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): November 30, 2005

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))

Item 7.01. Regulation FD Disclosure.

The Williams Companies, Inc. ("Williams") wishes to disclose for Regulation FD purposes its slide presentation, furnished herewith as Exhibit 99.1, to be utilized during a public conference call and webcast the morning of November 30, 2005.

The slide presentation is 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' slide presentation dated November 30, 2005.

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: November 30, 2005

/s/ Brian K. Shore

Name: Brian K. Shore
Title: Secretary

INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
Exhibit 99.1	Copy of Williams' slide presentation dated November 30, 2005.

Exhibit 99.1

Williams Midstream & Power Update

November 30, 2005

Williams

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 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.

Agenda

- Midstream Update — 8:30 a.m. - 10:30 a.m.
- Break — 10:30 a.m. - 10:45 a.m.
- Power Update — 10:45 a.m. - 12:15 p.m.

Williams Midstream & Power Update

Steve Malcolm
Chairman, President & CEO

Midstream Update

Alan Armstrong
Senior Vice President, Midstream

November 30, 2005

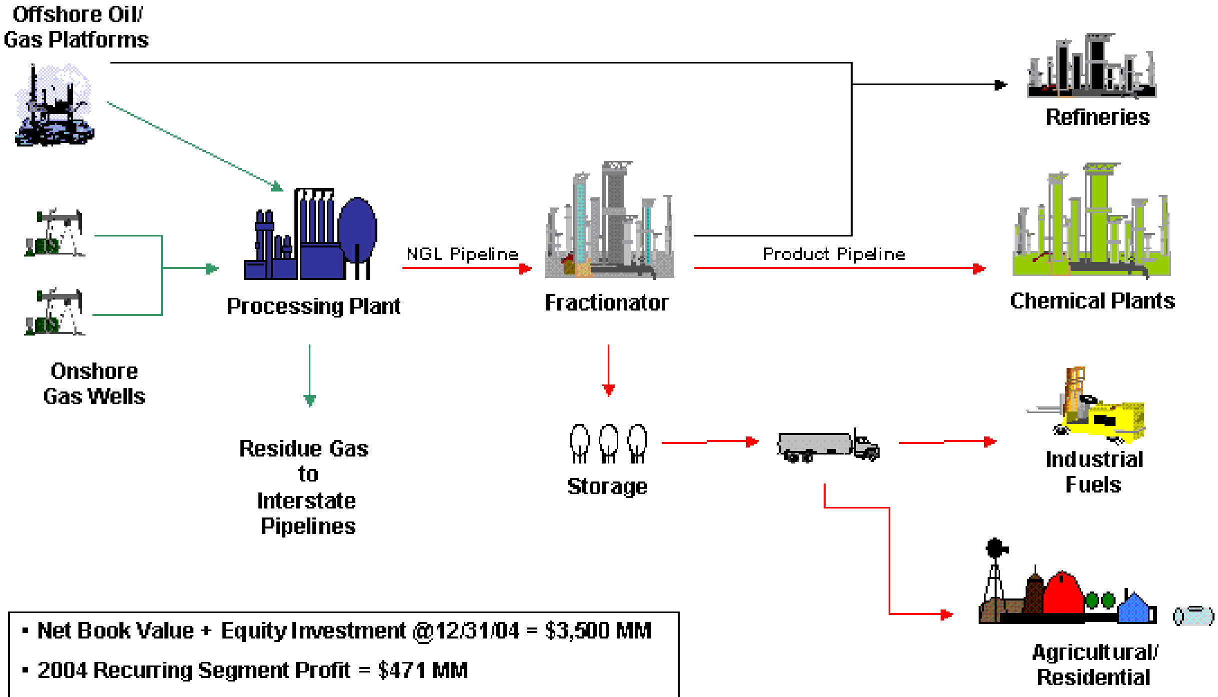
Williams

Agenda

- Midstream Strategy and Outlook — Alan Armstrong
- Midstream Deepwater Gulf of Mexico Story — Rory Miller
- Dissecting Midstream's Earnings — Dave Darcey
- Conclusion and Wrap Up — Alan Armstrong
- Q&A

Midstream

What is Midstream's Business?



- Net Book Value + Equity Investment @12/31/04 = $3,500 MM
- 2004 Recurring Segment Profit = $471 MM
- 2004 Recurring Segment Profit + DD&A = $649 MM

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

Business Overview

- **Strategy Overview**
- **Regional Overview**
- **Growth Overview**

Strategy & Business Focus

Strategy

We safely operate large-scale midstream infrastructure where there is a high potential for extremely high capacity utilization and low per-unit costs. We leverage the scale of these assets to defend the lowest-cost operations in the markets we serve. We consistently attract new business to our assets by providing the highest level of reliability.

Customer Value Proposition

Williams delivers the most reliable midstream services that maximize the value of our reserves.

Business Focus

Productive Capacity
Large-volume, high-utilization factors on large-scale gathering and processing assets.

Competitive Necessity

Quality
Be considered the most reliable service provider.

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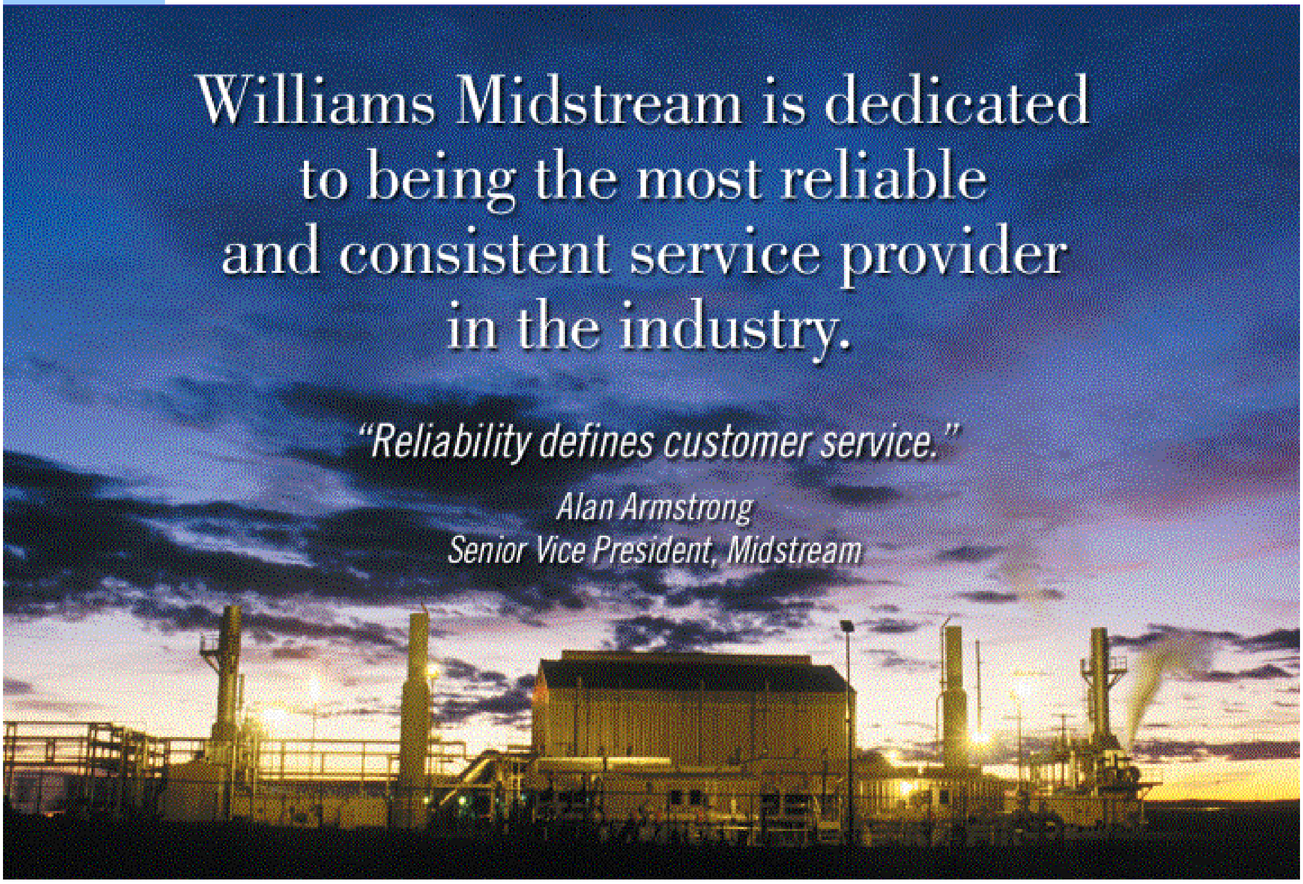
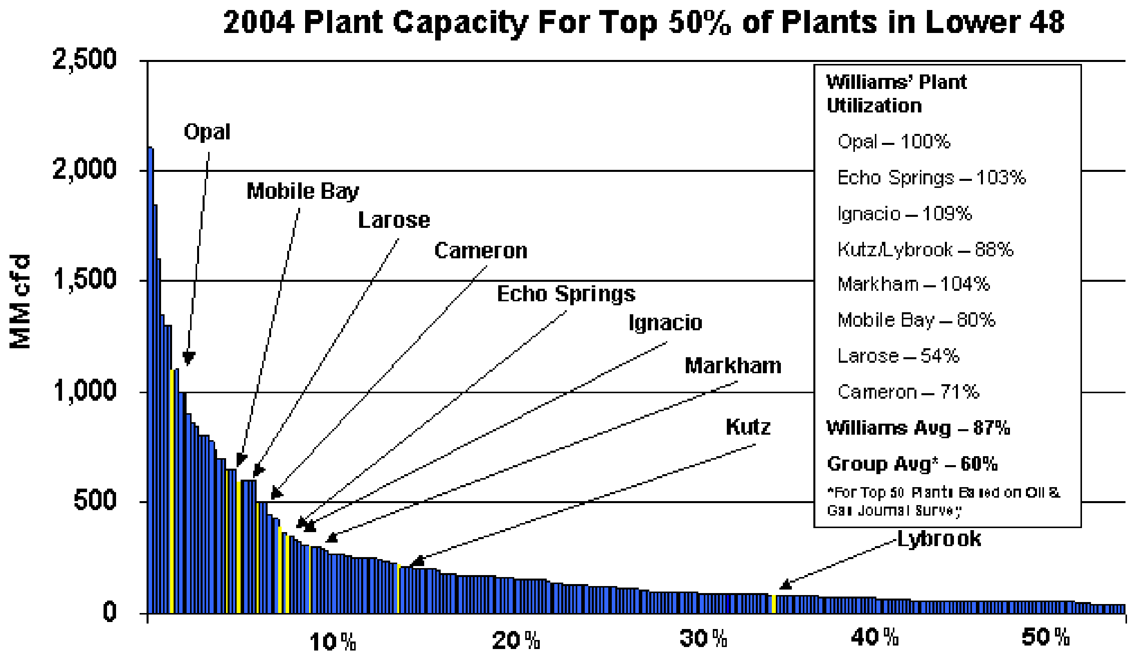
Reliability



Midstream

Gas Processing Plant Scale And Utilization



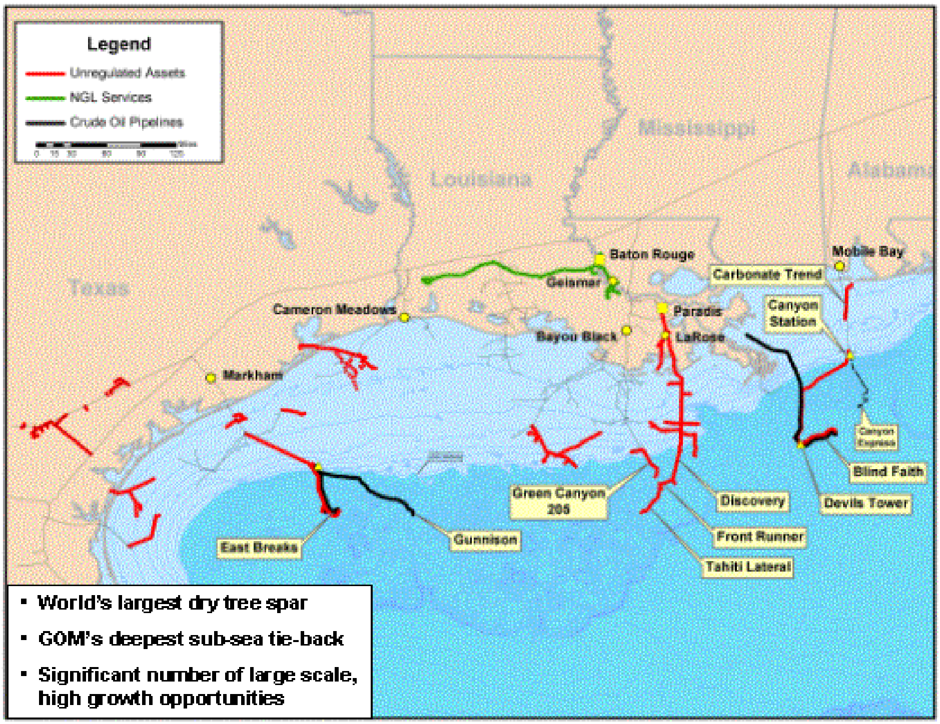
Midstream

Business Overview

- Strategy Overview
- Regional Overview
- Growth Overview

Midstream

Gulf Coast Assets



- World's largest dry tree spar
- GOM's deepest sub-sea tie-back
- Significant number of large scale, high growth opportunities

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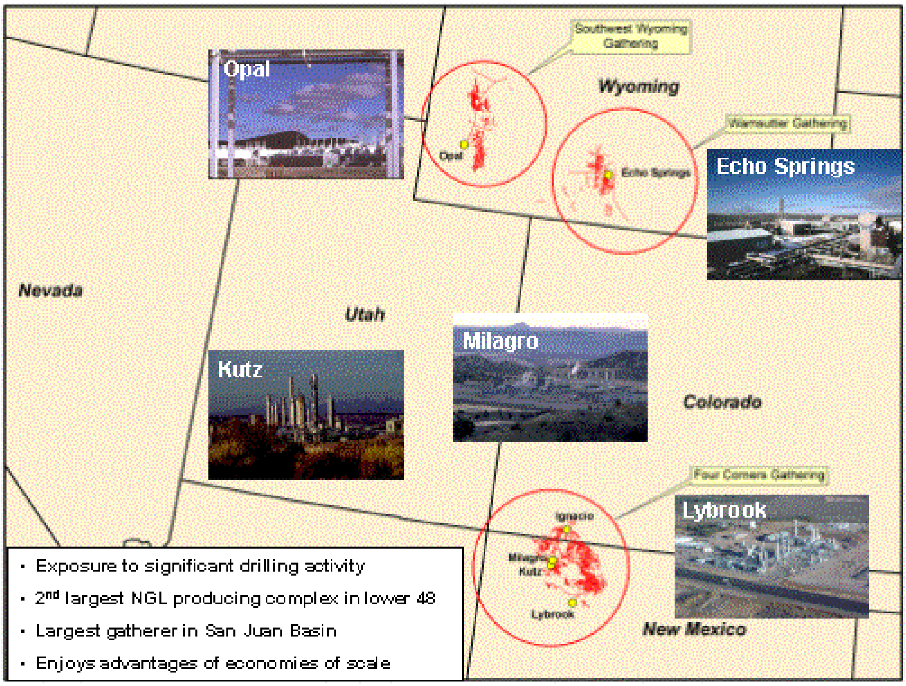
West Region Assets



- Exposure to significant drilling activity
- 2nd largest NGL producing complex in lower 48
- Largest gatherer in San Juan Basin
- Enjoys advantages of economies of scale

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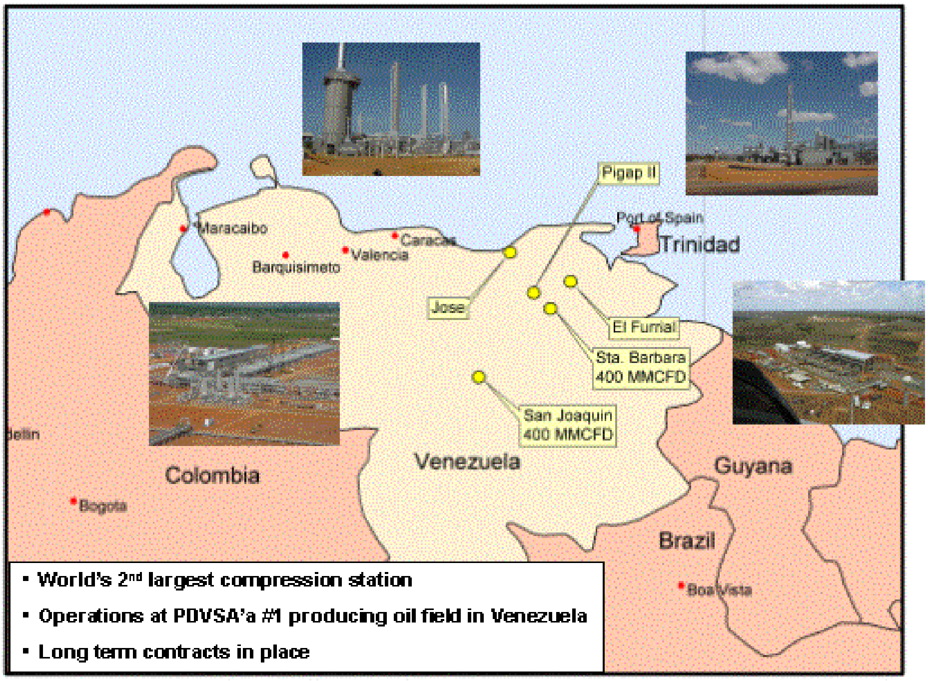
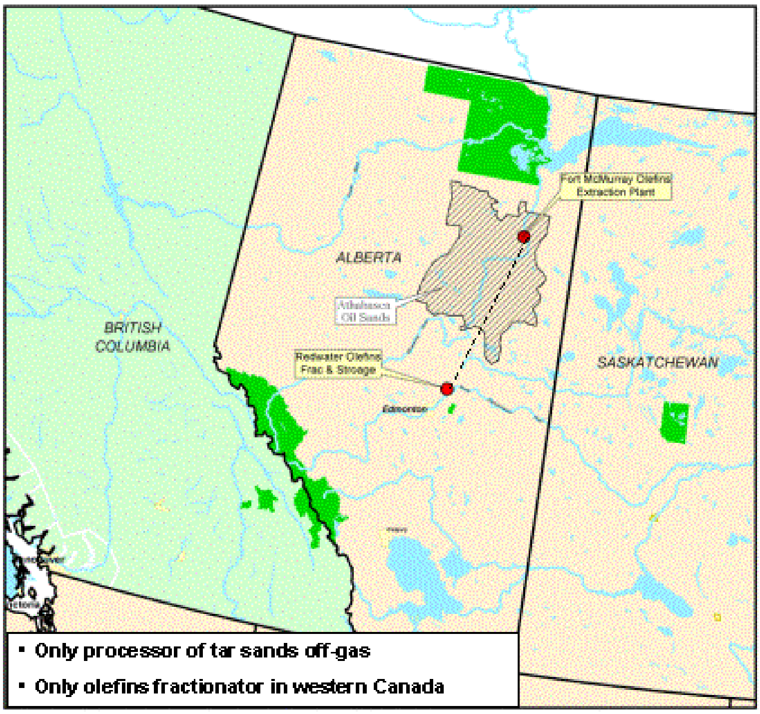
Venezuela Assets



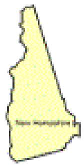
- World's 2nd largest compression station
- Operations at PDVSA'a #1 producing oil field in Venezuela
- Long term contracts in place

Midstream

Canadian Assets



- Only processor of tar sands off-gas
- Only olefins fractionator in western Canada

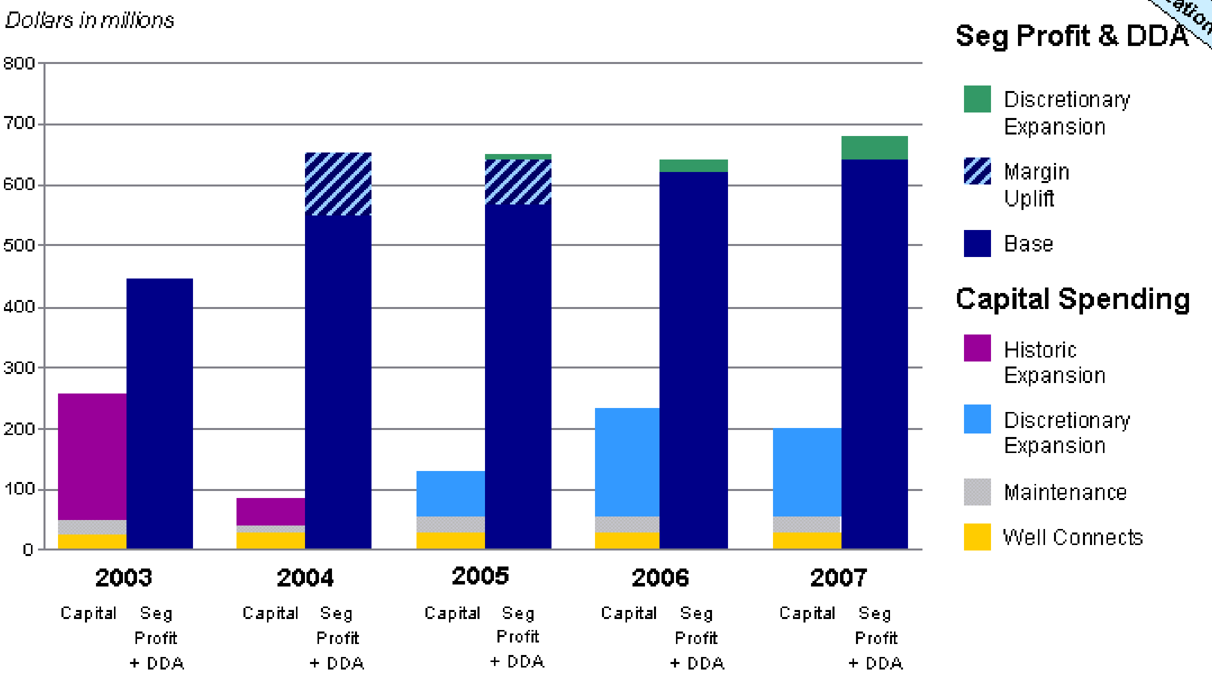


Business Overview

- Strategy Overview
- Regional Overview
- Growth Overview

Strong Free Cash Flow

From 3Q 2005 Analyst Presentation



Note:
- Segment Profit is stated on a recurring basis. Segment Profit for 2003 & 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.

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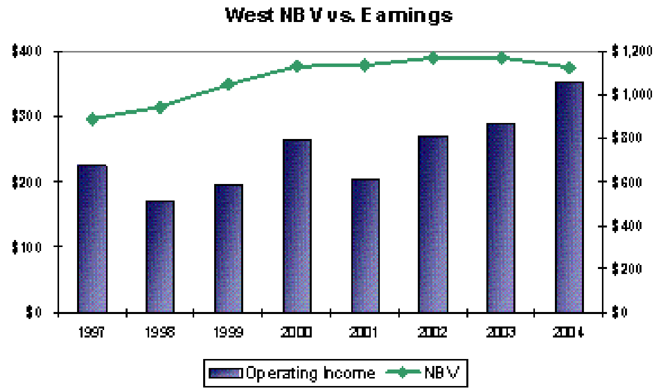
Midstream

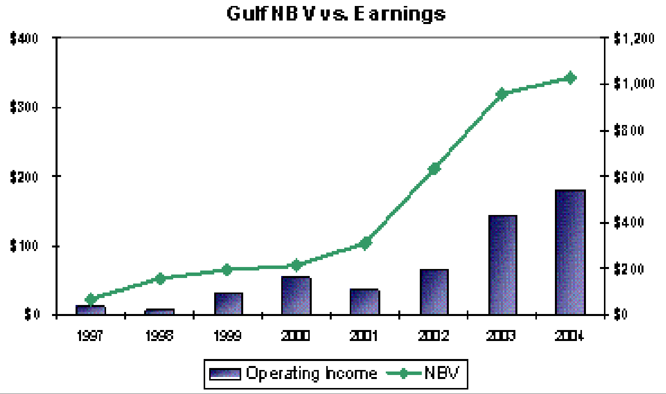
Life Cycle Comparison – West Versus Gulf

Operating Income + DD&A



Net Book Value

Operating Income + DD&A

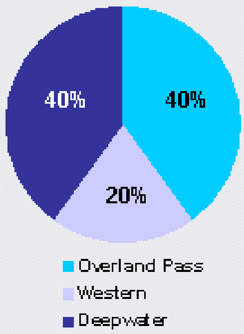


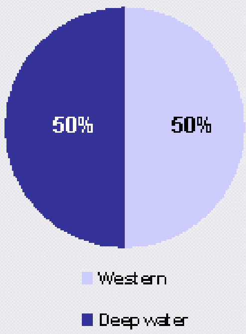
Net Book Value

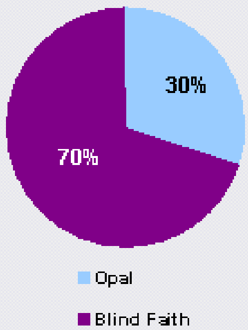
Midstream

Major Growth Projects Update

Development/Proposal Stage 2006 **2007 2008** Spending $500-700MM	Under Negotiation 2006 **2007** 2008 Spending $200-300MM	Contracted/Approved 2005 **2006** 2007 Spending $250MM
Western G&P Expansions Overland Pass NGL Pipeline Deepwater Expansions	**Western Region:** Wamsutter Phase II Echo Springs TXP-IV **Deepwater:** Bass Lite Telemark Pipelines	Blind Faith Opal TXP-V







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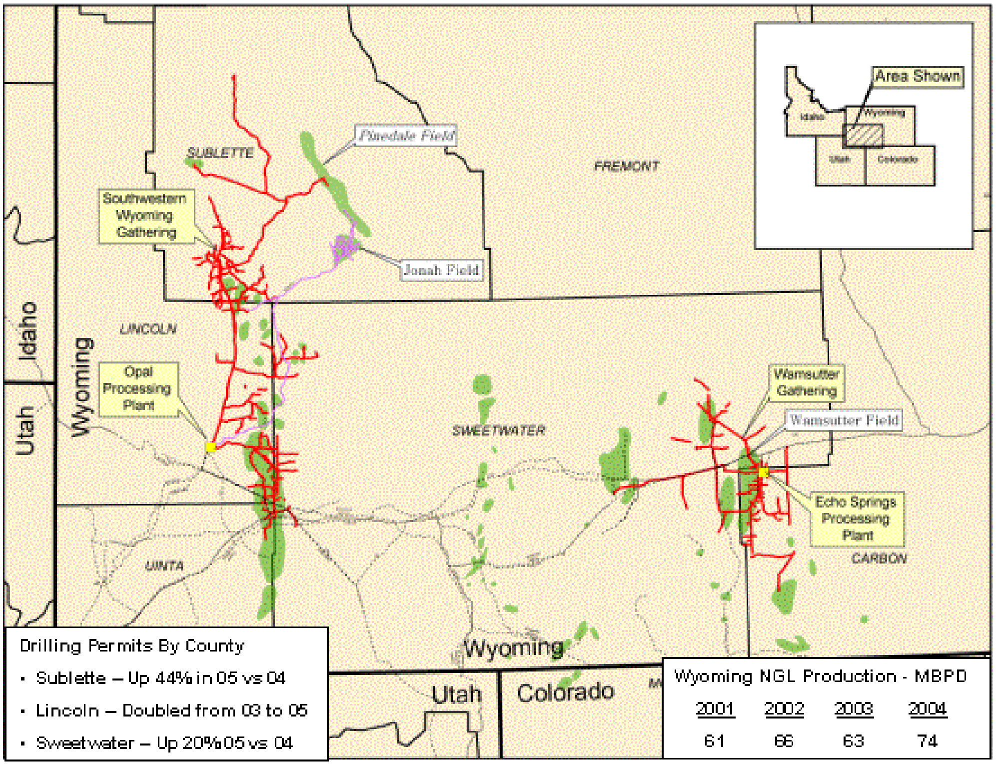
Wyoming Assets



Drilling Permits By County

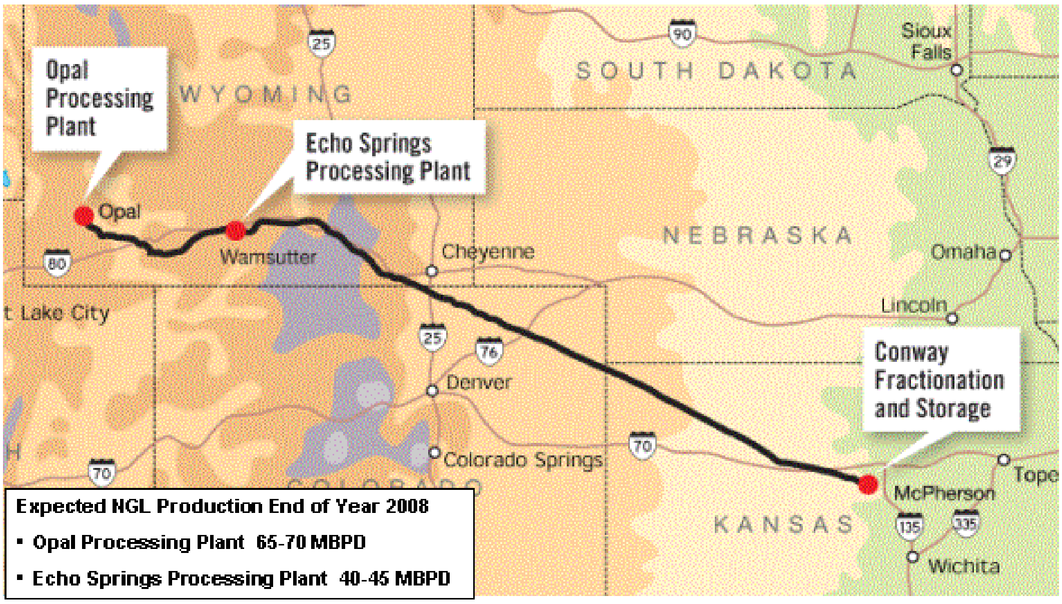
- Sublette – Up 44% in 05 vs 04
- Lincoln – Doubled from 03 to 05
- Sweetwater – Up 20% 05 vs 04

Wyoming NGL Production - MBPD

2001	2002	2003	2004
61	66	63	74

Midstream

Proposed Overland Pass Pipeline



Expected NGL Production End of Year 2008

- **Opal Processing Plant 65-70 MBPD**
- **Echo Springs Processing Plant 40-45 MBPD**

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The Midstream Deepwater Gulf of Mexico Story

Rory Miller, Vice President Gulf Coast Midstream

November 30, 2005

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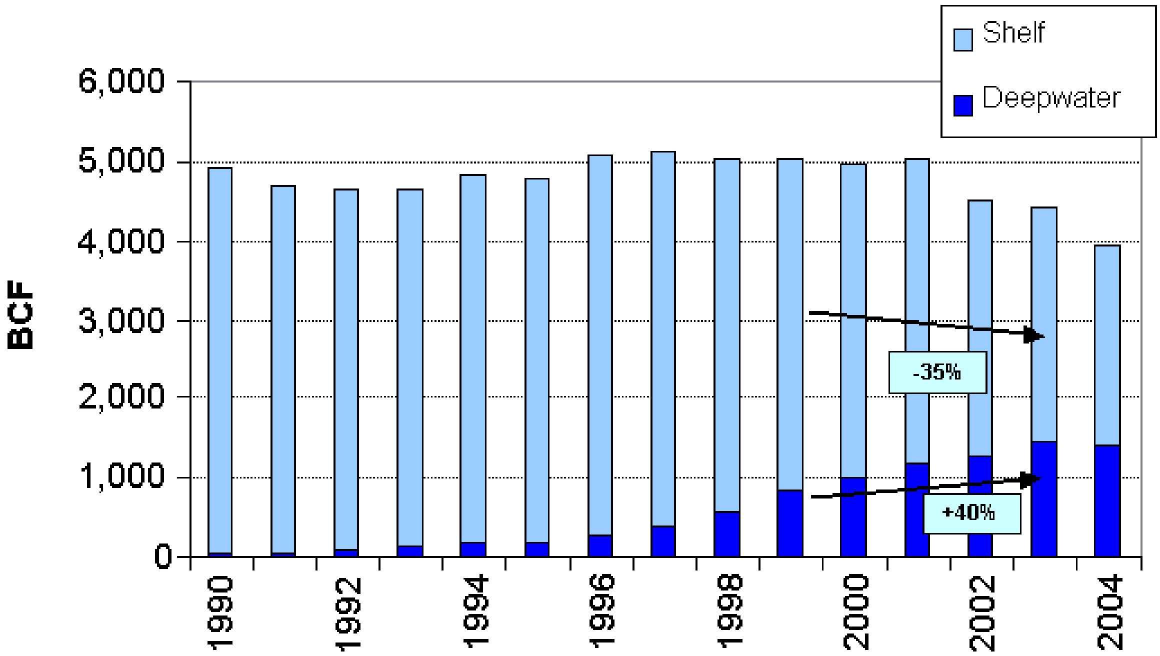
Midstream: Deepwater

Overview of Major Sections

- Why the deepwater Gulf?
- What about existing deepwater projects?
- Is the aggregation thesis working?
- What are the key competencies?
- Where will growth come from?

Midstream: Deepwater

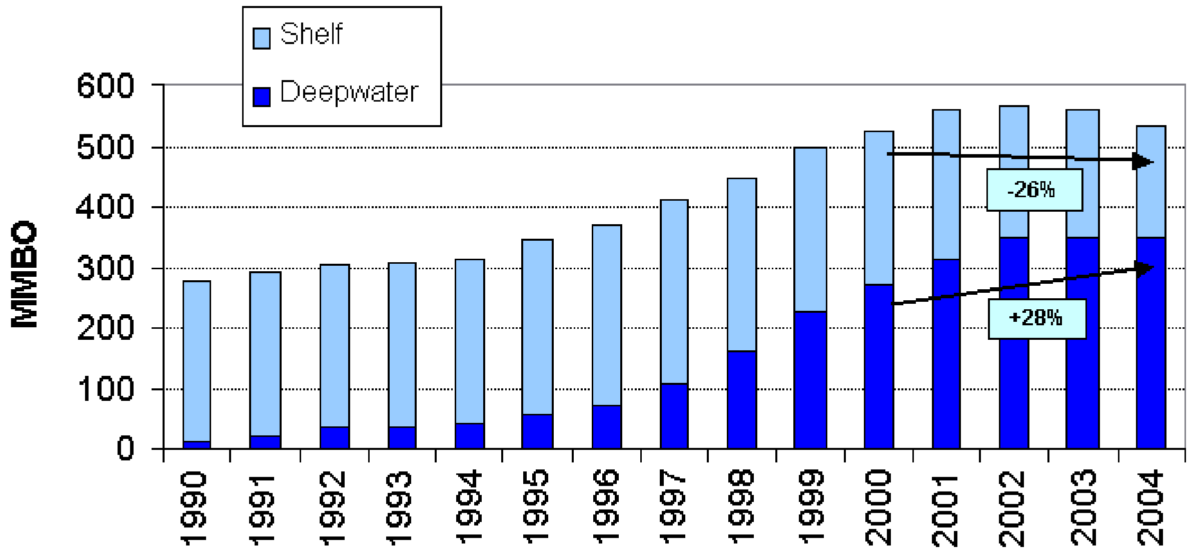
Gulf of Mexico Annual Gas Production



*2004 – Some production lost due to Hurricane Ivan

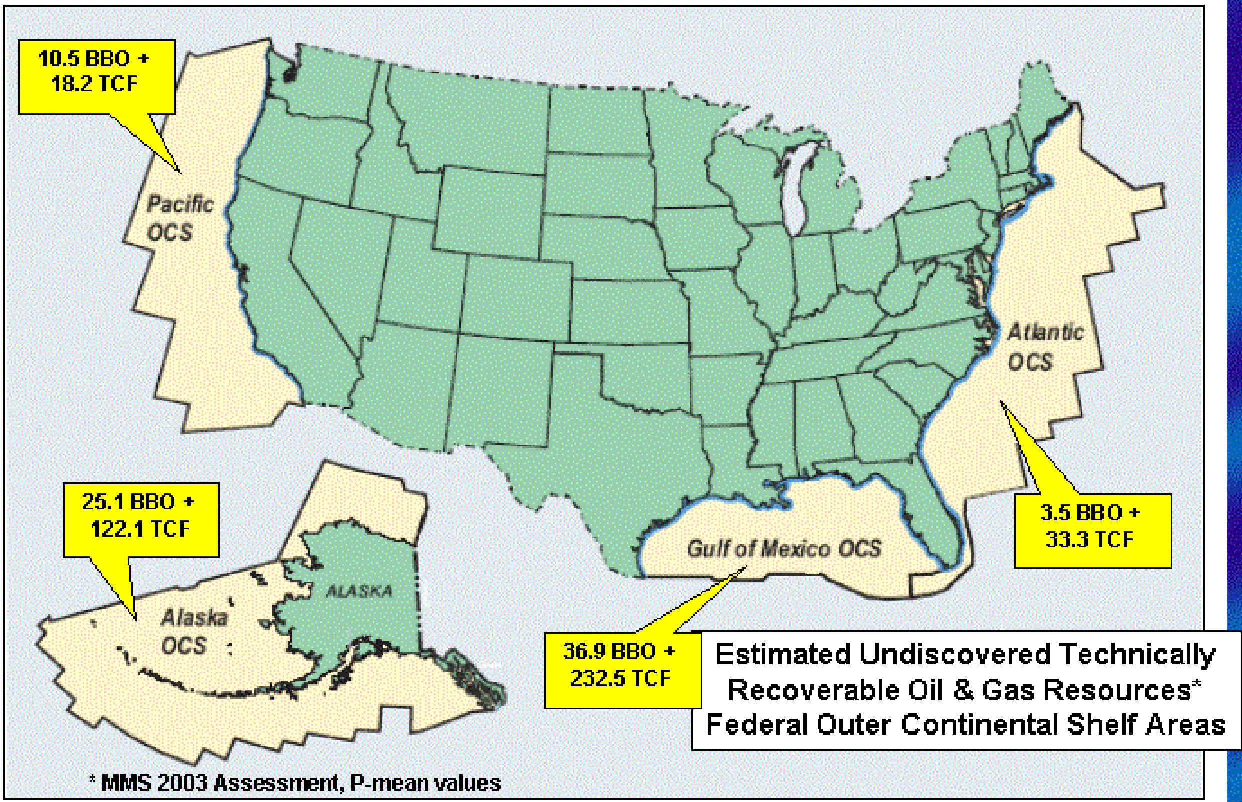
Midstream: Deepwater

Gulf of Mexico Annual Oil Production



*2004 – Some production lost due to Hurricane Ivan

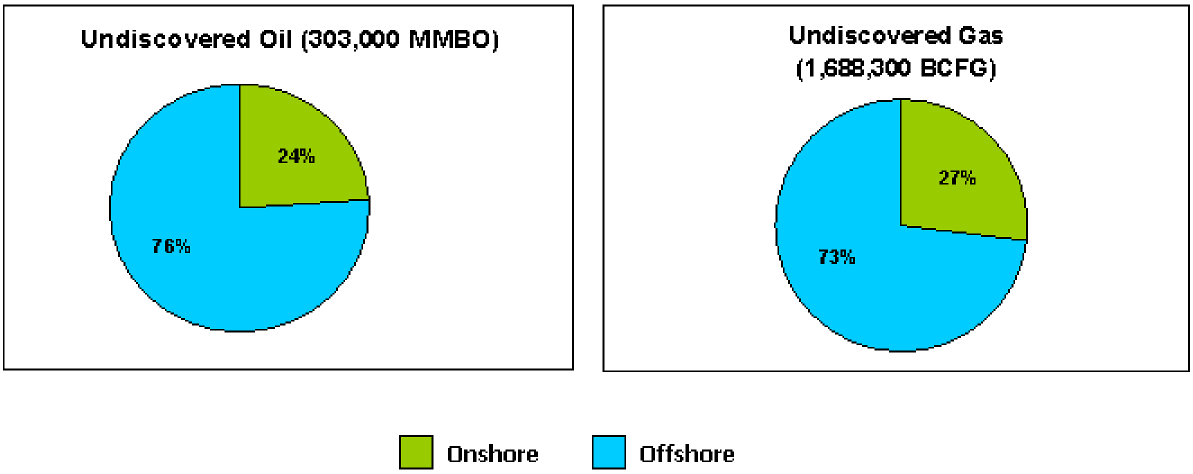
Estimated Undiscovered Oil & Gas Reserves



Midstream: Deepwater

Worldwide Undiscovered Resources

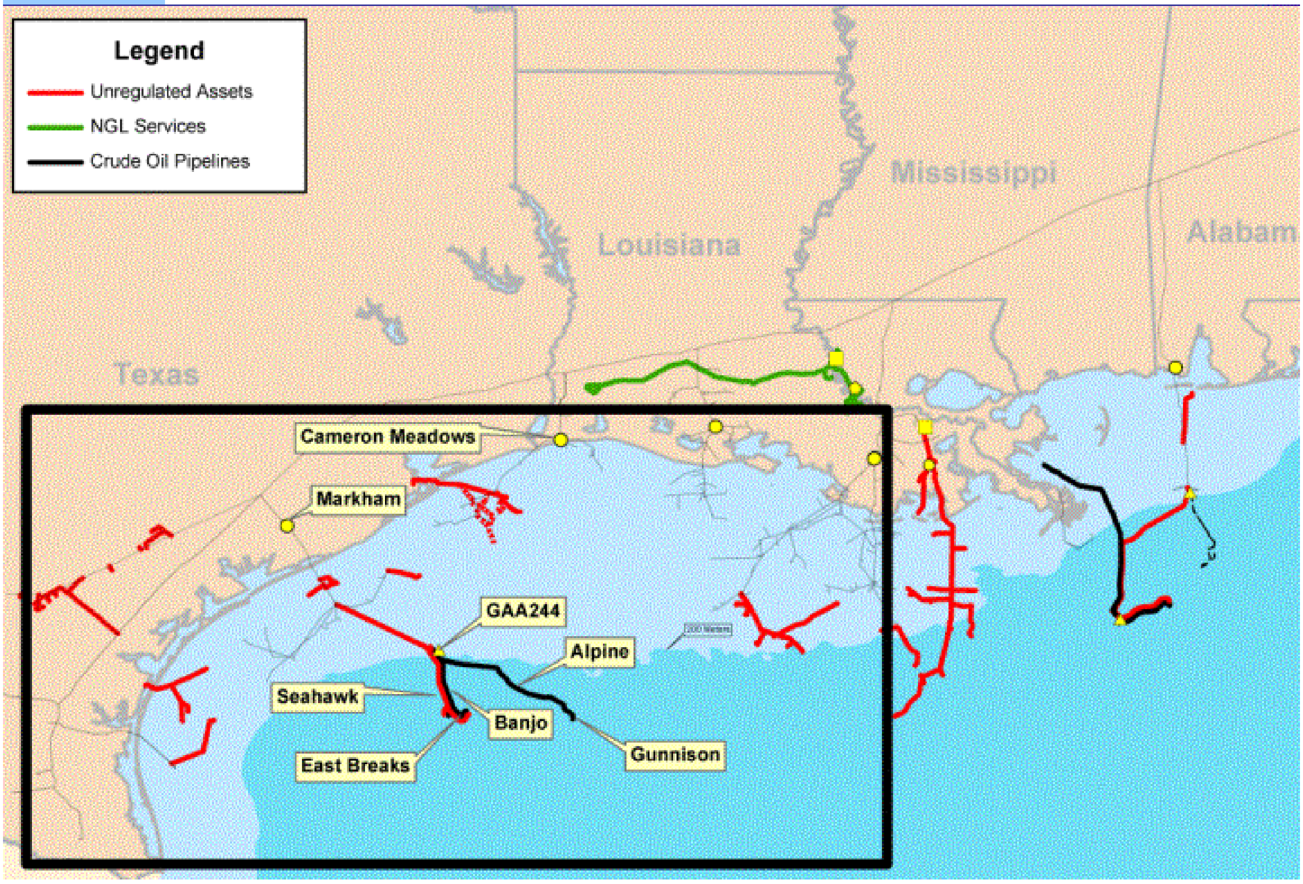
Regions 3 – Region 8



USGS Study – Proportions of onshore and offshore assessed undiscovered resources for the world excluding regions identified as OPEC and Former Soviet Union.

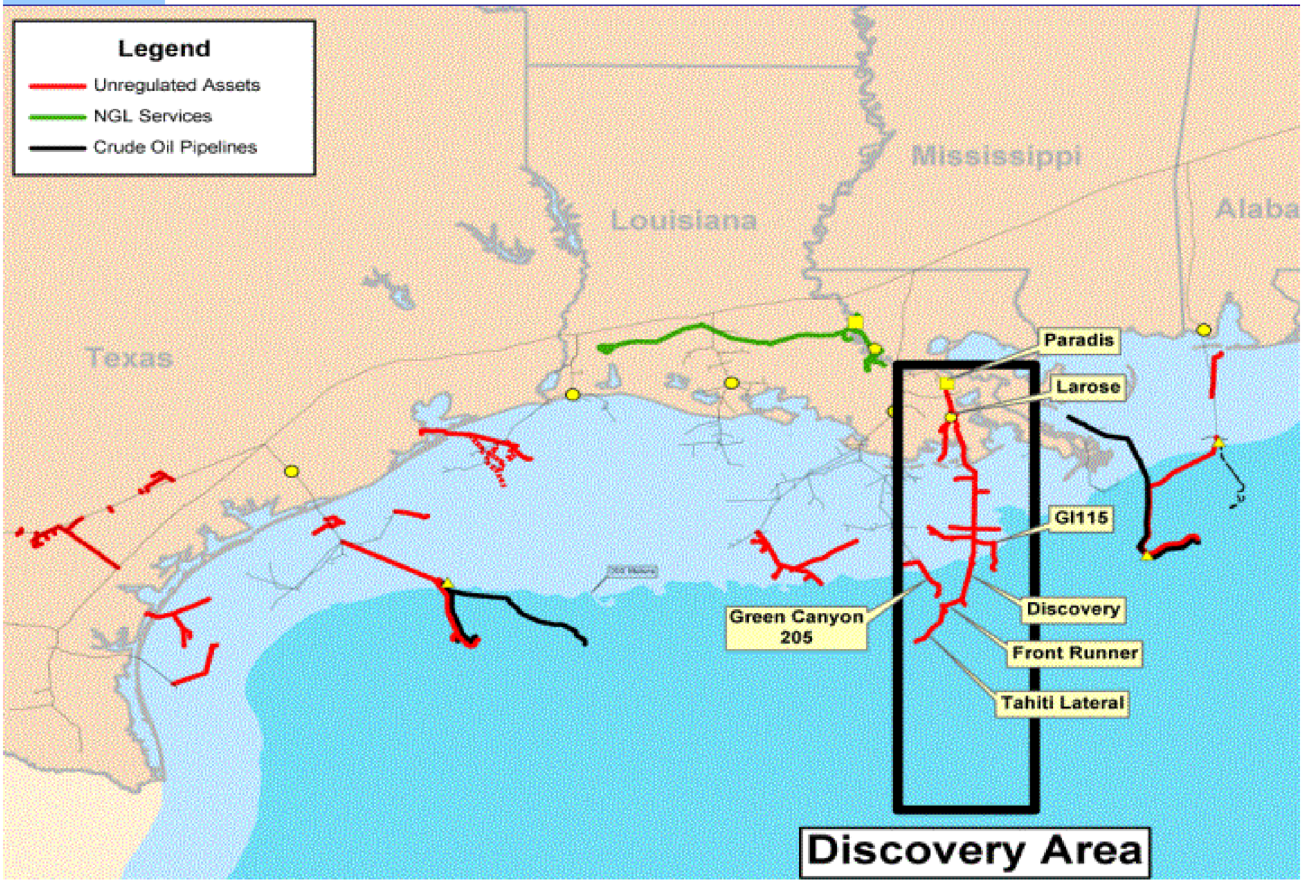
Midstream: Deepwater

Gulf of Mexico – Western Gulf Area



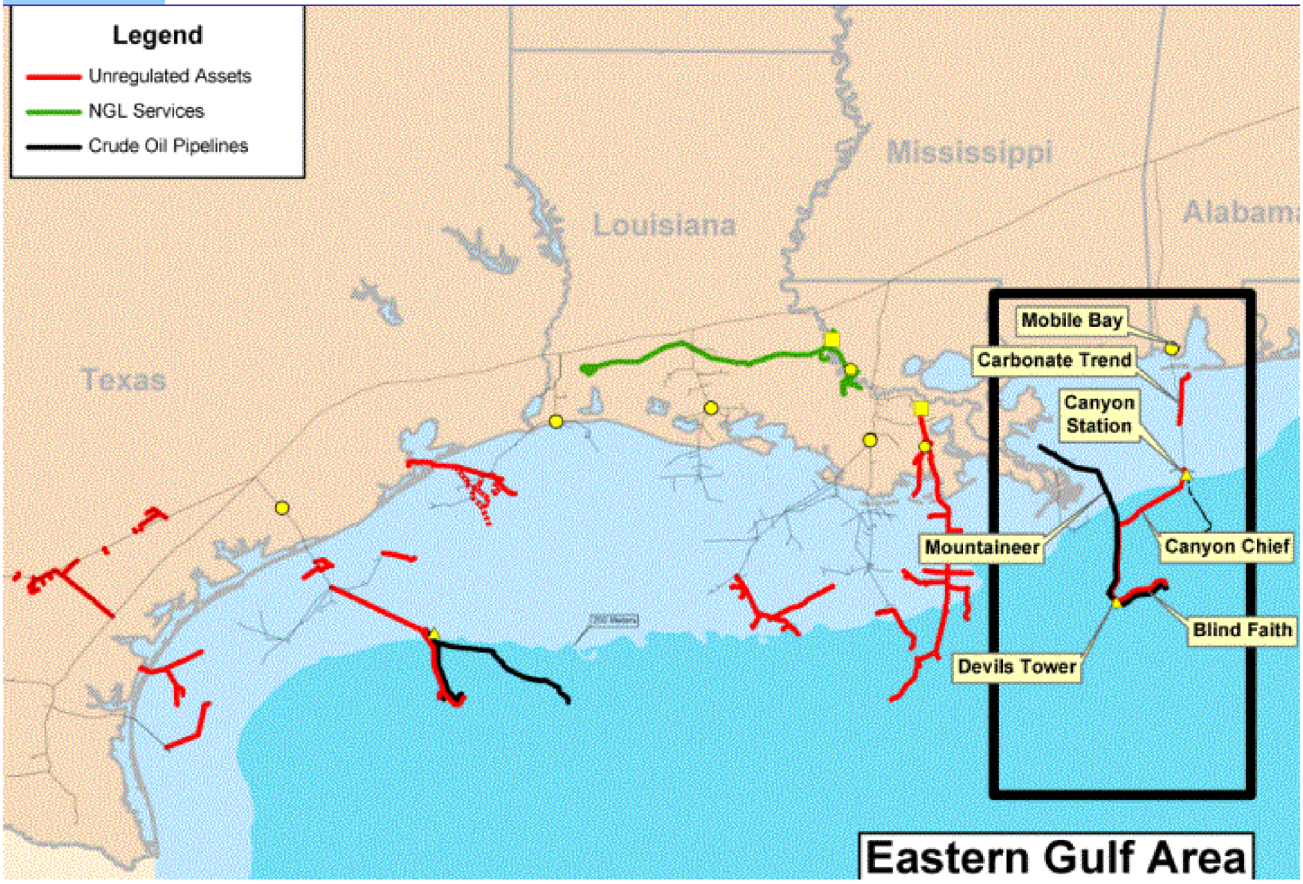
Midstream: Deepwater

Gulf of Mexico – Discovery Area



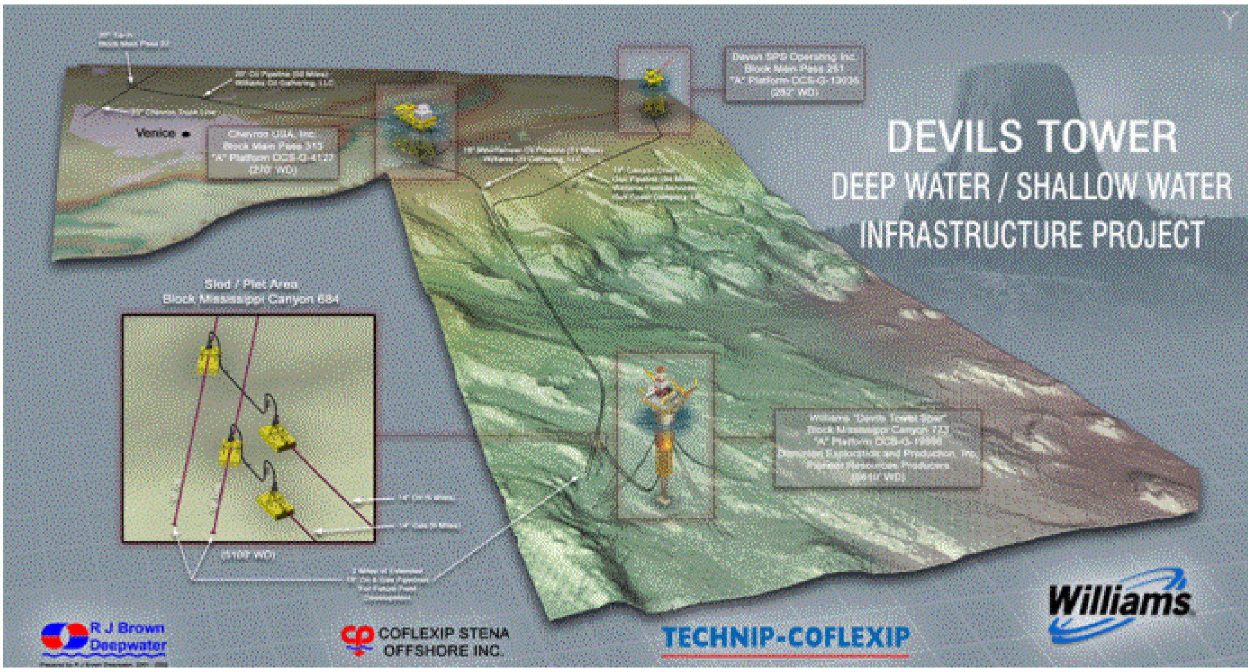
Midstream: Deepwater

Gulf of Mexico – Eastern Gulf Area



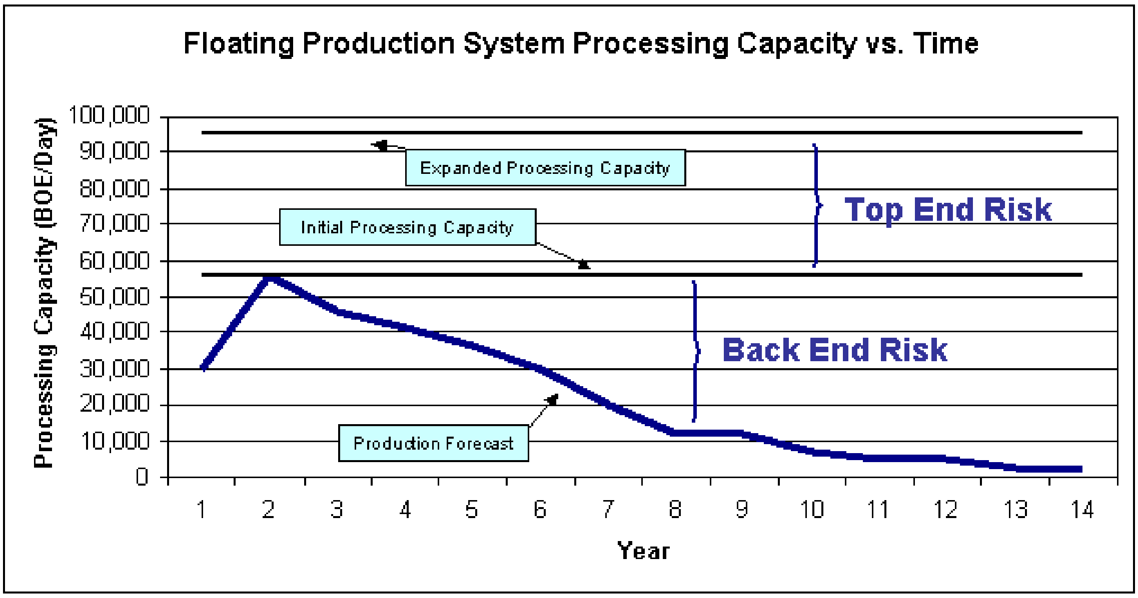
Midstream: Deepwater

The Architecture of Aggregation



Midstream: Deepwater

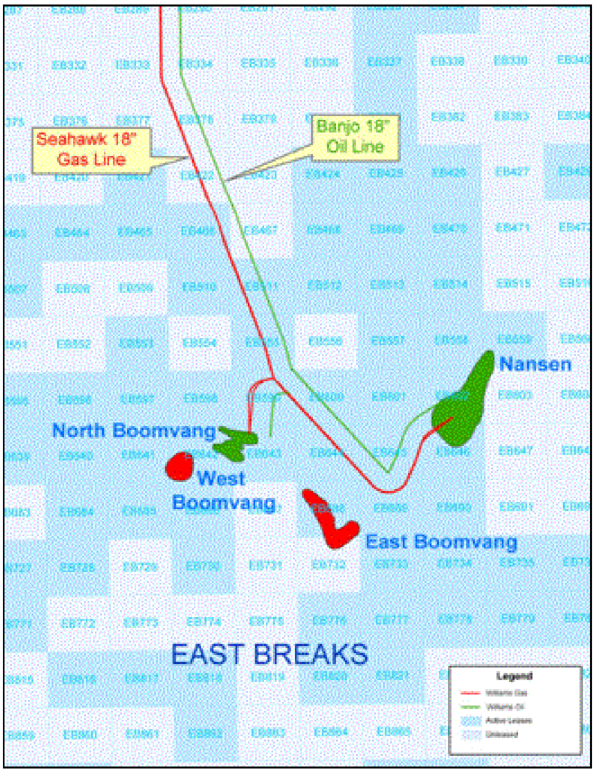
Aggregation: Reducing Risk

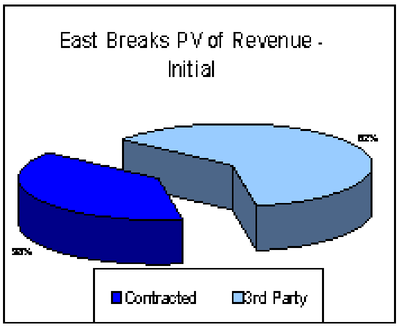


- Producers toll across floating production systems and export systems
- Lower tolls due to economies of scale
- Williams assumes aggregation risks; lower than sum of individual risks
- Reduces cycle time and economic threshold for marginal prospects

Midstream: Deepwater

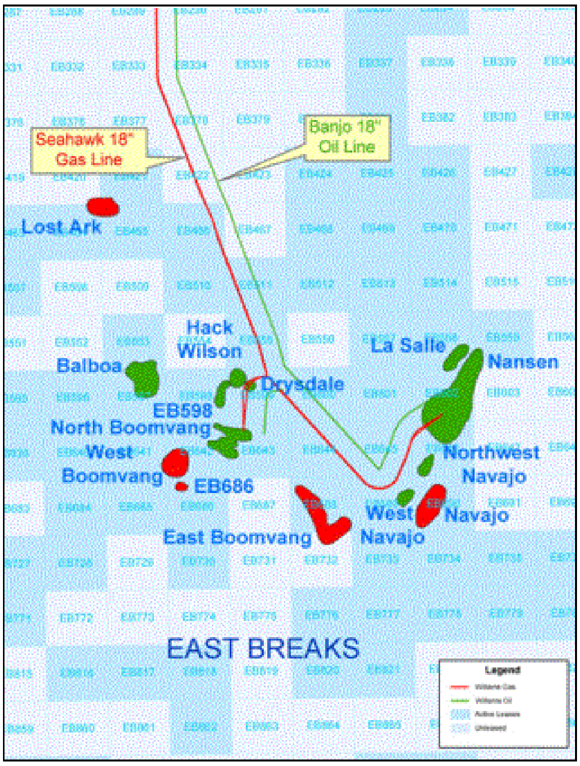
East Breaks: Initial Justification

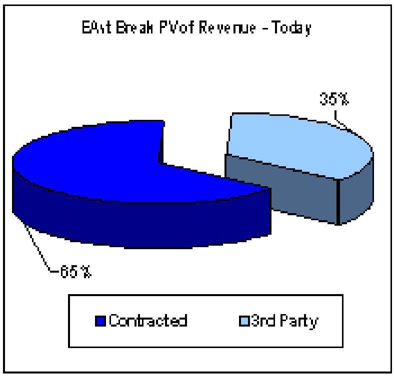




- 4 discoveries at time of sanctioning
- Original reserve forecast (P_{50}) provides return of capital (to small single digit returns on capital)
- Initial justification: 1999 - 2000

East Breaks: Today and the Future

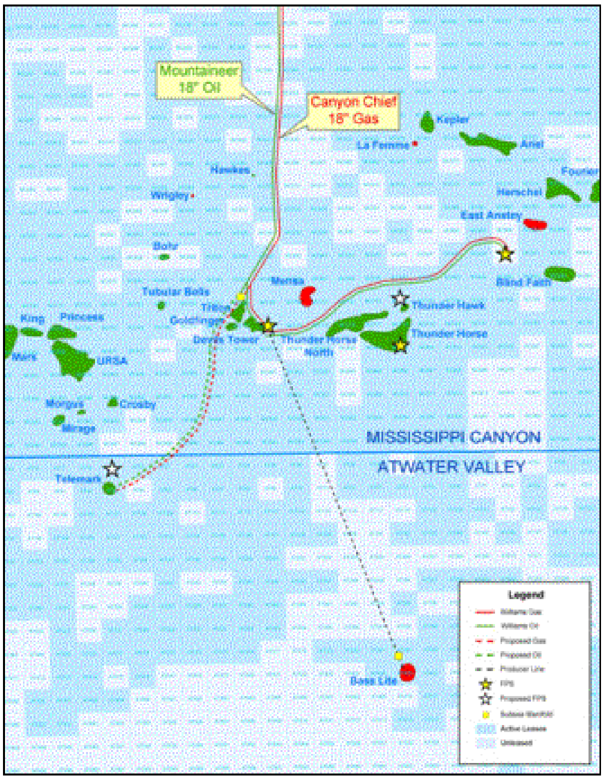


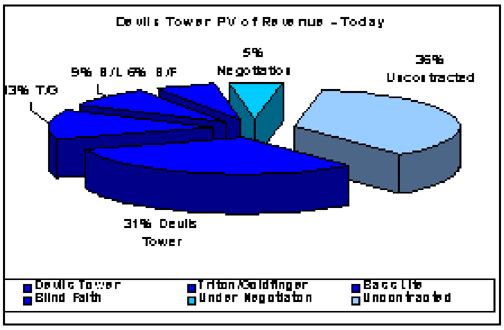


- 12 discoveries in dedicated area today
- Additional undedicated discovery in area
- 3 - 5 additional exploration wells planned next year
- Pipeline well situated for Alaminos Canyon development
- Earning a return in excess of cost of capital

Midstream: Deepwater

Devils Tower: Today and the Future





- 59% contracted
- 5% in negotations
- 36% uncontracted

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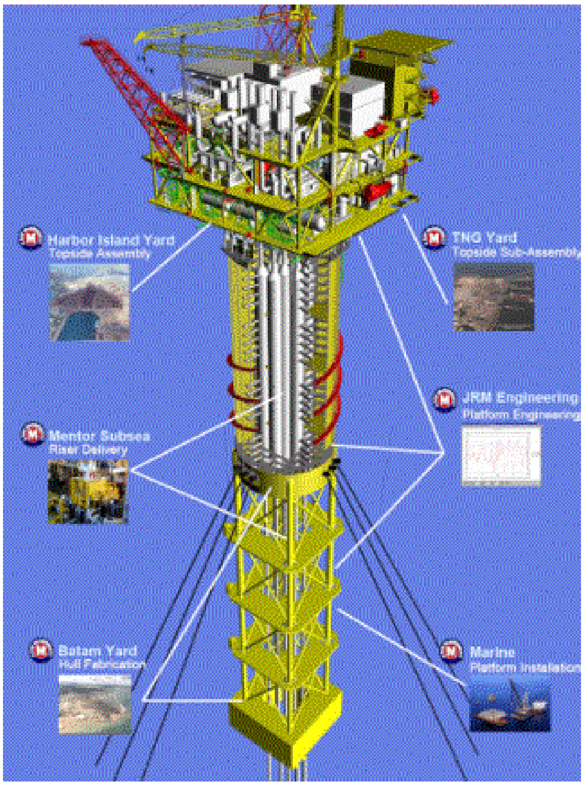
Building Our Deepwater Competencies



- Leadership
- Structural Engineering
  - SCR Design/Verification
  - Topsides
  - Hull & Mooring
- Hydraulics
- Cost Estimating
- Project Management
- Commercial Expertise
- Deepwater Operations

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Midstream: Deepwater

Our Strategy Highlights

- Deliver safe, reliable, efficient service
- Pursue only when scale and scope warrant
- Understand the basin before pricing the business
- Build competencies specific to deepwater infrastructure
- Projects require high trust, transparent negotiations
- Grow business based on attraction rather than promotion

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Midstream: Deepwater

Deepwater Expansion Projects

- **Tahiti 16" Gas Pipeline**
  - Discovery system offshore interconnect
  - 34 Mile length; approx. $60 – $70MM capital expenditure
  - Completion est. Q3 2007
- **Blind Faith 16" Oil & Gas Pipelines**
  - Tie-in point to Mountaineer & Canyon Chief tails
  - 37 mile length; $177 MM capital expenditure
  - Completion est. Q3 2007
- **Triton-Goldfinger Devils Tower Tie-back**
  - Dominion & Pioneer joint project
  - No additional capital expenditure for Midstream
  - Initial delivery 11/16/05
- **New Deepwater Projects currently under negotiation**
  - $550 million of pipeline projects to be awarded in the market in the next 6 months
  - Numerous floating production system investment opportunities over next several years (approximately $250-350MM each)
  - Midstream well positioned to win these projects

Questions?

Dissecting Midstream's Earnings

Dave Darcey
Director of Planning and Analysis
Midstream

November 30, 2005

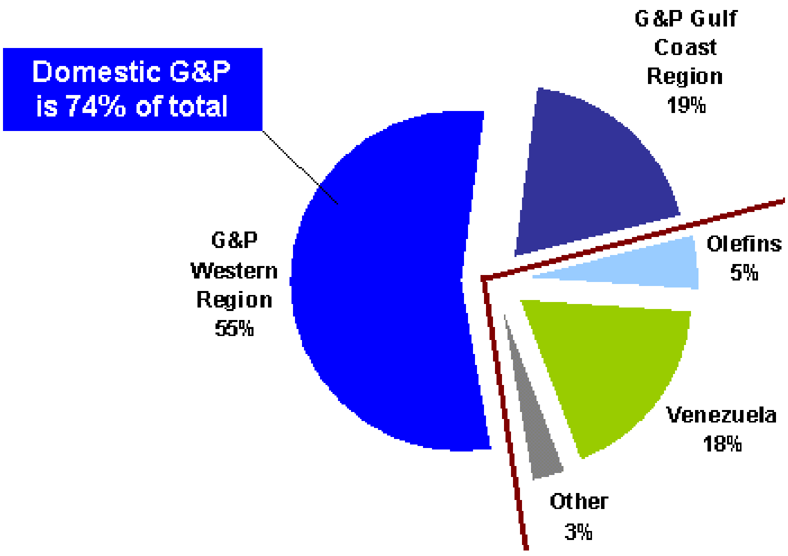
Midstream: Earnings

Dissecting Midstream's Earnings

- Breakdown of Midstream's segment profit by asset
- Overview of Midstream's Gathering & Processing (G&P) operations and impact upon the financials
- Frac Spread 101, Net Liquid Margin 101
- Deciphering Midstream's net liquid margins
- Can Midstream make money in today's commodity price environment?
- Impact of changing net liquid margins upon Midstream's earnings
- The stability of Midstream's G&P fee revenues

Midstream: Earnings

Midstream Segment Profit Breakdown – YTD Sept 2005



Segment Profit**

**Excludes Allocated G&A

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Dissecting Midstream's Earnings

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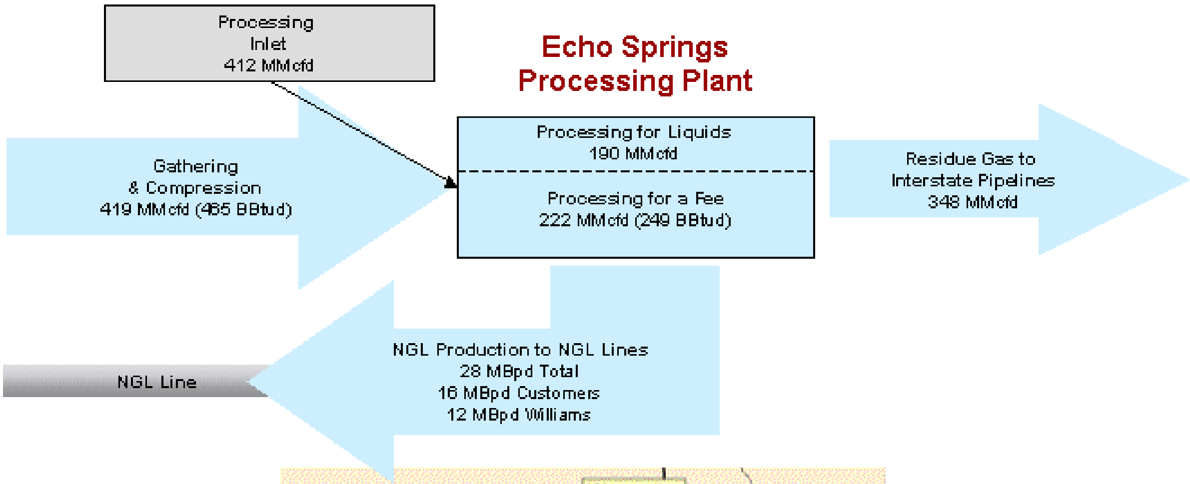
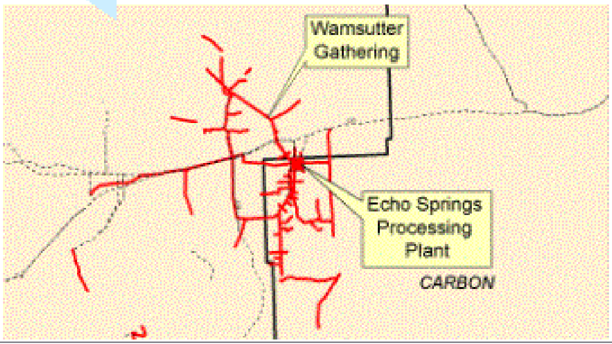
Midstream: Earnings

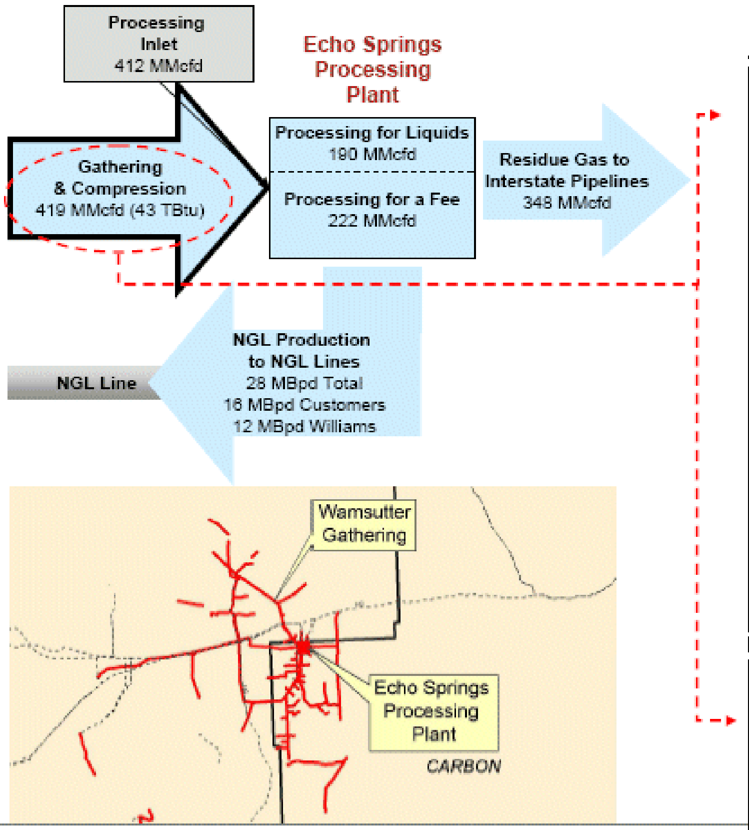
What Do G&P Operations Look Like?





Midstream: Earnings

Linking G&P Operations to Financials



Midstream Gas & Liquids

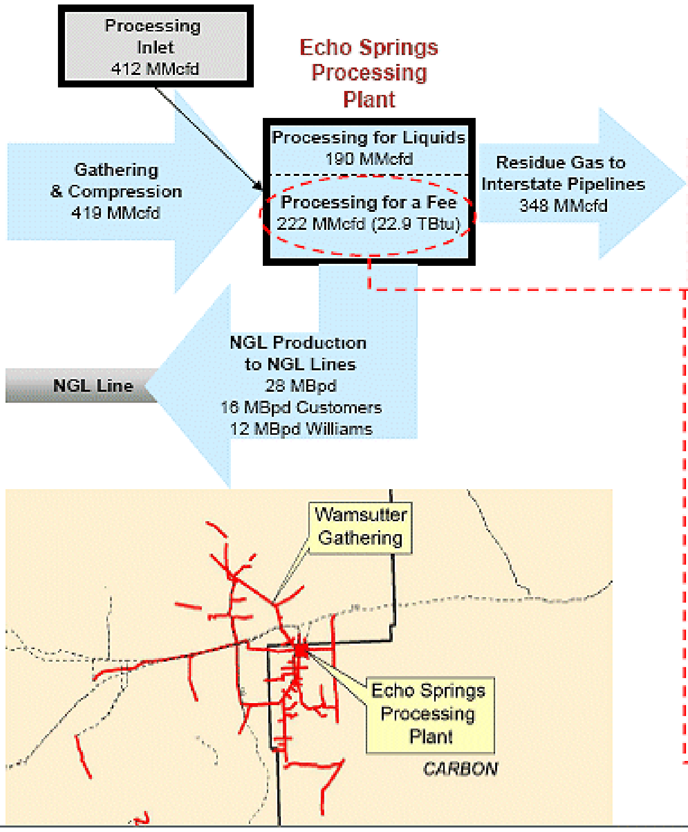
(UNAUDITED)
(Dollars in millions)

	2005 3rd Qtr *
Revenues:	
Gathering	$ 74.0
Processing	25.5
Venezuela fee revenue	40.4
NGL sales from gas processing	244.2
Production handling and transportation	14.7
Olefins sales (Incl Gulf and Canada)	121.4
Trading/marketing sales	522.0
Other revenues	31.7
	1,073.9
Intrasegment eliminations	(319.1)
Total revenues	754.8
Segment costs and expenses:	
NGL cost of goods sold	189.6
Olefins cost of goods sold	102.2
Trading/marketing cost of goods sold	510.1
Venezuela operating costs	17.4
Operating costs	112.8
Other	
Selling, general and administrative expenses	23.1
Other (income) expense - net	0.8
Intrasegment eliminations	(319.1)
Total segment costs and expenses	636.9
Equity earnings (losses)	3.2
Income (loss) from investments	
Reported segment profit	**121.1**
Nonrecurring adjustments	
Recurring segment profit, pre-tax	**$ 121.1**

Operating statistics	
Gathering volumes (TBtu)	310.3
Gathering margins ($/MMBtu)	$ 0.2386
Processing volumes (TBtu)	190.3
Processing rate ($/MMBtu)	$ 0.1342
NGL equity sales (million gallons)	276.4
NGL margin ($/gallon)	$ 0.1976
Olefins sales (Ethylene & Propylene) (million lbs)	204.3

Midstream: Earnings

Linking G&P Operations to Financials



Midstream Gas & Liquids

(UNAUDITED)

(Dollars in millions)

	2005 *3rd Qtr **
Revenues:	
Gathering	$ 74.0
Processing	25.5
Venezuela fee revenue	40.4
NGL sales from gas processing	244.2
Production handling and transportation	14.7
Olefins sales (incl Gulf and Canada)	121.4
Trading/marketing sales	522.0
Other revenues	31.7
	1,073.9
Intrasegment eliminations	(319.1)
Total revenues	754.8
Segment costs and expenses:	
NGL cost of goods sold	189.6
Olefins cost of goods sold	102.2
Trading/marketing cost of goods sold	510.1
Venezuela operating costs	17.4
Operating costs	112.8
Other	
Selling, general and administrative expenses	23.1
Other (income) expense - net	0.8
Intrasegment eliminations	(319.1)
Total segment costs and expenses	636.9
Equity earnings (losses)	3.2
Income (loss) from investments	
Reported segment profit	121.1
Nonrecurring adjustments	
Recurring segment profit, pre-tax	$ 121.1

Operating statistics

Gathering volumes (TBtu)	310.3
Gathering margins ($/MMBtu)	$ 0.2386
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Midstream: Earnings

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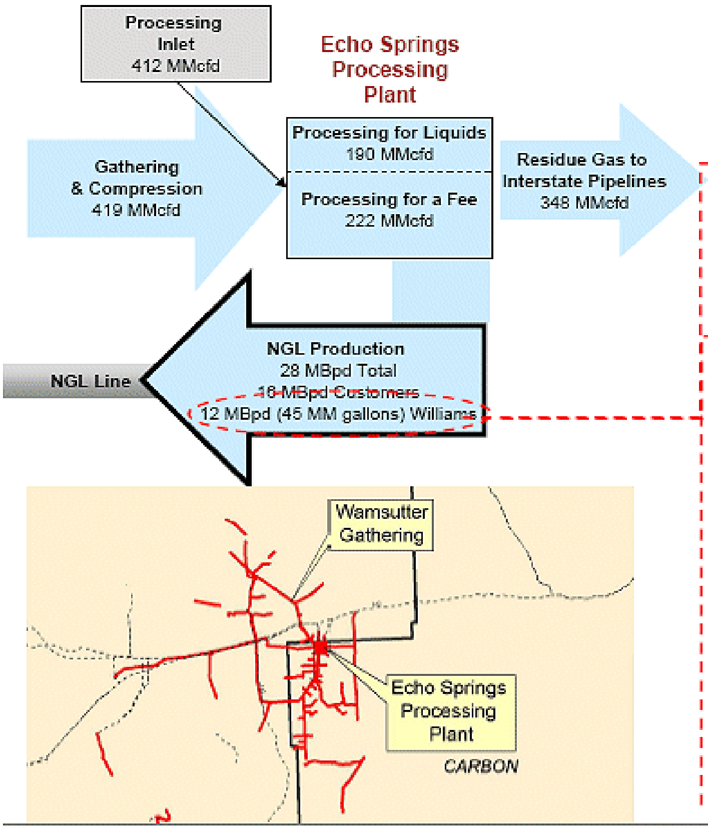

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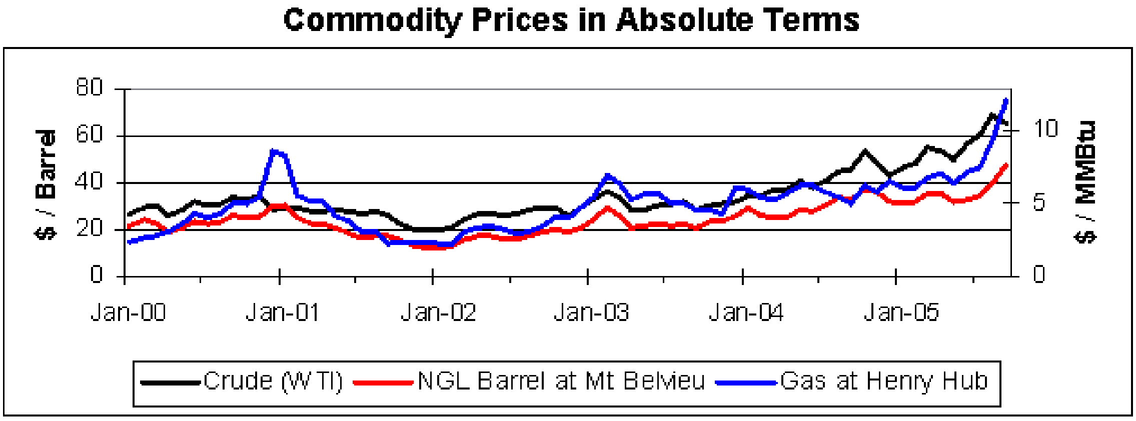
Midstream: Earnings

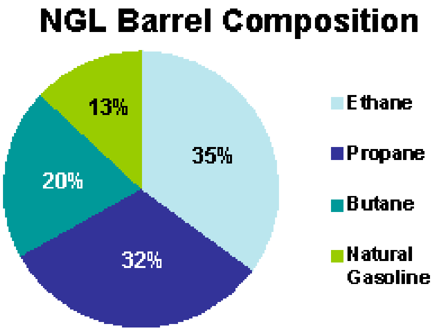
Dissecting Midstream's Earnings

- Breakdown of Midstream's segment profit by asset
- Overview of Midstream's Gathering & Processing (G&P) operations and impact upon the financials
- Frac Spread 101, Net Liquid Margin 101
- Deciphering Midstream's net liquid margins
- Can Midstream make money in today's commodity price environment?
- Impact of changing net liquid margins upon Midstream's earnings
- The stability of Midstream's G&P fee revenues

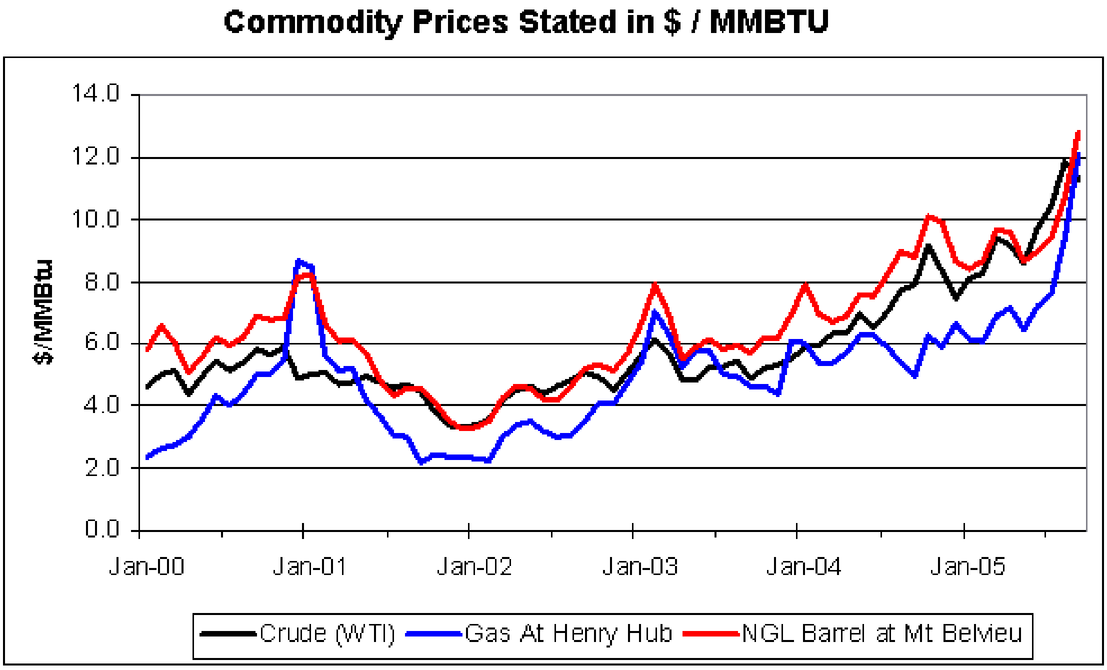
Williams

So, Which Commodity is the Most Valuable?





The NGL Barrel Is the Most Valuable



Midstream: Earnings

Calculating Frac Spreads and Net Liquid Margins

To Calculate a NGL Frac Spread

	Shrink Cost $ / MMBtu	NGL Price / gal	NGL Barrel Composition	Btus / Gallon	Shrink Cost $ / Gallon	Composite $ / Gallon
Step 1: NGL Pricing @ Belvieu						
Ethane		$0.58	35%			
Propane		$0.86	32%			
Butane		$1.06	20%			
Natural Gasoline		$1.23	13%			
Composite Gallon Avg			100%			**$0.85**
Step 2: Subtract Shrink Cost						
Natural Gas at Henry Hub	$7.69					
Add/Subtract Plant Basis Spread						
Net Plant Shrink Cost	$7.69					
Ethane				66,369	$0.51	
Propane				91,599	$0.70	
Butane				101,688	$0.78	
Natural Gasoline				114,157	$0.88	
Composite Gallon Avg				87,719		**$0.67**
Mt. Belvieu - Henry Hub Frac Spread						**$0.18**

To Calculate a NGL Regional Net Liquid Margin

Mt. Belvieu - Henry Hub Frac Spread	**$0.18**
Subtract:	
Transportation & Frac Costs	$0.05
Plant Processing Fuel	$0.06
Gulf Coast Regional Net Liquid Margin	**$0.07**

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Midstream: Earnings

Where Are NGL Margin Components On Midstream's Financials?

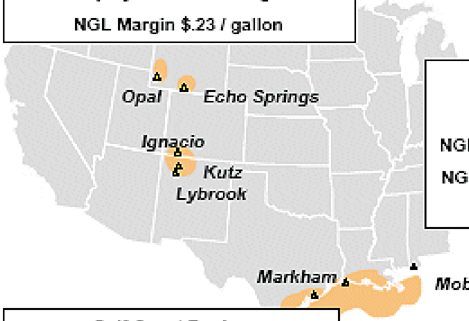
Western Region

NGL Sales $182.1 MM

NGL Cost of Goods Sold $134.7 MM

NGL Equity Sales 208 MM gallons

NGL Margin $.23 / gallon



Midstream Domestic

NGL Sales $244.2 MM

NGL Cost of Goods Sold $189.6 MM

NGL Equity Sales 276.4 MM gallons

NGL Margin $.1976 / gallon

Gulf Coast Region

NGL Sales $62.1 MM

NGL Cost of Goods Sold $54.9 MM

NGL Equity Sales 68 MM gallons

NGL Margin $.11 / gallon

NGL Cost of Goods Sold include Shrink, Fuel and Trans & Frac Charges

Midstream Gas & Liquids

(UNAUDITED) *(Dollars in millions)*	2005 *3rd Qtr **
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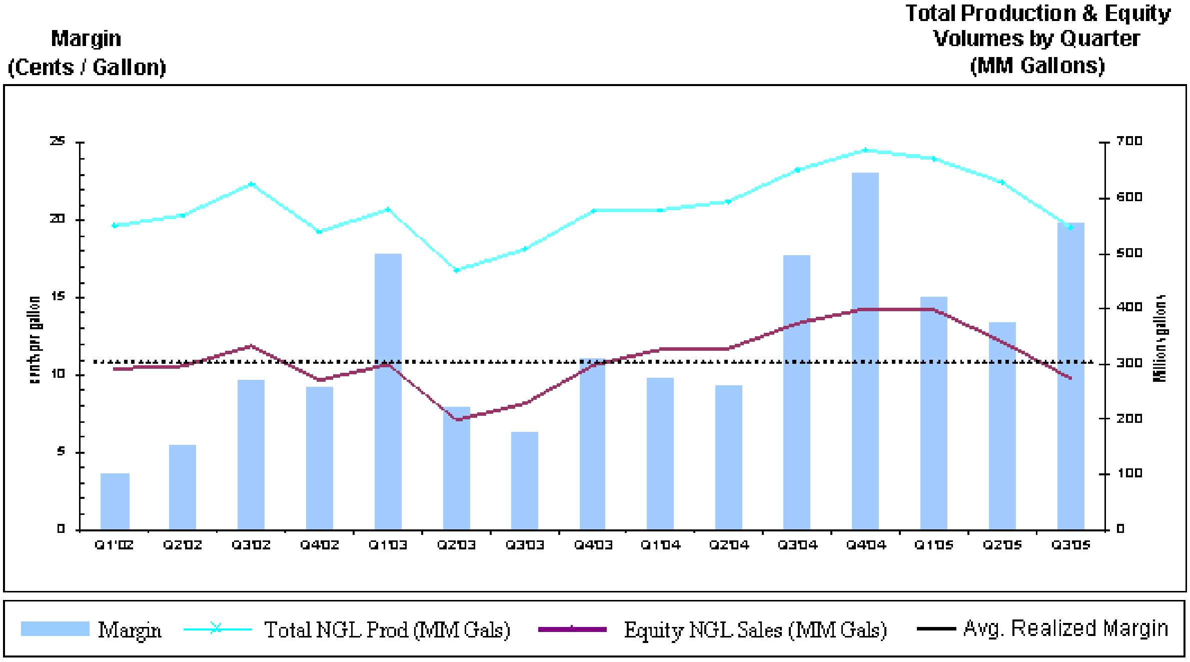
Midstream: Earnings

Margins Above Average

From 3Q 2005 Analyst Presentation

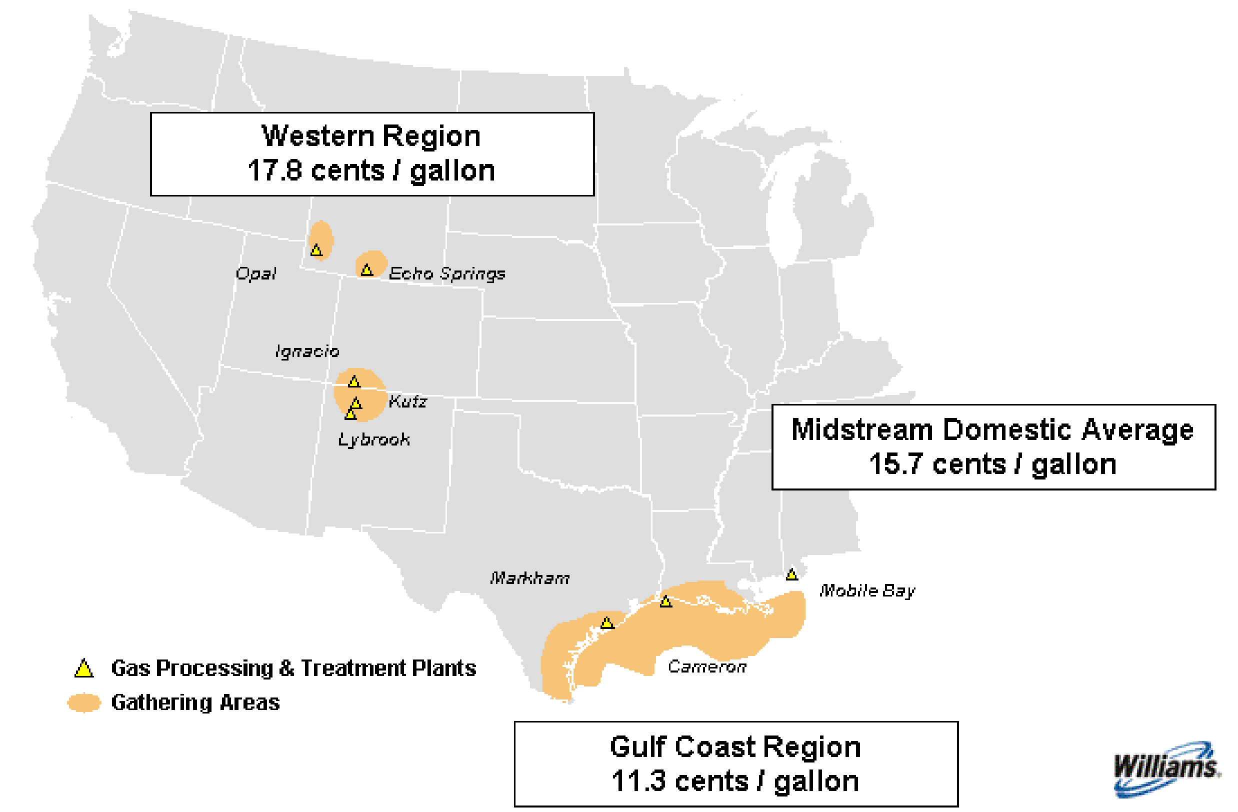
Domestic NGL Average Realized Net Margin and Volumes by Quarter



Note: Based on actual realized prices, contractual obligations, shrink, fuel, actual equity liquids percentages, etc. Average Realized Margin shown for 2000-04.

Midstream: Earnings

Midstream's Sept 2005/YTD 2005 NGL Margin by Region



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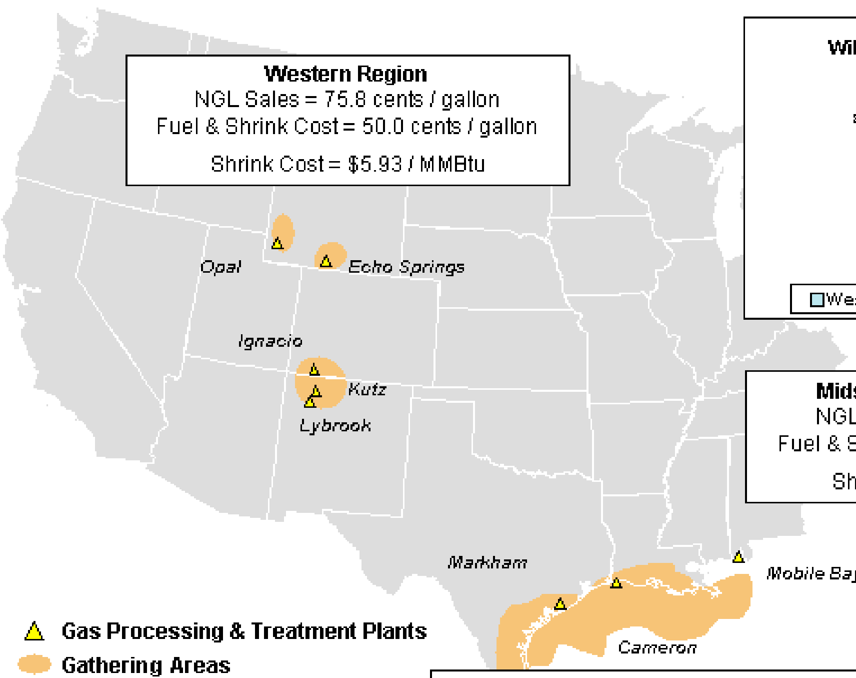
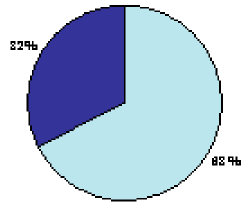
Midstream: Earnings

Midstream's Sept 2005/YTD 2005 NGL Margin Components



Western Region
NGL Sales = 75.8 cents / gallon
Fuel & Shrink Cost = 50.0 cents / gallon
Shrink Cost = $5.93 / MMBtu



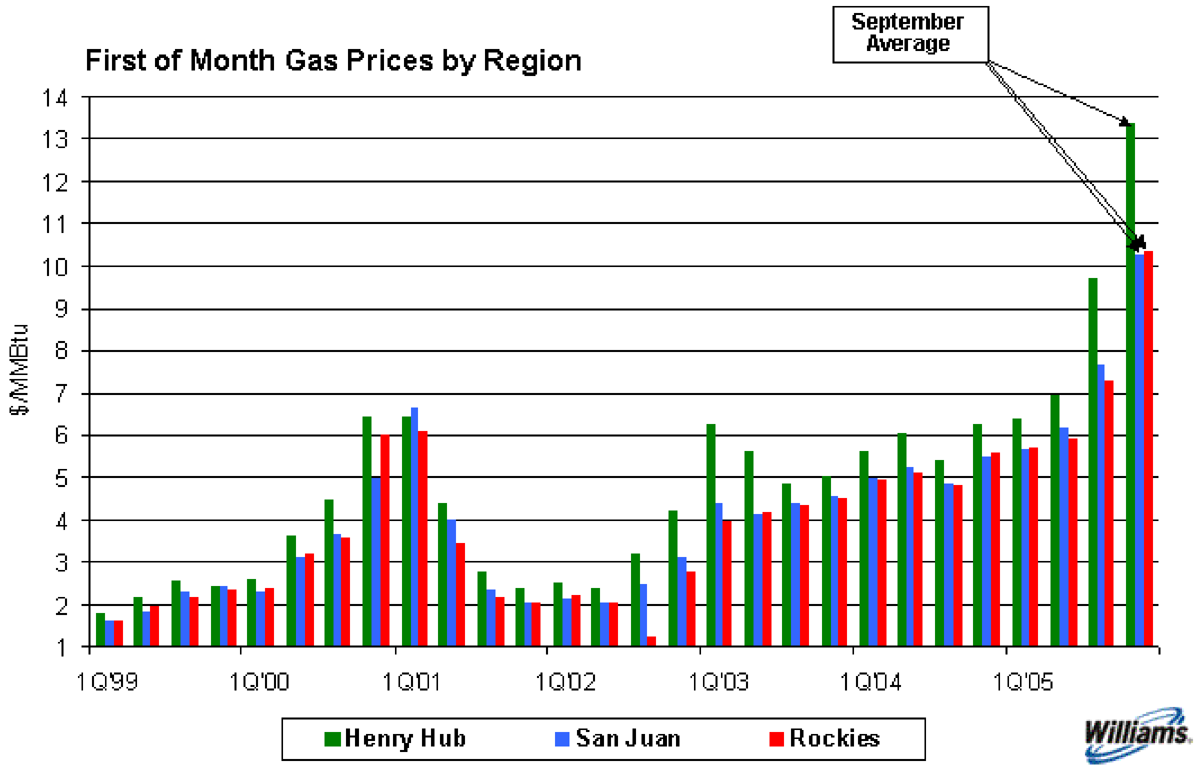
Midstream Domestic Average
NGL Sales = 76.6 cents / gallon
Fuel & Shrink Cost = 54.0 cents / gallon
Shrink Cost = $6.28 / MMBtu

Gulf Coast Region
NGL Sales = 78.3 cents per gallon
Fuel & Shrink Cost = 62.0 cents per gallon
Shrink Cost = $7.00 / MMBtu

Williams

Midstream: Earnings

Regional Gas Basis Differentials Bolster Our Diversified Portfolio



Williams.

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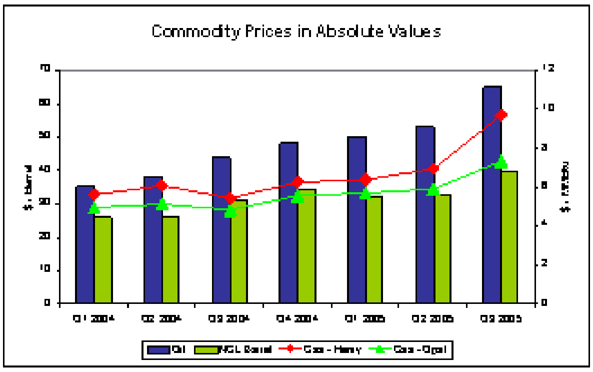
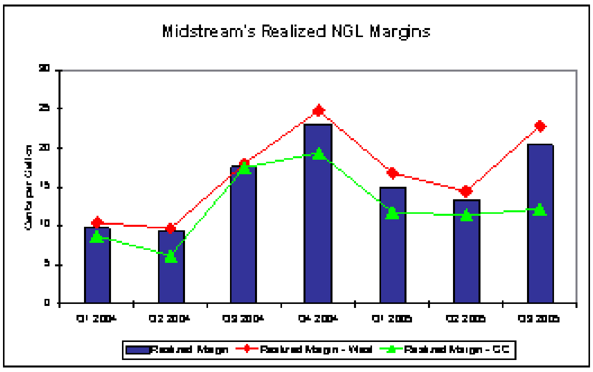
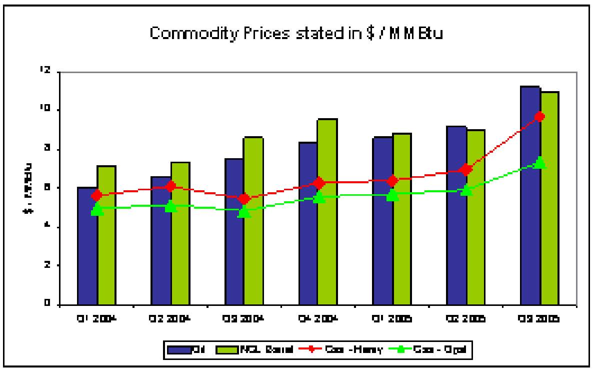
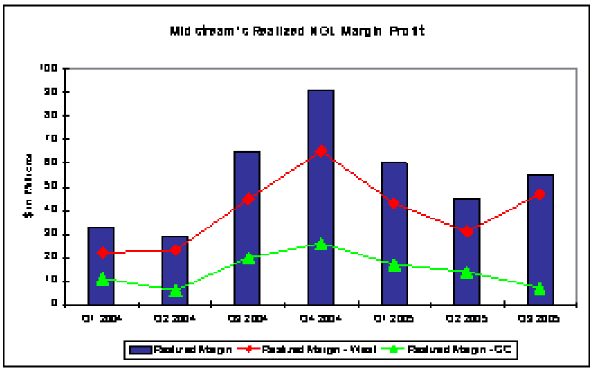
Can Midstream Make $$ With Current Commodity Prices?

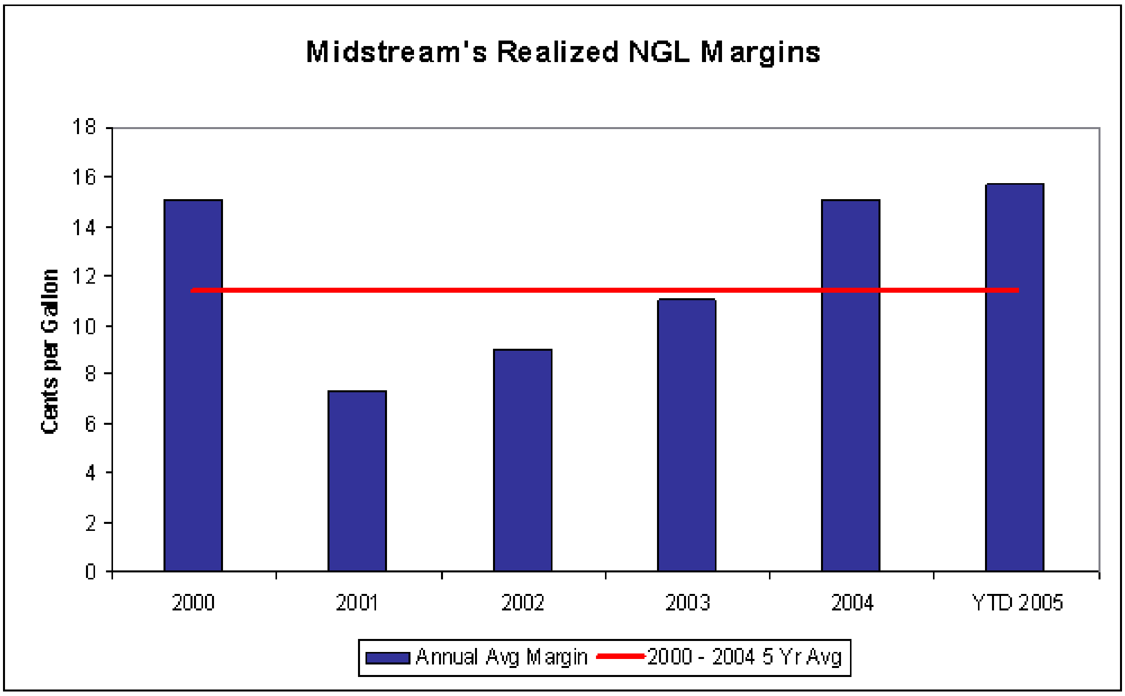




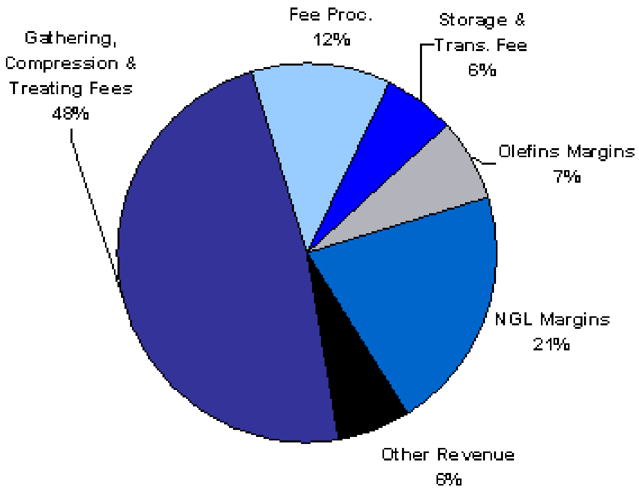




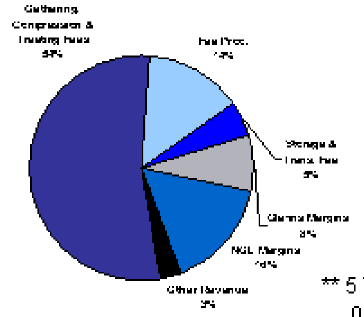
Five Years of Historical NGL Margins



Impact of Changing NGL Margins On Midstream's Net Revenues

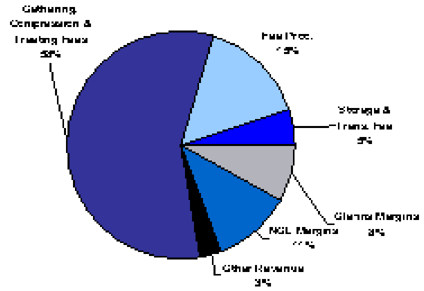


YTD Sept 2005 Net Revenues with Actual NGL Margins



** 5 Yr avg based on 2000-04

Net Revenues w/Historical 5 Yr Avg** NGL Margins



Net Revenues w/Lowest Annual Avg NGL Margins in Historical 5 Years

Midstream: Earnings

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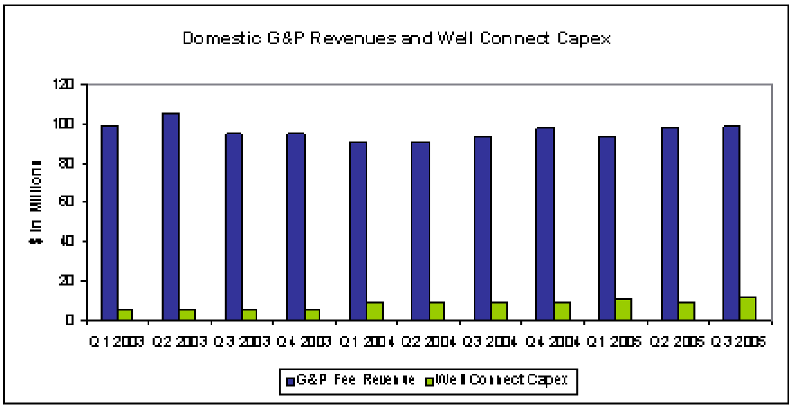
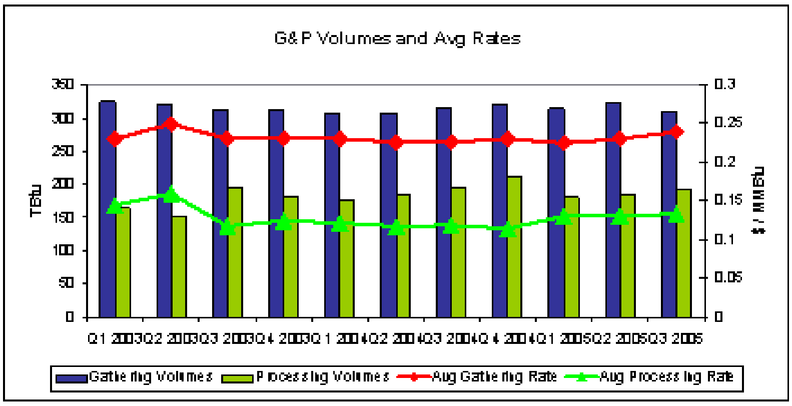
Midstream: Earnings

The Stability of Midstream's G&P Fee Revenues





A Typical Western Region Well Connect…

- Is the result of long-term contractual obligations and dedications
- Typically costs $45k to $80k
- Flows between 350-650 MMBtu / day in 1st year
- Flows approximately 0.8-1.4 TBtu over the first 10 years
- Provides a combined G&P revenue stream:
  - Between $45k and $70k in 1st year
  - Declines 6-14% / year thereafter
- Is contractually covered if well doesn't flow to expectations

Conclusion & Wrap Up

Alan Armstrong
Senior Vice President, Midstream

November 30, 2005

Williams

Summary of Key Points

- Well-positioned, large-scale Midstream infrastructure produces EVA® and strong net cash flows
- Williams has created and maintains competitive advantages
- Base is strong, poised for growth via expansion of existing platform
- Williams Partners is great complement to our scale-based strategy
- Deepwater Gulf of Mexico is an emerging but important infrastructure play
- Midstream business benefits from geographic and contractual diversity

Power Overview and 2005 Highlights

Bill Hobbs
Senior Vice President, Power

November 30, 2005

Williams

Power

Agenda

- Power overview and 2005 highlights — Bill Hobbs
- Market fundamentals — Phil Scalzo
- Financial review — Andrew Sunderman
- Conclusion and Wrap Up — Bill Hobbs
- Q&A

Power

New Power Contracts – 2005 Highlights

3Q05 Earnings Call

- **Deals consummated around each toll**
- **All customer classes have been represented**
  - Utilities
  - Co-ops and munis
  - Hedge funds and banks
- **Favorable credit terms**
  - Zero margining provisions in two deals in excess of 4 years
  - Margin caps in place for approx. 2,000 MW of toll resale
  - Lower margining agreements and netting will result in lower liquidity needs

Williams

Power

Structured Deals More Efficient than OTC Hedges

- Structured deals are…
  - Customer-specific customized products
  - More reflective of hourly production rates
  - Priced to provide economic value and/or risk reduction
  - Extremely efficient mechanism for hedging commodity price exposure
    - Recent toll resale in West significantly reduces future liquidity volatility versus standard OTC/NYMEX products
    - Recent CLECO contract has zero collateral requirements, significantly reducing future liquidity volatility versus standard OTC/NYMEX products
  - A more effective hedge for less-liquid commodities (e.g., capacity and ancillary services)

Williams

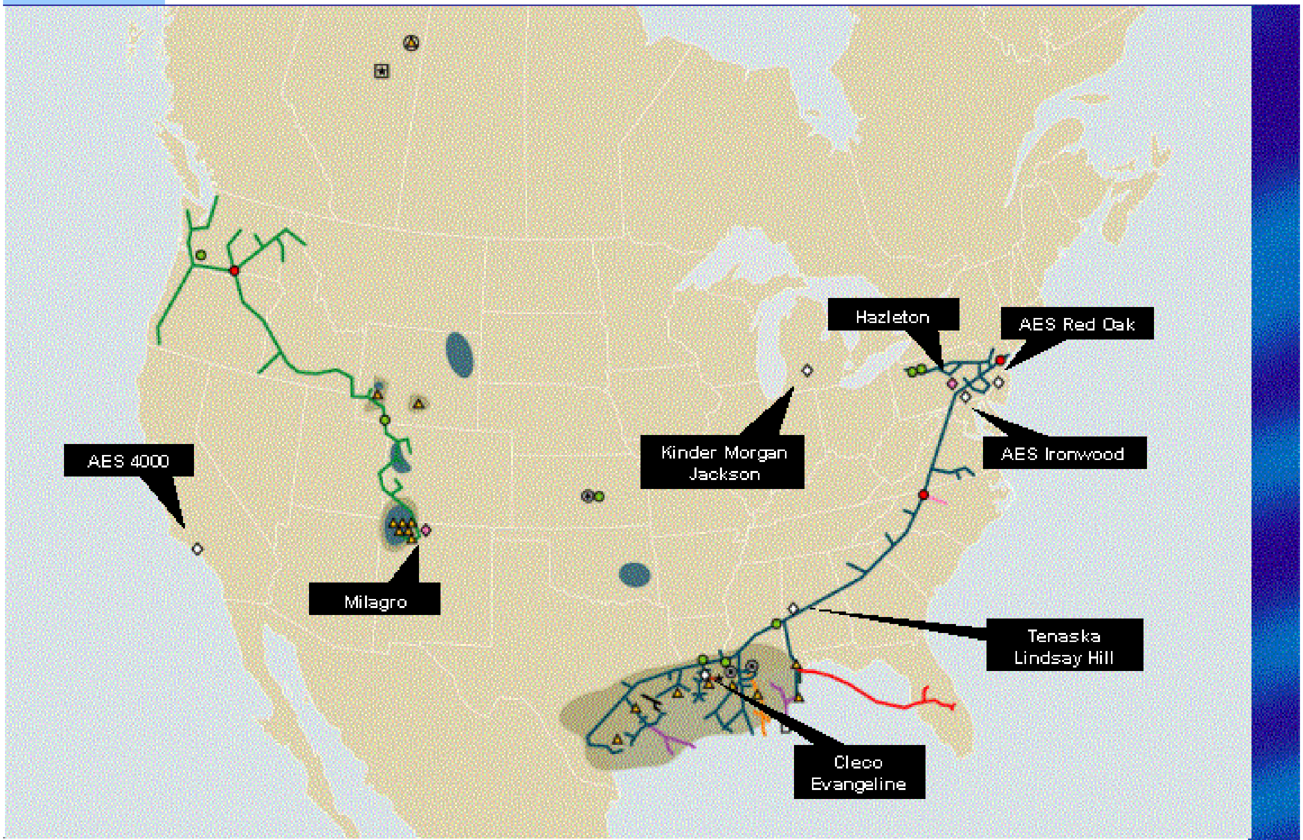
2005 Successes

Updated 3Q '05 Earnings Call

- **West**
  - 1,500 MW resale of tolling from AES 4000: 854 MW starting in 2006 and growing to 1,500 MW in 2007-10
  - 490-MW resale of toll from AES 4000 for 2006-08
  - 100-MW heat rate call option for 2008
  - 690-MW capacity sales: from AES 4000 for June-Sept 2005
- **Mid-Continent**
  - 500-MW heat rate-priced energy and capacity sale to CLECO utility starting in 2006-09
  - 100-MW heat-rate call option for 5 years – 2009 (Kinder toll)
  - 244-MW (max) block heat rate-priced energy sale for June-Sept 2005
- **Northeast**
  - 100-MW capacity sale from Ironwood to municipality for June 2005-May 2006
  - 1,000 MW of heat-rate call options sold through 2006

Williams

Power Positions and Other Williams Assets



Power Overview

November 30, 2005

Power Markets E&P Gas

- Total volumes marketed (as of November 1, 2005)

	MMBtu/d
Piceance Basin	465,000
San Juan Basin	167,000
Powder River	125,000
Arkoma	15,000
Green River	12,000
Fort Worth Basin	1,800
Total	**735,800**

- Transportation

	MMBtu/d
Colorado Interstate Gas Co.	359,000
Wyoming Interstate Pipeline	353,000
Trailblazer Pipeline	202,000
Transcolorado Gas Transmission	195,000
Northwest Pipeline	50,000
Questar Pipeline	30,000
Transwestern Pipeline	25,000
Total	**1,214,000**

- Storage – 6.4 Bcf at Clay Basin

Power Manages Midstream Fuel Requirements

- Supply fuel and shrink

	MMBtu/d
San Juan (includes X-haul)	240,000
Rockies	176,000
Gulf Coast	130,000
Canada	50,000
Total	**596,000**

- Transportation

	MMBtu/d
Mobile Bay	362,250

State of the Power Industry

- Spark spreads have bottomed out and are improving
- High gas prices favor coal and nuclear generation
- Regulatory environment stabilizing
- Market liquidity improving
- Economy continues to improve
- New builds of power plants have slowed dramatically
- Energy merchant sector remains troubled

Power

Key Issues and Mitigating Factors

Issue	Mitigating Factors
Tail risk	• Future structured deals • Improving spark spreads
Increasing natural gas prices	• Growing demand for electricity • Declining reserve margins
Williams' credit	• Improving WMB credit and liquidity • Customer net-outs • Open lines increasing
Financial woes of industry participants	• Actively managing credit risk • Part of an integrated energy company with long-term contracts
Unresolved litigation	• Significant progress has been made

Market Fundamentals

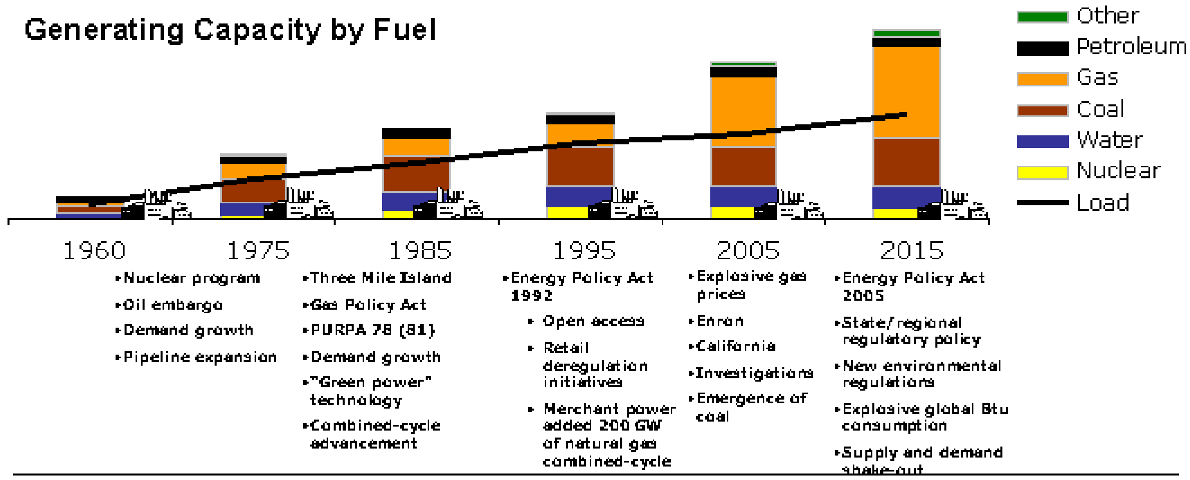
Phillip Scalzo
Vice President, Power

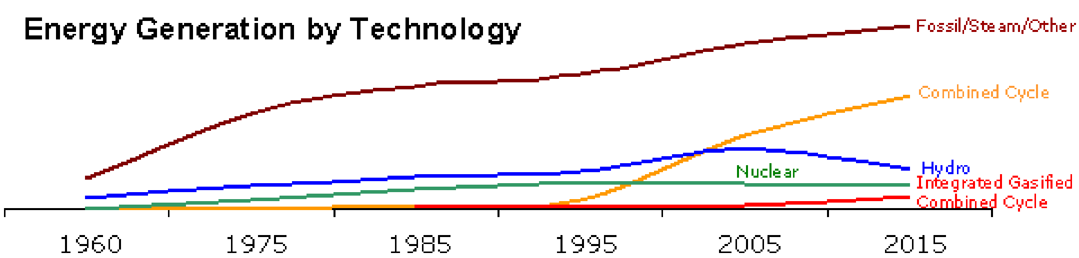
November 30, 2005

Power: Market Fundamentals

Power Industry History

Evolving Domestic Electric Generation Supply





Source: Global Energy Decisions; Company Analysis

Power: Market Fundamentals

Externalities Influencing Sector

Energy Policy Act of 2005
- Encourages spending on new energy infrastructure
- Bolsters FERC authority

State/Regional Regulatory Policy
- Capacity markets are developing
- RTO-lite organizations emerging as alternative to full RTOs

New Environmental Regulations
- CAIR/CAMR encouraging large industry spend to retrofit for further reduction in SO_2 and NOx
- Carbon policy to be determined

Global Btu Demand
- Global commodity markets are more connected than ever
- Domestic LNG deliveries will fall short

Supply/Demand Shakeout
- Resilient economy chipping away at surplus generation
- Next build will be slower and more expensive

New Entrants and Competitors
- Financial participates providing liquidity
- Unprecedented high commodity prices highlight need for providers of risk management services

External drivers setting stage for next cycle

Effect on Williams Power Company

- ✓ *Gradual improvement to route-to-market*
- ✓ *Uplift to existing generation*
- ✓ *Increased cost to competitors with no material cost to Power*
- ✓ *Electric prices will track gas prices in regions where gas is on-the-margin*
- ✓ *Reserve margins are tightening making Power generation more valuable*
- ✓ *Customer need for risk management services - back to our basics*

New Environmental Regulations

- **Clean Air Intrastate Rule (CAIR)**
  issued by EPA on March 10, 2005
  - Mandatory reductions of Sulfur (SO_2) and Nitrogen Oxides (NO_x)
    - SO_2 targeted reductions of 50% by 2010 and 65% by 2015
    - NO_x reductions of 60% by 2015
  - Will require retrofit of coal-fired generation facilities

- **Clean Air Mercury Rule (CAMR)**
  issued by EPA on March 15, 2005
  - First ever federally mandated requirements that coal-fired electric utilities reduce emissions of mercury (H_g)
  - Establishes standards of performance limiting mercury emissions from new and existing coal-fired power plants

- **Regional Green House Gas Initiative (RGGI)**
  submitted to governors August 25, 2005
  - Cooperative effort by nine Northeastern and Mid-Atlantic states to reduce carbon dioxide CO_2 emissions
  - Establishes market-based cap-and-trade program for states to meet $C0_2$ budgets

Power Fleet Existing Environmental Exposure

✓ **SO_2 Retrofit Cost**
None – Natural Gas fired plants don't emit sulfur

✓ **NO_x Retrofit Cost**
*No direct exposure on tolls as risk allocated to plant owner; indirect exposure due to potential reduced availability**

✓ **H_g Retrofit Cost**
None – Natural gas fired plants don't emit mercury

? **CO_2 Retrofit Cost**
Dependant on nature of rules implemented – if like existing NOx rules, risk allocated to plant owner under tolls*

* Williams retains environmental exposure of owned assets - Hazelton (150 MW) and Milagro (60 MW). Hazelton is located in a CAIR state and may be required to reduce NOx emissions or purchase emission credits.

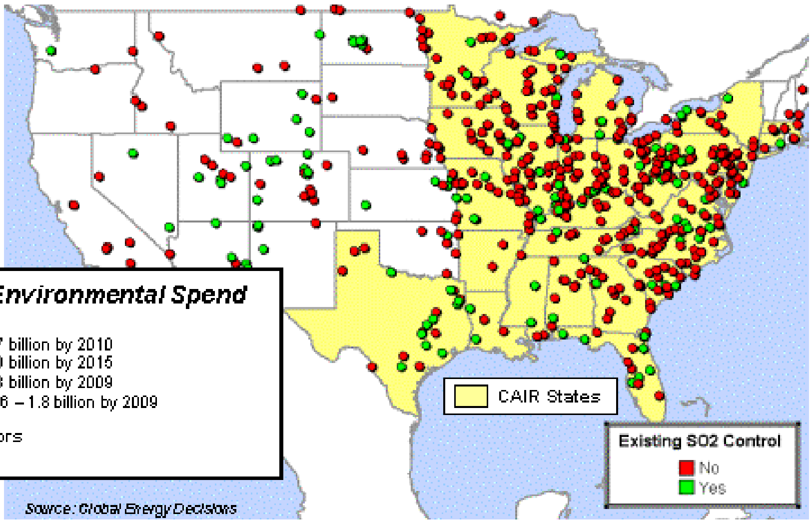
New environmental regulations will change the landscape of the power industry

Power: Market Fundamentals

Coal Generators' Environmental Spend

- **Of the 317 GW of coal-fired generation in the U.S. only 30% have any form of $S0_2$ control**
- **Assuming $140-$240/kW, scrubber retrofit will cost coal-fired generators $13-$23 billion***

US Coal Fired Generation



Announced Environmental Spend

Regulated Utilities

AEP:	$3.7 billion by 2010
Southern:	$6.0 billion by 2015
Cinergy:	$1.8 billion by 2009
Ameren:	$0.6 – 1.8 billion by 2009

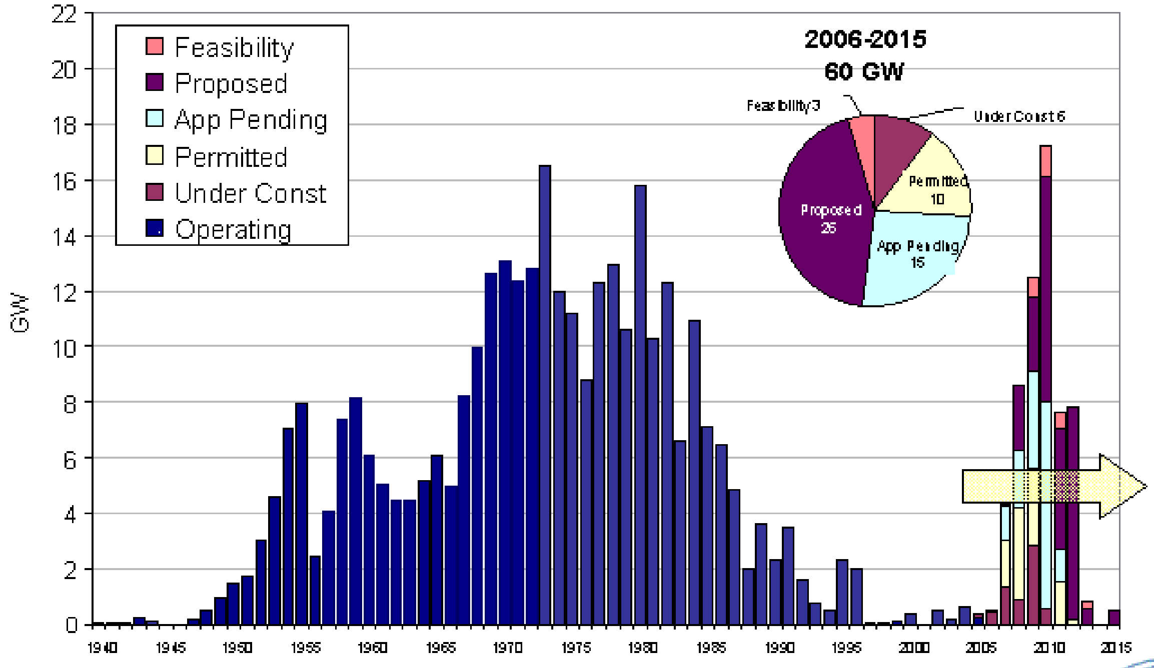
Merchant Generators
To date, largely silent

The cost of complying with new environmental regulations should increase the value of Williams gas-fired generation fleet

*Assuming scrubber retrofit cost $140-240 per kW; estimates of SO control cost from Southern Company's 2005 Analyst Meeting presentation material, March 16-17 2005

Power: Market Fundamentals

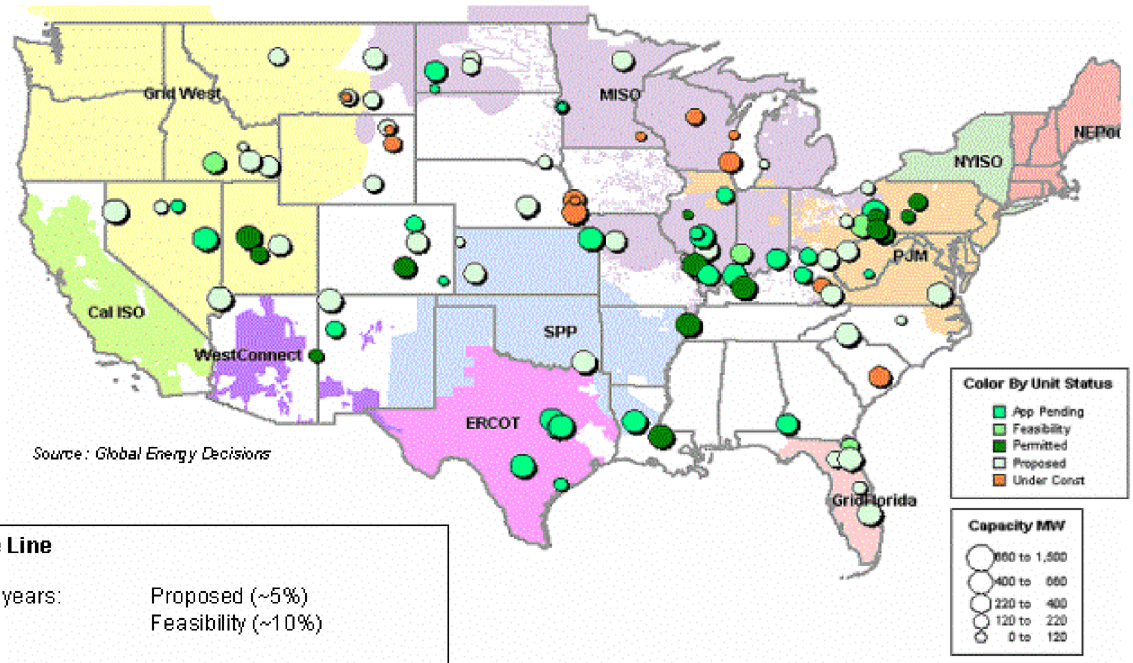
Domestic Incremental Coal Generation Capacity
By Status



Source: Global Energy Decisions

Power: Market Fundamentals

Proposed Coal Plant Additions



Source: Global Energy Decisions

Time Line

8-10 years:	Proposed (~5%) Feasibility (~10%)
7 years:	Application Pending (~30%)
5 years:	Permitted (~50%) Under Const. (<100%)

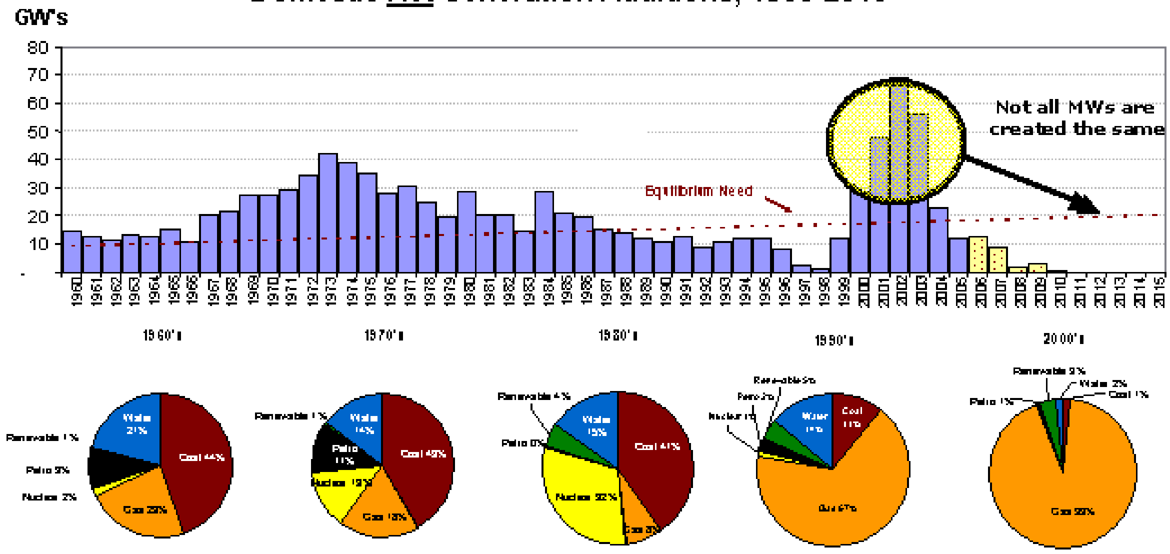
Williams

Power: Market Fundamentals

Supply/Demand Shake-out

Working Off the Excess

Domestic Net Generation Additions, 1960-2015



Source: *Global Energy Decisions*

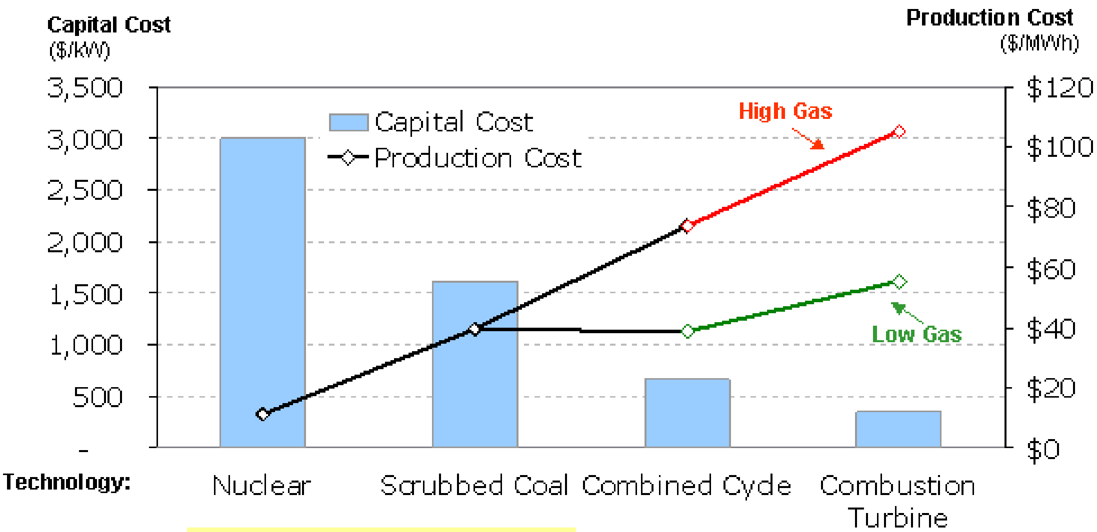
Notes: As of September 2005, equilibrium need assumes no retirements and a 15% reserve requirement. Beyond 2005, additions assume only generation which is currently under construction.

With the long lead time and environmental hurdles of coal and nuclear generation, excess gas-fired generation utilization must increase

Williams.

Power: Market Fundamentals

Power Plant Technology Costs



Development Time:	>15 yrs	8-10 yrs	3-5 yrs	1-2 yrs

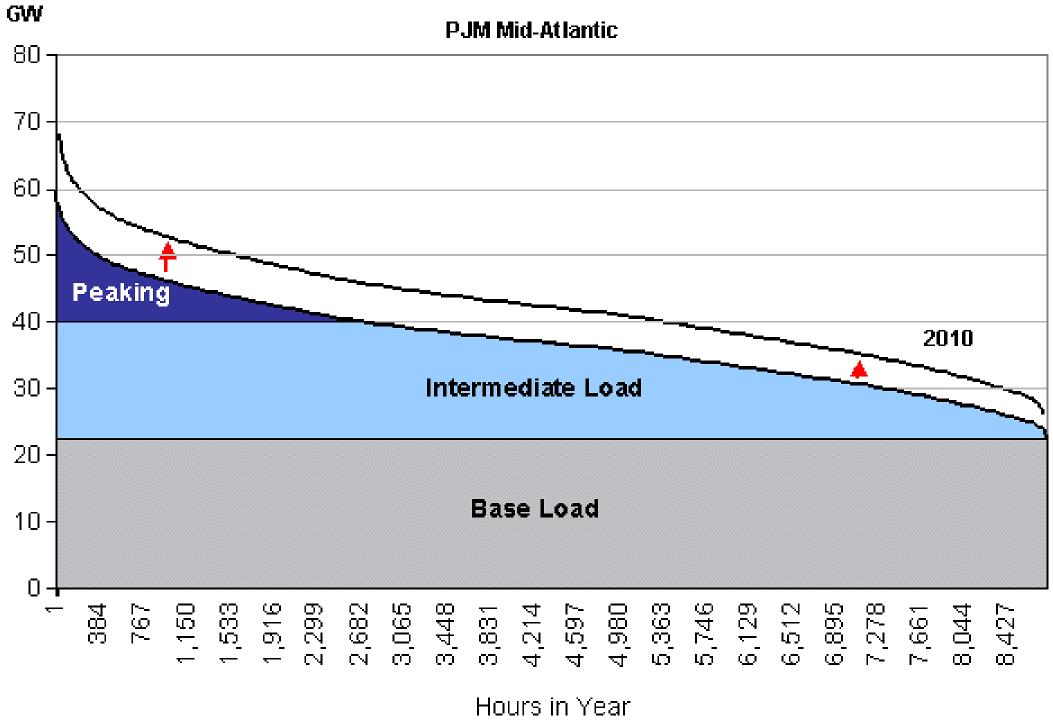
Assumes: Coal at $60/ton, NG at $10.00 and 5.00/MMBtu, NOx at $3,000/ton, and SO2 at $1,000/ton

Coal and nuclear, while seemingly good alternatives to high natural gas prices, require large capital investments and long lead times

Williams

Power: Market Fundamentals

Load Duration Curve



Source: PJM and Company Analysis

Macro economics drive shape and magnitude of power demand curve

Williams.

Production Cost: "The Supply Stack"

Production cost key determinates:

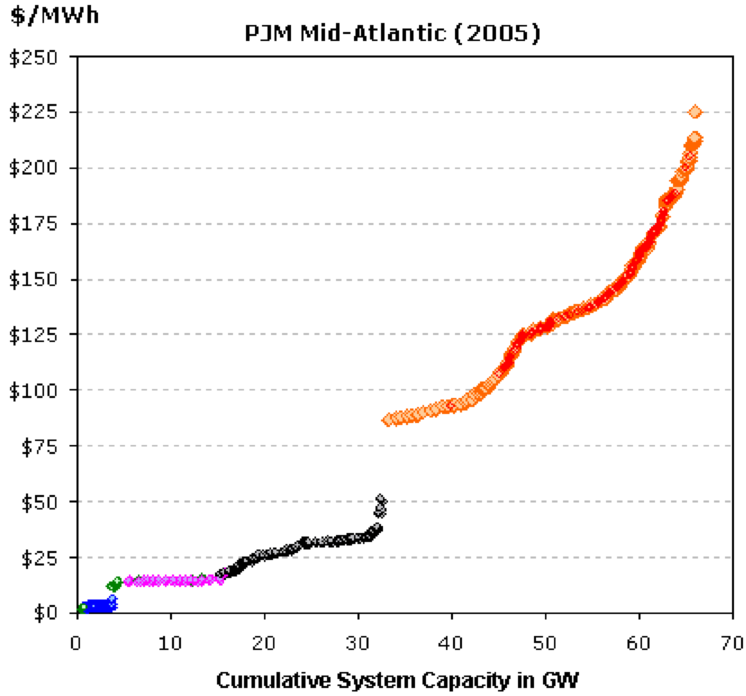
- Fuel prices
- Emission prices
- Technology
- Other variables

Fuel Prices

Hydro:	~$0
Renewable:	~$0
Nuclear:	
Coal:	$60
NG ($/MMBtu):	$13
Oil ($/Gallon):	$1.70

Emission Prices

NOx ($/ton):	$3,000
S02 ($/ton):	$1,000
C02 ($/ton):	$0



Supply Stack – *A region's total cumulative available generating capacity sorted from lowest to highest according to production cost*

Source: Global Energy Decisions; Company Analysis

Short-Term Electricity Prices

Key Determinates:

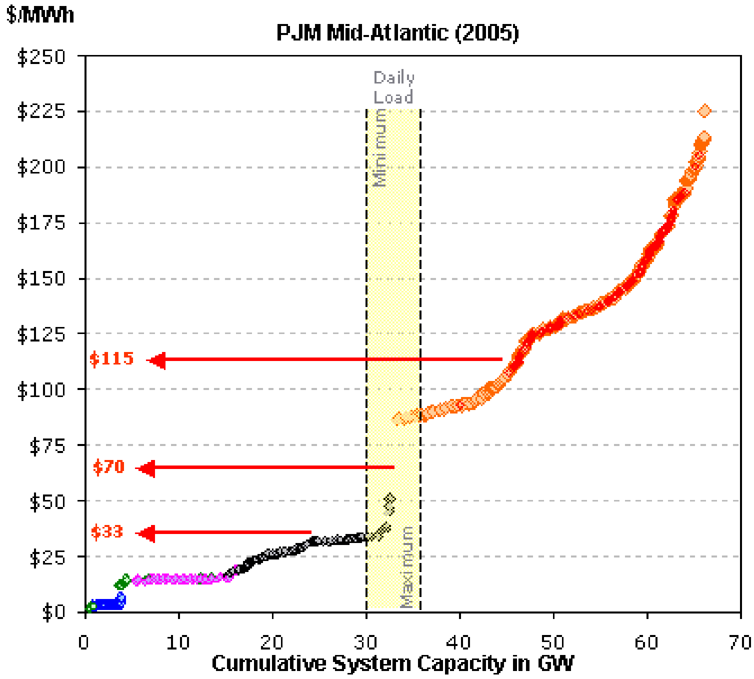
- System load (demand)
  - Weather
- Delivered fuel price
- Emission prices
- Supply (outages)
- Transmission import capability

Fuel Prices

Hydro:	~$0
Renewable:	~$0
Nuclear:	
Coal:	$60
NG ($/MMBtu):	$13
Oil ($/Gallon):	$1.70

Emission Prices

NOx ($/ton):	$3,000
S02 ($/ton):	$1,000
C02 ($/ton):	$0



Marginal Clearing Price – *the price at which the least costly unit can satisfy system's load*

Source: Global Energy Decisions; Company Analysis

Power: Market Fundamentals

Long-Term Electricity Prices

Key Determinates:

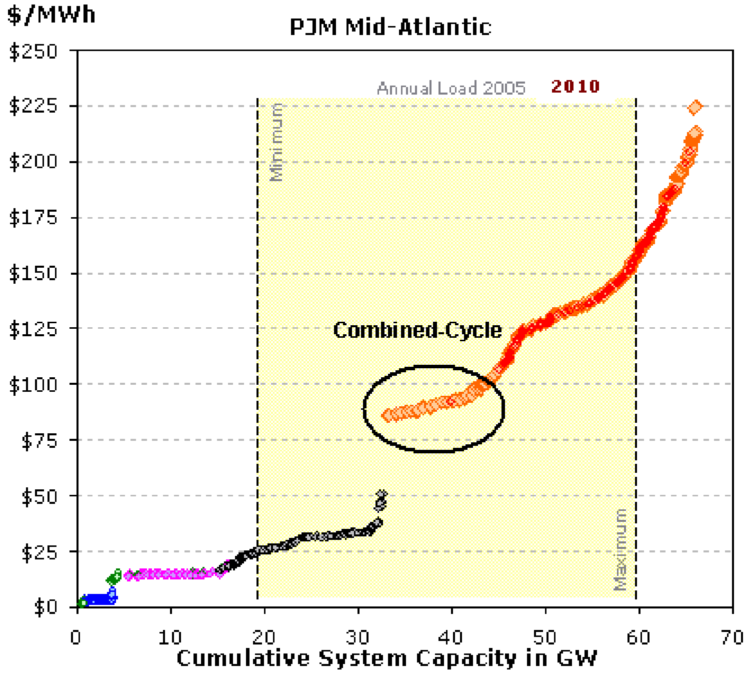
- System load
- Delivered fuel prices
- Regulatory & environmental policy
  - Generation supply
- New technology

Fuel Prices

Hydro:	~$0	
Renewable:	~$0	
Nuclear:		
Coal:	$60	
NG ($/MMBtu):	$13	$6
Oil ($/Gallon):	$1.70	$1.20

Emission Prices

NOx ($/ton):	$3,000
S02 ($/ton):	$1,000
C02 ($/ton):	$0



Source: Global Energy Decisions; Company Analysis

Load growth will increase the utilization of combined-cycle gas-fired units

Williams

Power: Market Fundamentals

Sector Long-Term Investment Alternatives

Long-Term Gas View

Long Term Environmental View

	High Gas > $7.00	Moderate Gas $5.00 - $7.00	Low Gas < $5.00
Onerous New Environmental Regulations	• Future Gen (Hydrogen) • Renewables (Wind, Biomass) • Large-scale transmission build-out • IGCC with CO_2 sequestration	• Retrofit existing PCs (with BACT) for CO_2 capture of sequestration.	• NG CC with BACT and CO_2 sequestration
Current / Contemplated Environmental Regulations	• IGCC with CO_2 • Retrofit existing PC with BACT • Renewables/Biomass • Gasification/LNG	• Existing transmission reinforcement • Compliance coal	• NG CC with BACT
Relaxed Environmental Regulations	• Unscrubbed PC life extension • IGCC without CO_2 • New PC with BACT	• PC life extension with BACT • Work off excess CC capacity • Stall new generation additions	• New conventional NGCC as required • Extend life of old, inefficient PCs

- (Black border) New Technology Focus
- (Yellow) Optimization and arbitrage focus with existing technology implementation
- (Blue) Status quo – existing portfolio harvest

BACT – Best Available Control Technology

IGCC – Integrated Gasification Combined Cycle

CC – Combined Cycle Plant

PC – Pulverized Coal Plants

Long-term fundamental view drives investments

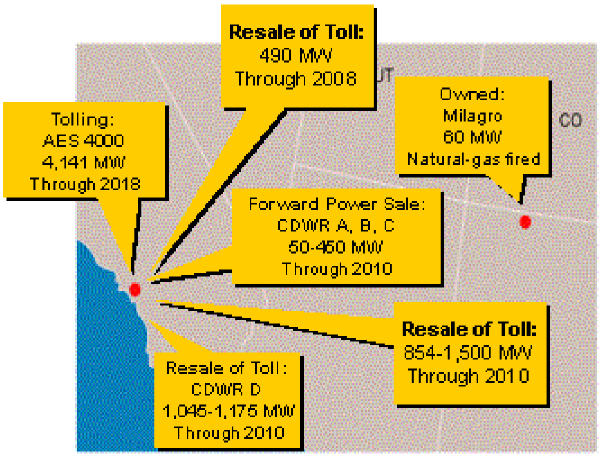
Williams

Regional Review

November 30, 2005

Williams.

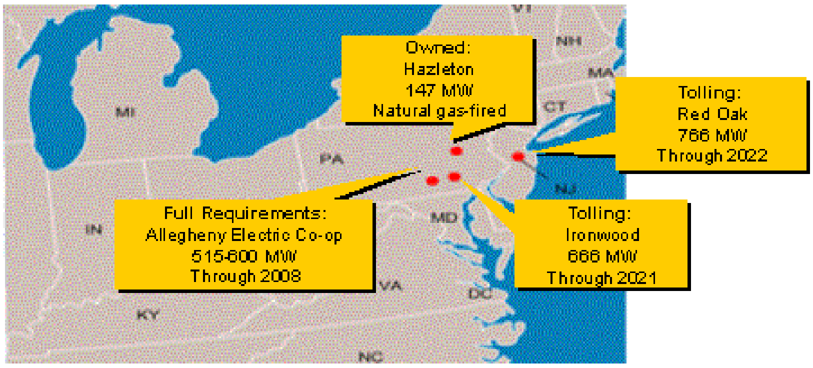
West



- In-city generation
- Highly hedged while retaining upside potential
- California likely to introduce capacity market in 2007
- Tolling agreement provides Williams with re-power rights
- Market for Williams' E&P gas
- Reserve margins tight and expected to compress further

Power: Regional Review

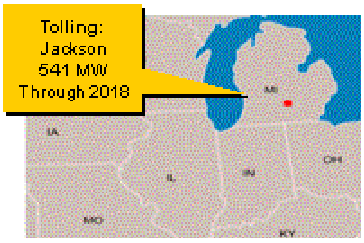
Northeast



- Positioned in most-developed competitive markets in U.S.
- New PJM demand-curve-style (NYISO like) capacity market implementation likely in 2007
- Neptune undersea transmission line will improve Red Oak's route to premium New York market
  - COD expected by summer of 2007
  - Path from Sayerville, NJ (Red Oak) to Long Island, NY
- Reserve margins tight and continuing to compress

Power: Regional Review

Mid-Continent and South Central

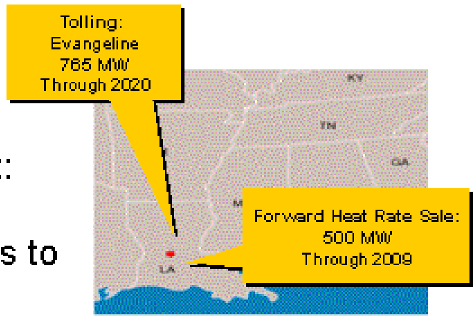


Jackson

- MISO market implemented in April, resulting in immediate improvement to Jackson's dispatch utilization
- Reserve margins beginning to tighten

Evangeline

- Toll is highly hedged
- Transmission constrained area provides opportunities for premium pricing
- Expected improvements in route to market:
  - Entergy's Independent Coordinator
  - Hurricanes may result in improvements to transmission infrastructure
- Regional reserve margins remain high

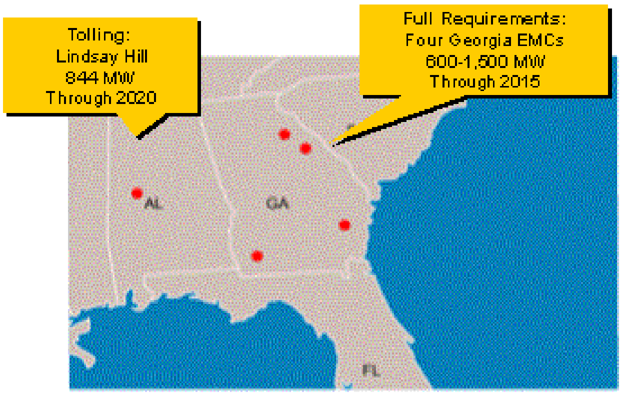


Williams

Power: Regional Review

Southeast

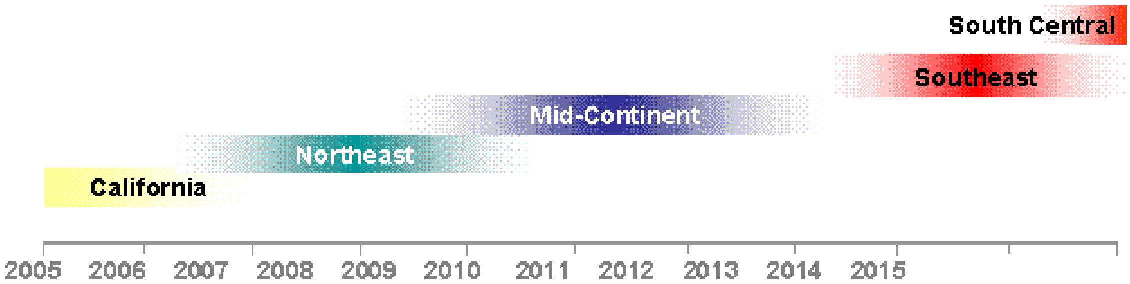
- Materially hedged with full-requirements load contracts
- Southern reserve margins remain high
  - Benefiting supply obligations for EMC's



Power: Regional Review

Supply/Demand Shakeout

Power Market Recovery Timeline



Region	Williams Generation Fleet	Estimated Reserve Margins 2005	2010	2015	Targeted Reserve Margin
Califorinia	AES 4000	12.0%	12.1%	2.8%	15-17%
Northeast	Red Oak, Ironwood, & Hazelton	16.2%	9.9%	1.4%	15%
Mid-Continent	Jackson	22.8%	17.4%	9.0%	15-17%
Southeast	Lindsay Hill	37.2%	25.1%	9.5%	15-17%
South Central *	Evangeline	85.6%	82.9%	66.7%	15-17%

Source: Energy Velocity (EV) and Company Analysis; Generation supply assumes 100% for Under Construction and Testing, for Proposed, Permitted, App Pending and Feasibility assumes 50%. Load projections are provided by EV and represent a ISO/NERC projections where available and EV forecast otherwise. EV load forecast only extend through 2013, values for subsequent years were extrapolated based on holding generation capacity and 2013 load growth rate constant.

* Represents Entergy NERC sub region, localized reserve margins in CLECO Evangeline's market are much tighter and transmission constrained.

Equilibrium in most markets by 2010

Power: Regional Review

Key Takeaways

- Not all megawatts are created equal
- Power plants are dispatched based on relative production costs
- For non-base-load plants, the relationship between plant utilization rates and profit margins is not linear
- Coming cycle will see new base-load generation (i.e., coal and nuclear)
  - Regulatory, financing and environmental uncertainties are delaying new additions
  - Long lead time
- Mid-term fundamentals look good for gas-fired generators

Financial Review

Andrew Sunderman
Vice President, Power

November 30, 2005

Power: Financial Review

Key Points from 3Q05

- Results for 3rd quarter impacted by several uncontrollable issues
  - Mild weather in West
  - Unplanned plant outages in East and West
  - Hurricanes and high natural gas prices
- CFFO YTD positive
- Full-year recurring segment profit after adjusting for impact of mark-to-market is nearly break-even despite mild weather and higher gas prices
- Deal flow has increased

Williams

Williams' Use of Derivatives

- Williams uses derivatives to hedge its commodity price and basis risks
  - Focus on using effective economic derivatives as hedges that also are effective hedges under FAS 133
- Williams accounts for these derivatives under FAS 133 with changes in fair value for effective, designated derivatives being deferred through Other Comprehensive Income (OCI).
- Changes in the fair value of the ineffective portion of a designated derivative and/or non-designated derivatives go through MTM income.
- Williams' normal derivative portfolio position is as follows:
  - E&P – short natural gas price positions
  - Power – long natural gas price positions and short power positions

Power: Financial Review

3Q Financial Statement Changes for Derivatives Positions

- Williams reported the following changes related to its derivative portfolio:

	Balance Sheet		Income Statement	
	Der A/L	OCI	MTM G / (L)	Realized (G) / L
Net Change in Consolidated Derivative Values	$ (538)	$ (391)	$ (157)	$ 10
E&P hedges change in Derivative A/L	$ (700)			
- change in OCI - unrealized		$ (771)		
- ineffectiveness booked to MTM			$ (16)	
- realized from OCI to Income				$ 87
Power hedges	$ 162			
- change in OCI - unrealized		$ 380		
- current period MTM losses			$ (141)	
- previously recognized MTM				$ (60)*
- realized from OCI to Income				$ (17)

- The net change in Derivative Assets and Liabilities for E&P was negative, reflecting the rise 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 gas prices against a long derivative position.

Note: Change in OCI is pre-tax and includes only commodity-based changes. Change in Derivative A/L includes only those changes that affect OCI or Income (e.g., not Prepaid Option Premiums).

** Income impact in prior period.*

Power: Financial Review

OK, We See the Overall Economic Change Was Positive… Why Was MTM Negative?

- During and subsequent to 3Q, Power successfully executed several new structured transactions that provided additional value, added cash flow certainty and reduced future liquidity requirements.
- Power then needed to reverse prior OTC and NYMEX hedges to ensure it did not find itself in an economic over-hedged position.
- To do this, Power entered into certain gas sales contracts and power purchase contracts.
- Certain of these gas sales and power purchase contracts were not designated during 3Q; thus, rising gas prices caused a derivative loss against certain of these trades that was recorded to MTM income.

Power: Financial Review

Conclusions

- MTM gains or losses are non-cash in the period recognized
- The majority of Power's derivatives positions are effective economic hedges
- Power has consistently presented non-GAAP results after adjusting for MTM changes (gains or losses) to better reflect cash flows and value of the business
- Continued focus on enhancing communication and transparency

Changes from Previous Power Update

- "Resale of Tolling & Heat Rate Option Premiums" represents cash premium to be received
  - Previously, "Resale of Tolling" represented market value of mirror tolls, net of premium
- "Percentage Capacity Available Hedged" represents contractual MW sales as a percentage of Total Capacity Available
  - Previously, the "Percentage Volume Hedged" represented expected MW sales as a percentage of Expected Output
- "Other Hedges and Hedged Tolling Revenues" represents the estimated value of the rest of the power hedges (OTC, NYMEX, Long-Term Forward Sales and Full Requirements), including the estimated underlying tolling revenues that have been hedged
  - Previously, each of these categories of hedges was broken out in addition to estimated hedged tolling revenues.

Williams

Power: Financial Review

Total Undiscounted Cash Flows

Undiscounted dollars in millions

Combined Power Portfolio Estimated as of 9/30/05	2006F	2007F	2008F	2009-2010F
Tolling Demand Payment Obligations	($403)	($405)	($410)	($820)
Resale of Tolling & Heat Rate Option Premiums	$299	$331	$302	$510
Other Hedges and Hedged Tolling Revenues	$247	$158	$168	$346
Subtotal	$143	$83	$60	$36
Estimated Merchant Cash Flows	$25	$132	$115	$434
Est. Combined Power Portfolio Cash Flows	$168	$215	$175	$470
Est. NG Portfolio Cash Flows	$4	($11)	$20	$40
SG&A and Other	($72)	($74)	($75)	($150)
Estimated Cash Flows After SG&A	$100	$130	$120	$360
Note: Working Capital changes not forecast				
Capacity Available (in MW)	7,365	7,365	7,365	7,365
Capacity Sold in Resale of Tolling & HR Options (in MW)	3,640	3,308	3,262	2,675
Capacity Sold in Other Hedges (in MW)	888	1,019	1,030	696
Total Capacity Sold	4,528	4,327	4,292	3,371
Remaining Available (in MW) after all hedges	2,837	3,038	3,073	3,994
Percentage Capacity Available Hedged	61%	59%	58%	46%
Percentage Capacity Available Hedged @ 3/31/05	43%	41%	34%	2%
Expected Output on Remaining MW (delta)	1,005	1,091	1,310	1,886

Note: 3Q05 forecast estimated as of 9/30/05 and includes new CA Resale of Tolling and Cleco Long Term Physical deals completed in 4Q05. 3Q05 actual cash flows agree in total with Power's Cash Flow Statement; however the allocation of actual cash flows to the various deal types is based on estimates. This schedule includes non-recurring items.

Power: Financial Review

Variance from Prior Power Update (New Methodology)

Total Undiscounted Cash Flows

Undiscounted dollars in millions

Combined Power Portfolio Estimated as of 9/30/05 vs. 03/31/05	2006F	2007F	2008F	2009-2010F
Tolling Demand Payment Obligations	($1)	$1	$1	$2
Resale of Tolling & Heat Rate Option Premiums	$90	$122	$135	$261
Other Hedges and Hedged Tolling Revenues	($125)	($93)	($26)	($74)
Subtotal	($36)	$30	$110	$190
Estimated Merchant Cash Flows	$8	($8)	($81)	($108)
Est. Combined Power Portfolio Cash Flows	($28)	$22	$30	$83
Est. NG Portfolio Cash Flows	$3	($16)	$9	($19)
SG&A and Other	$0	$0	($1)	($1)
Estimated Cash Flows After SG&A	($24)	$7	$39	$64
Note: Working Capital changes not forecast				
Capacity Available (in MW)	0	0	0	0
Capacity Sold in Resale of Tolling & HR Options (i	1,947	1,615	1,615	1,615
Capacity Sold in Other Hedges (in MW)	(564)	(296)	(148)	(473)
Total Capacity Sold	1,383	1,319	1,467	1,142
Remaining Available (in MW) after all hedges	(1,383)	(1,319)	(1,467)	(1,142)
Percentage Capacity Available Hedged	19%	18%	24%	44%
Expected Output on Remaining MW (delta)	(652)	(789)	(1,455)	(1,107)

Williams

2006-07 Guidance

3Q05 Earnings Call

Dollars in millions	2006	2007
Prior Segment Profit Guidance	($270) - (120)	($220) - (70)
MTM Earnings (3Q05)		
Est. Forward MTM Impact	50	40
Chg due to Mkt Conditions, New deals & Other	0 - (50)	
Total Impact	50 - 0	40
Change in Segment Profit Guidance	50 - 0	40
Segment Profit Guidance	(225) - (125)	(180) - (30)
Estimated MTM Adjustments	270 *320*	230 *270*
Reported Segment Profit after MTM Adj	50 - 150 *50 - 200*	50 - 200
Non-Recurring	0	0
Recurring Segment Profit after MTM Adj	50 - 150 *50 - 200*	50 - 200
Cash Flow from Operations	50 - 150	0 - 200
Capital Expenditures	-	-

Note: If guidance has changed, previous guidance from 2nd quarter is shown in italics directly below

Williams

Conclusion & Wrap Up

Bill Hobbs
Senior Vice President, Power

Power

Key Points

- Power's third quarter CFFO YTD remains positive
- Deal flow has increased
- Markets are expected to improve throughout guidance period
- Recently completed deals provide increased value and cash flow certainty
- Power remains committed to improving transparency around financial performance
- Power remains focused on reducing risk, creating cash flow certainty and honoring contractual commitments

Q&A

Williams Midstream & Power Update

November 30, 2005

Appendix

Non-GAAP Reconciliation

Non-GAAP Reconciliation Schedule

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Non-GAAP Reconciliation

Non-GAAP Reconciliation Schedule

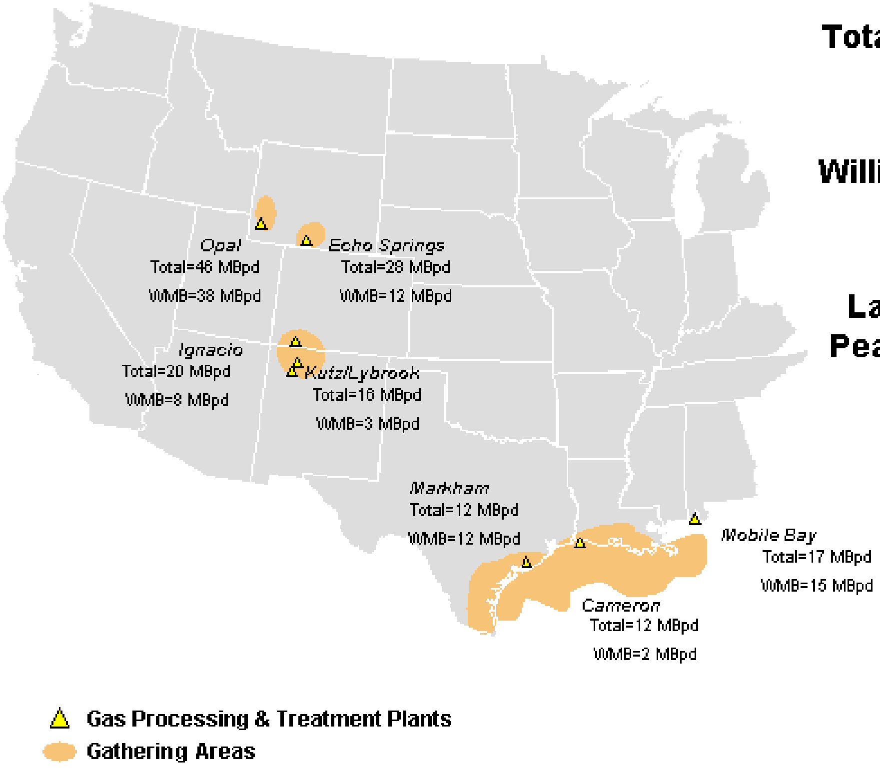
Reconciliation of Segment Profit (Loss) to Recurring Segment Profit (Loss)
(UNAUDITED)

(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 Year
Segment profit (loss):									
Power [1]	$ (32.0)	$ 43.8	$ 109.3	$ (44.4)	$ 76.7	$ 114.1	$ (75.0)	$ (226.4)	$ (187.3)
Gas Pipeline	147.4	132.8	148.8	156.8	585.8	167.4	164.5	161.1	493.0
Exploration & Production	51.5	43.3	70.1	70.9	235.8	103.7	118.3	158.8	380.8
Midstream Gas & Liquids	110.1	98.5	105.4	235.7	549.7	128.6	109.1	121.1	358.8
Other	(8.7)	(14.3)	2.4	(21.0)	(41.6)	(4.1)	(60.5)	(10.1)	(74.7)
Total segment profit	$ 268.3	$ 304.1	$ 436.0	$ 398.0	$ 1,406.4	$ 509.7	$ 256.4	$ 204.5	$ 970.6
Nonrecurring adjustments:									
Power	$ -	$ -	$ -	$ -	$ -	$ 11.4	$ 13.1	$ 0.4	$ 24.9
Gas Pipeline	-	9.0	-	-	9.0	(13.1)	(21.7)	(14.2)	(49.0)
Exploration & Production	-	11.3	-	4.1	15.4	(7.6)	-	(21.7)	(29.3)
Midstream Gas & Liquids	-	(16.5)	22.9	(85.0)	(78.6)	-	-	-	-
Other	6.5	10.8	-	11.8	29.1	-	53.1	-	53.1
Total segment nonrecurring adjustments	$ 6.5	$ 14.6	$ 22.9	$ (69.1)	$ (25.1)	$ (9.3)	$ 44.5	$ (35.5)	$ (0.3)
Recurring segment profit (loss):									
Power	$ (32.0)	$ 43.8	$ 109.3	$ (44.4)	$ 76.7	$ 125.5	$ (61.9)	$ (226.0)	$ (162.4)
Gas Pipeline	147.4	141.8	148.8	156.8	594.8	154.3	142.8	146.9	444.0
Exploration & Production	51.5	54.6	70.1	75.0	251.2	96.1	118.3	137.1	351.5
Midstream Gas & Liquids	110.1	82.0	128.3	150.7	471.1	128.6	109.1	121.1	358.8
Other	(2.2)	(3.5)	2.4	(9.2)	(12.5)	(4.1)	(7.4)	(10.1)	(21.6)
Total recurring segment profit	$ 274.8	$ 318.7	$ 458.9	$ 328.9	$ 1,381.3	$ 500.4	$ 300.9	$ 169.0	$ 970.3

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

[1] Power's segment profit for 2004 includes the effect of intercompany interest rate swaps entered into with the other parent.

Midstream's Domestic NGL Production – YTD Sept 2005



Total NGL Production
152 MBpd

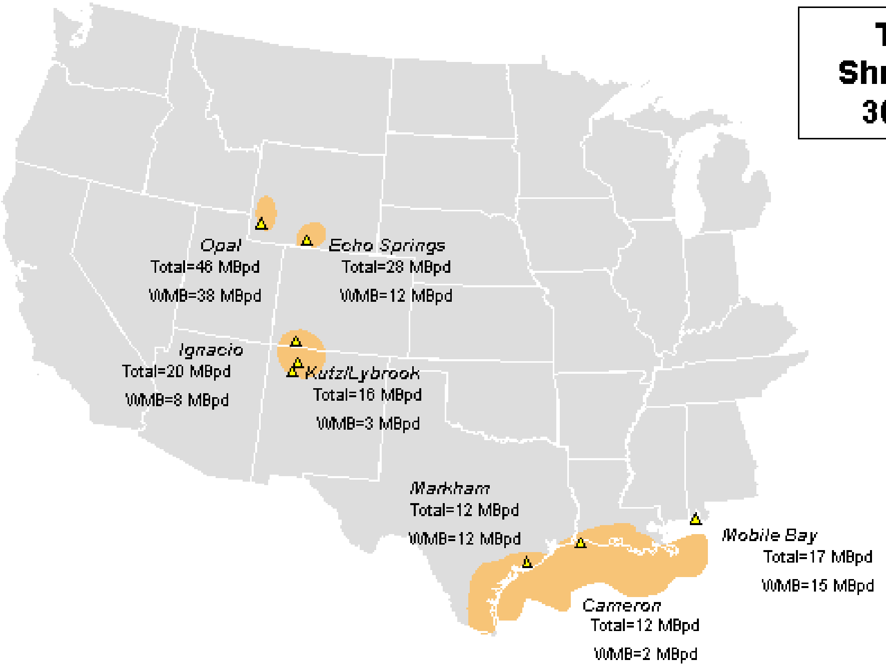
Williams' Equity Share
89 MBpd

Last Twelve Month
Peak Day Production
163 MBpd

Midstream

Midstream's Domestic NGL Shrink Requirements YTD Sept 2005

Total Domestic Shrink Requirement 306,628 MMBtu/d



Gas Processing & Treatment Plants

Gathering Areas

Williams

Midstream: Deepwater

Western Gulf Coast – Key Assets

- **Markham Gas Processing Facility**
  - 325mm scf/d capacity
  - 24/7 operation (Manned daylight hours only)
  - Residue delivery to Transco
- **Junction Platform GA A244**
  - 24/7 manned operation – 2 individuals 7/7 rotation
  - 20,000 HP of oil pumping capacity into Exxon HOOPS
- **BANJO (Oil) & Seahawk (Gas) Pipelines**
- **Export from Boomvang & Nansen Spars**
  - 16" Oil line and 18" Gas line
- **Alpine (Oil) Pipeline**
  - 18" export from Gunnison Spar
- **Cameron Meadows Gas Processing Facility**
  - 500mm scf/d capacity
  - 24/7 operation
  - Residue delivery to Transco/NGL to Dynegy
  - Down due to Hurricane Rita – will resume ~12/15/05

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Discovery – Key Assets

- **Larose Gas Processing Facility**
  - 600mm scf/d capacity
  - 24/7 manned operation
  - Residue outlets Tennessee, Columbia, Bridgeline, Transco, TETCO
- **Paradis Fractionator**
  - 40,000 bbl/d capacity
  - Purity Products EP, P, I, N, G
  - Truck & Rail loading
- **GI 115 Platform**
  - Leased to POGO
- **Deepwater Export Gas P/L Supply**
  - Agip – Allegheny and Morpeth
  - Murphy – Front Runner
  - Chevron – Tahiti
  - Numerous additional discoveries/prospects being pursued
- **All Discovery assets are in a partnership (partially MLP)**

Midstream: Deepwater

Eastern Gulf Coast Area – Key Assets

- **Mobile Bay Gas Processing Facility**
  - 650mm scf/d capacity
  - 24/7 operation
- **Canyon Station Platform**
  - 500mm scf/d capacity
  - Methanol Distillation, Glycol Dehydration & Gas Compression
  - 24/7 operation – 7 individuals 7/7 rotation
  - TFE operates Canyon Express, 2 TFE employees on location
- **Devils Tower Spar**
  - Owned by Midstream/Operated by Dominion
  - Midstream maintains 1 employee on location
  - Triton and Goldfinger tied in and flowing as of 11/16/05
  - Additional gas discovery tie-back dedicated
- **Mountaineer (Oil) Pipeline & Canyon Chief (Gas) Pipeline**
  - 18” oil export and 18” gas export from Devils Tower
  - 16” oil and gas lateral from Blind Faith under construction
  - Three additional discoveries under negotiation
- **Carbonate Trend (Offshore gas) Pipeline (MLP Asset)**

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Segment Profit

3Q05 Earnings Call

Dollars in millions	3rd Qtr 2005	3rd Qtr 2004	YTD 2005	YTD 2004
Gross Margin (Includes MTM)	($203)	$131	($98)	$202
SG&A	(21)	(20)	(54)	(56)
Operating & Other Inc./(Expense)	(2)	(2)	(35)	(25)
Segment Profit/(Loss) (Includes MTM)	(226)	109	(187)	121
MTM Adjustments	201	(142)	149	(87)
Segment Profit/(Loss) After MTM Adjustments	($25)	($33)	($38)	$34
Segment Profit/(Loss) (Includes MTM)	($226)	$109	($187)	$121
Nonrecurring:				
Expense related to Settlements and Litigation Contingencies	0	0	13	0
Expense related to prior period	0	0	12	0
Recurring Segment Profit/(Loss)	(226)	109	(162)	121
MTM Adjustments (recurring)	213	(142)	160	(87)
Recurring Segment Profit/(Loss) After MTM Adjustments	($13)	($33)	($2)	$34

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

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YTD - Segment Profit to Cash Flow

3Q05 Earnings Call

Dollars in Millions	Power and Natural Gas	Other	Total YTD
Gross Margin	($98)		($98)
SG&A & Other Inc/(Exp)	(89)		(89)
Segment Profit/(Loss) [1]	**(187)**	**0**	**(187)**
MTM Adjustments:			
Reverse Forward Unrealized MTM (Gains)	(101)		(101)
Add Realized Gains from MTM previously recognized	250		250
Segment Profit/(Loss) after MTM Adjustments [1]	**(38)**	**0**	**(38)**
Total Working Capital Change	0	82	82
Power Segment CFFO [1]	**(38)**	**82**	**44**
Est. Working Capital Used for Other BU's	0	(39)	(39)
Power Segment Standalone CFFO	**($38)**	**$43**	**$5**

[1] Includes YTD nonrecurring adjustments which decrease reported Segment Profit by $25 million and reported Segment Profit after MTM Adjustments and CFFO by $37million. Power Segment Profit after MTM Adjustments and Power Segment Standalone CFFO would be $36 million higher on a recurring basis. 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.

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Items Impacting 3Q Performance

3Q05 Earnings Call

Dollars in millions

Segment Profit After MTM Adjustments:

Q305 Forecast (as of 6/30/05)	**$54**
■ Estimated impact of mild weather in the West:	(30)
▪ Cooling Degree Days (CDDs) at Los Angeles (LAX) YTD are 17% below 5 yr avg and 43% below '04	
▪ Average September peak load in Cal-ISO system 13% below 2004	
■ Estimated impact of higher NG prices, hurricanes & others	(25)
■ Estimated impact of plant outages	(12)
■ Buyout of gas supply contract	(12)
Q305 Segment Profit After MTM Adjustments	**($25)**

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Cash Flow Analysis

3Q05 Earnings Call

Undiscounted dollars in millions (GAAP Measure)

Combined Power Portfolio *Actual v. Forecast 3Q'05*	**Q3'05A**	**Q3'05F**	**YTD05A**	**YTD05F**
Tolling Demand Payment Obligations	($126)	($126)	($310)	($310)
Resale of Tolling	34	14	116	87
Full Requirements	(6)	0	(1)	6
Long-term Physical Forward Power Sales	3	10	46	54
OTC Hedges	13	4	89	74
Est. Tolling Cash Flows Associated with Hedges	88	117	123	165
Estimated Merchant Cash Flows		60		64
Subtotal Cash Flows	7	79	64	142
NG & Other Commodity	(8)	(6)	(13)	(7)
SG&A and Other	(24)	(18)	(89)	(54)
Working Capital & Other	(15)	(7)	82	83
Power segment CFFO	(40)	48	44	164
Est. Working Capital Used for Other BU's	16	0	(39)	0
Power Standalone Cash Flows	($24)	$48	$5	$164

Note: 3Q05 forecast estimated as of 12/30/04. 3Q05 actual cash flows agree in total with Power's Cash Flow Statement; however, the allocation of actual cash flows to the various deal types is based on estimates.

Note: Estimated Cash Flows includes YTD nonrecurring adjustments which decrease reported cash flows by $36 million. Estimated cash flows would be $36million higher on a recurring basis.

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Types of Sales Around Tolling Deals

Generally from the Most- to Least-Effective Hedges

Type of Sale	How It Works
Resale of tolling	Williams buys tolling rights for a certain dollar amount per kilowatt-year and sells the same or similar tolling rights to another party. *Example: CDWR Product D*
Heat-rate sales	Sells call rights on energy, or fixed amounts of energy, at a price determined by a heat rate and fuel price.
Full requirements	Serves the load (demand) of an entity often at a fixed price, utilizing production from other Williams assets and/or the entity's resources. *Examples: EMC and Allegheny Co-op contracts*
Capacity sales	Sells the right to claim the generation as capacity. Some energy rights are usually associated.
Forward fixed-price sales	Sells fixed blocks of power at a specified price, usually w/o specifying a source. *Example: CDWR ABC*