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 28, 2006

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 28, 2006, The Williams Companies, Inc. ("Williams" or the "Company") issued a press release announcing its financial results for the quarter and year ended December 31, 2005. 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 28, 2006.

On February 28, 2006, Williams also announced that its domestic and international proved natural gas reserves as of December 31, 2005, increased to 3.6 trillion cubic feet equivalent. Williams replaced its 2005 U.S. natural gas production of 224 billion cubic feet equivalent at a ratio of 277 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.

The slide presentation and press release 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) Exhibits

Exhibit 99.1	Copy of Williams' press release dated February 28, 2006, publicly announcing its fourth quarter and year-end 2005 financial results.
Exhibit 99.2	Copy of Williams' slide presentation to be utilized during the

	February 28, 2006, public conference call and webcast.
Exhibit 99.3	Copy of Williams' press release dated February 28, 2006, publicly announcing its replacement of 2005 U.S. natural gas production.

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 28, 2006

/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

NewsRelease

NYSE: WMB

Date: Feb. 28, 2006

Williams Reports Fourth-Quarter and Full-Year 2005 Financial Results

- *U.S. Natural Gas Production Climbs 18% During 2005*
- *Businesses Generate $1.45 Billion in Net Cash from Operating Activities for 2005*
- *4Q Results Reduced by Litigation Accruals and Investment Impairments*
- *Company Plans to Double Drilling Activity in Piceance Highlands in 2006*
- *Company Provides Guidance Through 2008*

Year-End Summary Financial Information

Per share amounts are reported on a fully diluted basis	2005 millions	2005 per share	2004 millions	2004 per share
Income from continuing operations	$ 317.4	$ 0.53	$ 93.2	$ 0.18
Income (loss) from discontinued operations	($ 2.1)	–	$ 70.5	$ 0.13
Cumulative effect of change in accounting principle	($ 1.7)	–	–	–
Net income	$ 313.6	$ 0.53	$ 163.7	$ 0.31
Recurring income from continuing operations*	$ 427.8	$ 0.72	$ 261.5	$ 0.49
After-tax mark-to-market adjustments	$ 85.0	$ 0.14	($ 72.0)	($ 0.14)
Recurring income from continuing operations — after mark-to-market adjustment*	$ 512.8	$ 0.86	$ 189.5	$ 0.35

* 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 Information

Per share amounts are reported on a fully diluted basis	4Q 2005 millions	4Q 2005 per share	4Q 2004 millions	4Q 2004 per share
Income from continuing operations	$ 68.8	$ 0.11	$ 95.5	$ 0.17
Income (loss) from discontinued operations	($ 0.3)	–	($ 22.1)	($ 0.04)
Cumulative effect of change in accounting principle	($ 1.7)	–	–	–
Net income	$ 66.8	$ 0.11	$ 73.4	$ 0.13
Recurring income from continuing operations*	$ 168.1	$ 0.28	$ 68.0	$ 0.12
After-tax mark-to-market adjustments	($ 13.8)	($ 0.02)	($ 17.0)	($ 0.03)
Recurring income from continuing operations — after mark-to-market adjustment*	$ 154.3	$ 0.26	$ 51.0	$ 0.09

TULSA, Okla. – Williams (NYSE:WMB) announced 2005 unaudited net income of $313.6 million, or 53 cents per share on a diluted basis, compared with net income of $163.7 million, or 31 cents per share on a diluted basis, for 2004.

Results for 2005 reflect the benefit of increased natural gas production and higher net realized average prices for production sold, along with reduced levels of interest expense. Results for 2004 included $282.1 million in costs associated with the early retirement of debt.

Results for 2005 also include unrealized mark-to-market gains of $172 million from the Power business, compared with $304 million in 2004.

For fourth-quarter 2005, the company reported net income of $66.8 million, or 11 cents per share on a diluted basis, compared with net income of $73.4 million, or 13 cents per share on a diluted basis, for fourth-quarter 2004.

Results for fourth-quarter 2005 include $64 million in litigation accruals to resolve legacy issues associated with gas reporting and $61 million of impairment charges associated with two non-core equity investments.

The company reported 2005 income from continuing operations of $317.4 million, or 53 cents per share on a diluted basis, compared with $93.2 million, or 18 cents per share on a diluted basis, in 2004.

For fourth-quarter 2005, the company reported income from continuing operations of $68.8 million, or 11 cents per share on a diluted basis, compared with $95.5 million, or 17 cents per share on a diluted basis, for fourth-quarter 2004.

CEO Perspective

"Our growth is creating real economic value," said Steve Malcolm, chairman, president and chief executive officer. "The investments we're making in our businesses are generating significant results for shareholders and adding energy supplies and delivery reliability to the domestic market.

"In 2005, we more than doubled our performance on a key financial measure – our recurring earnings exclusive of the effect of mark-to-market accounting.

"We took critical steps last year to increase the pace of proving up natural gas reserves and increasing production in the United States. Our efforts paid off with significant increases in both production and reserves through drilling activity.

"This year, we are deploying still more drilling rigs. These rigs are designed to drill more efficiently and effectively. And we are continuing to expand our drilling horizon within the Piceance Basin of the Western Rockies, doubling the number of wells we drill in the comparatively undeveloped Highlands, where we drilled 25 wells last year. We clearly expect these continued efforts to yield proportional growth in financial performance in 2006 and beyond," Malcolm said.

“Williams is rich with opportunity that spans the natural gas value chain from domestic reserves and production growth to midstream infrastructure development and pipeline capacity growth to meet demand on the Eastern Seaboard, Florida and the Northwest.

“We are projecting a growth horizon that will push our 2008 consolidated recurring segment profit to more than $2 billion on a basis adjusted for the effect of mark-to-market accounting,” he said.

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 $512.8 million, or 86 cents per share, for 2005. In 2004, the adjusted recurring income from continuing operations was $189.5 million, or 35 cents per share.

For the fourth quarter of 2005, recurring income from continuing operations – after adjusting for the mark-to-market effect – was $154.3 million, or 26 cents per share, compared with $51 million, or 9 cents per share, for the same period in 2004.

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.

Business Segment Performance

Williams’ primary businesses – Exploration & Production, Midstream Gas & Liquids, Gas Pipeline and Power – reported combined segment profit of $1.39 billion in 2005. A year ago, these businesses reported combined segment profit of $1.45 billion.

Results for 2005 were reduced by lower levels of forward unrealized mark-to-market gains and litigation accruals associated with agreements to resolve gas reporting issues. This year’s results benefited from increased natural gas production volumes and higher net realized average prices.

In the fourth quarter of 2005, the four major businesses reported combined segment profit of $342.2 million, compared with $419 million for the same period last year. The fourth quarter of 2004 included a $93.6 million gain from an insurance arbitration award.

Exploration & Production: U.S. Volumes Up 18 Percent in 2005 from Drilling 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 2005 segment profit of $587.2 million.

A year ago, the business reported segment profit of $235.8 million. The improvement in 2005 reflects the benefit of significant increases in both production volumes and net realized average prices for production sold.

In addition, average sales prices in 2005 reflect a lower share of hedged volumes and increased contracted prices on hedged volumes, along with approximately $30 million in net gains on the sale of non-operated properties.

The benefit of higher volumes and prices in 2005 was only partially offset by higher operating expenses.

For 2005, average daily production from domestic and international interests was approximately 662 million cubic feet of gas equivalent (MMcfe), compared with 564 MMcfe for the same period in 2004 – an increase of approximately 17 percent.

Production solely from domestic interests increased 18 percent to approximately 612 MMcfe in 2005 from 519 MMcfe in 2004.

For the fourth quarter of 2005, Exploration & Production reported segment profit of $206.4 million, compared with $70.9 million for the same period last year.

During the fourth quarter of 2005, Williams realized net domestic average prices of $5.66 per thousand cubic feet of gas equivalent (Mcfe), compared with $3.16 per Mcfe in the fourth quarter a year ago – an increase of 79 percent. Hedging activities limited the extent of the company's ability to capture a higher benefit from market prices.

The improvement in the 2005 quarter also reflects an increase in production volumes. Average daily production from domestic volumes totaled 646 MMcfe during the fourth quarter of 2005. Increased production continues to primarily reflect higher volumes in the Piceance Basin.

In a separate announcement today, Williams reported year-end 2005 proved U.S. natural gas reserves of 3.4 trillion cubic feet equivalent, up 13.3 percent from year-end 2004 reserves. Including its international interests, Williams had total proved natural gas and oil reserves of 3.6 trillion cubic feet equivalent at year-end 2005.

Domestic additions and revisions of 603 billion cubic feet equivalent exceeded last year's 451 billion cubic feet in additions and revisions – an increase of approximately 34 percent. Over the past three years, Williams has successfully transferred more than 1.4 trillion cubic feet of domestic reserves from probable to proved.

In 2005, Williams had a drilling success rate of approximately 99 percent. The company drilled 1,629 gross wells, of which 1,617 were successful. In 2004, Williams also achieved a 99 percent success rate, drilling 1,395 gross wells.

Williams currently has 19 rigs operating in the Piceance Basin of western Colorado – the company's cornerstone for production and reserves growth.

Williams is deploying a new generation of drilling rig from Helmerich & Payne that is specifically designed for conditions in the Piceance Basin. Williams received two of the new rigs in the first quarter of 2006. Eight more rigs are scheduled for delivery at a pace of one per month during the year.

Williams plans to invest $950 million to $1.05 billion of capital in Exploration & Production in 2006. These investments are primarily focused on increasing domestic production by 15 to 20 percent during the year.

For 2006, Williams expects $650 million to $725 million in segment profit from Exploration & Production.

Midstream Gas & Liquids: Posts Strong Results, Despite Hurricanes and Lower Margins

Midstream, which provides natural gas gathering and processing services, along with natural gas liquids (NGL) fractionation and storage services and olefins production, reported 2005 segment profit of $471.2 million, compared with $549.7 million in 2004.

For the fourth quarter of 2005, Midstream reported segment profit of $112.4 million, compared with $235.7 million for the same period in 2004.

Results for 2004 were favorably affected by a fourth-quarter gain of $93.6 million related to an insurance arbitration award.

Results for 2005 benefited from $20.6 million in higher domestic gathering and processing fee-based revenues than a year ago, primarily a result of higher gathering fees and deepwater production handling payments.

These benefits were offset partially by a decrease in net NGL margins as volumes associated with natural gas processing facilities were affected by hurricane-related production shut-ins, power outages and intermittent periods of NGL rejection in the fourth quarter.

In 2005, Midstream sold 1.27 billion gallons of NGL equity volumes, compared with equity sales of 1.43 billion gallons in 2004. Third and fourth quarter performance in 2005 was negatively affected by hurricanes Katrina and Rita, as well as intermittent periods of unfavorable NGL recovery economics in the fourth quarter of 2005. These equity volumes are retained and subsequently marketed by Williams as payment-in-kind under the terms of certain processing contracts.

Gathering volumes increased slightly year-over-year despite the effects of the hurricanes during the third quarter. Gathering volumes were 1,253.3 trillion British thermal units (TBtu) in 2005, compared with 1,251.9 TBtu in 2004. As a result of the hurricanes, fee processing volumes declined year-over-year. In 2005, fee processing volumes were 721.4 TBtu, compared with 767.7 TBtu in 2004.

During the fourth quarter of 2005, Williams began receipt of new volumes of oil and gas from the Triton and Goldfinger fields at its Devils Tower deepwater spar in the eastern Gulf of Mexico. Also, Williams agreed to expand two of its deepwater pipelines in the same area to transport oil and gas production from the Blind Faith acreage beginning in 2008.

Effective Jan. 1, 2006, Williams acquired full ownership of the fourth cryogenic processing train at its Opal, Wyo., facility for approximately $32.5 million. Under a previous agreement, Williams shared the revenue stream from that unit. Williams now owns the entire Opal complex and is in the process of adding a fifth cryogenic processing train, scheduled for completion in second-quarter 2007.

Earlier this month, the company's Cameron Meadows natural gas processing plant returned to service at partial capacity. This facility in Louisiana's Cameron Parish had been offline since Hurricane Rita struck on Sept. 24. Williams expects to return the plant to full service in the second quarter this year.

Williams plans to invest $280 million to $300 million of capital in Midstream in 2006. These investments are primarily focused on expanding Midstream's gathering and processing systems in the western United States and in the deepwater Gulf of Mexico.

For 2006, Williams expects $400 million to $500 million in segment profit from Midstream.

Gas Pipeline: Assesses Customer Demand for Possible Expansions

Gas Pipeline, which primarily delivers natural gas to markets along the Eastern Seaboard, in Florida and in the Northwest, reported 2005 segment profit of $585.8 million, comparable to the same level of segment profit a year ago.

Compared with 2004, segment profit in 2005 reflects higher equity earnings of approximately $14 million from Gulfstream and a $14.2 million favorable adjustment from the resolution of litigation associated with fuel-tracker filings. Those benefits were partially offset by approximately $24 million in lower transportation revenues, mainly from the termination a firm transportation agreement related to the Grays Harbor lateral on the Northwest system.

Additionally, 2005 includes prior-period income of $17.1 million associated with corrections to 2003-2004 pension obligations and $17.7 million associated with reversal of prior-period accruals, offset by a prior-period charge of approximately $27.5 million related to accounting and valuation corrections for certain inventory items, and an accrual of approximately $9.8 million for contingent refund obligations.

For the fourth quarter of 2005, Gas Pipeline reported segment profit of $92.8 million compared with $156.8 million for the same period in 2004. The decrease is primarily because of the previously mentioned prior-period charge of $27.5 million for certain inventory items and the $9.8 million contingent loss accrual.

The decrease in fourth-quarter 2005 also reflects the termination of the Grays Harbor contract, effective January 2005, combined with higher labor and benefits costs as well as the write-off of certain previously capitalized system costs.

During the fourth quarter and already in 2006, Williams has announced a variety of potential projects for expansions on all of its major interstate gas pipeline holdings – Transco, Northwest and Gulfstream Natural Gas System L.L.C., a joint venture in which Williams owns a 50 percent interest.

These non-binding open seasons are a preliminary, necessary step in soliciting customer interest for potential service expansions.

As an example, Williams concluded an open season for the proposed Sentinel project during the fourth quarter. As proposed, the Transco project was designed to provide an additional 200,000 to 300,000 dekatherms of natural gas deliverability per day in the Northeast. Williams ultimately received requests for a total of 256,000 dekatherms per day of capacity – well within the scope of the original plan.

Williams is evaluating the facility requirements to support the Transco Sentinel capacity and is in the process of negotiating shipper agreements with the parties that expressed interest. Service could be available as early as November 2008, subject to Federal Energy Regulatory Commission approval.

In December – following the successful completion of a prior open season in the summer of 2004 and a subsequent customer contract in spring 2005 – Transco filed an application with FERC to construct the Leidy to Long Island expansion in 2007. It will add 100,000 dekatherms of capacity, along with a compressor station, at an approximate cost of $121 million. Most of that expenditure is planned for 2007.

Also in the fourth quarter, Williams completed construction of a $16 million project to add 105,000 dekatherms per day of firm service on its Transco system in central New Jersey. This expansion was placed into service Nov. 1.

Williams plans to invest $710 million to $785 million of capital in Gas Pipeline in 2006. These investments are predominantly tied to maintenance, a capacity replacement project on Northwest Pipeline in Washington and expansions.

For 2006, Williams expects $475 million to $520 million in segment profit from Gas Pipeline. The projected decline compared with 2005 results is in part because of a new accounting rule that requires certain pipeline assessment costs that have historically been capitalized to be recorded as expense beginning in 2006, and higher interest expense at Gulfstream as a result of a debt offering in October 2005.

Power: Generates Positive Cash Flow in 2005; Continues to Reduce Forward Risk

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

2005 Power Recurring Segment Profit Adjusted for Mark-to-Market Impact

	2005 (millions)	2004 (millions)
Segment profit (loss)	($ 256.7)	$ 76.7
Non-recurring adjustments	$ 116.6	–
Recurring Segment profit (loss)	($ 140.1)	$ 76.7
Mark-to-market adjustments — net	$ 137.7	($ 118.0)
Recurring segment loss after mark-to-market adjustments	($ 2.4)	($ 41.3)

4Q Power Recurring Segment Profit Adjusted for Mark-to-Market Impact

	4Q '05 (millions)	4Q '04 (millions)
Segment profit (loss)	($ 69.4)	($ 44.4)
Non-recurring adjustments	$ 91.7	–
Recurring Segment profit (loss)	$ 22.3	($ 44.4)
Mark-to-market adjustments — net	($ 22.4)	($ 29.1)
Recurring segment loss after mark-to-market adjustments	($ 0.1)	($ 73.5)

Power reported a 2005 segment loss of $256.7 million, compared with a segment profit of $76.7 million in 2004. Reported results include the effect of forward unrealized mark-to-market gains and losses.

The reduction is primarily the result of lower unrealized mark-to-market gains, lower tolling margins because of the effect of milder weather in California, and the effect of hurricanes on liquidity in the market. Results for 2005 also were reduced by significant litigation accruals and the impairment of a non-core equity investment.

Power reported a recurring segment loss adjusted for the effect of mark-to-market accounting of $2.4

million in 2005, compared with a loss of $41.3 million in 2004.

The year-over-year improvement on the adjusted basis primarily reflects the absence of losses from the interest rate and crude and refined products portfolios and lower selling, general and administrative expenses. That improvement was partially offset by lower margins from tolling and other accrual contracts in 2005.

Power reported a fourth quarter 2005 segment loss of $69.4 million, compared with a segment loss of $44.4 million in fourth-quarter 2004. Reported results include the effect of forward unrealized mark-to-market results.

The increased loss in the fourth quarter of 2005 is primarily the result of litigation accruals associated with resolving gas reporting issues and the impairment of a non-core equity investment, partially offset by higher unrealized mark-to-market gains and higher accrual revenues.

For the fourth quarter of 2005, Power reported a recurring segment loss adjusted for the effect of mark-to-market accounting of $0.1 million, compared with a loss of $73.5 million in 2004.

The year-over-year improvement on the adjusted basis primarily reflects the absence of losses from the interest rate and legacy natural gas portfolios and lower selling, general and administrative expenses.

In 2005, Power generated approximately $188 million in cash flow from operations, largely the result of working capital changes, including the return of margin dollars. In 2004, Power generated approximately $565 million in cash flow from operations, reflecting a significant return of margin dollars resulting from new letter of credit facilities, and changes in working capital.

Power last year also completed 17 new power sales contracts that range in term and volume through 2010. These contracts effectively reduce risk, increase value and increase cash-flow certainty. Additionally, the contracts reduce the portfolio’s future exposures to fuel-price and weather volatility.

For 2006, Williams expects a segment loss of between $135 million to $235 million from Power, absent the effect of any future unrealized mark-to-market gains or losses. In regard to cash flow from operations, Williams expects $50 million to $150 million from Power in 2006, excluding changes in working capital and payment of accruals associated with gas reporting agreements.

On a basis adjusted for the effect of mark-to-market accounting, Williams expects Power to generate 2006 recurring segment profit of $50 million to $150 million.

Cash and Debt: Company Ends 2005 With Available Liquidity of $2.6 Billion

At the close of business on Dec. 31, 2005, Williams had total liquidity of more than $2.6 billion. This consisted of approximately $1.6 billion in unrestricted cash and cash equivalents, approximately $123 million in other liquid investments and $961 million in unused and available revolving credit facilities.

Net cash provided by operating activities in 2005 was approximately $1.45 billion, comparable with the 2004 level of $1.49 billion.

Williams reduced its debt by approximately $249 million in 2005 through scheduled payments, maturities and conversions.

At Dec. 31, 2005, Williams' total outstanding debt was approximately $7.7 billion. Approximately $220 million of debt – via the form of 5.5 percent junior subordinated convertible debentures – was converted to common equity in January 2006.

As a result of significant debt reductions in prior years such as 2003 and 2004, Williams realized a $162.7 million decrease in interest expense in 2005 compared with the prior year. The company had interest expense of $671.7 million in 2005, compared with $834.4 million in 2004 – a decrease of 19 percent.

Guidance Through 2008

In 2006, Williams expects $1.52 billion to $1.86 billion in consolidated segment profit and earnings per share of 78 cents to $1.03, both on a recurring basis adjusted for the effect of mark-to-market accounting. The projected increase over 2005 is primarily the result of expected increases in natural gas production volumes and anticipated pricing for those volumes.

In 2007, Williams expects consolidated segment profit of $1.83 billion to $2.25 billion on a recurring basis adjusted for the impact of mark-to-market accounting. The projected increase over 2006 is primarily the result of anticipated increases in natural gas production volumes, successfully completing Gas Pipeline rate cases, and increases in natural gas liquids volumes.

In 2008, Williams expects consolidated segment profit of $2.02 billion to $2.58 billion on a recurring basis adjusted for the impact of mark-to-market accounting. The projected increase over 2007 is primarily the result of anticipated increases in natural gas production volumes, the completion of expansions in Gas Pipeline and increases in natural gas liquids volumes.

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

The company's overall capital budget is $1.95 billion to $2.15 billion for 2006; $1.6 billion to $1.8 billion for 2007; and $1.5 billion to $1.75 billion for 2008.

Today's Analyst Call

Williams' management will discuss the company's 2005 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) 818-5264. International callers should dial (913) 981-4910. 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 in early March. 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 Forms 10-K and 10-Q, available from our offices or from our website at www.williams.com.

Financial Highlights
(UNAUDITED)

(Millions, except per-share *amounts*)	Three months ended December 31, **2005**	2004	Years ended December 31, **2005**	2004
Revenues	**$ 3,676.1**	$ 2,964.2	**$12,583.6**	$12,461.3
Income from continuing operations	**$ 68.8**	$ 95.5	**$ 317.4**	$ 93.2
Income (loss) from discontinued operations	**$ (0.3)**	$ (22.1)	**$ (2.1)**	$ 70.5
Cumulative effect of change in accounting principle	**$ (1.7)**	$ —	**$ (1.7)**	$ —
Net income applicable to common stock	**$ 66.8**	$ 73.4	**$ 313.6**	$ 163.7
Basic earnings (loss) per common share:				
Income from continuing operations	**$ .12**	$ .17	**$ .55**	$ .18
Income (loss) from discontinued operations	**$ —**	$ (.04)	**$ —**	$ .13
Cumulative effect of change in accounting principle	**$ —**	$ —	**$ —**	$ —
Net income	**$ .12**	$ .13	**$ .55**	$ .31
Average shares (thousands)	**573,371**	552,272	**570,420**	529,188
Diluted earnings (loss) per common share:				
Income from continuing operations	**$ .11**	$ .17	**$ .53**	$ .18
Income (loss) from discontinued operations	**$ —**	$ (.04)	**$ —**	$ .13
Cumulative effect of change in accounting principle	**$ —**	$ —	**$ —**	$ —
Net income	**$ .11**	$ .13	**$ .53**	$ .31
Average shares (thousands)	**609,106**	586,497	**605,847**	535,611
Shares outstanding at December 31 (thousands)			**573,592**	557,957

Consolidated Statement of Operations
(UNAUDITED)

		Three months ended December 31,		Years ended December 31,	
	(Millions, except per-share amounts)	**2005**	2004	**2005**	2004
REVENUES	Power	**$2,786.7**	$2,038.6	**$ 9,093.9**	$ 9,272.4
	Gas Pipeline	**374.7**	351.3	**1,412.8**	1,362.3
	Exploration & Production	**420.2**	214.1	**1,269.1**	777.6
	Midstream Gas & Liquids	**890.9**	867.1	**3,232.7**	2,882.6
	Other	**7.8**	6.5	**27.2**	32.8
	Intercompany eliminations	**(804.2)**	(513.4)	**(2,452.1)**	(1,866.4)
	Total revenues	**3,676.1**	2,964.2	**12,583.6**	12,461.3
SEGMENT COSTS AND EXPENSES	Costs and operating expenses	**3,162.9**	2,543.5	**10,871.0**	10,751.7
	Selling, general and administrative expenses	**98.6**	97.8	**325.4**	355.5
	Other (income) expense – net	**62.5**	(77.4)	**61.2**	(51.6)
	Total segment costs and expenses	**3,324.0**	2,563.9	**11,257.6**	11,055.6
	General corporate expenses	**48.6**	35.3	**154.9**	119.8
OPERATING INCOME (LOSS)	Power	**(46.5)**	(50.8)	**(236.8)**	86.5
	Gas Pipeline	**85.5**	148.0	**542.2**	557.6
	Exploration & Production	**200.5**	67.7	**568.4**	223.9
	Midstream Gas & Liquids	**102.9**	247.0	**446.6**	552.2
	Other	**9.7**	(11.6)	**5.6**	(14.5)
	General corporate expenses	**(48.6)**	(35.3)	**(154.9)**	(119.8)
	Total operating income	**303.5**	365.0	**1,171.1**	1,285.9
	Interest accrued	**(176.4)**	(171.5)	**(671.7)**	(834.4)
	Interest capitalized	**2.9**	1.0	**7.2**	6.7
	Investing income (loss)	**(21.2)**	16.8	**23.7**	48.0
	Early debt retirement costs	**(0.4)**	(29.7)	**(0.4)**	(282.1)
	Minority interest in income of consolidated subsidiaries	**(8.9)**	(5.4)	**(25.7)**	(21.4)
	Other income – net	**14.6**	7.5	**27.1**	21.8
	Income from continuing operations before income taxes and cumulative effect of change in accounting principle	**114.1**	183.7	**531.3**	224.5
	Provision for income taxes	**45.3**	88.2	**213.9**	131.3
	Income from continuing operations	**68.8**	95.5	**317.4**	93.2
	Income (loss) from discontinued operations	**(0.3)**	(22.1)	**(2.1)**	70.5
	Income before cumulative effect of change in accounting principle	**68.5**	73.4	**315.3**	163.7
	Cumulative effect of change in accounting principle	**(1.7)**	—	**(1.7)**	—
	Net income applicable to common stock	**$ 66.8**	$ 73.4	**$ 313.6**	$ 163.7
EARNINGS (LOSS) PER SHARE	Basic earnings (loss) per common share:				
	Income from continuing operations	**$ .12**	$ .17	**$ .55**	$ .18
	Income (loss) from discontinued operations	—	(.04)	—	.13
	Income before cumulative effect of change in accounting principle	**.12**	.13	**.55**	.31
	Cumulative effect of change in accounting principle	—	—	—	—
	Net income	**$ .12**	$ .13	**$ .55**	$ .31
	Diluted earnings (loss) per common share:				
	Income from continuing operations	**$ .11**	$ .17	**$ .53**	$ .18
	Income (loss) from discontinued operations	—	(.04)	—	.13
	Income before cumulative effect of change in accounting principle	**.11**	.13	**.53**	.31
	Cumulative effect of change in accounting principle	—	—	—	—
	Net income	**$ .11**	$ .13	**$ .53**	$ .31

See accompanying notes.

1. BASIS OF PRESENTATION

Discontinued operations

The following are presented as discontinued operations in our Consolidated Statement of Operations:

- Refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment;
- Straddle plants in western Canada, previously part of the Midstream segment.

Unless indicated otherwise, the information in the Notes to Consolidated Statement of Operations relates to our continuing operations.

Cumulative effect of change in accounting principle

In March 2005, the Financial Accounting Standards Board (FASB) issued Interpretation 47, "Accounting for Conditional Asset Retirement Obligations – an interpretation of FASB Statement No. 143". The Interpretation clarifies that the term "conditional asset retirement" as used in Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations," refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

We adopted the Interpretation on December 31, 2005, and as a result, we recorded a cumulative effect of change in accounting principle of $1.7 million (net of $1 million of taxes).

2. HEDGE ACCOUNTING – POWER SEGMENT

As a result of our past intent to exit the Power business, our Power segment did not previously qualify for hedge accounting. Therefore, we reported changes in the forward fair value of our derivative contracts in earnings as unrealized gains or losses. However, with the decision to retain the business, Power became eligible for hedge accounting under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and elected hedge accounting beginning October 1, 2004, on a prospective basis for certain qualifying derivative contracts. Under cash flow hedge accounting, to the extent that the hedges are effective, prospective changes in the forward fair value of the hedges are reported as changes in other comprehensive income in the equity section of the balance sheet, and then reclassified to earnings when the underlying hedged transactions (i.e. power sales and gas purchases) affect earnings.

3. SEGMENT REVENUES AND PROFIT (LOSS)

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge. Other primarily consists of corporate operations and certain continuing operations that were included within the previously reported International and Petroleum Services segments.

We currently evaluate performance based on segment profit (loss) from operations, which includes segment revenues from external and internal customers, operating costs and expenses, depreciation, depletion and amortization, equity earnings (losses) and income (loss) from investments, including impairments related to investments accounted for under the equity method. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

During 2004, Power was party to intercompany interest rate swaps with the corporate parent, the effect of which is included in Power's segment revenues and segment profit (loss) as shown in the reconciliation within the following tables. We terminated all interest-rate derivatives in the fourth quarter of 2004.

The majority of energy commodity hedging by certain of our business units is done through intercompany derivatives with Power which, in turn, enters into offsetting derivative contracts with unrelated third parties. Power bears the counterparty performance risks associated with the unrelated third parties. External revenues of our Exploration & Production segment includes third-party oil and gas sales, more than offset by transportation expenses and royalties due third parties on intercompany sales.

3. Segment revenues and profit (loss) (continued)

(millions)	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids	Other	Eliminations	Total
Three months ended December 31, 2005							
Segment revenues:							
External	**$2,510.1**	**$365.6**	**$ (81.3)**	**$878.1**	**$ 3.6**	**$ —**	**$3,676.1**
Internal	**276.6**	**9.1**	**501.5**	**12.8**	**4.2**	**(804.2)**	**—**
Total segment revenues	**$2,786.7**	**$374.7**	**$420.2**	**$890.9**	**$ 7.8**	**$(804.2)**	**$3,676.1**
Segment profit (loss)	**$ (69.4)**	**$ 92.8**	**$206.4**	**$112.4**	**$(30.3)**	**$ —**	**$ 311.9**
Less:							
Equity earnings (losses)	**0.1**	**7.3**	**5.9**	**9.2**	**(2.0)**	**—**	**20.5**
Income (loss) from investments	**(23.0)**	**—**	**—**	**0.3**	**(38.0)**	**—**	**(60.7)**
Segment operating income (loss)	**$ (46.5)**	**$ 85.5**	**$200.5**	**$102.9**	**$ 9.7**	**$ —**	**352.1**
General corporate expenses							**(48.6)**
Consolidated operating income							**$ 303.5**
Three months ended December 31, 2004							
Segment revenues:							
External	$1,784.8	$345.7	$ (27.7)	$859.2	$ 2.2	$ —	$2,964.2
Internal	256.7	5.6	241.8	7.9	4.3	(516.3)	—
Total segment revenues	2,041.5	351.3	214.1	867.1	6.5	(516.3)	2,964.2
Less intercompany interest rate swap income	2.9	—	—	—	—	(2.9)	—
Total revenues	$2,038.6	$351.3	$214.1	$867.1	$ 6.5	$(513.4)	$2,964.2
Segment profit (loss)	$ (44.4)	$156.8	$ 70.9	$235.7	$(21.0)	$ —	$ 398.0
Less:							
Equity earnings (losses)	3.5	8.8	3.2	5.5	(9.3)	—	11.7
Loss from investments	—	—	—	(16.8)	(.1)	—	(16.9)
Intercompany interest rate swap income	2.9	—	—	—	—	—	2.9
Segment operating income (loss)	$ (50.8)	$148.0	$ 67.7	$247.0	$(11.6)	$ —	400.3
General corporate expenses							(35.3)
Consolidated operating income							$ 365.0

Notes to Consolidated Statement of Operations (continued)
(UNAUDITED)

3. SEGMENT REVENUES AND PROFIT (LOSS) (continued)

(millions)	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids	Other	Eliminations	Total
Year ended December 31, 2005							
Segment revenues:							
External	**$ 8,192.5**	**$ 1,395.0**	**$ (201.6)**	**$ 3,187.6**	**$ 10.1**	**$ —**	**$ 12,583.6**
Internal	**901.4**	**17.8**	**1,470.7**	**45.1**	**17.1**	**(2,452.1)**	**—**
Total segment revenues	**$ 9,093.9**	**$ 1,412.8**	**$ 1,269.1**	**$ 3,232.7**	**$ 27.2**	**$ (2,452.1)**	**$ 12,583.6**
Segment profit (loss)	**$ (256.7)**	**$ 585.8**	**$ 587.2**	**$ 471.2**	**$ (105.0)**	**$ —**	**$ 1,282.5**
Less:							
Equity earnings (losses)	**3.1**	**43.6**	**18.8**	**23.6**	**(23.5)**	**—**	**65.6**
Income (loss) from investments	**(23.0)**	**—**	**—**	**1.0**	**(87.1)**	**—**	**(109.1)**
Segment operating income (loss)	**$ (236.8)**	**$ 542.2**	**$ 568.4**	**$ 446.6**	**$ 5.6**	**$ —**	**1,326.0**
General corporate expenses							**(154.9)**
Consolidated operating income							**$ 1,171.1**
Year ended December 31, 2004							
Segment revenues:							
External	$ 8,346.2	$ 1,345.0	$ (84.0)	$ 2,844.7	$ 9.4	$ —	$ 12,461.3
Internal	912.5	17.3	861.6	37.9	23.4	(1,852.7)	—
Total segment revenues	9,258.7	1,362.3	777.6	2,882.6	32.8	(1,852.7)	12,461.3
Less intercompany interest rate swap loss	(13.7)	—	—	—	—	13.7	—
Total revenues	$ 9,272.4	$ 1,362.3	$ 777.6	$ 2,882.6	$ 32.8	$ (1,866.4)	$ 12,461.3
Segment profit (loss)	$ 76.7	$ 585.8	$ 235.8	$ 549.7	$ (41.6)	$ —	$ 1,406.4
Less:							
Equity earnings (losses)	3.9	29.2	11.9	14.6	(9.7)	—	49.9
Loss from investments	—	(1.0)	—	(17.1)	(17.4)	—	(35.5)
Intercompany interest rate swap loss	(13.7)	—	—	—	—	—	(13.7)
Segment operating income (loss)	$ 86.5	$ 557.6	$ 223.9	$ 552.2	$ (14.5)	$ —	1,405.7
General corporate expenses							(119.8)
Consolidated operating income							$ 1,285.9

Notes to Consolidated Statement of Operations (continued)
(UNAUDITED)

4. ASSET SALES, IMPAIRMENTS AND OTHER ACCRUALS

Significant gains or losses from asset sales, impairments and other accruals included in other (income) expense-net within segment costs and expenses for the three months and the years ended December 31, 2005 and 2004, are as follows:

	(Income) Expense			
	Three months ended December 31,		Years ended December 31,	
(millions)	**2005**	2004	**2005**	2004
Power				
Accrual for litigation contingencies	**$ 68.7**	$ —	**$ 82.2**	$ —
Gas Pipeline				
Write-off of previously-capitalized costs	**—**	—	**—**	9.0
Exploration & Production				
Gain on sale of certain natural gas properties	**—**	—	**(29.6)**	—
Loss provision related to an ownership dispute	**—**	4.1	**—**	15.4
Midstream Gas & Liquids				
Impairment of Gulf Liquids assets	**—**	2.5	**—**	2.5
Arbitration award on a Gulf Liquids insurance claim dispute	**—**	(93.6)	**—**	(93.6)
Other				
Environmental accrual related to the Augusta refinery facility	**—**	11.8	**—**	11.8
Gain on sale of land	**(9.0)**	—	**(9.0)**	—

Power

Accrual for litigation contingencies. This accrual for the year ended December 31, 2005, includes a $77.2 million charge for agreements reached to substantially resolve exposure related to the inaccurate reporting of natural gas prices and volumes to an industry publication in 2002.

Midstream Gas & Liquids

Arbitration award on a Gulf Liquids insurance claim dispute. Winterthur International Insurance Company (Winterthur) issued policies to Gulf Liquids providing financial assurance related to construction contracts. After disputes arose regarding obligations under the construction contracts, Winterthur disputed coverage resulting in arbitration between Winterthur and Gulf Liquids. In July 2004, the arbitration panel awarded Gulf Liquids $93.6 million, plus interest of $9.6 million. Following the arbitration decision, Winterthur filed a petition to vacate the final award in the New York State court and Gulf Liquids filed a cross-petition to confirm the final award. Prior to the State court's ruling, Winterthur agreed to the terms of the award and on November 1, 2004, remitted the proceeds to us. As a result, we recognized total income of approximately $103 million related to the arbitration award in fourth-quarter 2004.

Other

Environmental accrual related to the Augusta refinery facility. As a result of information obtained in the fourth quarter of 2004 related to the Augusta refinery site, we accrued additional expense for completion of certain remediation work and other reasonably estimated net remediation costs.

Additional items

Costs and operating expenses within our Gas Pipeline segment for the year ended December 31, 2005 includes:

- An adjustment to reduce costs by $12.1 million to correct the carrying value of certain liabilities recorded in prior periods;
- Income from a liability reversal of $14.2 million associated with a favorable ruling involving adjustments to estimated gas purchase costs for operations in prior periods;
- A prior period charge of approximately $27.5 million related to accounting and valuation corrections for certain inventory items;
- An accrual of approximately $9.8 million for contingent refund obligations.

Selling, general and administrative expenses within our Gas Pipeline segment for the year ended December 31, 2005, includes:

- An adjustment to reduce costs by $5.6 million to correct the carrying value of certain liabilities recorded in prior periods;
- A $17.1 million reduction in pension expense for the cumulative impact of a correction of an error attributable to 2003 and 2004.

General corporate expenses for the year ended December 31, 2005, includes $13.8 million of expense in our Other segment related to the settlement of certain insurance coverage issues with an insurer that had underwritten portions of the fiduciary insurance applicable to our Employee Retirement Income Security Act litigation settlement and the directors and officers insurance applicable to our pending securities litigation.

Notes to Consolidated Statement of Operations (continued)
(UNAUDITED)

5. INVESTING INCOME (LOSS)

Investing income (loss) for the three months and the years ended December 31, 2005 and 2004, is as follows:

	Three months ended December 31,		Years ended December 31,	
(millions)	**2005**	2004	**2005**	2004
Equity earnings*	**$ 20.5**	$ 11.7	**$ 65.6**	$ 49.9
Loss from investments*	**(60.7)**	(16.9)	**(109.1)**	(35.5)
Impairments of cost-based investments	—	(5.1)	**(2.2)**	(28.5)
Interest income and other	**19.0**	27.1	**69.4**	62.1
Total	**$ (21.2)**	$ 16.8	**$ 23.7**	$ 48.0

*Item also included in segment profit (see Note 3).

Loss from investments for the year ended December 31, 2005, includes:

- An $87.2 million additional impairment of our investment in Longhorn Partners Pipeline L.P. (Longhorn), which is included in our Other segment. Of the total impairment, $38.1 million relates to fourth quarter.
- A $23 million fourth-quarter additional impairment of our equity interest in Aux Sable Liquids Products, L.P., which is included in our Power segment.

Loss from investments for the year ended December 31, 2004, includes:

- A $10.8 million impairment of our Longhorn investment;
- $6.5 million net unreimbursed Longhorn recapitalization advisory fees;
- A $16.9 million fourth-quarter impairment of our equity investment in Discovery Producer Services LLC, which is included in our Midstream segment.

Impairments of cost-based investments for the years ended December 31, 2005 and 2004 primarily include impairments of certain international investments.

6. EARLY DEBT RETIREMENT

Early debt retirement costs include premiums, fees and expenses related to the retirement of debt.

7. PROVISION FOR INCOME TAXES

We provide for income taxes using the asset and liability method as required by SFAS No. 109, “Accounting for Income Taxes.” During 2005, as a result of the reconciliation of our tax basis and book basis assets and liabilities, we recorded a $20.2 million tax benefit adjustment.

8. DISCONTINUED OPERATIONS

Income (loss) from discontinued operations in 2004 is composed of gains on the sales of the Canadian straddle plants and the Alaska refining, retail and pipeline operations of $189.8 million and $3.6 million, respectively, as well as $22 million in income from our Canadian straddles discontinued operation. Partially offsetting these are $153 million of charges to increase our accrued liability associated with certain Quality Bank litigation matters involving valuation methodologies for products transported on the Trans-Alaska Pipeline System.

9. RECENT ACCOUNTING STANDARDS

In December 2004, the FASB issued revised SFAS No. 123, “Share-Based Payment.” The Statement requires that compensation costs for all share-based awards to employees be recognized in the financial statements at fair value. The Statement, as issued by the FASB, was to be effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. However, in April 2005, the Securities and Exchange Commission adopted a new rule that delayed the effective date for revised SFAS No. 123 to the beginning of the fiscal year that begins after June 15, 2005. We intend to adopt the revised Statement on January 1, 2006.

On June 30, 2005, the Federal Energy Regulatory Commission issued an order, “Accounting for Pipeline Assessment Cost,” to be effective January 1, 2006. The order requires companies to expense certain assessment costs that we have historically capitalized. As a result of this order, we anticipate expensing approximately $27 million to $35 million in 2006 that previously would have been capitalized.

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

(UNAUDITED)

(Dollars in millions, except per-share amounts)	2004					2005				
	1st Qtr	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*
Income (loss) from continuing operations available to common stockholders	$ —	($18.5)	$ 16.2	$ 95.5	$ 93.2	$ 202.2	$ 40.7	$ 5.7	$ 68.8	$ 317.4
Income (loss) from continuing operations — diluted earnings (loss) per common share	$ —	($0.03)	$ 0.03	$ 0.17	$ 0.17	$ 0.34	$ 0.07	$ 0.01	$ 0.11	$ 0.53
Nonrecurring items:										
Power										
Accrual for a regulatory settlement (1)	—	—	—	—	—	4.6	—	—	—	4.6
Accrual for litigation contingencies (1)	—	—	—	—	—	—	13.1	0.4	68.7	82.2
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
Gas Pipeline										
Prior period liability corrections — TGPL	—	—	—	—	—	(13.1)	(4.6)	—	—	(17.7)
Prior period pension adjustment — TGPL	—	—	—	—	—	—	(17.1)	—	—	(17.1)
Write-off of previously-capitalized costs — idled segment of Northwest’s pipeline	—	9.0	—	—	9.0	—	—	—	—	—
Income from favorable ruling on FERC appeal (1999 Fuel Tracker)	—	—	—	—	—	—	—	(14.2)	—	(14.2)
Prior period inventory corrections — TGPL	—	—	—	—	—	—	—	—	27.5	27.5
Accrual of contingent refund obligation — TGPL	—	—	—	—	—	—	—	—	9.8	9.8
Total Gas Pipeline nonrecurring items	—	9.0	—	—	9.0	(13.1)	(21.7)	(14.2)	37.3	(11.7)
Exploration & Production										
Gain on sale of E&P properties	—	—	—	—	—	(7.9)	—	(21.7)	—	(29.6)
Loss provision related to an ownership dispute	—	11.3	—	4.1	15.4	0.3	—	—	—	0.3
Total Exploration & Production nonrecurring items	—	11.3	—	4.1	15.4	(7.6)	—	(21.7)	—	(29.3)
Midstream Gas & Liquids										
La Maquina depreciable life adjustment	—	—	6.4	1.2	7.6	—	—	—	—	—
Gain on sale of Louisiana Olefins assets	—	—	—	(9.5)	(9.5)	—	—	—	—	—
Gulf Liquids arbitration award (Winterthur)	—	—	—	(93.6)	(93.6)	—	—	—	—	—
Impairment of Discovery	—	—	—	16.9	16.9	—	—	—	—	—
Devils Tower revenue correction	—	(16.5)	16.5	—	—	—	—	—	—	—
Total Midstream Gas & Liquids nonrecurring items	—	(16.5)	22.9	(85.0)	(78.6)	—	—	—	—	—
Other										
Impairment of Longhorn	—	10.8	—	—	10.8	—	49.1	—	38.1	87.2
Write-off of capitalized project development costs	—	—	—	—	—	—	4.0	—	—	4.0
Augusta environmental reserve	—	—	—	11.8	11.8	—	—	—	—	—
Gain on sale of real property	—	—	—	—	—	—	—	—	(9.0)	(9.0)
Longhorn recapitalization fee	6.5	—	—	—	6.5	—	—	—	—	—
Total Other nonrecurring items	6.5	10.8	—	11.8	29.1	—	53.1	—	29.1	82.2
Nonrecurring items included in segment profit (loss)	6.5	14.6	22.9	(69.1)	(25.1)	(9.3)	44.5	(35.5)	158.1	157.8

Nonrecurring items below segment profit (loss)										
Impairment of cost-based investments (Investing income (loss) -Various)	—	—	15.7	2.3	18.0	—	—	—	—	—
Write-off of capitalized debt expense (Interest accrued — Corporate)	—	3.8	—	—	3.8	—	—	—	—	—
Premiums, fees and expenses related to the debt repurchase and debt tender offer										
(Other income (expense) — net — Corporate and Exploration & Production)	—	96.7	155.1	29.7	281.5	—	—	—	—	—
Gulf Liquids arbitration award (Winterthur) — interest income — (Investing income / loss) — Midstream)	—	—	—	(9.6)	(9.6)	—	—	—	—	—
Gain on sale of remaining interests in Seminole Pipeline and MAPL (Investing income / loss — Midstream)	—	—	—	—	—	—	(8.6)	—	—	(8.6)
Loss provision related to an ownership dispute — interest component (Interest accrued — Exploration & Production)	—	1.9	—	2.1	4.0	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
Legal fees associated with shareholder litigation (General corporate expenses — Corporate)	—	—	—	—	—	—	—	—	9.4	9.4
	—	102.4	170.8	24.5	297.7	2.7	(8.6)	18.8	9.4	22.3
Total nonrecurring items	6.5	117.0	193.7	(44.6)	272.6	(6.6)	35.9	(16.7)	167.5	180.1
Tax effect for above items (1)	2.5	44.8	74.1	(17.1)	104.3	(2.8)	10.7	(6.4)	48.0	49.5
Adjustment for nonrecurring excess deferred tax benefit	—	—	—	—	—	—	—	—	(20.2)	(20.2)
Recurring income (loss) from continuing operations available to common stockholders	$ 4.0	$ 53.7	$ 135.8	$ 68.0	$ 261.5	$ 198.4	$ 65.9	($ 4.6)	$ 168.1	$ 427.8
Recurring diluted earnings (loss) per common share	$ 0.01	$ 0.10	$ 0.26	$ 0.12	$ 0.49	$ 0.33	$ 0.11	($ 0.01)	$ 0.28	$ 0.72
Weighted-average shares — diluted (thousands)	519,485	521,698	529,525	586,497	535,611	599,422	578,902	580,735	609,106	605,847

(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.

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.

Non-GAAP Utility Statement:

This press release includes certain financial measures, EBITDA, 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. 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, 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. Previously the Company did not qualify for hedge accounting with respect to its Power segment as a result of the Company's stated intent to exit the Power business. The Company ceased efforts to market the sale of Power during the third quarter 2004, and now qualifies 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 reported earnings 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.

Adjustment to remove MTM impact

Dollars in millions except for per share amounts

	2005				
	1Q	2Q	3Q	4Q	Year
Recurring income (loss) from cont. ops available to common shareholders	**$ 198**	**$ 67**	**$ (5)**	**$ 168**	**$ 428**
Recurring diluted earnings per common share	**$ 0.33**	**$ 0.11**	**$ (0.01)**	**$ 0.28**	**$ 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**	**$ 101**	**$ 125**	**$ 154**	**$ 513**
Recurring diluted earnings per share after MTM adj.	**$ 0.22**	**$ 0.17**	**$ 0.22**	**$ 0.26**	**$ 0.86**
weighted average shares — diluted (thousands)	599,422	578,902	580,735	609,106	605,847

	2004				
	1Q	2Q	3Q	4Q	Year
Recurring income from cont. ops available to common shareholders	**$ 4**	**$ 54**	**$ 136**	**$ 68**	**$ 261**
Recurring diluted earnings per common share	**$ 0.01**	**$ 0.10**	**$ 0.26**	**$ 0.12**	**$ 0.49**
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	(24)	(70)	(187)	(23)	(304)
Add realized gains/losses from MTM previously recognized	136	11	45	(6)	186
Total MTM adjustments	112	(59)	(142)	(29)	(118)
Tax effect of total MTM adjustments	44	(23)	(55)	(11)	(46)
After tax MTM adjustments	68	(36)	(87)	(17)	(72)
Recurring income from cont. ops available to common shareholders after MTM adjust.	**$ 72**	**$ 18**	**$ 49**	**$ 51**	**$ 190**
Recurring diluted earnings per share after MTM adj.	**$ 0.14**	**$ 0.03**	**$ 0.09**	**$ 0.09**	**$ 0.35**
weighted average shares — diluted (thousands)	519,485	521,698	529,525	586,497	535,611

Exhibit 99.2

Williams 2005
4th Quarter Earnings

February 28, 2006

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;
- 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 than 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.

Oil & 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.

2005 Review

Steve Malcolm
Chairman, President & CEO

Overview

2005 Headlines

- Key earnings measure more than doubles
- Generated $1.45 billion net cash from operations
- Production increases dramatically
- Took steps to accelerate reserves development
- Successful launch of master limited partnership
- Significant progress in resolving legacy issues

What you'll hear about 2005

- **E&P growing – production, reserves, profits**
  - Recurring results up 122%
  - U.S. production up 18% -- mostly via drill bit
  - 277% reserves replacement with >99% success rate
  - Total proved reserves 3.6 Tcfe
  - Piceance Highlands shows promise
- **Midstream sustains '04 record high; gears up for more growth**
  - Strength in the face of two hurricanes
  - Brings new deepwater volumes on line
  - Commits to expand capacity in Rockies
- **Gas Pipeline customer demand supports growth**
  - Growth strengthens competitive position
  - Sets delivery record again
  - Rate case preparation begins
- **Power reduces risk**
  - Executes additional mid-term deals
  - Generates positive cash flow

What you'll hear about 2006 and beyond

- Expect to grow key earnings measure over 3-year horizon
- Opportunity rich
  - Significant reserves for development
  - Sizable growth projects in gathering and processing
  - Stable of expansions that strengthen gas pipelines' competitive position
  - Demand growth in key areas should drive more hedging of power portfolio
- Investing in value growth
  - Committed more than $5 billion in capital projects
  - Weighting capital toward E&P
  - Opportunities expected to add CapEx for Midstream
  - Expect to increase segment profit nearly 50% by 2008
  - Continued improvement in debt-to-cap ratio

Williams

Financial Results and 2006 Outlook

Don Chappel
CFO

Consolidated

Financial Results

Dollars in millions (except per share amounts)	4th Qtr 2005	4th Qtr 2004	Year 2005	Year 2004
Income from Continuing Operations	$69	$95	$318	$93
Income (Loss) from Discontinued Operations	-	(22)	(2)	71
Cumulative effect of change in accounting principle	(2)	-	(2)	-
Net Income	$67	$73	$314	$164
Net Income/Share	$0.11	$0.13	$0.53	$0.31
Recurring Income from Cont. Ops./Share	$0.28	$0.12	$0.72	$0.49
Recurring Income from Continuing Operations After MTM Adjustments/Share	$0.26	$0.09	$0.86	$0.35

A more detailed schedule reconciling income (loss) 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.

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Recurring Income from Continuing Operations

Dollars in millions (except per share amounts)	4th Qtr 2005	4th Qtr 2004	Year 2005	Year 2004
Income from Continuing Operations	$69	$95	$318	$93
Nonrecurring Items				
Accrual for Regulatory & Litigation Contingencies/Settlements	78	-	96	-
Impairments/Losses/Write-offs	61	31	119	70
Expense related to prior periods	28	4	-	15
Gain on Sale of Assets	(9)	(10)	(47)	(10)
Debt Retirement Expense	-	30	-	282
Insurance Arbitration Award	-	(103)	-	(103)
Other - Net	9	4	12	18
Total nonrecurring	167	(44)	180	272
Tax Effect of Adjustments	48	(17)	50	104
Adjustment for nonrecurring excess deferred tax benefit	(20)	-	(20)	-
Recurring Income from Continuing Operations Available to Common	$168	$68	$428	$261
Recurring Income from Continuing Operations/Share	$0.28	$0.12	$0.72	$0.49

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.

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Recurring Income from Continuing Operations After Mark-to-Market Adjustments

Dollars in millions (except per share amounts)	4th Qtr 2005	4th Qtr 2004	Year 2005	Year 2004
Recurring Income from Continuing Ops. Available to Common	$168	$68	$428	$261
Recurring Diluted Earnings per Common Share	$0.28	$0.12	$0.72	$0.49
Mark-to-Market (MTM) adjustments for Power:				
Reverse forward unrealized MTM (gains) losses	(70)	(23)	(172)	(304)
Add realized gains from MTM previously recognized	48	(6)	310	186
Total MTM adjustments	(22)	(29)	138	(118)
Tax Effect of Total MTM Adjustments	(8)	(11)	53	(46)
After-tax MTM Adjustments	(14)	(17)	85	(72)
Recurring income from Continuing Operations Avail. To Common Shareholders After MTM Adjustments	$154	$51	$513	$190
Recurring Diluted Earnings Per Share After MTM adjustments	$0.26	$0.09	$0.86	$0.35

Note:
Adjustments have been made to reverse estimated forward unrealized 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 MTM adjustments is available on Williams' website at www.williams.com.

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Liquidity at Year-End 2005

Dollars in millions

Cash and cash equivalents		$ 1,597
Other current securities		123
Less:		
Subsidiary & international cash	$ 240	
Customer margin deposits payable	321	(561)
Available unrestricted cash		1,159
Available revolver capacity		961
Total Liquidity		**$ 2,120**

Business Unit Results

Exploration & Production

Ralph Hill
Senior Vice President

Williams

Segment Profit

Dollars in millions	4th Qtr 2005	4th Qtr 2004	Year 2005	Year 2004
Segment Profit	**$206**	**$71**	**$587**	**$236**
Nonrecurring:				
Ownership Issue	-	4	-	15
Gain on sale of assets	-	-	(29)	-
Recurring Segment Profit	**$206**	**$75**	**$558**	**$251**

- **4Q04 to 4Q05 financial highlights include:**
  - Volume increase of 14%
  - Domestic net realized price increase of 79%
  - Recurring segment profit increase of 175%

- **$173 million negative hedge impact in 4Q05, $359 million year to date**

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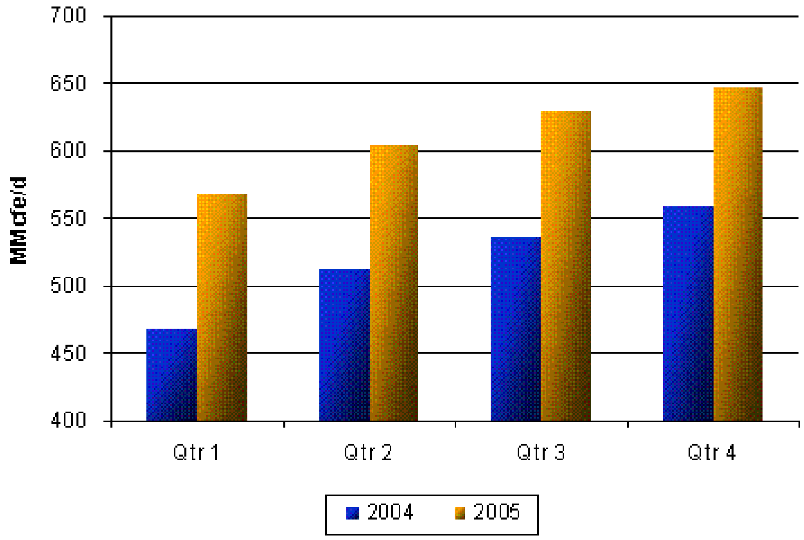
Exploration & Production

Strong Domestic Production Growth of 18%



- 2005 Domestic production grew 18% or 93 MMcfe/d over 2004
- 15 - 20% production growth projected for 2006

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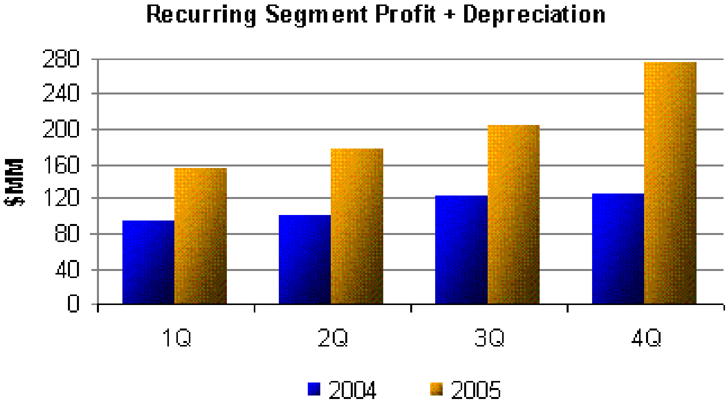
Exploration & Production

2005 Accomplishments and Current Update

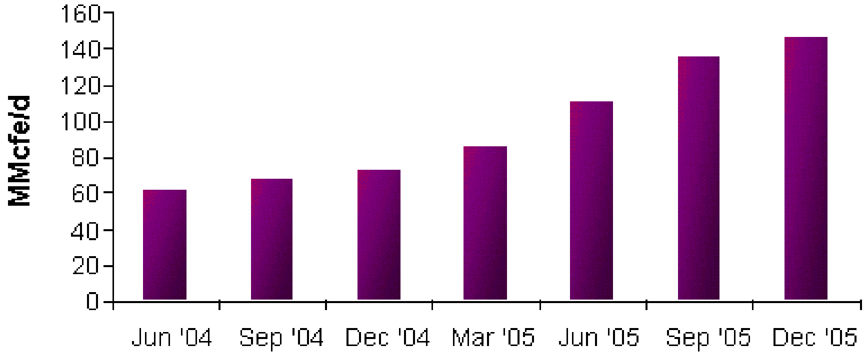
- Impressive domestic volume growth of 18%
- Domestic reserves replacement of 277%
- Successfully recruited talent, increased staff 34%
- Big George production continues to climb
- 2 rigs operating in Barnett Shale
- Mature San Juan basin production increased 4%
- Record International profit fueled by 8% volume increase and crude price
- 19 rigs operating in Piceance as of February 2006
- 2nd H&P rig on site
- Piceance Highlands production reaches 18 MMcfe/d



Powder River - Big George Coal Area

- Up 74 MMcfe/d or 101% over a year ago
- Up 11 MMcfe/d or 9% sequentially
- Big George production is driving basin growth

Williams' Big George Gross Production



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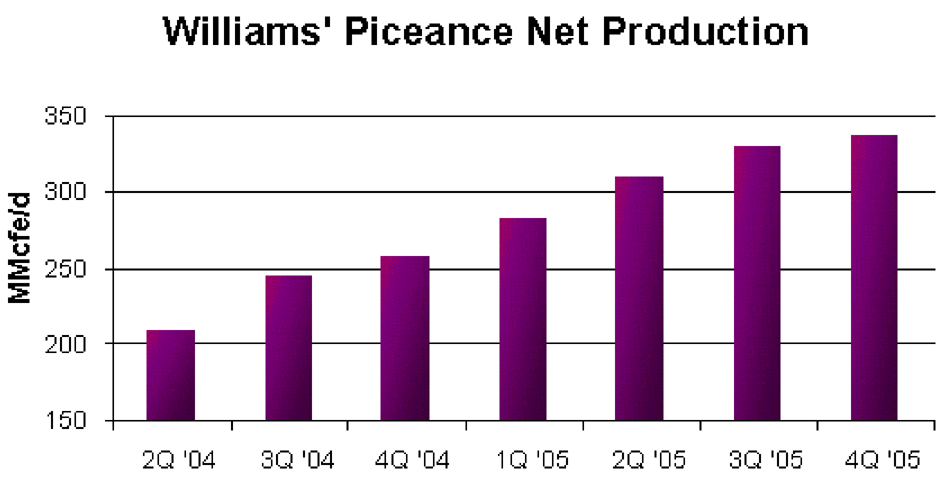
Exploration & Production

Piceance Production Growth

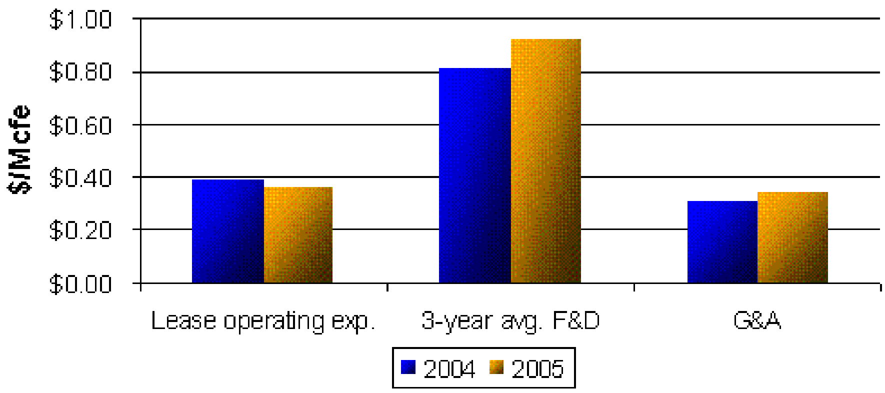
- Up 88 MMcfe/d or 34% over a year ago
- Up 17 MMcfe/d or 5% sequentially



Exploration & Production

An Industry Leader in 2005 Cost Performance

- Lease operating expense of $0.36 / Mcfe
- 3-year average F&D cost of $0.92 / Mcfe
- G&A cost of $0.34 / Mcfe



Strong 2005 Reserves Performance

- Total proved reserves 3.6 Tcfe
- Domestic proved reserves up 13.3% to 3.4 Tcfe
- 277% domestic reserves replacement
- 99% success rate
- Moved 603 Bcfe to proved

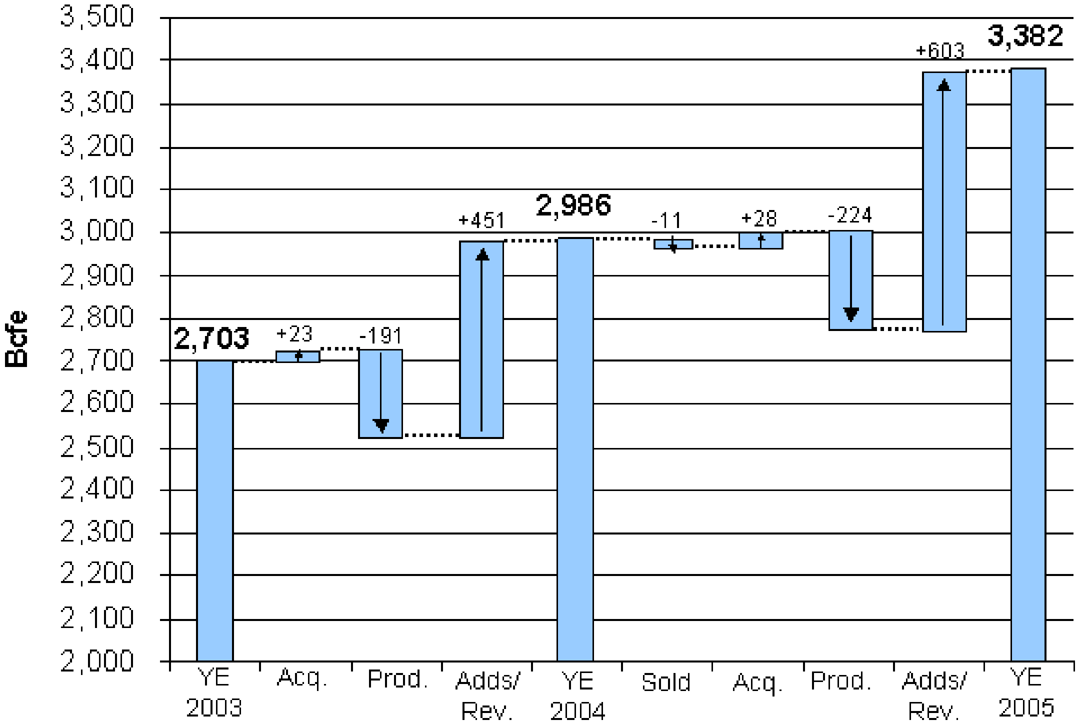
Transfers of Probable to Proved Reserves (Bcfe)

	2003	2004	2005	Total
Total for retained basins	408	451	603	1,462

Williams

Exploration & Production

Domestic Proved Reserves Reconciliation



Exploration & Production

Piceance Highlands Projects Summary

Project Area	Net Acres	Estimated Gross Potential Locations	Estimated Net Potential Reserves (Bcfe)	2004 Wells	2005 Wells	Projected 2006 Wells
Trail Ridge (10-acre density)	21,112	1,500	1,500 – 2,000	3	12	20
Ryan Gulch (40-acre density)	16,078	800	700	3	5	15
Allen Point (40-acre density)	6,240	200	140	0	6	9
Red Point (10-acre density)	1,908	190	200	0	2	10
Total	**45,338**	**2,690**	**2,540 – 3,040**	**6**	**25**	**54**

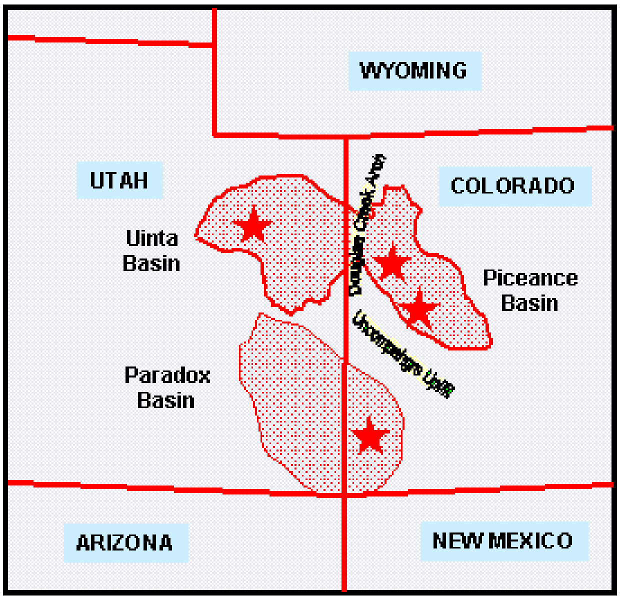
Piceance Highlands – Results To Date

Project Area	Wells Drilled	Average 30 Day Rate / Completed Well (MMcfe/d)	Expected EUR* Range (Bcfe/well)
Trail Ridge	15	1.1	1.2 - 1.6
Ryan Gulch	8	1.2	1.2 - 2.0
Allen Point	6	1.1	1.2 - 1.6
Red Point	2	1.2	1.2 - 1.4

* Estimated Ultimate Recovery

Exploration & Production

New E&P Opportunities



- Piceance Basin: Shale Ridge Prospect (Dakota Sandstone play)
  - Leased 13,904 gross/net acres
  - 100% WI; 87.5% NRI
  - 10-year lease term
- Piceance Basin: Pending Williams Fork Project
  - 2006 drill-to-earn commitment
  - 11,000 net acres
- Uinta Basin: Sterling Hollow Prospect (Mesaverde tight gas sands play)
  - Leased 39,911 contiguous gross/net acres
  - 100% WI; 87.5% NRI
  - 10-year lease term
- Paradox Basin: Resource Play (Ismay Group shales and tight gas sandstones)
  - Leased 30,608 gross/net acres
  - 100% WI; 87.5% NRI
  - 5-year and 10-year terms on leases

Exploration & Production

Williams is a Leader in US Gas Production Growth through the Drill Bit

Top 20 U.S. Gas Producers
(sorted by 2005 MMcfd)

	Company	MMcfd 2004	MMcfd 2005	Percent change
1	BP	2,748	2,547	-7.3%
2	ExxonMobil	1,947	1,739	-10.7%
3	Chevron	1,873	1,634	-12.8%
4	Devon	1,642	1,521	-7.4%
5	ConocoPhillips	1,223	1,212	-0.9%
6	Chesapeake	880	1,157	31.5%
7	Shell	1,332	1,150	-13.7%
8	Anadarko	1,363	1,136	-16.7%
9	EnCana	869	1,095	26.0%
10	XTO	835	1,033	23.7%
11	Kerr-McGee	836	962	15.1%
12	Burlington	908	950	4.6%
13	Dominion	893	794	-11.2%
14	EOG	631	718	13.8%
15	El Paso (1)	790	714	-9.6%
16	Williams	519	612	17.9%
17	Apache	647	598	-7.6%
18	Marathon	631	578	-8.5%
19	Occidental	507	553	9.1%
20	Newfield	540	523	-3.1%
	TOTAL	21,614	21,225	-1.8%

Top 20 U.S. Gas Producers
(sorted by Percent Change)

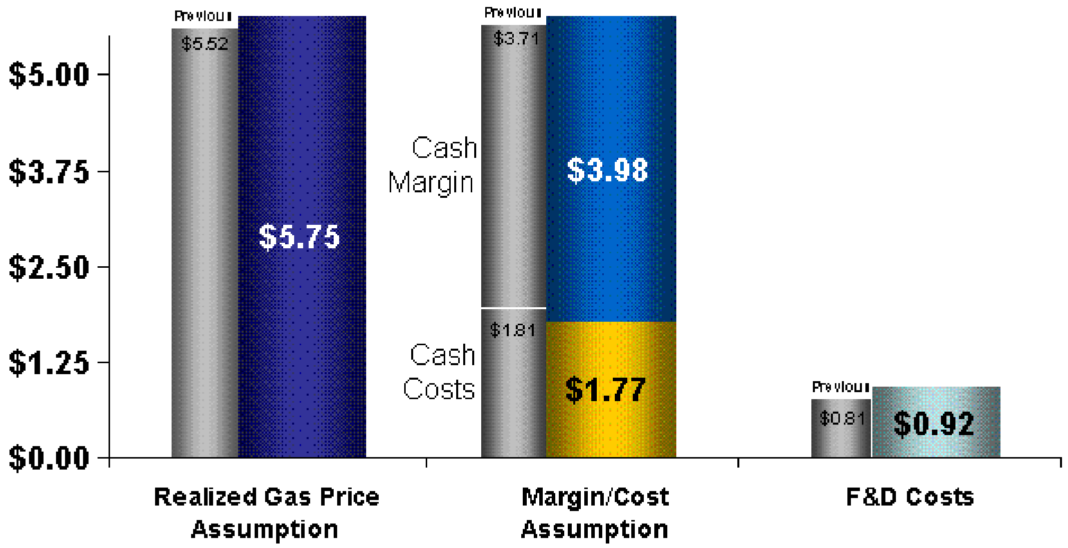
	Company	MMcfd 2004	MMcfd 2005	Percent change
1	Chesapeake	880	1,157	31.5%
2	EnCana	869	1,095	26.0%
3	XTO	835	1,033	23.7%
4	Williams	519	612	17.9%
5	Kerr-McGee	836	962	15.1%
6	EOG	631	718	13.8%
7	Occidental	507	553	9.1%
8	Burlington	908	950	4.6%
9	ConocoPhillips	1,223	1,212	-0.9%
10	Newfield	540	523	-3.1%
11	BP	2,748	2,547	-7.3%
12	Devon	1,642	1,521	-7.4%
13	Apache	647	598	-7.6%
14	Marathon	631	578	-8.5%
15	El Paso (1)	790	714	-9.6%
16	ExxonMobil	1,947	1,739	-10.7%
17	Dominion	893	794	-11.2%
18	Chevron	1,873	1,634	-12.8%
19	Shell	1,332	1,150	-13.7%
20	Anadarko	1,363	1,136	-16.7%
	TOTAL	21,614	21,225	-1.8%

(1) US production given on a natural gas equivalent basis, natural gas only production not available.
Source: Publicly reported data from EvaluateEnergy.com, press releases, and company websites

Exploration & Production

Cash Margin Analysis

3-Year Average (2006-08)



Reflective of core basins

- *$5.75 is after hedging and includes average basin market price of $6.75 before hedging*
- *Cash costs include LOE, G&A, taxes and gathering*
- *F&D costs include acquisition and development expenditures/proved reserves ('03-'05 average)*

Exploration & Production

2006-08 Guidance

Dollars in millions (except price assumptions)	2006	2007	2008
Segment profit	$650 - 725	$775 - 900	$950 - 1,100
Annual DD&A	335 - 375	425 - 475	475 - 525
Segment profit + DD&A	$985 - 1,100	$1,200 - 1,375	$1,425 - 1,625
Capital spending	$950 - 1,050	$950 - 1,050	$1,000 - 1,150
Production (MMcfe/d)	750 - 825	875 - 975	950 - 1,100
Unhedged Price Assumption, ($/Mcf)			
NYMEX	$8.50	$7.00	$7.00
Average San Juan/Rockies Price	$7.32	$6.09	$6.10

Note: 2006-08 hedge information included in Appendix
Note: If guidance has changed, previous guidance from 11/3/2005 is shown in italics directly below

Key Points

- **An industry leader in production growth, cost efficiencies and reserves replacement**
- Diligently managing increasing industry costs
- Strategy remains rapid development of our premier drilling inventory
- Delivering meaningful volume growth through expanded development drilling activity. Piceance is primary growth driver
- Long history of high drilling success, low finding costs
- Short time cycle investments, fast cash returns
- Long-term repeatable drilling inventory of significant proved undeveloped, probables, and possibles
- New opportunities contributing
- Experienced and talented work force

Midstream

Alan Armstrong
Senior Vice President

Midstream

Segment Profit

Dollars in millions	4th Qtr 2005	4th Qtr 2004	Year 2005	Year 2004
Segment Profit	**$112**	**$236**	**$471**	**$550**
Nonrecurring:				
Depreciable Life Adjustment	-	1	-	7
Gain on Asset Sales	-	(9)	-	(9)
Insurance Arbitration Award	-	(94)	-	(94)
Impairments	-	17	-	17
Recurring Segment Profit	**$112**	**$151**	**$471**	**$471**

- **4Q04 to 4Q05 financial highlights include:**
  - Significantly lower per unit NGL frac spreads
  - Lower operating expenses
  - Increased G&P fee revenue

Midstream

4th Quarter and 2005 Highlights

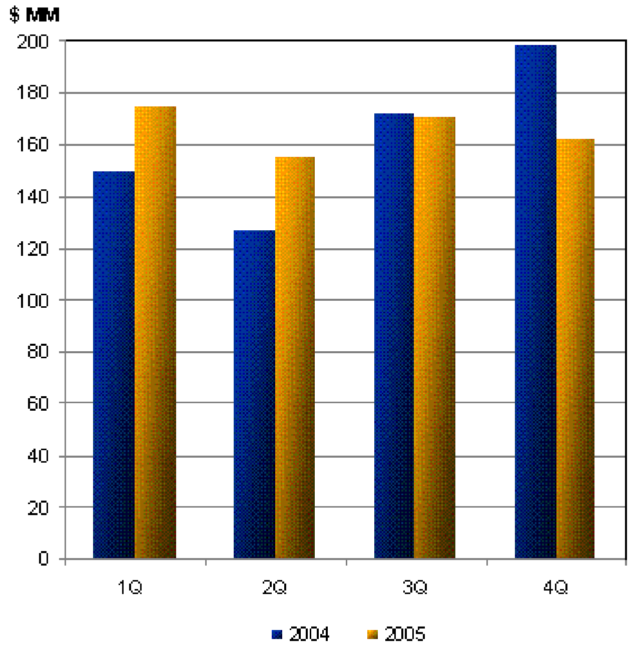
2005

- Opal TXP-5 construction commenced
- Construction of Tahiti and Blind Faith deepwater projects commenced
- Williams Partners L.P. (WPZ) successfully launched
- Hurricanes met with energetic response
- Sold $68MM in assets

4th Quarter

- Goldfinger and Triton production flowing on Devils Tower
- Significant progress on Overland Pass Pipeline project
- Opal TXP-4 acquisition

Recurring Segment Profit + Depreciation



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2006-08 Guidance

Dollars in millions	2006	2007	2008
Segment Profit	$400-500	$410-530	$440-580
Annual DD&A	190-200 *185-195*	200-210 *195-205*	210-220
Segment Profit + DDA	$590-700 *585-695*	$610-740 *590-720*	$650-800
Capital Spending [1]	$280-300 *230-250*	$230-270 *180-220*	$70-90

[1] **Major Growth Projects included in Guidance ($ Millions):**

Project Name – In Service Date	2006	2007	2008
Opal TXP IV (1Q 2006)	$30	-	-
Opal TXP V (2Q 2007)	50	$15	-
Blind Faith (3Q 2007)	90	85	-
Wamsutter Phase II (4Q 2007)	10	65	-

Note: If guidance has changed, previous guidance from 11/3/2005 is shown in italics directly below

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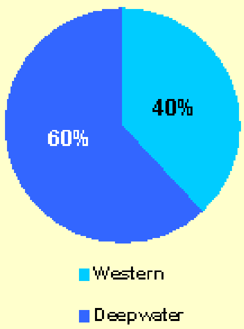
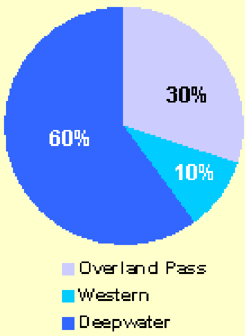
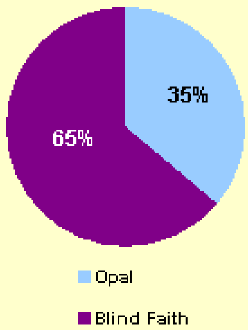
Significant Progress Made on Growth Projects

Devel. /Proposal Stage 2006 **2007 2008** Spending $200MM - 400MM	Under Negotiation 2006 **2007 2008** Spending $700MM– 900MM	Contracted/Approved **2006 2007** 2008 Spending $280MM
Not in Guidance	Western G&P Expansions ($75MM in guidance)	***In Guidance***
Western G&P Expansions	Overland Pass	Blind Faith
Deepwater Expansions	Deepwater Expansions ($30MM in guidance)	Opal TXP-V
		Opal TXP-IV







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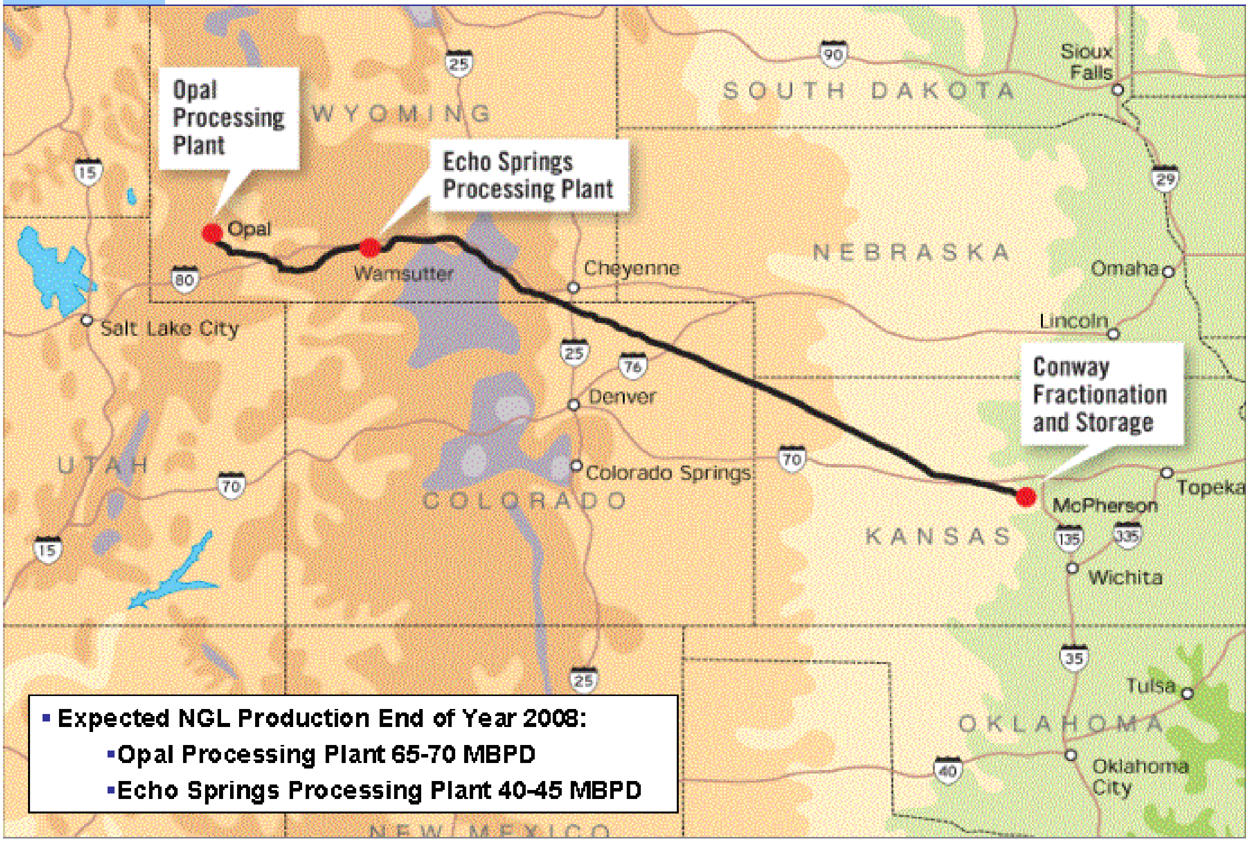
Overland Pass Pipeline Proposal



- Expected NGL Production End of Year 2008:
  - Opal Processing Plant 65-70 MBPD
  - Echo Springs Processing Plant 40-45 MBPD

Midstream

Key Points

- Another record year despite hurricanes and lower commodity margins
- Continued to generate excess free cash
  - Operating Cash Flow
  - MLP Proceeds
  - Asset sales
- Geographic diversification of processing assets mitigated decline in Mt. Belvieu frac spreads
- Significant progress on growth projects

Gas Pipeline

Phil Wright
Senior Vice President

Williams

Gas Pipeline

Segment Profit

Dollars in millions	4th Qtr 2005	4th Qtr 2004	Year 2005	Year 2004
Segment Profit	**$93**	**$157**	**$586**	**$586**
Nonrecurring:				
(Income)/expense related to prior periods	27	-	(8)	-
Accrual of contingent refund obligation	10	-	10	-
1999 Fuel Tracker adjustment	-	-	(14)	-
Write-off hydrostatic testing	-	-	-	9
Recurring Segment Profit	**$130**	**$157**	**$574**	**$595**

- **4Q04 to 4Q05 financial highlights include:**
  - Termination of Gray's Harbor contract - $5MM
  - Higher fuel and operating expenses - $10MM

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Gas Pipeline

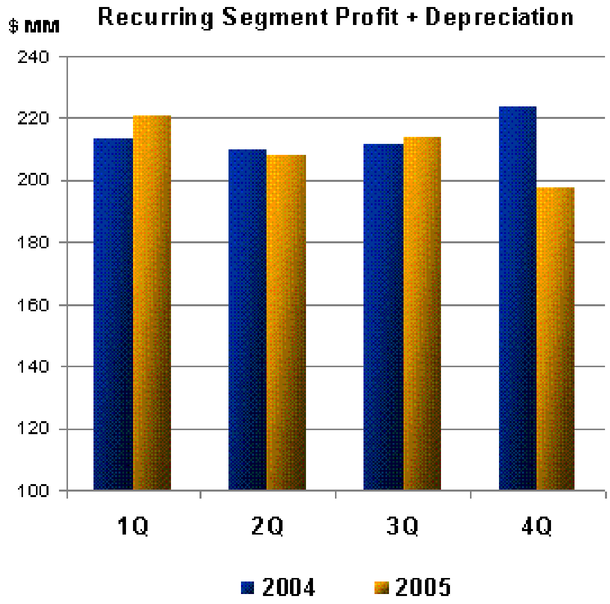
4th Quarter and 2005 Accomplishments

Transco:

- Central New Jersey project placed in-service
  - 105 MDth/d of firm transportation serving the northeast market
- Successful open season for Sentinel to serve northeast market
- Precedent agreements signed for Potomac Expansion
- FERC certificate application filed for Leidy to Long Island

Northwest:

- Successful open season for Parachute
  - FERC certificate application filed in Jan 2006



2006-08 Guidance

Dollars in millions	2006	2007	2008
Segment Profit	$475 - 520[1] *485 - 530*	$585 - 655	$590 - 665
Annual DD&A	280 - 300 *290 - 300*	290 - 310 *300 - 310*	295 - 315
Segment Profit + DDA	$755 - 820 *775 - 830*	$875 - 965 *885 - 965*	$885 - 980
Capital Spending	$710 - 785 *600 - 680*	$390 - 490 *300 - 390*	$410 - 510

[1] *Includes:*

- *Pipeline safety costs of approximately $27 million to $35 million due to new accounting rule that requires certain pipeline assessment costs that have historically been capitalized to be recorded as expense beginning in 2006*
- *Higher interest expense of $20 million at Gulfstream as a result of the October 2005 $850 million financing*

Note: If guidance has changed, previous guidance from 11/03/05 is shown in italics directly below

Gas Pipeline

2006-07 Capital Spending Detail

Dollars in millions	2006	2007	2008
Normal Maintenance/ Compliance	$340 - 405 *305 - 370*	$210 - 265 *180 - 235*	$180 - 260
NWP 26" Replacement	276	2	-
Expansion[1]	95 - 105 *20 - 35*	180 - 220 *120 - 155*	230 - 250
Total	$710 - 785 *600 - 680*	$390 - 490 *300 - 390*	$410 - 510

[1]**Major Growth Projects (in guidance):**	**2006**	**2007**	**2008**	**1st full yr Seg. Profit**
Parachute (In Service 1/07)	$50 - 60			$8
Leidy to Long Island (In Service11/07)	10 - 15	$85 - 100	$1 - 5	18
Potomac (In Service 11/07)	5 - 10	55 - 65	1 - 5	11
Sentinel (In Service 11/08)	10 - 15	35 – 45	195 - 205	41
Greasewood (In Service 11/08)			25 – 30	2 - 4

Note:

- Sum of ranges may not add due to rounding

- Ranges excludes AFUDC

Note: If guidance has changed, previous guidance from 11/03/05 is shown in italics directly below

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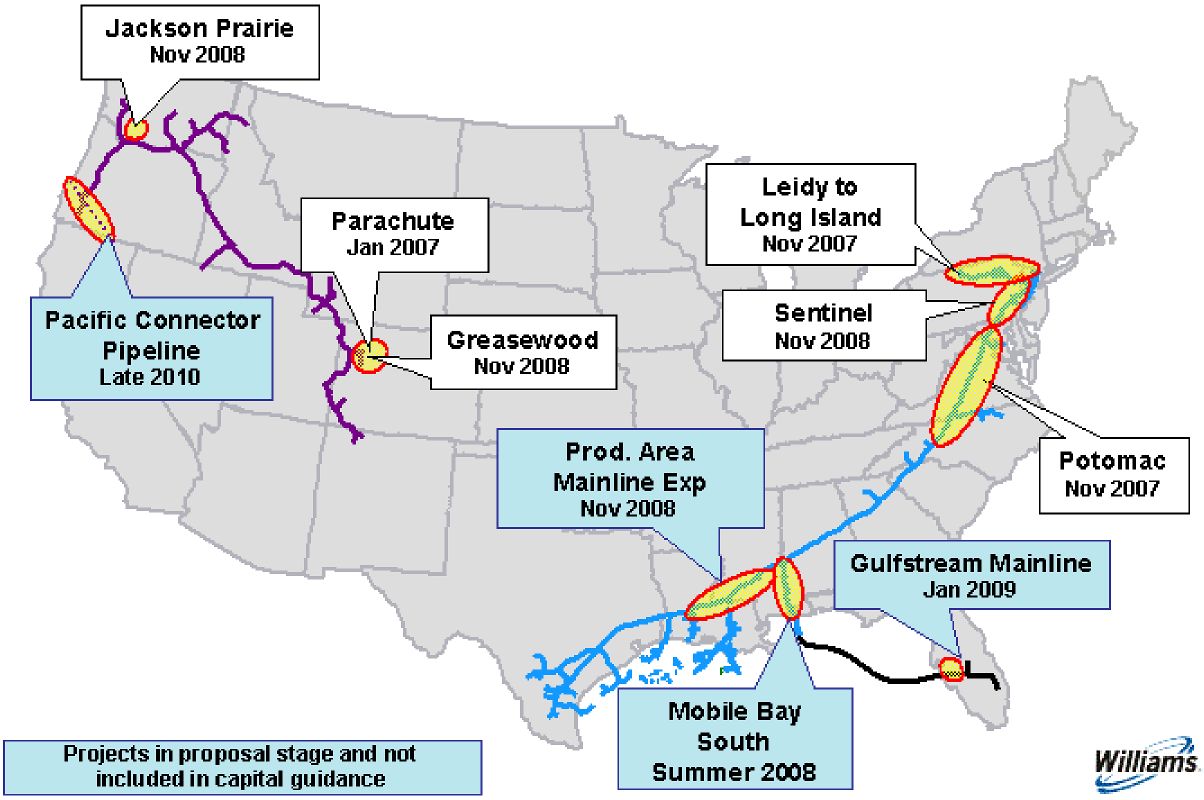
Growth Projects and Opportunities



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Gas Pipeline

Key Points

- 2005 another strong year
  - Strong cash flow provider
  - Operational excellence
    - Achieved new delivery records
    - Met customer demand through hurricane challenges
  - Customer focused
    - Meeting market demands with new growth projects
    - High rankings in customer satisfaction survey
- 2006 & forward
  - Anticipate additional new growth projects
  - Rate Case filings

Power

Bill Hobbs
Senior Vice President

Power

Segment Profit/(Loss)

Dollars in millions	4th Qtr 2005	4th Qtr 2004	Year 2005	Year 2004
Segment Profit/(Loss) Before MTM Adjustment	**($69)**	**($44)**	**($257)**	**$77**
Nonrecurring:				
Accrual for Regulatory & Litigation Contingencies/Settlements	69	-	87	-
Impairments, Losses, Write-offs	23	-	23	-
Expense Related to Prior Periods	-	-	7	-
Recurring Segment Profit/(Loss)	22	(44)	(140)	77
MTM Adjustment (Recurring)	(22)	(29)	138	(118)
Recurring Segment (Loss) After MTM Adjustment	-	($73)	($2)	($41)

Note: MTM Adjustments (recurring) excludes $12mm paid in 3Q05 for buyout of gas supply contract

Note: Might not sum due to rounding

Power

2005 - Segment Profit/(Loss) to Cash Flow From Operations

Dollars in millions	Commodity Power & NG	Working Capital/Other	2005
Segment Profit/(Loss) Before MTM Adjustments[1]	($147)	($110)	($257)
MTM Adjustments:			
Reverse Forward Unrealized MTM (Gains)	(172)		(172)
Add Realized Gains from MTM Previously Recognized[2]	298		298
Segment Profit/(Loss) after MTM Adjustments[3]	(21)	(110)	(131)
Total Working Capital Change	0	319	319
Power Segment CFFO	(21)	209	188
Est. Working Capital Used for Other Business Units	0	(61)	(61)
Power Segment Standalone CFFO	($21)	$148	$127

[1] Includes nonrecurring adjustments which decrease reported Segment Loss by $117 million, $110 million of which is included in the "Working Capital/Other" column. 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.

[2] Includes $12 million of nonrecurring loss from MTM Previously Recognized. Recurring MTM Adjustment is $138 million.

[3] Recurring Segment Profit/(Loss) After MTM is ($2)mm.

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Power

2006-08 Guidance

Dollars in millions	2006	2007	2008
Prior Guidance - Segment Loss before MTM Adj	**($225) - (125)**	**($180) - (30)**	
Est. Fwd Impact of 4Q05 MTM Earnings	**(11)**	**17**	
Change in Segment Loss Guidance	**(10)**	**20**	
New Guidance - Segment Loss before MTM Adj	**($235) - (135)** *(225) - (125)*	**($160) - (10)** *(180) - (30)*	**($150) - 0**
Estimated MTM Adjustments	**280** *270*	**210** *230*	**200**
Segment Profit after MTM Adj	**50 - 150**	**50 - 200**	**50 - 200**
Non-Recurring	--	--	--
Recurring Segment Profit after MTM Adjustment	**50 - 150**	**50 - 200**	**50 - 200**
Cash Flow from Operations [1]	**$50 - 150**	**$50 - 200** *0 - 200*	**$50 - 200**
Capital Expenditures	-	-	-

[1] 2006-2008 CFFO guidance assumes no changes in Working Capital. Changes in Working Capital are likely if future commodity prices are volatile or if counterparties exchange Letters of Credit for cash held by WMB. Payment of regulatory and litigation/settlement accruals are not included in CFFO guidance.

Note: If guidance has changed, previous guidance from 11/03/05 is shown in italics directly below

Power

2005 Contracts

Reducing Risk and Increasing Cash flow Certainty

Tolling Position	Region	Customer Type	MW's Sold	Term
AES 4000	West	Utility	843	May 06 - Dec 10
		Utility	668	Apr 07 - Dec 10
		Utility	487	Jan 06 - Dec 08
		Bank	100	Jan 08 - Dec 08
		Utility	688	Summer 05
CLECO - Evangeline	South Central	Utility	500	Jan 06 - Dec 09
		Utility	244	Summer 05
Tenaska - Lindsay Hill	Southeast	Coop	150	Jan 06 - Feb 06
Kinder Morgan - Jackson	Mid-Continent	Hedge Fund	100	Sept 05 - Dec 09
		Utility	250	Summer 05
AES - Ironwood	Northeast	Hedge Fund	100	Jan 05 - Dec 06
		Bank	100	July 05 - Jun 06
		Hedge Fund	250	Sept 05 - Dec 06
		Bank	250	Jan 06 - Dec 06
AES - Red Oak	Northeast	Coop	100	Jun-05 - May 06
		Hedge Fund	250	Sept 05 - Dec 06
		Bank	250	Jan 06 - Dec 06

Power

2006 Contracts

Reducing Risk and Increasing Cash flow Certainty

Tolling Position	Region	Customer Type	MW's Sold	Term
AES 4000	West	Utility	843	May 06 - Dec 10
		Utility	668	Apr 07 - Dec 10
		Utility	487	Jan 06 - Dec 08
		Bank	100	Jan 08 - Dec 08

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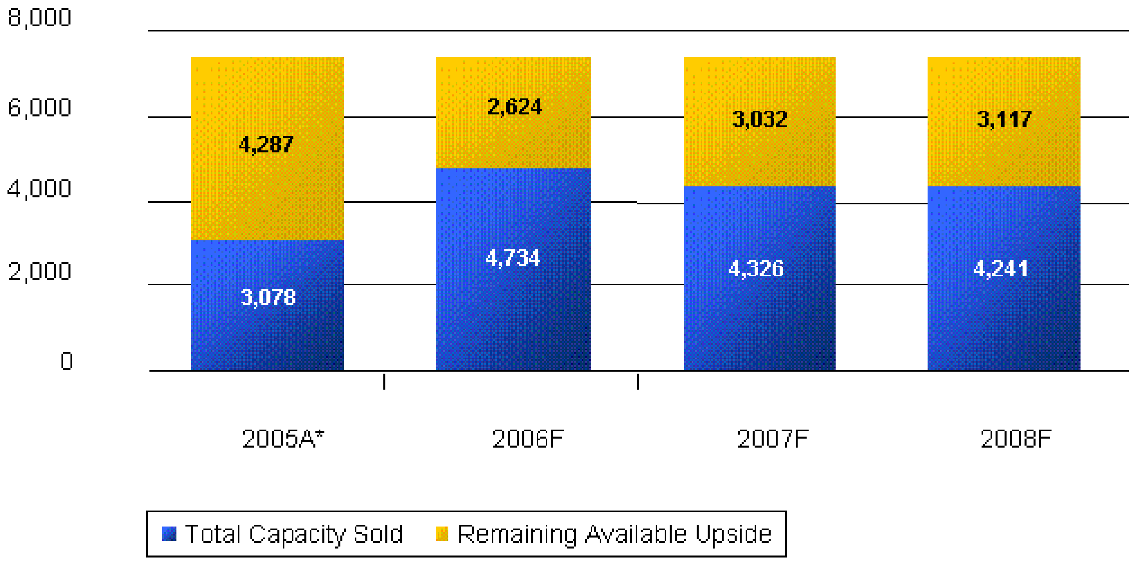
Capacity Sold by Year



*Note: 2005A based on hedged position @ 3/31/05 Tutorial Schedules.

Cash Flow Analysis

Estimated undiscounted dollars in millions

Power Portfolio *Actual vs. Forecast 2005*	**2005A**	**2005F**	**YTD Variance**	**2006F**	**2007F**	**2008F**
Tolling Demand Payment Obligations	($395)	($395)	$0	($398)	($402)	($407)
Hedged Cash Flows [2]	473 [1]	483	(90)	588	516	527
Merchant Cash Flows [3]		80		63	97	109
Total Cash Flows	$78	$168	($90)	$253	$211	$229
SG&A and Other	(209)	(75)	(134)	(85)	(85)	(85)
Working Capital & Other [4]	319	37	282	0	0	0
Estimated Power Segment Cash Flows	$188	$130	$58	$168	$126	$144

[1] 2005 Actual cash flows are realized from a combination of Hedged Cash Flows and Merchant Cash Flows and other risk management and trading activities.

[2] Forecasted Hedged Cash Flows represents (1) the estimated cash flows from hedges such as resale of tolls, heat rate options, full requirements contracts and fixed price power and gas contracts and (2) the estimated value of the tolling (spread option) cash flows associated with those hedges.

[3] Forecasted Merchant Cash Flows represents the tolling (spread option) cash flows which have not been hedged.

[4] Working Capital & Other changes are zero in future years, as they are not reasonably estimable.

Note: 2005 Forecast estimated as of 12/31/04. 2006 forward forecast estimated as of 12/31/05. Actual Cash Flows for 2005 includes impact of certain nonrecurring items. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

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2006 Forecast: Recurring Segment Profit/(Loss) After MTM Adjustments

Dollars in millions

2005 Recurring Segment Loss After MTM Adjustments	**$ (2) - (2)**
■ Estimated cash flows from new contracts executed in 2005	40 - 50
■ Current and forecasted improvement in markets	0 - 70
■ No unplanned plant outages & hurricanes forecasted	10 - 20
■ Other	2 - 12
2006 Estimated Segment Profit After MTM Adjustments	**$50 - 150**

Power

Key Points

- Positive CFFO for Power Segment and Power Standalone in 2005
- Recurring 2005 Segment Loss after MTM improves $39 million over 2004 levels despite record high gas prices, mild weather, hurricanes and unplanned outages
- Outlook for 2006 improves based upon strength of new contracts and improving market conditions
- Power remains focused on creating additional cash flow certainty, generating EVA and reducing risk in our portfolio
- Continued success closing new risk-reducing contracts

2006-08 Consolidated Outlook

Don Chappel
CFO

Consolidated

2006 Forecast Guidance

Dollars in millions, except per-share amounts	2006
Segment profit before MTM adjustment	**$1,240 - $1,580**
Net Interest Expense	(665) - (705)
Other (Primarily General Corp. Costs)	(90) - (120)
Pretax Income	485 - 755
Provision for Income Tax	(200) - (315)
Income from Continuing Ops	285 - 440
Income/(Loss) from Discontinued Ops	(5) - 0
Net Income	**$280 - 440**
Diluted EPS	**$0.46 - $0.72**
Recurring Income from Cont. Ops	**$303 - $458**
Diluted EPS – Recurring	**$0.50 - $0.75**
Diluted EPS – Recurring After MTM Adj. [1]	**$0.78 - $1.03**

[1] *Includes MTM adjustment of $280 million (pretax)*
Note: Fully diluted shares of 610 million

Consolidated

2006-08 Segment Profit After MTM Adj.

Dollars in millions	2006	2007	2008
Exploration & Production	$650 - 725	$775 - 900	$950 - 1,100
Midstream	400 - 500	410 - 530	440 - 580
Gas Pipeline	475 - 520 *485 - 530*	585 - 655	590 - 665
Power [1]	50 - 150	50 - 200	50 - 200
Other / Corp. / Rounding	(55) - (35) *(65) – (85)*	10 - (30)	(15) - 35
Total	$1,520 - 1,860 *1820*	$1,830 - 2,255	$2,015 - 2,580

[1] *Includes MTM adjustments for 2006-2008 of $280 million (pretax), $210 million (pretax), and $200 million (pretax), respectively*

Note: If guidance has changed, previous guidance from 11/3/05 is shown in italics directly below

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2006-08 Capital Expenditures

Dollars in millions	2006	2007	2008
Exploration & Prod.	**$950 - 1,050**	**$950 - 1,050**	**$1,000 - 1,150**
Midstream	**280 - 300** *230 - 250*	**230 - 270** *180 - 220*	**70 - 90**
Gas Pipeline	**710 - 785** *600 - 680*	**390 - 490** *300 - 390*	**410 - 510**
Power	**-**	**-**	**-**
Other/Corporate	**10 - 30**	**10 - 30**	**10 - 30**
Total	**$1,950 - 2,150** *1,825 - 2,050*	**$1,600 - 1,800** *1,425 - 1,625*	**$1,500 - 1,750**

Notes:
- Sum of ranges for each business line does not necessarily match total range
- If guidance has changed, previous guidance from 11/3/05 is shown in italics directly below

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2006-08 Outlook

Dollars in millions	2006	2007	2008
Segment Profit			
Reported	$1,240 - 1,580 *1,250 - 1,550*	$1,620 - 2,045 *1,600 - 2,025*	$1,815 - 2,380
MTM Adjustment	280 *270*	210 *230*	200
After MTM Adjustment	1,520 - 1,860 *1,820*	1,830 - 2,255	2,015 - 2,580
DD&A	790 - 890	900 - 1,000	1,000 - 1,100
Cash Flow from Ops.	1,625 - 1,925	1,850 - 2,150	2,200 - 2,600
Capital Expenditures	1,950 - 2,150 *1,825 – 2,050*	1,600 - 1,800 *1,425 - 1,625*	1,500 - 1,750
Operating Free Cash Flow [1]	(325) – (225) *(200) – (125)*	250 - 350 *425 – 525*	700 - 850

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

Note: If guidance has changed, previous guidance from 11/3/05 is shown in italics directly below

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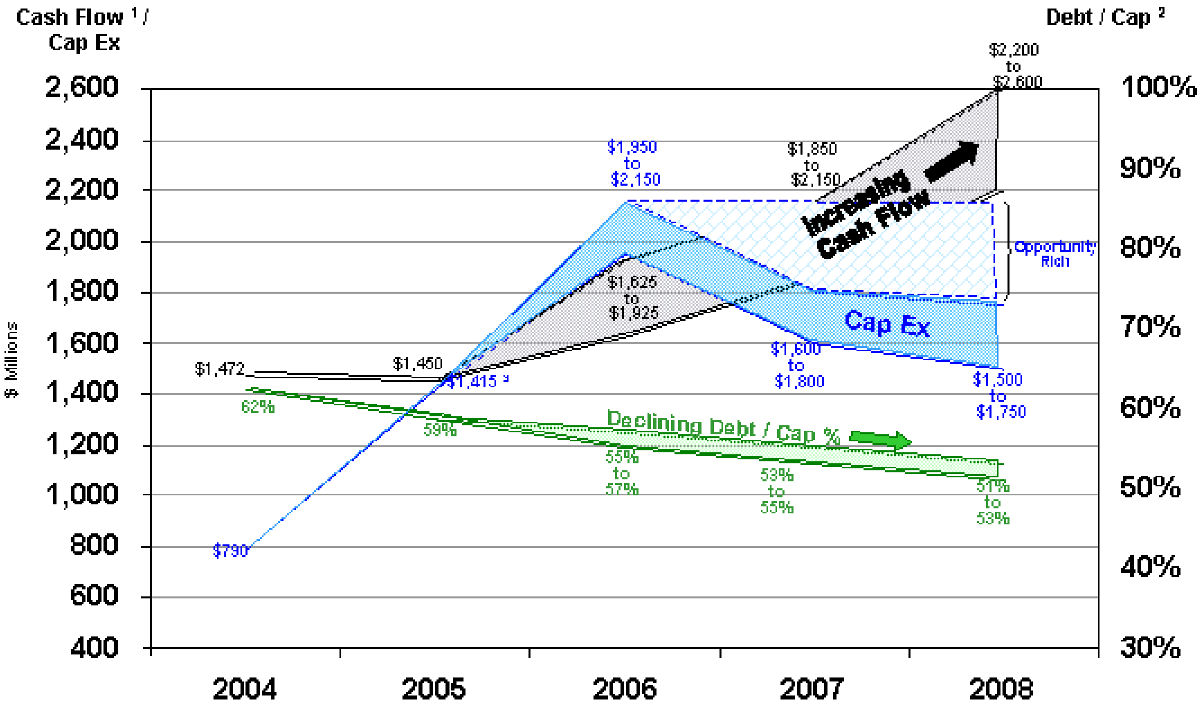
Strong Operating Cash Flow Growth & Increasing Investment Opportunities



[1] Cash Flow from Continuing Operations (CFFO)

[2] Debt to Capitalization = Total Debt / (Total Debt + Equity)

[3] Includes Purchases of Long-term Investments

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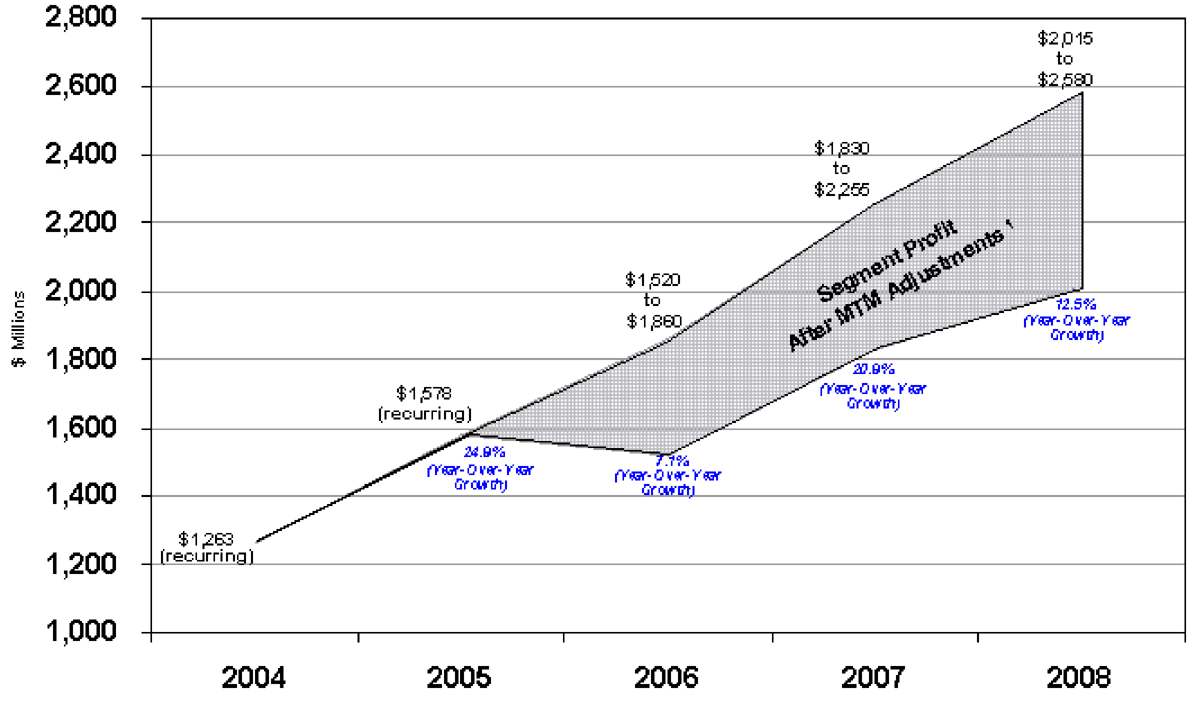
Segment Profit Guidance Trend



[1] *Includes pretax MTM adjustments of ($118) in 2004, $137 in 2005, $280 in 2006, $210 in 2007, and $200 in 2008.*
Note: Growth percentages are to midpoint of range

Financial Strategy/Key Points

- Drive/enable sustainable growth in EVA®/shareholder value
- Maintain a cash/liquidity cushion of $1.0 billion plus
- Continue to steadily improve credit ratios/ratings; ultimately achieving investment grade ratios
- Reduce risk in Power segment
- Opportunity rich
  - Increasing focus and disciplined EVA®-based investments in natural gas businesses
  - Attractive EVA-adding opportunities may require new capital
  - If new capital is needed, choose optimal sources of capital
  - Combination of growth in operating cash flows and EVA drives value creation

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Summary

Steve Malcolm
Chairman, President & CEO

Summary

Key Points

- Expect to grow key earnings measure at 15% rate
- Opportunity rich
- Investing in value growth

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Q&A

Non-GAAP Reconciliations

Non-GAAP Disclaimer

This presentation includes certain financial measures, EBITDA, recurring earnings, 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. 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 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. Previously the Company did not qualify for hedge accounting with respect to its Power segment as a result of the Company's stated intent to exit the Power business. The Company ceased efforts to market the sale of Power during the third quarter 2004, and now qualifies 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 reported earnings 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.

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Non-GAAP Reconciliation

Non-GAAP Reconciliation Schedule

[illegible]

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Non-GAAP Reconciliation Schedule

Reconciliation of Segment Profit (Loss) to Recurring Segment Profit (Loss)
(UNAUDITED)

(Dollars in millions)	2004 1st Qtr	2004 2nd Qtr	2004 3rd Qtr	2004 4th Qtr	2004 Year	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year
Segment profit (loss):										
Power*	$ (11.0)	$ 41.8	$ 109.1	$ (44.4)	$ 96.7	$ 114.1	$ (75.0)	$ (116.4)	$ (69.4)	$ (156.7)
Gas Pipeline	147.4	112.8	148.8	156.8	585.8	167.4	164.5	161.1	91.8	585.8
Exploration & Production	51.5	41.1	70.1	70.9	175.8	101.7	118.7	158.8	106.4	487.1
Midstream Gas & Liquids	110.1	98.5	105.4	175.7	549.7	128.6	109.1	121.1	112.4	471.1
Other	(8.7)	(14.1)	14	(11.0)	(41.6)	(4.1)	(60.5)	(10.1)	(10.1)	(105.0)
Total segment profit	$ 165.3	$ 304.1	$ 436.0	$ 395.0	$ 1,306.4	$ 509.7	$ 156.4	$ 104.5	$ 311.9	$ 1,181.5
Nonrecurring adjustments:										
Power	$ -	$ -	$ -	$ -	$ -	$ 114	$ 17.1	$ 0.4	$ 91.7	$ 116.6
Gas Pipeline	-	9.0	-	-	9.0	(17.1)	(21.7)	(14.1)	17.1	(11.7)
Exploration & Production	-	11.1	-	4.1	15.4	(7.6)	-	(21.7)	-	(19.1)
Midstream Gas & Liquids	-	(16.5)	11.9	(85.0)	(78.6)	-	-	-	-	-
Other	6.5	10.8	-	11.8	19.1	-	51.1	-	19.1	81.1
Total segment nonrecurring adjustments	$ 6.5	$ 14.6	$ 11.9	$ (69.1)	$ (15.1)	$ (9.3)	$ 44.5	$ (36.5)	$ 156.1	$ 157.8
Recurring segment profit (loss):										
Power	$ (11.0)	$ 41.8	$ 109.1	$ (44.4)	$ 96.7	$ 113.5	$ (61.9)	$ (116.0)	$ 11.7	$ (140.1)
Gas Pipeline	147.4	141.8	148.8	156.8	594.8	154.7	141.8	146.9	170.1	574.1
Exploration & Production	51.5	54.6	70.1	75.0	151.1	96.1	118.7	117.1	106.4	557.9
Midstream Gas & Liquids	110.1	81.0	118.7	150.7	471.1	118.6	109.1	121.1	112.4	471.1
Other	(1.1)	(1.5)	14	(9.1)	(11.5)	(4.1)	(7.4)	(10.1)	(1.1)	(11.8)
Total recurring segment profit	$ 174.8	$ 318.7	$ 456.9	$ 315.9	$ 1,381.3	$ 500.4	$ 300.9	$ 169.0	$ 470.0	$ 1,440.3

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

* Power's segment profit for 2004 includes the effect of intercompany interest rate swaps entered into with the corporate parent.

Non-GAAP Reconciliation

Non-GAAP Reconciliation Schedule

Dollars in millions except for per share amounts

	2005				
	1Q	2Q	3Q	4Q	Year
Recurring income (loss) from cont. ops available to common shareholders	$ 198	$ 67	$ (5)	$ 168	$ 428
Recurring diluted earnings per common share	$ 0.33	$ 0.11	$ (0.01)	$ 0.28	$ 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	$ 101	$ 125	$ 154	$ 513
Recurring diluted earnings per share after MTM adj.	$ 0.22	$ 0.17	$ 0.22	$ 0.26	$ 0.86
weighted average shares - diluted (thousands)	599,422	578,902	580,735	609,106	605,847

	2004				
	1Q	2Q	3Q	4Q	Year
Recurring income from cont. ops available to common shareholders	$ 4	$ 54	$ 136	$ 68	$ 261
Recurring diluted earnings per common share	$ 0.01	$ 0.10	$ 0.26	$ 0.12	$ 0.49
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	(24)	(70)	(187)	(23)	(304)
Add realized gains/losses from MTM previously recognized	136	11	45	(6)	186
Total MTM adjustments	112	(59)	(142)	(29)	(118)
Tax effect of total MTM adjustments	44	(23)	(55)	(11)	(46)
After tax MTM adjustments	68	(36)	(87)	(17)	(72)
Recurring income from cont. ops available to common shareholders after MTM adjust.	$ 72	$ 18	$ 49	$ 51	$ 190
Recurring diluted earnings per share after MTM adj.	$ 0.14	$ 0.03	$ 0.09	$ 0.09	$ 0.35
weighted average shares - diluted (thousands)	519,485	521,698	529,525	586,497	535,611

Non-GAAP Reconciliation

EBITDA Reconciliation

Dollars in millions	4Q05	2005
Net Income	$ 67	$ 314
Loss from Discontinued Operations	-	2
Cumulative effect of change in accounting principle	2	2
Net Interest Expense	174	665
DD&A	194	740
Provision for Income Taxes	45	214
EBITDA	$ 482	$ 1,937

Non-GAAP Reconciliation

4Q 2005 Segment Contribution

Dollars in millions

	Gas Pipes	E&P	Midstream	Power	Other	Total
Segment Profit (Loss)	$ 93	$ 206	$ 112	$ (69)	$ (30)	**$ 312**
DD&A	68	70	50	4	2	**194**
Segment Profit before DDA	**$ 161**	**$ 276**	**$ 162**	**$ (65)**	**$ (28)**	**$ 506**
General Corporate Expense						**(49)**
Investing Income*						**19**
Other Income						**6**
TOTAL						**$ 482**

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

Non-GAAP Reconciliation

2005 Segment Contribution

Dollars in millions

	Gas Pipes	E&P	Midstream	Power	Corp/ Other	Total
Segment Profit (Loss)	$ 586	$ 587	$ 471	$ (257)	$ (104)	**$ 1,283**
DD&A	267	254	192	15	12	**740**
Segment Profit before DDA	**$ 853**	**$ 841**	**$ 663**	**$ (242)**	**$ (92)**	**$ 2,023**
General Corporate Expense						**(155)**
Investing Income*						**67**
Other Income						**2**
TOTAL						**$ 1,937**

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

Williams

Non-GAAP Reconciliation

2006 Forecast EBITDA Reconciliation

Dollars in millions	Feb 28 Guidance
Net Income	**$280 – 440**
Loss from Disc. Ops.	5 – 0
Net Interest	665 – 705
DD&A	790 – 890
Provision for Income Taxes	200 – 315
Other/Rounding	10 – 0
EBITDA	**$1,950 - 2,350**
MTM Adjustments	280
EBITDA - After MTM Adj.	**$2,230 - 2,630**

Williams

2006 Forecast Segment Contribution

Dollars in millions	E&P	Midstream	Gas Pipeline	Power [1]	Corp/ Other	Total
Segment Profit (Loss)	$650 - 725	$400 - 500	$475 - 520	$(235) - (135)	$(50) - (30)	$1,240 - 1,580
DD&A	335 - 375	190 - 200	280 - 300	10 - 20	(25) – (5)	790 - 890
Segment Profit Before DDA	$985 - 1,100	$590 - 700	$755 - 820	$(225) - (115)	$(75) – (35)	$2,030 - 2,470
Other (Primarily General Corporate Expense & Investing Income)						(90) - (120)
Rounding						10 - 0
TOTAL						$1,950 - 2,350

[1] *Segment Profit is prior to MTM adjustments*

Non-GAAP Reconciliation

2006 Forecast Guidance Reconciliation

Dollars in millions, except per-share amounts	Feb 28 Guidance
Net Income	**$280 – 440**
Less: Discontinued Operations	5 – 0
Income from Continuing Ops	**$285 – 440**
Non-Recurring Items (Pretax)	30
Less Taxes @ Approx. 39%	12
Non-Recurring After Tax	18
Recurring Income from Cont. Ops	**$303 – 458**
Recurring EPS	**$0.50 - $0.75**
Mark-to-Market Adjustment (Pretax)	280
Less Taxes @ 39%	(109)
Mark-to-Market Adjust. After Tax	171
Inc. from Cont. Ops after MTM Adj.	**$474 - 629**
Inc. from Cont. Ops after MTM Adj. EPS	**$0.78 - $1.03**

Williams

Appendix

Consolidated

Fourth Quarter Segment Profit

Dollars in millions	Reported 4Q05	Reported 4Q04	Recurring 4Q05	Recurring 4Q04
Exploration & Production	$206	$71	$206	$75
Midstream Gas & Liquids	112	236	112	151
Gas Pipeline	93	157	130	157
Power	(69)	(44)	22	(44)
Other	(30)	(22)	-	(10)
Segment Profit	$312	$398	$470	$329
MTM Adjustments - Power			(22)	(29)
Segment Profit after MTM Adjustments			**$448**	**$300**
Memo:				
Power after MTM adjustments			**$0**	**$(73)**

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.

Williams

Consolidated

2005 Segment Profit

Dollars in millions	Reported 2005	Reported 2004	Recurring 2005	Recurring 2004
Exploration & Production	$587	$236	$558	$251
Midstream Gas & Liquids	471	550	471	471
Gas Pipeline	586	586	574	595
Power	(257)	77	(140)	77
Other	(104)	(43)	(23)	(13)
Segment Profit	$1,283	$1,406	$1,440	$1,381
MTM Adjustments			138	(118)
Segment Profit after MTM Adjustments			**$1,578**	**$1,263**
Memo:				
Power after MTM adjustments			**($2)**	**$(41)[1]**

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.

[1] Includes impact of legacy natural gas portfolio that was liquidated in 1Q04.

Consolidated

Debt Balance[1]

Dollars in millions

		Avg. Cost
Debt Balance @ 12/31/04	**$7,962**	**7.4%**
Scheduled Debt Retirements & Amortization	(216)	
Capitalized Lease	4	
Debt Balance @ 3/31/05	**7,750**	**7.4%**
Scheduled Debt Retirements & Amortization	(6)	
Debt Balance @ 6/30/05	**7,744**	**7.5%**
Scheduled Debt Retirements & Amortization	(23)	
Debt Balance @ 9/30/05	**$7,721**	**7.5%**
Scheduled Debt Retirements & Amortization	(8)	
Debt Balance @ 12/31/05	**$7,713**	**7.6%**
Fixed Rate Debt @ 12/31/05	**$7,066**	**7.7%**
Variable Rate Debt @ 12/31/05	**$647**	**6.3%**

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

Williams

Consolidated

2005 Cash Information

Dollars in millions	4th Qtr	Year
Beginning Unrestricted Cash	**$ 1,361**	**$ 930**
Cash flow from Continuing Operations	368	1,450
Proceeds from Issuing Common Stock[1]	7	310
Proceeds from Gulfstream recapitalization	310	310
Proceeds from sale of limited partnership units	-	111
Sale of WilTel Note	-	55
Contract Termination Payment	-	88
Debt Retirements	(8)	(251)
Capital Expenditures	(413)	(1,299)
Dividends	(43)	(143)
Other-Net	15	36
Change in Cash and Cash equivalents	$ 236	$ 667
Ending Unrestricted Cash at 12/31/05		$ 1,597
Restricted Cash at 12/31/05 (not included above)		$ 129

[1] *$273 MM of proceeds related to settlement of purchase contract underlying FELINE PACS*

Williams

Consolidated

EPS Metrics

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

2004	1Q	2Q	3Q	4Q	Total
Diluted EPS from Cont. Ops.	-	($0.03)	$0.03	$0.17	$0.17
Recurring EPS	0.01	0.10	0.26	0.12	0.49
Rec. EPS after MTM Adj.	**0.14**	**0.03**	**0.09**	**0.09**	**0.35**
Average Shares (MM)	519	522	530	586	536

Consolidated

2006 Interest Expense Guidance

Dollars in millions	2006
Interest on Long-Term Debt	$574 - $591
Amortization Discount/Premium and other Debt Expense	35 - 43
Credit Facilities: (incl. Commitment Fees plus LC Usage)	42 – 52
Interest on other Liabilities	22 – 32
Interest Expense	$673 - $718
Less: Capitalized Interest	(8) - (13)
Net Interest Expense Guidance	**$665 - $705**

Consolidated

2005 Effective Tax Rates

	2005									
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter		Year-to-Date	
Statutory Rate	115	35 %	29	35 %	1	35 %	41	35 %	186	35 %
State	14	4%	1	3 %	2	49 %	4	4%	21	4 %
Foreign	(5)	-2 %	5	6 %	(2)	-49 %	9	8%	7	1 %
Other	5	2%	7	7 %	(4)	-115 %	(8)	-7 %	0	0 %
Tax Provision/(Benefit)	129	39 %	42	51 %	(3)	-80 %	46	40 %	214	40 %

	2005	2006	2007	2007	2008
Effective Tax Rate Guidance [1]	See Above	39%	39%	39%	39%
Cash Tax Rate Guidance [2]	$230 million	5-10%	5-10%	5-10%	5-10%

Note 1: An additional $5-10 million income tax expense is forecast in 2006, 2007 and 2008.

Note 2: Of the $230 million in cash payments for 2005, $204 million relates to settlements with taxing authorities.

Note 3: Discontinued operations in 2005 have an immaterial impact.

Williams

2006-08 Hedge Update

Dollars in millions	2006	2007	2008
Fixed Price at the basin:			
Volume (MMcfe/d)	299	172	73
Price ($/Mcfe)	$3.82	$3.90	$3.96
NYMEX Collars:			
Volume (MMcfe/d)	65	15	-
Price ($/Mcfe)	$6.62 - $8.42	$6.50 - $8.25	
At the Basin Collars:			
NWPL Rockies[1]			
Volume (MMcfe/d)	50	50	-
Price ($/Mcfe)	$6.05 - $7.90	$5.65 - $7.45	
EPNG San Juan[1]			
Volume (MMcfe/d)		80	-
Price ($/Mcfe)		$5.85 - $9.33	
Mid-Continent[1]			
Volume (MMcfe/d)		20	-
Price ($/Mcfe)		$6.76 - $11.83	

[1] *Please note basin locations not NYMEX*

Exploration & Production

4Q 2005 Net Realized Price Calculation

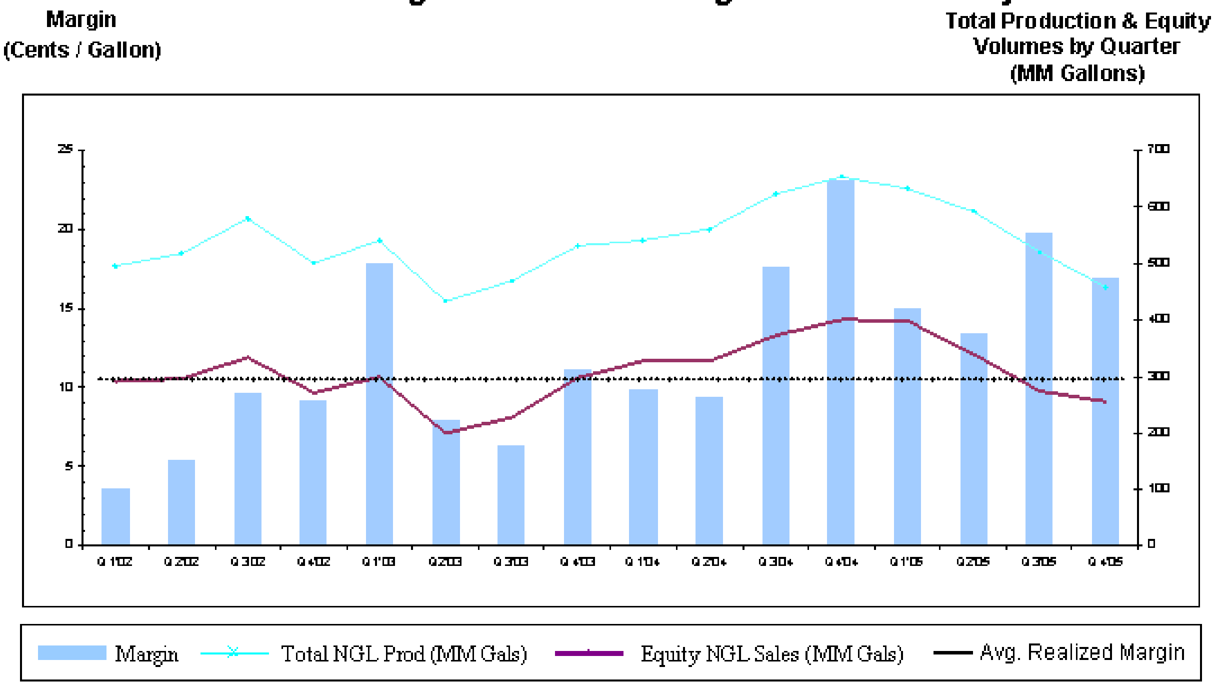
	Unhedged	4Q '05 Hedge
Market Price:		
NYMEX	\$12.10 - \$13.90	4.49
NYMEX collars		(0.05)
Basis Differential	(2.70 - 2.90)	(0.40)
Net basin market price	\$9.20 - \$11.20	\$4.04
Net basin market price	**\$9.20 - \$11.20**	**\$4.04**
Fuel & Shrinkage/Gathering/ Transportation	(0.80 - 1.00)	(0.80 - 1.00)
Net Price	**\$8.20 - \$10.40**	**\$3.04 - \$3.24**
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)

Williams

Midstream

Margins Above Average

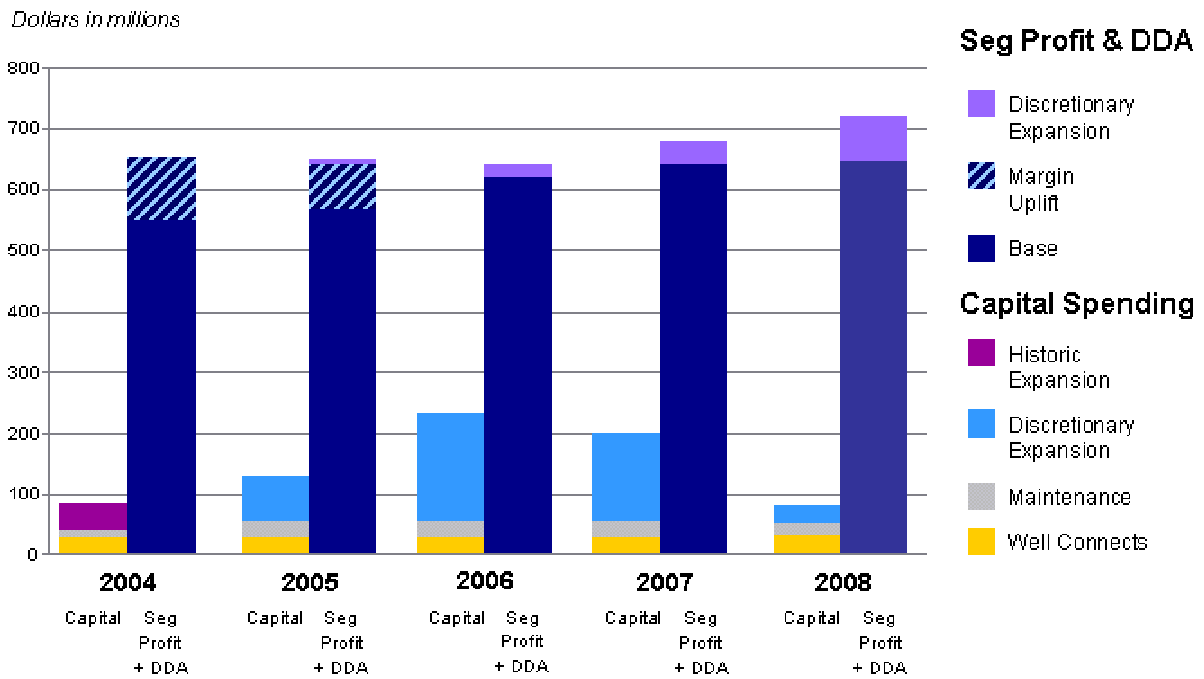
Domestic NGL Average Realized Net Margin and Volumes by Quarter



Note: Based on actual realized prices, contractual obligations, shrink, fuel, actual equity liquids percentages, etc. Average Realized Margin shown for 2001-2005. Does not include Discovery volumes.

Midstream

Strong Free Cash Flow



Note:
- Segment Profit is stated on a recurring basis. Segment Profit for 2004 has been restated to reflect reclassifications
- Segment Profit + DDA and Capital Spending reflect midpoint of ranges.
- Margin uplift represents actual realized margin in excess of forecasted margin.

Williams

Gas Pipeline

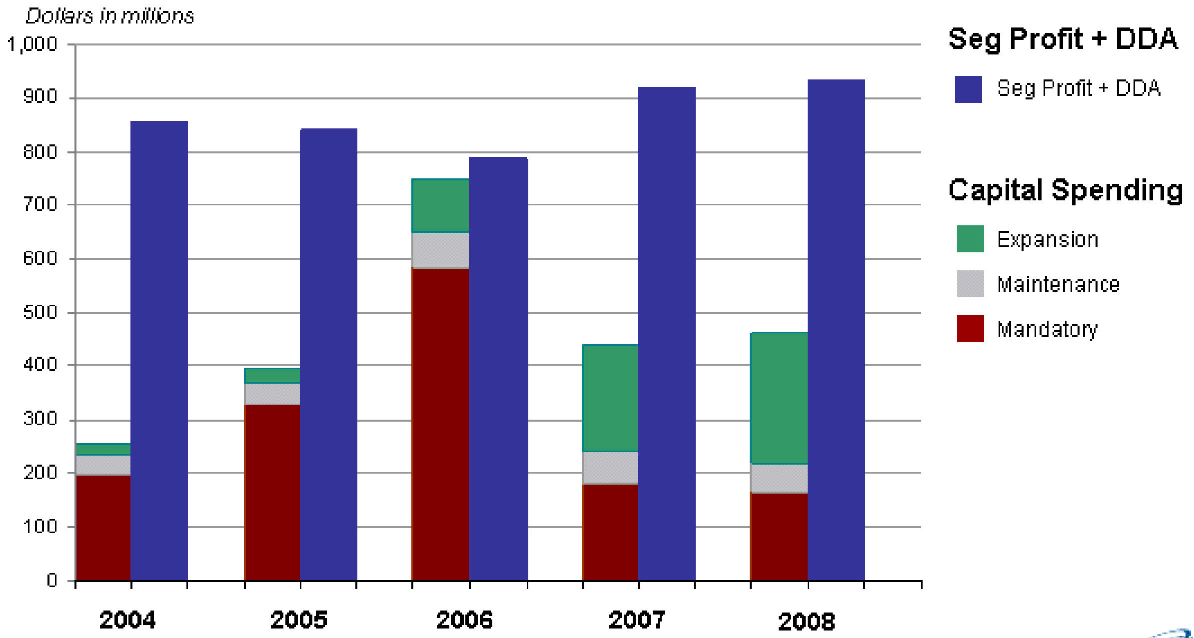
2005 vs 2006 Segment Profit

2005 Reported Segment Profit		$586
Non-recurring Items	(12)	
2005 Recurring Segment Profit		574
Pipeline Safety Costs – Acctg Change	(31)	
Gulfstream Interest Exp/Completion Fee [1]	(15)	
Subtotal		528
Pacific Connector	(6) - 0	
Higher DDA/Operating Expenses	(50) -(8)	
2006 Segment Profit Range		$475 - 520

[1] Lower equity earnings from Gulfstream LLC in 2006 due to Gulfstream LLC issuing $850 million of new long term debt in October 2005.
Note: May not add due to rounding

Gas Pipeline

Strong Free Cash Flow



Note:
- Segment Profit is stated on a recurring basis.
- Segment Profit + DDA and Capital Spending reflect midpoint of ranges for 2006 - 2008.

Power

4Q05 Financial Statement Changes for Derivatives

- During 4Q05, 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	$390	$258	$68	$64
Less change in Option Premiums/Termination Settlements/Other	(2)			(2)
Remaining Change in Consolidated Derivative Values	$392	$258	$68	$66
Change in E&P Hedge Values	338	154	(2)	
- Prior MTM Realized (Ineffectiveness)				8
- OCI Realized				178
Change in Power Hedge Values	54	104	70	
- Prior MTM Realized				(48)
- OCI Realized				(72)

- The net change in Derivative Assets and Liabilities for E&P was positive reflecting the 2006 decrease in gas prices against a short derivative position.
- The net change in Derivative Assets and Liabilities for Power was positive, reflecting the increased economic value of the Power derivatives primarily due to the rise in 2007 forward gas prices against our long derivative position. Additional gains were made on price decreases on our short power position.

NOTE: Change in OCI shown is economic change before taxes. Therefore, change shown does not tie to balance sheet change which is net of taxes.

Power

West Undiscounted Cash Flows

Expected undiscounted dollars in millions

West Power Portfolio Estimated as of 12/31/05	**2005A**	**2006F**	**2007F**	**2008F**
Tolling Demand Payment Obligations	($154)	($152)	($153)	($155)
Hedged Cash Flows [2]	378 [1]	418	403	366
Merchant Cash Flows [3]		6	4	5
Total Cash Flows	$224	$272	$254	$216
Capacity Available (in MW)		3,783	3,783	3,783
Total Capacity Sold		2,854	3,462	3,416
Remaining Available (in MW) after all hedges		929	321	367

[1] 2005 Actual cash flows are realized from a combination of Hedged Cash Flows and Merchant Cash Flows and other risk management and trading activities.

[2] Forecasted Hedged Cash Flows represents (1) the estimated cash flows from hedges such as resale of tolls, heat rate options, full requirements contracts and fixed price power and gas contracts and (2) the estimated value of the tolling (spread option) cash flows associated with those hedges.

[3] Forecasted Merchant Cash Flows represents the tolling (spread option) cash flows which have not been hedged.

Note: 2005 Forecast estimated as of 12/31/04. 2006 forward forecast estimated as of 12/31/05. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

Mid-Con Undiscounted Cash Flows

Expected undiscounted dollars in millions

Mid-Continent Power Portfolio Estimated as of 12/31/05	2005A	2006F	2007F	2008F
Tolling Demand Payment Obligations	($87)	($88)	($89)	($90)
Hedged Cash Flows [2]	11 [1]	40	39	34
Merchant Cash Flows [3]		19	24	27
Total Cash Flows	($76)	($29)	($26)	($29)
Capacity Available (in MW)		1,296	1,296	1,296
Total Capacity Sold		625	600	600
Remaining Available (in MW) after all hedges		671	696	696

[1] 2005 Actual cash flows are realized from a combination of Hedged Cash Flows and Merchant Cash Flows and other risk management and trading activities.

[2] Forecasted Hedged Cash Flows represents (1) the estimated cash flows from hedges such as resale of tolls, heat rate options, full requirements contracts and fixed price power and gas contracts and (2) the estimated value of the tolling (spread option) cash flows associated with those hedges.

[3] Forecasted Merchant Cash Flows represents the tolling (spread option) cash flows which have not been hedged.

Note: 2005 Forecast estimated as of 12/31/04. 2006 forward forecast estimated as of 12/31/05. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

Power

East Undiscounted Cash Flows

Expected undiscounted dollars in millions

East Power Portfolio *Estimated as of 12/31/05*	**2005A**	**2006F**	**2007F**	**2008F**
Tolling Demand Payment Obligations	($154)	($158)	($160)	($162)
Hedged Cash Flows [2]	84 [1]	130	74	127
Merchant Cash Flows [3]		38	69	77
Total Cash Flows	($70)	$10	($17)	$42
Capacity Available (in MW)		2,279	2,279	2,279
Total Capacity Sold		1,255	264	226
Remaining Available (in MW) after all hedges		1,024	2,015	2,053

[1] 2005 Actual cash flows are realized from a combination of Hedged Cash Flows and Merchant Cash Flows and other risk management and trading activities.

[2] Forecasted Hedged Cash Flows represents (1) the estimated cash flows from hedges such as resale of tolls, heat rate options, full requirements contracts and fixed price power and gas contracts and (2) the estimated value of the tolling (spread option) cash flows associated with those hedges.

[3] Forecasted Merchant Cash Flows represents the tolling (spread option) cash flows which have not been hedged.

Note: 2005 Forecast estimated as of 12/31/04. 2006 forward forecast estimated as of 12/31/05. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

WMB Collateral Outstanding

As of 12/31/05

Dollars in millions	E&P	Midstream	Power	Corp./ Other	Total
Margins & Ad. Assurances[1]	$1	$0	$47	$0	$48
Prepayments	0	1	13	0	14
Subtotal	1	1	60	0	62
Letters of Credit	745	242	283	91	1,361
Total as of 12/31/05	746	243	343	91	1,423
Total as of 9/30/05	1,147	225	322	91	1,785
Change	$(401)	$18	$21	$0	$(362)

[1]Reflects net amount of margins out less margins in.

WMB Collateral Sensitivity

Estimated dollars in millions

WMB Collateral Sensitivity

Margin Volatility (1% chance of exceeding)

-Potential incremental collateral requirement

Days	12/31/2005	9/30/2005	6/30/2005	3/31/2005
30	($325)	($469)	($178)	($124)
180	($559)	($868)	($458)	($328)
360	($567)	($926)	($351)	($341)

Note: The margin numbers above assume only the forward marginable position values are included.

Enterprise Risk Management

Estimated dollars in millions (except price assumptions)

Enterprise Risk Management
Sensitivity Analysis

	Enterprise[1] Natural Gas Per MMBtu	Power Co.[2] West Spark Spread Power Price per MWh	Midstream[3] Processing Margin Per Gallon of NGL's
Price Increase	**$0.10**	**$5.00**	**$0.01**
2006	$5-$7 MM	$5-$15 MM	$10-$15 MM
2007	$15-$17 MM	$5-$15 MM	$10-$15 MM
2008	$23-$25 MM	$5-$15 MM	$10-$15 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 West power prices only, no change in power volatility, full extrinsic value not included. Heat rate and position change associated with Spark Spread increase is consistent across all months. Cash flow ranges are not linear.

3 Assumes a non-correlated change in NGL processing spread (i.e. change in NGL price only).

The Williams Companies, Inc.

Exhibit 99.3

NewsRelease

NYSE: WMB

Date: Feb. 28, 2006

Williams Replaces 277 Percent of 2005 U.S. Natural Gas Production

Total Domestic and International Proved Reserves Grow to 3.6 Tcfe

TULSA, Okla. – Williams (NYSE:WMB) announced today that its domestic and international proved natural gas and oil reserves as of Dec. 31, 2005, increased to 3.6 trillion cubic feet equivalent (Tcfe).

Reserves in the United States increased 13.3 percent to approximately 3.4 Tcfe, compared with approximately 3.0 Tcfe a year earlier. More than 99 percent of Williams' U.S. proved reserves are natural gas.

International reserves increased slightly to approximately 37 million barrels of oil equivalent in 2005 compared with approximately 36 million barrels of oil equivalent in 2004. Sixty-five percent of Williams' international proved reserves are crude oil and liquids; the remainder is 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. Williams also acquired a position in the Fort Worth Basin in 2005.

In 2005, Williams had a drilling success rate of approximately 99 percent. The company drilled 1,629 gross wells, of which 1,617 were successful.

Williams' drilling activity in 2005 resulted in the addition of 603 billion cubic feet equivalent (Bcfe) in net reserves. Williams added 451 Bcfe in net reserves in 2004 and 408 Bcfe in net reserves in 2003. The company's three-year finding and developing costs in the U.S. averaged 92 cents per Mcfe.

"We continue to rapidly develop our long-term drilling inventory at a highly successful rate," said Ralph Hill, senior vice president of Williams' exploration and production business. "This is a credit to the quality of our highly skilled employees and our portfolio, which consists of large, well-defined resources.

"Williams is focused on delivering measurable and meaningful growth in both volumes and reserves. Over the past three years, we have added more than 1.4 trillion cubic feet equivalent in domestic net reserves from our drilling activities," Hill said.

Williams replaced its 2005 U.S. natural gas production of 224 billion cubic feet equivalent (Bcfe) at a ratio of 277 percent. A reserves reconciliation follows the main text in this news release.

Average daily production from domestic and international interests was approximately 662 million cubic feet of gas equivalent (MMcfe), compared with 564 MMcfe for the same period in 2004 – an increase of approximately 17 percent.

Production solely from domestic interests increased 18 percent to approximately 612 MMcfe in 2005 from 519 MMcfe in 2004.

In 2006, Williams plans to invest $950 million to $1.05 billion in capital to develop production from its long-term drilling inventory.

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

Williams also owns an approximately 69 percent interest in APCO Argentina (NASD:APAGF), a separately traded oil and gas company with properties in Argentina, and a 10 percent interest in the La Concepcion oil field in Venezuela.

Approximately 97 percent of Williams' year-end 2005 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 APCO Argentina were prepared by Ryder Scott Company.

The reserve replacement ratio of 277 percent was calculated by dividing the sum of changes (acquisitions, divestitures, additions and revisions) to the estimated proved reserves during 2005 by Williams' 2005 production of 224 Bcfe.

The three-year average finding and development cost of 92 cents per Mcfe in the United States was calculated by dividing total capital spent, including facilities and acquisitions, by the change in proved reserves balances for the retained basins 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

Proved reserves Dec. 31, 2004	2,986
Acquisitions	28
Divestitures	(11)
Additions and revisions	603
Production	(224)
Proved reserves Dec. 31, 2005	3,382

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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