

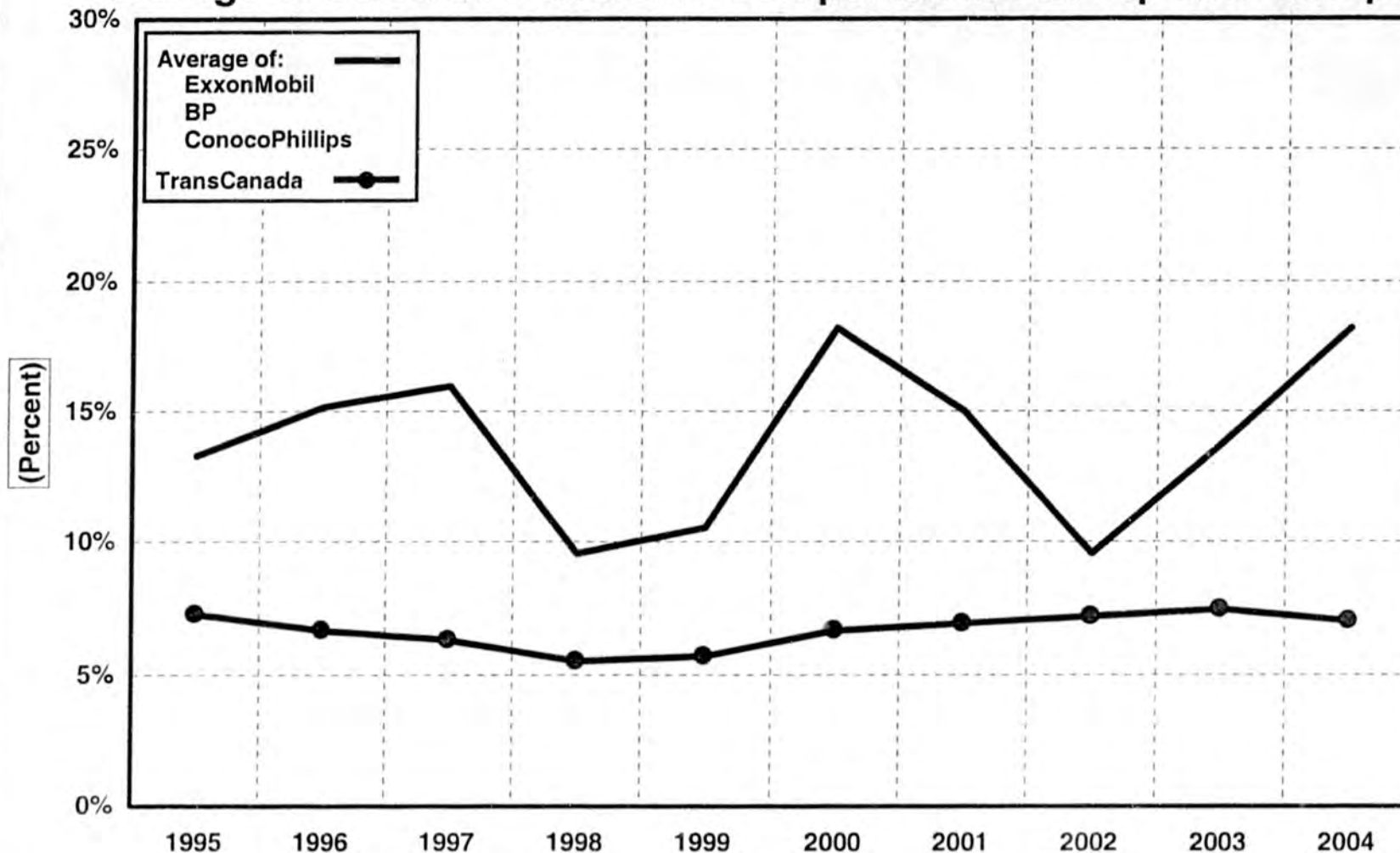
ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

3093 SCOMM 14.2: HOUSE SPECIAL COMMITTEE ON WAYS & MEANS 2005-2006

Return on Capital Employed

(1995 - 2004)

Average of Selected Petroleum Companies & Gas Pipeline Company

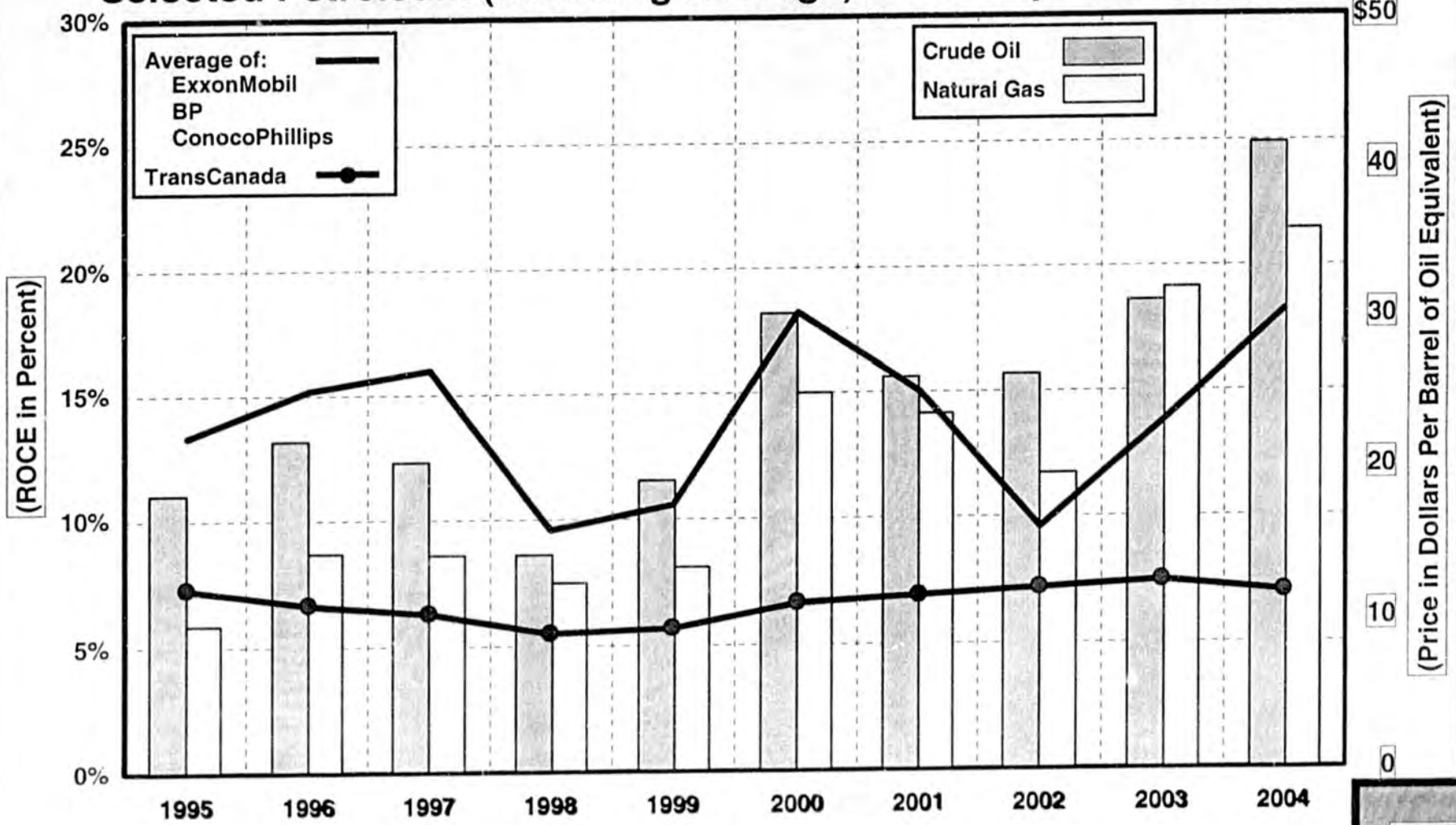


Source: Value Line (March 18, 2005).

Return on Capital Employed

(1995 - 2004)

Selected Petroleum (Including Average) & Gas Pipeline Companies



Source: Value Line (March 18, 2005); NYMEX.

Return on Capital Employed

(1995-2004)

4-10

	<u>5-Year Average</u> (Percent)	<u>10-Year Average</u> (Percent)
	(1)	(2)
ExxonMobil	19.4%	16.8%
BP	15.0	14.8
ConocoPhillips	10.5	10.3
Average of Above 3	15.0	14.0
TransCanada	7.1	6.7
NYMEX Crude Oil (\$/Bbl.)	\$30.96	\$24.96
NYMEX Natural Gas (\$/MMBtu)	\$4.68	\$3.46

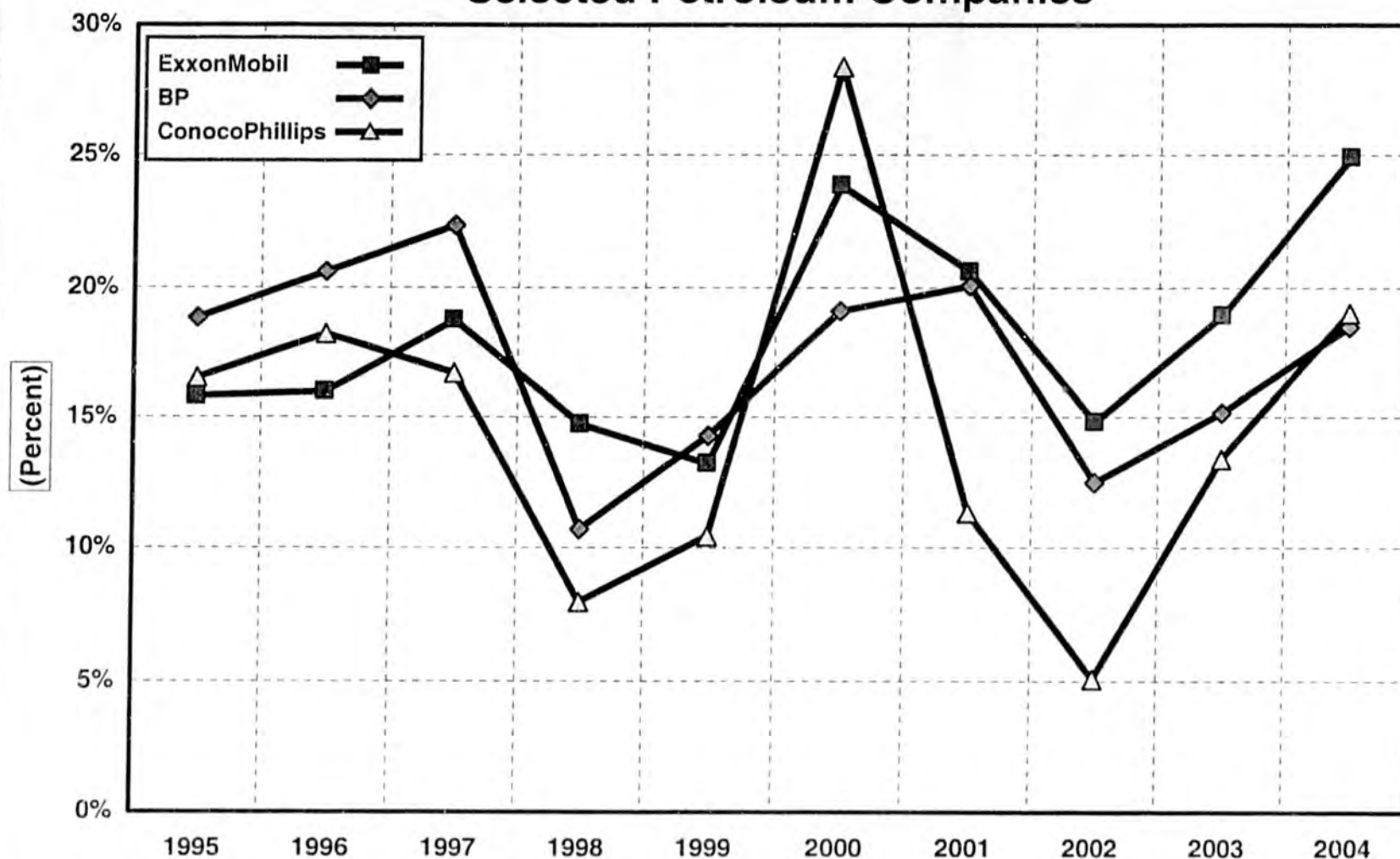
Source: Value Line (March 18 2005); NYMEX.

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Return on Shareholder Equity

(1995 - 2004)

Selected Petroleum Companies

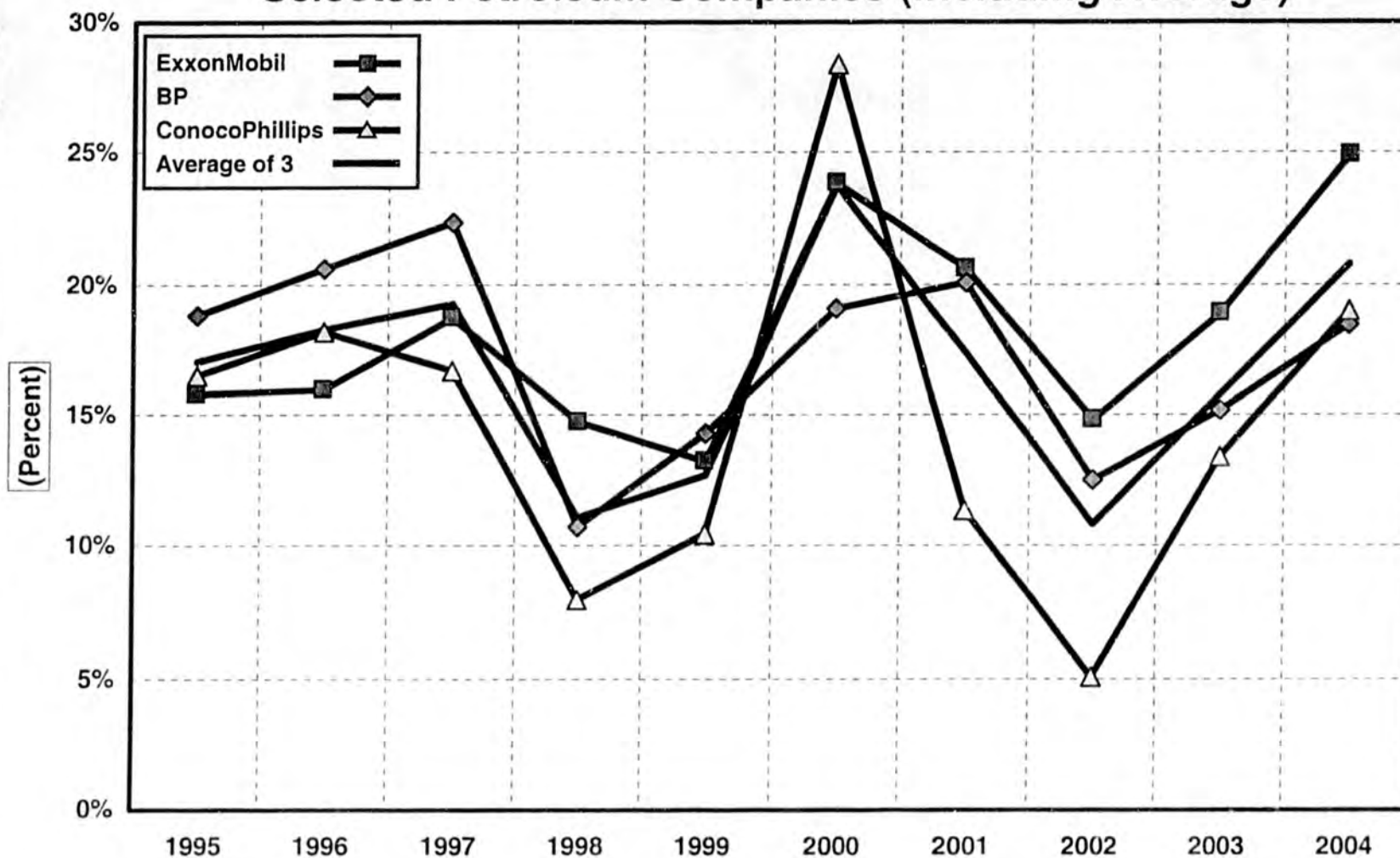


Source: Value Line (March 18, 2005).

Return on Shareholder Equity

(1995 - 2004)

Selected Petroleum Companies (Including Average)

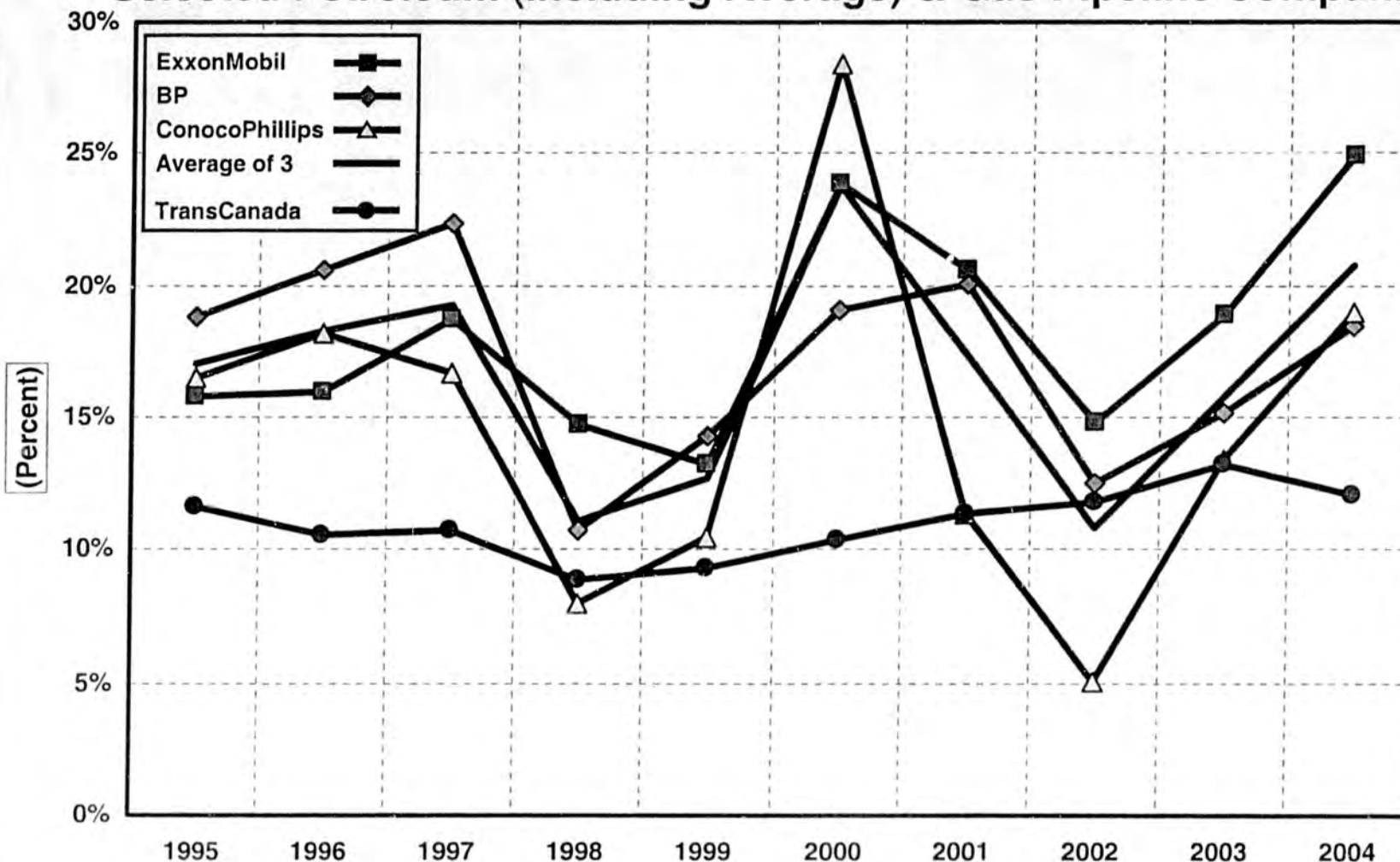


Source: Value Line (March 18, 2005).

Return on Shareholder Equity

(1995 - 2004)

Selected Petroleum (Including Average) & Gas Pipeline Companies

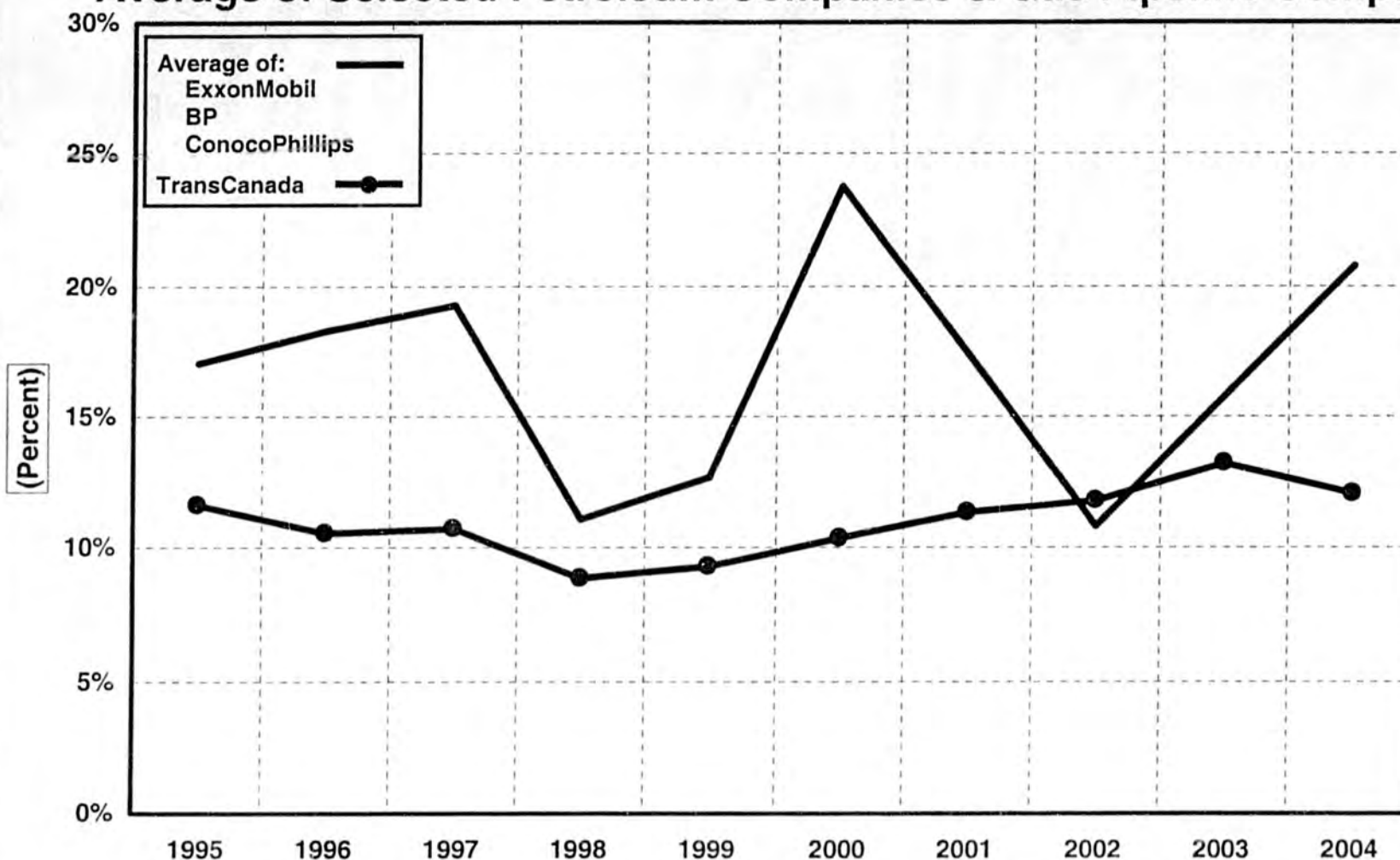


Source: Value Line (March 18, 2005).

Return on Shareholder Equity

(1995 - 2004)

Average of Selected Petroleum Companies & Gas Pipeline Company



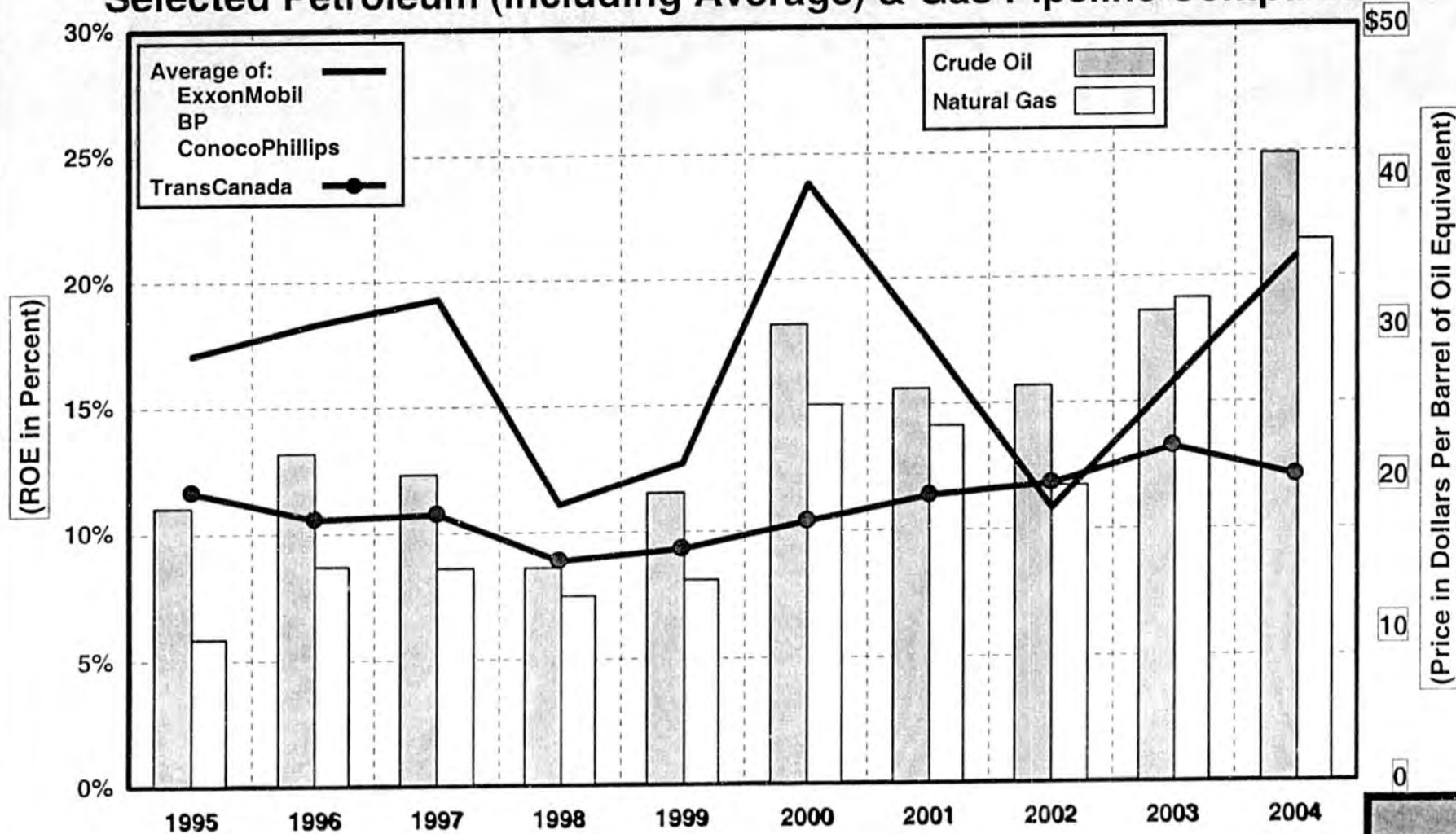
Source: Value Line (March 18, 2005).

Return on Shareholder Equity

(1995 - 2004)

4-15

Selected Petroleum (Including Average) & Gas Pipeline Companies



Source: Value Line (March 18, 2005); NYMEX.

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Return on Shareholder Equity

(1995 - 2004)

	<u>5-Year Average</u>	<u>10-Year Average</u>
	(Percent)	
	(1)	(2)
ExxonMobil	20.6%	18.2%
BP	17.1	17.2
ConocoPhillips	15.5	14.7
Average of Above 3	17.7	16.7
TransCanada	11.8	11.0
NYMEX Crude Oil (\$/Bbl.)	\$30.96	\$24.96
NYMEX Natural Gas (\$/MMBtu)	\$4.68	\$3.46

Source: Value Line (March 18, 2005); NYMEX.

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Weighted Average Cost of Capital

- The *Weighted Average Cost of Capital* (WACC) is the average cost to the firm of attracting capital
- WACC is equal to the average cost of the firm's debt (D) and equity (E)
- WACC depends on the proportion of debt and equity that comprise the firm's capital structure
- WACC is measured based on the market value of the firm's debt and equity, not the book value

Weighted Average Cost of Capital

- WACC is measured based on “after tax” costs
- After-tax cost of debt is lower than pre-tax cost because interest payments are tax-deductible
- After-tax Cost of Debt = Borrowing Cost (%) x (1 - Tax Rate)
- Example:

Borrowing Cost	= 8%
Tax Rate	= 35%
Cost of Debt	= 8% x (1 - 35%) = 5.2%

Weighted Average Cost of Capital

- After-tax cost of equity is the return required by investors for the firm's common stock
- Cost of equity is commonly measured using the Capital Asset Pricing Model (CAPM)
- Cost of equity under the CAPM formula depends on:
 - Risk-free returns (Federal government bonds)
 - Market equity risk premium (e.g., S&P 500 return over the risk-free rate)
 - The risk of the particular firm relative to the market or "beta"

Weighted Average Cost of Capital

- **Examples of cost of equity:**

1. **Firm with risk equal to market-wide average:**

Risk-free rate	= 5%
Market risk premium	= 7%
Company specific beta	= 1.0
Cost of equity	= $5\% + (7\% \times 1.0) = 12.0\%$

2. **Firm with risk equal to 1/2 market-wide average:**

Risk-free rate	= 5%
Market risk premium	= 7%
Company specific beta	= 0.5
Cost of equity	= $5\% + (7\% \times 0.5) = 8.5\%$

Weighted Average Cost of Capital

- Betas for companies in petroleum and natural gas pipeline industry are typically less than 1.0, reflecting less than market-average risk
- 2004 betas for selected companies range between 0.25 and 0.83

ExxonMobil = 0.41

BP = 0.61

ConocoPhillips = 0.83

TransCanada = 0.25

Weighted Average Cost of Capital

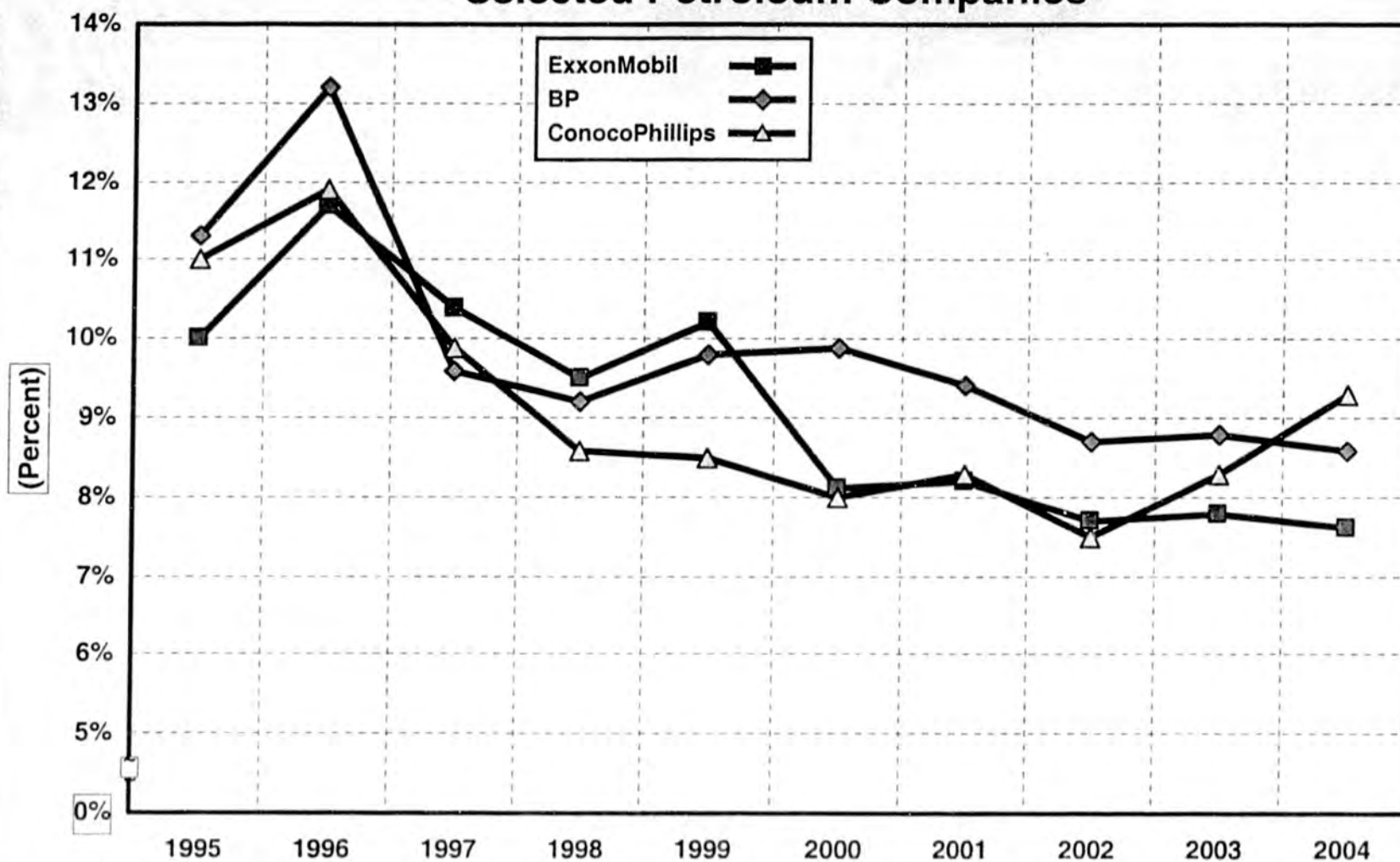
- WACC is after-tax cost of debt and equity weighted by the proportion of each in firm's capital structure
- 2004 cost of capital for selected companies:

	<u>Exxon Mobil</u>	<u>BP</u>	<u>Conoco Phillips</u>	<u>Trans Canada</u>
Cost of debt	5.6%	5.9%	6.7%	6.7%
Tax rate	38.6%	34.5%	43.6%	36.8%
After-tax cost of debt	3.5%	3.9%	3.8%	4.2%
After-tax cost of equity	7.8%	9.2%	10.8%	6.6%
Debt %	2.7%	10.5%	21.9%	48.7%
Equity %	97.3%	89.5%	78.1%	51.3%
WACC	7.6%	8.6%	9.3%	5.5%

Weighted Average Cost of Capital

(1995 - 2004)

Selected Petroleum Companies

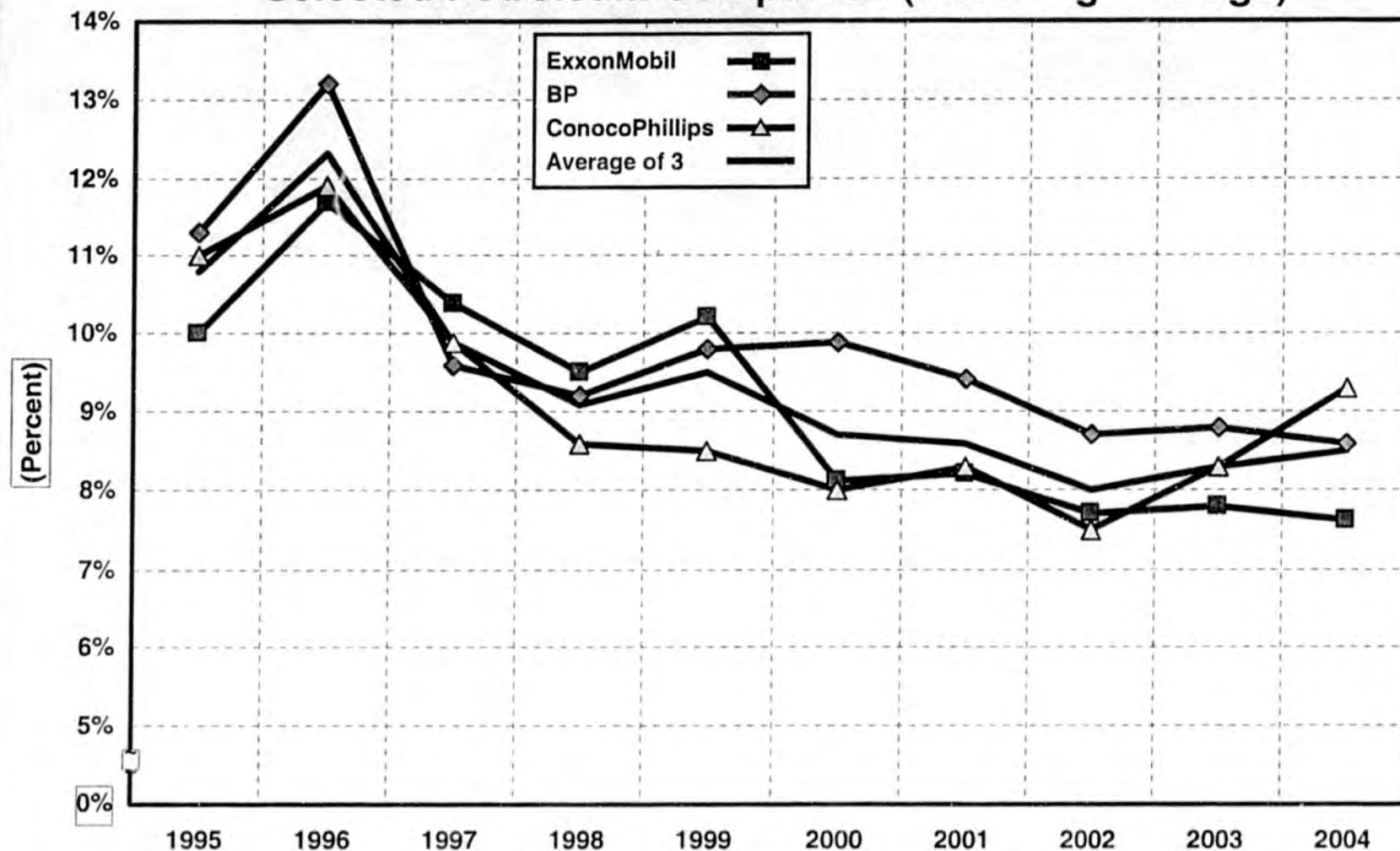


Source: Value Line (March 18, 2005); Ibbotson SBBI Valuation Edition, 2005 Yearbook.

Weighted Average Cost of Capital

(1995-2004)

Selected Petroleum Companies (Including Average)



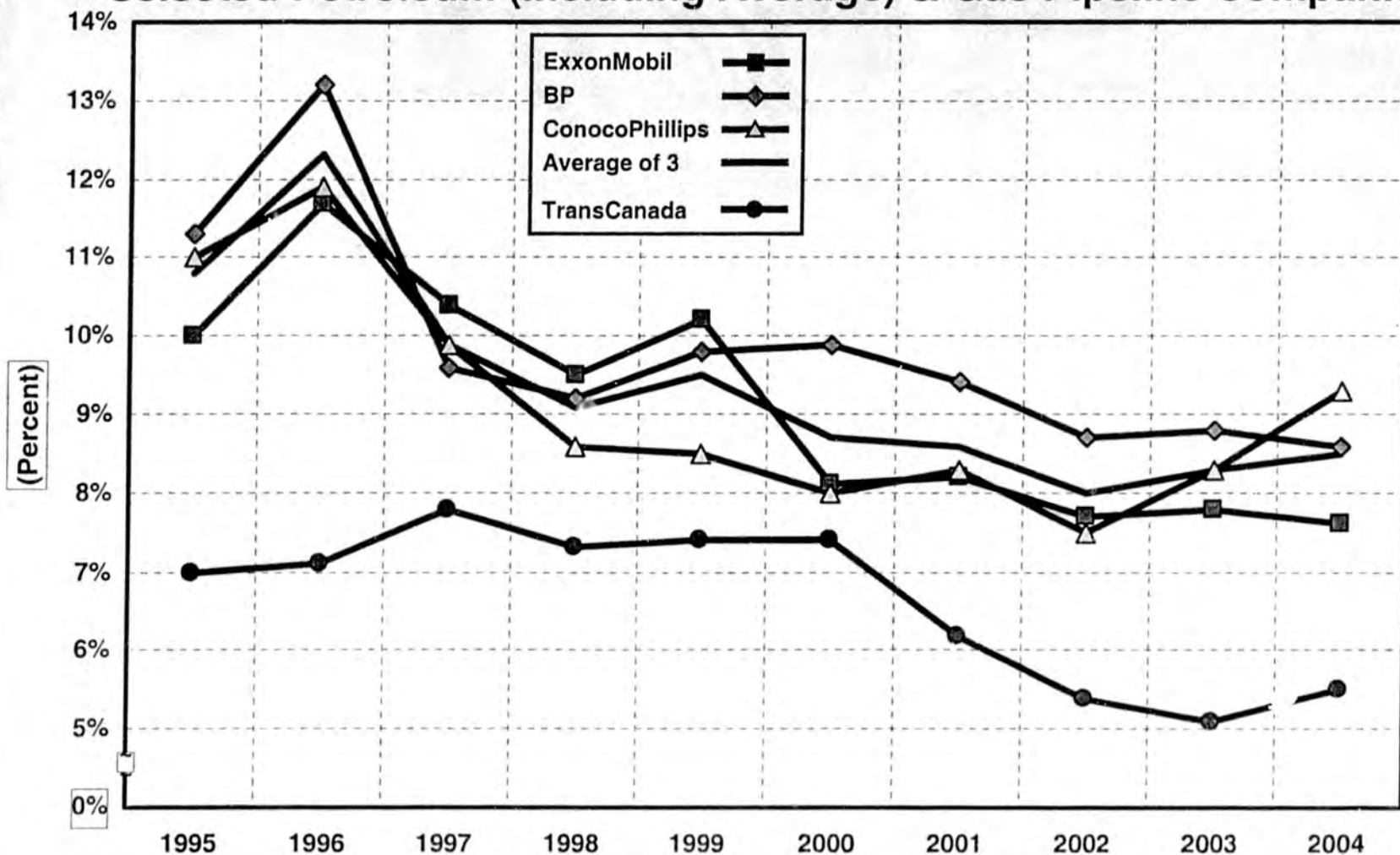
Source: Value Line (March 18, 2005); Ibbotson SBBI Valuation Edition, 2005 Yearbook.

Weighted Average Cost of Capital

(1995 - 2004)

4-25

Selected Petroleum (Including Average) & Gas Pipeline Companies



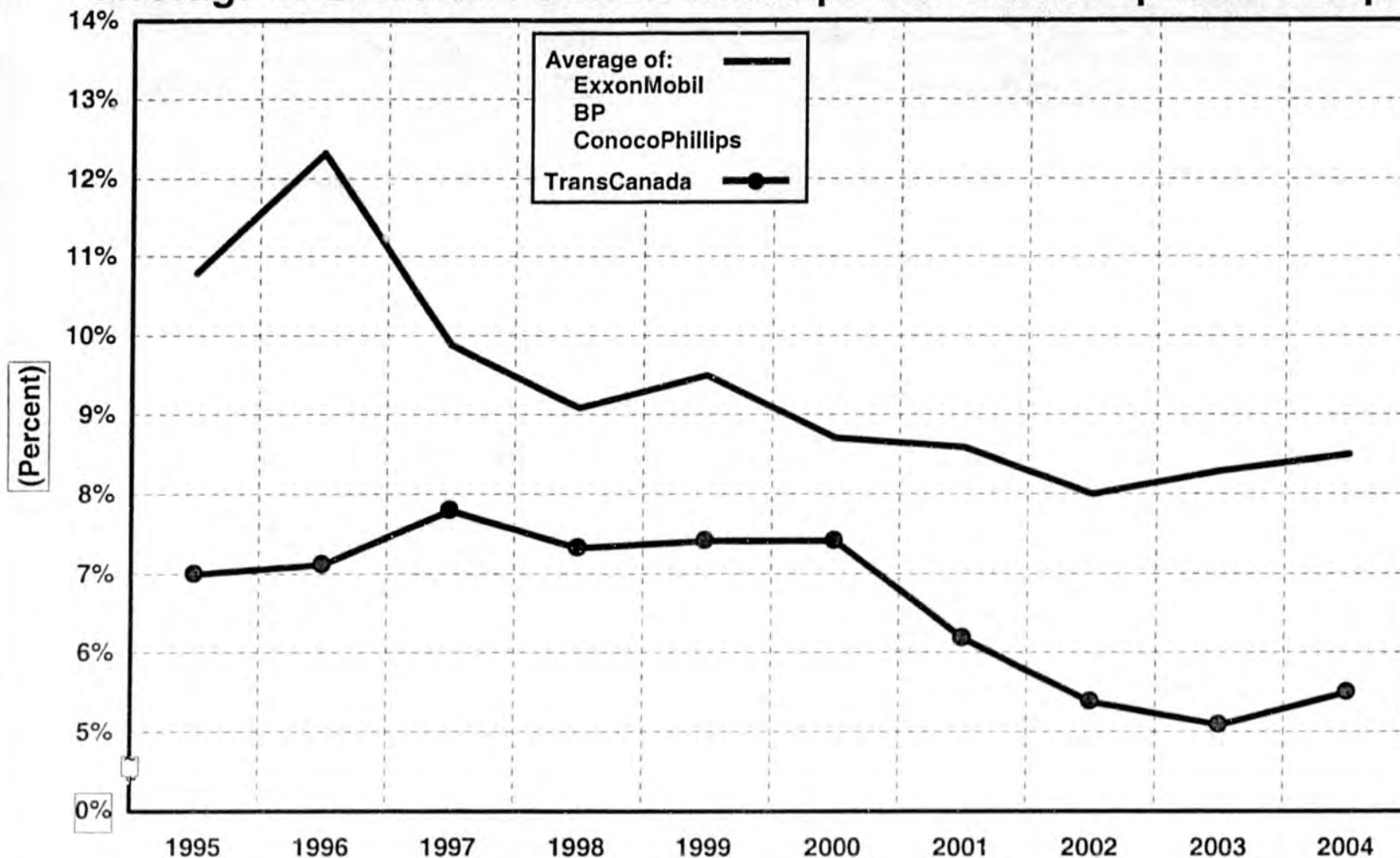
Source: Value Line (March 18, 2005); Ibbotson SBBI Valuation Edition, 2005 Yearbook.

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Weighted Average Cost of Capital

(1995 - 2004)

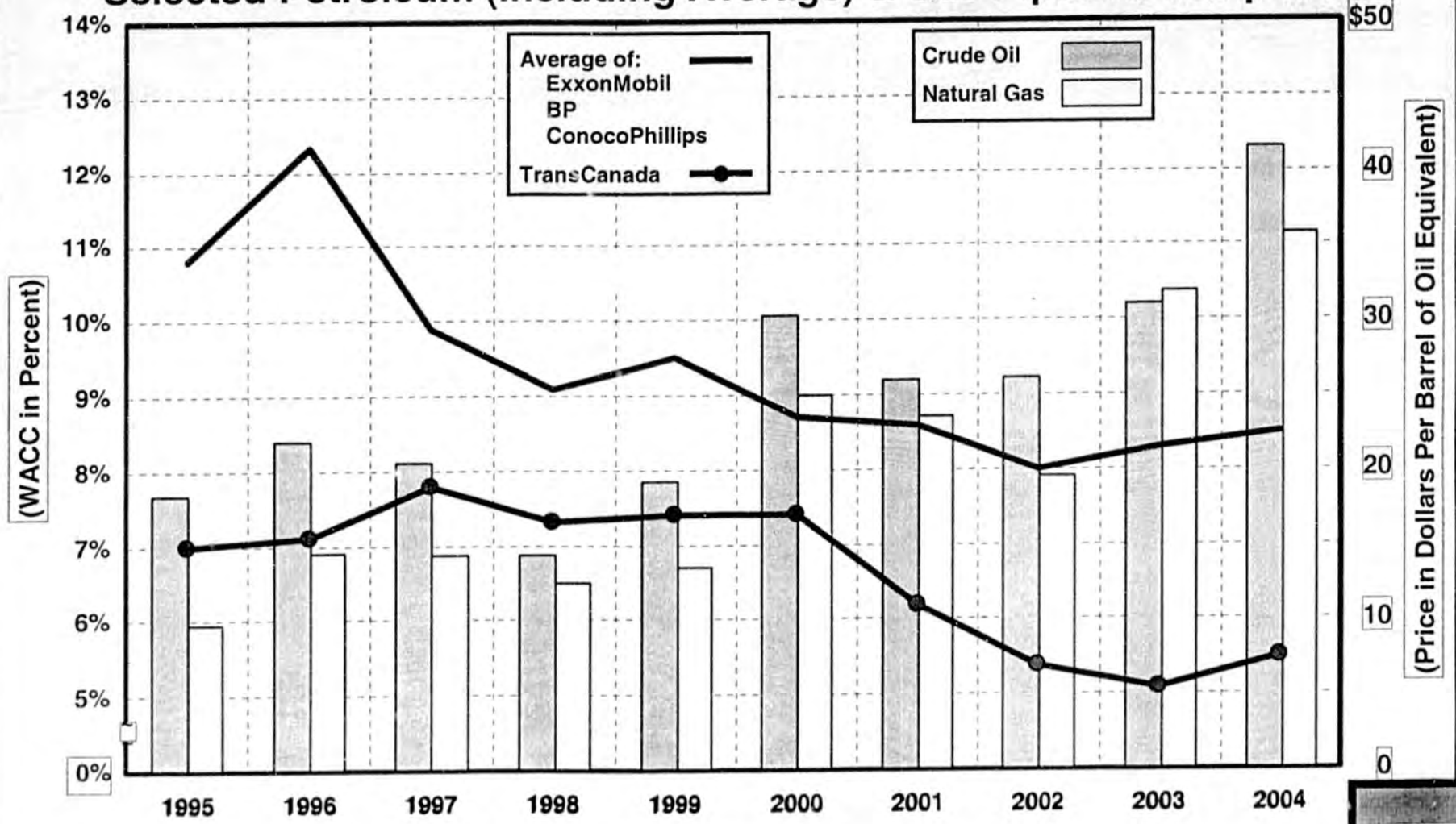
Average of Selected Petroleum Companies & Gas Pipeline Company



Source: Value Line (March 18, 2005); Ibbotson SBBI Valuation Edition, 2005 Yearbook.

Weighted Average Cost of Capital (1995-2004)

Selected Petroleum (Including Average) & Gas Pipeline Companies



Source: Value Line (March 18, 2005); Ibbotson SBBI Valuation Edition, 2005 Yearbook; NYMEX.

Weighted Average Cost of Capital

(1995-2004)

	<u>5-Year Average</u>	<u>10-Year Average</u>
	(Percent)	
	(1)	(2)
ExxonMobil	7.9%	9.1%
BP	9.1	9.9
ConocoPhillips	8.3	9.1
Average of Above 3	8.4	9.4
TransCanada	5.9	6.6
NYMEX Crude Oil (\$/Bbl.)	\$30.96	\$24.96
NYMEX Natural Gas (\$/MMBtu)	\$4.68	\$3.46

Source: Calculation of Weighted Average Cost of Capital, for each company; NYMEX

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PRESENTATION ON
ALASKA GAS PIPELINE PROJECT
to Alaska State Legislative Budget & Audit Committee
August 31, 2005

Investment Decision-Making by Oil and Gas Companies

Dr. Anthony Finizza
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How Oil and Gas Companies Look At Projects

- Does it offer a strategic fit?
- Does it offer diversification?
- Does it create wealth ($NPV > 0$ at market cost of capital)?
- Treat investment and financing as separate decisions
 - Evaluate project as if it were all equity financed
 - But, take account of ability to create value if special financing is available (e.g. federal loan guarantee)

Financial Criteria

- NPV – Net Present Value
- NPV per BOE (Barrels of Oil Equivalent)
- IRR – Internal Rate of Return
- PI - Profitability Index
- Cash Flow (Undiscounted)

Choice of Discount Rate

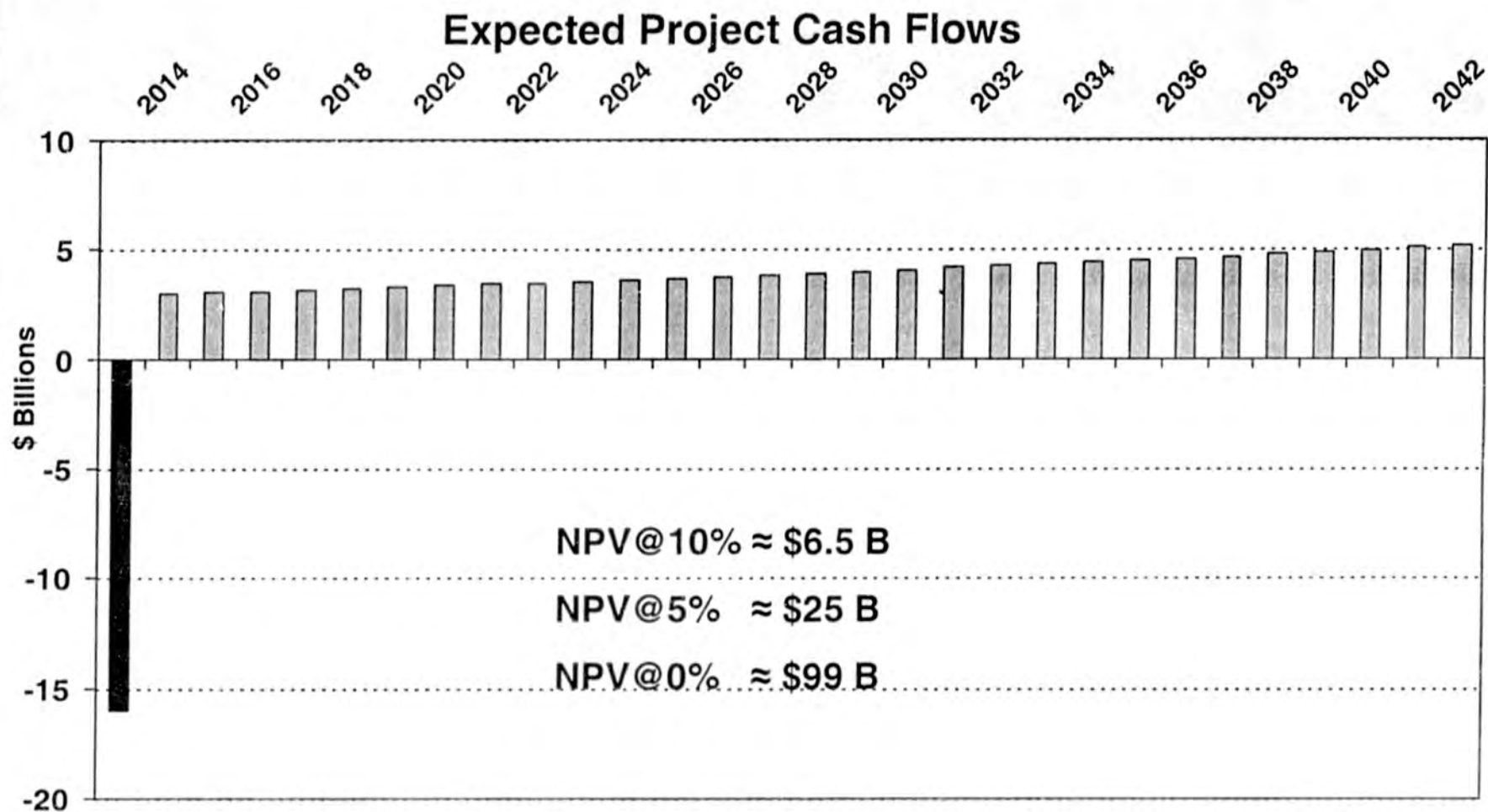
- Discount at risk-adjusted of capital, the expected rate of return that can be realized on similar investments with equivalent risk
 - Currently, using 10% for Gasline discount rate
- Projects need to be evaluated at the risk-adjusted cost of capital, which may be above the Weighted Average Cost of Capital
- What makes a project riskier?
 - Uncertainty
 - Political risk
 - Economic risk

Financial Criteria

Net Present Value (NPV)

- Present value of future cash flows including capital investment
- A project with a positive NPV is a candidate for acceptance

Stylized Cash Flow



- Measure is highly sensitive to price forecasts
- \$1.00/BOE typical of gas projects with large infrastructure costs (e.g. LNG)

Financial Criteria

Internal Rate of Return (IRR)

- The discount rate at which the NPV of a project equals zero.
- All projects with an IRR greater than the risk-adjusted cost of capital should be accepted when there are no capital budget restraints. Choose higher IRR projects when there are capital budget restraints. Although the “market” would fund projects with IRR above cost of capital, project can be postponed.
- IRR of 12-15% currently indicates threshold rate of return without significant risk factors.
- Energy companies are developing alternative projects in 15%-20% range.

Financial Criteria

Profitability Index (PI)

5-9

- **PI = [present value of cash inflows/present value of cash outflows] at a given discount rate.**

$$PI = [NPV + PV(\text{Investment})] / PV(\text{Investment})$$

- **Profitability Index captures the present value per dollar of investment - "biggest bang for the buck."**
- **PI > 1 for those projects which have a positive NPV.**
- **Measure is useful to allocate capital if there are capital restraints.**
- **Array projects from high to low and choose projects with highest PI subject to capital constraint.**

- **Note: Some analysts use a different definition of the profitability index:**

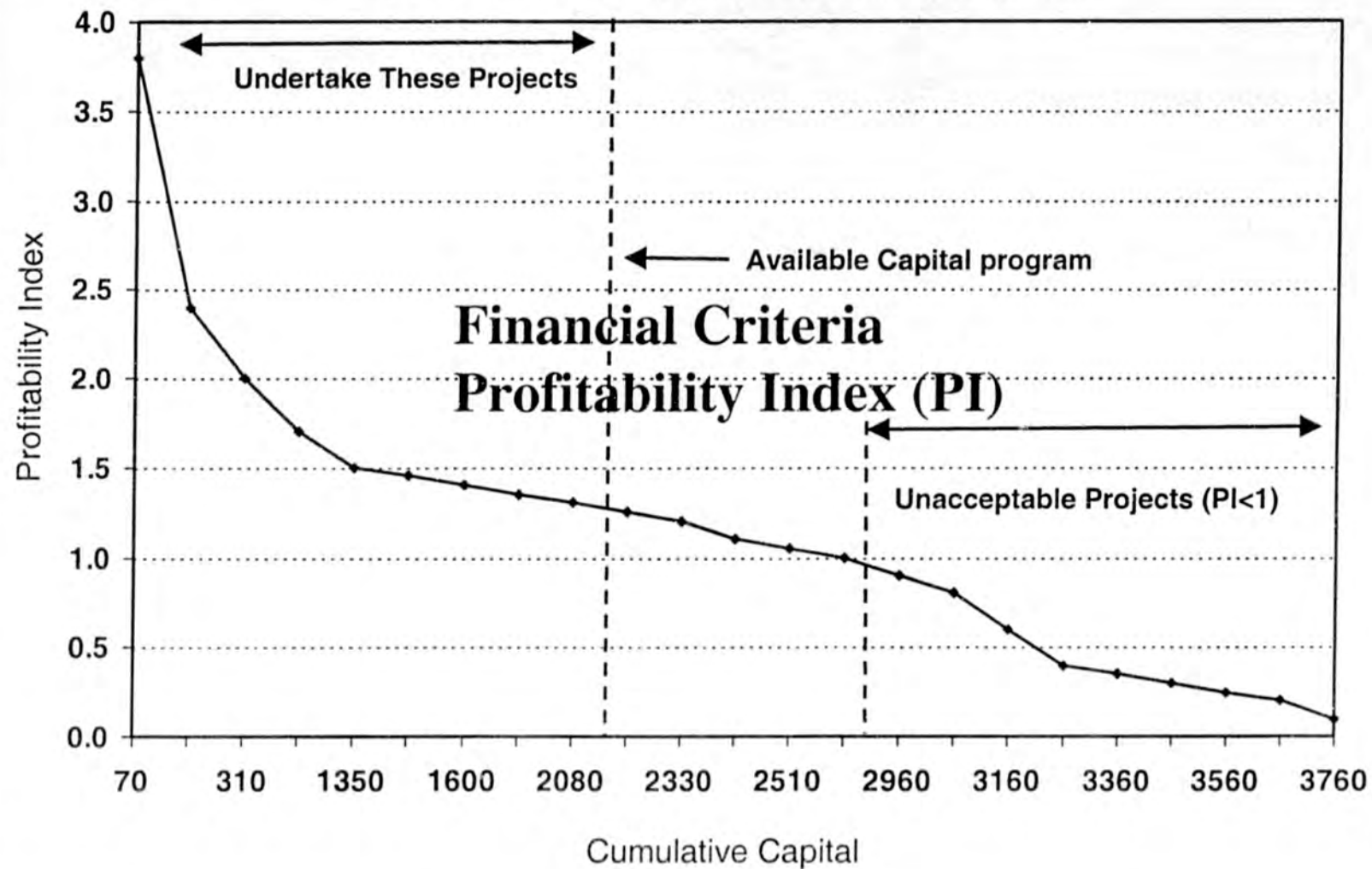
$$NPV/I = NPV / PV(\text{Investment})$$

$$PI = NPV/I + 1$$

Financial Criteria

Profitability Index (PI)

Useful To Allocate Available Capital

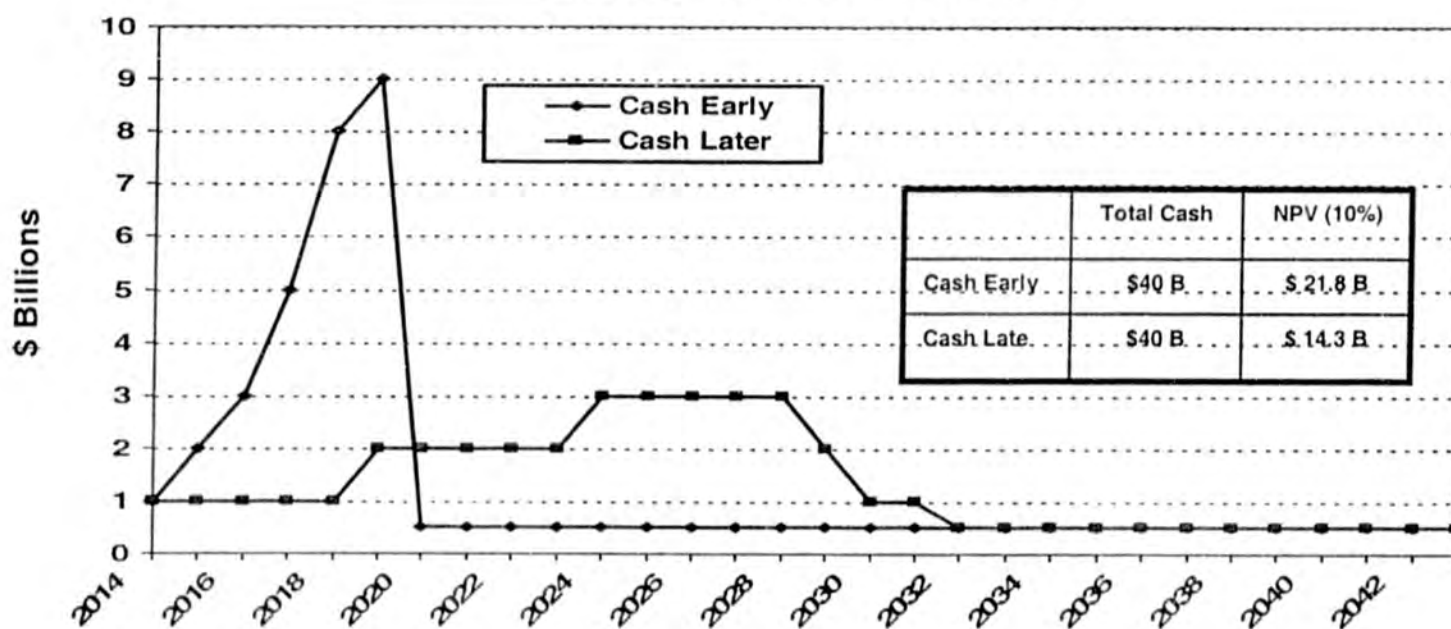


Financial Criteria

Cash (Undiscounted)

- Not used as key investment metric
- Often used to view size of project in presentations to sovereign governments
- Antithetical to discounted cash flow analysis
 - Suffers from failure to reward cash early
 - E.g. Cash flows below are equivalent, but not in discounted terms

Undiscounted Project Cash Flows



Use of Financial Metrics

- Comparing Gasline project with other projects in the firm's project portfolio.
 - Assuming capital constraints, an oil and gas company would compare alternative independent projects of the same riskiness on the basis of PI (Profitability Index). If an alternative project is riskier, the PI of the riskier project would be discounted at a higher rate to reflect the riskiness of the cash flows.
- Comparing a Gasline proposal with another Gasline proposal or with the "Status Quo."
 - An oil and gas company would use NPV (Net Present Value).
 - Note that the two proposals may not have the same risk. (e.g. fiscal certainty making cash flows less risky)
 - As a practical matter, discount rate adjustment may not be considered.
- Evaluating the effect of a delay in the Gasline.
 - An oil and gas company would use NPV, not IRR (Internal Rate of Return).
 - Note: the IRR of a project in which the cash flows are simply delayed will be unchanged.

Incorporating Risk in the Discount Rate

- If cash flows are risky, they should be adjusted to account for this risk
- As a practical matter, this is not generally done
- Instead, firms may adjust the discount rate to account for risk
 - Somewhat subjective, but guided by analytical work
 - e.g. Ibbotson work indicated the following international costs of capital, based on market data and country credit ratings
 - US ~ 12%
 - Norway ~13%
 - Qatar ~ 21%
 - Venezuela ~ 25%
 - An oil company comparing projects in the US with those in other countries will increase the discount rate to reflect the divergent risks
 - They will also lower the discount rate if there are less risky cash flows from guaranteed purchasers, fiscal certainty, etc.

Potential Constraints

Producers will not use financial metrics exclusively

Producers will address additional issues in their project evaluation

- **Do we have the personnel and skill sets to undertake the project?**
- **Will Management be able to focus on managing the project?**
 - **Is the project so complex that it will distract Management's attention from other projects?**
 - **Does the project size offer economies of scale?**
- **Is the project discretionary?**
- **What is the effect of a delay on project economics?**
 - **Will a delay allow us to undertake other projects in a more timely manner?**
 - **Do we risk losing the project or a more attractive project if we delay?**
 - **Do we have contractual obligations that impact timing?**
- **Does the project offer improved diversification?**
 - **Business Line**
 - **Regionally**
- **Do we have a competitive advantage in this project?**

Producer View of Future Gas Prices

- Producers have been “burned” by their forecasts of high gas prices in the past
 - e.g. Gas Bubble of 1990s
- Producers will test their projects against a price path that is below their “Most Likely” view
 - They use the “official price view” as a speed limit to signal aggressiveness
 - By “high-grading,” they will have a suite of projects resilient to price risk
 - Their price view lags the current market price by as much as 5-7 years as prices rise, and by 2 years as prices fall. Current view might be: \$24-26 oil (~\$4-4.25 gas)
- Producers will also “stress” test their projects
- The consequences of error are not symmetrical
 - If a producer underestimates the future path of prices, they will not undertake high risk projects and their returns will skyrocket (the current situation relative to a few years ago)
 - If a producer overestimates the future path of prices, they will be scorned by Wall Street and investors (their position in the late 1990s)
 - They will “miss” opportunities, but these misses will not be fully “penalized” by the market

Strong Incentives for Conservative Investment Strategy

5-16

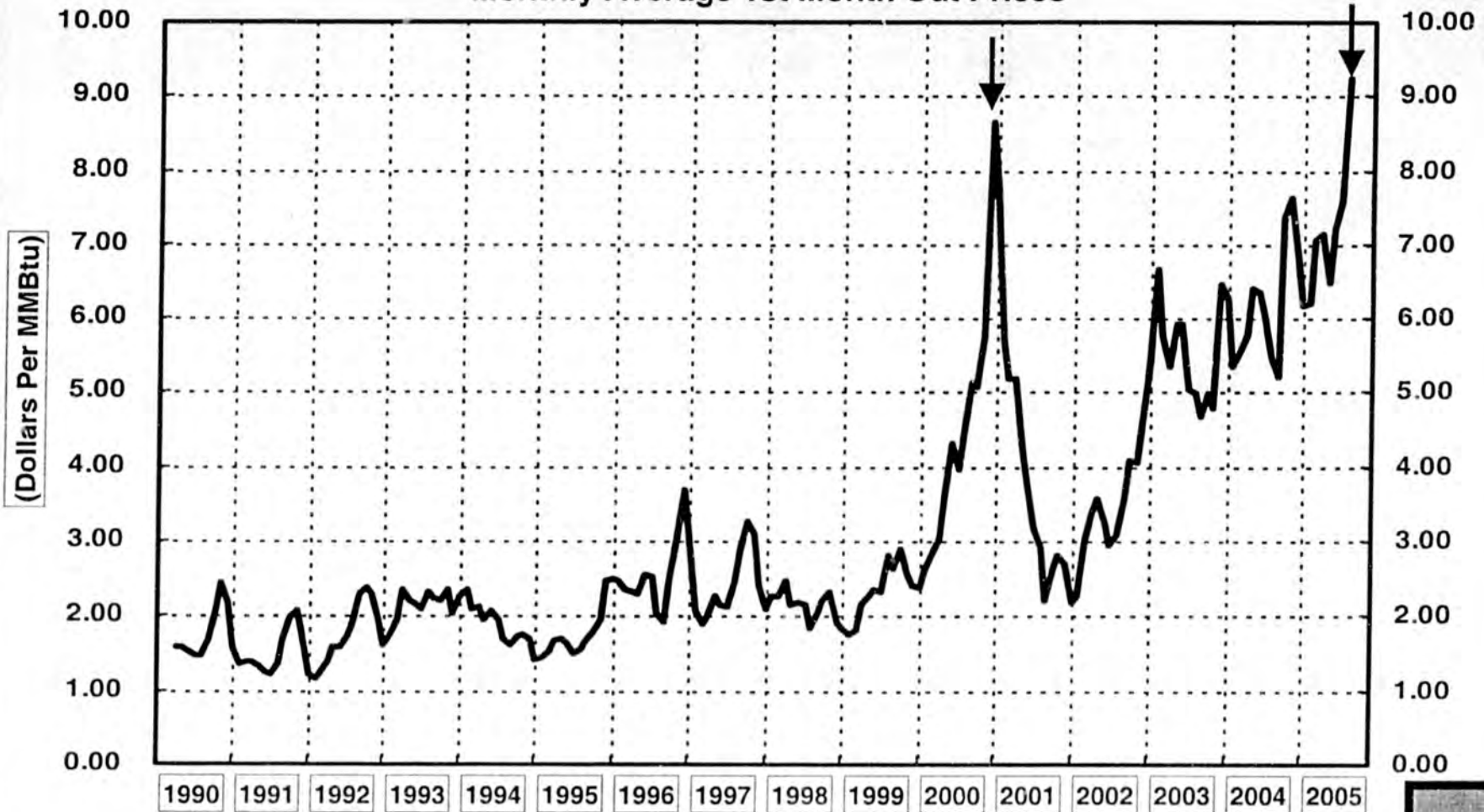
Conservative Investment Strategy Dominates In Capital Restrained World

	<i>Gas Prices High</i>	<i>Gas Prices Low</i>
<i>Aggressive Investment Strategy</i>	High ROCE	
<i>Conservative Investment Strategy</i>	Very High ROCE	Moderate ROCE

ROCE = Return on Capital Employed

Past Natural Gas Bubbles

NYMEX Natural Gas Futures Prices
Monthly Average 1st Month Out Prices



Source: NYMEX.

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PRESENTATION ON ALASKA GAS PIPELINE PROJECT

**to Alaska State Legislative Budget & Audit Committee
August 31, 2005**

Analysis of Project Viability with Vertical Components

**Dr. Jeffrey Leitzinger
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Analysis of Project Viability with Vertical Components

6-2

- Where to Look?
- Transfer Prices
- Capacity Commitments

Where to Look?

- Regulated pipeline is viable as a standalone investment
- Project integration should only improve economics
- Therefore, look to upstream economics
- If upstream economics are attractive, the gas pipeline is viable

Transfer Prices

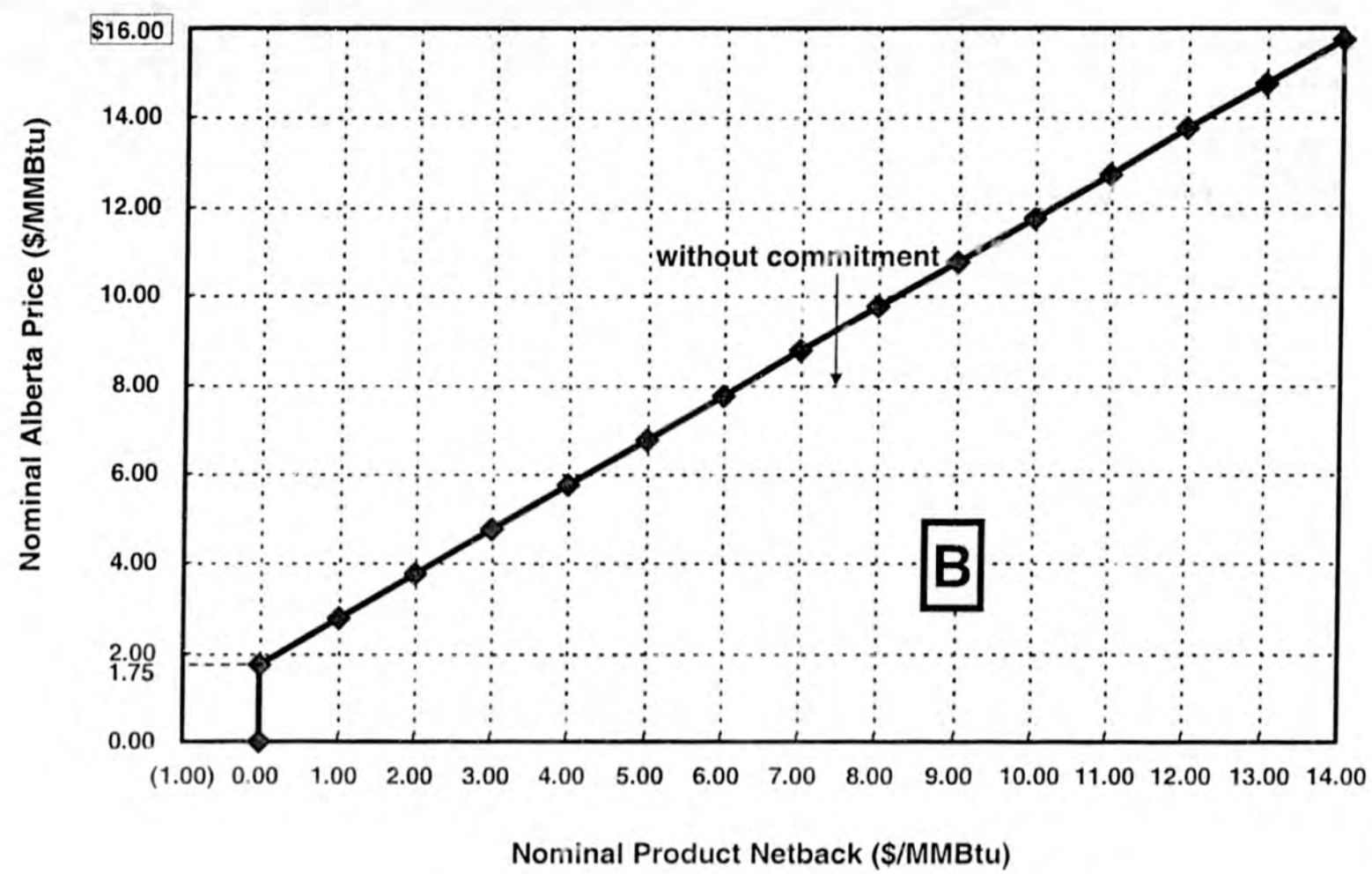
- Division of revenue between upstream and midstream should reflect market efficiencies
- Regulations will keep tariffs to cost of service (pipeline return dictated by regulatory allowances)
- Upstream capacity commitments will be necessary

Economics of Capacity Commitment

- Does not create integrated project
- Not the same as debt; not a consumer of debt capacity
- Changes expected cash flow and risk
- However, these effects are small

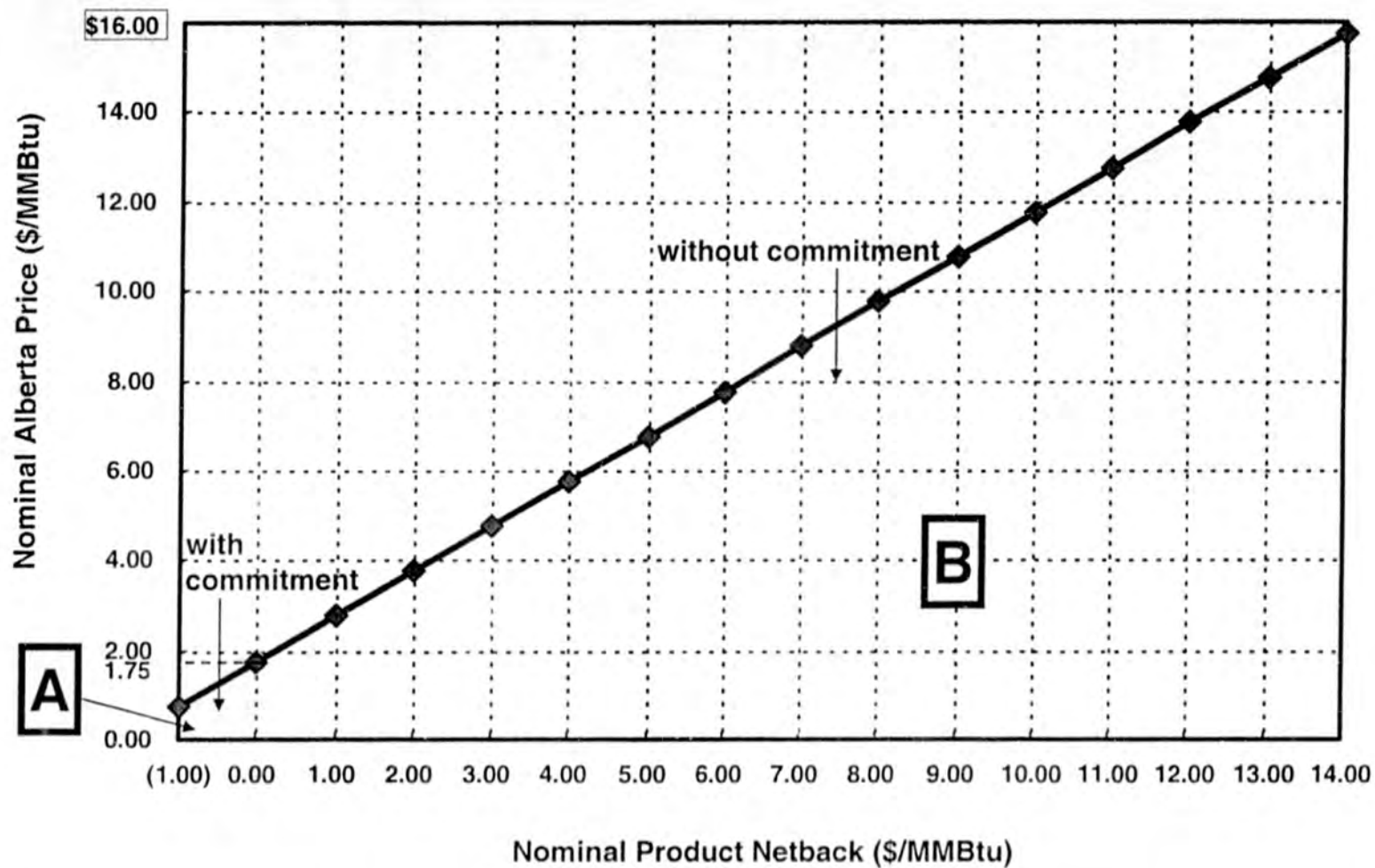
Gas Prices and Netbacks

(without Capacity Commitment)



Gas Prices and Netbacks

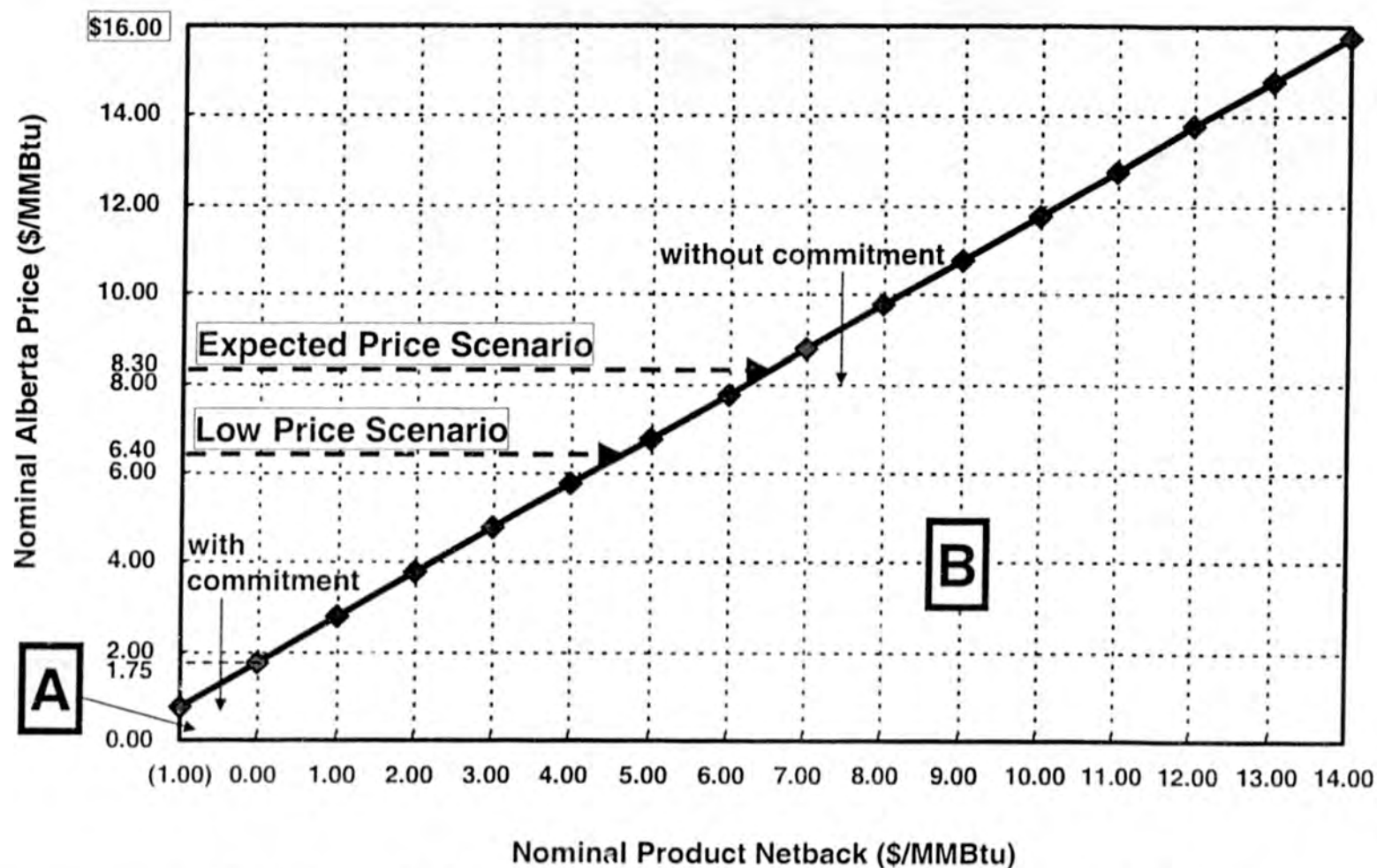
(with Capacity Commitment)



Note: A is small relative to B.

Gas Prices and Netbacks

(with Capacity Commitment)



Note: A is small relative to B and is much smaller than the expected market price of gas.

Avoiding Some Pitfalls

- Integrated project return is less than upstream return; but so is integrated project risk
- Size matters; a lower integrated return may be preferable to a higher return on a smaller standalone investment
- Beware of rate-of-return comparisons across projects with differing risk and investment profiles

PRESENTATION ON ALASKA GAS PIPELINE PROJECT

**to Alaska State Legislative Budget & Audit Committee
August 31, 2005**

**Net Present Value, Rate of Return, and Profitability Index on
Producer Investment**

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Estimated Project Returns to Producers

- Development of Model
- Major Assumptions
- Scenarios
- Sensitivities
- Results

Estimated Project Returns to Producers

Development of Model

- The Administration has developed models of the Gas Pipeline project using a combination of publicly available and confidential data
- Models analyze the economics of the pipeline project from the standpoint of the producers and the State
- At this point, we are not able to discuss the results of those models, their assumptions, or the confidential data they contain

Estimated Project Returns to Producers

Development of Model (cont'd)

- The model reflects:
 - Gas pipeline running from the North Slope, along the Alaska Highway route, with delivery to Alberta
 - Existing fiscal terms (i.e., existing royalty and tax rates)
 - The State and SGDA Applicants have discussed and made proposals that would reflect different terms; we are not able to discuss those at this time
- We examine alternative gas price, cost, and pipeline ownership scenarios

Estimated Project Returns to Producers

Major Assumptions:

- Gas pipeline developed and gas sold under current fiscal terms
- 30-year project, with sale beginning by year-end 2012
- Gas production of 4.5 BCF per day; approximately 50% from Prudhoe Bay, 16% from Point Thomson, and the balance from other fields
- Gas sales of 4.2 BCF per day in Alberta (AECO Hub)
- Gas prices in Alberta average \$0.90/MMBtu below Henry Hub/Chicago levels
- Average heat content of 1.1 MMBtu per MCF
- Gas treatment plant, pipeline, and Point Thomson facilities financed with a combination of 80% debt (with federal guarantees) and 20% equity
- Borrowing costs on federally guaranteed debt of 5% per year
- FERC allows a 14% rate of return on equity for U.S. portion of pipeline; NEB allows a 12% return for Canadian portion

Estimated Project Returns to Producers

Major Assumptions (cont'd)

- Costs and prices inflated by 2.5% per year from 2004
- Capital costs consistent with producer presentation to legislature in August 2001 and June 2004
 - Capital cost include gas treatment plant, pipeline, and Point Thomson field development costs
 - We have added additional capital for construction of a “feeder” pipeline from Point Thomson to the gas treatment plant and for development of gas reserves outside of Prudhoe Bay and Point Thomson
- We assume gas sold on a “BTU” basis (i.e., no uplift for potential NGL extraction) -- likely a conservative assumption
- Consistent with this assumption, we have not included capital for a NGL extraction facility
- We have not attempted to model any related impact on liquids production at this time

Estimated Project Returns to Producers

Scenarios

- **Pipeline Ownership**

- 1. Baseline: Producers build and own 100% of pipeline**
- 2. Producers own 50% of pipeline with another party**
- 3. Third-party (such as TransCanada) builds and owns 100% of pipeline**

Estimated Project Returns to Producers

Sensitivities

- Gas prices
- Costs

Estimated Project Returns to Producers

Sensitivities (cont'd)

- **Gas Prices**
 - **EIA Annual Energy Outlook (AEO) 2005 (\$4.90)***
 - **Prices (in 2004 dollars) range from \$4.05 to \$5.10 over time**
 - **Futures Market Implied (\$5.00)***
 - **Low Price Scenario (\$4.00)***
 - **High Price Scenario (\$6.00)***

* Constant 2004 dollars.

Estimated Project Returns to Producers

Sensitivities (cont'd)

- **Costs**
 - **Baseline Capital and Operating Costs**
 - **20 Percent Increase Relative to Baseline
in Capital and Operating Costs**
 - **20 Percent Decrease Relative to Baseline
in Capital and Operating Costs**

Estimated Project Returns to Producers

Results

**Scenario 1:
Producers Own 100% of Pipeline**

- Producers' capital outlays include cost of all facilities, including gas treatment plant, pipelines, and field development
- Producers ship all gas on pipeline constructed, financed, and regulated as described earlier in "Assumptions" section

Estimated Project Returns to Producers
(Producers Own 100% of Pipeline)

Estimated Project Returns to Producers

(Producers Own 100% of Pipeline)

Price Assumption	NPV ¹⁰ (\$ Billion) (1)	NPV ¹⁰ /BOE (\$/Bbl.) (2)	Profitability Index ¹⁰ (3)	IRR (Percent) (4)
<i>EIA AEO 2005 (\$4.90)*</i>	<i>\$14.1</i>	<i>\$1.85</i>	<i>2.36</i>	<i>19.2%</i>
Futures Market Implied (\$5.00)*	15.5	2.03	2.49	20.4%
Low Price Scenario (\$4.00)*	9.8	1.28	1.94	17.2%
High Price Scenario (\$6.00)*	21.2	2.77	3.04	23.1%

* Constant 2004 dollars.

Estimated Project Returns to Producers

(Producers Own 100% of Pipeline -- Costs Increased by 20%.)

Base Case

Price Assumption	NPV ¹⁰ (\$ Billion) (1)	NPV ¹⁰ /BOE (\$/Bbl.) (2)	Profitability Index ¹⁰ (3)	IRR (Percent) (4)
EIA AEO 2005 (\$4.90)*	\$14.1	\$1.85	2.36	19.2%
Futures Market Implied (\$5.00)*	15.5	2.03	2.49	20.4%
Low Price Scenario (\$4.00)*	9.8	1.28	1.94	17.2%
High Price Scenario (\$6.00)*	21.2	2.77	3.04	23.1%

Base Case

Costs Increased by 20%

Price Assumption	NPV ¹⁰ (\$ Billion) (1)	NPV ¹⁰ /BOE (\$/Bbl.) (2)	Profitability Index ¹⁰ (3)	IRR (Percent) (4)
EIA AEO 2005 (\$4.90)*	\$12.6	\$1.65	2.05	17.4%
Futures Market Implied (\$5.00)*	14.0	1.83	2.16	18.4%
Low Price Scenario (\$4.00)*	8.3	1.09	1.69	15.5%
High Price Scenario (\$6.00)*	19.7	2.57	2.63	21.0%

Costs Increased by 20%

* Constant 2004 dollars.

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Estimated Project Returns to Producers

(Producers Own 100% of Pipeline Costs Decreased by 20%)

Base Case

Price Assumption	NPV ¹⁰ (\$ Billion) (1)	NPV ¹⁰ /BOE (\$/Bbl.) (2)	Profitability Index ¹⁰ (3)	IRR (Percent) (4)
<i>EIA AEO 2005 (\$4.90)*</i>	<i>\$14.1</i>	<i>\$1.85</i>	<i>2.36</i>	<i>19.2%</i>
Futures Market Implied (\$5.00)*	15.5	2.03	2.49	20.4%
Low Price Scenario (\$4.00)*	9.8	1.28	1.94	17.2%
High Price Scenario (\$6.00)*	21.2	2.77	3.04	23.1%

Base Case

Costs Decreased by 20%

Price Assumption	NPV ¹⁰ (\$ Billion) (1)	NPV ¹⁰ /BOE (\$/Bbl.) (2)	Profitability Index ¹⁰ (3)	IRR (Percent) (4)
<i>EIA AEO 2005 (\$4.90)*</i>	<i>\$15.6</i>	<i>\$2.05</i>	<i>2.80</i>	<i>21.5%</i>
Futures Market Implied (\$5.00)*	17.0	2.22	2.95	22.9%
Low Price Scenario (\$4.00)*	11.3	1.48	2.30	19.4%
High Price Scenario (\$6.00)*	22.6	2.96	3.61	25.8%

Costs Decreased by 20%

* Constant 2004 dollars.

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Scenario 2: Producers Own 50% of Pipeline

Estimated Project Returns to Producers
Results

Estimated Project Returns to Producers

(Producers Own 50% of Pipeline)

- **Producers' capital outlays includes cost of gas treatment plant, Point Thomson field development, and additional capital for future gas development, plus 50% of pipeline costs**
- **Producers ship all gas on 50% owned pipeline constructed, financed, and regulated as described earlier in assumptions section**

Estimated Project Returns to Producers

(Producers Own 50% of Pipeline)

Price Assumption	NPV ¹⁰ (\$ Billion) (1)	NPV ¹⁰ /BOE (\$/Bbl.) (2)	Profitability Index ¹⁰ (3)	IRR (Percent) (4)
<i>EIA AEO 2005 (\$4.90)*</i>	<i>\$15.3</i>	<i>\$2.01</i>	<i>3.21</i>	<i>23.4%</i>
Futures Market Implied (\$5.00)*	16.7	2.18	3.40	25.1%
Low Price Scenario (\$4.00)*	11.0	1.44	2.58	21.1%
High Price Scenario (\$6.00)*	22.4	2.93	4.22	28.5%

* Constant 2004 dollars.