

SCOMM

155:8

Sharon Long

From: Laing, Ian M (DOR) [ian.laing@alaska.gov]
Sent: Tuesday, June 10, 2008 12:16 AM
To: Sharon Long
Subject: Re: Tomorrow's schedule

Sharon,

The senator should be made aware that that will make for a very confusing order for the rest of the members. You'll be bouncing back and forth between pipeline economics and LNG and back to pipelines. We have worked the risk assessment information he requested into the presentations in a way that makes sense, but the order he has requested puts things quite out of context. Is he willing to reconsider? It will be unfortunate not to cover the NPV analysis.

----- Original Message -----

From: Sharon Long <Sharon_Long@legis.state.ak.us>
To: Laing, Ian M (DOR)
Sent: Mon Jun 09 21:12:21 2008
Subject: Re: Tomorrow's schedule

Thanks Ian,

Senator wants to start w/Pat and the admins 1. synopsis of a Risk Analysis Comparisons and 2. explanation of how the Parol Evidence clause applies to elements of the AGIA license. Then, starting where we left off this afternoon (slide 8) wrap up the LNG slides before moving in to TC project financing and NPV. Same stuff; different order.

Sharon

----- Original Message -----

From: Laing, Ian M (DOR) <ian.laing@alaska.gov>
To: Sharon Long
Sent: Mon Jun 09 20:42:35 2008
Subject: Tomorrow's schedule

Sharon,

Here's what it is! Sorry for the late delivery as usual..

Tuesday

June 10

LNG Cost and Schedule – Kieth Dobson (Westney Consulting) / Bill Sparger (Energy Project Consultants)

LNG NPV (Resumed from Monday) – Scott Smith (Black & Veatch) / Deepa Poduval (Black and Veatch)

Lunch Break

Parol Evidence – Commissioner Pat Galvin

Financing TC Alaska Project – Paul Bloom (Goldman Sachs) / Timothy Romer (Goldman Sachs)

NPV/LOS Panel – Scott Smith (Black and Veatch) / Deepa Poduval (Black & Veatch) / Bill Sparger (Energy Project Consultants) / Loyola Keough (Bennett Jones)

LH
Ian Laing

State of Alaska

Department of Revenue

ANC tel 907.375.7747

6/10/2008

Re: Tomorrow's schedule

Page 2 of 2

JNU tel 907.465.3665

cell 907.382.9449

6/10/2008

ALASKA STATE LEGISLATURE

Senator Charlie Huggins, Chair
Senate Special Committee on Energy
State Capitol, Room 119
Juneau, AK 99801
Phone: 465-3878
Fax: 465-3265



Representative John Harris, Chair
House Rules Subcommittee on AGIA
State Capitol, Room 208
Juneau, AK 99801
Phone: 465-4859
Fax: 465-3799

Third Special Session
Twenty-Fifth Legislature

Terry Miller Building, Juneau Alaska
Tuesday June 10, 2008
10:00-5:00 p.m.

Joint Meeting AGENDA

Presentations: Review of AGIA Findings and Determination; Natural Gas Pipeline Project as proposed by TransCanada Alaska Company, LLC and Foothills Pipelines Ltd. (TC Alaska) to the State of Alaska.

Administration and TransCanada

➤ Administration responses:

Risk Assessment Comparison
"Parol Evidence"

(3)

Continued from yesterday (starting on slide # 8)

➤ -LNG: Economics, Likelihood of Success & Path Forward

Robert Fenton, Gas Strategies
Deepa Poduval, Black & Veatch
Scott Smith, Black & Veatch

(2)

➤ -LNG: Cost & Schedule

Keith Dobson, Westney Consulting
Bill Sparger, Energy Project Consultants

(1)

➤ -Financing TC Alaska Project

Paul Bloom, Goldman Sachs
Timothy Romer, Goldman Sachs

(4)

➤ NPV & Likelihood of Success

Scott Smith, Black & Veatch
Deepa Poduval, Black & Veatch
Bill Sparger, Energy Project Consultants
Loyola Keough, Bennett Jones

(5)

Testimony: By Invitation
Teleconference

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Deepa Poduval, Black & Veatch

Scott Smith, Black & Veatch

➤ -LNG: Cost & Schedule

1 Keith Dobson, Westney Consulting

Bill Sparger, Energy Project Consultants

➤ -Financing TC Alaska Project

4 Paul Bloom, Goldman Sachs

Timothy Romer, Goldman Sachs

➤ NPV & Likelihood of Success

5 Scott Smith, Black & Veatch

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Bill Sparger, Energy Project Consultants

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Continued from yesterday (starting on slide # 8)

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Robert Fenton, Gas Strategies
Deepa Poduval, Black & Veatch
Scott Smith, Black & Veatch

1st ➤ -LNG: Cost & Schedule
Keith Dobson, Westney Consulting
Bill Sparger, Energy Project Consultants

4th ➤ -Financing TC Alaska Project
Paul Bloom, Goldman Sachs
Timothy Romer, Goldman Sachs

5th ➤ NPV & Likelihood of Success
Scott Smith, Black & Veatch
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Scott Smith, Black & Veatch
Deepa Poduval, Black & Veatch
Bill Sparger, Energy Project Consultants
Loyola Keough, Bennett Jones
- Testimony: By Invitation
Teleconference

The RFA says (@ pg 40, # 4.3 "license as integrated document")

"The provisions of the license may not be explained, supplemented or qualified through parol evidence"

Can you explain in layperson's terms what this means?

The reason I ask is that the RFA will be part of a license. You are giving us assurances about what some of the terms of the license mean. But if we end in court arguing about just those points, does this provision mean that these assurances won't matter? They would not be something that the court looks at? Under the terms of the license, we are not building a record here as to what these provisions mean or even what the state thought they meant?

4. LICENSE TERMS AND CONDITIONS

Applicant agrees that the terms and commitments in this section are incorporated into the License that is awarded to the Applicant, if any, under this RFA.

4.1. COMMITMENTS AND OBLIGATIONS

All Required Commitments and Additional Commitments specified in the Licensee's Application are part of the License. If a Required Commitment or an Additional Commitment is contingent or conditional, each contingency and condition will be considered to be part of the commitment. Applicant shall file a list of its Required and Additional Commitments with its application as required in Appendix D.

4.2. LICENSE INCORPORATES AGIA

AGIA, AS 43.90.010-AS 43.90.990 [SCS for CSHB 177 (FIN)], as codified on the date that this RFA is issued (attached as Appendix B) is incorporated in its entirety into the License and shall apply, unchanged, to this RFA, Applications accepted under this RFA and an AGIA License awarded pursuant to this RFA.

4.3. LICENSE AS INTEGRATED DOCUMENT

standard practice in a well written contract

The License constitutes the final contractual agreement between the state and the Licensee. All prior draft agreements, notes, understandings and clarifications of the state and the Licensee on the subject matters provided for in this AGIA License are superseded by the License. The provisions of the License may not be explained, supplemented, or qualified through parol evidence.

The License is an integrated document comprised of AGIA, Certificate of License, accepted Application, RFA, and Terms and Conditions constituting one instrument.

4.4. EQUAL EMPLOYMENT OPPORTUNITY

The Licensee may not discriminate against any employee or applicant for employment because of race, religion, color, national origin, age, physical handicap, sex, marital status, changes in marital status, pregnancy, or parenthood. The Licensee shall post in a conspicuous place, available to employees and applicants for employment, a notice setting out the provisions of this paragraph.

The Licensee shall state, in all solicitations or advertisements for employees to work that will be reimbursed by the state, that it is an equal opportunity employer (EEO) and that all qualified Applications will receive consideration for employment without regard to race, religion, color, national origin, age, physical handicap, sex, marital status, changes in marital status, pregnancy or parenthood.

*Don't bury the license
outside the license*

June 10, 2008

10 AM

3rd Special Session

AGIA License

LNG Project Costs/Schedule

AGIA Analysis Technical Team

June 9, 2008

Bill Sparger
Energy Project Consultants, LLC

Keith Dodson
Westney Consulting Group, Inc

LNG Cases

- **Case 1** – 2.7 or 4.5 bcf/d to Valdez - 48"/42" pipeline - 19.0mmtpa LNG
- **Case 2** – **TransCanada's Y line** - 6.5 bcf/d to Delta Junction, 4.5 bcf/d to Alberta and 2.0 bcf/d to Valdez - 48" pipeline to Alberta and 30" pipeline to Valdez – 13.9mmtpa LNG
- **Case 3** – 4.5 bcf/d to Valdez - 48" pipeline – 31.5mmtpa LNG

Analysis Results

- Higher capital cost
- Similar schedule duration
- Later project start
- Higher cost/schedule risk
- LNG plant costs developed
- comparable worldwide
- GTP and pipeline schedule and cost factored
- from TransCanada's proposed project
- Miscellaneous and development phase costs factored from TransCanada application
- analysis
- Start of LNG project one year later than TransCanada project

LNG Analysis

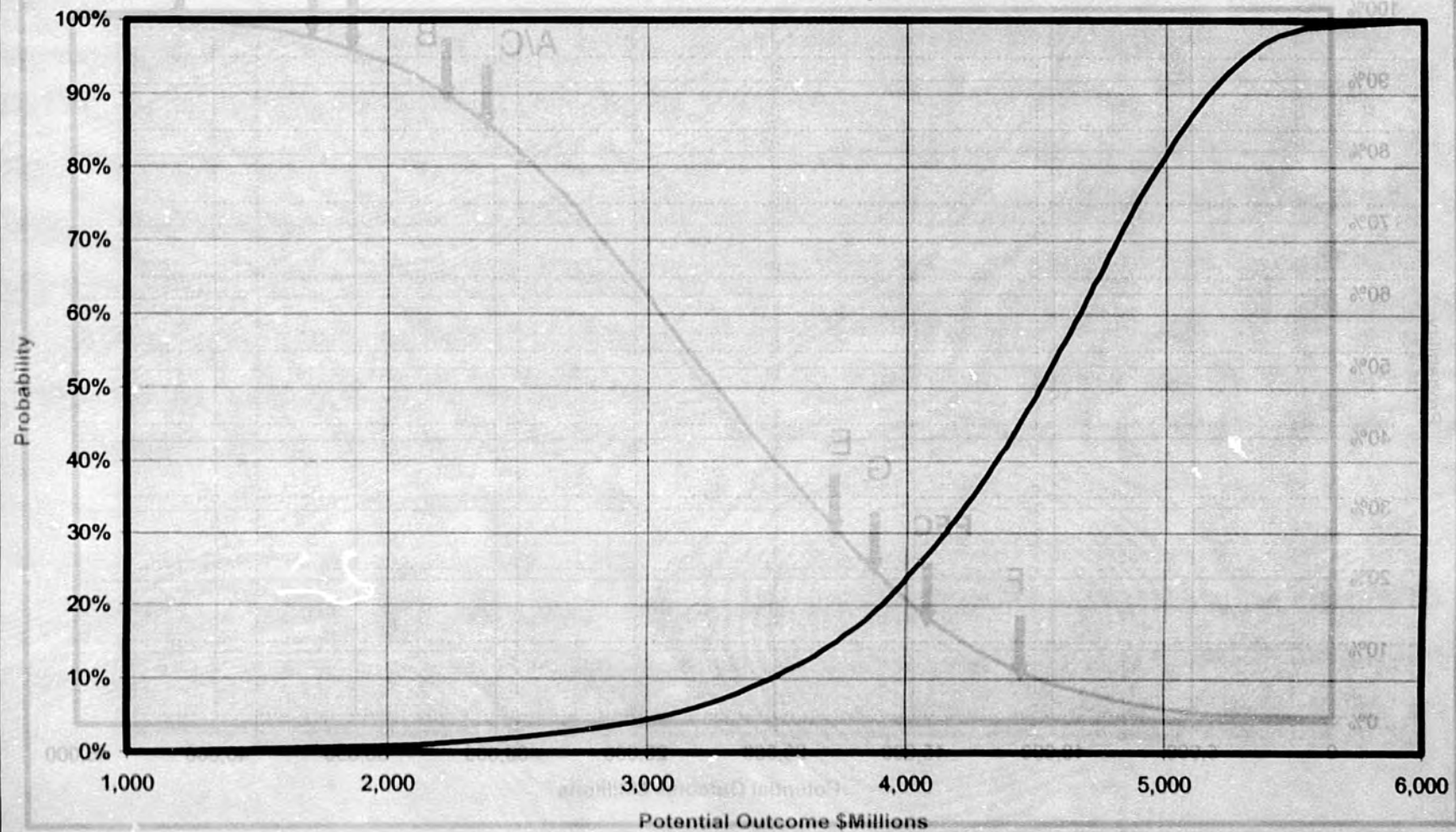
Assumptions/Methodology

- LNG plant costs developed from recent comparable worldwide projects
- GTP and pipeline schedule and cost factored from TransCanada's proposed project
- Miscellaneous and development phase costs factored from TransCanada application analysis
- Start of LNG project one year later than TransCanada project

AGIA LNG Options

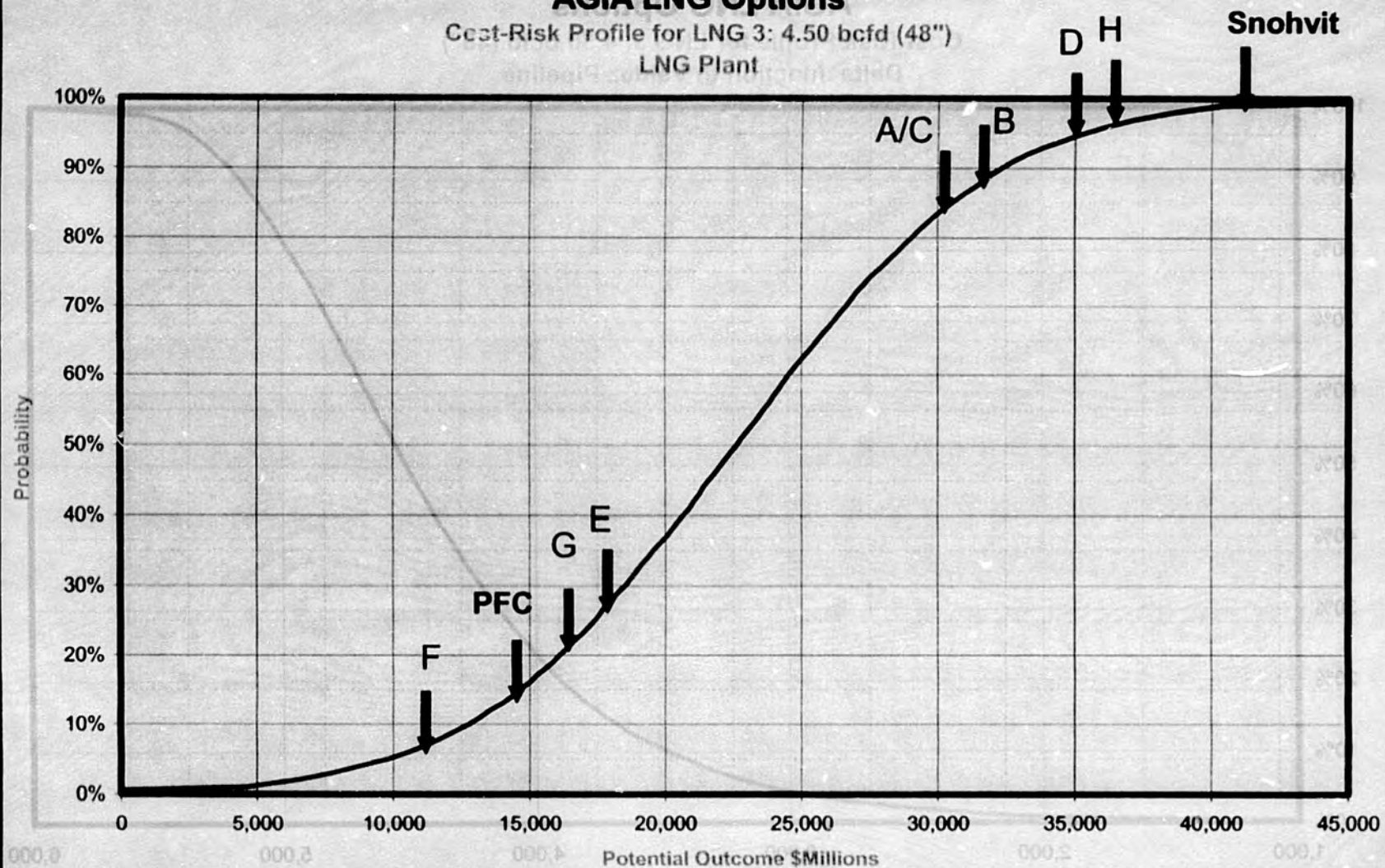
Cost-Risk Profile for LNG 3: 4.50 bcfd (48")

Delta Junction to Valdez Pipeline



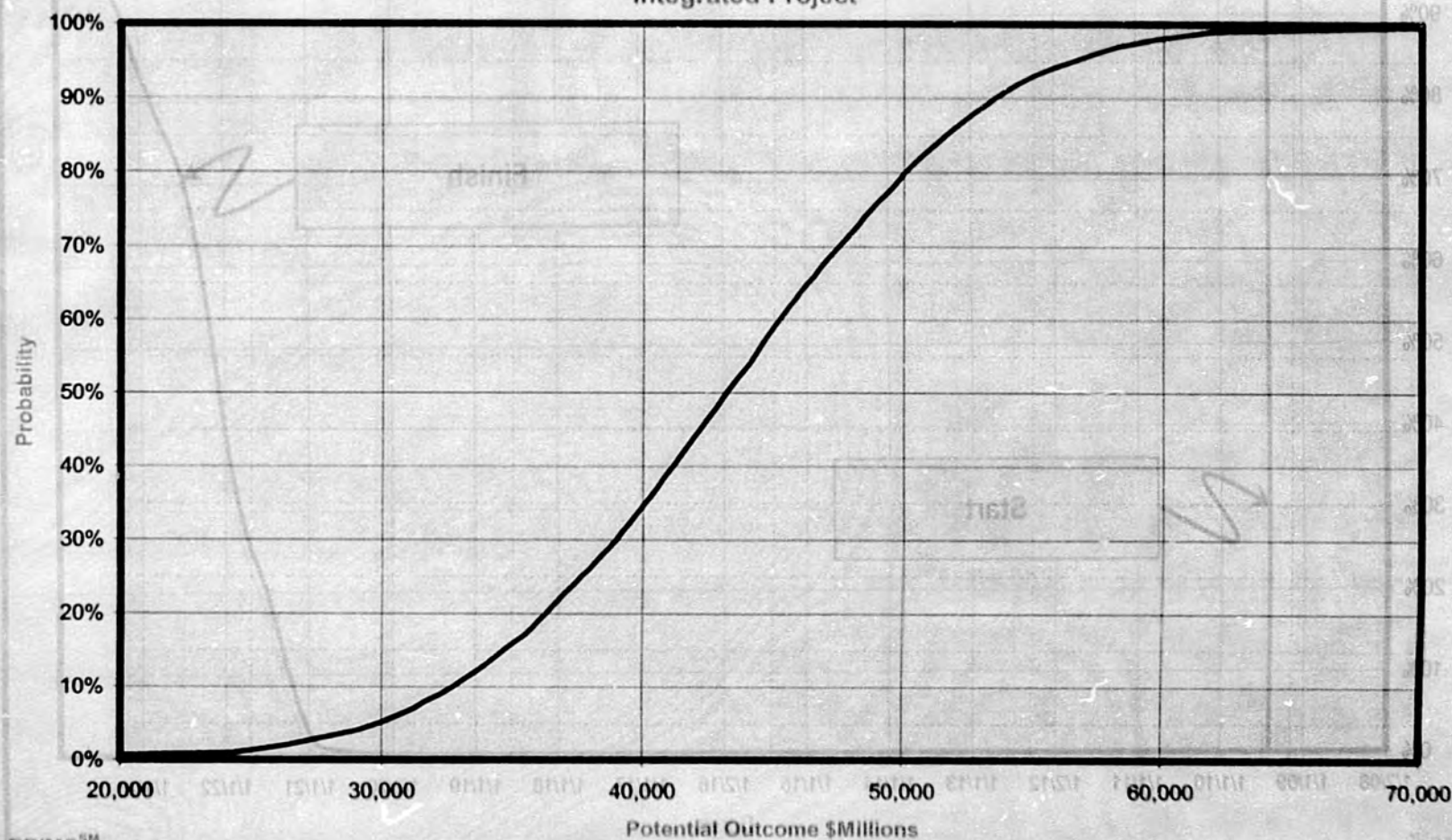
AGIA LNG Options

Cost-Risk Profile for LNG 3: 4.50 bcf/d (48")
LNG Plant



AGIA LNG Options

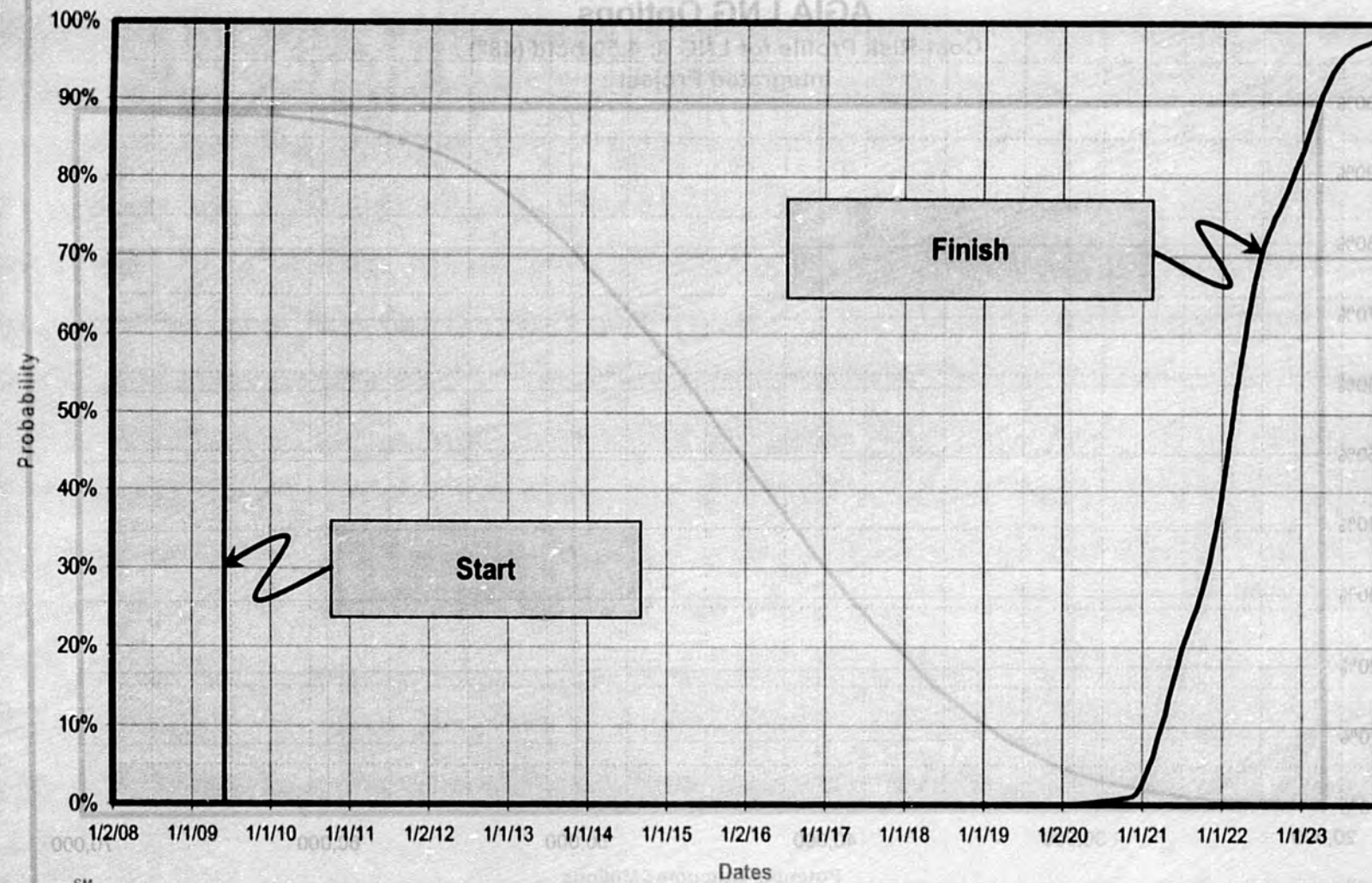
Cost-Risk Profile for LNG 3: 4.50 bcfd (48")
Integrated Project



AIGA LNG Options

Time-Risk Model Profile for LNG 3: 4.50 bcf/d (48")

Project

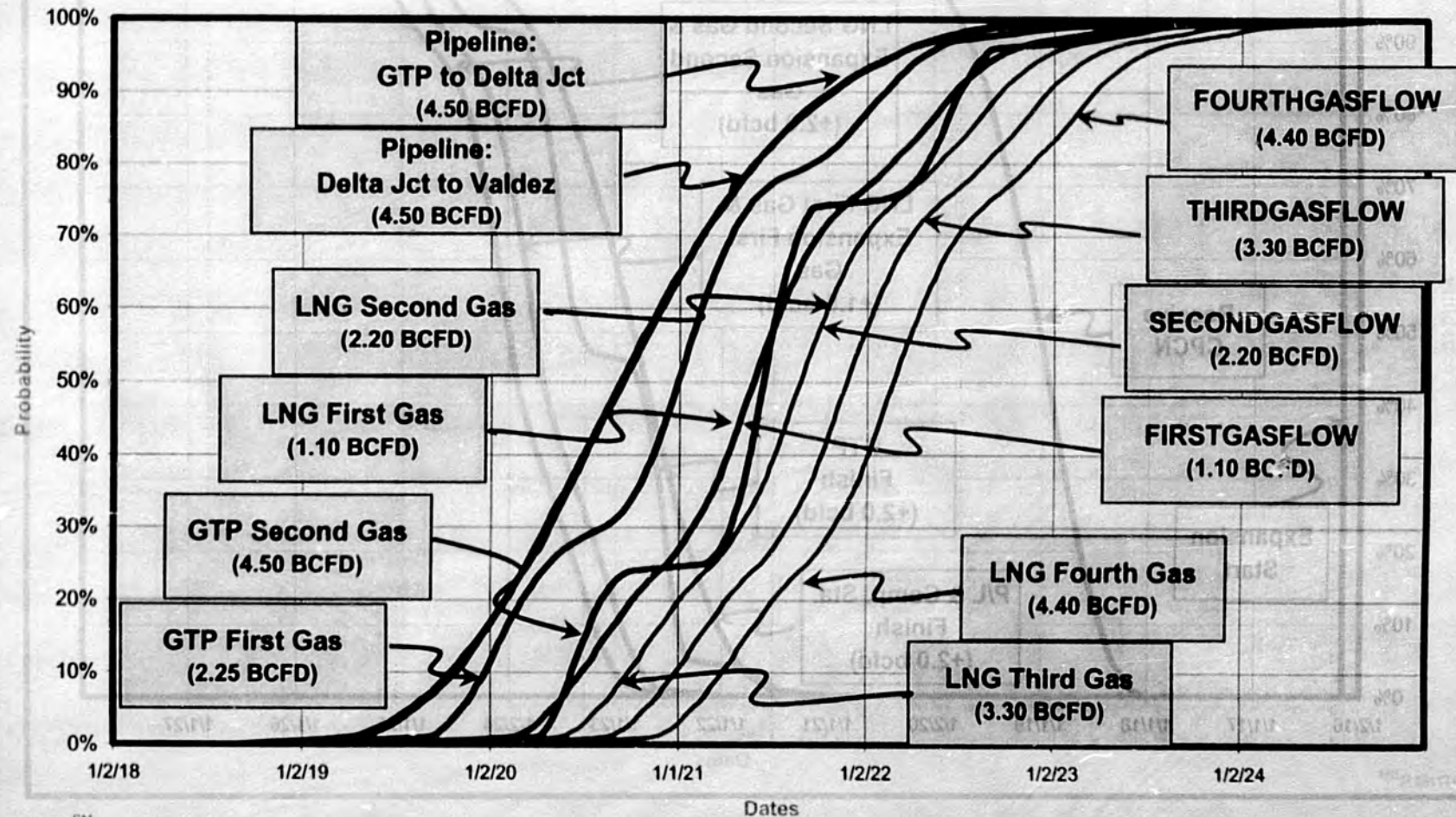


PRIMSSM

AIGA LNG Options

Time-Risk Model Profile for LNG 3: 4.50 BCFD (48")

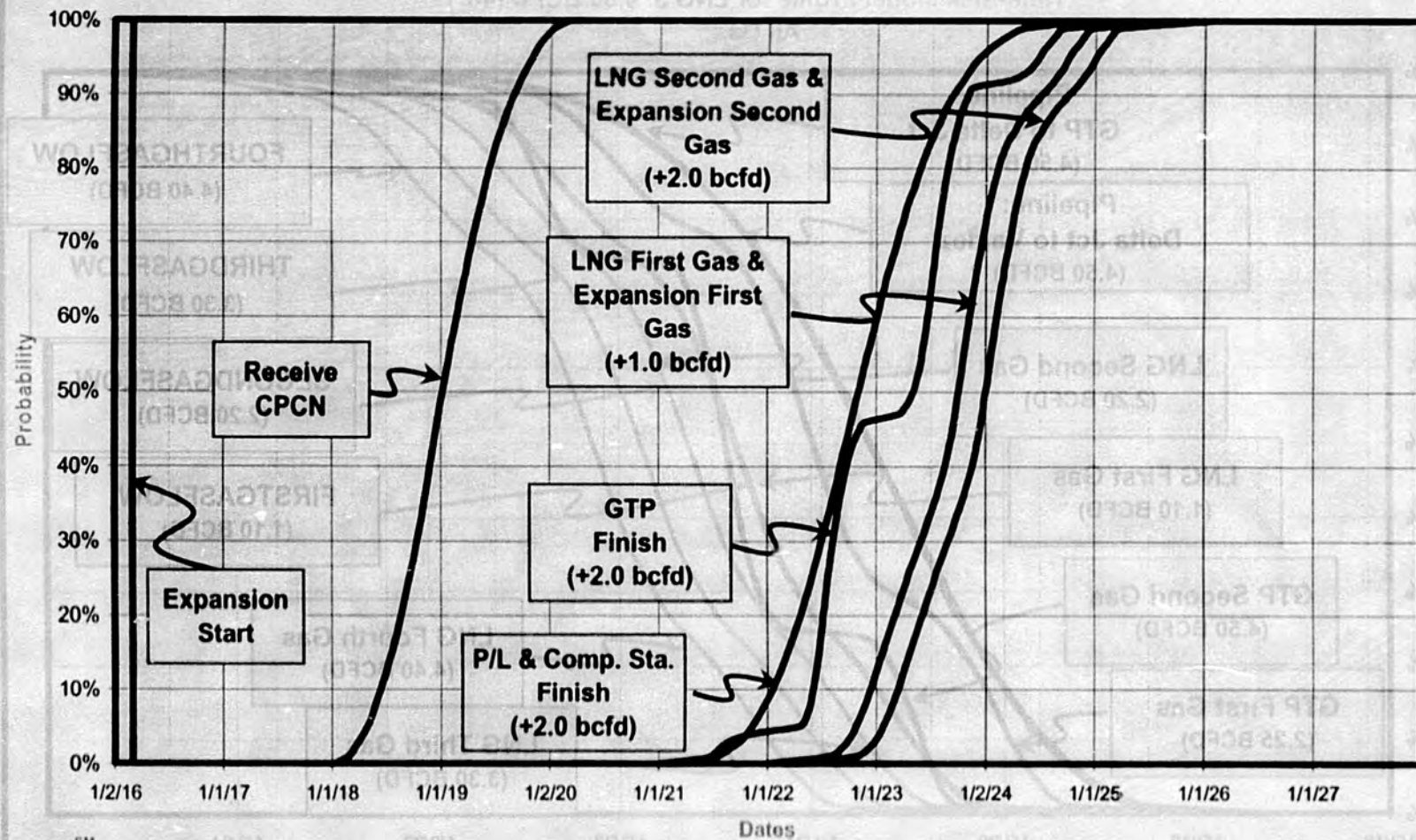
All Gas



PRIMSSM

AGIA Additional Expansion Cases

Time-Risk Model Profile for LNG 2a: Expansion of 4.50 bcfd (Base Case) to 6.50 incl 2.00 LNG
All Gas





10:00 AM -
placed in the
record on



All of FERC

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Press Room

Press Release: May
25, 2005

[View Printable
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Docket Number: RM05-1-001

Contact
Information:

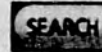
Tamara Young-
Allen
Telephone:
202-502-8680

Commission reaffirms and clarifies open-season rules for Alaska natural gas transportation proposals

The Federal Energy Regulatory Commission today reaffirmed and clarified its rules establishing requirements governing the conduct of open seasons for capacity for future Alaska natural gas pipeline projects.

The Order No. 2005 rules, designed to promote competition, exploration, development and production of Alaska natural gas, establish standards for creating open seasons for potential shippers to compete for and acquire initial capacity and future expansion capacity on any potential Alaska pipeline. The rules also provide standards for allocating the capacity to ensure nondiscriminatory access to any Alaska transportation projects.

The State of Alaska, Enbridge Inc., Chevron/Texaco Natural Gas, a division of Chevron U.S.A. Inc., and a joint filing by North Slope Producers – ExxonMobil Corporation, BP Exploration (Alaska)



All of FERC



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Press Room

Press Release: May
25, 2005

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The State of Alaska, Enbridge Inc., Chevron/Texaco Natural Gas, a division of Chevron U.S.A. Inc., and a joint filing by North Slope Producers – ExxonMobil Corporation, BP Exploration (Alaska)

Contact Information:

Tamara Young-
Allen
Telephone:
202-502-8680

Inc. and ConocoPhillips – requested either clarification or repeal of certain aspects of the open season rules, issued February 9, 2005.

The Commission clarified that the Commission may require design changes necessary to ensure that some portion of a proposed voluntary expansion will be allocated to new shippers, or shippers seeking to transport gas from areas other than the Prudhoe Bay or Point Thomson areas, provided they agree to sign qualifying, long-term transportation contracts.

Parties had maintained the rules erred by allowing Commission-mandated design changes at the conclusion of the open season process and that design changes would be an illegal extension of FERC authority. But the Commission rejected those arguments, citing legal precedent that any design change would not constitute a mandatory expansion of any project and that the Natural Gas Act provides FERC authority to attach to any certificate of public convenience and necessity any conditions it deems necessary to meet the public interest.

Among other things, the Commission:

- o expanded criteria for evaluating late bids for capacity and the requirement that any late bid contain a good-faith showing. Parties had asserted the rule needed additional standards to encourage participation in the initial open season and to

address late bidding for capacity;

- clarified that the open-season plan must contain the actual open-season notice and eliminates the 30-day advance notice requirement that applicants must file open-season procedures to FERC. Parties had contended the original 90-day advance filing time frame could potentially result in unnecessary delays in FERC's processing of their request;
- clarified that applicants must establish a separate entity to conduct the open season; and
- clarified that open season notices need not include a cap on contract terms.

Revisions to Order No. 2005 will become effective on the date the order is published in the Federal Register.

R-05-29

-30-

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Updated: May 25, 2005

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R-05-29

-30-

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Updated: May 25, 2005

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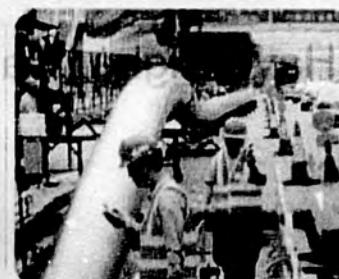
3rd Sp. Session: AG/IA License
June 9, 2008
Juneau

Monday
4:30 PM



BUILDING A WORLD OF DIFFERENCE®

BLACK & VEATCH



Presentation to the State of Alaska Legislature

Liquid Natural Gas (LNG) NPV Analysis and Results

June 9, 2008

made it to slide #8 on 6/9/08
continued on 6/10/08

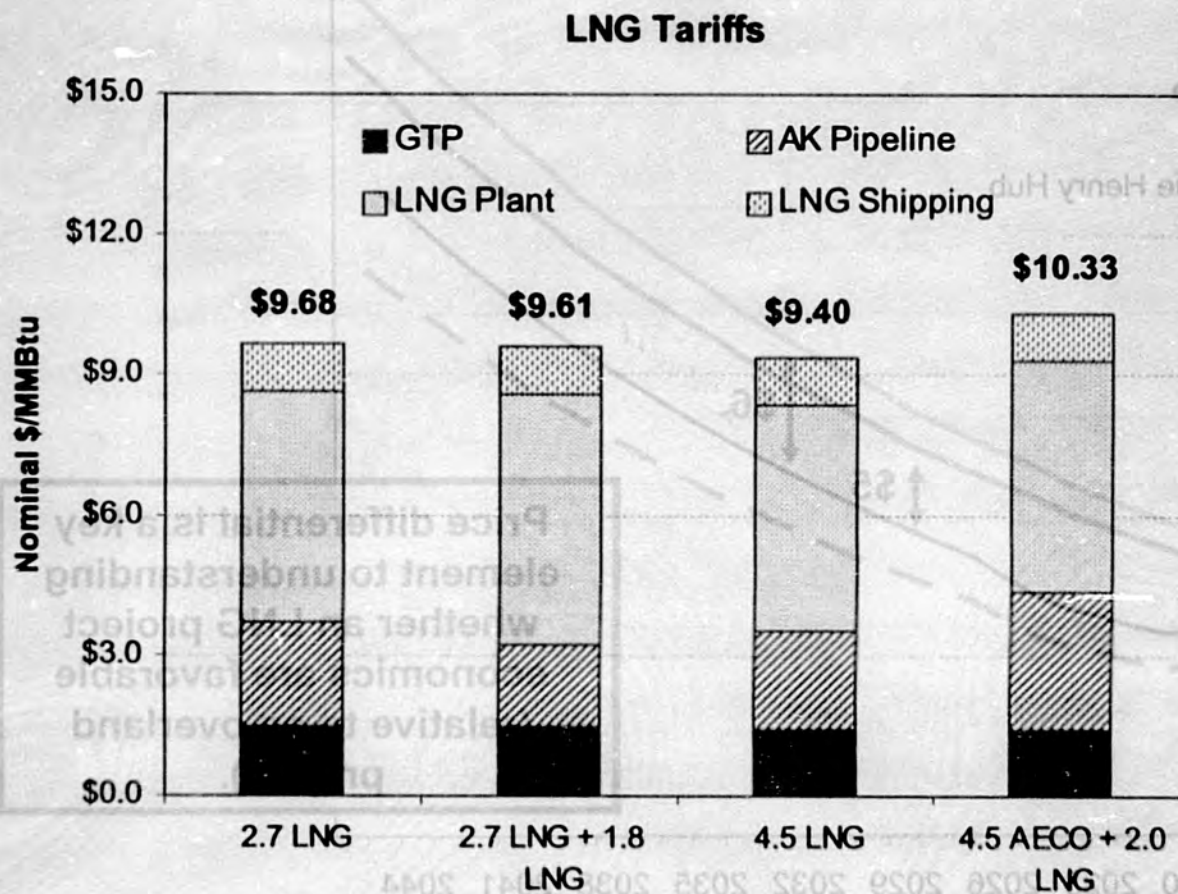


Key Conclusions

- LNG Projects Have Higher Capital Costs and Therefore Greater Risk than a Pipeline Project
- Similar to an Overland Project, Price Remains the Primary Risk to a LNG Project
- LNG Projects Have Positive NPVs with Base and High LNG Price Assumptions
- The 4.5 Bcf/d Proposal Base Case Project Produces a Higher NPV than a 4.5 Bcf/d LNG Project
- A Sustained High Oil to Gas Price Relationship is Required for an LNG Project to be Favorable when Compared to an Overland Route



Expected LNG Tariffs for the LNG Project Configurations Considered



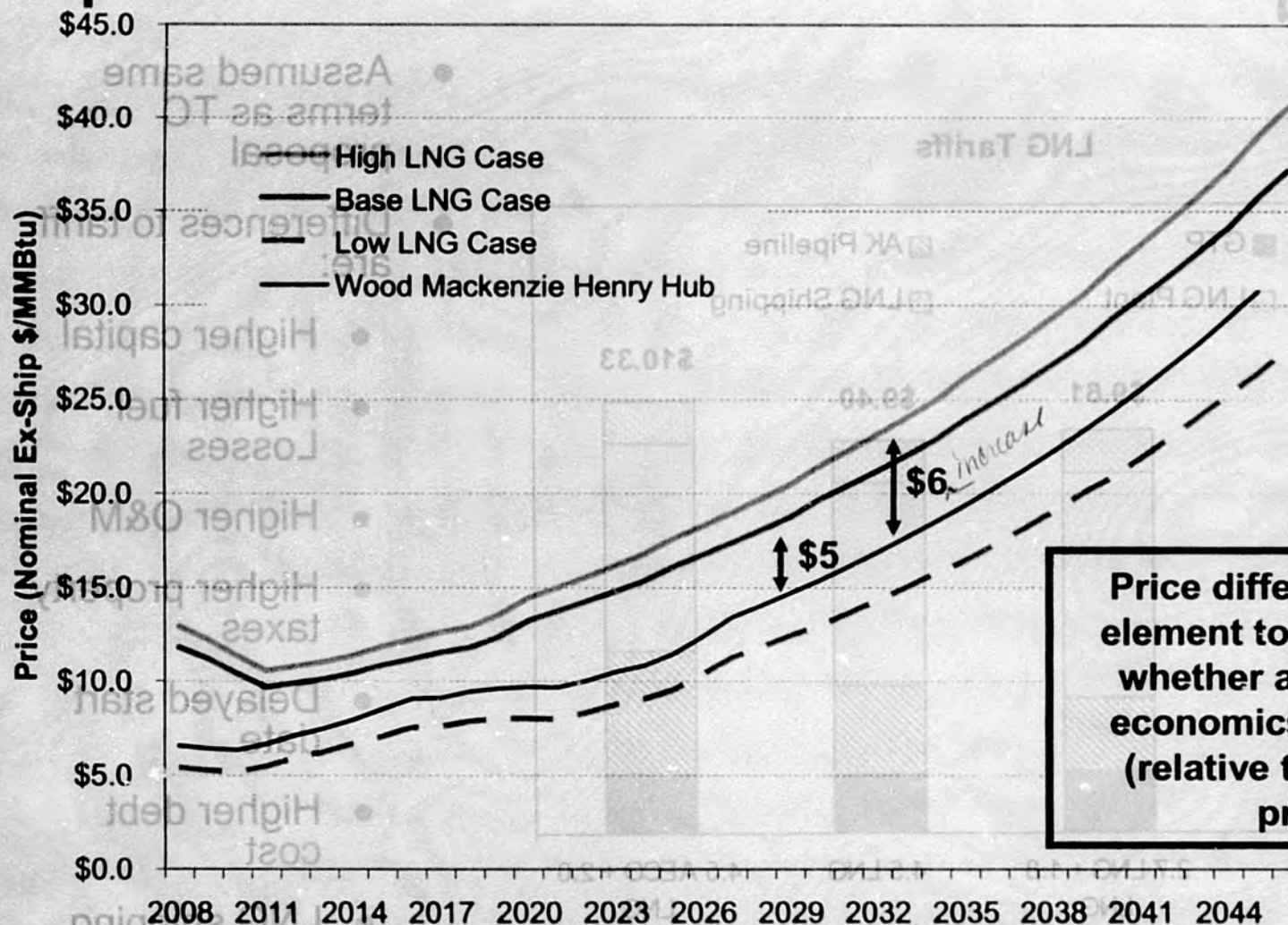
- Assumed same terms as TC proposal

- Differences to tariff are:

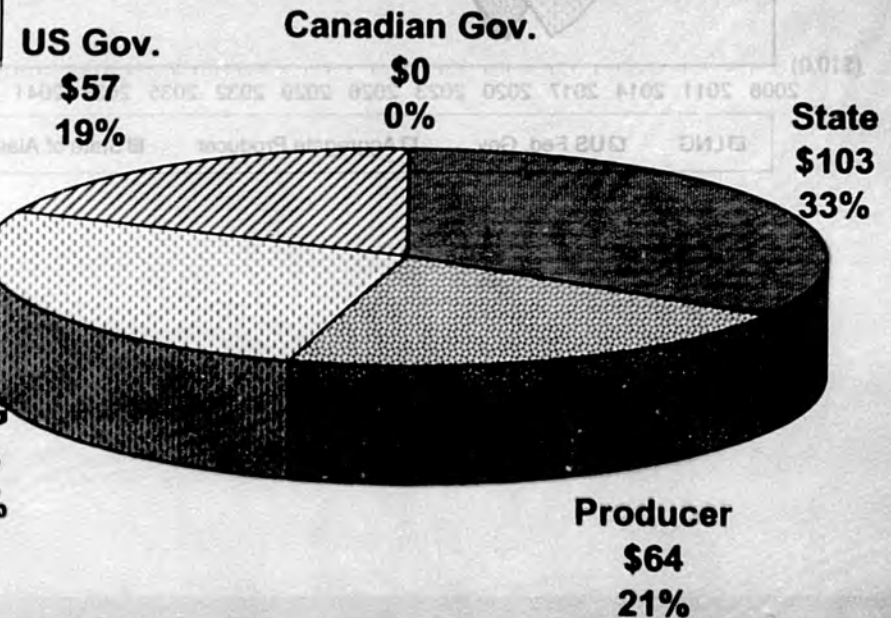
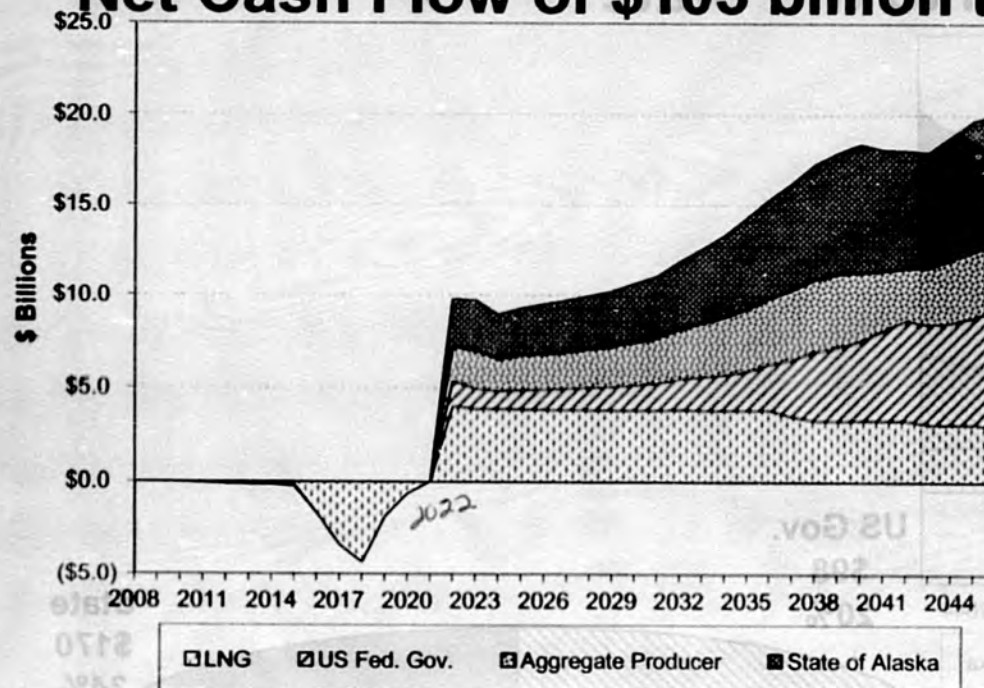
- Higher capital
- Higher fuel Losses
- Higher O&M
- Higher property taxes
- Delayed start date
- Higher debt cost
- LNG shipping



Applying the Gas Strategies Asian Price Formula Expectations



Estimated Cash Flow for the 2.7 Bcf/d LNG Case: Positive Net Cash Flow of \$103 billion to the State



%s not returns - but just percent of total cash (net)

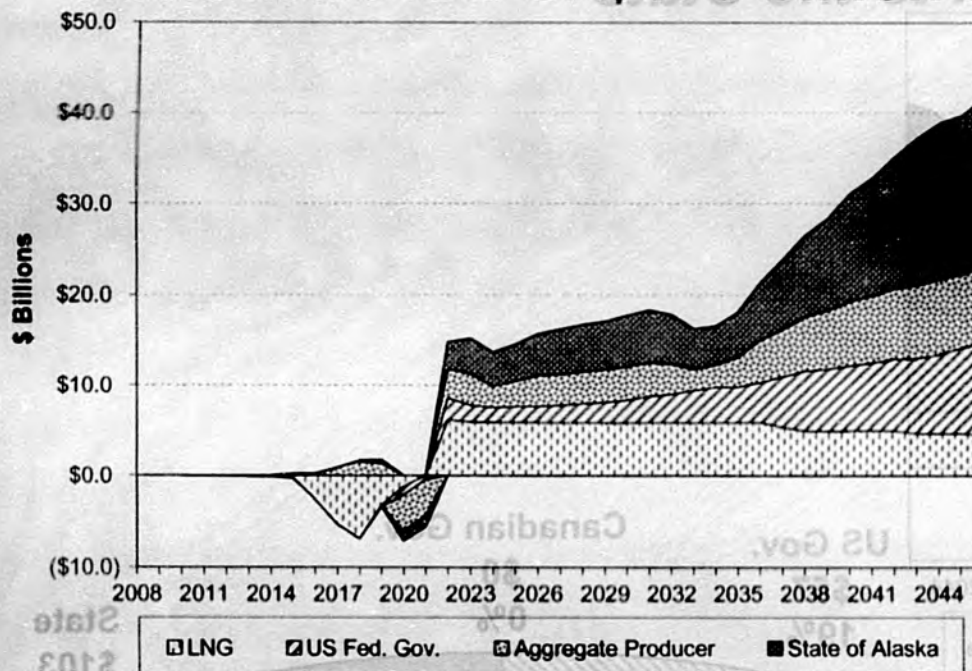
nominal \$ cash flow (not NPV - see pg 8)

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Estimated Cash Flow for the 4.5 Bcf/d LNG Case: Positive Net Cash Flow of \$170 billion to the State



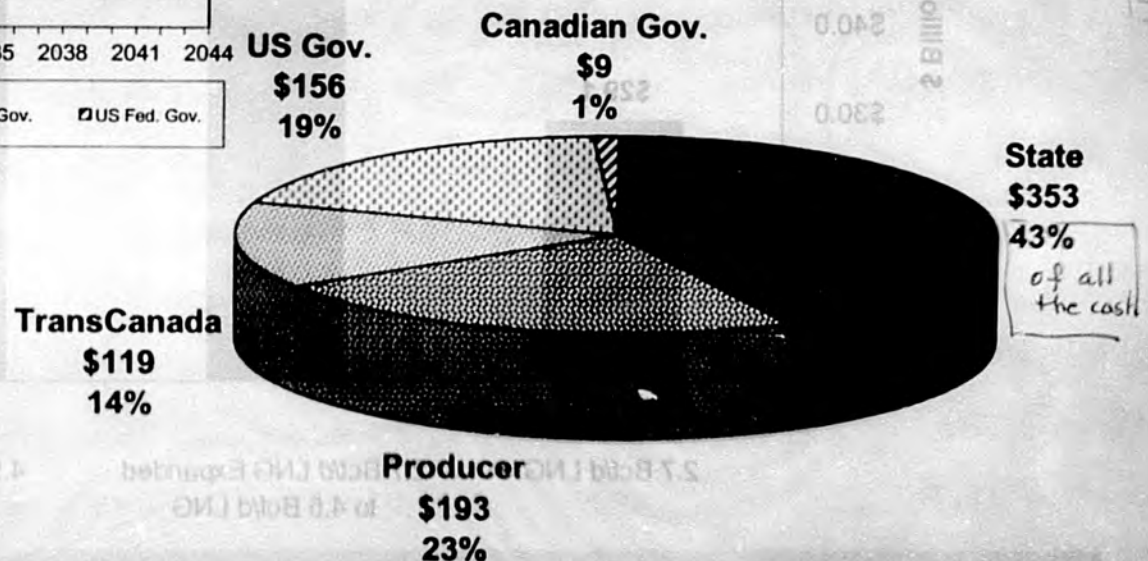
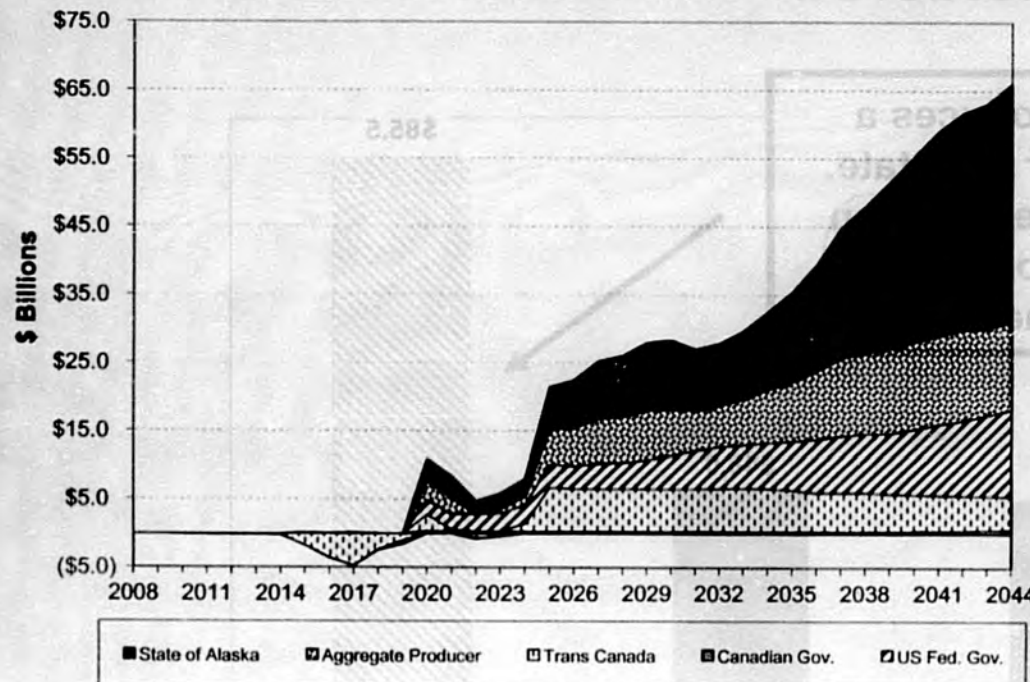
US Gov.
\$98
20%

State
\$170
34%

LNG
\$126
26%

Producer
\$99
20%

Y-Line – Aggregate Project Cash Flow: Positive Net Cash Flow of \$353 billion to the State



nominal cash flow - (not NPV - see next chart) per NPV

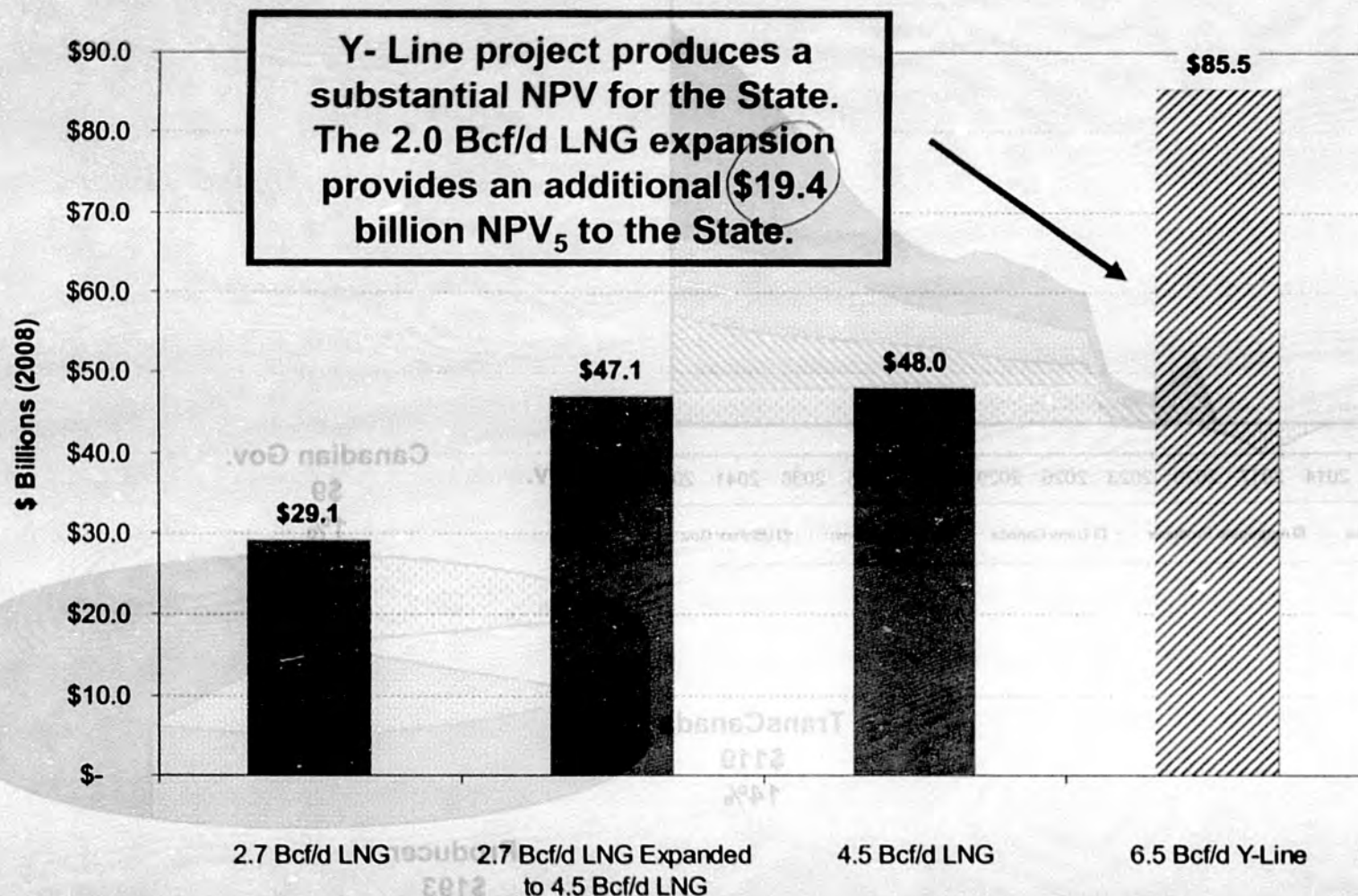
a dollar in the future is not worth as much as it is today -
NPV calculates the worth of those \$ we're waiting for. (subtracts the cost of waiting)

BUILDING A WORLD OF DIFFERENCE



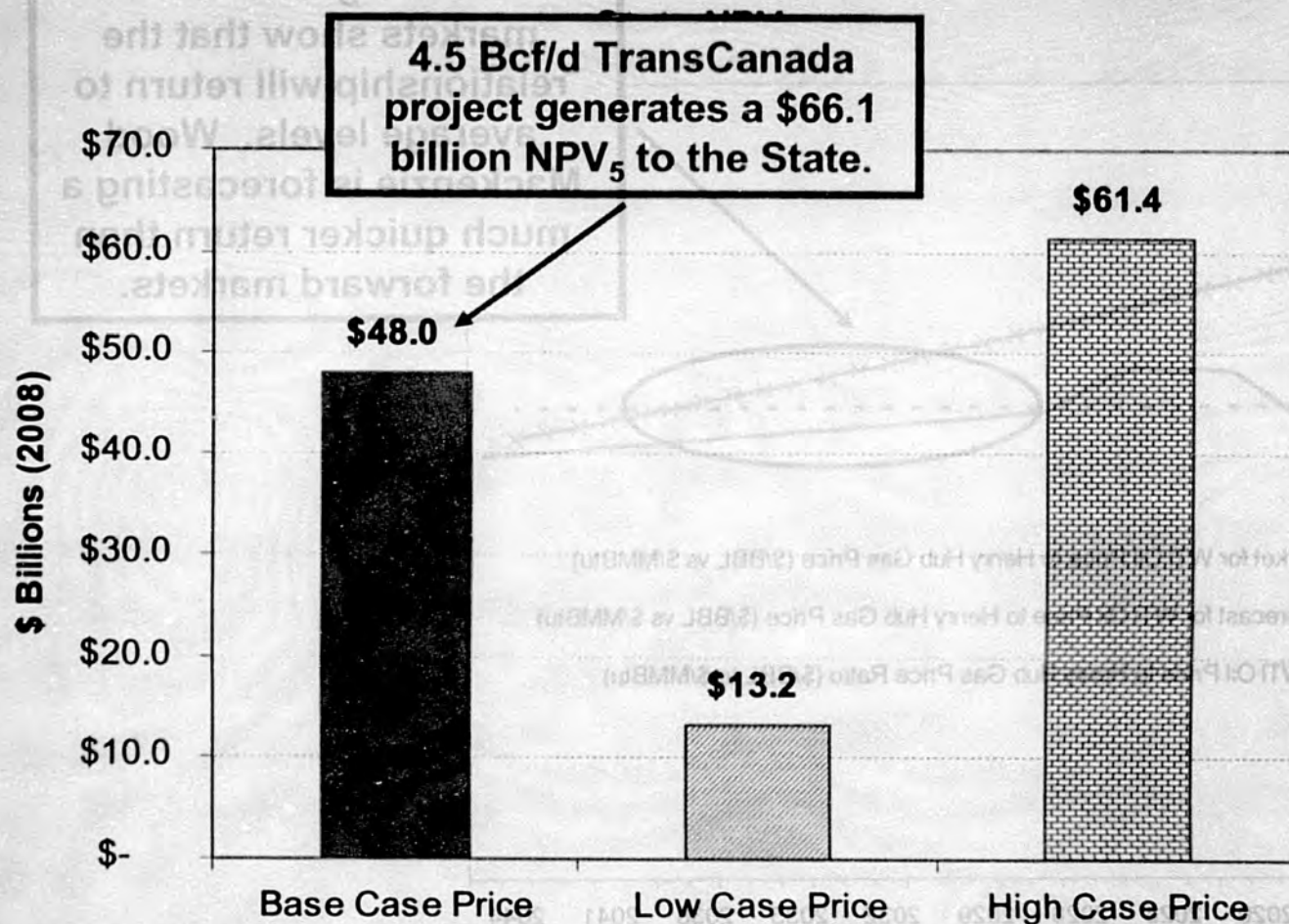
BLACK & VEATCH

Estimated State NPV₅ is Substantially Positive for all LNG Project Configurations Considered





LNG Price Scenario Impacts on the State NPV₅ for the 4.5 Bcf/d LNG Project

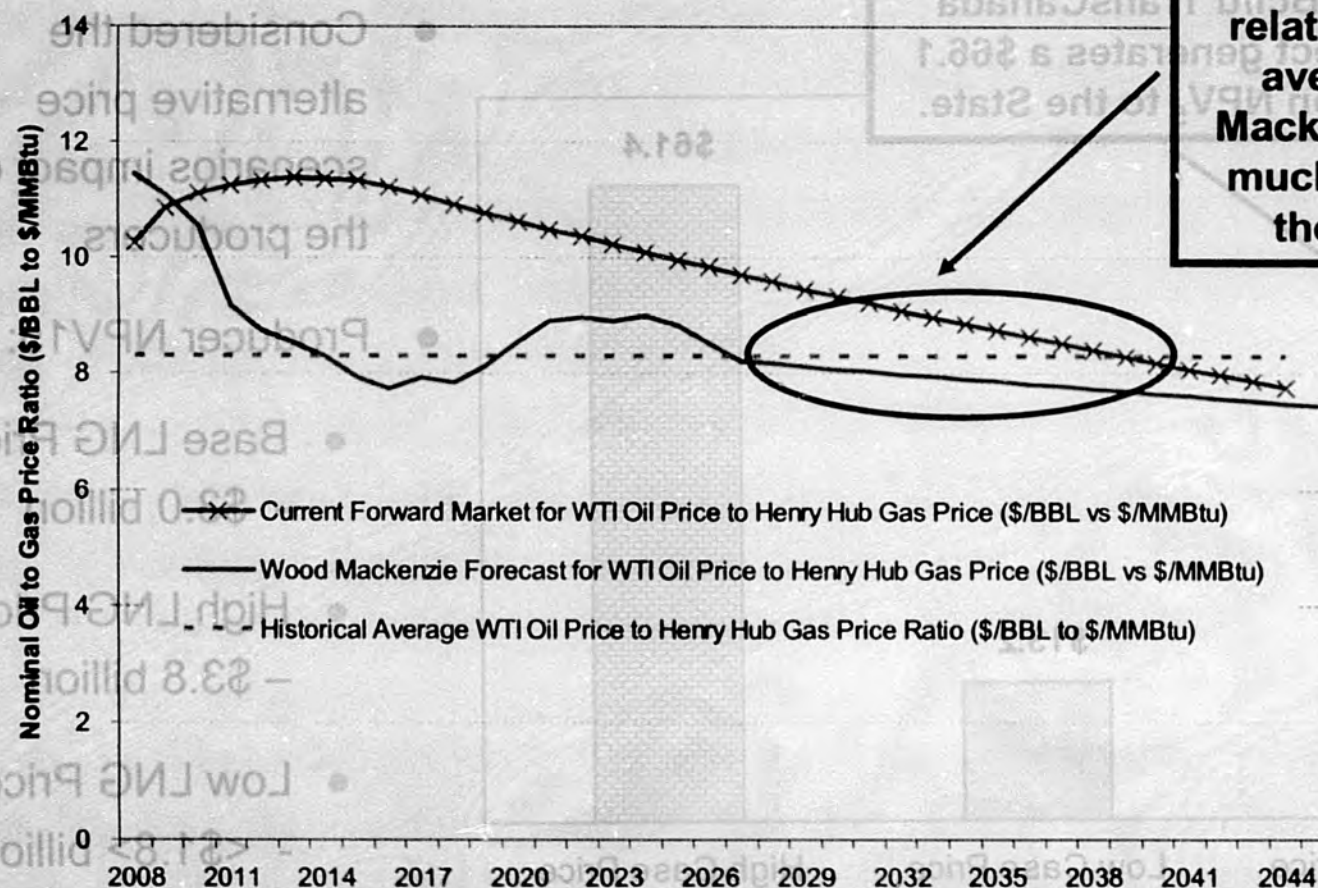


- Considered the alternative price scenarios impact on the producers
- Producer NPV₁₅:
 - Base LNG Price - \$3.0 billion
 - High LNG Price - \$3.8 billion
 - Low LNG Price - <\$1.8> billion

June 10th 2011



Current Market Relationship between Oil and Gas Prices is Substantially Higher than Historical Average



June 10th



Implications to LNG Project NPV from High Oil Prices

Analysis Assumptions:

- Considered oil to gas price ratio assumptions of 8, 9, 10 and 11 to 1

Analysis Results:

- High oil prices, relative to gas prices, must be maintained in order for LNG project NPV to be greater than an overland route
- Assumes that the Gas Strategy generated relationships do not change

Base Case LNG Price

- State: 10 to 1 or greater
- Producer: 11 (12) to 1 or greater

High Case LNG Price

- State: 9 to 1 or greater
- Producer: 10 or 11 to 1 or greater

Sharon

Tuneau

June 10, 2008
2:45 PM

3rd Sp. Session: AGIA License

Goldman
Sachs

Discussion Topics

Goldman
Sachs

Key Findings

Financial Review of TransCanada and Proposal

Financing Review of Proposal

June 10, 2008

Paul Bloom, Goldman Sachs
Timothy Romer Goldman Sachs
went through slide #5

Conclusion: the project is financeable



Discussion Topics



- Key Findings
- Financial Strength of TransCanada
- Financing Review of Proposal

Summary of Findings

Is the Proposal Base Case Viable from a financing standpoint?

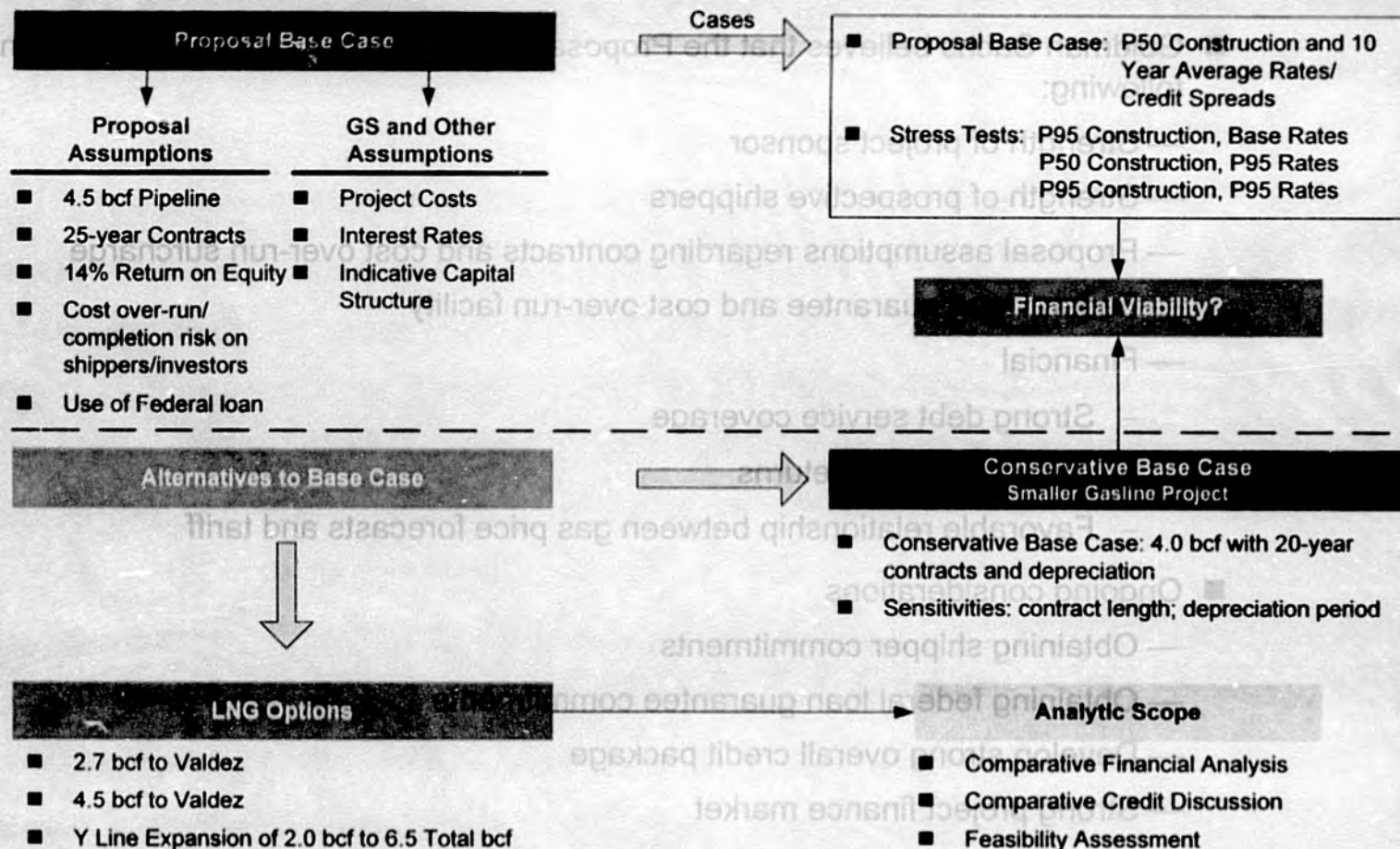
■ Goldman Sachs believes that the Proposal Base Case is financeable based on the following:

- Strength of project sponsor
- Strength of prospective shippers
- Proposal assumptions regarding contracts and cost over-run surcharge
- Federal loan guarantee and cost over-run facility
- Financial
 - Strong debt service coverage
 - Attractive equity returns
 - Favorable relationship between gas price forecasts and tariff

■ Ongoing considerations

- Obtaining shipper commitments
- Obtaining federal loan guarantee commitments
- Develop strong overall credit package
- Strong project finance market

Cases Analyzed



Summary of Findings

Does TransCanada Have the Financial Strength to Meet its AGIA Obligations?

- Goldman Sachs believes the TransCanada has the financial strength to meet its AGIA obligations
 - TransCanada has very stable, durable, and free cash flow generative businesses;
 - TransCanada generates substantial free cash flow at the corporate level that should enable the Company to debt-finance the majority of its equity contribution;
 - TransCanada's business and financial risk profiles substantially improve if the Project is completed;
 - Rating agency concerns about additional capital calls on TransCanada during construction likely would be alleviated by the cost overrun facility;
 - If capital calls are required because costs escalate, TransCanada should have the ability to contribute additional capital (if needed);
 - If TransCanada finances its capital contribution to the pipeline entirely with debt, ratings downgrades are possible (all else being equal) but maintenance of investment-grade ratings is expected; and
 - Maintenance of current ratings is possible if TransCanada takes [actions to fortify] its financial strength in anticipation of the project and ensures the agencies view the pipeline as having a high probability of success.

Call Q what can
they do to "fortify"
Answer (Romer) 5
start now
to raise
capital

■ Goldman Sachs believes the TransCanada has the financial strength to meet its AGIA obligations

- TransCanada has a strong track record of generating substantial free cash flow at the corporate level that should enable the Company to debt-finance the majority of its equity contribution;
- TransCanada's business and financial risk profiles substantially improve if the Project is completed;
- Rating agency concerns about additional capital calls on TransCanada during construction likely would be alleviated by the cost overrun facility;
- If capital calls are required because costs escalate, TransCanada should have the ability to contribute additional capital (if needed);
- If TransCanada finances its capital contribution to the pipeline entirely with debt, ratings downgrades are possible (all else being equal) but maintenance of investment-grade ratings is expected; and
- Maintenance of current ratings is possible if TransCanada takes actions to fortify its financial strength in anticipation of the project and ensures the agencies view the pipeline as having a high probability of success.

What can we do to "fortify" the project? (Answer) (Homer's) have to have capital

How Will the Markets Assess TransCanada's Financial Strength?

■ **Lenders, ratings analysts, and investors will review:**

- TransCanada's existing financial and business profile
- What can go wrong with the Project and within TransCanada's core businesses?
- How will TransCanada finance their equity contribution?
- Will TransCanada be required to make additional capital contributions if the pipeline project experiences delays or cost overruns?
- Should analysis consolidate or not consolidate the project debt onto TransCanada's books?
- Would TransCanada ever really "walk away" either during construction or after operations commence?
- Overall Credit Assessment: Rate to the trough (i.e., the point in time during construction when financial pressure is highest), likely post-construction profile, or somewhere in between?

Key Rating Agency Commentary Regarding TransCanada

Moody's

Senior Unsecured Rating Outlook **A2¹**
Review (Downgrade)

Key Strengths

- Predominately low risk, regulated gas pipeline operations with clear focus on gas transmission and power businesses
- Strong competitive position driven by importance of TransCanada's Canadian pipelines in transporting gas out of the WCSB
- TCPL's electricity generation assets tend to be characterized by either low marginal cost of production or long-term power purchase agreements with highly rated counterparties
- Stable and predictable free cash flow generation

Key Weaknesses

- Weak financial profile for the rating category – high leverage driven by deemed capital structure allowed on Canadian regulated pipelines and mitigated by generally more supportive regulatory and business environments in Canada
- Long-term declining WCSB production leads to increasing supply risk (may be offset by non-conventional production)
- Increasing exposure to power and unregulated businesses that may necessitate lower corporate leverage to offset a rise in business risk
- Growing portfolio of projects exposes the company to increasing levels of execution risk including allocation of management resources, management of construction cost and schedule risks and financing risk

Standard & Poor's

Senior Unsecured Rating Outlook **A-
Stable**

Key Strengths

- Business profile is "excellent" driven by predictable earnings from TCPL's mature, wholly-owned Canadian and US natural gas transmission systems which are supported by transparent regulation
- Strong competitive position driven by importance of Canadian pipelines in transporting gas out of the WCSB
- Investments in other pipeline operations provide a stabilizing offset to gradually declining earnings from traditional pipelines
- Consistent free cash flow generation remains a fundamental Company strength and provides a buffer against cost overruns and other project setbacks

Key Weaknesses

- Somewhat high leverage levels although credit ratios remain acceptable for its ratings
- Increasing earnings volatility as TCPL purchases power for resale into primarily unregulated markets (somewhat mitigated by forward sales contracts)
- Declining rate base (related to maturity of gas production in western Canada) and ROE (due to linkage to interest rates) has reduced earnings in recent years
- Near-term cost and operating uncertainty related to Bruce A Restart

¹ Moody's has assigned an A2 corporate rating to TransCanada PipeLines Ltd., which is an operating company and intermediate holding company of TransCanada Corp. The A3 rating on TransCanada Corp. reflects the effect of structural subordination of TransCanada Corp. to debt at TransCanada PipeLines.

Current Moody's and S&P Ratings for TransCanada Comparables¹

	TransCanada	Enbridge	MidAmerican Energy Holdings	Spectra Energy	Kinder Morgan Energy Partners
Corporate Ratings	A3/A-	Baa1/A-	Baa1/A-	Baa1/BBB+	Baa2/BBB
Outlook	Negative/Stable	Stable/Stable	Stable/Stable	Stable/Stable	Stable/Stable
Assets (\$ millions)	\$30,717	\$20,161	\$39,216	\$22,970	\$15,178
Revenues	8,941	12,072	12,376	4,742	9,218
EBITDA	3,888	1,768	3,838	1,965	1,732
Net Income	1,239	716	1,189	957	590
Debt/EBITDA ²	4.0x	6.0x	5.2x	4.8x	4.1x
Debt/Cap ²	59%	64%	67%	55%	61%
EBIT/Interest ³	2.7x	2.1x	2.1x	2.3x	3.0x
RCF/Debt	14%	9%	12%	12%	4%

¹ Credit statistics as of 12/31/07 from Capital IQ.

² Lower is better

³ Higher is better

TransCanada and its Comparables Have Accessed the Financial Markets in Good and Troubled Times

TransCanada's Recent Issues

- **2008** - \$1.1 billion in common shares
- **2007** - \$1.725 billion in common shares and \$600 million in common units; \$2.6 billion of long term debt and \$1 billion of junior subordinated notes
- **2006** - \$700 million of medium-term notes and \$500 million of senior unsecured notes
- **2005** - \$400 million of senior debt and \$300 million of medium-term notes

MidAmerican

- **2008** - \$650 million of senior unsecured notes
- **2007** - \$600 million of long-term debt
- **2006** - \$1.7 billion of senior unsecured notes and \$350 million of long-term debt
- **2002** - \$700 million of senior notes

Spectra

- **2007** - \$450 million of senior unsecured notes

Kinder Morgan

- **2008** - \$290 million of ordinary shares
- **2007** - \$300 million of LP common units and \$300 million of common shares
- **2006** - \$250 million of LP common units
- **2005** - \$75 million in common shares and \$380 million of LP common units

Enbridge

- **2007** - \$800 million of notes and \$450 million of common shares
- **2002** - \$150 million of common shares
- **2000** - \$100 million of common shares



TransCanada Could Employ a Range of Alternatives to Fund its AGIA Obligations

■ Goldman Sachs Analyzed Four Alternative Approaches for TransCanada to Absorb Project Costs

- **Case 1 – “Base Case”**: Assumes that the costs related to TransCanada are equal to its equity investment only and are being financed 100% with debt. The equity method of consolidation accounting is used (i.e., revenues, costs, assets, debt, and cash flows at the Alaska pipeline level are not consolidated; only net income available to TransCanada is consolidated) and cash payments to TransCanada are equal to the amount distributed to equity holders and is recorded as other income.
- **Case 2 – “Fully Loaded”**: Assumes that TransCanada fully consolidates the project and all costs are on its balance sheet, financed 100% with debt. All income and expenses of the project are recorded on TransCanada's financial statements.
- **Case 3 – “50% JV Sell Down”**: Assumes TransCanada splits 50% of the project with a third party and proportional accounting is used. As such, 50% of the project's income and expenses are recorded on TransCanada's financial statements.
- **Case 4 – “Base with 25% Stock Financing”**: Uses the same methodology as Case 1, only instead of funding the costs with 100% debt, 25% of its capital commitment to the pipeline during years 2014-2017 are being financed through common equity issuance.

■ Goldman Sachs Analyzed Four Alternative Approaches for TransCanada to Absorb Project Costs

Financing Review of Proposal

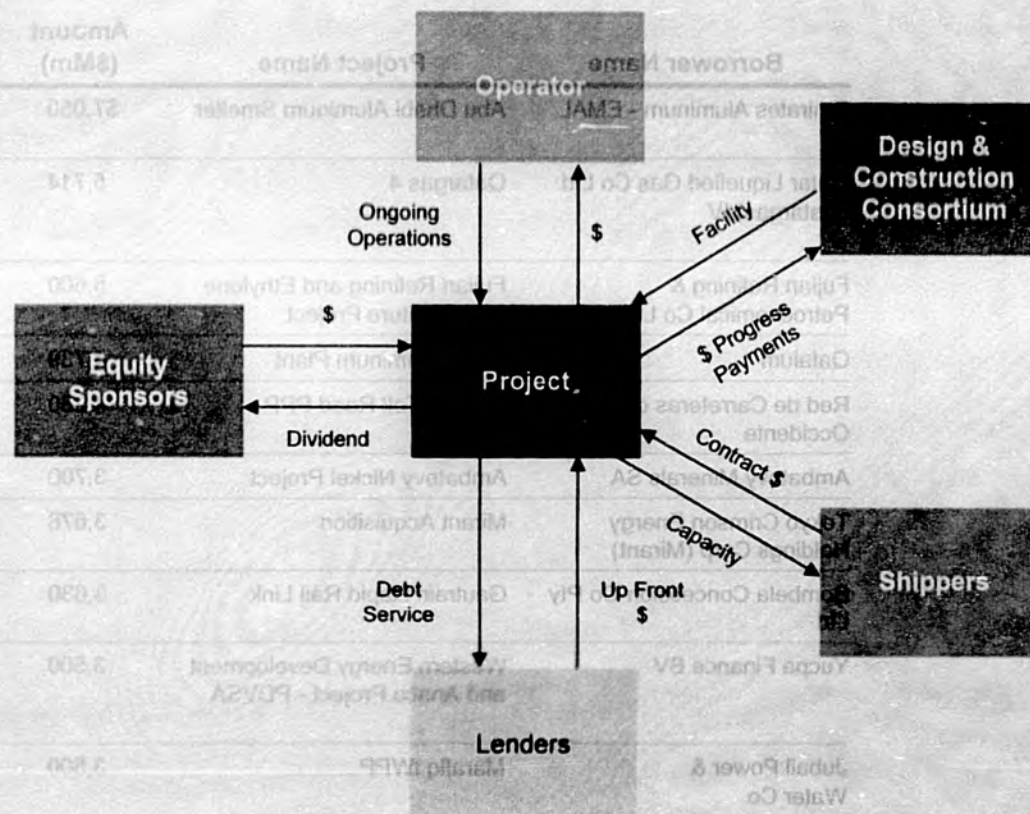
- Case 1 – “Base Case”: Assumes that TransCanada fully consolidates the project and all costs are on its balance sheet, financed 100% with debt. All income and expenses of the project are recorded on TransCanada's financial statements.
- Case 2 – “50% JV Sell Down”: Assumes TransCanada splits 50% of the project with a third party and proportional accounting is used. As such, 50% of the project's income and expenses are recorded on TransCanada's financial statements.
- Case 3 – “Base with 25% Stock Financing”: Uses the same methodology as Case 1, only instead of funding the costs with 100% debt, 25% of its capital commitment to the pipeline during years 2014-2017 are being financed through common equity issuance.
- Case 4 – “Fully Loaded”: Assumes that TransCanada fully consolidates the project and all costs are on its balance sheet, financed 100% with debt. All income and expenses of the project are recorded on TransCanada's financial statements.
- Case 5 – “Base Case”: Assumes that TransCanada fully consolidates the project and all costs are on its balance sheet, financed 100% with debt. All income and expenses of the project are recorded on TransCanada's financial statements.

Project Finance Loans are Based on a Complex Set of Contractual Arrangements

In a project financing, the lender's source of repayment is limited to project revenues and assets.

Lenders will:

- Take limited completion risk – construction risk typically mitigated through EPC contracts and/or a combination of pre-completion guarantees or cost overrun protection facilities;
- Want to insure that all funding needs are provided for
- Assess operating risk as part of the overall project – seek protections from revenue interruption



Project Financings are Common in the Energy and Oil & Gas Sectors

Borrower Name	Project Name	Amount (\$Mm)	Country	Sector	Financial Close
Emirates Aluminum - EMAL	Abu Dhabi Aluminum Smelter	\$7,050	United Arab Emirates	Processing Plant	12-Dec-2007
Qatar Liquefied Gas Co Ltd (Qatargas) IV	Qatargas 4	5,714	Qatar	Oil Refinery /LNG and LPG Plants	30-Jul-2007
Fujian Refining & Petrochemical Co Ltd - FREP	Fujian Refining and Ethylene Joint Venture Project	5,600	China	Petrochem/ Chemical Plant	6-Sep-2007
Qatalum	Qatar Aluminum Plant	4,739	Qatar	Processing Plant	23-Aug-2007
Red de Carreteras de Occidente	FARAC Toll Road PPP	4,280	Mexico	Road	27-Sep-2007
Ambatovy Minerals SA	Ambatovy Nickel Project	3,700	Madagascar	Mining	22-Aug-2007
Tokyo Crimson Energy Holdings Corp (Mirant)	Mirant Acquisition	3,678	Philippines	Power	7-Jun-2007
Bombela Concession Co Pty Ltd	Gautrain Rapid Rail Link	3,630	South Africa	Rail-Infrastructure	25-Jan-2007
Yucpa Finance BV	Western Energy Development and Anaco Project - PDVSA	3,500	Venezuela	Oil Refinery/ LNG and LPG Plants	21-Feb-2007
Jubail Power & Water Co	Marafiq IWPP	3,500	Saudi Arabia	Power	14-May-2007

Source: Project Finance Magazine March 2008



Proposal Assumptions that Impact the Proposal Base Case Financing Structure

- The Project is a 4.5 bcf/day system to transport natural gas from Prudhoe Bay to the Alberta market hub;
- 25-year ship-or-pay contracts with market standard shipper credit requirements;
- Debt is non-recourse to TransCanada (i.e., the debt is 'project debt');
- Capitalization of 70% debt and 30% equity during construction;
- Capital cost overruns to be financed through federally guaranteed cost overrun loans;
- Federally guaranteed capital cost overrun loans to be repaid through shipper surcharge; and
- No project completion guarantee or pre-completion debt guarantee from equity sponsors is assumed.

It is important to note that these assumptions underlie all of our conclusions with regards to the Proposal, and unless otherwise noted, any cases based on the Proposal.

Developing the Proposal Base Case Capital Structure

Key Drivers

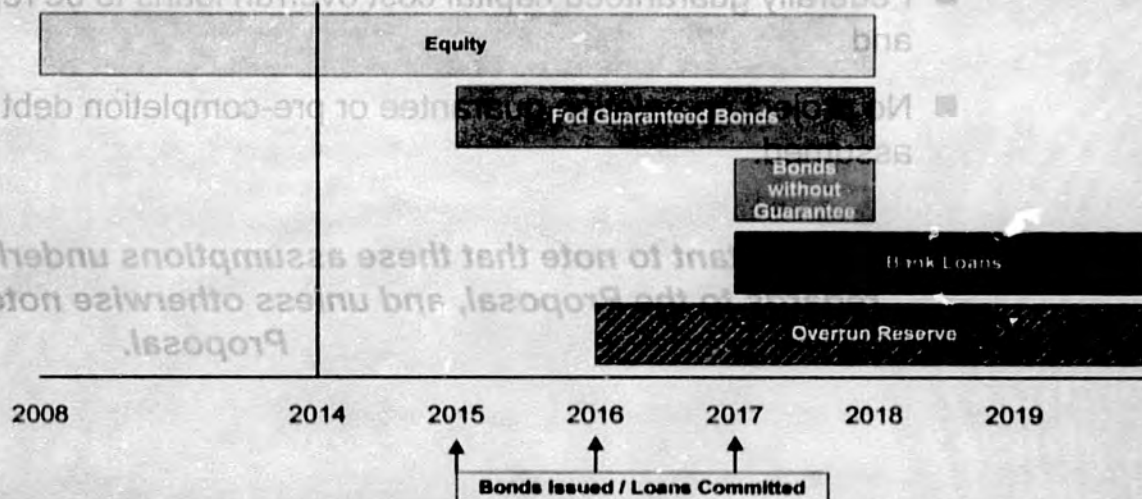
- Annual Funding Requirements
- Mix of Funding Sources
- Use of the Federal Loan Guarantee
- Interest Rate Assumptions

Funding Considerations

- Timing of Equity vs. Debt
- Debt: Bank Loans vs. Bonds
- Allocation of Federal Loan Guarantee

Allocation of Funding Sources

- Equity requirement is significant and front loaded to attract lenders and to ensure investment grade ratings
- Optimize impact of Federal Loan Guarantee
- Minimize overall interest costs





Disclaimers

The analysis and conclusions set forth herein are based on economic, financial, political, market and other conditions as they exist and can be evaluated on the date hereof, and we have not undertaken to reaffirm or revise our findings or otherwise comment upon any conditions or events occurring after the date hereof. Our analysis and conclusions also involve numerous assumptions and uncertainties, many of which cannot be verified or ascertained presently. Goldman Sachs does not provide accounting, tax or legal advice, and we make no representation as to the appropriateness or adequacy of the information contained herein or our procedures for, and express no view as to, the tax, accounting or legal treatment of any matter.

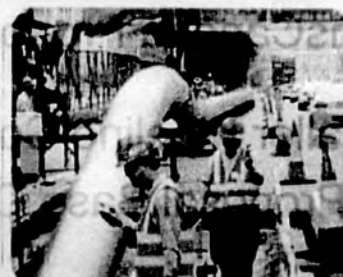
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BUILDING A WORLD OF DIFFERENCE®



BLACK & VEATCH



Net Present Value (NPV) Analysis

June 10, 2008

scheduled but
not presented
on June 10

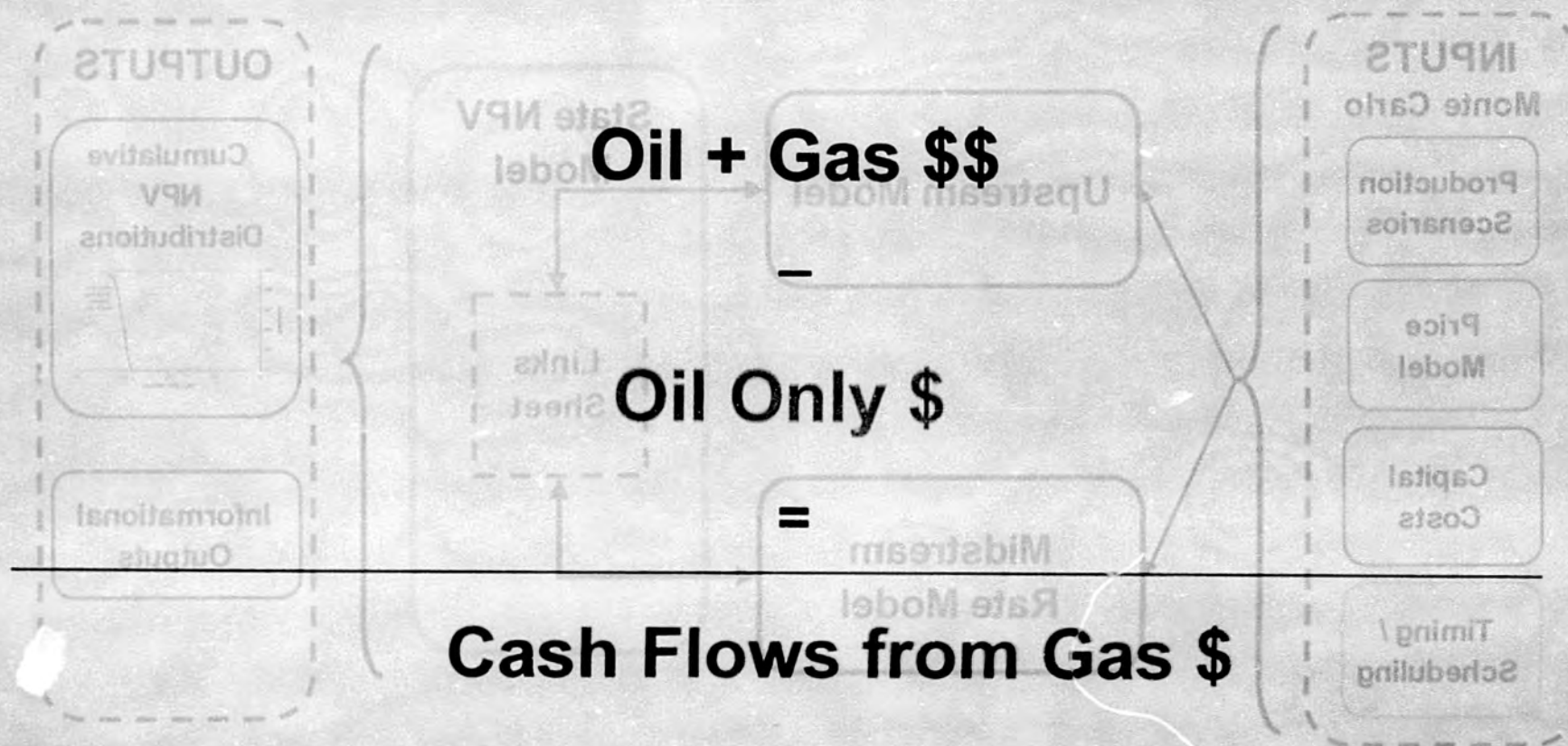


Key Conclusions

- 4.5 Bcf/d TransCanada Proposal has Positive NPV Benefits to All Stakeholders
- Tariffs for Smaller Pipeline Configurations Increase by 13% to 21% Relative to the 4.5 Bcf/d Proposal Base Case
- NPV for Key Stakeholders Indicates Positive NPV for the Conservative Base Case
- NPV Results are Sensitive to Many Factors with Commodity Prices being the Most Significant
 - Producer NPV Remains Positive with Low Market Price Assumptions
- Production from Proven Reserves Drive Positive Stakeholder NPV
- Smaller Initial Pipeline Capacity and Contract Period for Smaller Pipeline Configurations Reduce Reserve Risk Relative to the Proposal Base Case

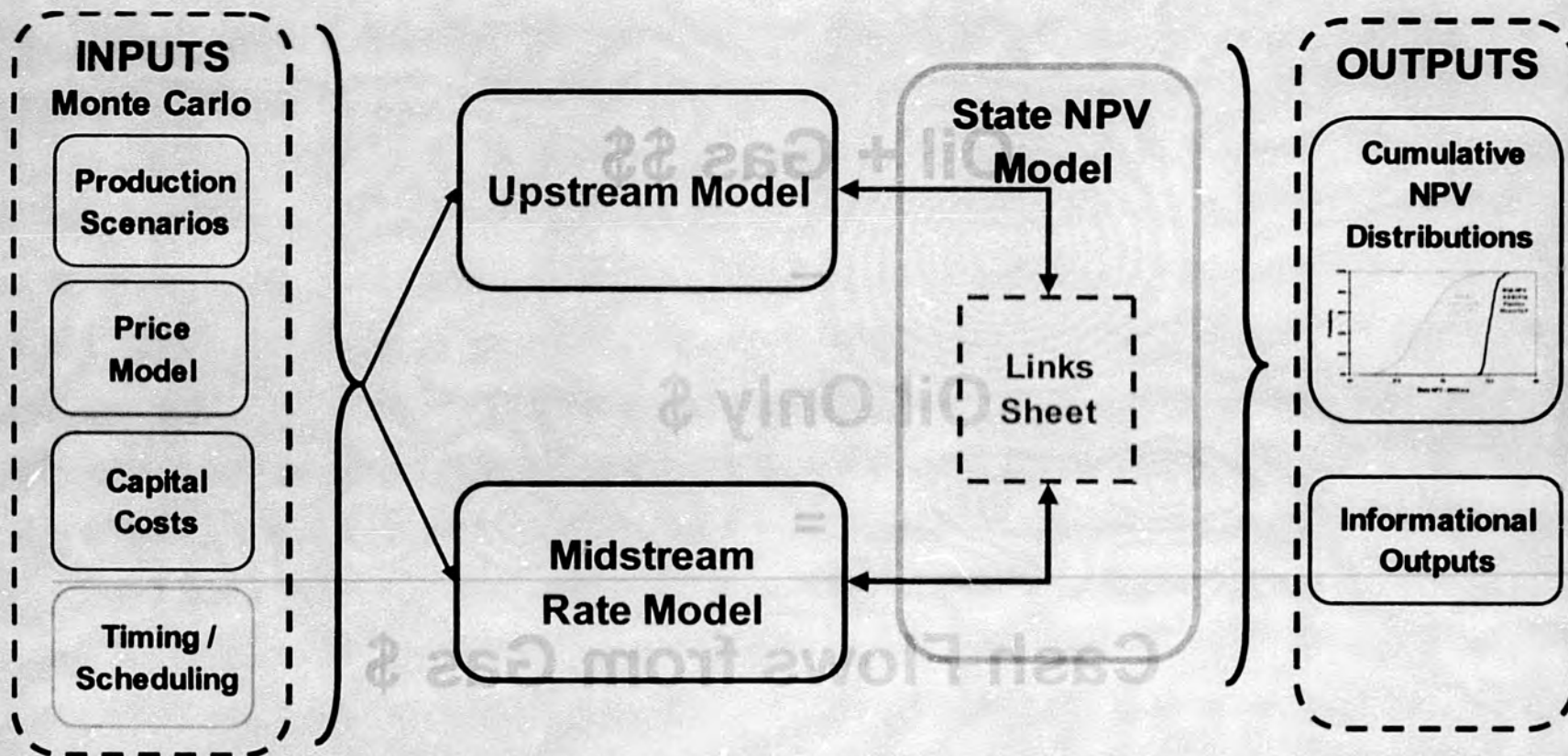


Impact of the Gasline: Cash flows and NPV calculated are the difference between oil+gas and oil only operations.





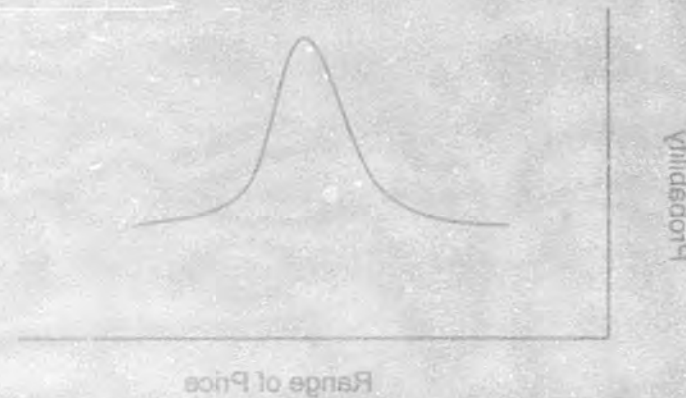
The NPV Modeling Approach Utilized by Black & Veatch





Overview of Natural Gas Price Assumptions Utilized in the NPV Analysis

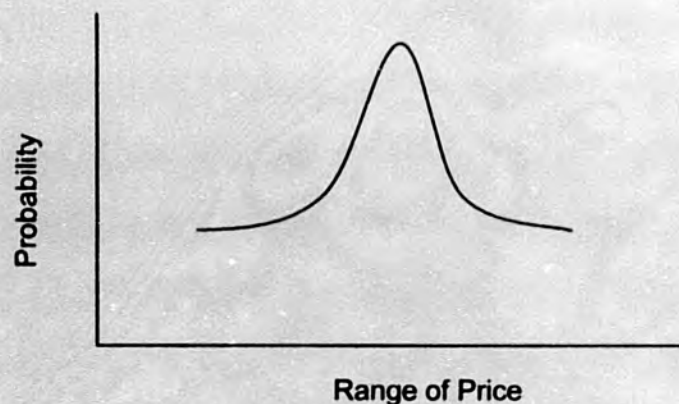
- Gas delivered to different locations has different prices: Henry Hub vs. AECO
- Prices dependent on the supply/demand balance and pipeline infrastructure
- Forecasts are required to evaluate the project from 2020 to 2045+
- Relied on range of forecasts
 - EIA
 - Wood Mackenzie
 - B&V
 - Others
- Wood Mackenzie is the base case for analysis
 - Independent market assessment
 - Projects an AECO price





Understanding the Factors that Lead to Future Prices

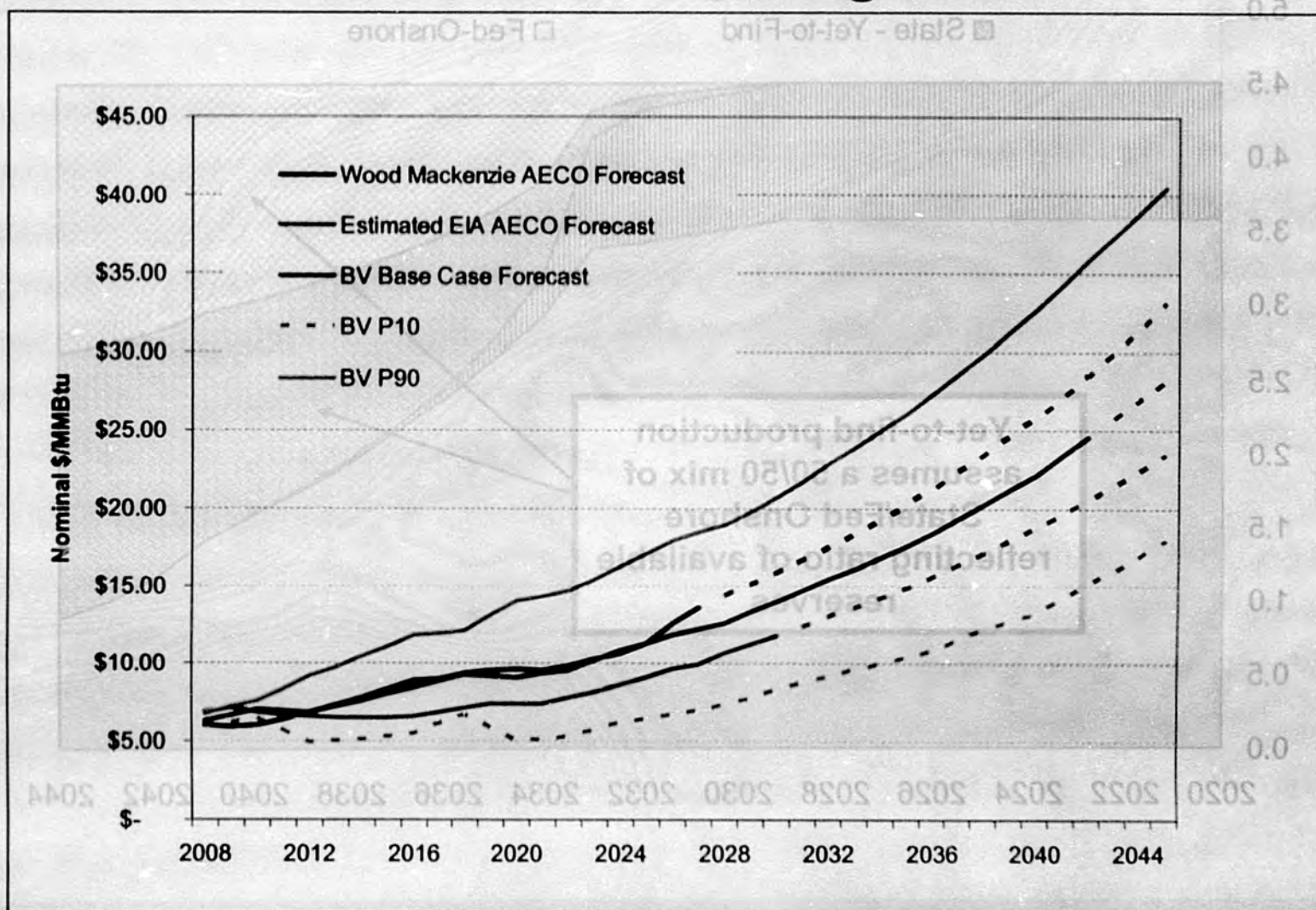
- Forecasted prices are “point” estimates, all dependent on a specific set of assumptions
- None are expected to be on the dot “correct”
- Price uncertainty and associated risks could be better illustrated using a forecasted price distribution:



- Black & Veatch assumes that the majority of price risks comes from uncertainty in fundamental factors:
 - Finding & development costs
 - Technological improvement
 - LNG imports
 - Power generation demand
 - US industrial demand
 - CDN industrial demand

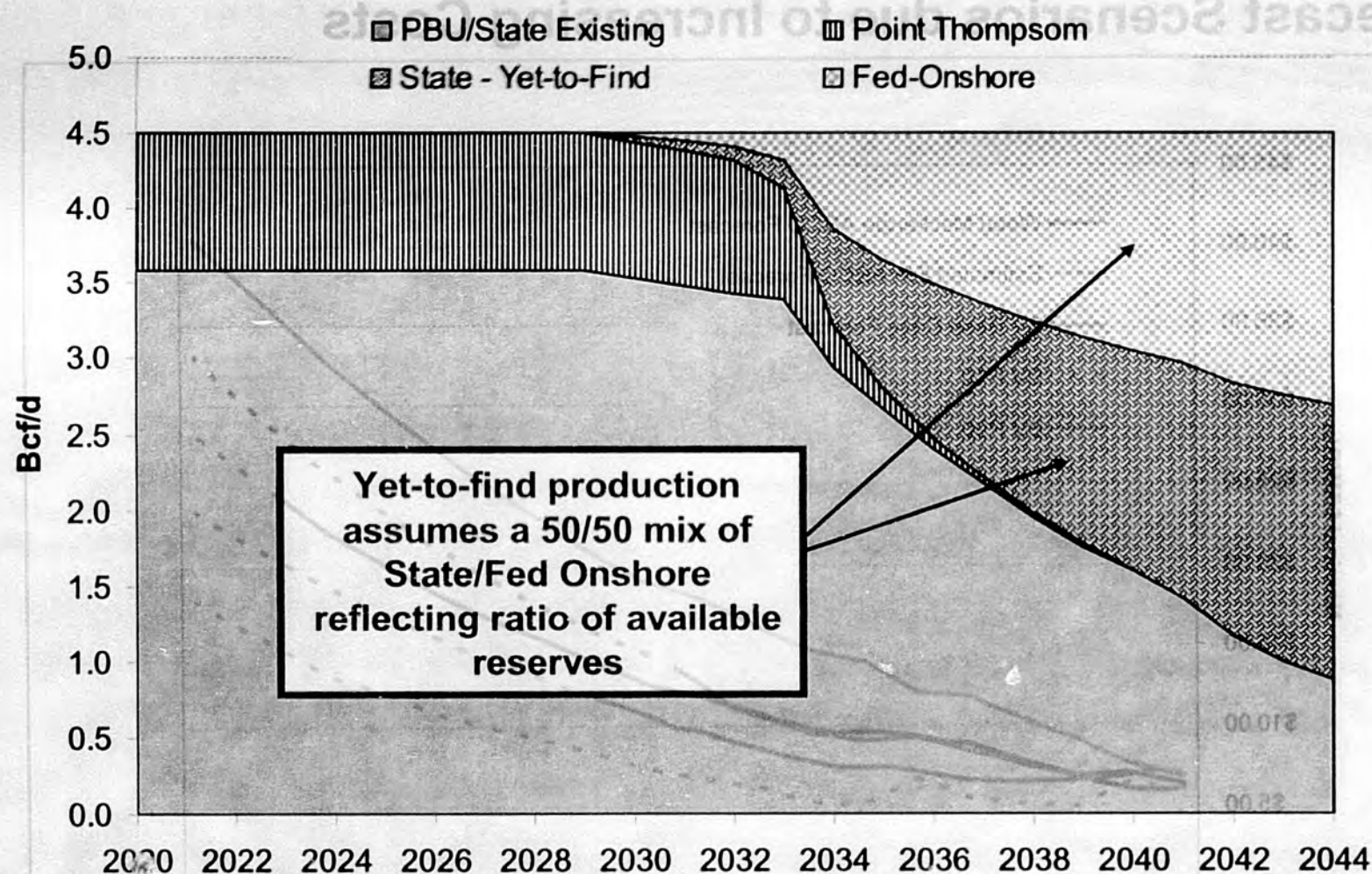


Real Price Growth at AECO is Expected Under All Price Forecast Scenarios due to Increasing Costs



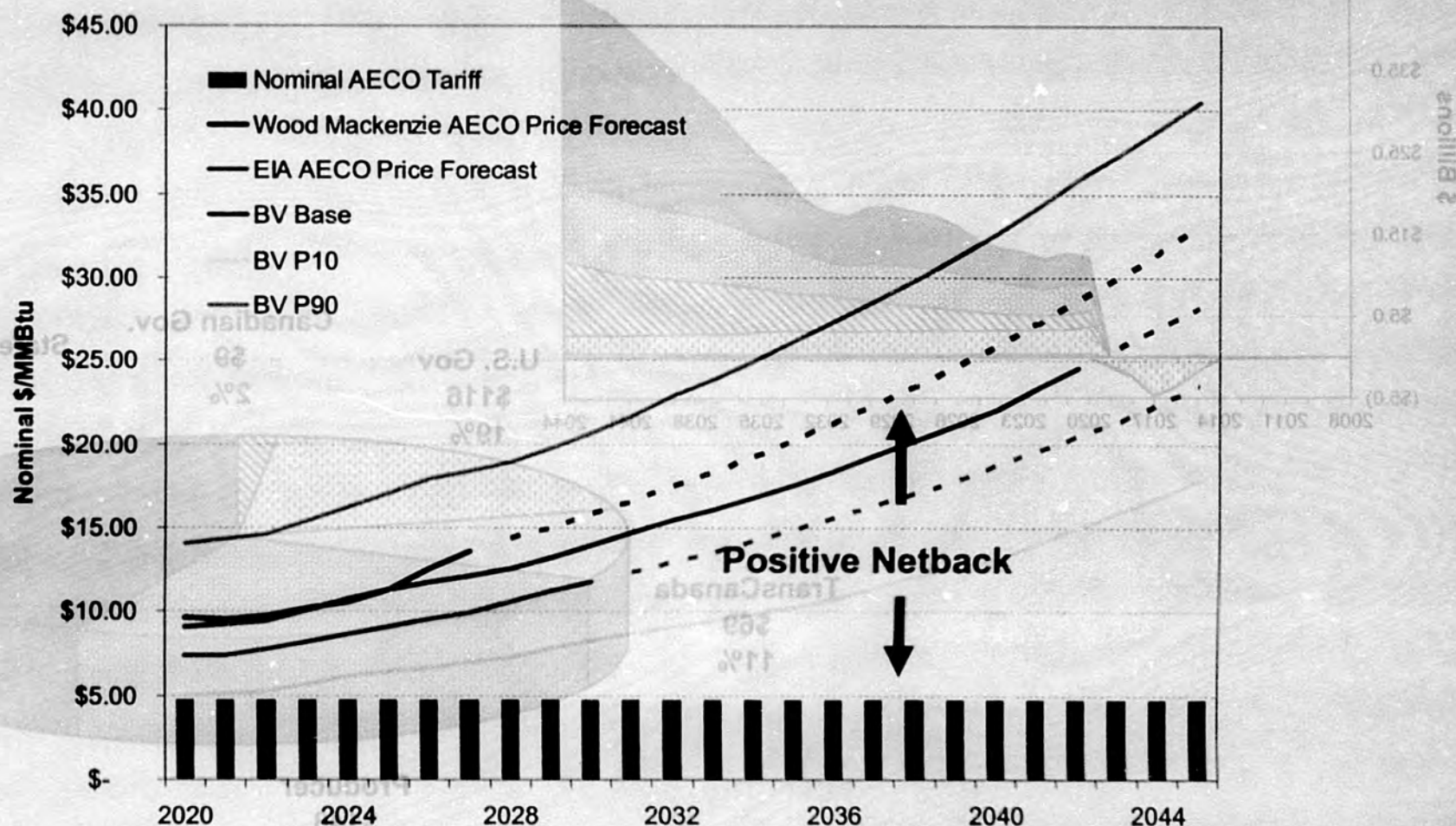


Production Assumptions: 4.5 Bcf/d Proposal Base Case



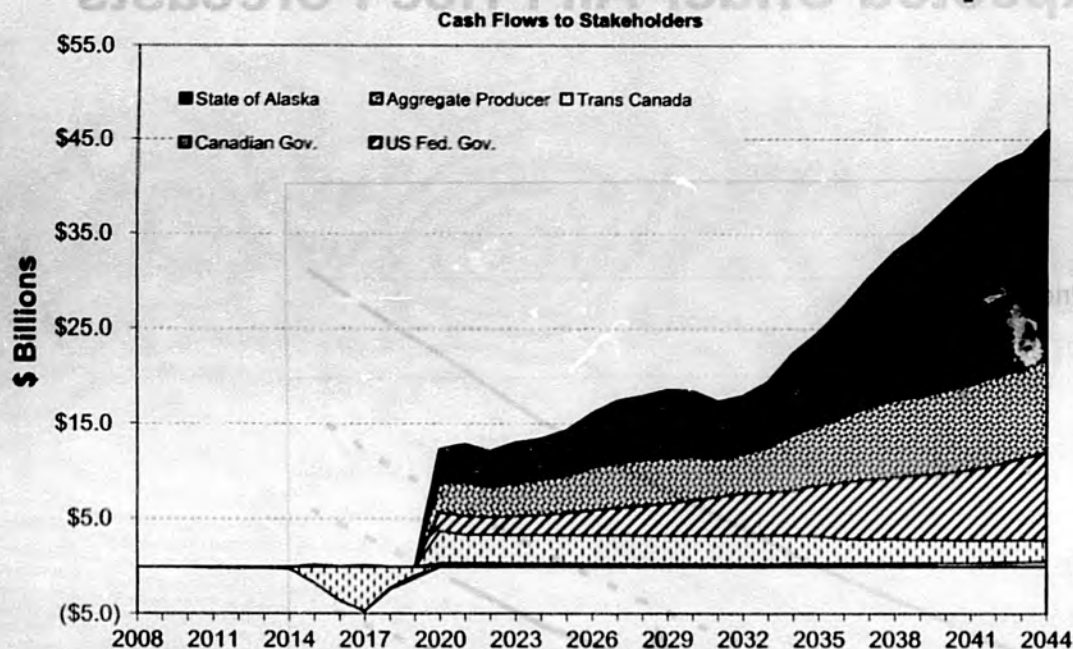


Positive Netbacks Are Expected Under All Price Forecasts





Cash flows from 4.5 Bcf/d Proposal Base Case



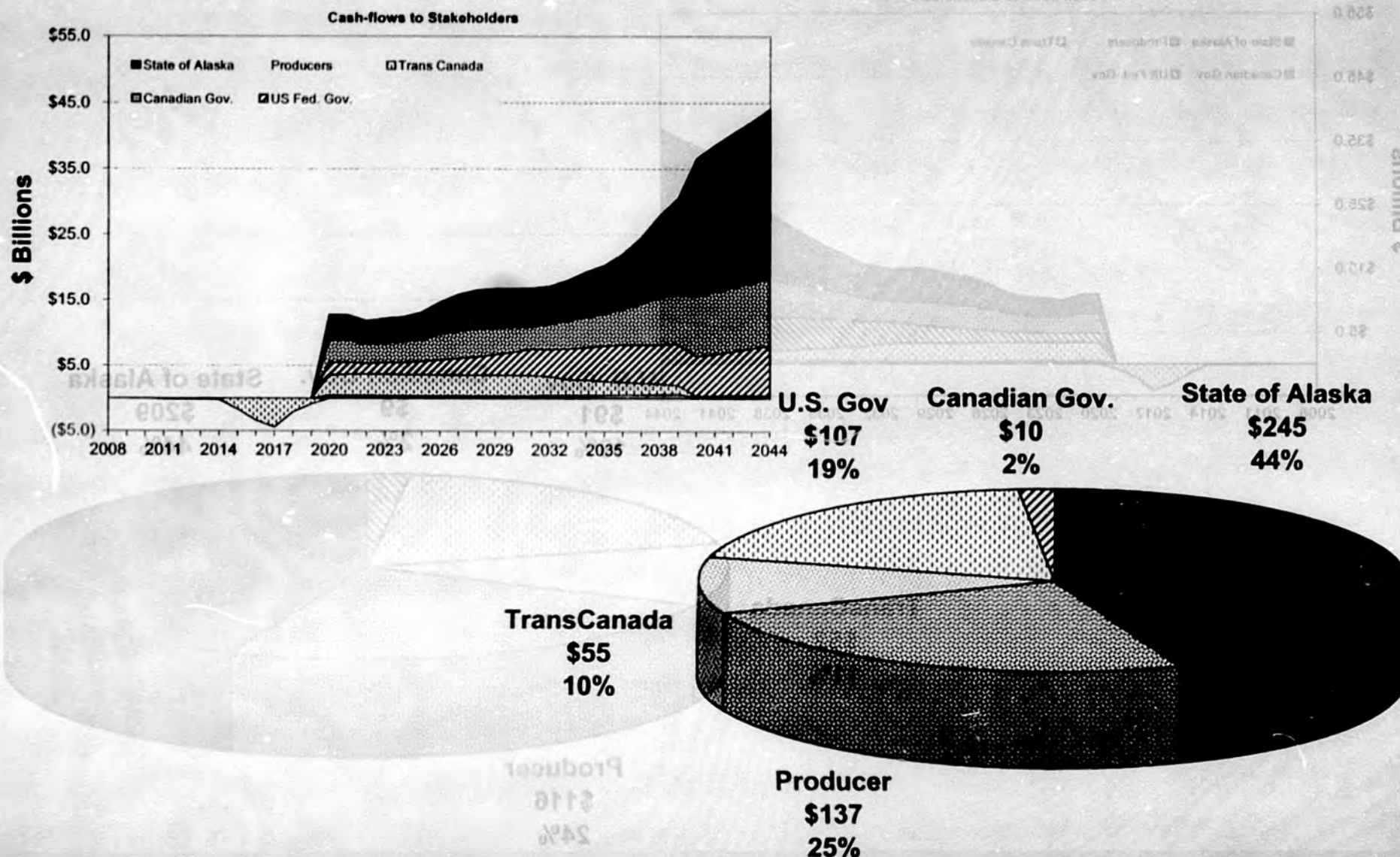
U.S. Gov	Canadian Gov.	State of Alaska
\$116	\$9	\$262
19%	2%	44%

TransCanada
\$69
11%

Producer
\$148
24%

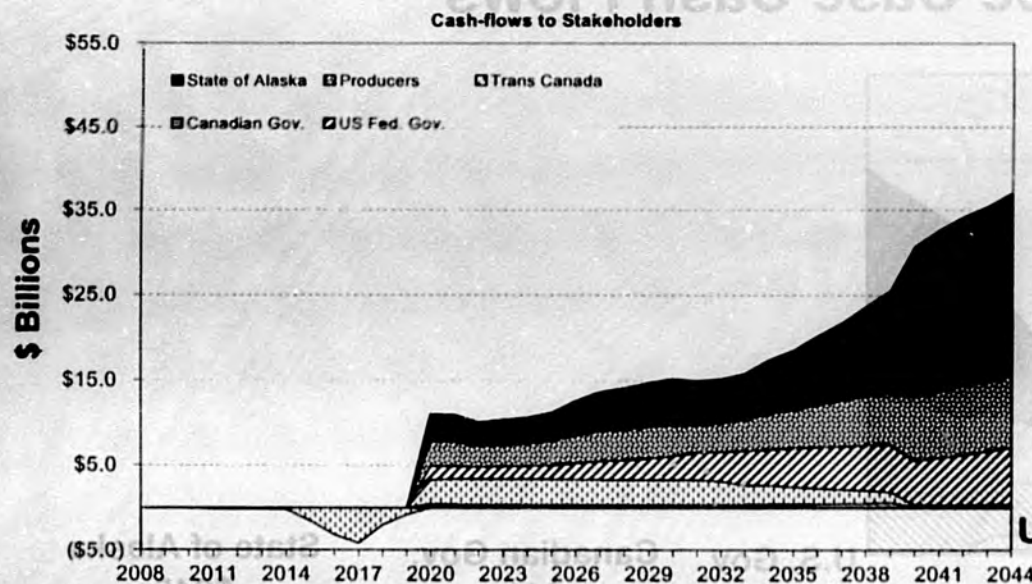


4.0 Bcf/d Conservative Base Case Cash Flows

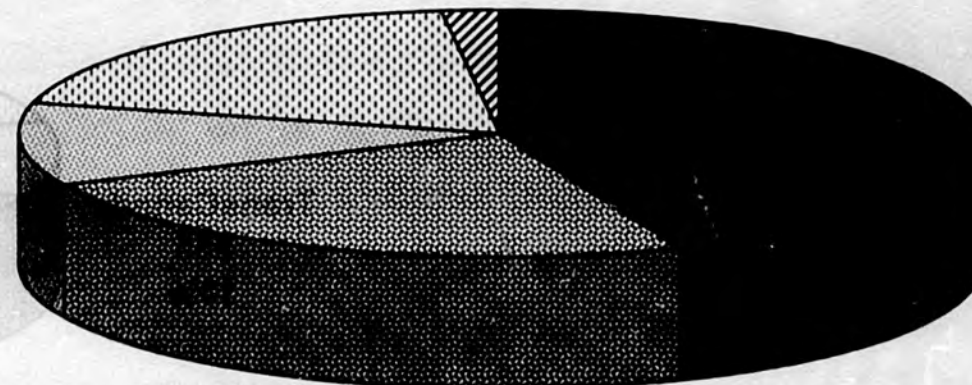
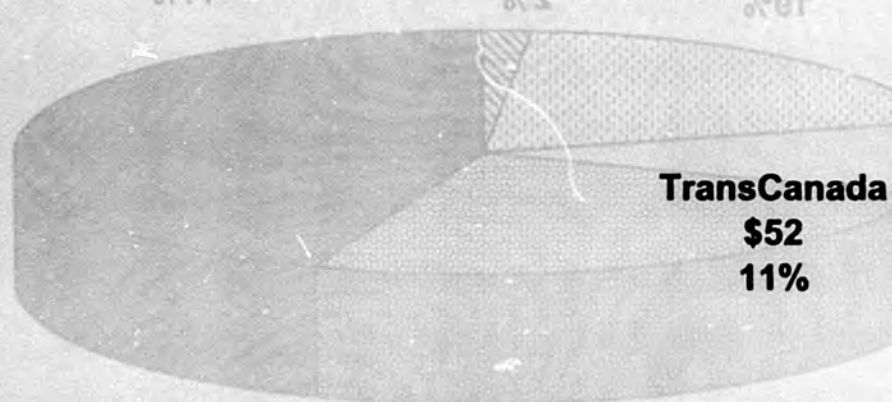




3.5 Bcf/d Low Volume Sensitivity Case

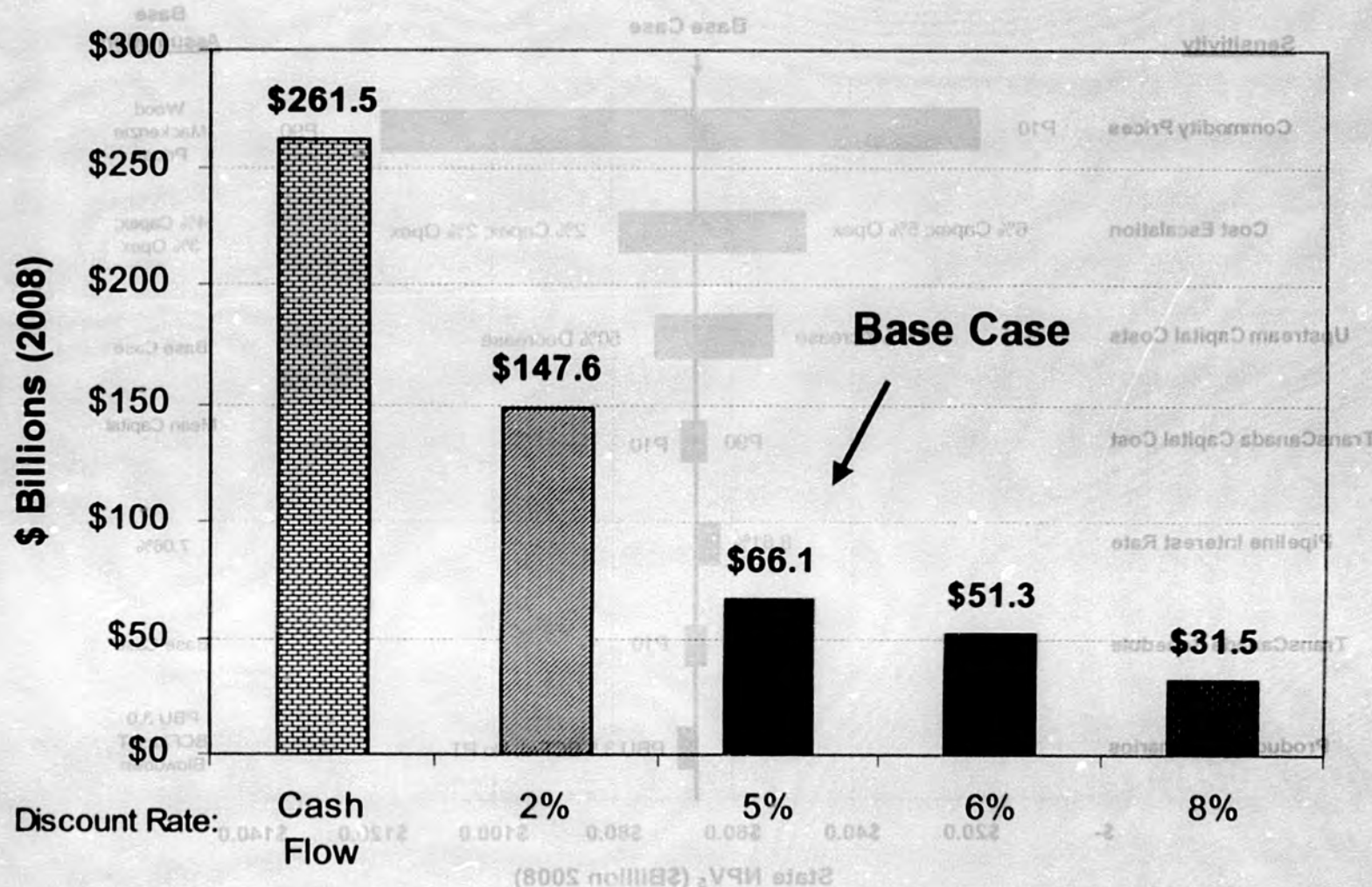


U.S. Gov	Canadian Gov.	State of Alaska
\$91	\$9	\$209
19%	2%	44%



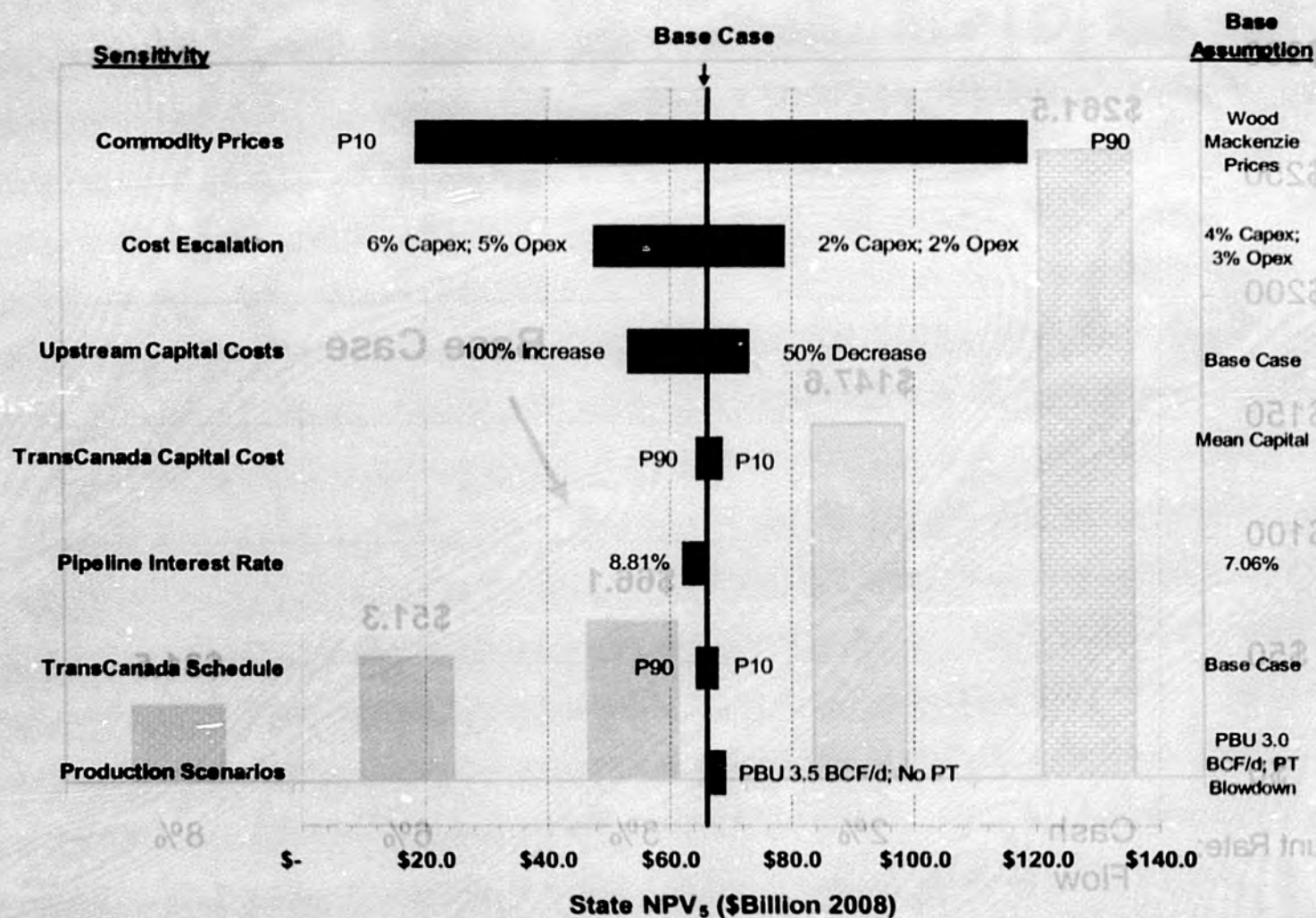


Expected State of Alaska NPV₅ is \$66.1 billion



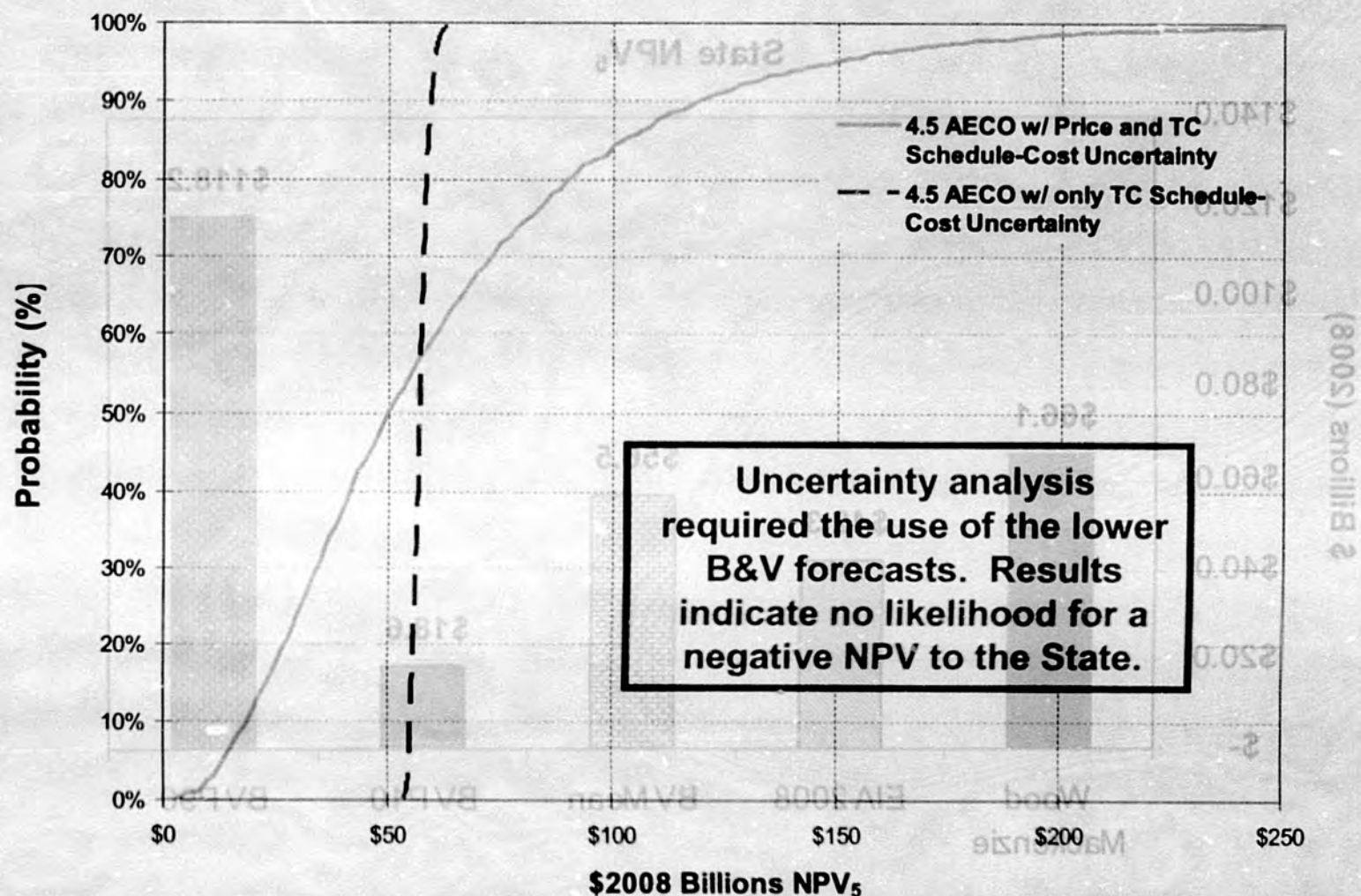


Price is a Key Driver to Variations in the NPV₅ to the State of Alaska



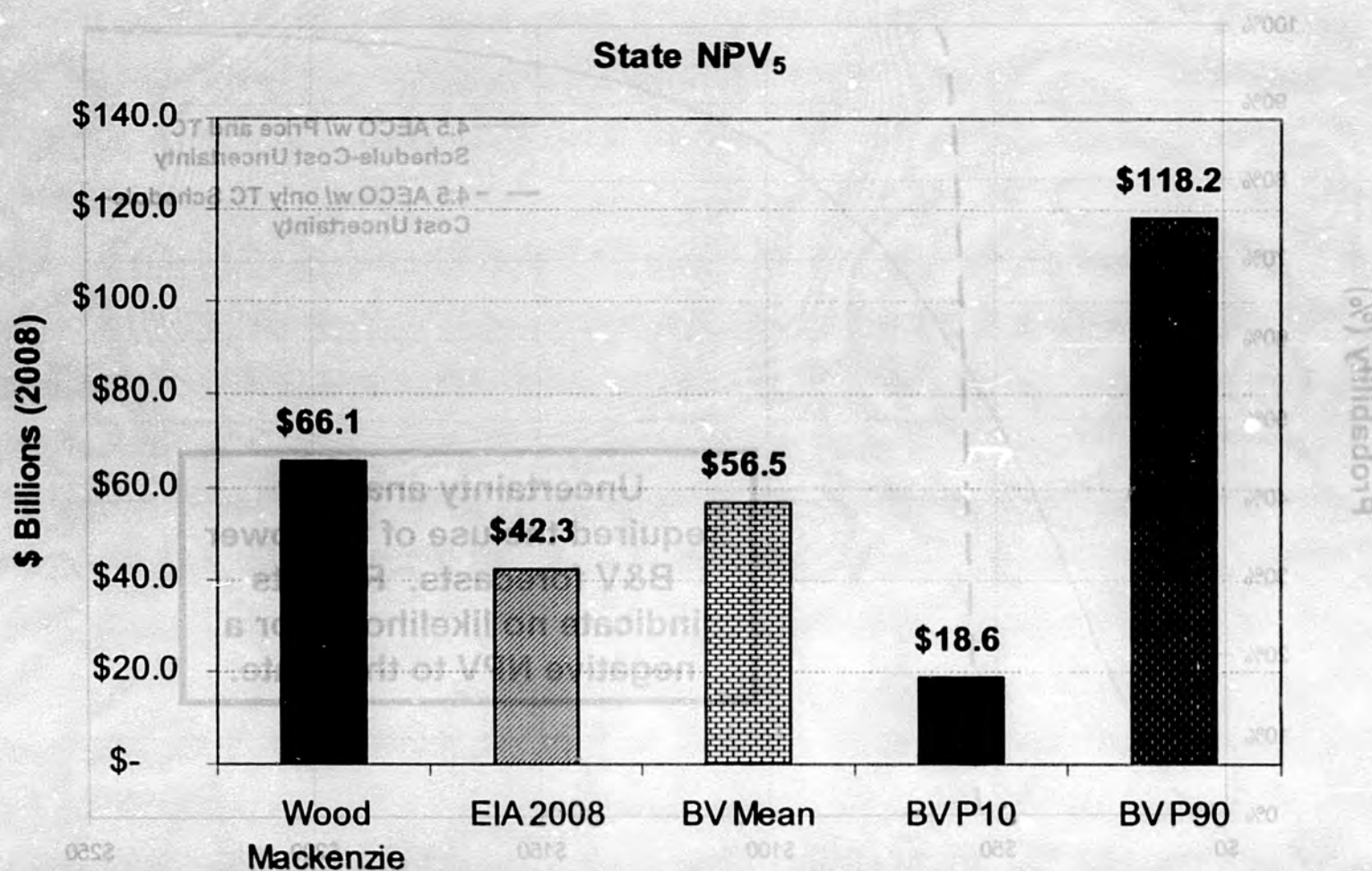


The impact from price uncertainty swamps estimated capital cost and schedule uncertainty.



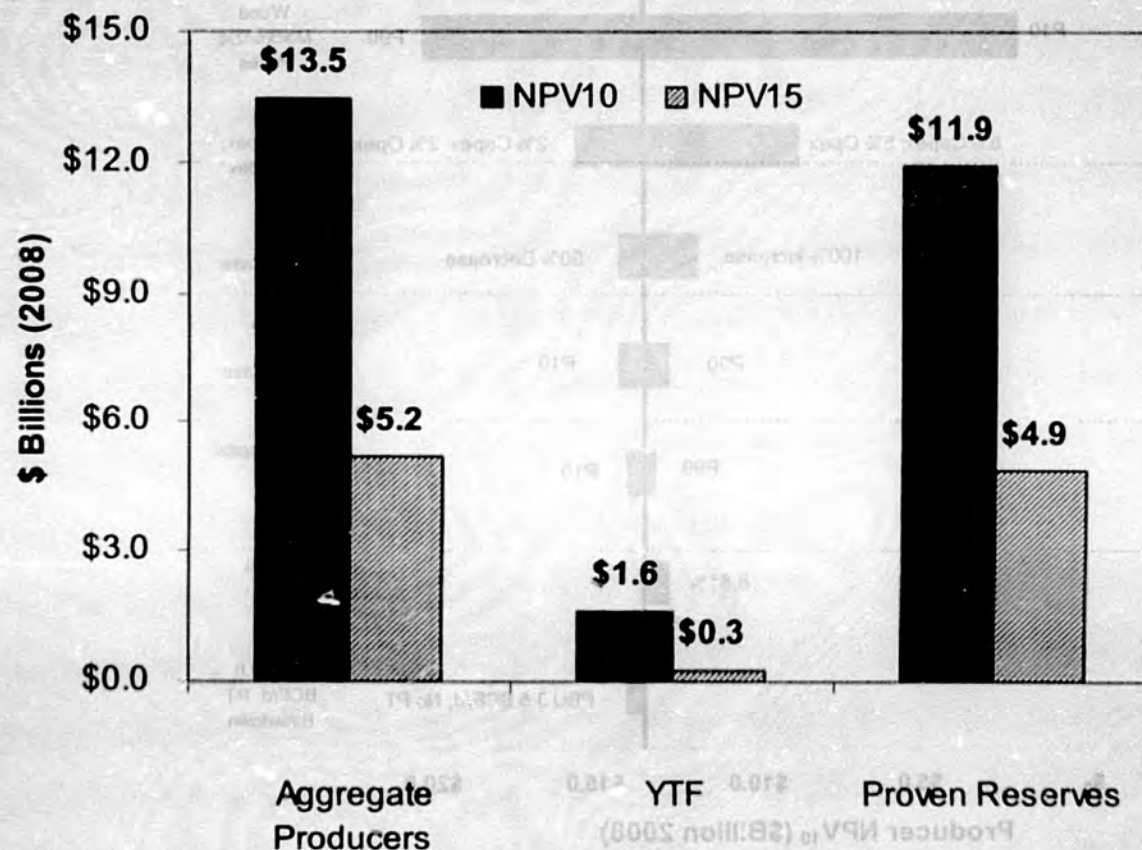


NPV for the State is Expected to be Positive Under all Price Scenarios





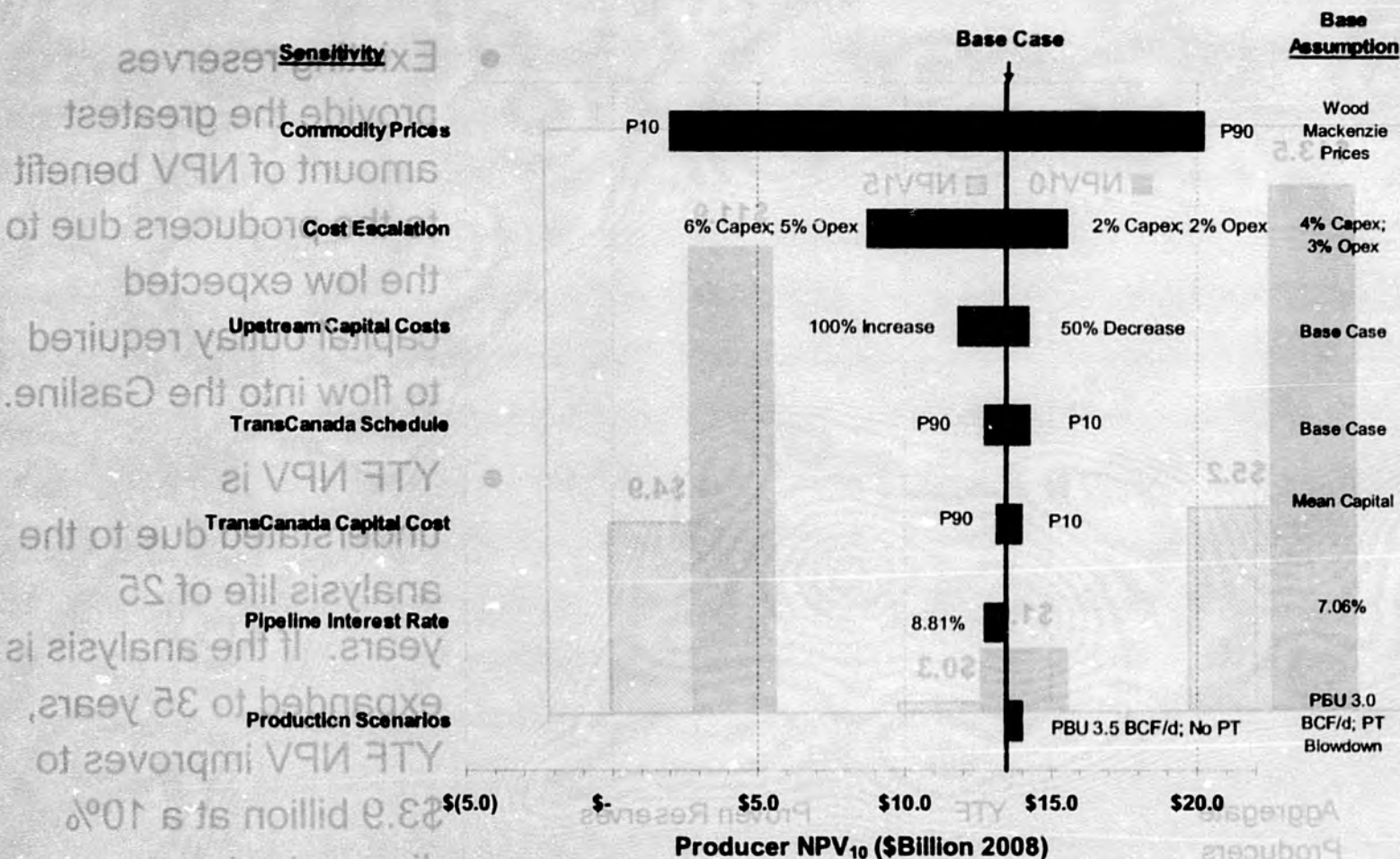
Like the State, NPV for the Producers is Expected to be Substantial under Base Case Assumptions



- Existing reserves provide the greatest amount of NPV benefit to the producers due to the low expected capital outlay required to flow into the Gasline.
- YTF NPV is understated due to the analysis life of 25 years. If the analysis is expanded to 35 years, YTF NPV improves to \$3.9 billion at a 10% discount rate.

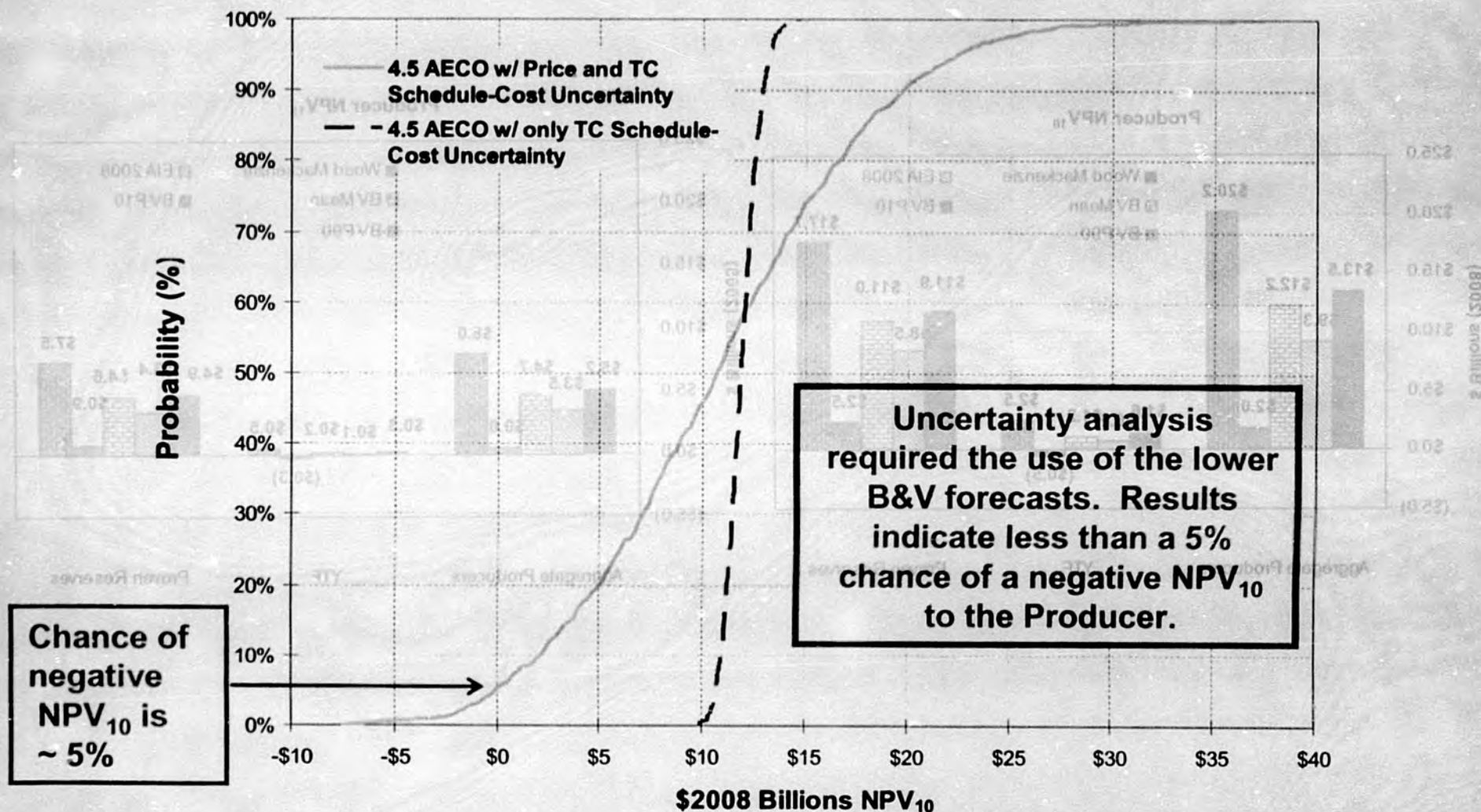


Producer Sensitivity to Key Variables is Similar to the State



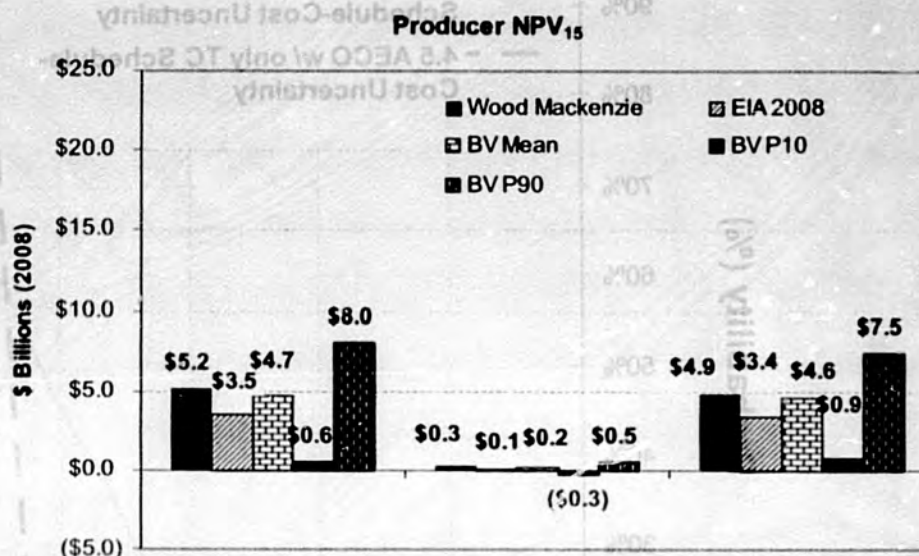
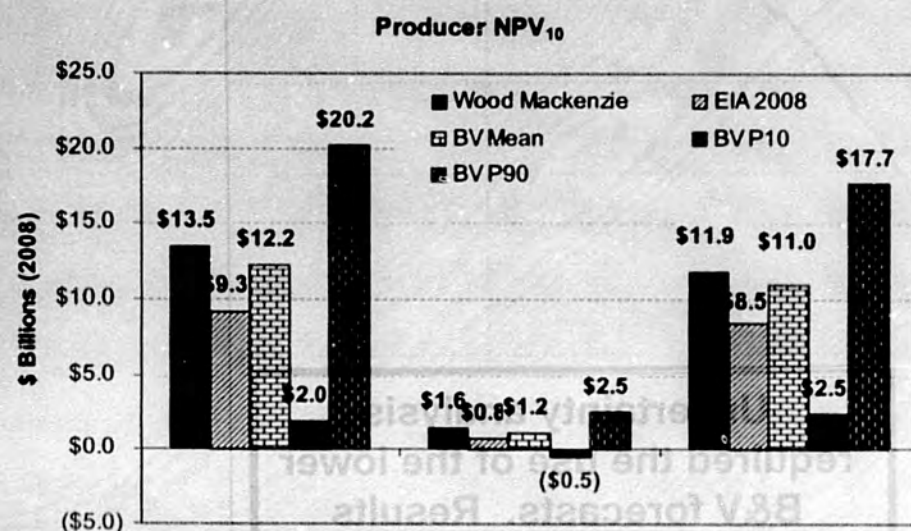


The producers have a very low likelihood for a negative NPV₁₀ from low prices, no likelihood from cost scope risk.



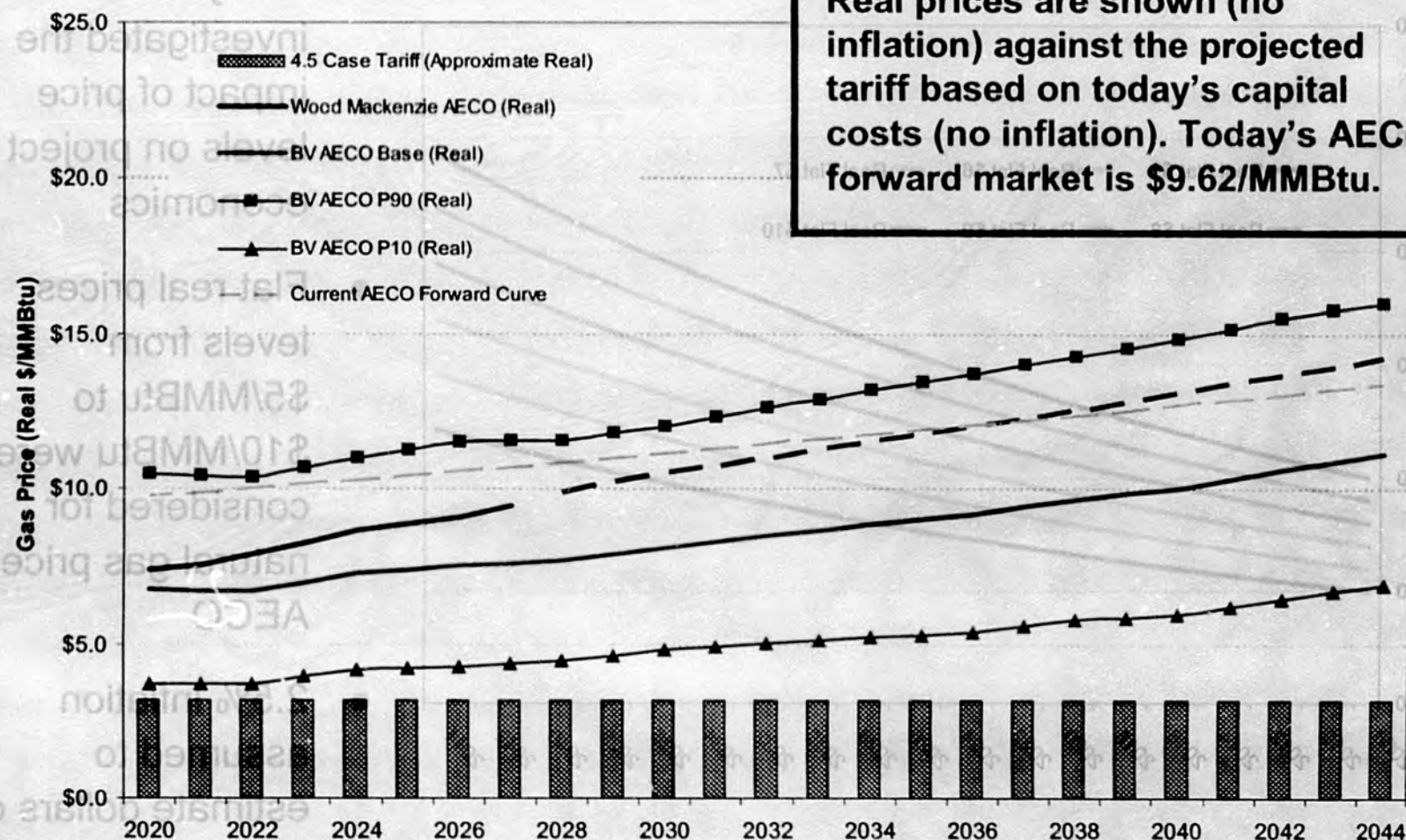


NPV for the Producers is Expected to be Positive Under all Price Scenarios



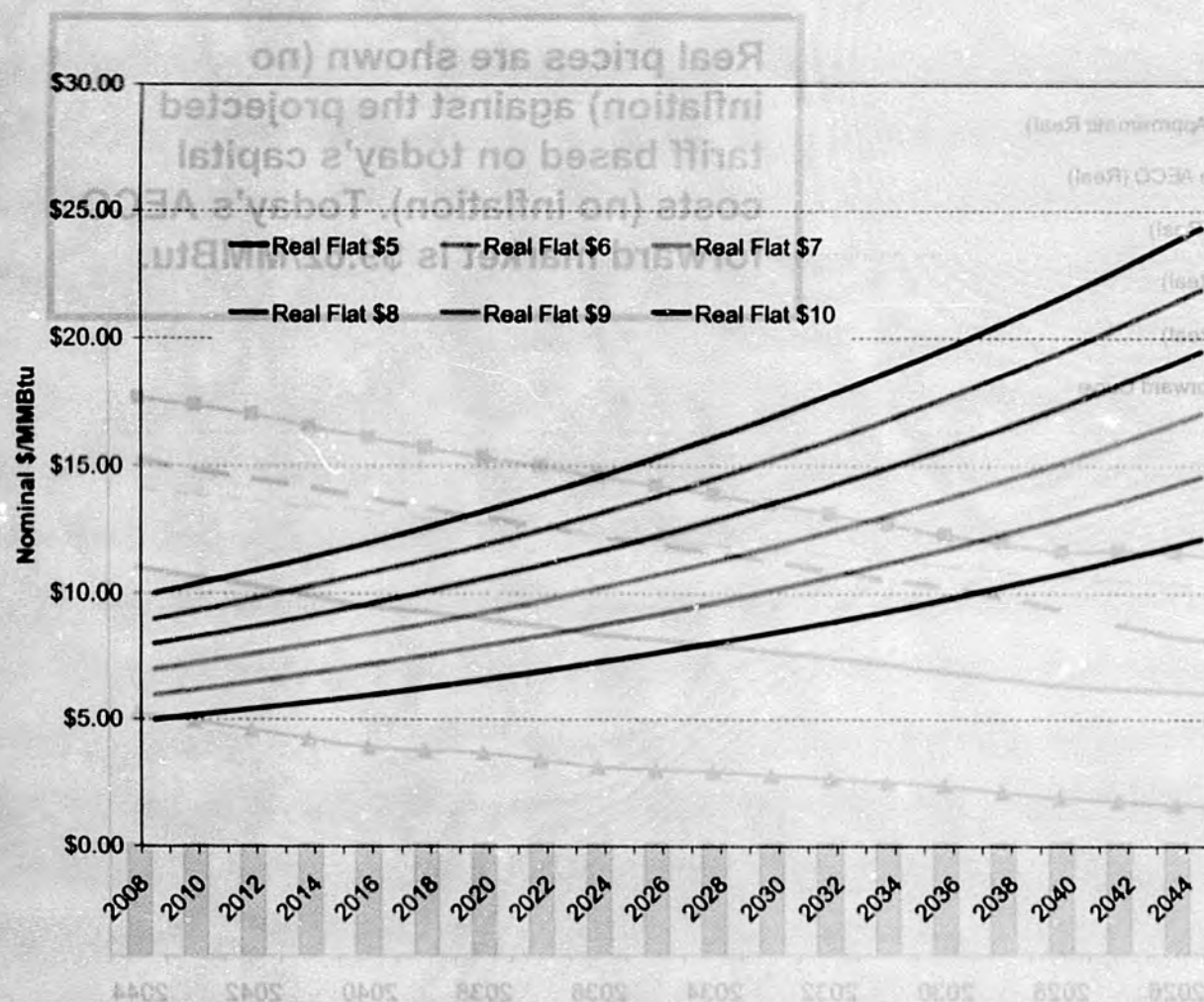


Project Cash Flows are Favorable if Built Today



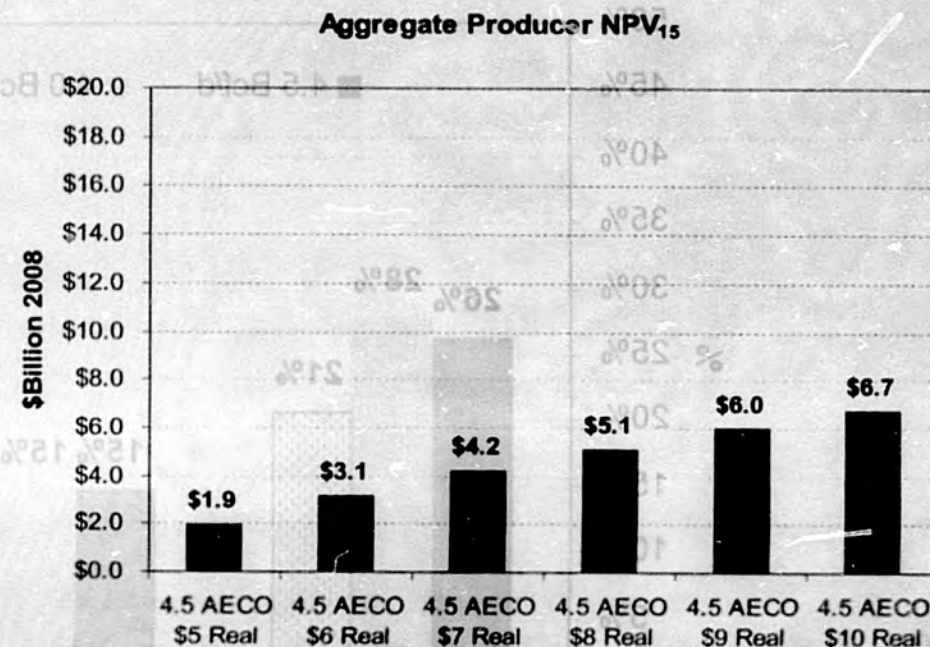
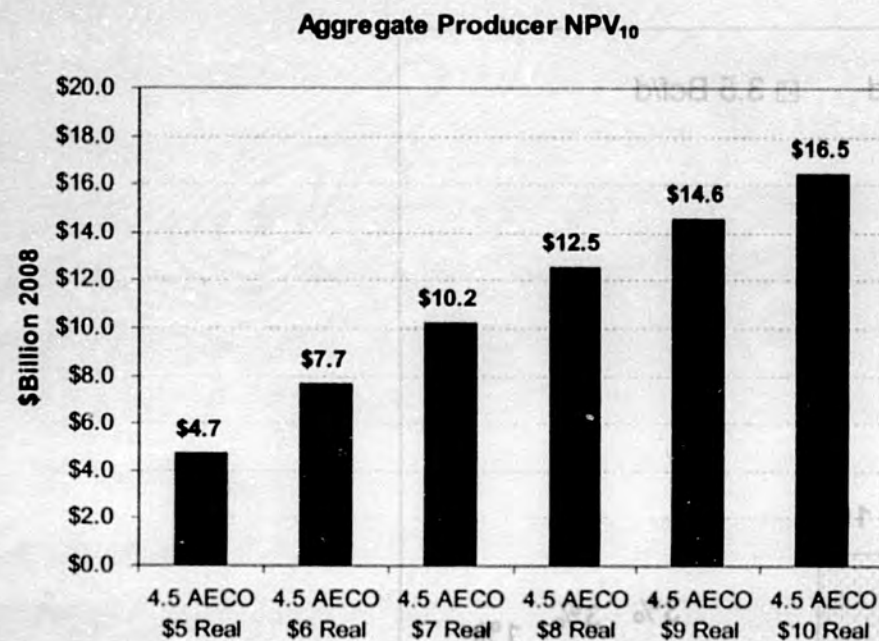


Analysis of Impact of Price Levels - Flat Real Prices



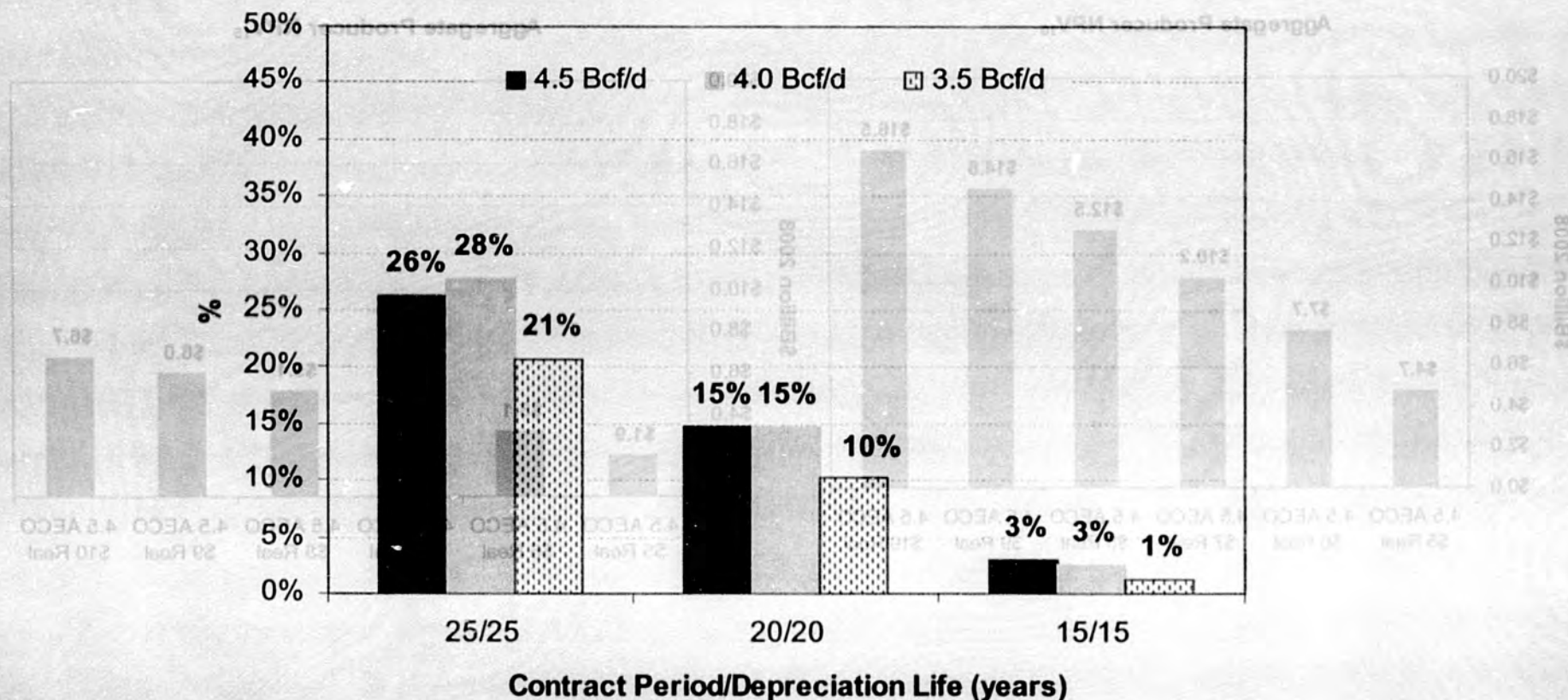
- Analysis investigated the impact of price levels on project economics
- Flat real prices levels from \$5/MMBtu to \$10/MMBtu were considered for natural gas price at AECO
- 2.5% inflation assumed to estimate dollars of the day prices

Price levels have a significant impact on Producer NPV.
 NPV₁₀ remains positive with real prices in \$5-\$10/MMBtu range.

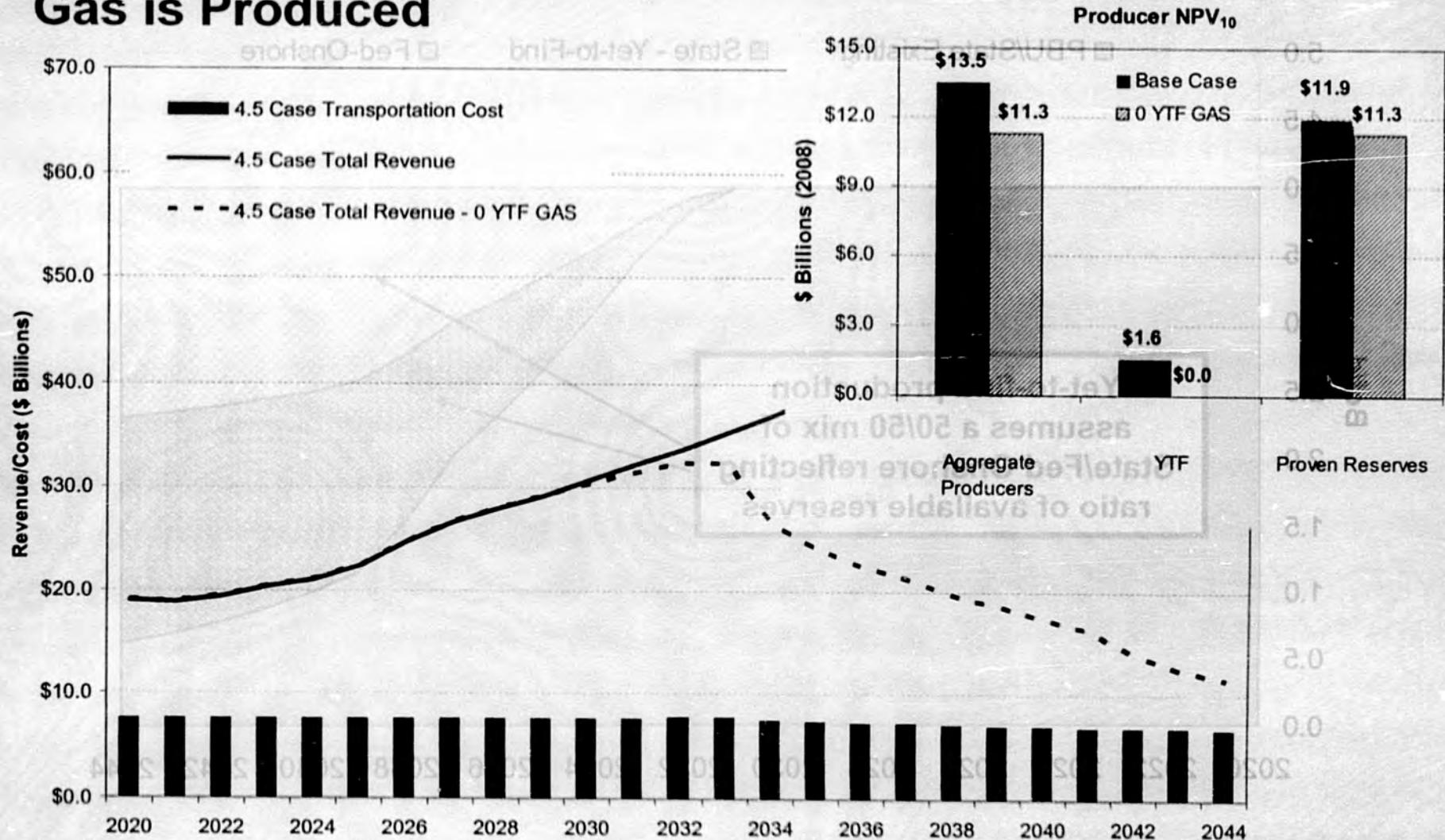


YTF Gas Required to Keep Pipeline Full under Different Contract Periods and for Different Pipeline Capacities

% of Contract Volume Requiring YTF Gas

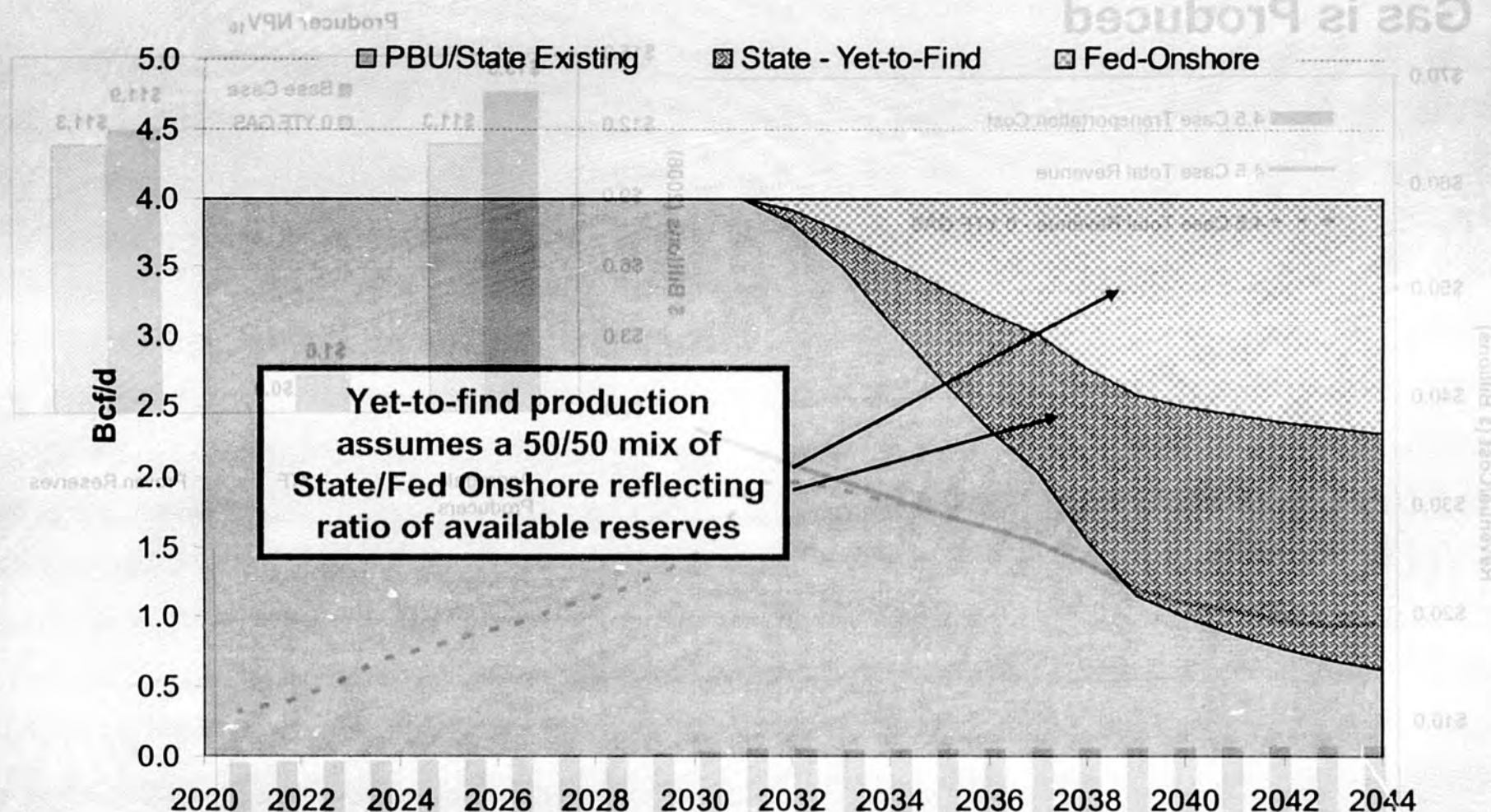


Producer NPV is Expected to Remain Positive if No YTF Gas is Produced



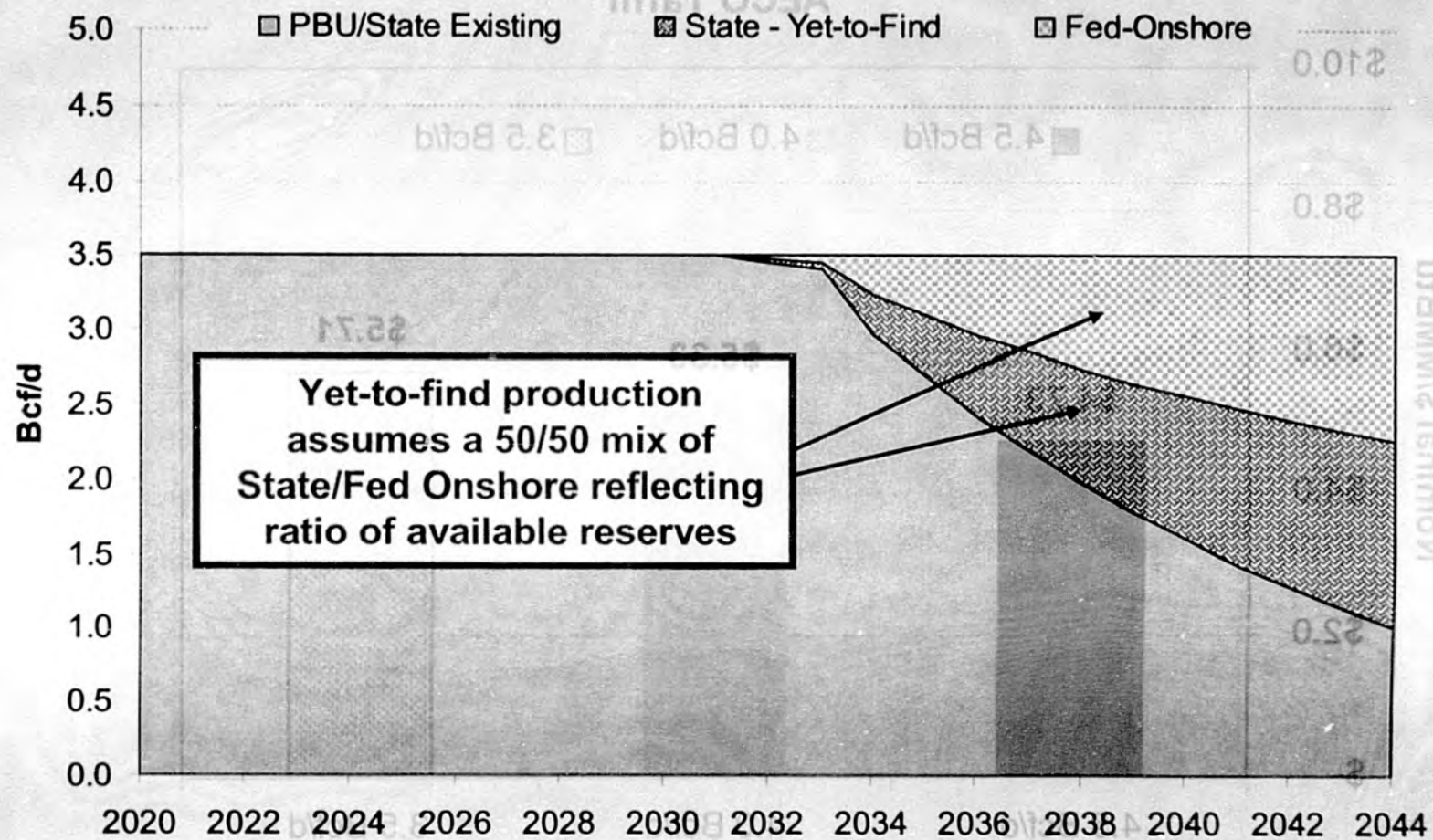


Production Assumptions: 4.0 Bcf/d Case



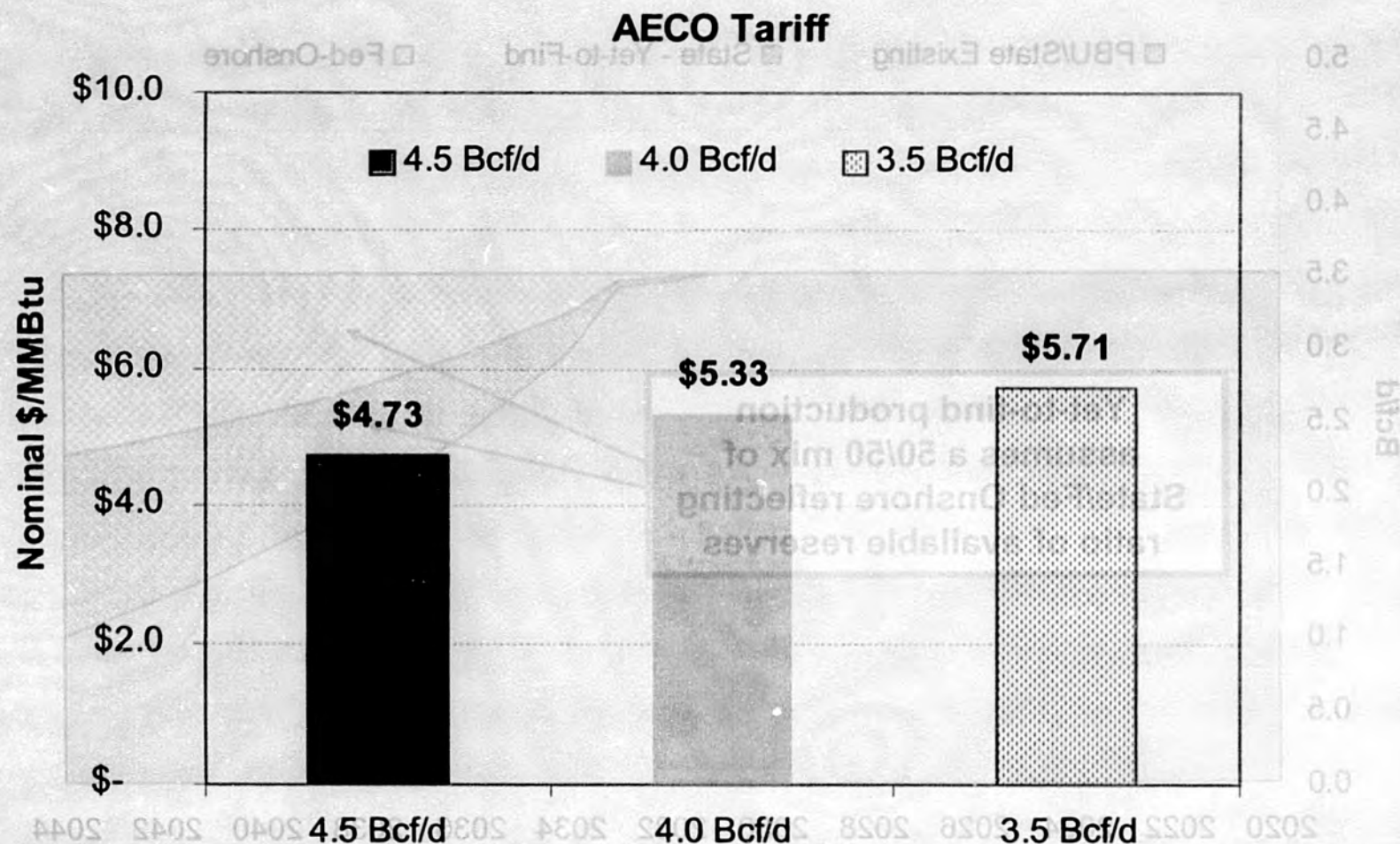


Production Assumptions: 3.5 Bcf/d Case





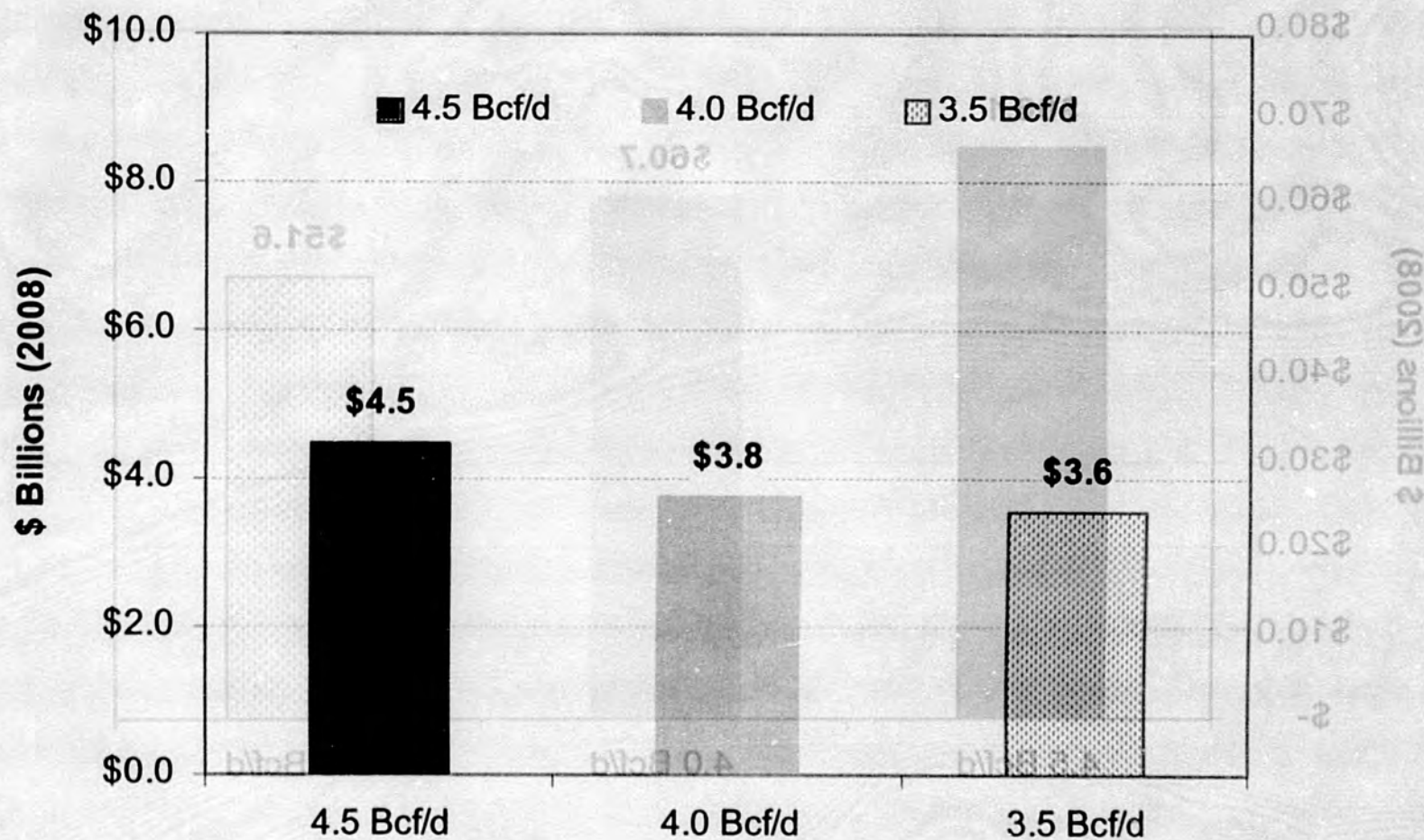
Expected Tariffs from the North Slope to the AECO Market





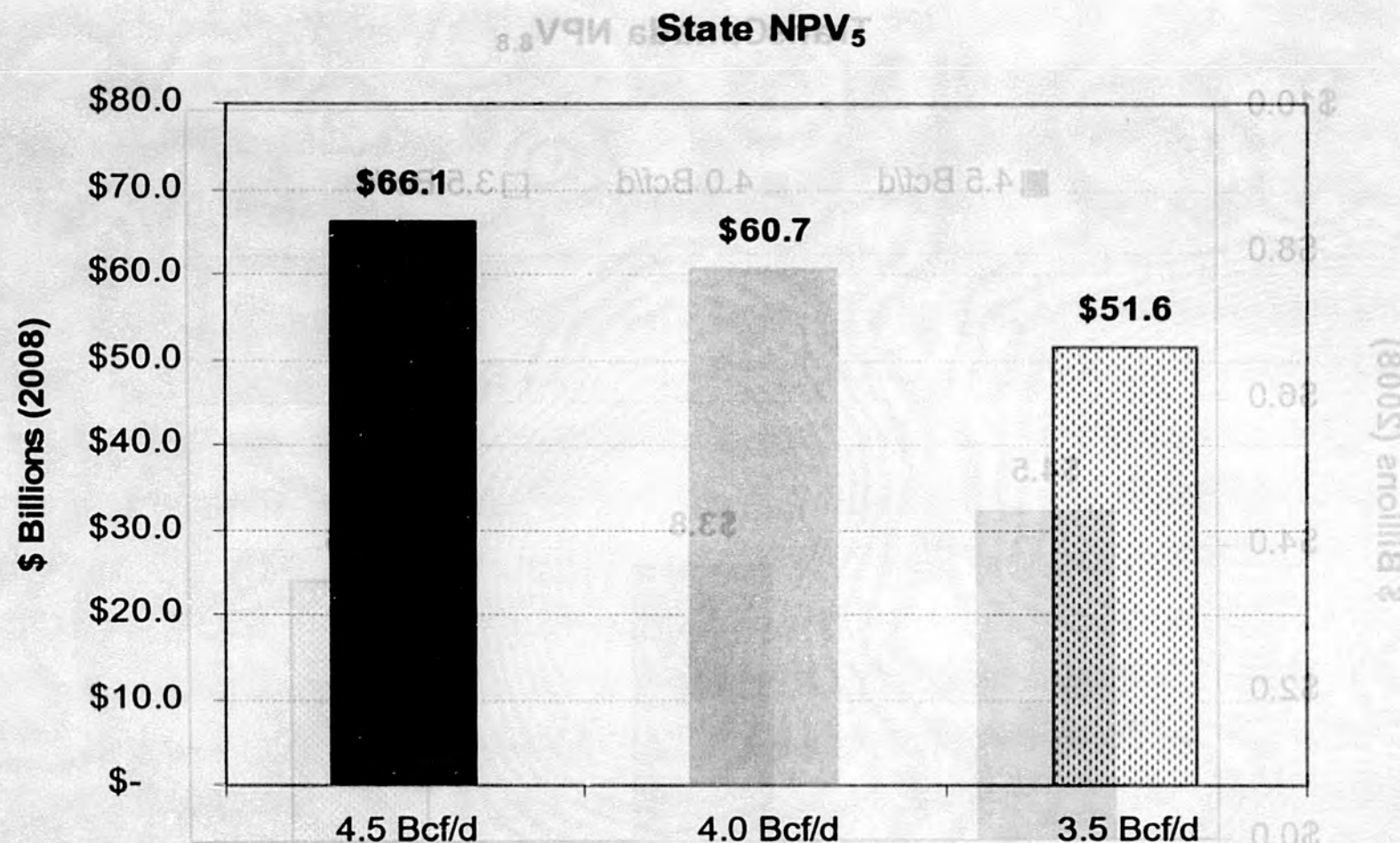
TransCanada NPV_{8.8} is Significant under Proposed Terms and Base Case Assumptions

TransCanada NPV_{8.8}



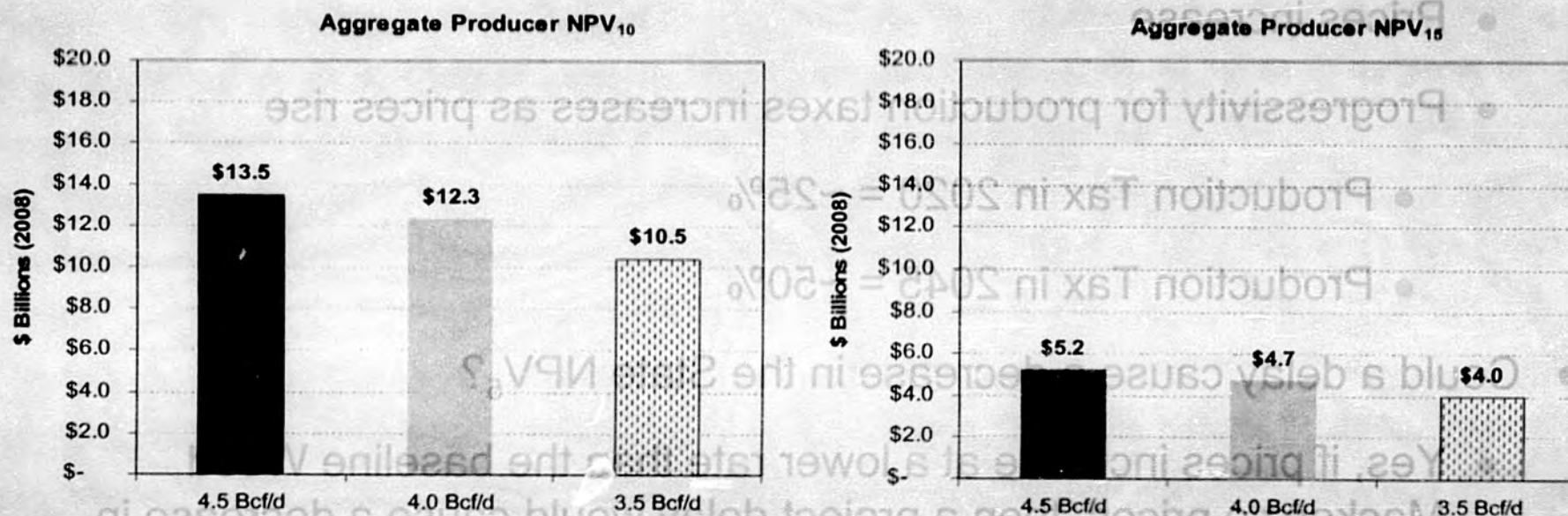


The State's NPV₅ Project is Lower with Lower Project Capacity but Remains Significant





Producer NPV Shows a Similar Trend When Compared to the State and TransCanada





Why does a delay increase State NPV₅?

- Why does a delay increase State NPV₅?

- Prices increase

- Progressivity for production taxes increases as prices rise

- Production Tax in 2020 = ~25%

- Production Tax in 2045 = ~50%

- Could a delay cause a decrease in the State NPV₅?

- Yes, if prices increase at a lower rate than the baseline Wood Mackenzie prices, then a project delay would cause a decrease in the State NPV₅

Alaska Gasline Inducement Act Legislative License Hearings

Juneau, Alaska

June 6-10, 2008

Analysis of Project Costs/Schedule and Tariffs

AGIA Analysis Technical Team

Bill Sparger
Energy Project Consultants, LLC

Eric Briel
Westney Consulting Group, Inc.

Cost and Schedule Analysis

- General analysis methodology
- Base case specific analysis methodology
- Base case cost/schedule results
- Expansion cases specific analysis methodology
- Expansion cases cost/schedule results

Why Cost/Schedule Ranges?

- Cost escalation is applied later in the NPV
- Single point estimates for large complex projects may not be the most useful to evaluate future project outcomes
- Understanding and applying the ranges in which the costs and schedule durations are likely to fall will result in a more representative analysis of the economic expectations for a project

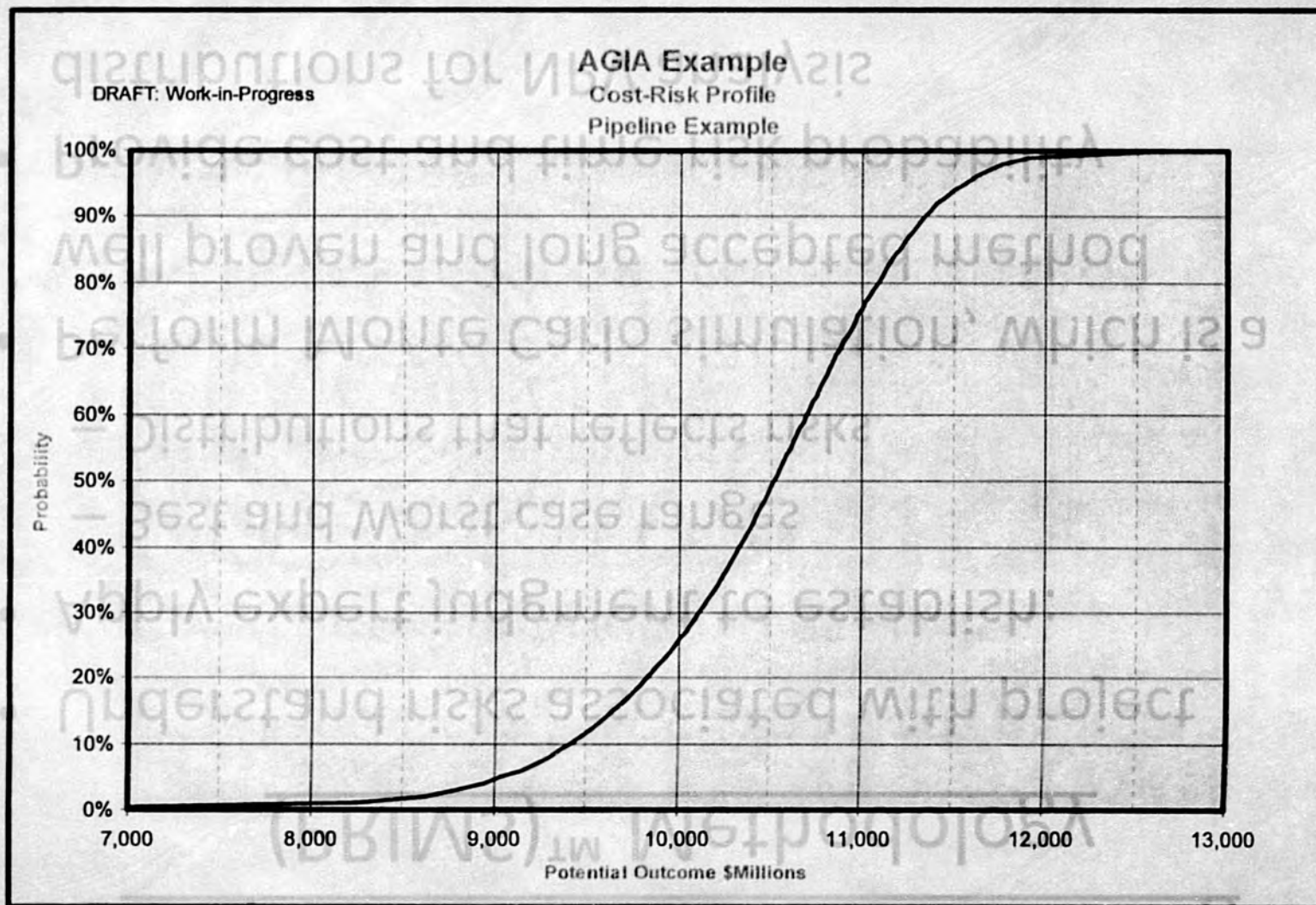
General Analysis Approach

General Analysis Approach

- Analyze cost and schedule on a sub-project level
- Based on 2007 dollars (removes uncertain cost escalation risk from the base analysis and)
- Cost escalation is applied later in the NPV analysis as a sensitivity

Project Risk Indicative Modeling (PRIMS)TM Methodology

- Understand risks associated with project
- Apply expert judgment to establish:
 - Best and Worst case ranges
 - Distributions that reflects risks
- Perform Monte Carlo simulation, which is a well proven and long accepted method
- Provide cost and time-risk probability distributions for NPV analysis



4.5 bcf/d Base Case - Technical Team Input

Cost

- Development
- GTP
- Alaska Pipeline
- Canadian Pipeline
- Integrated Project
- Miscellaneous

Schedule

- Subprojects
- Integrated Project

Spend Curves (cash flow)

Costs/Schedule Analysis

Costs

- Started with review of TransCanada cost breakdown by subproject
- Prepared independent cost estimates using same subproject breakdown
- Established best/worse case ranges
- Established other Miscellaneous Costs

Costs/Schedule Analysis

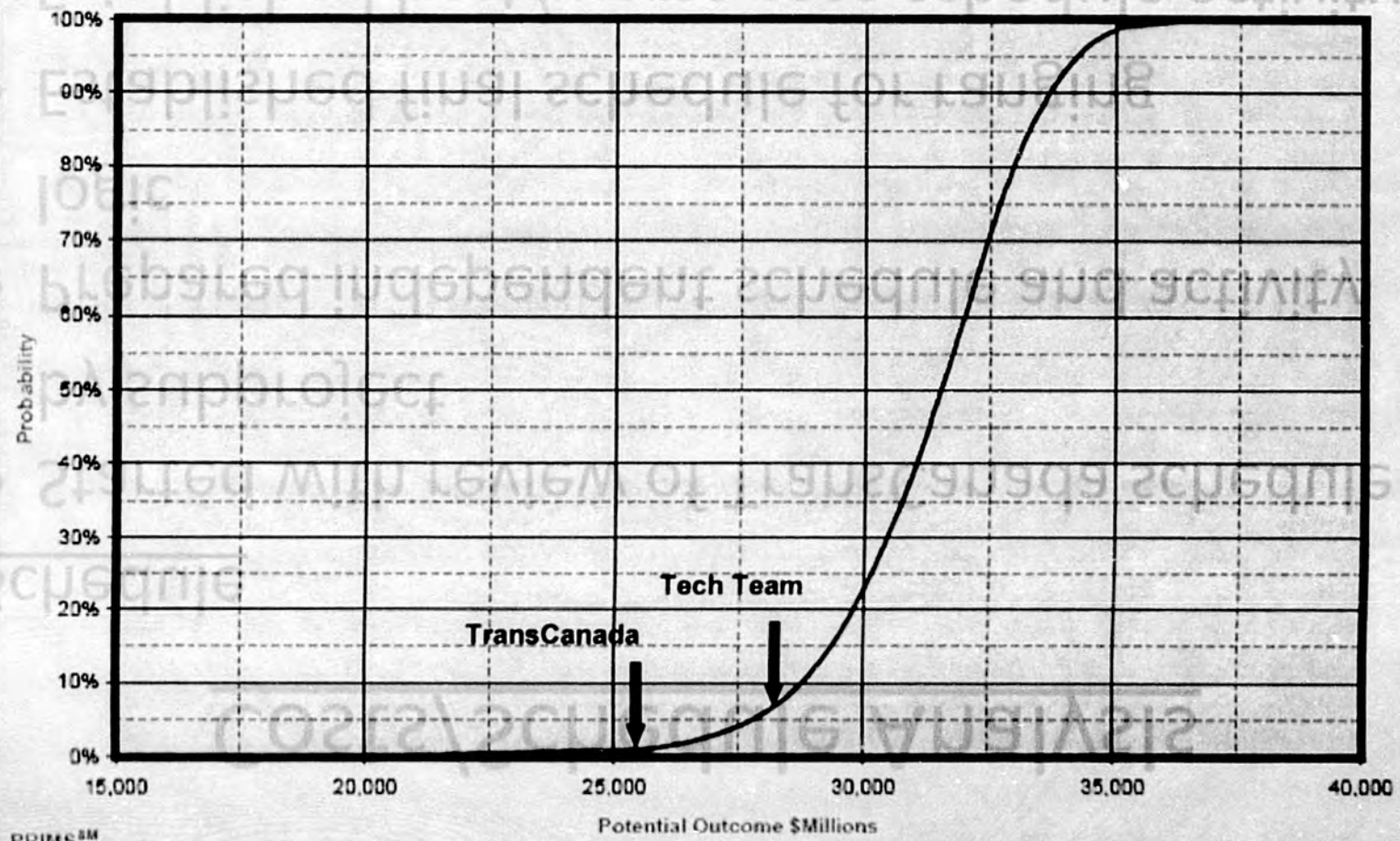
Schedule

- Started with review of TransCanada schedule by subproject
- Prepared independent schedule and activity logic
- Established final schedule for ranging
- Established best/worse case schedule activity durations

AGIA TransCanada Application - Base Case

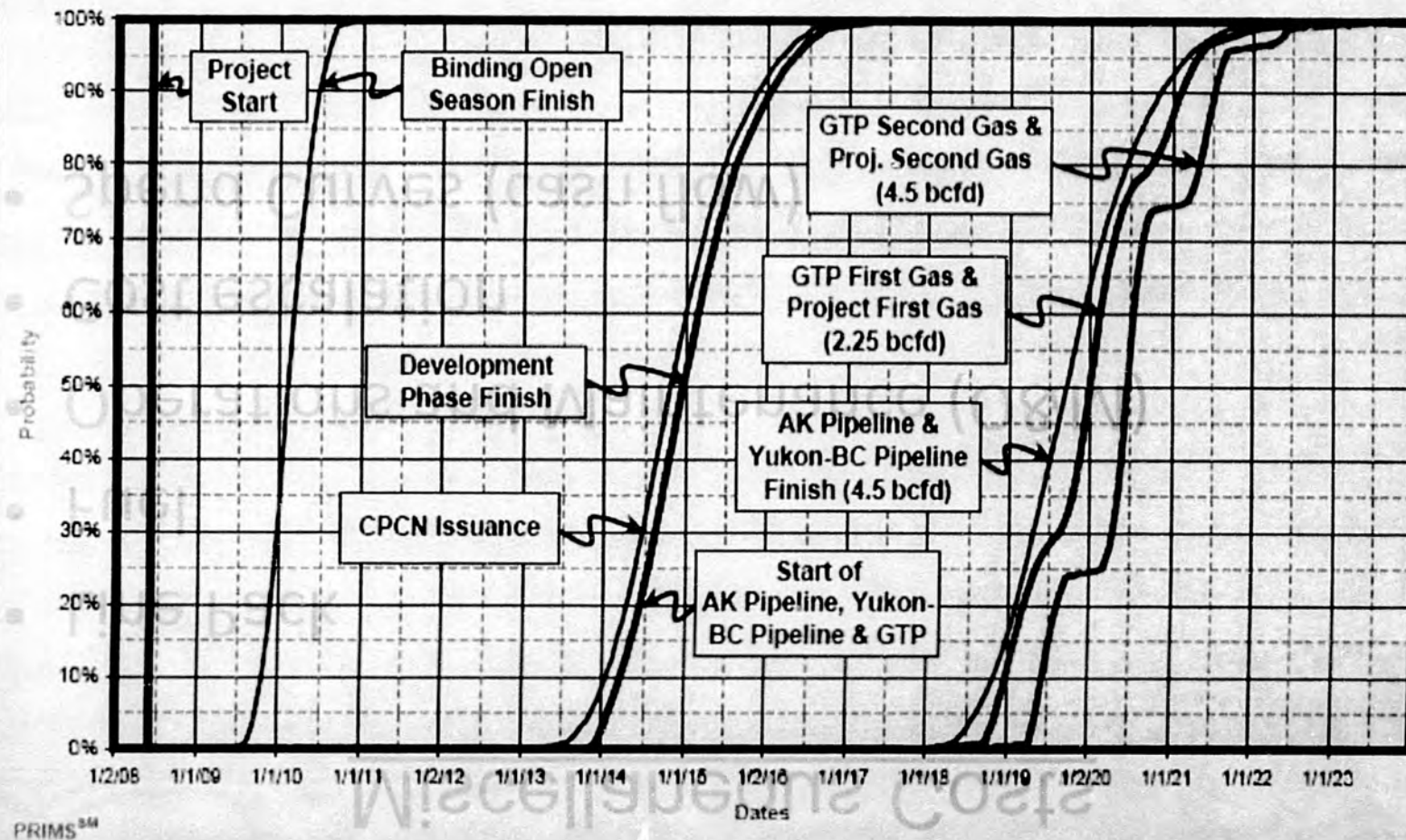
Cost-Risk Profile for Base Case: 4.50 bcfd

Integrated Project



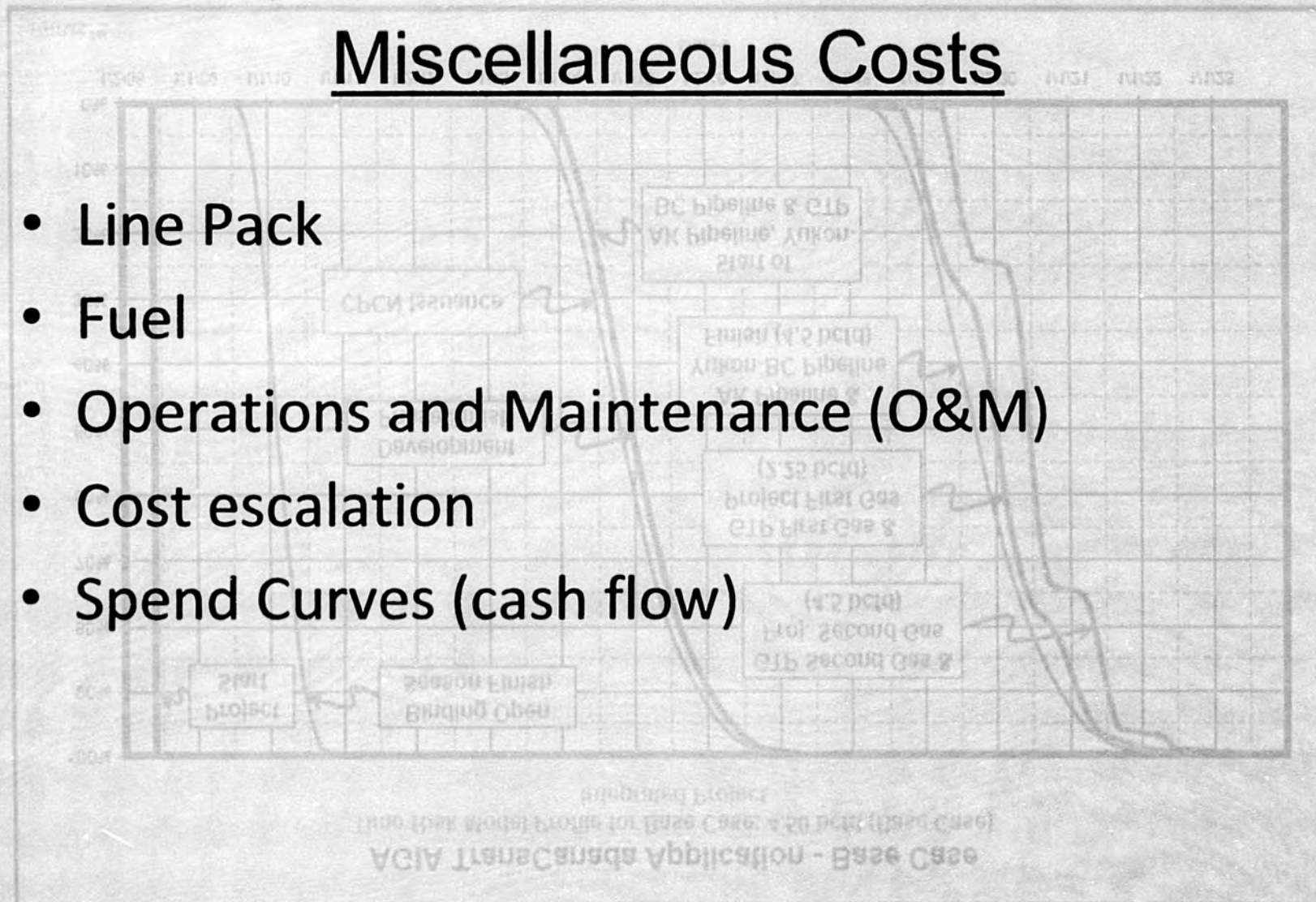
AGIA TransCanada Application - Base Case

Time-Risk Model Profile for Base Case: 4.50 bcfd (Base Case)
Integrated Project



Miscellaneous Costs

- Line Pack
- Fuel
- Operations and Maintenance (O&M)
- Cost escalation
- Spend Curves (cash flow)

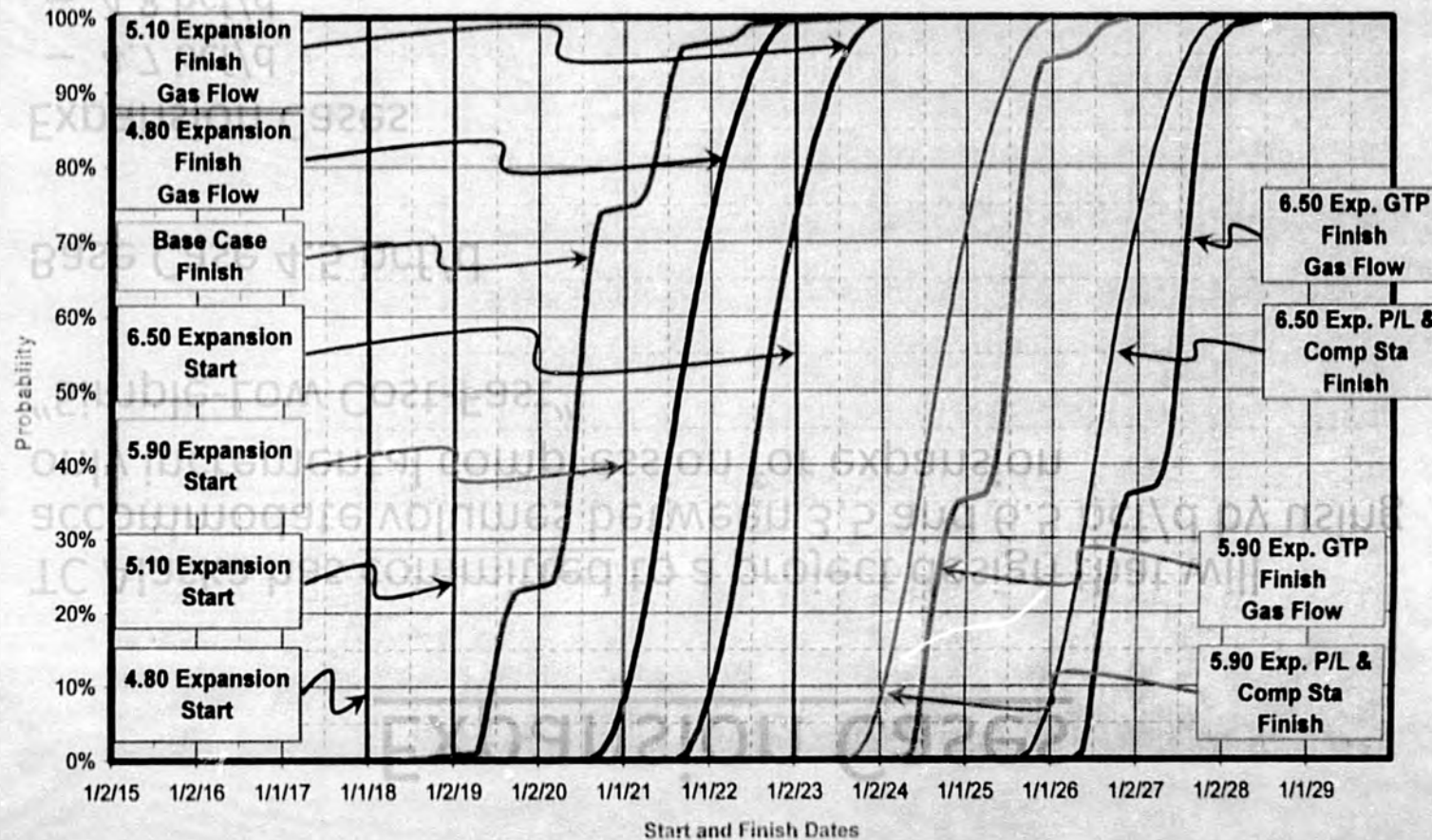


Expansion Cases

- TC Alaska has committed to a project design that will accommodate volumes between 3.5 and 6.5 bcf/d by using only incremental compression for expansion
“Simple-Low Cost-Fast”
- Base Case 4.5 bcf/d
- Expansion Cases
 - 4.7 bcf/d
 - 4.8 bcf/d
 - 5.1 bcf/d
 - 5.9 bcf/d
 - 6.5 bcf/d

AGIA TransCanada Application - Expansion Cases

Time-Risk Model Profile for Expansion
All Expansion Projects



Expansion The Bottom Line

- Simple
- Low Cost
- Fast