Williams 2007
1st Quarter Earnings

May 3, 2007

Forward Looking Statements

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

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

Forward Looking Statements (cont.)

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

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

Investors are urged to closely consider the disclosures and risk factors in our annual report on Form 10-K filed with the Securities and Exchange Commission on February 28, 2007, and our quarterly reports on Form 10-Q available from our offices or from our website at www.williams.com.

Oil and Gas Reserves and Resource Potential Disclaimer

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 presentation such as “probable” reserves and “possible” reserves and "unrisked theoretical resource estimates" that the SEC’s guidelines strictly prohibit us from including in filings with the SEC. The SEC defines proved reserves as estimated hydrocarbon 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. Generally under such techniques, probable reserve estimates are more than 50% certain and possible reserve estimates are less than 50% but more than 10% certain. Unrisked theoretical resource estimates are even less certain than those for possible reserves and are not risk adjusted. Unrisked theoretical resource estimates include (i) an estimate of hydrocarbon quantities for new areas for which we do not have sufficient information to date to classify the resources as probable or even possible reserves and (ii) the amount by which we have reduced our probable and possible reserves for existing areas to take into account the reduced level of certainty of recovery of the resources. Unlike probable and possible reserves, unrisked theoretical resource estimates do not take into account the uncertainty of resource recovery and, therefore, are not indicative of the expected future recovery and should not be relied upon.

Reference to “Resource Potential” includes proved, probable and possible reserves as well as unrisked theoretical resource estimates that might never be recoverable and are contingent on exploration success, technical improvements in drilling access, commerciality and other factors.

Investors are urged to closely consider the disclosures and risk factors in our annual report on Form 10-K filed with the Securities and Exchange Commission on Feb. 28, 2007, and our quarterly reports on Form 10-Q available from our offices or from our website at www.williams.com.

Overview

Steve Malcolm
Chairman, President & CEO

Headlines

- > Key earnings measure* increases 12%
- > Production increases
  - +28% total domestic
  - +37% Piceance Basin
- > Update reserves and total resource potential
- > Sustained margins boost Midstream performance
- > New, higher rates increase gas pipeline segment profit
- > Improved overall operating results offset by mark-to-market change
- > Williams named top major pipeline for customer service
- > Dividend increased 11%

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

Value-growth catalysts to watch

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

Financial Results

Don Chappel
Chief Financial Officer

Financial Results

Dollars in millions (except per share amounts)	1st Quarter 2007	1st Quarter 2006
Income from Continuing Operations	$132	$131
Income from Discontinued Operations	2	1
Net Income	$134	$132
Net Income/Share	$0.22	$0.22
Recurring Income from Continuing Operations /Share	$0.21	$0.23
Recurring Income from Continuing Operations After MTM Adjustments/Share	**$0.29**	**$0.26**

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

Recurring Income from Continuing Operations

Dollars in millions (except per share amounts)	1st Quarter 2007	1st Quarter 2006
Income from Continuing Operations	$132	$131
Nonrecurring Items		
Debt Retirement Expense	-	27
Regulatory & Litigation Contingencies/Settlements	1	(7)
(Income)/expense related to prior periods	(8)	(6)
Gain on sale of investments	-	(7)
Other - Net	-	1
Total Nonrecurring items before taxes	(7)	8
Tax effect of adjustments	3	(3)
Recurring Inc. from Continuing Ops. Avail. to Com.	$128	$136
Recurring Income from Cont. Ops./Share	$0.21	$0.23

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

Recurring Income from Cont. Ops. after MTM Adjustment

Dollars in millions (except per share amounts)	1st Quarter 2007	1st Quarter 2006
Recurring Income from Continuing Ops. Avail. to Common	$128	$136
Recurring Diluted Earnings per Common Share	$0.21	$0.23
Mark-to-Market (MTM) adjustments for Power:		
Reverse forward unrealized MTM (gains) losses	71	(43)
Add realized gains from MTM previously recognized	8	77
Total MTM adjustments	79	34
Tax Effect of Total MTM Adjustments	(31)	(13)
After-Tax MTM Adjustments	48	21
Recurring Income from Cont. Ops. Avail. to Common Shareholders after MTM Adjustments	$176	$157
Recurring Diluted Earnings Per Share after MTM adjustments	$0.29	$0.26

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

First Quarter Segment Profit

Dollars in millions	Reported 2007	Reported 2006	Recurring 2007	Recurring 2006
Exploration & Production (see slide 47)	$ 188	$ 148	$ 188	$ 148
Midstream Gas & Liquids (see slide 54)	154	151	146	145
Gas Pipeline (see slide 61)	150	135	150	133
Power (see slide 67)	(81)	(23)	(81)	(23)
Other	-	1	-	1
Segment Profit	$ 411	$ 412	$ 403	$ 404
MTM Adjustments - Power			79	34
Segment Profit after MTM Adjustments			**$ 482**	**$ 438**
Memo:				
Power after MTM Adjustments			$ (2)	$ 11

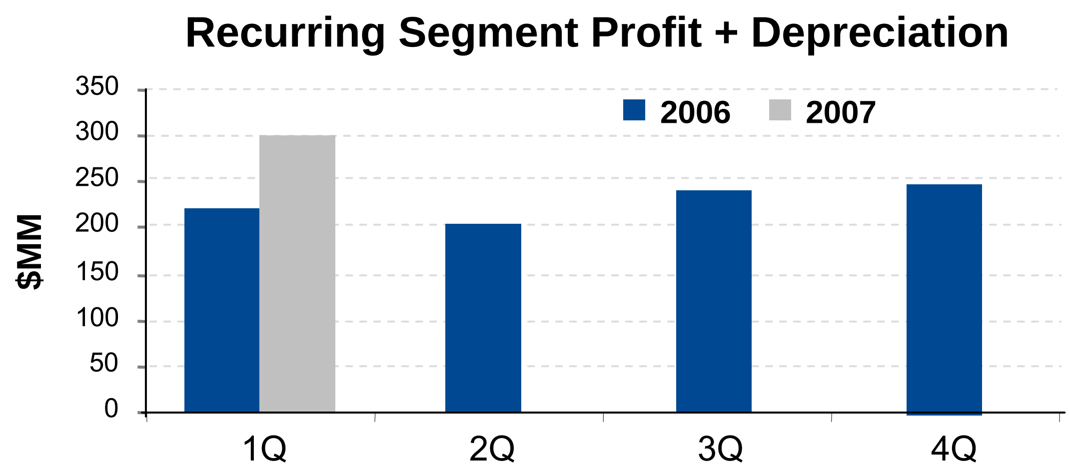
A more detailed schedule reconciling income (loss) from continuing operations to recurring income from continuing operations is available on Williams' Web site at www.williams.com and at the end of this presentation.

Exploration & Production

Ralph Hill
President

2007 Accomplishments

- 1Q ’07 total production 891 MMcfed, up 25% compared to 1Q ’06
- 1Q ’07 segment profit up 27% compared to 1Q ‘06
- Rig fleet high-grading in process
- Successful winter drilling at Highlands/Trail Ridge
- Major road infrastructure to Highlands complete



Basin Highlights

Piceance Valley

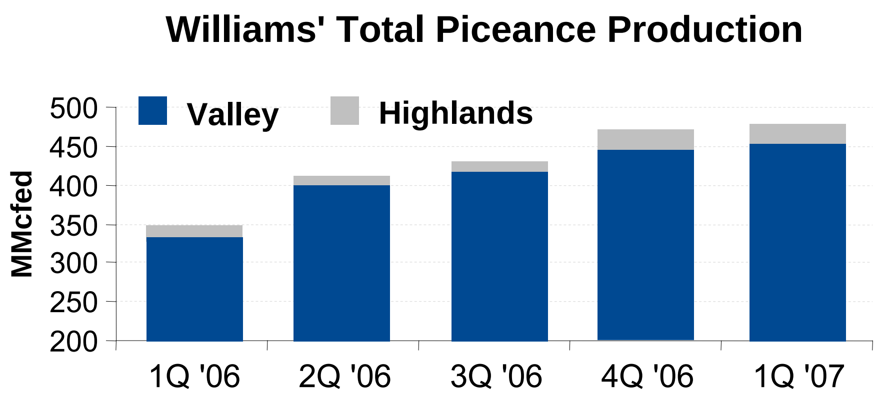
- 453 MMcfd, up 34% over one year ago
- 22 rigs operating
- SIMOPS continuing to improve cycle times

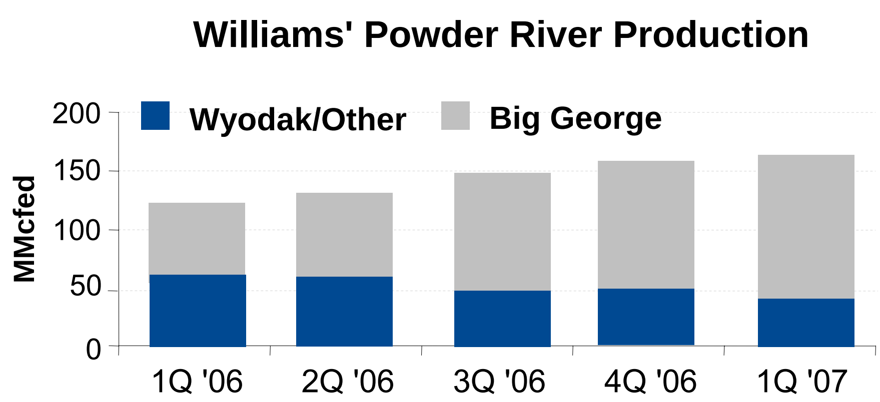
Piceance Highlands

- 25 MMcfd, up 108% over one year ago
- 3 rigs operating
- Well performance meeting expectations

Powder River

- 165 MMcfd, up 29% over one year ago
- Big George up 89% year over year
- 12 rigs operating





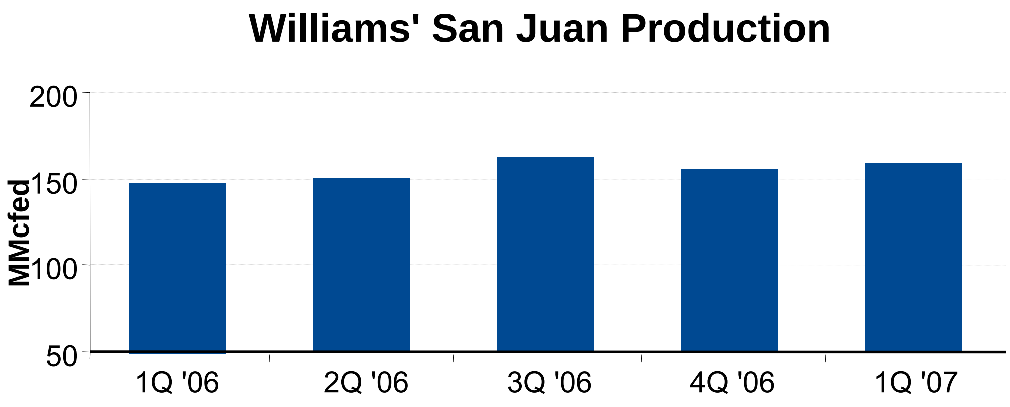
Basin Highlights (cont.)

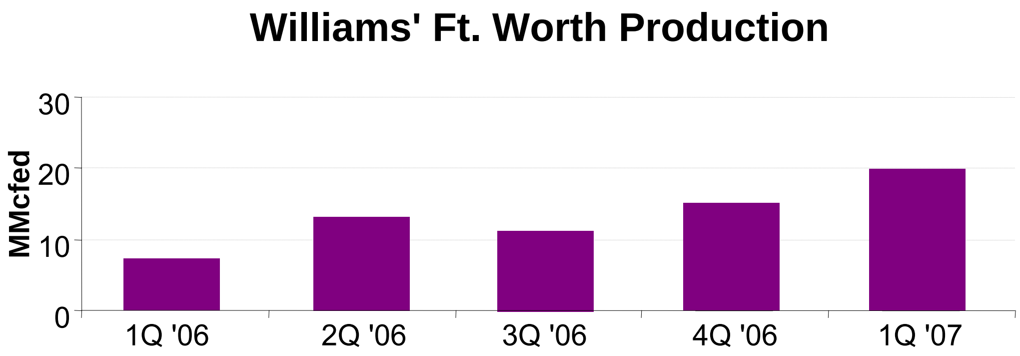
San Juan

- 158 MMcfd, up 7% over year ago
- Solid performer in mature basin
- Optimization efforts paying dividends

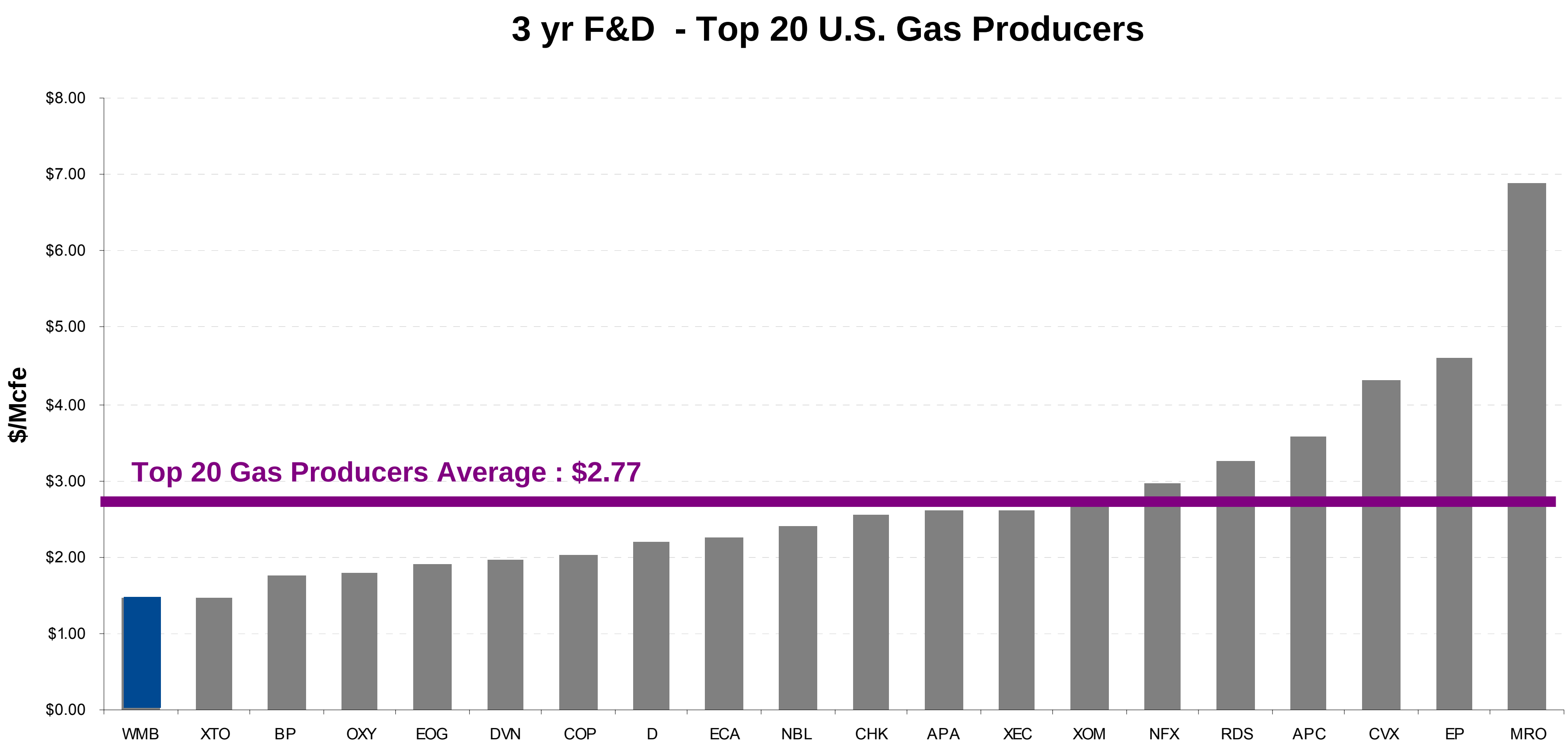
Ft. Worth

- 20 MMcfd, up almost three-fold over year ago
- Current drilling program exceeding expectations
- Deal flow/tighter well density offer significant growth





Outperforming Industry in Finding & Development Costs



- Williams consistently remains in top quartile for F&D costs
- A leader in drill bit reserves replacement

Source: Publicly reported data from EvaluateEnergy.com

Leader in US Gas Production Growth through the Drill Bit

Williams

Top 20 U.S. Gas Producers
(sorted by 2006 MMcfd)

	Company	MMcfd 2005	MMcfd 2006	Percent Change
1	BP	2,546	2,376	-6.7%
2	ConocoPhillips	1,381	2,173	57.3%
3	Chevron	1,634	1,810	10.8%
4	ExxonMobil	1,739	1,625	-6.6%
5	Devon	1,521	1,551	2.0%
6	Anadarko	1,134	1,529	34.8%
7	Chesapeake	1,157	1,442	24.6%
8	XTO	1,033	1,186	14.8%
9	EnCana	1,096	1,181	7.8%
10	Shell	1,150	1,163	1.1%
11	EOG	718	817	13.8%
12	Dominion	753	817	8.4%
13	**Williams**	**612**	**752**	**22.9%**
14	Apache	597	667	11.6%
15	Occidental	553	595	7.6%
16	El Paso	566	584	3.1%
17	Newfield	523	544	4.0%
18	Marathon	578	532	-8.0%
19	Noble	344	452	31.3%
20	Cimarex	275	342	24.4%
	Total	19,911	22,137	11.2%

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

	Company	MMcfd 2005	MMcfd 2006	Percent Change
1	ConocoPhillips	1,381	2,173	57.3%
2	Anadarko	1,134	1,529	34.8%
3	Noble	344	452	31.3%
4	Chesapeake	1,157	1,442	24.6%
5	Cimarex	275	342	24.4%
6	**Williams**	**612**	**752**	**22.9%**
7	XTO	1,033	1,186	14.8%
8	EOG	718	817	13.8%
9	Apache	597	667	11.6%
10	Chevron	1,634	1,810	10.8%
11	Dominion	753	817	8.4%
12	EnCana	1,096	1,181	7.8%
13	Occidental	553	595	7.6%
14	Newfield	523	544	4.0%
15	El Paso	566	584	3.1%
16	Devon	1,521	1,551	2.0%
17	Shell	1,150	1,163	1.1%
18	ExxonMobil	1,739	1,625	-6.6%
19	BP	2,546	2,376	-6.7%
20	Marathon	578	532	-8.0%
	Total	19,911	22,137	11.2%

Source: Publicly reported data from EvaluateEnergy.com, press releases, and company websites

Williams a Leader in Growing Reserves Organically

Top 20 U.S. Gas Producers - Bcfe
(sorted by Reserves Replacement %)

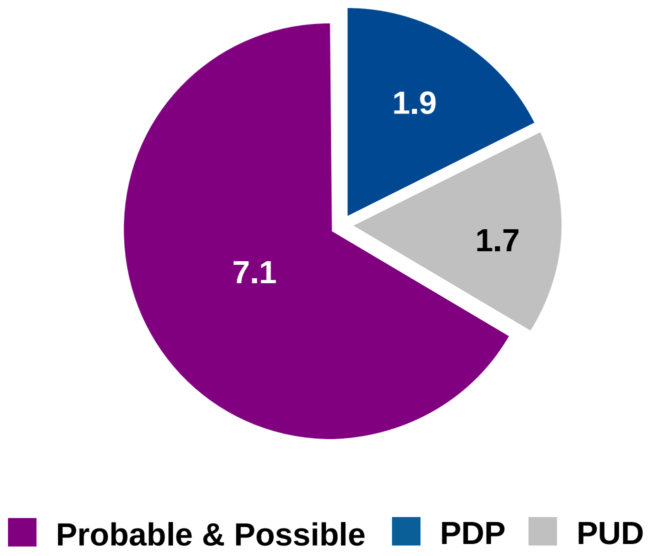
		2005 YE	Net Additions	Production	2006 YE	Reserves Replacement %*	2006 Acquisitions	Acq. % of Net Additions
1	Anadarko	6,578	4,466	558	10,486	800%	4,256	95%
2	ConocoPhillips	7,586	5,755	900	12,441	639%	5,264	91%
3	Chesapeake	6,901	1,945	526	8,319	369%	628	32%
4	Devon	5,164	1,757	566	6,355	310%	580	33%
5	XTO	6,086	1,292	433	6,944	298%	158	12%
6	EOG	2,948	827	304	3,471	272%	17	2%
7	Williams	3,382	596	277	3,701	215%	41	7%
8	Newfield	1,327	397	190	1,535	210%	1	0%
9	Cimarex	1,004	211	125	1,090	169%	55	26%
10	Noble	1,641	263	165	1,739	159%	142	54%
11	Apache	2,566	373	243	2,695	153%	196	52%
12	Occidental	2,338	321	217	2,442	148%	274	85%
13	Dominion	4,856	407	302	4,961	135%	48	12%
14	EnCana	5,267	554	431	5,390	129%	68	12%
15	El Paso	1,831	246	213	1,864	115%	1	0%
16	Shell	2,680	373	424	2,629	88%	97	26%
17	BP	15,382	657	941	15,098	70%	0	0%
18	Chevron	4,428	261	661	4,028	39%	19	7%
19	Marathon	1,209	54	194	1,069	28%	0	0%
20	ExxonMobil	13,692	(937)	706	12,049	-133%	19	-2%
	Total	96,866	19,817	8,376	108,307	237%	11,863	60%

** Reserves Replacement % calculated as follows: (Revisions+Additions+Acquisitions +Divestitures)/Production*

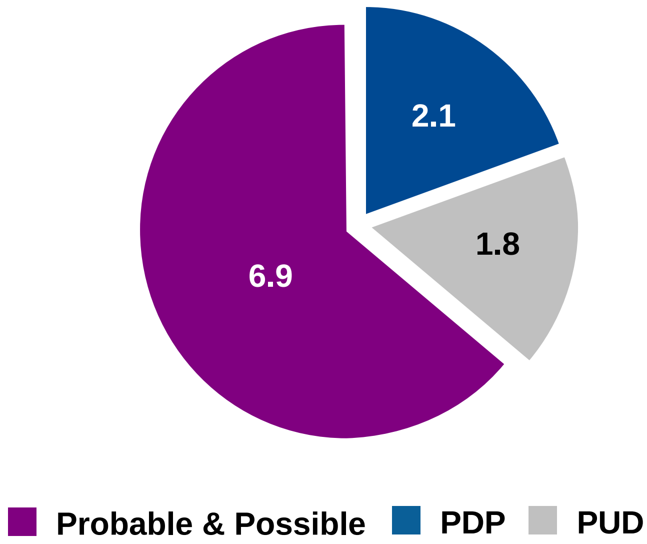
Source: Publicly reported data from EvaluateEnergy.com, press releases, and company websites

3P Reserves and Resource Potential Update

2005 3P Reserves (10.7 Tcfe)



2006 3P Reserves (10.8 Tcfe)

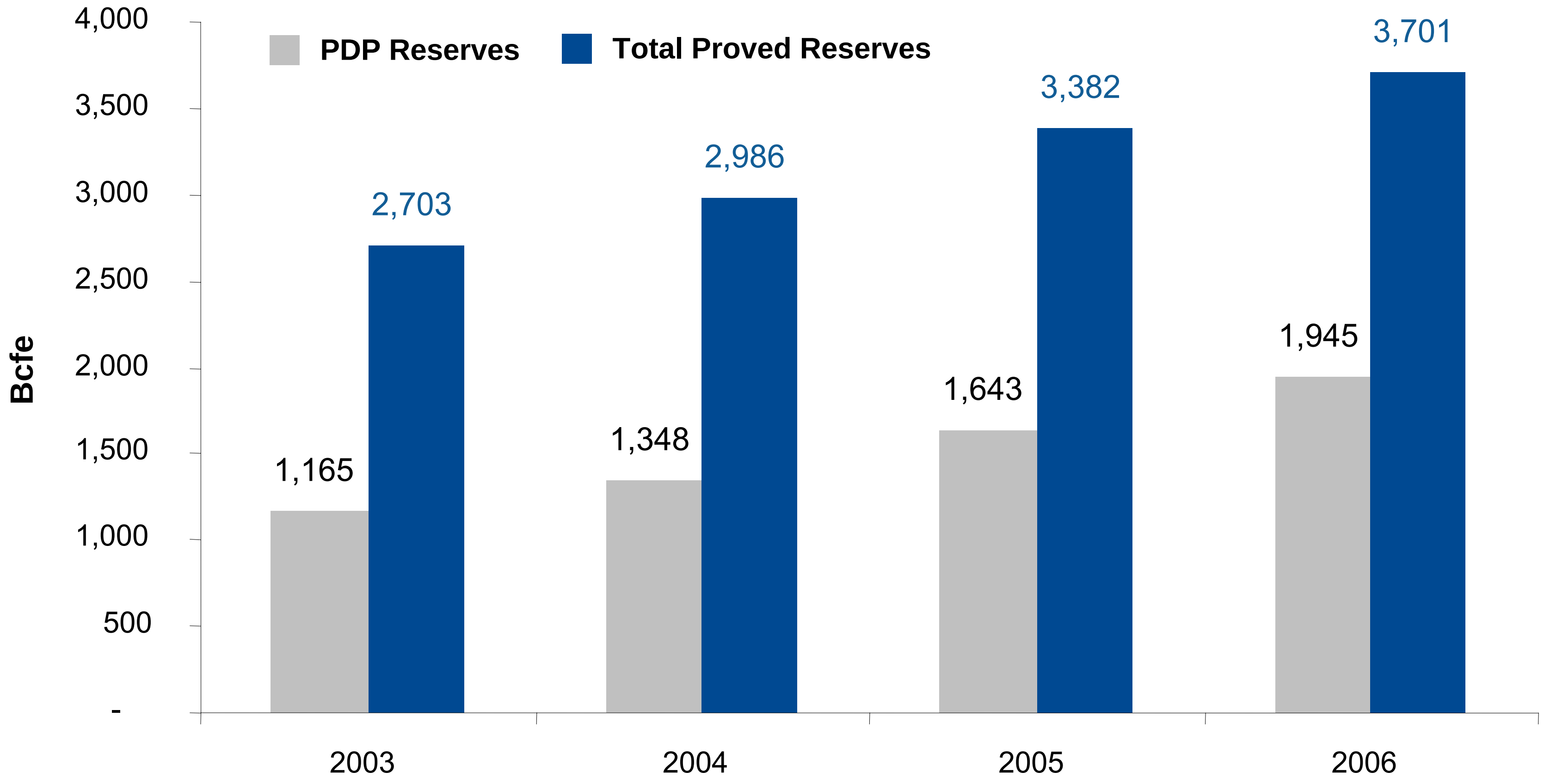


- Proved reserves are up 8% over one year ago
- Proved, probable and possible of 10.8 Tcfe
- Resource potential of up to 22 Tcfe

“Resource potential” is defined as proved, probable and possible reserves plus unrisked theoretical resource estimates that might never be recoverable and are contingent upon exploration success, technical improvements in drilling access, commerciality, and other factors. Unlike probable and possible reserves, unrisked theoretical resource estimates do not take into account the uncertainty of resource recovery and therefore are not indicative of the expected future recovery and should not be relied upon.

Growing Productive Capacity

Domestic PDP's have increased from 43% to 53% over last 4 years



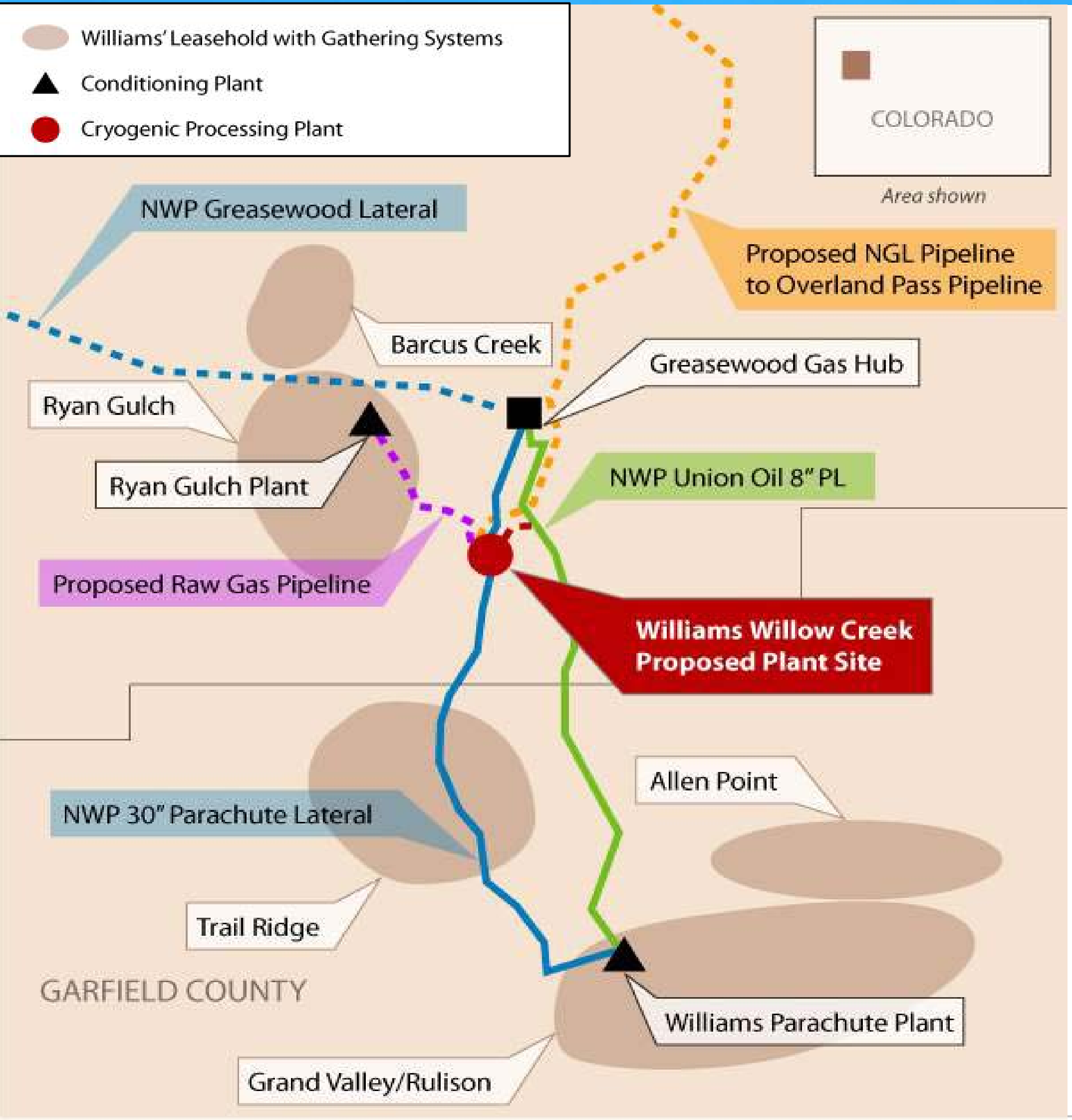
Key Points – Value Creation Continues

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

Midstream

Alan Armstrong
President

Willow Creek Project



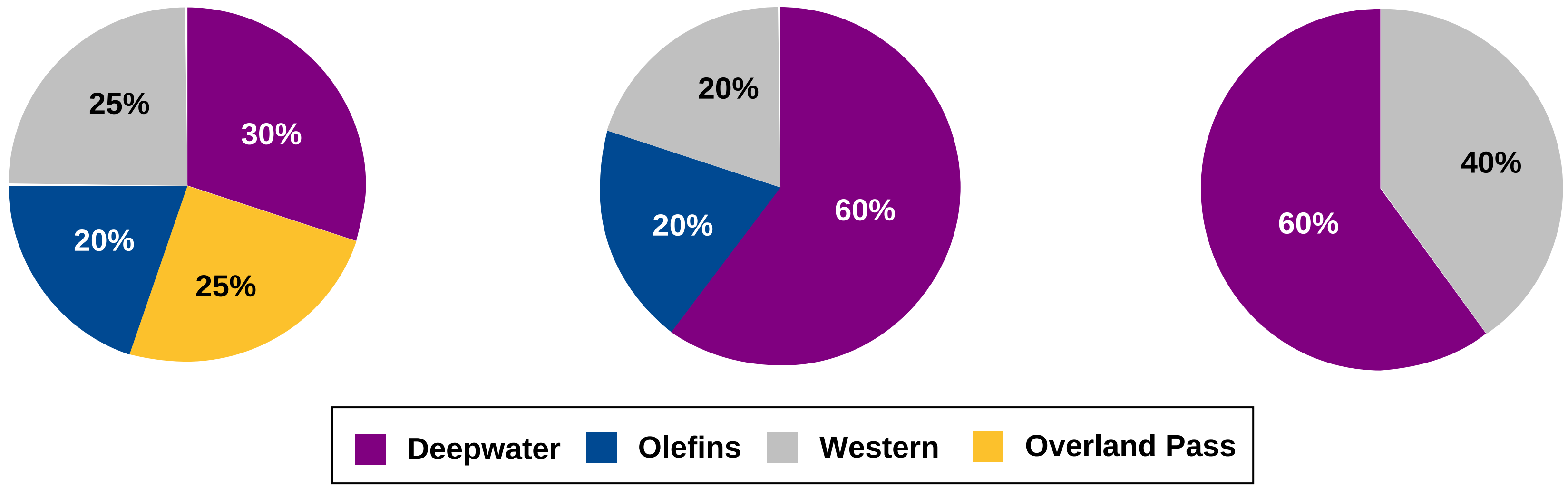
- Williams' Midstream Piceance Basin Entry
  - $350 MM CapEx
  - In-service 3Q 2009
- Coupled with existing E&P infrastructure provides platform for growth
- One of the three largest midstream plays in North America
- Optimizes E&P position value
- Adds significant value to Overland Pass Pipeline
- Increased utilization of NWP

Significant Progress Made on Growth Projects

In Development/Proposal (2007+)
Spending $700MM–1,100MM

Under Negotiation (2007+)
Spending $300MM–500MM

In Guidance (2007+)
Spending $1,000-1,100MM



Major Growth Projects Included in Guidance ($ Millions)

Project Name – In Service Date	2007	2008	Segment Profit*
Willow Creek (3Q ’09)	$110	$205	$30 - 60
Blind Faith (2Q ‘08)	$135	$10	$19
Other Wyoming G&P (4Q ’07 & Various)	$50	$10	$8
Perdido Norte (3Q ’09)	$165	$180	$82

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

2007-08 Consolidated Outlook

Don Chappel
Chief Financial Officer

Williams

2007 Forecast Guidance

Dollars in millions, except per-share amounts	May 3 Guidance	Feb 22 Guidance
Segment profit before MTM adjustment	$1,833 - $2,283	$1,775 - $2,275
Net Interest Expense	(640) - (700)	(640) - (700)
Other (Primarily General Corp. Costs)	(140) - (170)	(140) - (170)
Pretax Income	1,053 - 1,413	995 - 1,405
Provision for Income Tax	(418) - (563)	(395) - (560)
Income from Continuing Operations	$635 - $850	$600 - $845
Income from Discontinued Operations	2	0
Net Income	$637 - $852	$600 - $845
Diluted EPS	$1.04 - $1.39	$0.98 - $1.37
Recurring Income from Continuing Operations	$631 - $846	$600 - $845
Diluted EPS – Recurring	$1.03 - $1.38	$0.98 - $1.37
Diluted EPS – Recurring After MTM Adj. [1]	$1.15 - $1.50	$1.10 - $1.50

[1] *Includes MTM adjustment of $125 million (pretax) in May 3 and Feb. 22 guidance*
Note: Fully diluted shares of 615 million

Note: See slide 75 for commodity price assumptions

2007-08 Segment Profit

Dollars in millions	**2007**	**2008**
Exploration & Production	\$700 - 975	\$950 - 1,250
Midstream	500 - 750 *450*	550 - 825
Gas Pipeline	585 - 655	590 - 665
Power	(75) - 0	(130) - 20
Other / Corp. / Rounding	23 - (22) *15 - (30)*	(15) - 35
Total Reported Before MTM Adj. [1]	\$1,833 - 2,283 *1,775 - 2,275*	\$1,945 - 2,795
MTM Adjustment	125	180
Total Reported After MTM Adj. [1]	\$1,958 - 2,408 *1,900 - 2,400*	\$2,125 - 2,975
Nonrecurring Items	(8) *0*	-
Total Recurring After MTM Adj. [1]	**\$1,950 - 2,400** *1,900*	**\$2,125 - 2,975**

Power After MTM Adj.	\$50 - 125	\$50 - 200

Note: If guidance has changed, previous guidance from 2/22/07 is shown in italics directly below. [1] Sum of the ranges for the business units does not match the consolidated total due to the offsetting effect of natural gas prices within our business units. See slide 75 for commodity price assumptions

2007-08 Capital Expenditures

Dollars in millions	2007	2008
Exploration & Prod.	$1,300 - 1,400	$1,250 - 1,400
Midstream	550 - 600 *430 - 470*	475 - 525 *260 - 300*
Gas Pipeline	425 - 535	285 - 410
Power	-	-
Other/Corporate	10 - 30	10 - 30
Total	$2,350 - 2,550 *2,225 - 2,425*	$2,075 - 2,350 *1,850 - 2,125*

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

2007-08 Outlook

Dollars in millions	2007	2008
Segment Profit		
Reported After MTM Adj.	$ 1,958 - 2,408 *1,900 - 2,400*	$2,125 - 2,975
Recurring After MTM Adj.	1,950 - 2,400 *1,900*	2,125 - 2,975
DD&A	1,010 - 1,110 *970 - 1,070*	1,130 - 1,230 *1,110 - 1,210*
Cash Flow from Ops.[1]	2,000 - 2,300	2,425 - 2,825
Capital Expenditures	2,350 - 2,550 *2,225 - 2,425*	2,075 - 2,350 *1,850 - 2,125*
Operating Free Cash Flow [2]	(350) - (250) *(225) - (125)*	350 - 475 *575 - 700*

[1] Cash flow from continuing operations.

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

Note: If guidance has changed, previous guidance from 2/22/07 is shown in italics directly below

Financial Strategy/Key Points

Williams

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

Summary

Steve Malcolm
Chairman, President & CEO

Value-growth catalysts to watch

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

Q&A

Non-GAAP Reconciliations

Non-GAAP Disclaimer

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

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

Non-GAAP Reconciliation Schedule

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

(Dollars in millions, except per-share amounts)	2006 *1st Qtr*	2006 *2nd Qtr*	2006 *3rd Qtr*	2006 *4th Qtr*	2006 *Year*	2007 *1st Qtr*
Income (loss) from continuing operations available to common stockholders	$131.1	($63.9)	$110.1	$155.5	$332.8	$131.8
Income (loss) from continuing operations - diluted earnings (loss) per common share	$0.22	($0.11)	$0.19	$0.25	$0.55	$0.22
Nonrecurring items:						
Gas Pipeline						
Reversal of litigation contingency due to favorable ruling - TGPL	(2.0)	-	-	-	(2.0)	-
Total Gas Pipeline nonrecurring items	(2.0)	-	-	-	(2.0)	-
Midstream Gas & Liquids						
Reversal of a maintenance accrual	-	-	-	-	-	(7.9)
Gains on sales of MGL properties	-	-	(7.9)	-	(7.9)	-
Adjustment of accounts payable accrual	-	-	10.6	-	10.6	-
Losses on asset retirements and abandonments	-	-	5.2	-	5.2	-
Accrual for Gulf Liquids litigation contingency	-	68.0	2.4	2.3	72.7	-
Settlement of an international contract dispute	(6.3) [1]	-	-	-	(6.3)	-
Total Midstream Gas & Liquids nonrecurring items	(6.3)	68.0	10.3	2.3	74.3	(7.9)
Power						
Reduction of contingent obligations associated with our former distributive power generation business	-	-	(12.7)	-	(12.7)	-
Accrual for litigation contingencies [(1)]	-	-	3.5	1.3	4.8	-
Total Power nonrecurring items	-	-	(9.2)	1.3	(7.9)	-
Nonrecurring items below segment profit (loss)						
Impairment of cost-based investment - Petrowayu (Investing income / loss - Exploration & Production)	-	-	-	16.4	16.4	-
Securities litigation settlement and related costs [(1)]	1.2	160.7	3.4	2.0	167.3	-
Reversal of interest accrual related to reversal of litigation contingency noted above (Interest accrued - Gas Pipeline - TGPL)	(5.0)	-	-	-	(5.0)	-
Early debt retirement costs (Corporate and Exploration & Production)	27.0 [1]	4.4	-	-	31.4	-
Gain on sale of Algar/Triangulo shares (Investing income / loss - Other)	(6.7)	-			(6.7)	-
Interest related to Gulf Liquids litigation contingency (Interest accrued - Midstream)	-	20.0	0.6	1.4	22.0	1.4
	16.5	185.1	4.0	19.8	225.4	1.4
Total nonrecurring items	8.2	253.1	5.1	23.4	289.8	(6.5)
Tax effect for above items [(1)]	3.4	76.6	1.8	2.8	84.6	(2.5)
Adjustment for nonrecurring excess deferred tax provision	-	-	-	7.4	7.4	-
Adjustment for tax benefit related to federal income tax litigation	-	-	-	(25.1)	(25.1)	-
Recurring income from continuing operations available to common stockholders	$135.9	$112.6	$113.4	$158.4	$520.3	$127.8
Recurring diluted earnings per common share	$0.23	$0.19	$0.19	$0.26	$0.86	$0.21
Weighted-average shares - diluted (thousands)	607,073	595,561	609,062	610,352	608,627	611,470

[(1)] The tax rate applied to Midstream's international contract dispute settlement in 1st quarter 2006 is 34%. The tax rate applied to nonrecurring items for 2nd quarter 2006 has been adjusted for the effect of nondeductible expenses associated with securities litigation settlement and related costs and early debt retirement costs related to our convertible debt. The tax rate applied to 3rd and 4th quarter 2006 has been adjusted for the effect of nondeductible expenses associated with the securities litigation settlement and related costs. The tax rate applied to 4th quarter 2006 has also been adjusted for the effect of a nondeductible international impairment.

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

Non-GAAP Reconciliation Schedule

Reconciliation of Segment Profit to Recurring Segment Profit

(UNAUDITED)

(Dollars in millions)	2006 *1st Qtr*	2006 *2nd Qtr*	2006 *3rd Qtr*	2006 *4th Qtr*	2006 *Year*	2007 *1st Qtr*
Segment profit (loss):						
Exploration & Production	$ 147.6	$ 119.8	$ 144.5	$ 139.6	$ 551.5	$ 188.1
Gas Pipeline	134.7	122.7	109.0	101.0	467.4	149.7
Midstream Gas & Liquids	151.5	130.7	212.2	163.9	658.3	154.0
Power	(22.5)	(79.6)	(69.7)	(39.0)	(210.8)	(81.1)
Other	1.0	(0.7)	(0.2)	1.8	1.9	0.7
Total segment profit	**$ 412.3**	**$ 292.9**	**$ 395.8**	**$ 367.3**	**$ 1,468.3**	**$ 411.4**
Nonrecurring adjustments:						
Exploration & Production	$ -	$ -	$ -	$ -	$ -	$ -
Gas Pipeline	(2.0)	-	-	-	(2.0)	-
Midstream Gas & Liquids	(6.3)	68.0	10.3	2.3	74.3	(7.9)
Power	-	-	(9.2)	1.3	(7.9)	-
Other	-	-	-	-	-	-
Total segment nonrecurring adjustments	**$ (8.3)**	**$ 68.0**	**$ 1.1**	**$ 3.6**	**$ 64.4**	**$ (7.9)**
Recurring segment profit (loss):						
Exploration & Production	$ 147.6	$ 119.8	$ 144.5	$ 139.6	$ 551.5	$ 188.1
Gas Pipeline	132.7	122.7	109.0	101.0	465.4	149.7
Midstream Gas & Liquids	145.2	198.7	222.5	166.2	732.6	146.1
Power	(22.5)	(79.6)	(78.9)	(37.7)	(218.7)	(81.1)
Other	1.0	(0.7)	(0.2)	1.8	1.9	0.7
Total recurring segment profit	**$ 404.0**	**$ 360.9**	**$ 396.9**	**$ 370.9**	**$ 1,532.7**	**$ 403.5**

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

Non-GAAP Reconciliation Schedule – EPS after MTM adjustment

Dollars in millions except per share amounts

	2007 1Q	2007 2Q	2007 3Q	2007 4Q	2007 Year
Recurring income from cont. ops available to common shareholders	**$ 128**				**$ 128**
Recurring diluted earnings per common share	**$ 0.21**				**$ 0.21**
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	71				71
Add realized gains/losses from MTM previously recognized	8				8
Total MTM adjustments	79				79
Tax effect of total MTM adjustments	31				31
After tax MTM adjustments	48				48
Recurring income from cont. ops available to common shareholders after MTM adjust.	**$ 176**				**$ 176**
Recurring diluted earnings per share after MTM adj.	**$ 0.29**				**$ 0.29**
weighted average shares - diluted (thousands)	611,470				611,470

	2006 1Q	2006 2Q	2006 3Q	2006 4Q	2006 Year
Recurring income from cont. ops available to common shareholders	**$ 136**	**$ 113**	**$ 113**	**$ 158**	**$ 520**
Recurring diluted earnings per common share	**$ 0.23**	**$ 0.19**	**$ 0.19**	**$ 0.26**	**$ 0.86**
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	(43)	38	16	11	22
Add realized gains/losses from MTM previously recognized	77	100	80	25	282
Total MTM adjustments	34	138	96	36	304
Tax effect of total MTM adjustments	13	53	37	14	116
After tax MTM adjustments	21	85	59	22	188
Recurring income from cont. ops available to common shareholders after MTM adjust.	**$ 157**	**$ 198**	**$ 172**	**$ 180**	**$ 708**
Recurring diluted earnings per share after MTM adj.	**$ 0.26**	**$ 0.33**	**$ 0.28**	**$ 0.30**	**$ 1.17**
weighted average shares - diluted (thousands)	607,073	595,561	609,062	610,352	608,627

EBITDA Reconciliation

Dollars in millions	1Q07
Net Income	$ 134
Income from Discontinued Operations	(2)
Net Interest Expense	168
DD&A	248
Provision for Income Taxes	82
EBITDA	$ 630

1Q 2007 Segment Contribution

Dollars in Millions

	E&P	Midstream	Gas Pipeline	Power	Other	Total
Segment Profit (Loss)	$ 188	$ 154	$ 150	$ (81)	$ -	**$ 411**
DD&A	114	53	77	2	2	**248**
Segment Profit (Loss) before DDA	**$ 302**	**$ 207**	**$ 227**	**$ (79)**	**$ 2**	**$ 659**
General Corporate Expenses						**(39)**
Investing Income*						**22**
Other Income						**(12)**
TOTAL						**$ 630**

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

2007 Forecast EBITDA Reconciliation

Dollars in millions	**May 3 Guidance**	**Feb 22 Guidance**
Net Income	**$637 - 852**	**$600 - 845**
Income from Discontinued Operations	(2)	-
Net Interest	640 - 700	640 - 700
DD&A	1,010 - 1,110	970 - 1,070
Provision for Income Taxes	418 - 563	395 - 560
Other/Rounding	(3)	(5) - 0
EBITDA	**$2,700 - 3,220**	**$2,600 - 3,175**
MTM Adjustments	125	125
EBITDA - After MTM Adj.	**$2,825 - 3,345**	**$2,725 - 3,300**

2007 Forecast Segment Contribution

Dollars in millions	**E&P**	**Midstream**	**Gas Pipeline**	**Power** [1]	**Corp/ Other**	**Total**
Segment Profit (Loss)	$700 - 975	$500 - 750	$585 - 655	$(75) - 0	$23 - (22)	$1,833 - 2,283 [2]
DD&A	485 - 535	205 - 215	310 - 330	0 - 10	10 - 20	1,010 - 1,110
Segment Profit Before DDA	$1,185 - 1,510	$705 - 965	$895 - 985	$(75) - 10	$33 - (2)	$2,843 - 3,393 [2]
Other (Primarily General Corporate Expense & Investing Income)						(140) - (170)
Rounding						(3)
TOTAL						$2,700 - 3,220

[1] Segment Profit assumes no future unrealized MTM gains or losses

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

2007 Forecast Guidance Contribution

Dollars in millions, except per-share amounts	May 3 Guidance	Feb 22 Guidance
Net Income	**$637 - 852**	**$600 - 845**
Less: Income From Disc. Ops	**$2**	**-**
Income from Continuing Operations:	**$635 - 850**	**$600 - 845**
Non-Recurring Items (Pretax)	(7)	-
Less Taxes	(3)	-
Non-Recurring After Tax	(4)	-
Recurring Income from Cont. Ops	**631 - 846**	**600 - 845**
Recurring EPS	**$1.03 - $1.38**	**$0.98 - $1.37**
Mark-to-Market Adjustment (Pretax)	125	125
Less Taxes @ 39%	49	49
Mark-to-Market Adjust. After Tax	76	76
Inc. from Cont. Ops after MTM Adj.	**707 - 922**	**676 - 921**
Inc. from Cont. Ops after MTM Adj. EPS	**$1.15 - $1.50**	**$1.10 - $1.50**

Appendix

Exploration & Production

Segment Profit

Dollars in millions	1st Quarter 2007	1st Quarter 2006
Segment Profit	$188	$148
Nonrecurring	-	-
Recurring segment profit	$188	$148

> 1Q06 to 1Q07 financial highlights:
- 25% total production growth
- 27% segment profit growth

2007-08 Guidance

Dollars in millions	**2007**	**2008**
Segment Profit	$700 - 975	$950 - 1,250
Annual DD&A	485 - 535	575 - 625
Segment Profit + DD&A	$1,185 - 1,510	$1,525 - 1,875
Capital Spending	$1,300 - 1,400	$1,250 - 1,400
Production (MMcfe/d)	905 - 1,005	990 - 1,140

Note: 2007-08 hedge information included on slide 52

Rockies Producer Not Necessarily a Rockies Price Taker

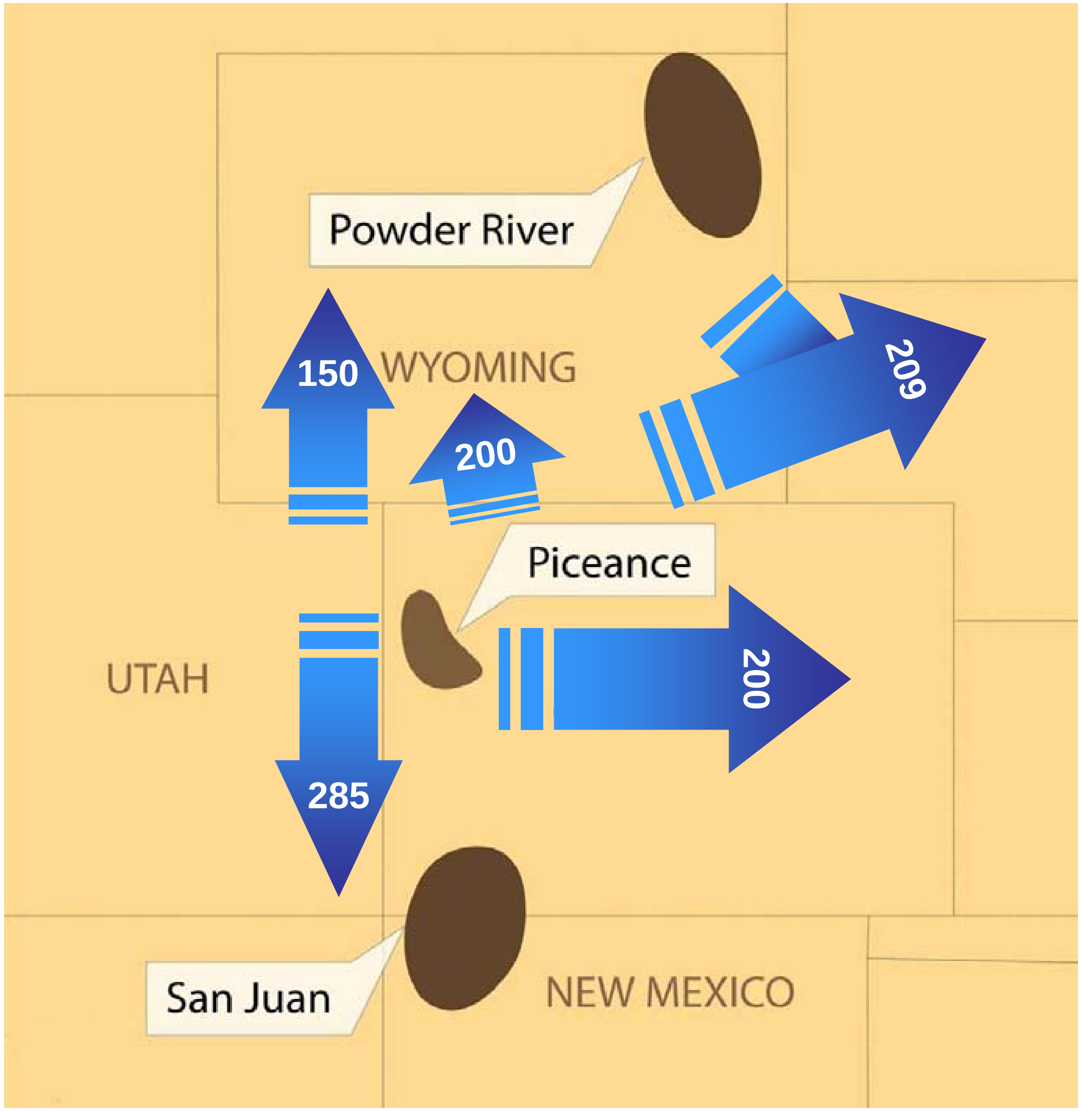
- Rockies price risk managed through transport and basis hedges
- Our contracted pipeline capacity to moves our Rockies production to more favorable price markets

Firm Capacity Under Contract

Wamsutter	**200**
East to Midcontinent	**209**
South to San Juan	**285**

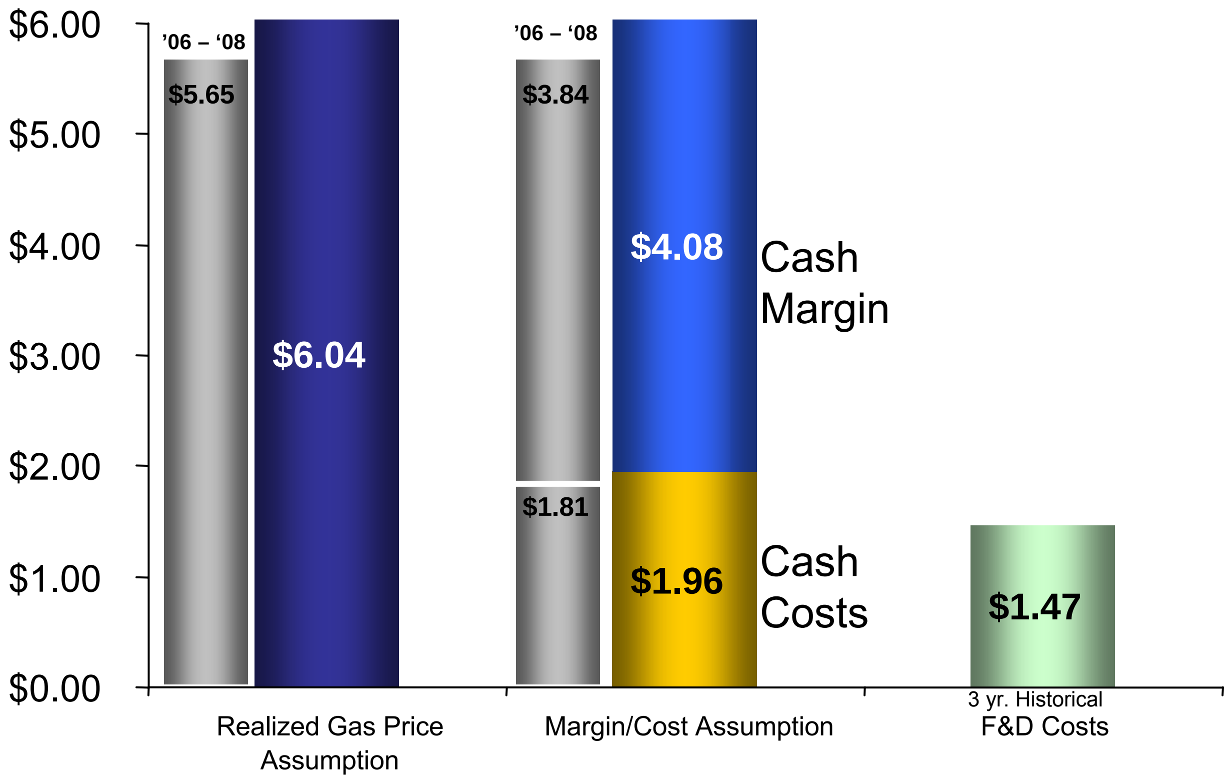
Addt'l Firm Capacity Coming in '08-'09

Opal	**150**
East to Appalachia (REX)	**200**



Cash Margin Analysis

2-Year Average (2007-08)



Reflective of core basins

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

1Q07 Net Realized Price Summary

	Unhedged	Hedge
Market Price:		
NYMEX	$6.70 - $6.85	$4.14
NYMEX & Basis Collars		0.89
Basis Differential	(0.40) - (0.50)	(0.28)
Net basin market price	$6.20 - $6.45	$4.75
Net basin market price	**$6.20 - $6.45**	**$4.75**
Fuel & Shrinkage/Gathering/ Transportation	(0.50) - (0.60)	(0.50) - (0.60)
Net Price	**$5.60 - $5.95**	**$4.15 - $4.25**
Quarter Volume Totals	(qtr daily volumes - qtr daily volumes) x (90/1000)	(qtr daily hedge volumes) x (90/1000)
Net Gas Revenue	=(unhedged volumes x net price)	=(hedged volumes x net hedge price)

2007-08 Hedge Update

Dollars in millions	2Q-4Q 2007	2008
Fixed Price at the basis		
Volume (MMcf/d)	172	73
Average Price ($/Mcf)	$3.89	$3.96
Collars [1]		
Nymex		
Volume (MMcf/d)	15	
Average Price ($/Mcf)	$6.50 - $8.25	
NWPL		
Volume (MMcf/d)	50	125
Average Price ($/Mcf)	$5.65 - $7.45	$6.02 - $9.18
EPNG San Juan		
Volume (MMcf/d)	130	75
Average Price ($/Mcf)	$5.98 - $9.63	$6.20 - $9.16
Mid-Continent		
Volume (MMcf/d)	77	10
Average Price ($/Mcf)	$6.82 - $10.75	$7.12 - $8.67

[1] Please note basin locations are not NYMEX

Note: The only remaining legacy fixed price hedges are in 2009 of 109MMcfd @ $3.67 and in 2010 of 70MMcfd @ $3.73

Midstream

Segment Profit

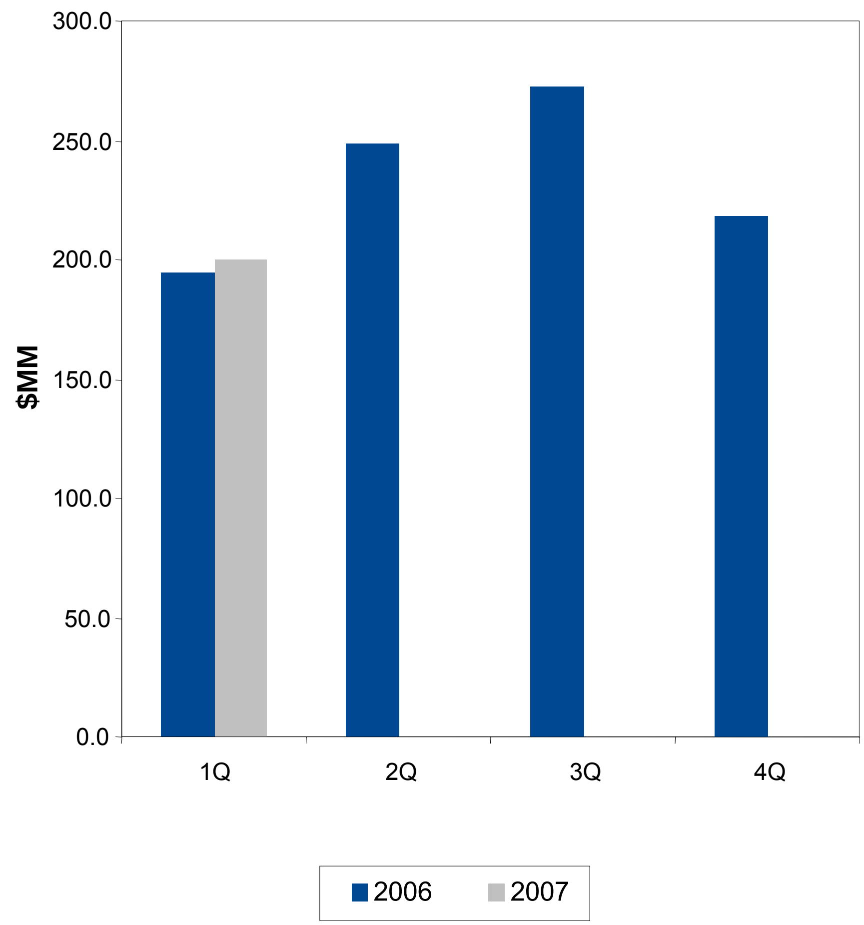
Dollars in millions	1st Quarter 2007	1st Quarter 2006
Segment Profit	$154	$151
Nonrecurring		
Maintenance Expense Accrual Reversal	(8)	-
International Contract Settlement	-	(6)
Recurring segment profit	$146	$145

> 1Q07 to 1Q06 financial drivers:
- Higher liquids unit margins & volumes
- Deepwater volumes moderate from 1Q ’06
- Higher expenses
  - Property insurance on Gulf assets
  - Depreciation
  - Favorable fuel contract expiration
  - General and administrative expense

2007 Accomplishments

- Record first quarter recurring segment profit
- NGL unit margins set new first quarter record
- Willow Creek project announced
- On-time start up of Opal TXP-5
- Deepwater construction efforts

Recurring Segment Profit + Depreciation

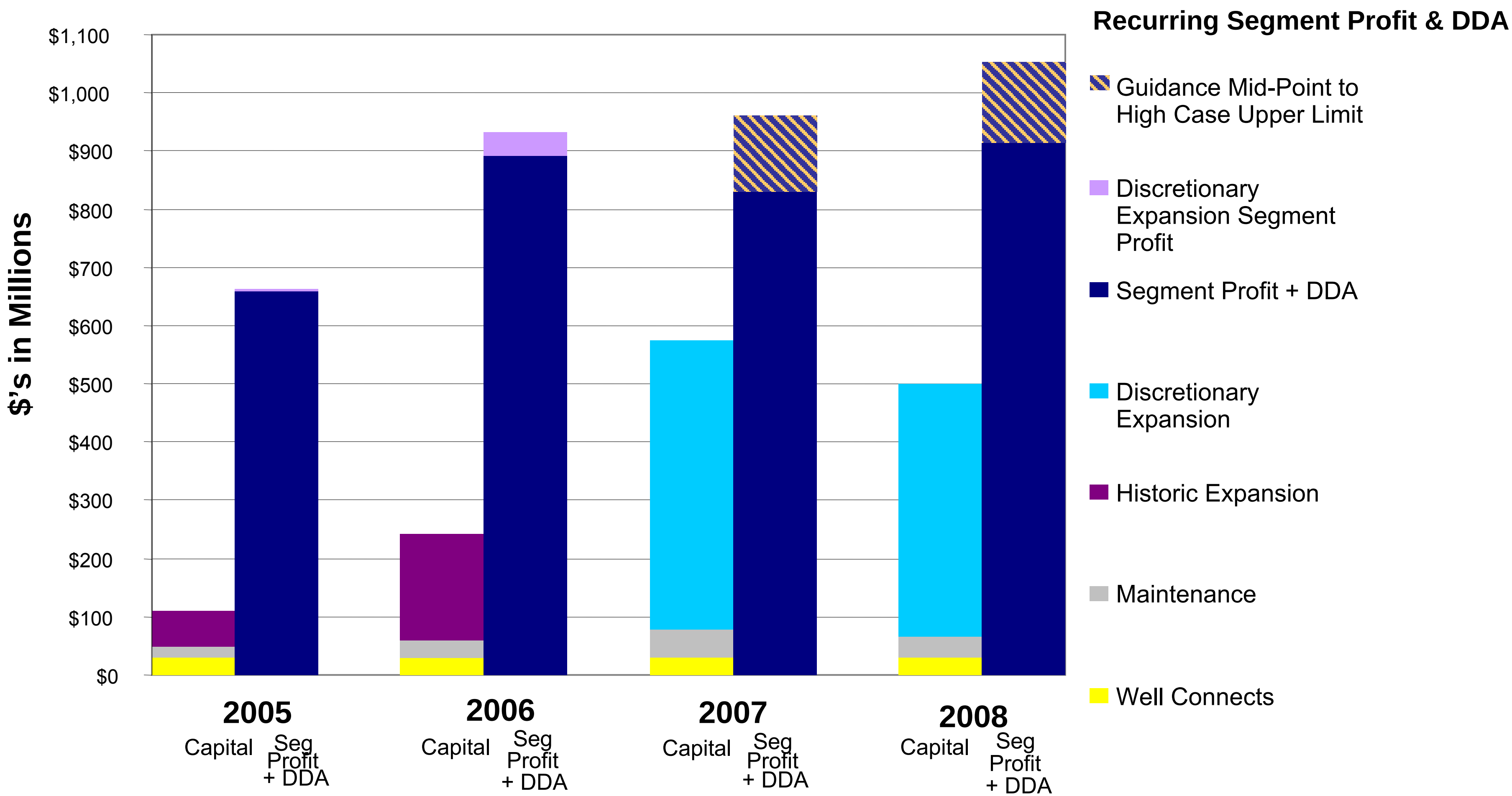


2007-08 Guidance

Dollars in millions	**2007**	**2008**
Segment Profit	$500 - 750 *$450 - 750*	$550 - 825
Annual DD&A	205 - 215 *$200 – 210*	220 - 230
Segment Profit + DD&A	$705 - 965 *$650 - 960*	$770 – 1,055
Capital Spending	$550 – 600 *$430 - 470*	$475 - 525 *$260 - 300*

Note: If guidance has changed, previous guidance from 2/22/2007 is shown in italics directly below.

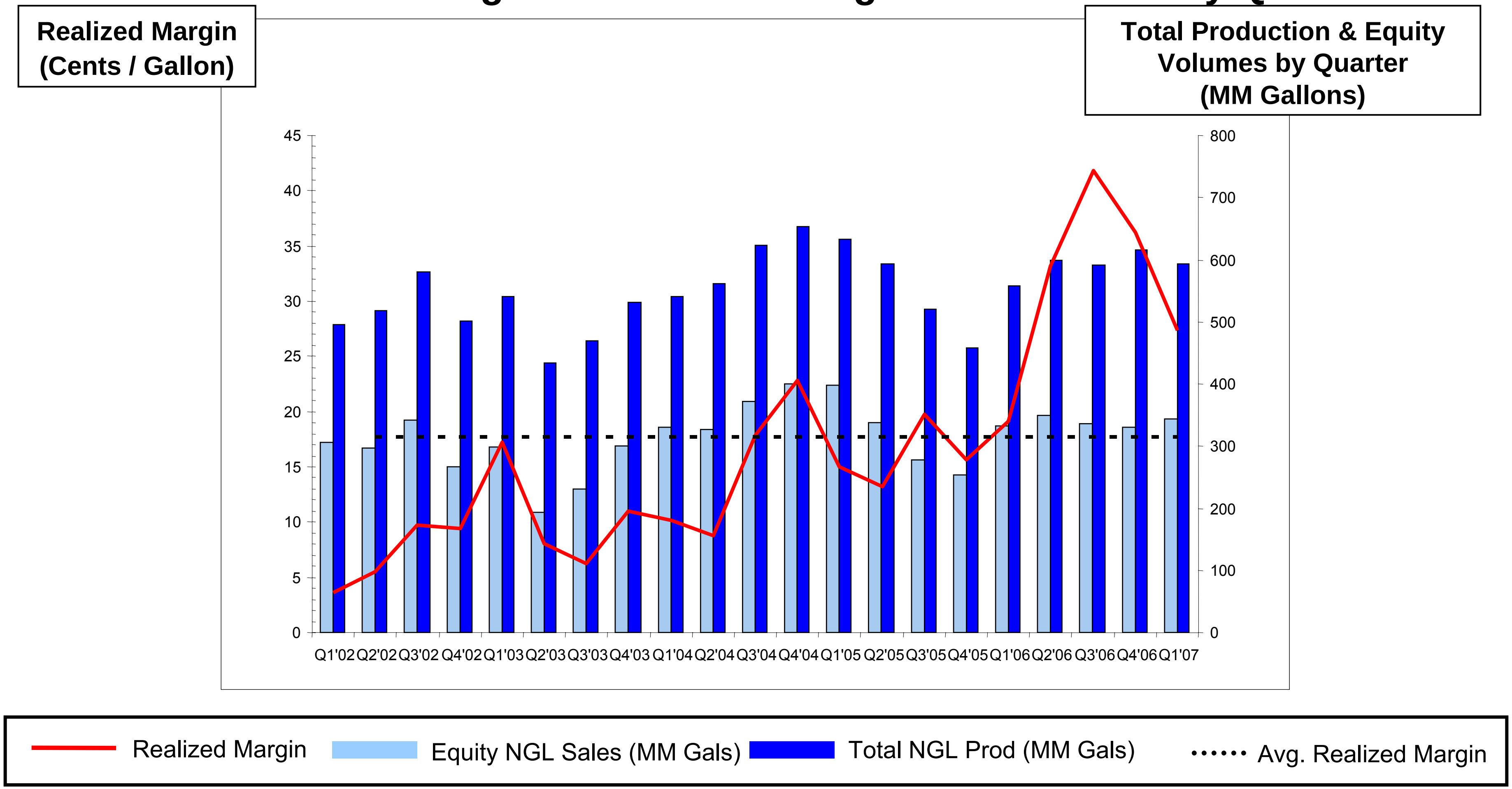
Free Cash Flow - Forecast



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

Margins Above Average

Domestic NGL Average Realized Net Margin and Volumes by Quarter



Note: Actual realized margins, does not include Discovery volumes. Five year average of 17.6 cpg is calculated for the period 2Q02-1Q07.

Key Points

- Willow Creek project marks Midstream's Piceance Basin entry
- Well positioned for growth
- NGL margins remain near historic levels
- Differentiating our business on reliability
- Base business continues to generate healthy returns and free cash flows

Gas Pipeline

Segment Profit

Dollars in millions	1st Quarter 2007	1st Quarter 2006
Segment Profit	$150	$135
Nonrecurring		
Excess royalty reserve reversal	-	(2)
Recurring segment profit	$150	$133

> 1Q07 to 1Q06 financial highlights:
- Higher revenues due primarily to rate filings - $33 million
  - NWP effective January 1, 2007
  - Transco effective March 1, 2007
- Partially offset by higher costs related to insurance and DD&A

2007 Accomplishments

Northwest:

- Rate case settlement receives FERC approval on March 30, 2007
- Received top ranking in Mastio & Company's 2007 Customer Value Benchmarking Study
- Jackson Prairie Deliverability Expansion receives FERC approval

Transco:

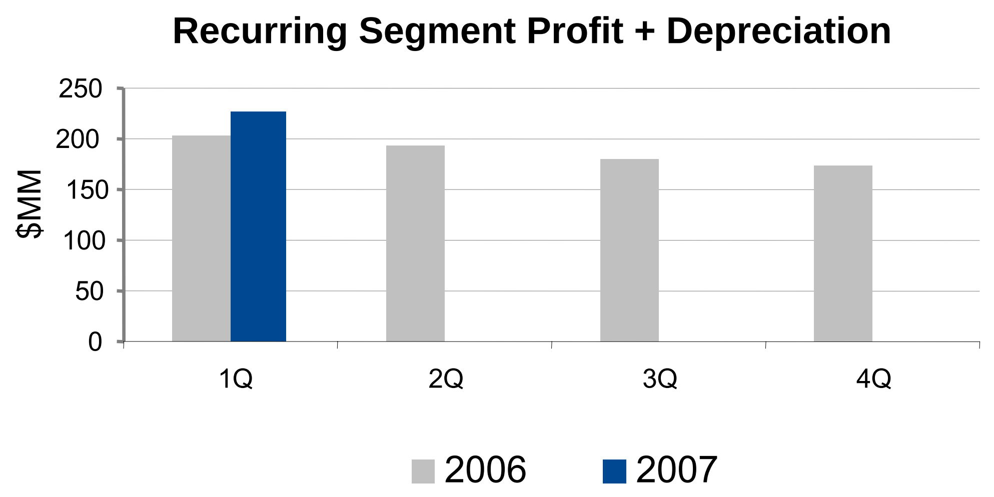
- Filed rate case August 31, effective March 1, 2007, negotiations progressing
- Potomac certificate issued, in service date November 2007
- Leidy to Long Island construction commenced, in service date November 2007
- Commenced open season for Eminence Enhancement Project

Gulfstream:

- All shipper conditions met for Gulfstream Phase III

WGP:

- Pacific Connector Project has successful open season



2007-08 Guidance

Dollars in millions	**2007**	**2008**
Segment Profit	$585 - 655	$590 - 665
Annual DD&A	310 - 330 *280 - 300*	320 - 340 *300 - 325*
Segment Profit + DD&A	$895 - 985 *865 - 955*	$910 - 1,005 *890 – 990*
Capital Spending	$425 - 535	$285 - 410

Note: If guidance has changed, previous guidance from 02/22/07 is shown in italics directly below.

2007-08 Capital Spending Detail

Dollars in millions	2007	2008
Normal Maintenance/Compliance	$215-270	$180 - 260
Expansion	210 - 265	105 - 150
Total	$425-535	$285 - 410

Note: If guidance has changed, previous guidance from 02/22/07 is shown in italics directly below.

Major Growth Projects Included In Guidance ($ Millions)

Project Name – In-Service Date	2007	2008	Segment Profit*
Parachute (5/07)	$35 - 40		$7
Leidy to Long Island (11/07)	85 - 115	1 - 5	23
Potomac (11/07)	55 - 65	1 - 5	13
Sentinel (Phase 1 - 11/08, Phase 2 - 11/09)	5 - 15	70 - 80	25
Jackson Prairie Deliverability (11/08)	5 - 10	5 - 15	2

* Segment Profit - Segment profit generated in first full year of operation

Key Points

- NWP rate case settlement receives FERC approval on March 30, 2007
- Growth projects progressing on schedule
  - 2007 Projects:
    - Leidy to Long Island
    - Potomac
    - Parachute
- Transco rate case settlement discussions underway
- 2007 supported by new rate cases and lower capital expenditures
- Return to cash generator in 2007

Power

Segment Profit

Dollars in millions	1st Quarter 2007	1st Quarter 2006
Segment Loss	($81)	($23)
Nonrecurring		
	-	-
Recurring segment profit	($81)	($23)
MTM Adjustment (Recurring)	79	34
Recurring segment profit/(loss) after MTM Adj.	($2)	$11

> 1Q07 to 1Q06 financial highlights include:
- Q106 includes $24MM income from the sale of certain receivables

2007 - Segment Profit/(Loss) to Cash Flow from Ops

Dollars in Millions

	Commodity Power & NG	Working Capital/ Other	Total
Segment Loss	($62)	($19)	($81)
MTM Adjustments:			
Reverse Forward Unrealized MTM Losses	71		71
Add Realized Gains from MTM Previously Recognized	8		8
Segment Profit/(Loss) After MTM Adjustments	17	(19)	(2)
Total Working Capital and Other Change		(16)	(16)
Power Segment CFFO	**$17**	**($35)**	**($18)**

2007-08 Guidance

Dollars in millions	**2007**	**2008**
Prior Guidance - Segment Profit/(Loss) before MTM Adj	($75) – 0	($130) – 20
Est. Fwd Impact of 1Q07 MTM Earnings and other portfolio adjustments	0	0
New Guidance - Segment Profit/(Loss) before MTM Adj	($75) – 0	($130) –20
Estimated MTM Adjustments	125	180
Segment Profit after MTM Adj	50 - 125	50 - 200
Recurring Segment Profit after MTM Adj	**$50 - 125**	**$50 - 200**
Capital Expenditures	-	-

Note: If guidance has changed, previous guidance from 2/22/07 is shown in italics directly below.

Enterprise Risk Management

WMB Collateral Sensitivity

Dollars in millions

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

Days	3/31/2007	12/31/2006	9/30/2006	6/30/2006
30	($199)	($98)	($155)	($246)
180	($442)	($434)	($459)	($580)
360	($559)	($521)	($471)	($489)

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

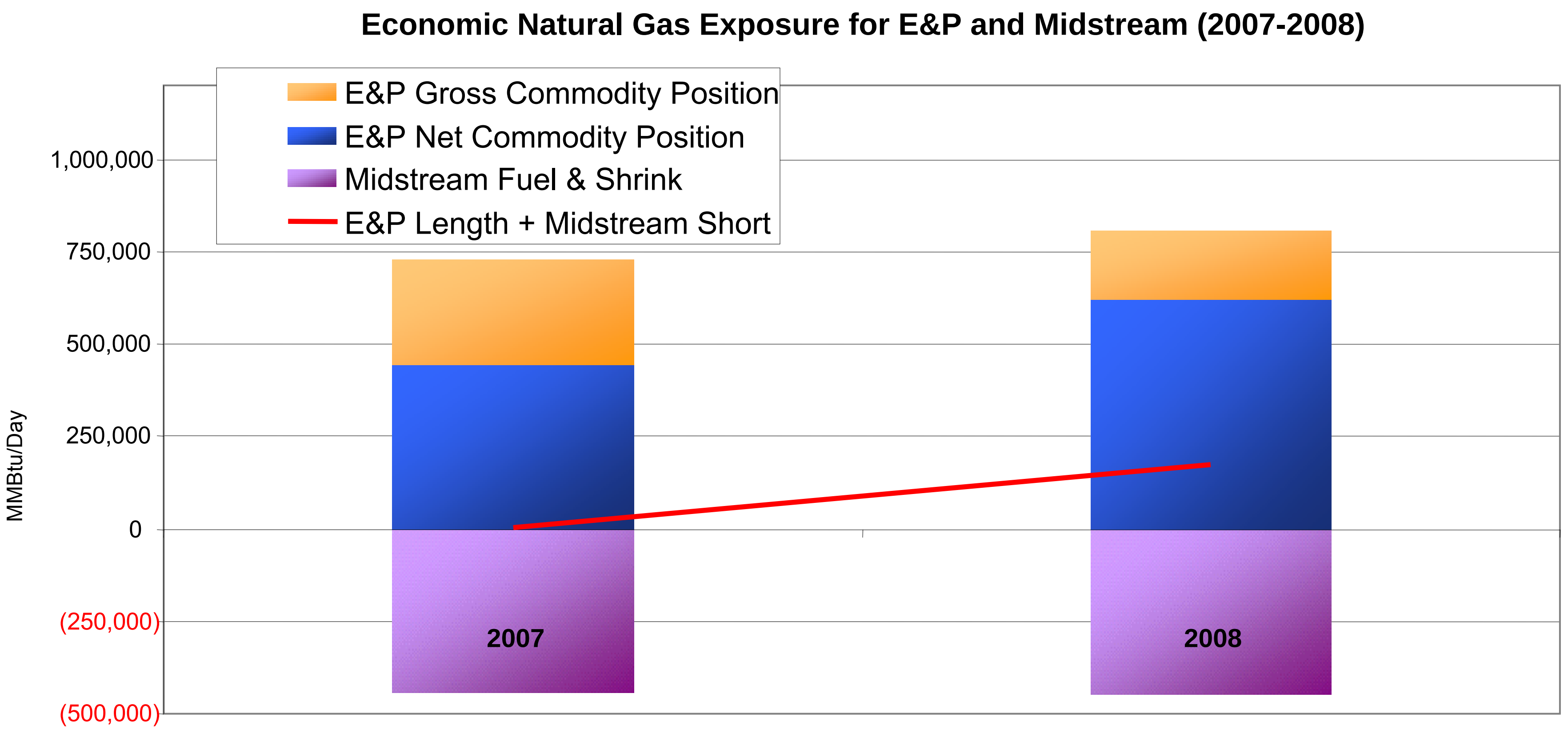
Sensitivity Analysis

Dollars in millions, except per unit increases

	Enterprise[1] Natural Gas Per MMBtu	Power Co.[2] Power Per MWh	Midstream[3] Processing Margin Per Gallon of NGL's
Increase	**$0.10**	**$1**	**$0.01**
2007	$4-$6 MM	$1-$3 MM	$12-$14 MM
2008	$13-$15 MM	$4-$6 MM	$15-$17 MM

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

Natural hedges in our commodity businesses



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

Consolidated

Commodity Price Summary

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

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

Note: Oil is $/Bbl and natural gas is $/Mcf

Liquidity at March 31, 2007

Dollars in millions

Cash and cash equivalents		$ 1,811
Other current securities		235
Less:		
Subsidiary and Int'l cash & cash equivalents	$ 528	
Customer margin deposits payable	204	(732)
Available unrestricted cash		1,314
Available revolver capacity		1,841
Total Liquidity		**$ 3,155**

2007 Cash Information

Dollars in millions

	1st Quarter
Beginning unrestricted cash	**$ 2,269**
Cash flow from continuing operations	300
Capital expenditures	(509)
Debt retirements	(119)
Dividends	(54)
Dividends to minority interests	(20)
Other-net	(56)
Change in cash and cash equivalents	$ (458)
Ending unrestricted cash at 03/31/07	**$ 1,811**
Restricted cash at 03/31/07 (not included above)	$ 92

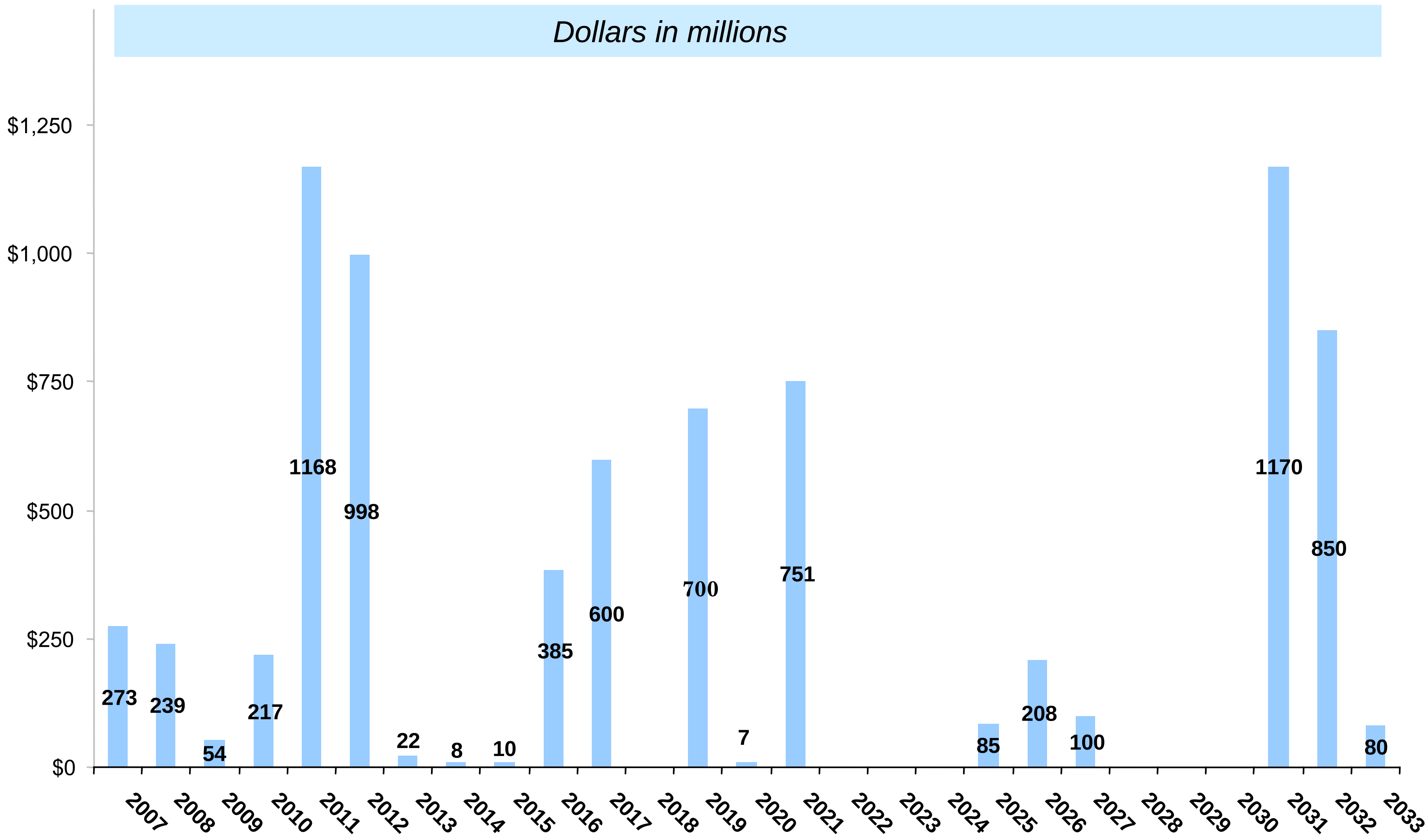
Debt Balance[1]

Dollars in millions

		Avg. Cost
Debt Balance @ 12/31/06	**$8,014**	**7.6%**
Scheduled Debt Retirements & Amortization	(119)	
Debt Balance @ 3/31/07	**$7,895**	**7.7%**
Fixed Rate Debt @ 03/31/07	**$7,751**	**7.7%**
Variable Rate Debt @ 03/31/07	**$144**	**6.4%**

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

Debt Amortization – As of 3/31/2007



EPS Metrics

2007	1Q	2Q	3Q	4Q	Total
Diluted EPS from Cont. Ops.	$0.22	-	-	-	$0.22
Recurring EPS	0.21	-	-	-	0.21
Recurring EPS after MTM Adj.	**0.29**	**-**	**-**	**-**	**0.29**
Average Shares (MM)	611	-	-	-	611

2006	1Q	2Q	3Q	4Q	Total
Diluted EPS from Cont. Ops.	$0.22	($0.11)	$0.19	$0.25	$0.55
Recurring EPS	0.23	0.19	0.19	0.26	0.86
Recurring EPS after MTM Adj.	**0.26**	**0.33**	**0.28**	**0.30**	**1.17**
Average Shares (MM)	607	596	609	610	609

2007 Interest Expense Forecast Guidance

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

2007 Effective Tax Rates

	2007 First Quarter	
Statutory Rate	75	35%
State	5	3%
Foreign	3	2%
Other	(1)	-1%
Tax Provision	82	39%

	2007	2008
Full Year Effective Tax Rate Guidance	**40%**	**40%**
Cash Tax Rate Guidance	**5-10%**	**5-10%**

The Williams Companies, Inc.