentation is accompanied by a reconciliation of these non-GAAP financial measures to their nearest GAAP financial measures. Prior to September 2004, Power's derivative contracts did not qualify for hedge accounting because of our stated intent to exit the Power business. In September 2004, we announced our decision to continue operating the Power business. As a result of that decision, Power's derivative contracts became eligible for hedge accounting. Hedge accounting reduces earnings volatility associated with Power's portfolio of certain derivative hedging instruments. Prior to the adoption of hedge accounting, these derivative hedging instruments were accounted for on a mark-to-market basis with the change in fair value recognized in earnings each period. Management uses the mark-to-market adjustments to better reflect Power's results on a basis that is more consistent with Power's portfolio cash flows and to aid investor understanding. The adjustments reverse forward unrealized mark-to-market gains or losses from derivatives and add realized gains or losses from derivatives for which mark-to-market income has been previously recognized, with the effect that the resulting adjusted segment profit is presented as if mark-to-market accounting had never been applied to designated hedges or other derivatives. The measure is limited by the fact that it does not reflect potential unrealized future losses or gains on derivative contracts. However, management compensates for this limitation since derivative assets and liabilities do reflect unrealized gains and losses of derivative contracts. Overall, management believes the mark-to-market adjustments provide an alternative measure that more closely matches realized cash flows for the Power segment but does not substitute for actual cash flows. We also apply the mark-to-market adjustment and the recurring adjustments to present a measure referred to as recurring income from continuing operations after mark-to-market adjustments.

Non-GAAP Reconciliation Schedule

Williams

Non-GAAP Reconciliation Schedule

Williams

Reconciliation of Segment Profit to Recurring Segment Profit
(UNAUDITED)

(Dollars in millions)	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year	2006 1st Qtr	2006 2nd Qtr	2006 3rd Qtr	2006 4th Qtr	2006 Year
Segment profit (loss)										
Exploration & Production	$ 103.7	$ 118.3	$ 158.8	$ 206.4	$ 587.2	$ 147.6	$ 119.8	$ 144.5	$ 139.6	$ 551.5
Gas Pipeline	167.4	164.5	161.1	92.8	585.8	134.7	122.7	109.0	101.0	467.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	151.5	130.7	212.2	163.9	658.3
Power	114.1	(75.0)	(226.4)	(69.4)	(256.7)	(22.5)	(79.6)	(69.7)	(39.0)	(210.8)
Other	(4.1)	(60.5)	(10.1)	(30.3)	(105.0)	1.0	(0.7)	(0.2)	1.8	1.9
Total segment profit	$ 509.7	$ 256.4	$ 204.5	$ 311.9	$ 1,282.5	$ 412.3	$ 292.9	$ 395.8	$ 367.3	$ 1,468.3
Nonrecurring adjustments:										
Exploration & Production	$ (7.6)	$ -	$ (21.7)	$ -	$ (29.3)	$ -	$ -	$ -	$ -	$ -
Gas Pipeline	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)	-	-	-	(2.0)
Midstream Gas & Liquids	-	-	-	-	-	(6.3)	68.0	10.3	2.3	74.3
Power	11.4	13.1	0.4	91.7	116.6	-	-	(9.2)	1.3	(7.9)
Other	-	53.1	-	29.1	82.2	-	-	-	-	-
Total segment nonrecurring adjustments	$ (9.3)	$ 44.5	$ (35.5)	$ 158.1	$ 157.8	$ (8.3)	$ 68.0	$ 1.1	$ 3.6	$ 64.4
Recurring segment profit (loss):										
Exploration & Production	96.1	118.3	137.1	206.4	557.9	147.6	119.8	144.5	139.6	551.5
Gas Pipeline	154.3	142.8	146.9	130.1	574.1	132.7	122.7	109.0	101.0	465.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	145.2	198.7	222.5	166.2	732.6
Power	125.5	(61.9)	(226.0)	22.3	(140.1)	(22.5)	(79.6)	(78.9)	(37.7)	(218.7)
Other	(4.1)	(7.4)	(10.1)	(1.2)	(22.8)	1.0	(0.7)	(0.2)	1.8	1.9
Total recurring segment profit	$ 500.4	$ 300.9	$ 169.0	$ 470.0	$ 1,440.3	$ 404.0	$ 360.9	$ 396.9	$ 370.9	$ 1,532.7

Note: Segment profit (loss) includes equity earnings (loss) and certain income (loss) from investments reported in Investing income (loss) in the Consolidated Statement of Income. Equity earnings (loss) results from investments accounted for under the equity method. Income (loss) from investments results from the management of certain equity investments.

Non-GAAP Reconciliation Schedule – EPS after MTM adjustment

Dollars in millions except per share amounts

	2005 1Q		2Q		3Q		4Q		Year	
Recurring income from cont. ops available to common shareholders	$	136	$	108	$	113	$	158	$	520
Recurring diluted earnings per common share	$	0.22	$	0.18	$	0.19	$	0.26	$	0.86
Mark-to-Market (MTM) adjustments:										
Reverse forward unrealized MTM gains/losses		(43)		38		16		11		22
Add realized gains/losses from MTM previously recognized		77		100		80		25		282
Total MTM adjustments		34		138		96		36		304
Tax effect of total MTM adjustments		13		53		37		14		116
After tax MTM adjustments		21		85		59		22		188
Recurring income from cont. ops available to common shareholders after MTM adjust.	$	157	$	193	$	172	$	180	$	708
Recurring diluted earnings per share after MTM adj.	$	0.26	$	0.32	$	0.28	$	0.30	$	1.17
Weighted average shares - diluted (thousands)		607,073		595,561		609,052		610,352		608,627

	2006 1Q		2Q		3Q		4Q		Year	
Recurring income from cont. ops available to common shareholders	$	198	$	66	$	(4)	$	178	$	433
Recurring diluted earnings per common share	$	0.33	$	0.11	$	(0.01)	$	0.29	$	0.72
Mark-to-Market (MTM) adjustments:										
Reverse forward unrealized MTM gains/losses		(221)		(22)		141		(70)		(172)
Add realized gains/losses from MTM previously recognized		113		77		72		48		310
Total MTM adjustments		(108)		55		213		(22)		138
Tax effect of total MTM adjustments		(42)		21		83		(8)		53
After tax MTM adjustments		(66)		34		130		(14)		85
Recurring income from cont. ops available to common shareholders after MTM adjust.	$	132	$	100	$	126	$	164	$	518
Recurring diluted earnings per share after MTM adj.	$	0.22	$	0.17	$	0.22	$	0.27	$	0.86
Weighted average shares - diluted (thousands)		599,422		578,902		580,735		609,106		605,847

Some annual figures may differ from sum of quarterly figures due to rounding.

EBITDA Reconciliation

Dollars in millions	4Q06	Year
Net Income	$ 146	$ 309
Loss from Discontinued Operations	9	24
Net Interest Expense	164	659
DD&A	238	866
Provision for Income Taxes	17	206
EBITDA	$ 574	$ 2,064

4Q 2006 Segment Contribution

Dollars in Millions

	E&P	Midstream	Gas Pipeline	Power	Other	Total
Segment Profit (Loss)	$ 140	$ 164	$ 101	$ (39)	$ 1	$ 367
DD&A	108	52	72	2	4	238
Segment Profit before DDA	**$ 248**	**$ 216**	**$ 173**	**$ (37)**	**$ 5**	**$ 605**
General Corporate Expenses						(33)
Securities litigation settlement and related costs						(2)
Investing Income*						8
Other Income						(4)
TOTAL						**$ 574**

* Excluding equity earnings and income (loss) from investments contained in segment profit

Non-GAAP Reconciliation

2006 Segment Contribution

Dollars in Millions

	E&P	Midstream	Gas Pipeline	Power	Other	Total
Segment Profit (Loss)	$ 552	$ 658	$ 467	$ (211)	$ 2	**$ 1,468**
DD&A	360	201	282	11	12	**866**
Segment Profit before DDA	**$ 912**	**$ 859**	**$ 749**	**$ (200)**	**$ 14**	**$ 2,334**
General Corporate Expenses						**(132)**
Securities litigation settlement and related costs						**(167)**
Investing Income*						**74**
Other Income						**(45)**
TOTAL						**$ 2,064**

* Excluding equity earnings and income (loss) from investments contained in segment profit

2007 Forecast EBITDA Reconciliation

Dollars in millions	Feb 22 Guidance
Net Income	**$600 - 845**
Net Interest	640 - 700
DD&A	970 - 1,070
Provision for Income Taxes	395 - 560
Other/Rounding	(5) - 0
EBITDA	**$2,600 - 3,175**
MTM Adjustments	125
EBITDA - After MTM Adj.	**$2,725 - 3,300**

2007 Forecast Segment Contribution

Dollars in millions	E&P	Midstream	Gas Pipeline	Power [1]	Corp/ Other	Total
Segment Profit (Loss)	$700 - 975	$450 - 750	$585 - 655	$(75) - 0	$15 - (30)	$1,775 - 2,275 [2]
DD&A	485 - 535	200 - 210	280 - 300	0 - 10	5 - 15	970 - 1,070
Segment Profit Before DDA	$1,185 - 1,510	$650 - 960	$865 - 955	$(75) - 10	$20 - (15)	$2,745 - 3,345 [2]
Other (Primarily General Corporate Expense & Investing Income)						(140) - (170)
Rounding						(5) - 0
TOTAL						$2,600 - 3,175

[1] *Segment Profit is prior to MTM adjustments*
[2] *Sum of the ranges for the business units does not match the consolidated total due to the offsetting effect of natural gas prices within our business units*

2007 Forecast Guidance Contribution

Dollars in millions, except per-share amounts	Feb 22 Guidance
Recurring Income from Cont. Ops	**$600 - 845**
Recurring EPS	**$0.98 - $1.37**
Mark-to-Market Adjustment (Pretax)	125
Less Taxes @ 39%	49
Mark-to-Market Adjust. After Tax	76
Inc. from Cont. Ops after MTM Adj.	**$676 - 921**
Inc. from Cont. Ops after MTM Adj. EPS	**$1.10 - $1.50**

Appendix

Exploration & Production

Segment Profit – Exploration & Production

Dollars in millions	4th Quarter 2006	4th Quarter 2005	Year 2006	Year 2005
Segment Profit	$140	$206	$552	$587
Nonrecurring				
Gains on sales of assets	-	-	-	(29)
Recurring segment profit	$140	$206	$552	$558

4Q06 to 4Q05 financial highlights:

- 26% volume production growth
- Sequential volume growth of 5.6%
- Basin market prices down 47%

2006 to 2005 financial highlights:

- 21% volume production growth
- Basin market prices down 17%

Note: Negative hedge impact of $21 million in 4Q06 and $200 million in full year 2006

Piceance Valley – Cornerstone Asset

- One of the largest gas producers in the Basin
- 2006 Proved reserves total 2.1 Tcfe
- ~460 MMcfd net Valley production
- Approx. 115,000 net acres
- Operate ~1,800 wells, 98% WI
- Operate 250+ miles of gathering and 4 gas plants
- Access to 5 major pipelines
- Currently operating 22 rigs

Piceance Highlands – Momentum Continues

- 45,000 net acres
- 2006 Proved reserves total 338 Bcfe
- ~2,800 potential drilling locations
- 2.6 - 3.1 Tcf potential net reserves
- 26 MMcfd net production (up from 15 MMcfd one year ago)
- Operate 74 wells (up from 31 one year ago); 81% avg. W.I.
- Key infrastructure projects nearing completion

Piceance Basin : Highlands Ownership Position

Trail Ridge

- 21,512 acres (10-acre density), 1,500 potential locations

Farm-In Deals

Ryan Gulch

- Earned 16,000 net acres by drilling 6 wells

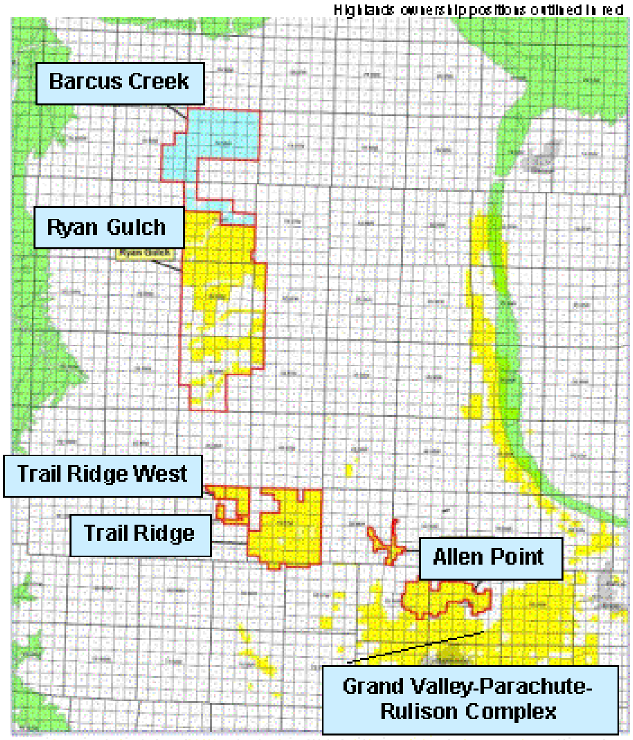
Allen Point

- Earned 6,200 net acres by drilling 6 wells

Barcus Creek

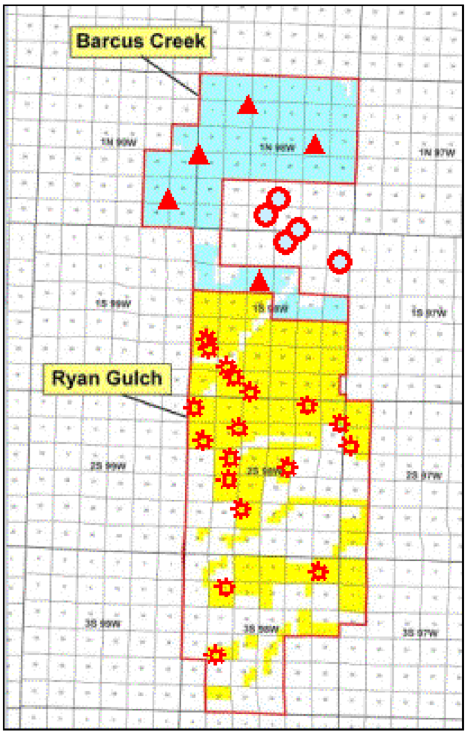
- Newly added farm-in deal

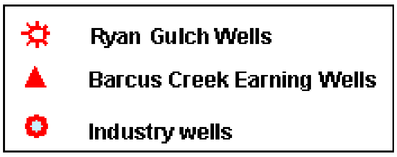
Highlands ownership positions outlined in red



Barcus Creek Farm-In Deal

- Direct bolt-on to Ryan Gulch Project
- Targets Williams Fork Formation
- Drill 5 wells by October 2007, drilling program under way
- Earn 45% working interest in ~25,000 gross acres (~11,000 acres net to Williams)
- 87.5% NRI
- 45% working interest in future gas gathering/processing systems
- 600+ potential drill locations (40-acre density)
- Williams to operate





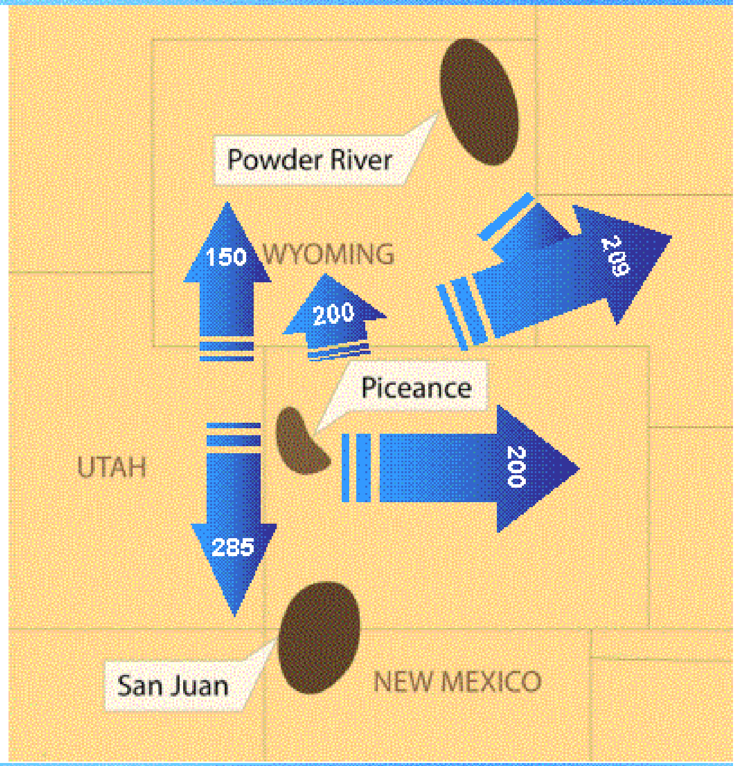
Powder River Basin – Coalbed Methane

- High potential, low-risk development play, low cost wells
- Proved reserves of 372 Bcfe (YE06), plus 1.4 Tcf Prob/Pos
- ~7,000 total JV wells, 54% operated
- 2006 drilling success rate of 99%
- Typical well production 140 Mcf/d peak Wyodak and 400 Mcf/d peak Big George
- ~160 MMcfe/d net production
- Approx. 1,000,000 gross acres
- ~8,500 drilling locations; 50% operated

We move Rockies gas to higher-price markets for sale

- Rockies price risk managed through transport and basis hedges
- Our contracted pipeline capacity to moves our Rockies production to more favorable price markets

Firm Capacity Under Contract	
Wamsutter	200
East to Midcontinent	209
South to San Juan	285
Addt'l Firm Capacity Coming in '08-'09	
Opal	150
East to Appalachia (REX)	200

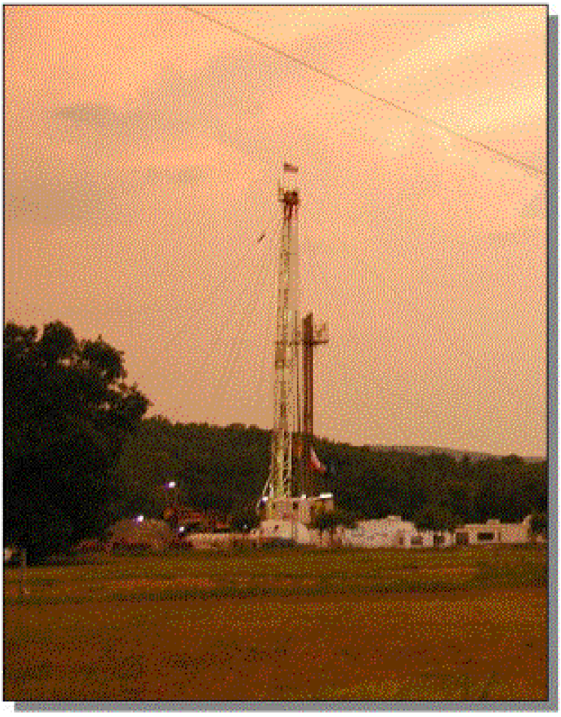


San Juan Basin - Foundation

- Conventional and coalbed methane production
- Long life / slow decline wells
- Proved reserves of 614 Bcfe (YE06)
- ~160 MMcfe/d net production
- Approx. 120,000 net acres
- Low risk in-fill drilling
- 40-60 operated wells drilled per year
- 200 – 250 undeveloped locations
- Attractive returns with near 100% success rates
- ~820 operated and ~2,200 joint interest wells
- Good pipeline infrastructure/market access

Arkoma Basin – Horizontal Expertise

- CBM and shale activity
- Proved reserves of 87 Bcfe (YE06)
- 20 MMcf/d net production
- Approx. 90,000 net acres
- Have drilled ~199 extended reach horizontal lateral wells
- Five year drilling success rate of 90%
- Operate 285 wells and ~150 joint interest wells
- Shale and other conventional sources offer opportunities
- Woodford Shale development rapidly expanding



Fort Worth Basin – Barnett Shale

- 3 rigs active in the play
- 20,000 net acres
- Proved reserves of 80 Bcf (YE 2006)
- Current net production 23 MMcfed
- High working interest
- 56 operated and 15 joint interest wells
- Utilizes Williams' integrated capabilities
- Adding value through bolt-on opportunities

International E&P

- YE06 Proved reserves total 27 MMboe (163 Bcfe)
- 5,800 Bbl/d net oil & liquids production
- 18 MMcf/d net gas production
- 69% ownership in Apco Argentina
- 525,000 net acres owned/controlled
- In-fill, field extension drilling
- Exploration upside
- High investment returns, fast cash cycle
- Complements domestic long life reserves strategy
- Provides perspective on international opportunities

3.0% Acambuco

50% Capricorn Exploration Permit

23% direct interest in Entre Lomas

41% stock interest in Petrolera

82% Cañadón Ramirez

26% Tierra del Fuego

4Q06 Net Realized Price Summary

	Unhedged	Hedge
Market Price:		
NYMEX	$6.40 - $6.60	$4.50
NYMEX collars		0.32
Basis Differential	(0.70) - (1.00)	(0.63)
Net basin market price	$5.40 - $5.90	$4.19
Net basin market price	**$5.40 - $5.90**	**$4.19**
Fuel & Shrinkage/Gathering/ Transportation	(0.60) - (0.70)	(0.50) - (0.60)
Net Price	**$4.70 - $5.30**	**$3.59 - $3.69**
Quarter Volume Totals	(qtr daily volumes - qtr daily volumes) x (92/1000)	(qtr daily hedge volumes) x (92/1000)
Net Gas Revenue	=(unhedged volumes x net price)	=(hedged volumes x net hedge price)

Midstream

Segment Profit - Midstream

Dollars in millions	4th Quarter 2006	4th Quarter 2005	Year 2006	Year 2005
Segment Profit	$164	$112	$658	$471
Nonrecurring				
Accrual for Gulf Liquids litigation	2	-	73	-
International Contract Settlement	-	-	(6)	-
Asset sales, retirement & abandonment	-	-	(3)	-
Accounts payable accrual adjustment	-	-	11	-
Recurring segment profit	$166	$112	$733	$471

- **4Q06 to 4Q05 financial highlights:**
  - Strong NGL unit margins
  - Higher fee revenue
  - Increased operating expenses
- **2006 to 2005 financial highlights:**
  - Record NGL unit margins
  - Higher fee revenue
  - Increased operating expenses
  - Lower ethylene cracking margins

2007-08 Guidance

Dollars in millions	2007	2008
Segment Profit	$450 - 750 *$500 - 750*	$550 - 825 *$550 - 800*
Annual DD&A	200 - 210	220 - 230 *$210 - 220*
Segment Profit + DD&A	$650 - 960 *$700 - 960*	$770 – 1,055 *$760 – 1,020*
Capital Spending	$430 – 470 *$420 - 460*	$260 - 300

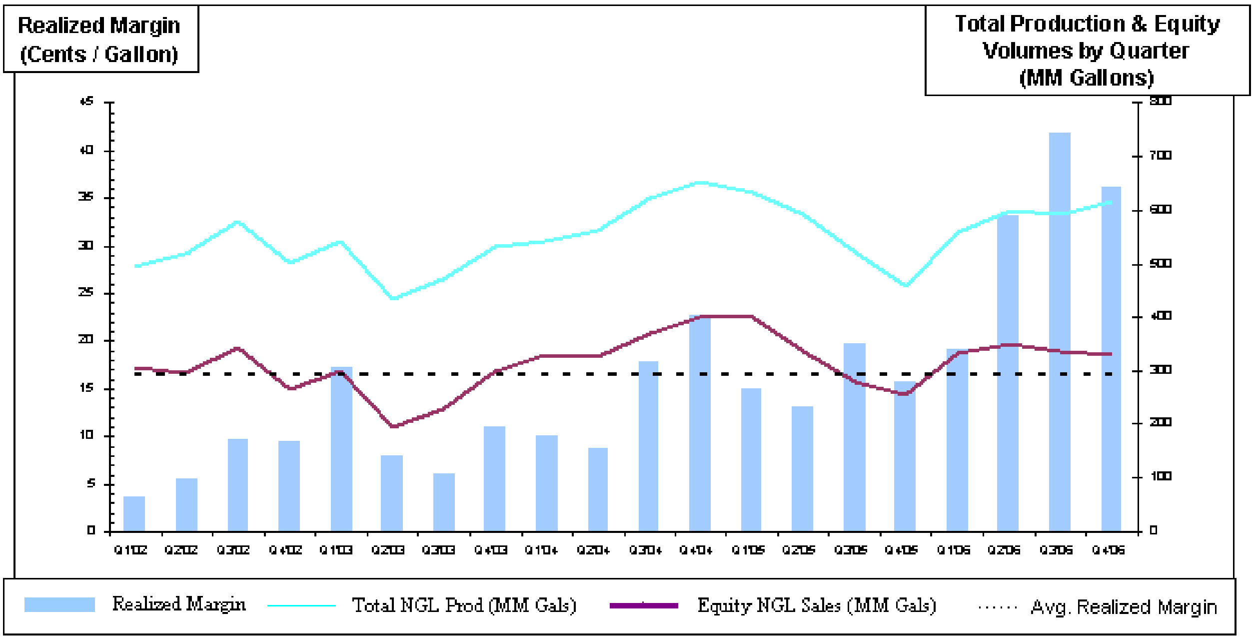
Note: If guidance has changed, previous guidance from 11/02/2006 is shown in italics directly below.

Midstream

Margins Above Average

Williams

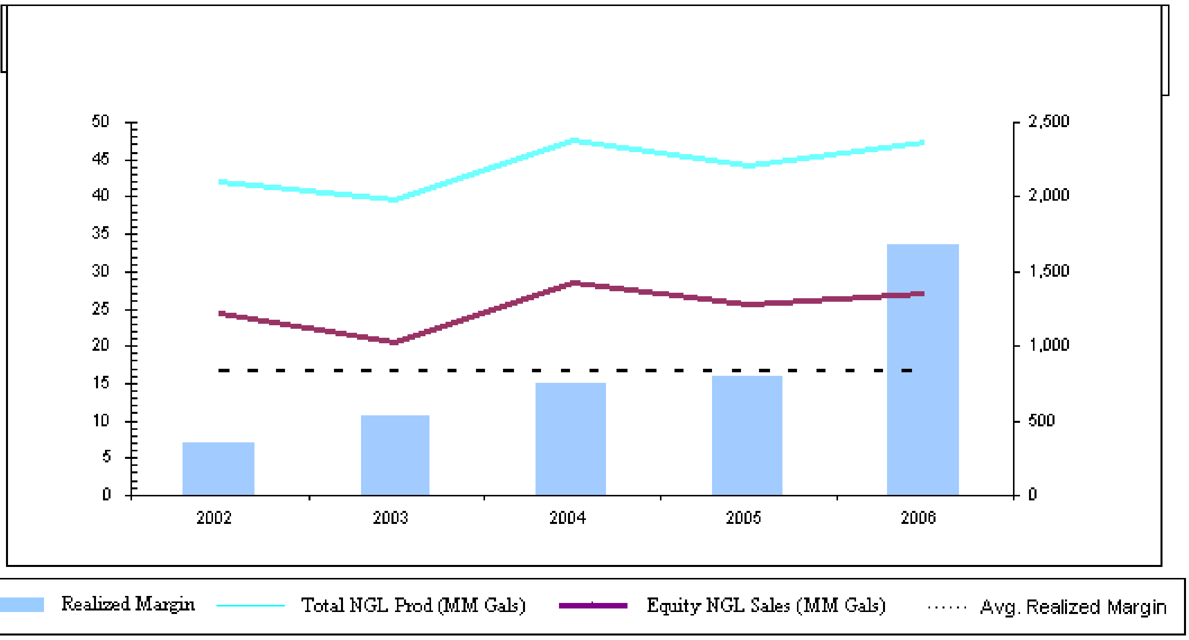
Domestic NGL Average Realized Net Margin and Volumes by Quarter



Note: Actual realized margins, does not include Discovery volumes. Five year average of 16.4 cpg is calculated for the period 1Q02-4Q06.

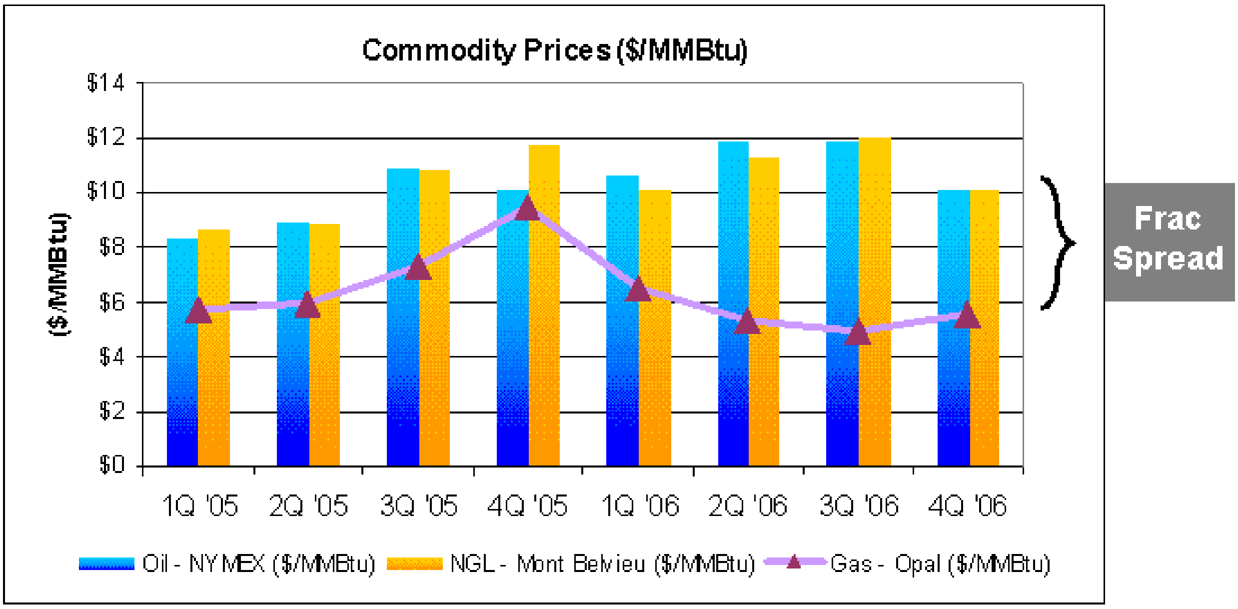
Margins Above Average

Domestic NGL Average Realized Net Margin and Volumes by Year



Note: Actual realized margins, does not include Discovery volumes. Five year average of 16.4 cpg is calculated for the period 1Q02-4Q06.

Frac Spread Drivers



Gas prices based on average *Gas Daily* settle prices at NWP, Wyoming. NGL prices based on composition weighted average of Mont Belvieu daily liquids prices; does not include fuel or T&F. Oil prices are based on average of daily NYMEX prompt settle prices.

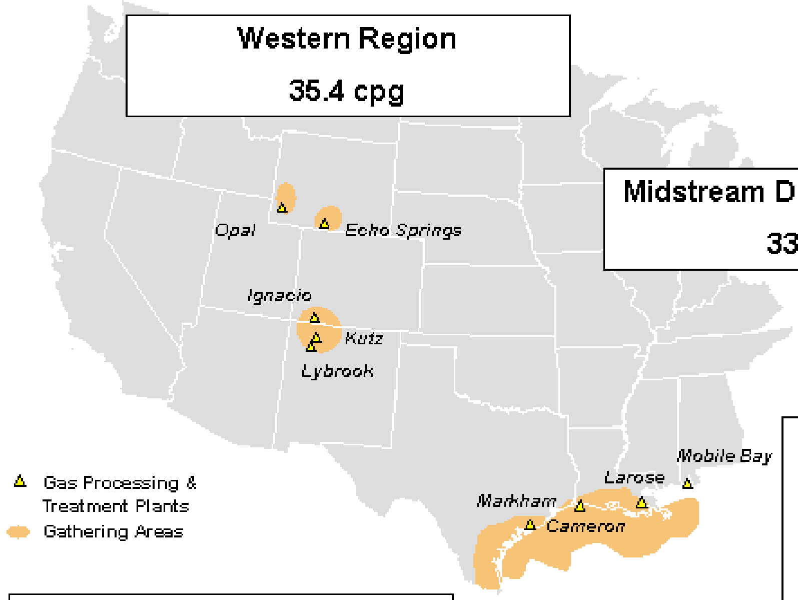
2006 Domestic Equity NGL Margins by Region

Western Region

35.4 cpg

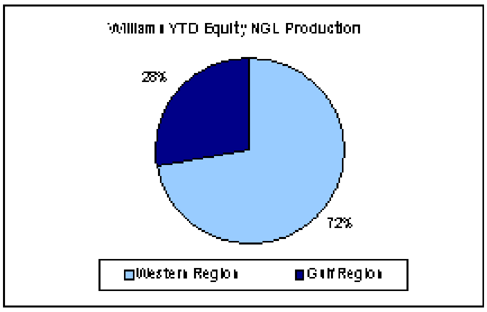
Midstream Domestic Average

33.5 cpg



Gulf Coast Region

29.4 cpg



Gas Pipeline

Segment Profit – Gas Pipeline

Dollars in millions	4th Quarter 2006	4th Quarter 2005	Year 2006	Year 2005
Segment Profit	$101	$93	$467	$586
Nonrecurring				
(Income)/Expense related to prior periods	-	32	-	(3)
Accrual of contingent refund obligation	-	5	-	5
1999 Fuel Tracker adjustment	-	-	-	(14)
Excess royalty reserve reversal	-	-	(2)	-
Recurring segment profit	$101 [1]	$130	$465	$574

- **4Q06 to 4Q05 financial highlights:**
  - Higher SG&A Costs
    - Labor & Benefits
    - Property & Liability Insurance
    - IT Support Costs
  - Higher O&M Costs
    - Pipeline Safety
    - Offshore Maintenance Costs
  - Higher DDA Costs
- **2006 to 2005 financial highlights:**
  - Higher SG&A Costs
    - Labor & Benefits
    - Property & Liability Insurance
    - IT Support Costs
  - Higher O&M Costs
    - Pipeline Safety & Offshore Maintenance Costs
  - Higher DDA Costs
  - Higher Operating Taxes

Note: 1 - Recurring Segment Profit includes $9 million of revenue associated with a deferred state income tax adjustment, which is offset in provision for Income Taxes.

Gas Pipeline

2007-08 Guidance

Dollars in millions

	2007	2008
Segment Profit	$585 - 655	$590 - 665
Annual DD&A [1]	280 - 300	300 - 325
	305 - 325	*325 - 350*
Segment Profit + DD&A	$865 - 955	$890 – 990
	890 - 980	*915 – 1,015*
Capital Spending	$425 - 535	$285 - 410
	370 - 470	*340 - 440*

1 - Change due to reclassification of certain non-cash expenses from DD&A to Other Operating Expense

Note: If guidance has changed, previous guidance from 11/02/06 is shown in italics directly below.

Power

Segment Profit - Power

Dollars in millions	4th Quarter 2006	4th Quarter 2005	Year 2006	Year 2005
Segment Loss	($39)	($69)	($211)	($257)
Nonrecurring				
Accrual for regulatory & litigation				
Contingencies/Settlements	1	69	5	87
Impairments, Losses, Write-offs	-	23	-	23
Contingent obligation adjustments	-	-	(13)	-
Expense related to prior periods	-	-	-	7
Recurring segment profit/(loss)	(38)	22	(219)	(140)
MTM Adjustment (Recurring)	36	(22)	304	138
Recurring segment profit/(loss) after MTM Adj.	$(2)	$0	$85	($2)

4Q06 to 4Q05 financial highlights

- Q405 includes $10MM income from the sale of certain Enron receivables
- Q405 includes $5MM loss on discontinued crude & refined products business

2006 to 2005 financial highlights

- $75MM increase in portfolio cash flows due to the benefits of structured power hedges, offset by lower Q406 NG inventory withdrawls.
- 2006 SG&A includes the effect of $15MM higher income from the sale of certain Enron receivables

Note: columns may not foot due to rounding

2006 - Segment Profit/(Loss) to Cash Flow from Ops

Dollars in Millions

	Commodity Power & NG	Working Capital/ Other	Total
Segment Loss	($152)	($59)	($211)
MTM Adjustments:			
Reverse Forward Unrealized MTM Losses	22		22
Add Realized Gains from MTM Previously Recognized	282		282
Segment Profit/(Loss) After MTM Adjustments	152	(59)	93
Total Working Capital Change			
Power Segment CFFO	**$152**	**($59)**	**$93**

2007-08 Guidance

Dollars in millions	2007	2008
Prior Guidance - Segment Profit/(Loss) before MTM Adj	($75) – 25	($150) – 0
Est. Fwd Impact of 4Q06 MTM Earnings and other portfolio adjustments	(25)	20
New Guidance - Segment Profit/(Loss) before MTM Adj	($75) - 0	($130) –20
Estimated MTM Adjustments	125	180
		200
Segment Profit after MTM Adj	50 - 125	50 - 200
	50 - 150	
Recurring Segment Profit after MTM Adj	**$50 - 125**	**$50 - 200**
	50 - 150	
Capital Expenditures	-	-

Note: If guidance has changed, previous guidance from 11/02/06 is shown in italics directly below. No previous guidance for 2009.

Key 2006 and YTD 2007 Contracts

Tolling Position	Year Transacted	Commodity	Customer Type(s)	Term
AES 4000	2006	Energy	Bank, Utility	Jan 11/Dec 11
West	2006	Capacity	Various	Jun 06/Dec 07
	2007	Energy & Capacity	Utility	Jan 08/Dec 11
CLECO Evangeline	2006	Energy	Hedge Fund, Marketer, Utility	Feb 06/Aug 07
South Central				
Tenaska Lindsay Hill	2006	Energy	Bank, Utility	Apr 06/Dec 09
Southeast	2006	Energy & Capacity	Cooperative	Jan 09/Feb 10
Kinder Morgan Jackson	2006	Energy	Bank, Utility	Jun 06/Dec 07
Mid-Continent	2006	Capacity	Cooperative, Marketer, Utility	Jan 07/Dec 08
	2006	Energy & Capacity	Utility	May 07/Sep 07
AES Ironwood	2006	Energy	Bank, Marketer	Sep 06/Dec 07
Northeast	2006	Capacity	Utility	Jun 06/May 07
	2006	Energy & Capacity	Utility	Jun 06/May 07
AES Red Oak	2006	Energy	Marketer	Jun 06/May 09
Northeast	2006	Capacity	Bank, Marketer, Utility	Jun 06/May 09
	2007	Capacity	Utility	Jan 07/May 11

*Certain deals in this table are reflected in "Key Agreements" in the following Portfolio Overview slides for each region.

Regional Highlights

West

- Highly hedged through 2011, In-city generation
- New local resource-adequacy requirement in 2007
- Re-designed energy market to be implemented January 2008
- Tolling agreement provides re-power rights
- Reserve margins tight, expected to compress further
- Market for Williams' E&P gas

East

- Northeast one of most developed competitive markets in U.S.
- New PJM capacity market auctions expected April 2007
- Neptune undersea DC transmission line will improve Red Oak's access to premium New York power market
- Transmission-constrained area provides opportunities for premium pricing in South Central area
- Expected improvements in South Central's route to market via Entergy's Independent Coordinator
- Reserve margins tight and continuing to compress in NE, beginning to tighten in Mid-Con, remain high in South and South Central

4Q06 Financial Statement Changes for Derivatives

During 4Q06, Williams reported the following changes related to its derivative portfolio:

Dollars in millions	Balance Sheet		Income Statement	
	Der A/L	OCI	MTM Gain/(Loss)	Realized (Gain)/Loss
Total Change in Consolidated Derivative Values[1]	9	49	(8)	(14)
Less change in Option Premiums/Other	(18)			
Remaining Change in Consolidated Derivative Values	27	49	(8)	(14)
Change in E&P Hedge Values	94	70	3	
- Prior MTM Realized (Ineffectiveness)				(4)
- OCI Realized				25
Change in Midstream Hedge Values	(2)	2		
- Prior MTM Realized				
- OCI Realized				(4)
Change in Power Hedge Values	(65)	(23)	(11)	
- Prior MTM Realized				(23)
- OCI Realized				(8)

- The net change in Derivative Assets and Liabilities for E&P was positive primarily due to a 4Q06 decrease in gas prices against a short derivative position.
- The net change in Derivative Assets and Liabilities for Midstream was negative primarily due to OCI realizations.
- The net change in Derivative Assets and Liabilities for Power was negative due to realizations and a 4Q06 decrease in gas prices against a long derivative position.

[1] Change in OCI shown is before taxes. Therefore, change shown does not tie to balance sheet change which is net of taxes.

Enterprise Risk Management

WMB Collateral Outstanding

	As of 12/31/06				
Dollars in millions	**E&P**	**Midstream**	**Power**	**Corp./ Other**	**Total**
Margins & Ad. Assur.	$0	$0	($69)	$0	($69)
Prepayments	0	0	7	0	7
Subtotal	0	0	(62)	0	(62)
Letters of Credit	456	138	305	25	924
Total as of 12/31/06	456	138	243	25	862
Total as of 12/31/05	746	243	343	91	1,423
Change	($290)	($105)	($100)	($66)	($561)

* Note: Negative Margin & Adequate Assurance value represents a margin liability, where Power is a net receiver of cash margin.

WMB Collateral Sensitivity

Williams

Dollars in millions

Margin Volatility (1% chance of exceeding)
-Potential incremental collateral requirement

Days	12/31/2006	9/30/2006	6/30/2006	3/31/2006
30	($98)	($155)	($246)	($223)
180	($434)	($459)	($580)	($769)
360	($521)	($471)	($489)	($626)

Assumption: The Margin numbers above consist of only forward marginable positions.

Sensitivity Analysis

Dollars in millions, except per unit increases

	Enterprise[1] Natural Gas Per MMBtu	Power Co.[2] Power Per MWh	Midstream[3] Processing Margin Per Gallon of NGL's
Increase	**$0.10**	**$1**	**$0.01**
2007	$5-$8 MM	$1-$3 MM	$13-$15 MM
2008	$13-$15 MM	$4-$6 MM	$15-$17 MM

[1] Assumes a correlated movement in prices across all commodities, including spreads, for all Williams business units combined.
[2] Assumes a non-correlated change in Power prices across the entire Power Co. portfolio
[3] Assumes a non-correlated change in NGL processing spread (i.e. change in NGL price only).

Consolidated

Consolidated

Liquidity at December 31, 2006

Dollars in millions

Cash and cash equivalents		$ 2,269
Other current securities		103
Less:		
Subsidiary and Int'l cash & cash equivalents	$ 347	
Customer margin deposits payable	129	(476)
Available unrestricted cash		1,896
Available revolver capacity		1,776
Total Liquidity		**$ 3,672**

Consolidated

2006 Cash Information

Williams

Dollars in millions

	4th Quarter	Year
Beginning unrestricted cash	**$ 1,075**	**$ 1,597**
Cash flow from continuing operations	575	1,883
Debt retirements	(3)	(777)
Proceeds from debt issuance	600	1,299
Proceeds from sale of limited partnership units	638	863
Capital expenditures	(750)	(2,509)
Dividends	(55)	(207)
Dividends to minority interests	(8)	(36)
Other-net	197	156
Change in cash and cash equivalents	$ 1,194	$ 672
Ending unrestricted cash at 12/31/06		**$ 2,269**
Restricted cash at 12/31/06 (not included above)		$ 126

Debt Balance[1]

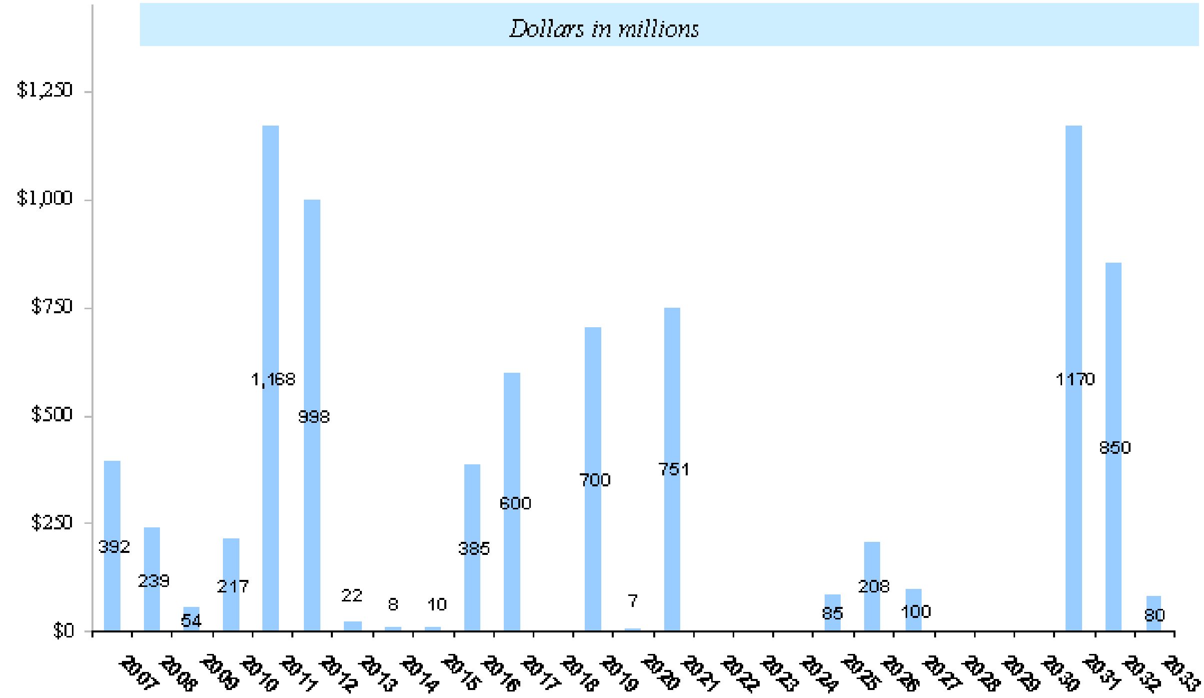
Dollars in millions

		Avg. Cost
Debt Balance @ 12/31/05	**$7,713**	**7.6%**
Early Conversions	(220)	
Scheduled Debt Retirements & Amortization	(64)	
Debt Balance @ 3/31/06	**$7,429**	**7.7%**
Additions	699	
Early Retirements	(485)	
Scheduled Debt Retirements & Amortization	(180)	
Debt Balance @ 6/30/06	**$7,463**	**7.7%**
Scheduled Debt Retirements & Amortization	(45)	
Debt Balance @ 9/30/06	**$7,418**	**7.7%**
Additions	600	
Scheduled Debt Retirements & Amortization	(4)	
Debt Balance @ 12/31/06	**$8,014**	**7.6%**
Fixed Rate Debt @ 12/31/06	**$7,864**	**7.7%**
Variable Rate Debt @ 12/31/06	**$150**	**6.4%**

[1] *Debt is long-term debt due within 1 year plus long-term debt.*

Consolidated

Debt Amortization – As of 12/31/2006



Consolidated

EPS Metrics

2006	1Q	2Q	3Q	4Q	Total
Diluted EPS from Cont. Ops.	$0.22	($.11)	$0.19	$0.25	$0.55
Recurring EPS	0.23	0.19	0.19	0.26	0.86
Recurring EPS after MTM Adj.	**0.26**	**0.33**	**0.28**	**0.30**	**1.17**
Average Shares (MM)	607	596	609	610	609

2005	1Q	2Q	3Q	4Q	Total
Diluted EPS from Cont. Ops.	$0.34	$0.07	$0.01	$0.11	$0.53
Recurring EPS	0.33	0.11	(0.01)	0.28	0.72
Recurring EPS after MTM Adj.	**0.22**	**0.17**	**0.22**	**0.26**	**0.86**
Average Shares (MM)	599	579	581	609	606

2007 Interest Expense Forecast Guidance

Williams

Dollars in millions	**2007**
Interest on Long-Term Debt	$600 - $620
Amortization Discount/Premium and other Debt Expense	25 - 30
Credit Facilities: (Incl. Commitment Fees Plus LC Usage)	35 - 45
Interest on other Liabilities	10 - 20
Interest Expense	$670 - $715
Less: Capitalized Interest	(30) - (15)
Net Interest Expense Guidance	**$640 - $700**

Consolidated

2006 Effective Tax Rates

	2006									
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter		Full Year	
Statutory Rate	77	35%	(22)	35%	74	35%	60	35%	189	35%
State	10	5%	(1)	1%	14	6%	(16)	-9%	7	1%
Foreign	0	0%	7	-10%	7	3%	11	6%	25	5%
Federal Income Tax Litigation	1	0%	1	-1%	1	1%	(43)	-25%	(40)	-8%
Nondeductible Convertible Debenture Expenses	0	0%	10	-16%	0	0%	0	0%	10	2%
Other	0	0%	6	-10%	4	3%	5	3%	15	3%
Tax Provision/(Benefit)	88	40%	1	-1%	100	48%	17	10%	206	38%

	2007	2008
Effective Tax Rate Guidance	**39%**	**39%**
Cash Tax Rate Guidance	**5-10%**	**5-10%**

Note 1: In addition to the 39% effective tax rate guidance provided above, $7-15 million of increased tax provision is also being forecasted in 2007 while an additional $5-10 million is forecasted in 2008.

The Williams Companies, Inc.

News Relase

NYSE: WMB

Date: Feb. 22, 2007

Williams Replaces 216% of 2006 U.S. Natural Gas Production
Total Domestic and International Proved Reserves Grow to 3.9 Tcfe
Domestic Production Increases 23%

TULSA, Okla. — Williams (NYSE:WMB) announced today that its domestic and international proved natural gas and oil reserves as of Dec. 31, 2006, increased to approximately 3.9 trillion cubic feet equivalent (Tcfe).

Reserves in the United States increased 9.5 percent to approximately 3.7 Tcfe, compared with approximately 3.38 Tcfe a year earlier. More than 99 percent of Williams' U.S. proved reserves are natural gas.

Williams attributed the majority of its U.S. reserves additions to drilling and to increasing the density of well spacing below the surface in the Piceance Basin, along with drilling in the Powder River Basin and other basins.

In 2006, Williams had a drilling success rate of approximately 99 percent. The company drilled 1,783 gross wells, of which 1,770 were successful.

Williams' activities in 2006 resulted in a total addition of 597 billion cubic feet equivalent (Bcfe) in net reserves. Williams added a total of 620 Bcfe in net reserves in 2005 and a total of 477 Bcfe in net reserves in 2004. The company's three-year average U.S. finding and developing cost was $1.55 per Mcfe. Excluding capital for facilities, the cost was $1.46 per Mcfe.

Williams replaced its 2006 U.S. wellhead production of 276 billion cubic feet equivalent (Bcfe) at a ratio of 216 percent. A reserves reconciliation follows the main text in this news release.

"Our approach to responsible development continues to provide positive outcomes in production growth, reserves replacement and our ability to work with landowners, communities and regulatory agencies," said Ralph Hill, president of Williams' exploration and production business.

"Over the past three years, we have added more than 1.6 trillion cubic feet equivalent in domestic net reserves from our long-term drilling inventory. Our employees continue to lead the way as they perform at a highly successful rate to develop a large, well-defined resource more safely and efficiently each year," Hill added.

International reserves were approximately 27 million barrels of oil equivalent at year-end 2006, compared with approximately 37 million barrels of oil equivalent in 2005.

The reduction in international reserves primarily reflects the absence of Venezuelan reserves after Williams' 10 percent direct working interest in a Venezuelan operating contract changed to a 4 percent equity interest in a Venezuelan corporation. As a result of this change, Venezuelan reserves are not included in Williams' 2006 year-end reserves.

Sixty-one percent of Williams' international proved reserves are crude oil and liquids; the remainder is natural gas. Williams' international reserves are predominantly located in Argentina.

Average daily production from domestic and international interests was approximately 803 million cubic feet of gas equivalent (MMcfe), compared with 662 MMcfe for the same period in 2005 - an increase of 21 percent. Production solely from interests in the United States increased 23 percent to 752 MMcfe per day, compared with 612 MMcfe per day in 2005.

Williams' exploration and production business primarily develops natural gas reserves in the Piceance, Powder River, San Juan, Fort Worth and Arkoma basins in the United States.

In late 2006, Williams was named Hydrocarbon Producer of the Year at the Global Energy Awards, which recognized the company for its reserves additions, return on investment, new drilling technology, environmental stewardship, operational safety and increased production.

Approximately 98 percent of Williams' year-end 2006 U.S. proved reserves estimates were audited by Netherland, Sewell & Associates, Inc., who in their judgment determined the estimates to be reasonable in the aggregate for each basin.

Reserves estimates related to properties underlying the Williams Coal Seam Gas Royalty Trust (NYSE:WTU), were prepared by Miller and Lents, LTD. These properties comprise another 2 percent of Williams' total U.S. proved reserves.

Proved reserves estimates for Argentine properties were prepared by Ryder Scott Company.

The U.S. reserve replacement ratio of 216 percent was calculated by dividing the sum of changes (acquisitions, divestitures, additions and revisions) to the estimated proved reserves during 2006 by Williams' 2006 production of 276 Bcfe.

The three-year average U.S. finding and development cost of $1.55 per Mcfe was calculated by dividing total capital and exploration costs by the change in proved reserves balances over the three-year period, adding back production sold.

For purposes of converting volumes of crude oil and liquids reserves to a natural-gas-equivalent measure in this report, the company used a ratio of one barrel to 6,000 cubic feet.

Proved reserves are estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under assumed economic conditions.

U.S. Proved Reserves Reconciliation

Figures in billion cubic feet equivalent of natural gas. May not add due to rounding.

Proved reserves Dec. 31, 2005	3,382
Acquisitions	41
Divestitures	(1)
Additions and revisions	557
Production	(277)
Proved reserves Dec. 31, 2006	3,701

About Williams (NYSE:WMB)

Williams, through its subsidiaries, primarily finds, produces, gathers, processes and transports natural gas. The company also manages a wholesale power business. Williams' operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, Southern California and Eastern Seaboard. More information is at www.williams.com.

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# # #

Exhibit 99.4

News Release

NYSE: WMB

Date: Feb. 22, 2007

Williams Sells Certain Power rights to Southern California Edison

Agreements Reduce Risk and Increase Cash Flow by Extending Power Sales Through 2011.

TULSA, Okla. – Williams (NYSE:WMB) today announced the sale of dispatch and tolling rights and natural gas supply arrangements to Southern California Edison, a subsidiary of Edison International (NYSE:EIX).

The seven contracts "mirror" Williams' rights under its tolling agreement with certain subsidiaries of the AES Corporation and represent up to 1,920 megawatts of power.

Southern California Edison is an investor-owned utility serving customers in southern, central and coastal California. The agreements will be part of the supply resources that allow the electric utility to meet its customers' growing energy needs.

"These contracts help Williams' power business reduce risk and generate cash flows beyond 2010," said Bill Hobbs, president of Williams Power. "The deal is an effective economic hedge with favorable credit and pricing terms, and is consistent with our strategy by locking in future power sales from the AES plants in Southern California," he said.

About Williams (NYSE:WMB)

Williams, through its subsidiaries, primarily finds, produces, gathers, processes and transports natural gas. The company also manages a wholesale power business. Williams' operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, Southern California and Eastern Seaboard. More information is at www.williams.com.

About Southern California Edison

An Edison International (NYSE:EIX) company, Southern California Edison is one of the nation's largest electric utilities, serving a population of more than 13 million via 4.7 million customer accounts in a 50,000-square-mile service area within central, coastal and Southern California. www.sce.com

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# # #

Portions of this document may constitute "forward-looking statements" as defined by federal law. Although the company believes any such statements are based on reasonable assumptions, there is no assurance that actual outcomes will not be materially different. Any such statements are made in reliance on the "safe harbor" protections provided under the Private Securities Reform Act of 1995. Additional information about issues that could lead to material changes in performance is contained in the company's annual reports filed with the Securities and Exchange Commission.