ALASKA LEGISLATURE COMMITTEE FILES 1987-2006

12264 HOUSE RES

Tax increases effects on NPV → Fiscal certainty 15 years

AGIA

The Alaska Gasline Inducement Act

Producer NPV_{10} in billions of dollars with increase in production tax rate at 16th year of project

		NPV_{10}			% change		
	0%	**15%**	**30%**	**50%**	**15%**	**30%**	**50%**
$3.50	3.8	3.8	3.7	3.7	-1.4%	-2.8%	-4.6%
$4.00	5.7	5.6	5.6	5.5	-1.2%	-2.4%	-4.1%
$4.50	7.6	7.5	7.4	7.3	-1.1%	-2.3%	-3.8%
$5.00	9.4	9.3	9.2	9.1	-1.1%	-2.2%	-3.7%
$5.50	11.3	11.2	11.1	10.9	-1.1%	-2.1%	-3.5%
$6.00	13.1	13.0	12.9	12.7	-1.0%	-2.1%	-3.5%
$6.50	14.9	14.8	14.6	14.4	-1.0%	-2.0%	-3.4%
$7.00	16.7	16.5	16.3	16.1	-1.0%	-2.0%	-3.4%
$7.50	18.3	18.1	18.0	17.7	-1.0%	-2.0%	-3.4%
$8.00	19.9	19.7	19.5	19.2	-1.0%	-2.0%	-3.4%
$8.50	21.4	21.2	21.0	20.7	-1.0%	-2.0%	-3.4%

Note: Oil effects excluded

Tax increases effects on IRR → No fiscal certainty

AGIA
The Alaska Gasline Inducement Act

Producer IRR with increase in production tax rate at start of project

		IRR			difference		
	0%	15%	30%	50%	15%	30%	50%
$3.50	29.1%	28.1%	26.9%	25.4%	-1.1%	-2.2%	-3.7%
$4.00	37.6%	36.3%	34.9%	33.0%	-1.3%	-2.7%	-4.6%
$4.50	45.2%	43.6%	42.1%	39.8%	-1.5%	-3.1%	-5.3%
$5.00	51.9%	50.2%	48.5%	46.1%	-1.7%	-3.4%	-5.8%
$5.50	57.9%	56.1%	54.3%	51.7%	-1.8%	-3.7%	-6.3%
$6.00	63.4%	61.5%	59.5%	56.8%	-1.9%	-3.9%	-6.6%
$6.50	68.4%	66.4%	64.4%	61.5%	-2.0%	-4.0%	-6.9%
$7.00	73.0%	70.9%	68.8%	65.8%	-2.0%	-4.2%	-7.1%
$7.50	77.3%	75.2%	73.0%	69.9%	-2.1%	-4.3%	-7.4%
$8.00	81.1%	79.0%	76.7%	73.6%	-2.2%	-4.4%	-7.6%
$8.50	84.5%	82.3%	80.0%	76.7%	-2.2%	-4.5%	-7.8%

Note: Oil effects excluded

Tax increases effects on IRR
→ Fiscal certainty 10 years

AGIA
The Alaska Gasline Inducement Act

Producer IRR with increase in production tax rate at 11th year of project

		IRR			difference		
	0%	**15%**	**30%**	**50%**	**15%**	**30%**	**50%**
$3.50	29.1%	29.0%	28.8%	28.6%	-0.2%	-0.3%	-0.5%
$4.00	37.6%	37.5%	37.4%	37.3%	-0.1%	-0.2%	-0.3%
$4.50	45.2%	45.1%	45.0%	45.0%	-0.1%	-0.1%	-0.2%
$5.00	51.9%	51.9%	51.8%	51.7%	0.0%	-0.1%	-0.2%
$5.50	57.9%	57.9%	57.9%	57.8%	0.0%	-0.1%	-0.1%
$6.00	63.4%	63.4%	63.3%	63.3%	0.0%	0.0%	-0.1%
$6.50	68.4%	68.4%	68.3%	68.3%	0.0%	0.0%	-0.1%
$7.00	73.0%	72.9%	72.9%	72.9%	0.0%	0.0%	0.0%
$7.50	77.3%	77.3%	77.2%	77.2%	0.0%	0.0%	0.0%
$8.00	81.1%	81.1%	81.1%	81.1%	0.0%	0.0%	0.0%
$8.50	84.5%	84.5%	84.5%	84.5%	0.0%	0.0%	0.0%

Note: Oil effects excluded

Tax increases effects on IRR → Fiscal certainty 5 years

AGIA
The Alaska Gasline Inducement Act

Producer IRR with increase in production tax rate at 6th year of project

	IRR				difference		
	0%	15%	30%	50%	15%	30%	50%
$3.50	29.1%	28.7%	28.2%	27.5%	-0.5%	-0.9%	-1.6%
$4.00	37.6%	37.2%	36.8%	36.2%	-0.4%	-0.8%	-1.4%
$4.50	45.2%	44.8%	44.5%	44.0%	-0.4%	-0.7%	-1.2%
$5.00	51.9%	51.6%	51.3%	50.9%	-0.3%	-0.6%	-1.0%
$5.50	57.9%	57.7%	57.4%	57.0%	-0.3%	-0.5%	-0.9%
$6.00	63.4%	63.2%	62.9%	62.6%	-0.2%	-0.5%	-0.8%
$6.50	68.4%	68.2%	68.0%	67.7%	-0.2%	-0.4%	-0.7%
$7.00	73.0%	72.8%	72.6%	72.3%	-0.2%	-0.4%	-0.6%
$7.50	77.3%	77.1%	76.9%	76.7%	-0.2%	-0.3%	-0.6%
$8.00	81.1%	81.0%	80.8%	80.6%	-0.2%	-0.3%	-0.5%
$8.50	84.5%	84.4%	84.2%	84.0%	-0.1%	-0.3%	-0.5%

Note: Oil effects excluded

Tax increases effects on IRR
→ Fiscal certainty 15 years

AGIA
The Alaska Gasline Inducement Act

Producer IRR with increase in production tax rate at 16th year of project

		IRR			% change		
	0%	**15%**	**30%**	**50%**	**15%**	**30%**	**50%**
$3.50	29.1%	29.1%	29.1%	29.0%	0.0%	-0.1%	-0.1%
$4.00	37.6%	37.6%	37.6%	37.6%	0.0%	0.0%	-0.1%
$4.50	45.2%	45.2%	45.2%	45.1%	0.0%	0.0%	0.0%
$5.00	51.9%	51.9%	51.9%	51.9%	0.0%	0.0%	0.0%
$5.50	57.9%	57.9%	57.9%	57.9%	0.0%	0.0%	0.0%
$6.00	63.4%	63.4%	63.4%	63.4%	0.0%	0.0%	0.0%
$6.50	68.4%	68.4%	68.4%	68.4%	0.0%	0.0%	0.0%
$7.00	73.0%	73.0%	73.0%	73.0%	0.0%	0.0%	0.0%
$7.50	77.3%	77.3%	77.3%	77.3%	0.0%	0.0%	0.0%
$8.00	81.1%	81.1%	81.1%	81.1%	0.0%	0.0%	0.0%
$8.50	84.5%	84.5%	84.5%	84.5%	0.0%	0.0%	0.0%

Note: Oil effects excluded

Tax increases effects on P/I
→ No fiscal certainty

AGIA
The Alaska Gasline Inducement Act

Producer PI with increase in production tax rate at start of project

		PI			difference		
	0%	**15%**	**30%**	**50%**	**15%**	**30%**	**50%**
$3.50	3.7	3.6	3.4	3.2	-0.2	-0.4	-0.6
$4.00	5.1	4.8	4.6	4.3	-0.2	-0.5	-0.8
$4.50	6.4	6.1	5.8	5.4	-0.3	-0.6	-1.0
$5.00	7.7	7.4	7.0	6.5	-0.4	-0.7	-1.2
$5.50	9.1	8.6	8.2	7.7	-0.4	-0.8	-1.4
$6.00	10.4	9.9	9.4	8.8	-0.5	-1.0	-1.6
$6.50	11.7	11.1	10.6	9.8	-0.5	-1.1	-1.8
$7.00	12.9	12.3	11.7	10.9	-0.6	-1.2	-2.0
$7.50	14.1	13.4	12.7	11.8	-0.7	-1.3	-2.2
$8.00	15.2	14.5	13.7	12.8	-0.7	-1.5	-2.4
$8.50	16.3	15.5	14.7	13.6	-0.8	-1.6	-2.6

Note: Oil effects excluded

Tax increases effects on P/I
→ Fiscal certainty 10 years

AGIA
The Alaska Gasline Inducement Act

Producer PI with increase in production tax rate at 11th year of project

		PI			difference		
	0%	**15%**	**30%**	**50%**	**15%**	**30%**	**50%**
$3.50	3.7	3.7	3.6	3.5	-0.1	-0.2	-0.3
$4.00	5.1	5.0	4.9	4.7	-0.1	-0.2	-0.3
$4.50	6.4	6.3	6.1	6.0	-0.1	-0.3	-0.4
$5.00	7.7	7.6	7.4	7.2	-0.1	-0.3	-0.5
$5.50	9.1	8.9	8.7	8.5	-0.2	-0.3	-0.6
$6.00	10.4	10.2	10.0	9.7	-0.2	-0.4	-0.7
$6.50	11.7	11.4	11.2	10.9	-0.2	-0.4	-0.7
$7.00	12.9	12.6	12.4	12.1	-0.2	-0.5	-0.8
$7.50	14.1	13.8	13.6	13.2	-0.3	-0.5	-0.9
$8.00	15.2	14.9	14.6	14.2	-0.3	-0.6	-1.0
$8.50	16.3	15.9	15.6	15.2	-0.3	-0.6	-1.0

Note: Oil effects excluded

Tax increases effects on P/I
→ Fiscal certainty 5 years

AGIA
The Alaska Gasline Inducement Act

Producer PI with increase in production tax rate at 6th year of project

		PI			difference		
	0%	15%	30%	50%	15%	30%	50%
$3.50	3.7	3.6	3.5	3.3	-0.1	-0.3	-0.4
$4.00	5.1	4.9	4.7	4.5	-0.2	-0.3	-0.6
$4.50	6.4	6.2	6.0	5.7	-0.2	-0.4	-0.7
$5.00	7.7	7.5	7.2	6.9	-0.2	-0.5	-0.8
$5.50	9.1	8.8	8.5	8.1	-0.3	-0.6	-1.0
$6.00	10.4	10.0	9.7	9.3	-0.3	-0.7	-1.1
$6.50	11.7	11.3	10.9	10.4	-0.4	-0.7	-1.2
$7.00	12.9	12.5	12.1	11.5	-0.4	-0.8	-1.3
$7.50	14.1	13.6	13.2	12.6	-0.4	-0.9	-1.5
$8.00	15.2	14.7	14.2	13.6	-0.5	-1.0	-1.6
$8.50	16.3	15.7	15.2	14.5	-0.5	-1.0	-1.7

Note: Oil effects excluded

Tax increases effects on P/I
→ Fiscal certainty 15 years

AGIA

The Alaska Gasline Inducement Act

Producer PI with increase in production tax rate at 16th year of project

		PI			difference		
	0%	15%	30%	50%	15%	30%	50%
$3.50	3.7	3.7	3.7	0.3	0.0	-0.1	-3.4
$4.00	5.1	5.0	5.0	0.4	0.0	-0.1	-4.7
$4.50	6.4	6.3	6.3	0.5	-0.1	-0.1	-6.0
$5.00	7.7	7.7	7.6	0.5	-0.1	-0.1	-7.2
$5.50	9.1	9.0	8.9	0.6	-0.1	-0.2	-8.5
$6.00	10.4	10.3	10.2	0.6	-0.1	-0.2	-9.7
$6.50	11.7	11.5	11.4	0.7	-0.1	-0.2	-11.0
$7.00	12.9	12.8	12.6	0.7	-0.1	-0.2	-12.2
$7.50	14.1	13.9	13.8	0.8	-0.1	-0.3	-13.3
$8.00	15.2	15.1	14.9	0.8	-0.1	-0.3	-14.4
$8.50	16.3	16.1	15.9	0.8	-0.2	-0.3	-15.4

Note: Oil effects excluded

Appendix
Project Assumptions

The Alaska Gasline Inducement Act

- Here we assume:
  - 4.3 Bcf/day to Alberta, no expansions
  - $20.5 billion base case cost ($2007)
  - 70/30 debt to equity, 14% ROE
  - Current PPT tax structure
  - Producers own GTP, no investment credit
  - Oil impacts of gas production included
  - 30 year project life
  - Gas flow 2016-2046
  - Oil price of $36.50 fixed real for project life
  - $ values increase at 2%/yr

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

Economics of AGIA's rolled-in rate provisions
Presentation to Senate Judiciary Committee
4/16/2007

Summary of economics of AGIA rolled-in rate provisions

AGIA
The Alaska Gasline Inducement Act

- AGIA rolled-in rates promote competition, exploration and development. Contrast: if the FERC's lower-48 policy were used it is unlikely that the last Bcf of in-fill compression will occur, and very unlikely that looping will occur.
- Rolled-in rates are in the state's interest given uncertainty of where expansion gas will come.
- The objective evidence indicates that rolled-in rates cost Producers only modestly, are mostly off-set by State's $500M contribution, and ***are unlikely to affect their investment decisions***.

Expansion Scenarios Physical characteristics

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- **Base Case**: 4.5 Bcf/day
- **1st Expansion**: 1 Bcf, infill compression
- **2nd Expansion**:1 Bcf, infill compression
- **3rd Expansion**: 1 Bcf, looping

Note: Volumes here reported at pipe inlet

Initial shippers' rates $3.50 gas (real)

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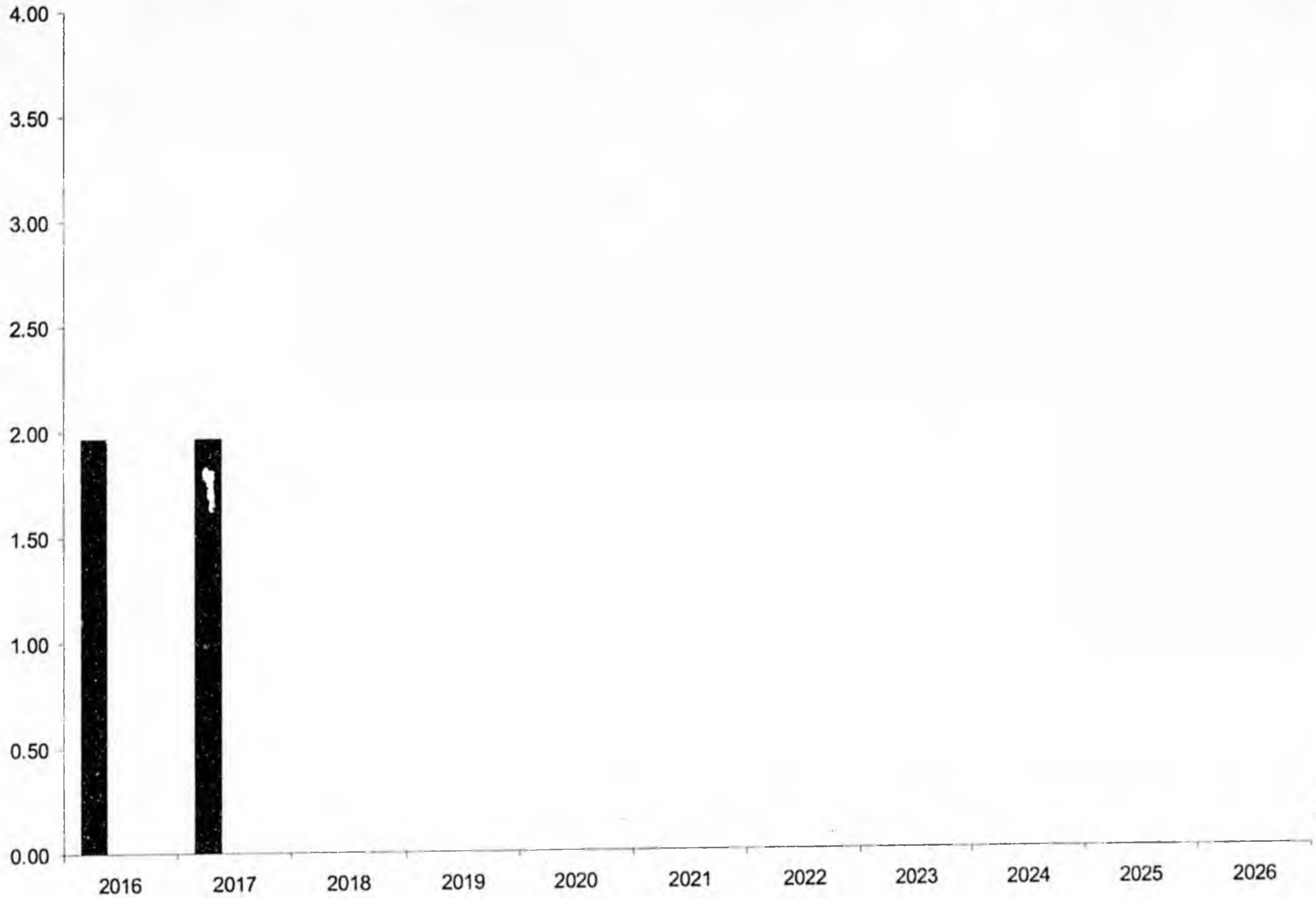

FERC L48 rate policy 1st Expansion

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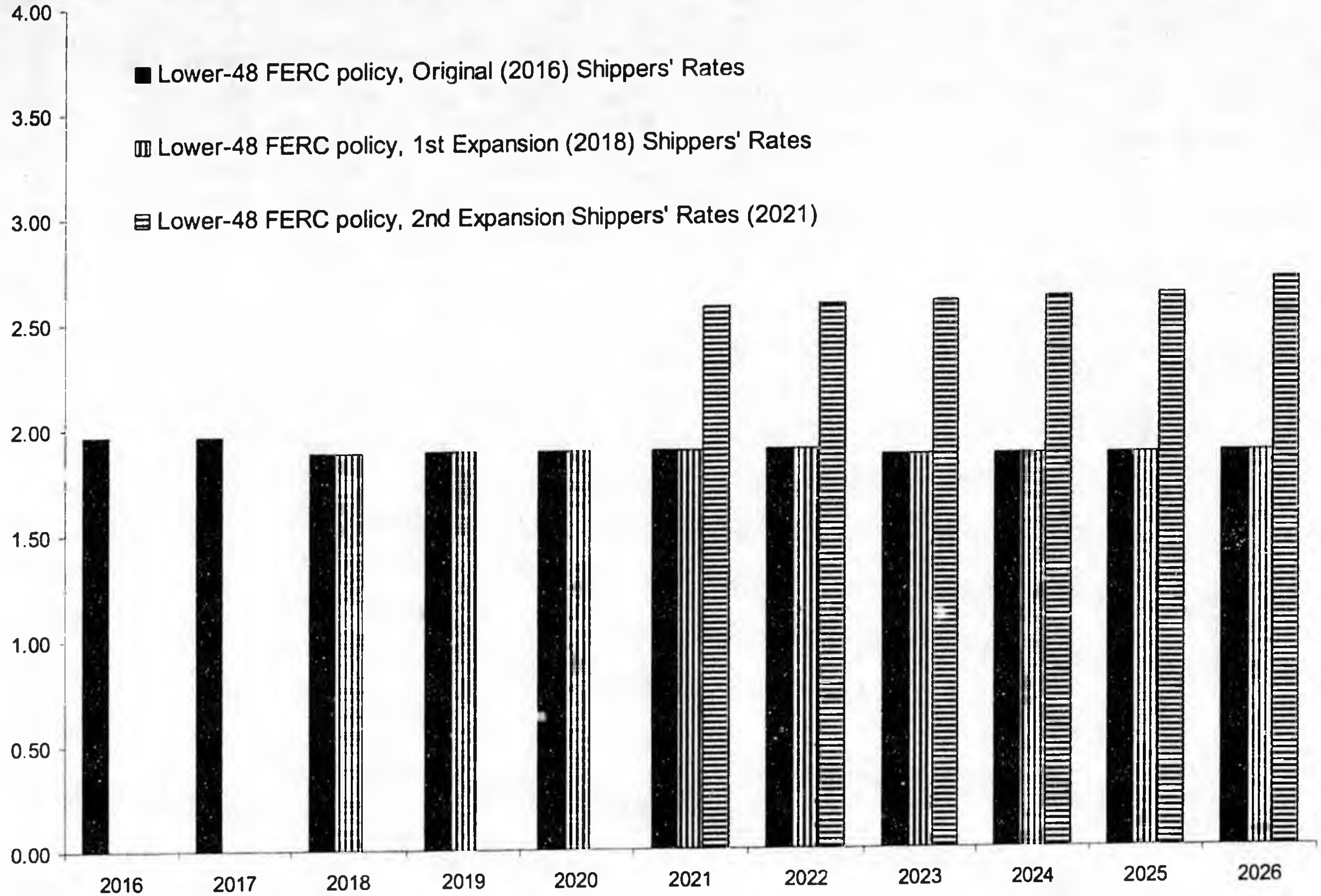

FERC L48 rate policy 2nd Expansion

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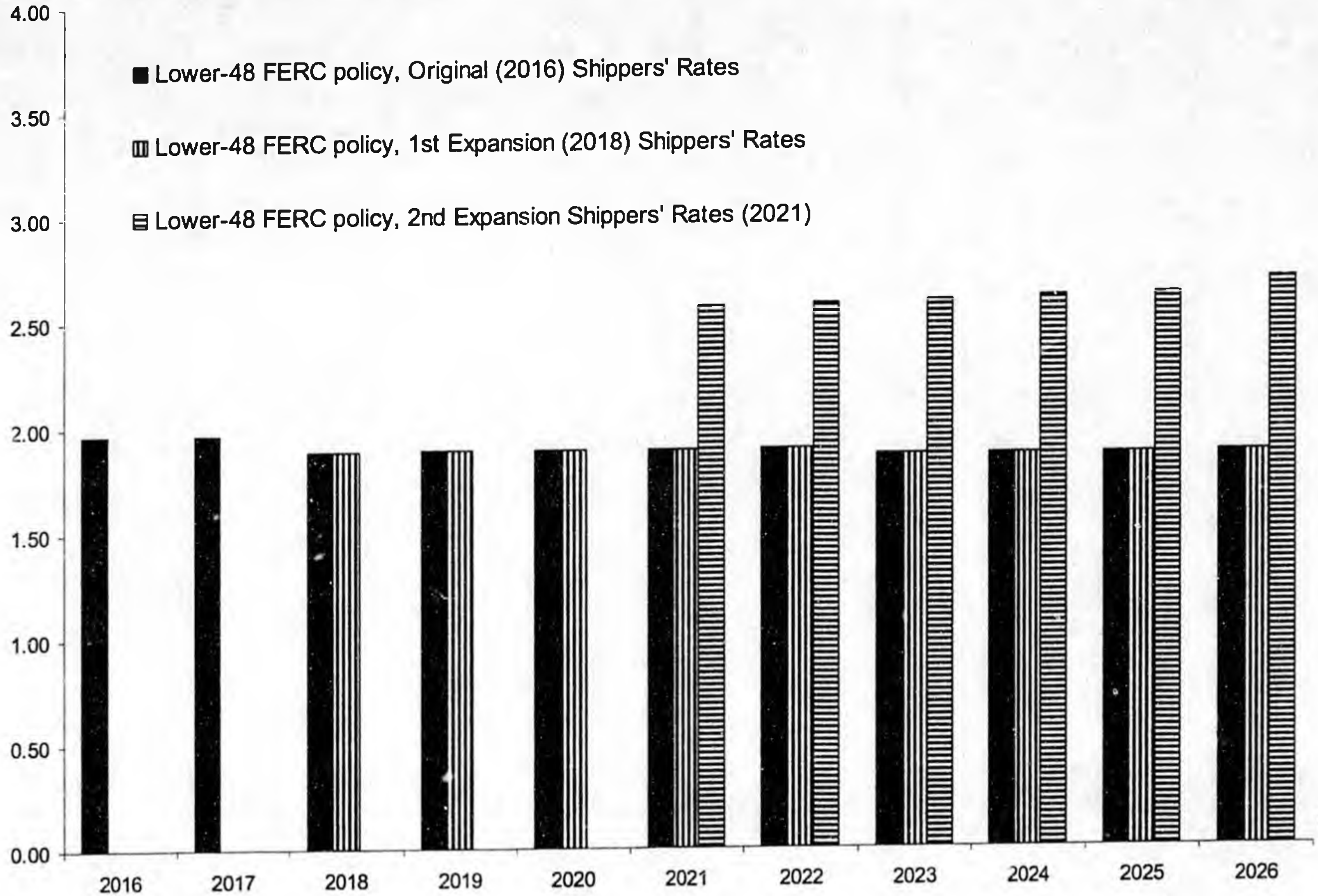
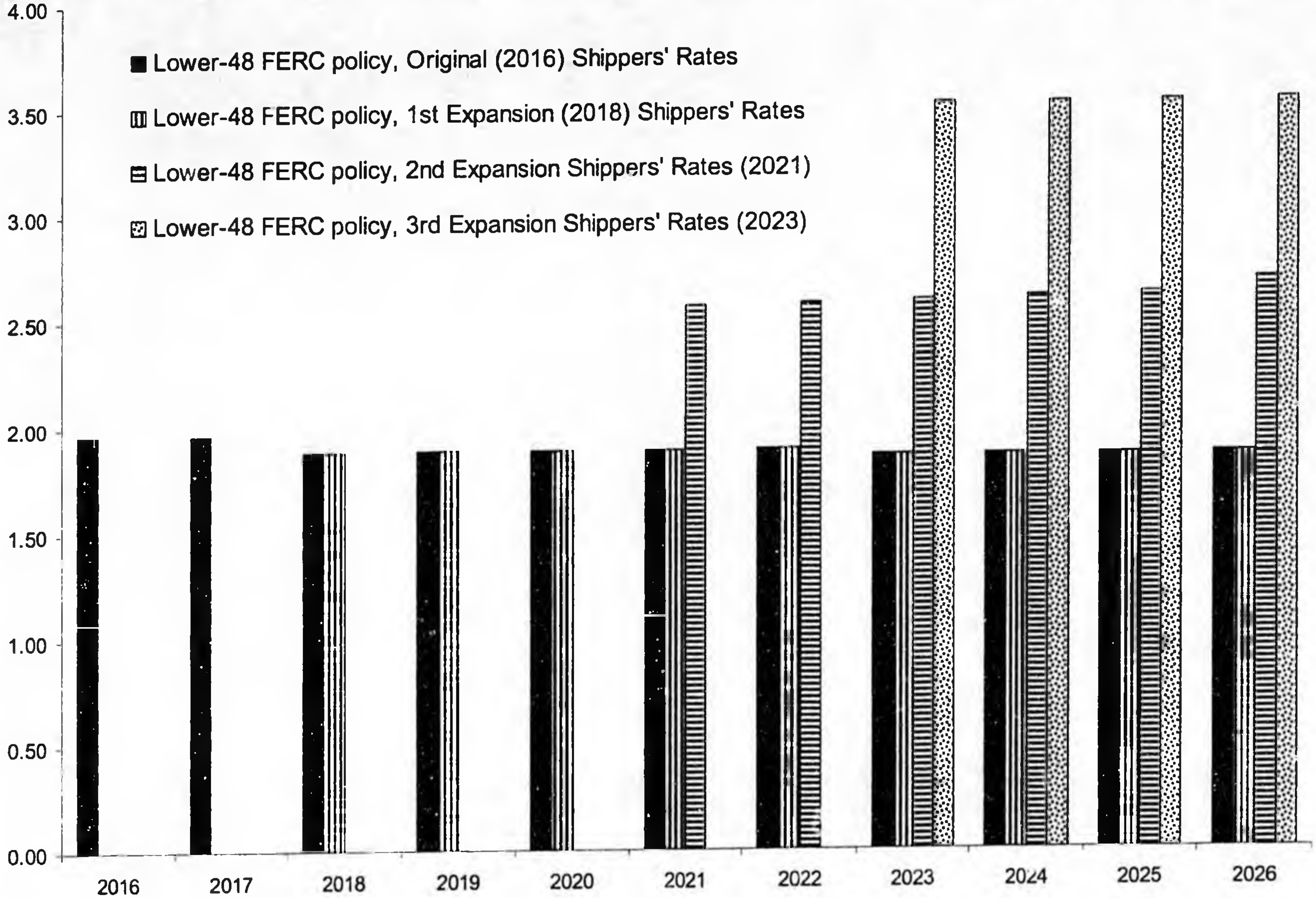


FERC L48 rate policy 3rd Expansion



AGIA rate policy

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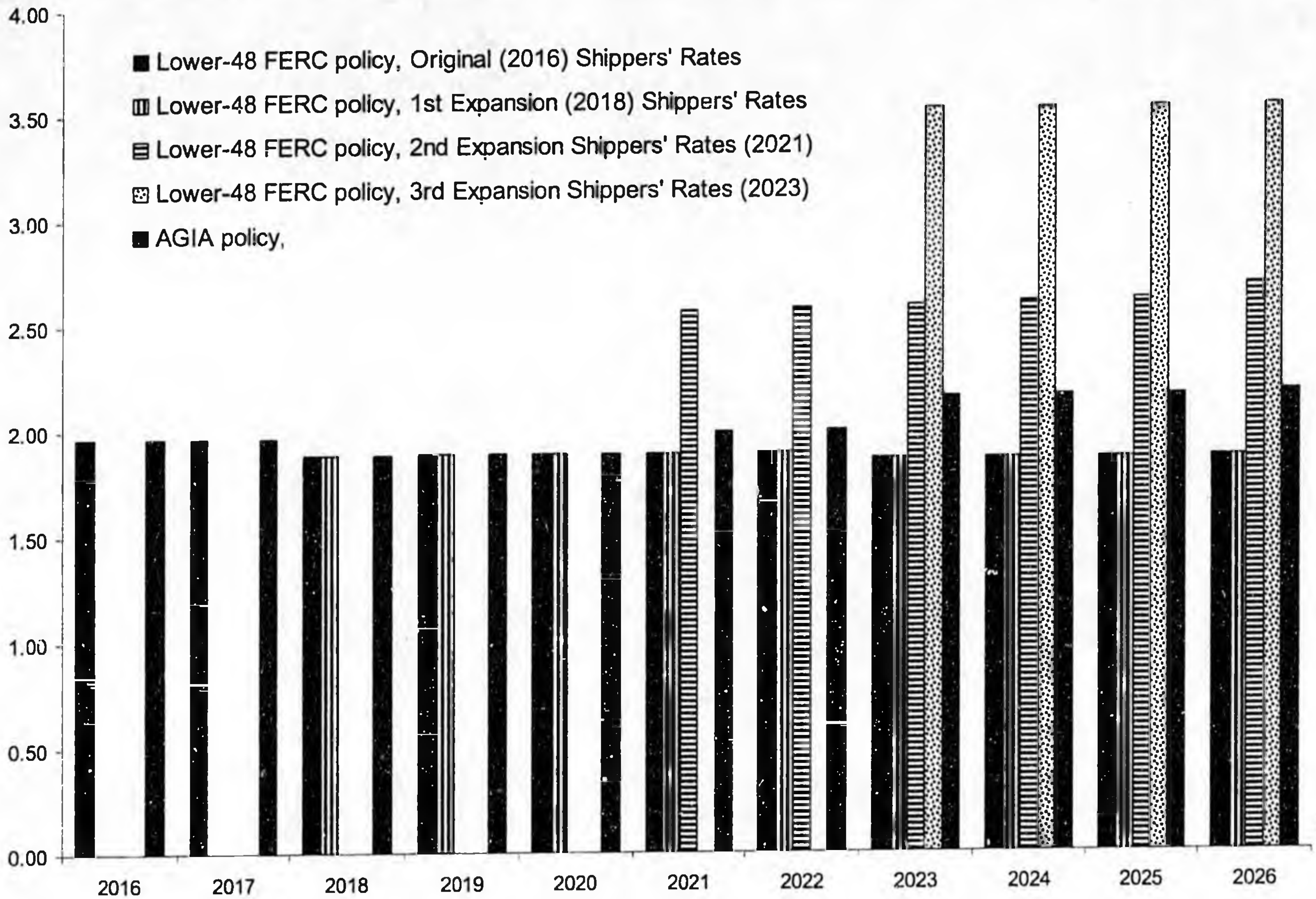
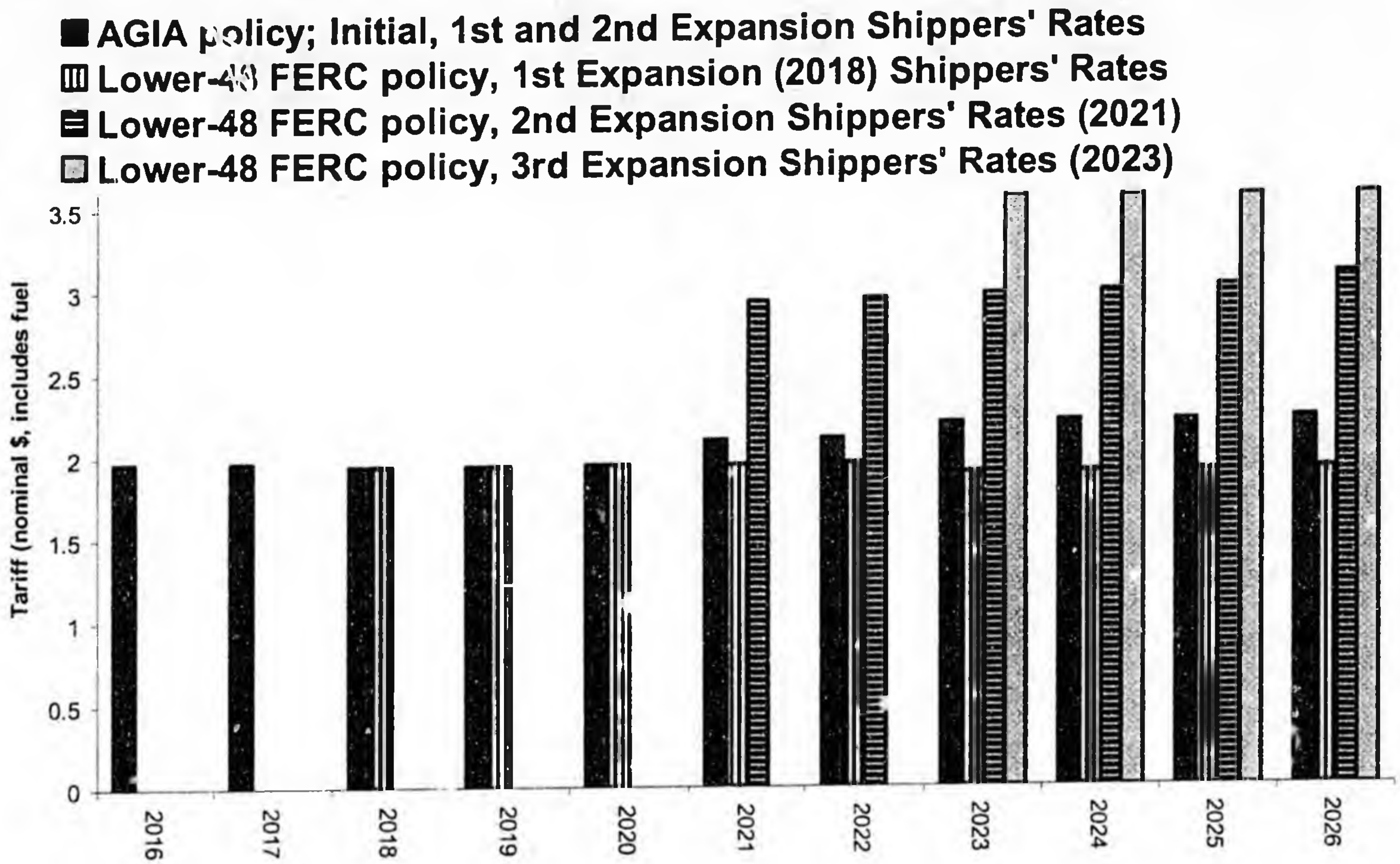


Tariff Effects of AGIA vs. FERC-L48 Rate Policy

AGIA

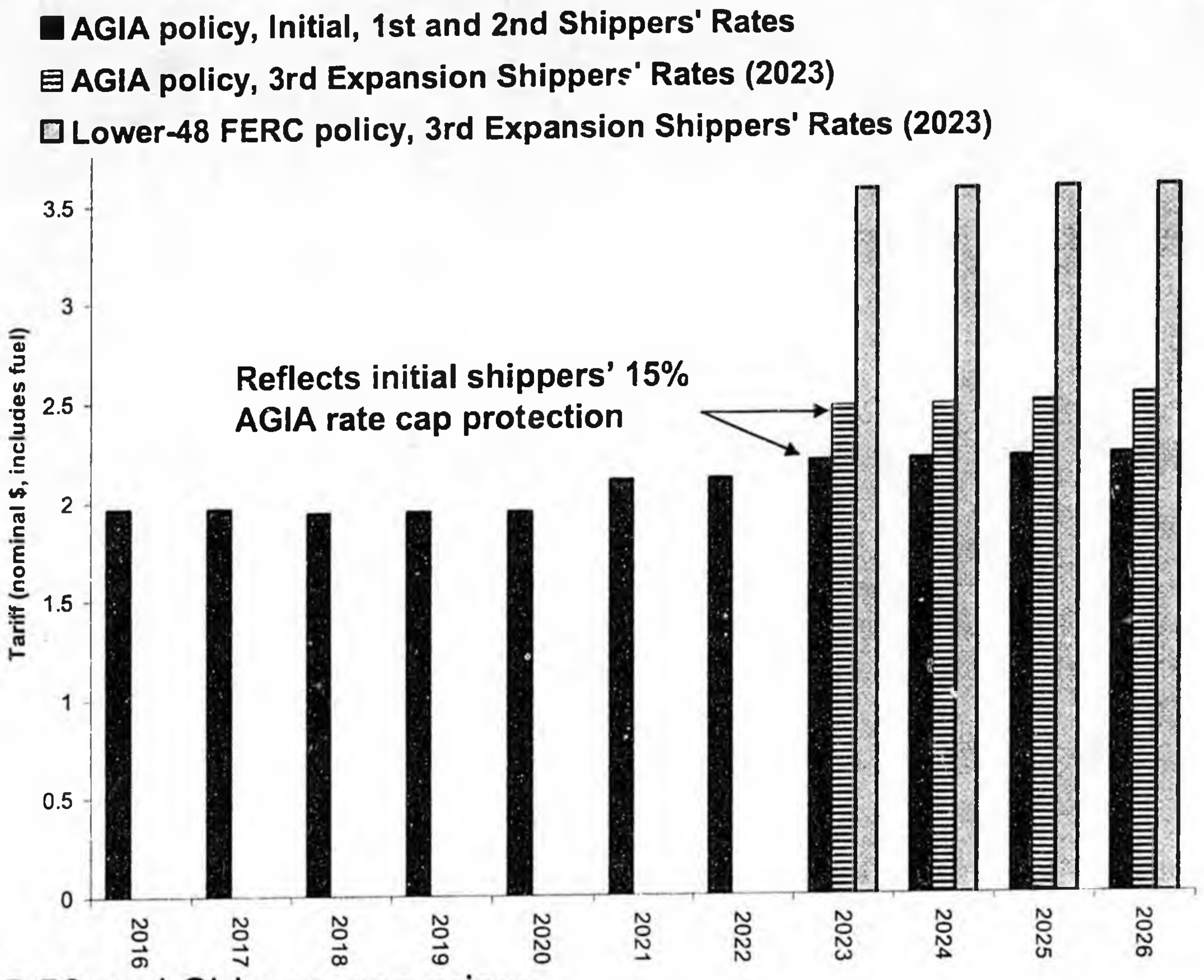
The Alaska Gasline Inducement Act



Assumes $5.50 real Chicago gas prices

Tariff Effects of AGIA vs. FERC-L48 Rate Policy (cont.)

AGIA
The Alaska Gasline Inducement Act



Assumes $5.50 real Chicago gas prices

State Revenue, AGIA Rates Background

AGIA

The Alaska Gasline Inducement Act

- We don't know from where gas for a given expansions will come – state lands (12.5% royalty + PPT), federal lands (1/2 fed. royalty + PPT), or the OCS (0% royalty, no PPT).
- Given such uncertainty the state is clearly better off with AGIA's rolled-in rate provisions.

<u>Case A: "State gas first"</u>

1^{st} bcf from state lands
2^{nd} bcf from NPR-A
3^{rd} bcf from OCS

<u>Case B: "State gas second"</u>

1^{st} bcf from NPR-A
2^{nd} bcf from state lands
3^{rd} bcf from OCS

<u>Case C: "State gas last"</u>

1^{st} bcf from OCS
2^{nd} bcf from NPR-A
3^{rd} bcf from state lands

State Revenue, AGIA Rates: All Expansions Occur

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The Alaska Gasline Inducement Act

- Without rolled-in rates it is **very *un*likely all** expansions would occur. But if they did:

[AGIA revenue] – [L48 FERC revenue] =

	State NPV_5 difference, \$2007 (billion)			
	Case A State gas first	Case B State gas 2nd	Case C State gas last	Expected Value
\$3.50	(0.91)	(0.79)	0.15	(0.52)
\$5.50	(0.75)	(0.58)	0.25	(0.36)
\$7.00	(0.71)	(0.52)	0.05	(0.39)

State Revenue, AGIA Rates: No Looping

AGIA
The Alaska Gasline Inducement Act

- Without rolled-in rates it is **very *likely*** the **last** expansion **won't occur**. If it doesn't:

[AGIA revenue] – [L48 FERC revenue] =

	State NPV_5 difference, $2007 (billion)			
	Case A State gas first	Case B State gas 2nd	Case C State gas last	Expected Value
$3.50	(1.13)	(1.05)	0.85	(0.44)
$5.50	(0.74)	(0.65)	3.30	0.64
$7.00	(0.56)	(0.46)	5.00	1.33

State Revenue, AGIA Rates: No Looping, No Full in-fill

AGIA
The Alaska Gasline Inducement Act

- Without rolled-in rates it is ***likely neither 2nd*** nor ***3rd*** expansion occur. If they don't:

[AGIA revenue] – [L48 FERC revenue] =

	State NPV_5 difference, $2007 (billion)			
	Case A State gas first	Case B State gas 2nd	Case C State gas last	Expected Value
$3.50	1.71	1.67	2.18	1.85
$5.50	5.63	5.57	6.28	5.83
$7.00	8.51	8.45	9.27	8.75

State Revenue, AGIA Rates: AGIA rates state's best bet

AGIA

The Alaska Gasline Inducement Act

- Even given the **bad** assumption of equal chance for each expansion path (e.g. odds of looping unaffected by rate treatment), AGIA maximizes expected state returns.

	Expected Value State NPV_5 difference, $2007 (billions)			
	All Three Exp.	1st Two Exp.	Only 1st Exp.	Avg of Cases
$3.50	(0.52)	(0.44)	1.85	0.30
$5.50	(0.36)	0.64	5.83	2.03
$7.00	(0.39)	1.33	8.75	3.23

Worst-Case Producer Effects of AGIA Rates

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- The following shows Producer upstream investment measures given the three expansions under the "worst case" of no producer gas in any of the expansions.

	NPV	IRR	P/I	NPV per BOE	% Δ NPV	Δ IRR	% Δ P/I
$3.50	3.8	29.5%	3.0	$0.46	-7.0%	-0.22%	-4.8%
$5.50	11.7	62.8%	7.3	$1.41	-3.3%	-0.10%	-2.9%
$7.00	17.4	79.0%	10.3	$2.10	-2.3%	-0.13%	-2.1%

Worst-Case Producer Effects of AGIA Rates - NPV

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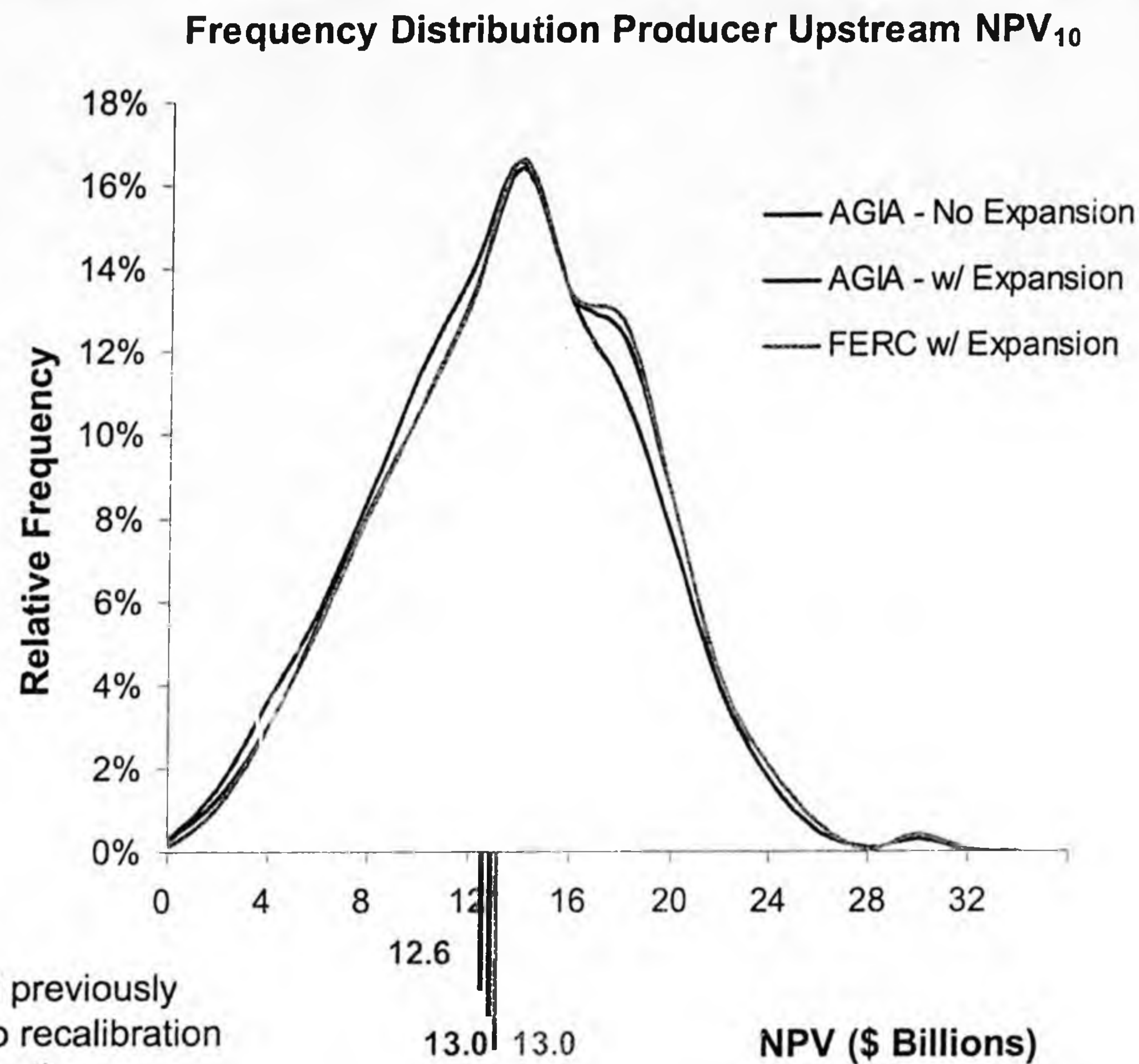
The Alaska Gasline Inducement Act



Note: Results differ from previously reported estimates due to recalibration of $2004 to $2006 price paths.

Worst-Case Producer Effects of AGIA Rates - IRR

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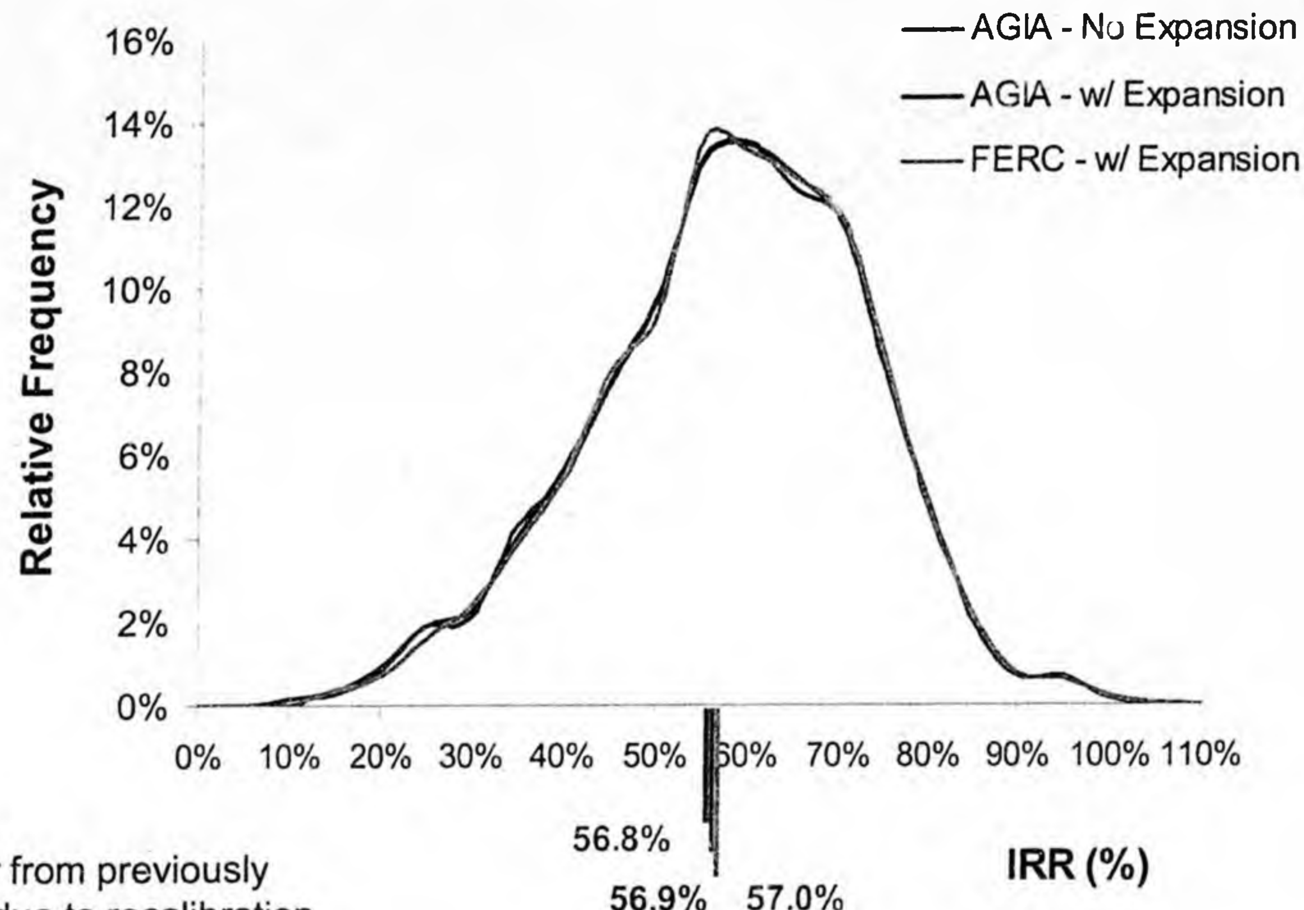
Frequency Distribution Producer Upstream IRR



Note: Results differ from previously reported estimates due to recalibration of $2004 to $2006 price paths.

Worst-Case Producer Effects of AGIA Rates – P/I

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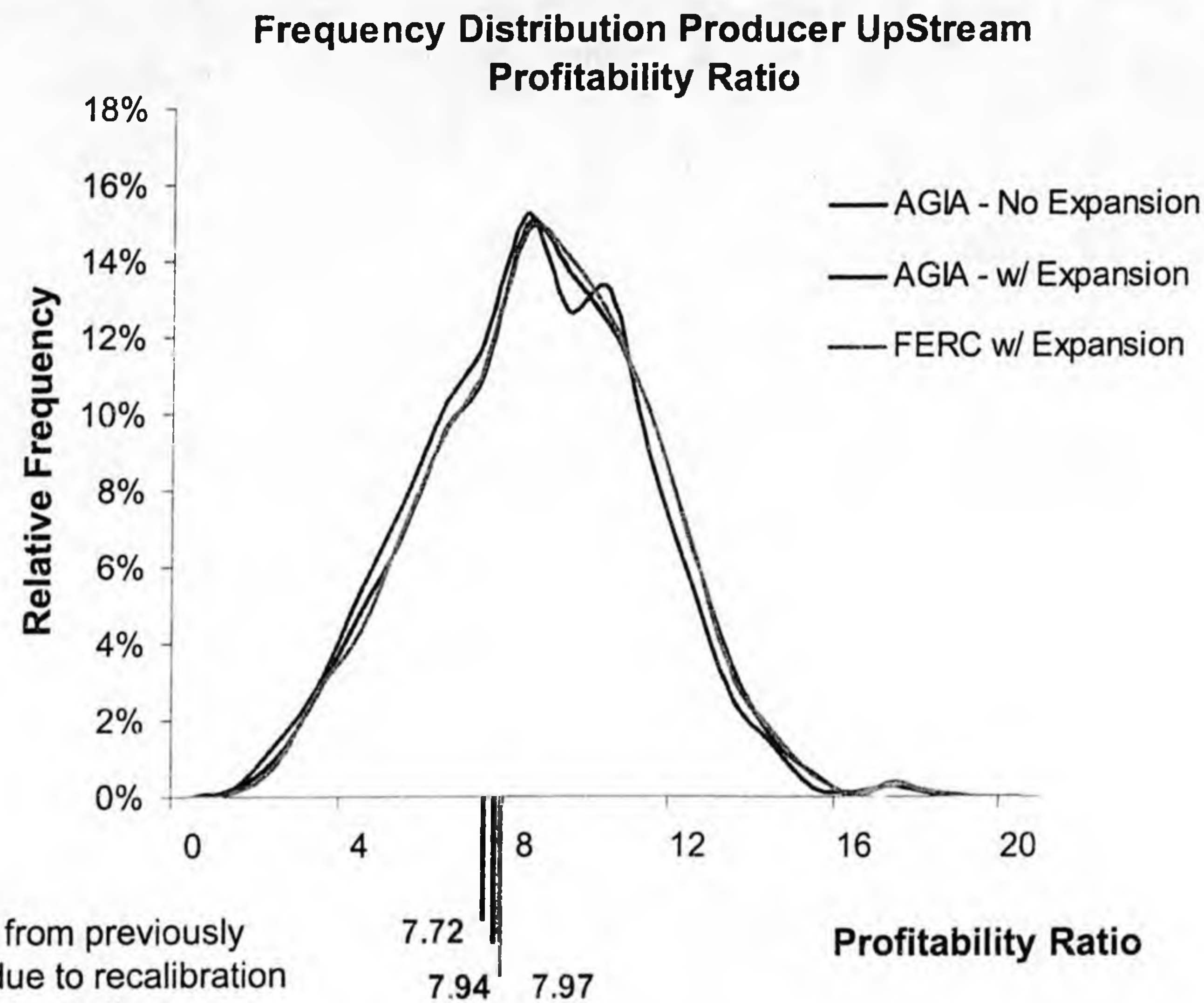
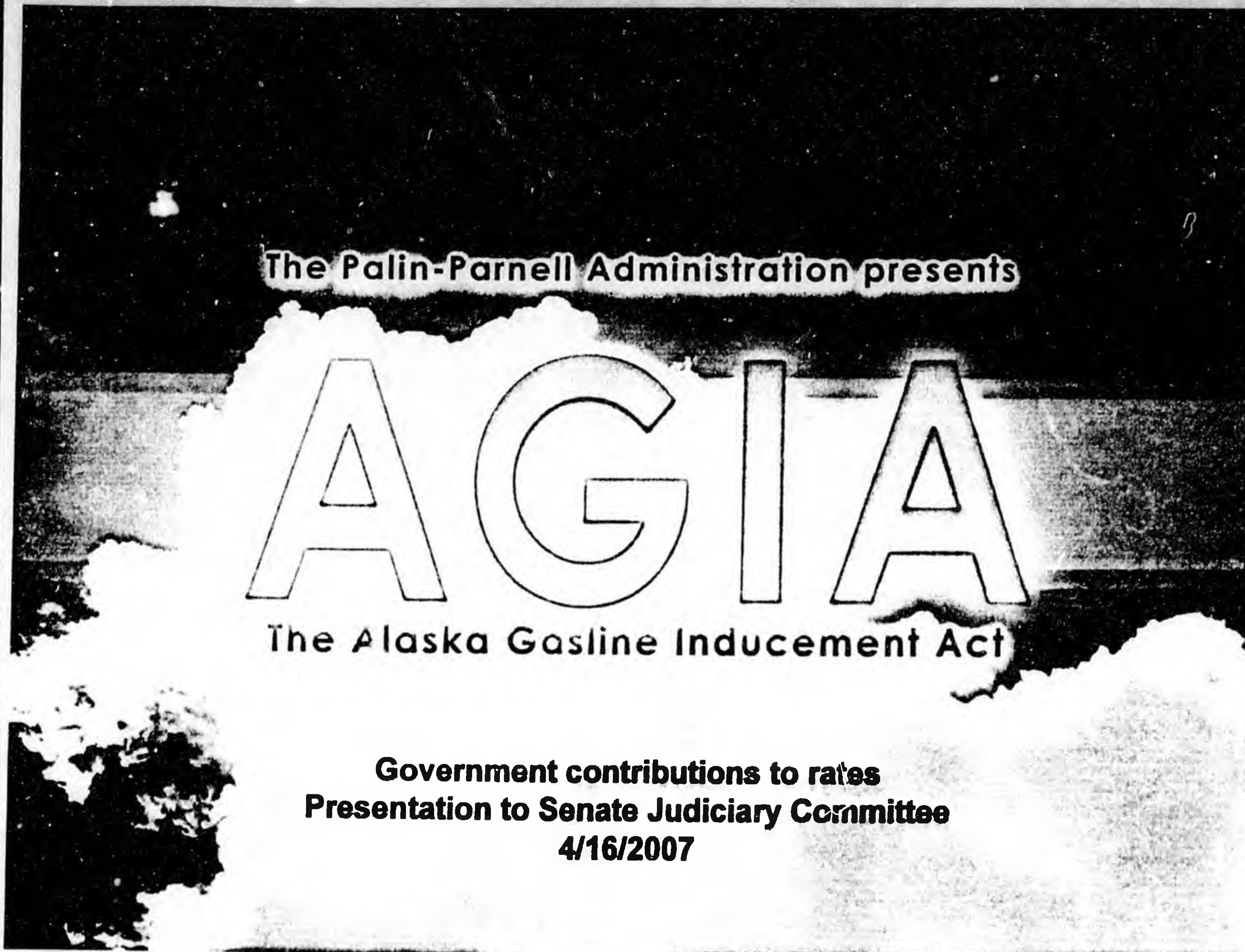


Note: Results differ from previously reported estimates due to recalibration of \$2004 to \$2006 price paths.

Summary

AGIA
The Alaska Gasline Inducement Act

- AGIA rolled-in rates promote competition, exploration and development.
- Given uncertainties, AGIA's rolled-in rates are clearly in the state's monetary interest.
- The objective evidence indicates that AGIA's rolled-in provisions cost the Producers only modestly and ***are unlikely to affect their initial investment decisions***.


The Palin-Parnell Administration presents
AGIA
The Alaska Gasline Inducement Act
Government contributions to rates
Presentation to Senate Judiciary Committee
4/16/2007

Effects of Government Subsidies on Rates

The Alaska Gasline Inducement Act

Base rate: All subsides included
- For a pipeline into Alberta, tariff = **$2.00**

Federal loan guarantee: reduces cost of debt
- Without loan guarantee, tariff rises to **$2.10**
- This is a 5% subsidy to rates

Accelerated depreciation: 7-year vs. 15-year
- Without accelerated depreciation, rises to **$2.19**
- This is an additional 4.3% subsidy to rates

AGIA contribution: $500 million reduces rate base
- Without AGIA contribution, tariff rises to **$2.25**
- This is an additional 3% subsidy to rates

Summary of Government Subsidies on Rates

AGIA
The Alaska Gasline Inducement Act

- Government subsidies total about 25¢, reducing rates from $2.25 to $2.00
- Initial rates are therefore subsidized by government by about 12.5%
- Further, owners of Gas Treatment Plant get *additional* 15% Investment Tax Credit
- If this subsidy is included then total government subsidies exceed 15%

Appendix

Base Case Assumptions for Rates to Alberta

AGIA

The Alaska Gasline Inducement Act

- Base rate assumes the following government subsidies:
  - Federal loan guarantee (assumed here to reduce debt costs by 0.75%)
  - Accelerated 7-year tax depreciation (part of Federal enabling legislation)
  - AGIA contribution of $500 million (50% until open season, 80% after)
- And assumes further:
  - 70/30 debt/equity ratio
  - 14% ROE
  - 6. 5% cost of debt
  - 30 year depreciation schedule
  - 25-year FT contracts
  - Cost input price escalation at 2%/year
  - Pipeline cost to Alberta of $20.5 billion ($2007)
  - Rates calculated on a levelized cost of service basis

Appendix
Federal Loan Guarantee: Value is Scenario-dependent

AGIA
The Alaska Gasline Inducement Act

Alaska Natural Gas Pipeline

Value of [federal] loan guarantee offers significant benefits

150-200 bp savings

Presentation from Goldman Sachs to State of Alaska on June 3, 2004
"Partnering and Risk Allocation Strategies for the Alaska Natural Gas Pipeline"
Assumes creative use of loan guarantees to achieve maximum benefits

Federal Loan Guarantee could reduce taxable yields by approximately 50 basis points.

Presentation from JP Morgan to Legislative Budget and Analysis Committee, June 16, 2004
"Interim Hearings: Alaska Natural Gas Pipeline Issues"
Assumes underlying credit rating of A, at most 60% debt

"…application of the DOE Guarantees to Alaska LLC's debt will probably lower the cost of borrowing with respect to such debt by approximately 50 to 100 basis points, depending on market conditions."

Dept. of Revenue, SGDA Contract FIF

COMMENTS TO LEGISLATURE

on GAS CONTRACT and FISCAL INTEREST FINDINGS

to Alaska State Legislature
June 14, 2006

Investment Performance Metrics and Decision-Making: How Do by Oil and Gas Companies Make Investment Decisions?

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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
  - To ensure that all investments are evaluated on a consistent basis
  - 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)

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Choice of Discount Rate

- Discount at risk-adjusted cost 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

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Financial Criteria

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

Financial Criteria
Net Present Value (NPV)

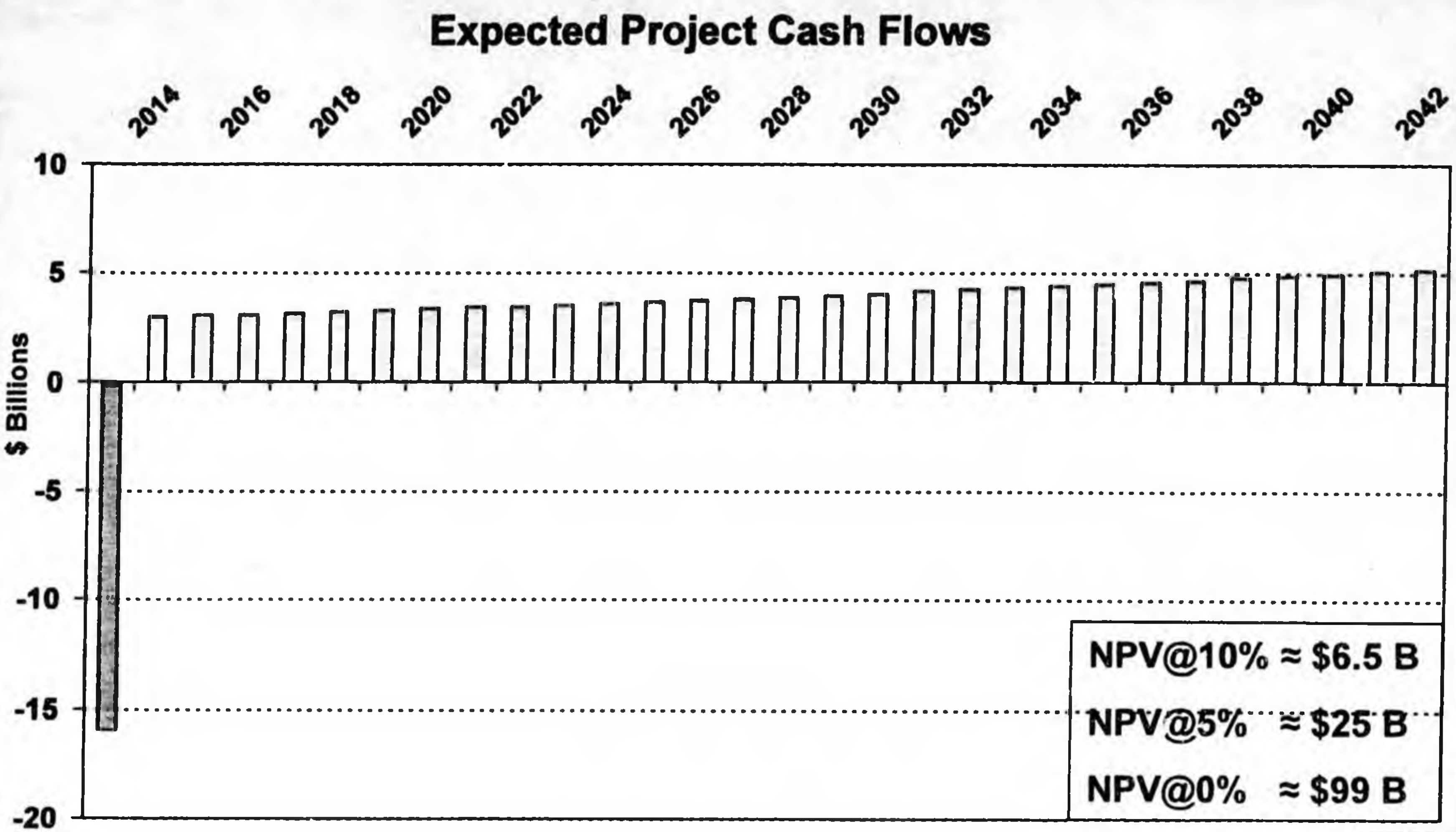
- **Present value of future cash flows including capital investment**

- **This is the "supreme" financial metric since a project with a positive NPV adds value to the firm**
  - **Value of the firm = PV of all future cash flows**
    = PV of cash flows from assets in place
    + PV of cash flows from future investments

- **Future cash flows discounted at rate that represents uncertainty of cash flows and when they are expected**

- **If a project generates cash in excess of that to compensate for the risk taken, the value of the firm increases**

Stylized Cash Flow



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Financial Criteria
NPV per BOE

- **Measure of how much cash flow is generated from reserves found**
- **Measure is highly sensitive to price forecasts**

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**
- **IRR of 10% currently indicates threshold rate of return without significant risk factors**
- **Energy companies are developing alternative projects above 15%**

Potential Inconsistencies with NPV and IRR

- The NPV and IRR metrics can be in conflict. NPV dominates.
- The IRR should be used to test if a project exceeds the firm's risk adjusted cost of capital, which indicates it is a candidate for acceptance
- The IRR should NOT be used:
  - To compare mutually exclusive projects
  - To compare independent projects that are of different scale or if the timing of the cash flows are vastly different
  - To compare independent projects with different risks unless the cash flows have been risk adjusted or if the IRRs are compared to different risk-adjusted hurdle rates
  - When the IRR is considerably higher than the cost of capital, since it assumes that proceeds are invested at the IRR rate

Financial Criteria
Profitability Index (PI)

- PI = [present value of cash inflows/present value of cash outflows] at a given discount rate.
  PI = [NPV+PV(Investment)]/PV(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.

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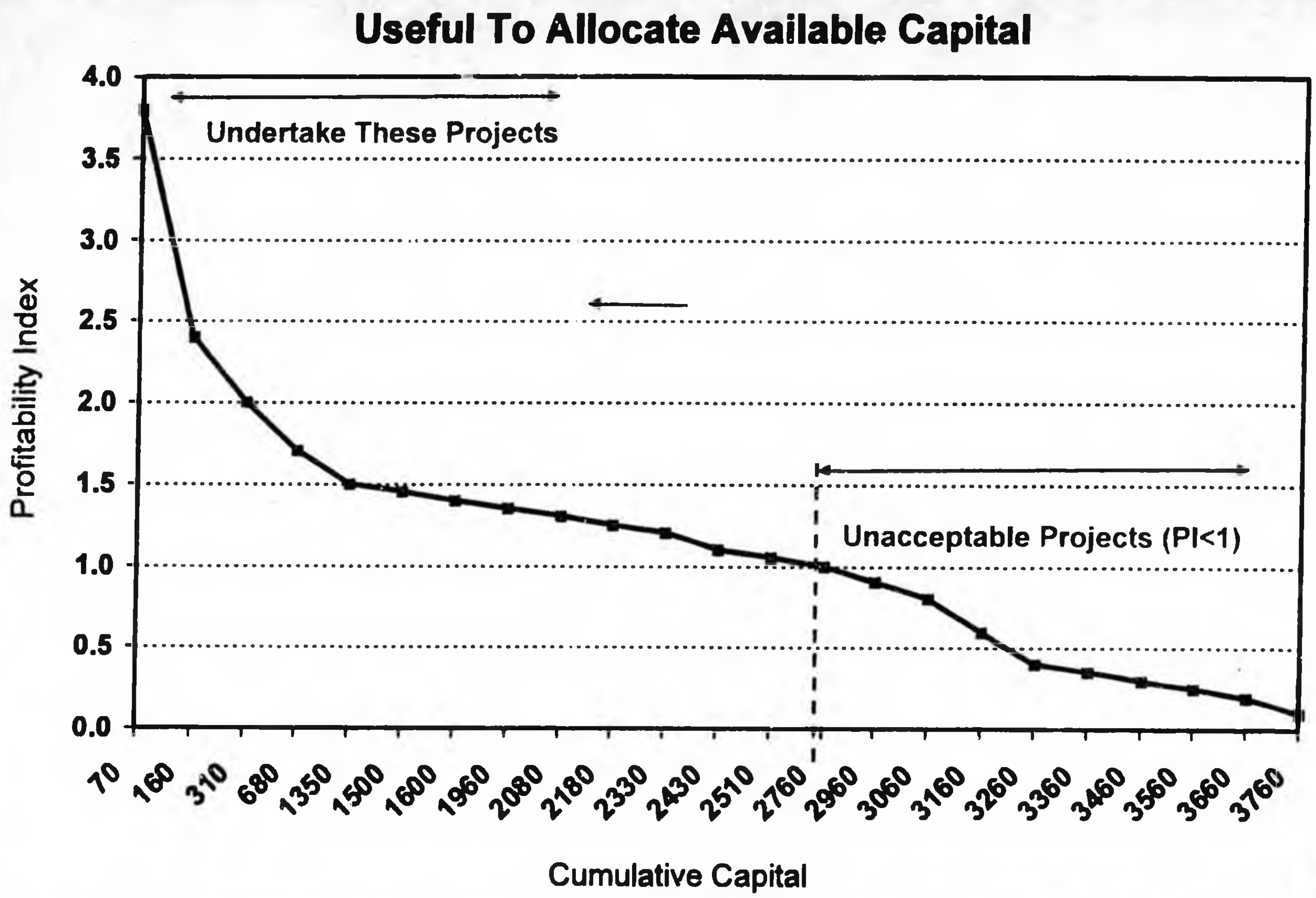
Financial Criteria
Profitability Index (PI)



Use of Financial Metrics

Comparison of Gasline Project with Other Opportunity Projects

	Projects are Independent (Can do both)	Projects are Mutually Exclusive (Cannot do both)
	Example: Comparison of Gasline with other International Projects	Example: Comparison of Gasline (Status Quo) with Gasline (Proposed Contract)
No Capital Constraint	• Any of discounting methods work: NPV, IRR • Undertake all with NPV>0 • Note: IRR not valid if projects are of different scale	• If same scale and same risk, pick highest NPV. • If different risk, adjust cash flows for risk and use NPV • Note: IRR not valid for comparing mutually exclusive projects
Capital Constraint	• NPV preferred. • Rank projects by PI and deplete opportunity set until sum of NPVs equal capital available	• Not relevant, since the assumption is that neither projects will exceed capital constraint.

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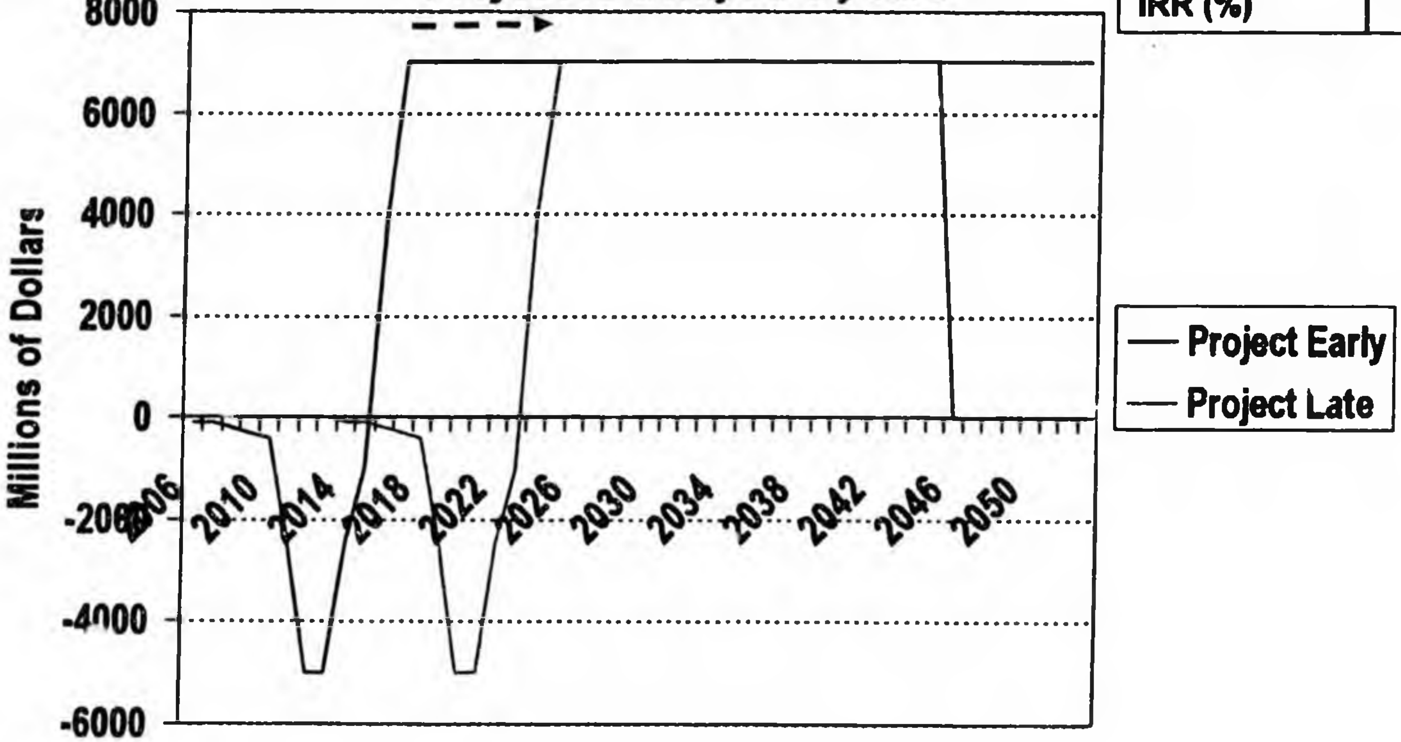
Comparison of Two Stylized Projects

	Project Early	Project Late
NPV10 ($M)	15,858	7,398
IRR (%)	21.6	21.6

Project Net Cash Flow

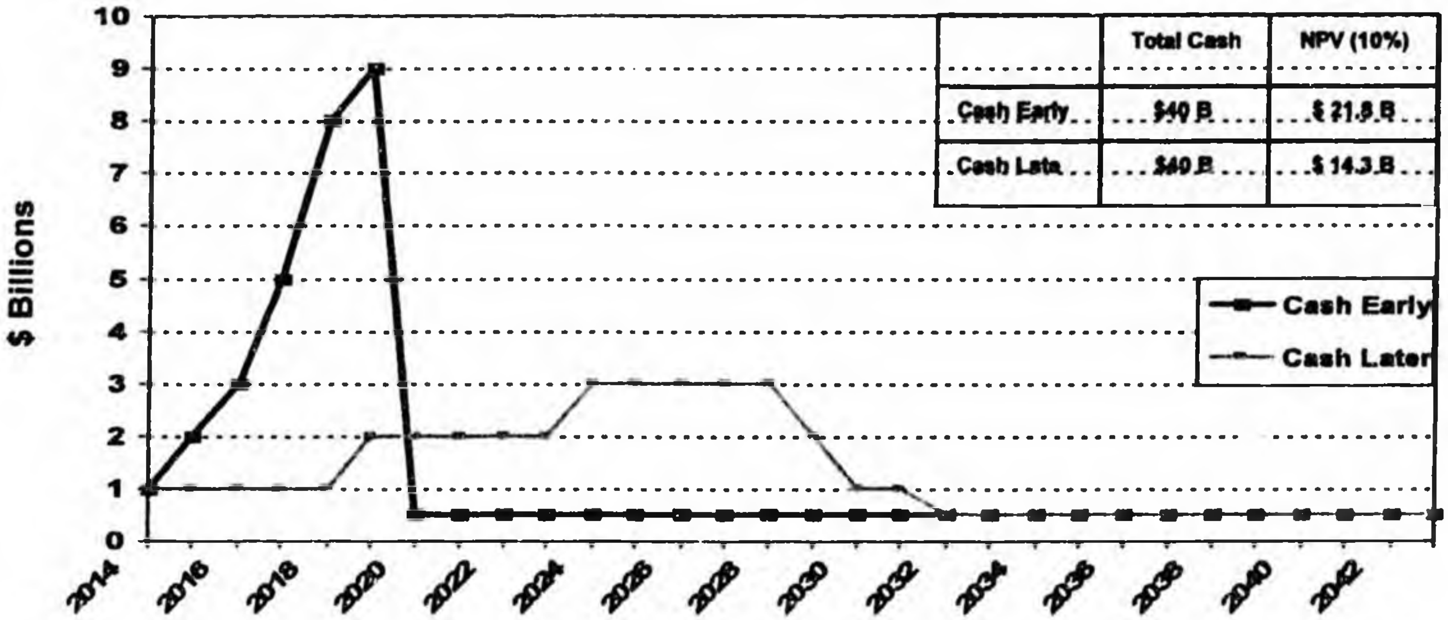
Project is delayed 8 years



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



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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.**

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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.

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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?

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SECOND DRAFT – SUBJECT TO REVISION

Financial Analysis of the Alaska Gas Pipeline Project

Modeling the Commitment to Pipeline Contracts

Dr. Jay Lukens

June 30, 2005

I. INTRODUCTION

A. Purpose of this Report

1. The primary question addressed in this report is how the State of Alaska should understand the financial modeling of a long-term commitment by the North Slope producers to a pipeline contract with a third party pipeline company. The hypothetical situation is one where a third-party owns the Alaskan Gas Pipeline and sells transportation capacity to the producers. I want to consider the North Slope Gas Project economic analysis. The specific question is how to treat the commitment to the pipeline capacity contract. In particular, should the payments from the producers to the pipeline be reflected in Project cash flows in the period when they are actually made? Or, because the contract between the producers and the pipeline is for a long term, is it appropriate to calculate the net present value of the future payments and reflect such present value as an up-front capital commitment?

2. A subsidiary question is, if the future payments are discounted to the present and reflected as a capital commitment, what is the appropriate discount rate to use? Is it appropriate to use a lower discount rate for pipeline capacity payments than that used for other components of Project cash flows?

B. Summary of My Findings and Opinions

1. If the cash flows are discounted properly, it makes not difference to the NPV calculation whether or not the NPV of the pipeline capacity payments are recognized as an up-front commitment.

2. It is not appropriate to use a lower (debt proxy) discount rate to NPV the pipeline capacity payments than the discount rate used for other components of the cash flow.

3. The financial community generally does not view pipeline capacity commitments as debt. In analyzing an analogous situation of purchased power commitments by electric utilities, Standard & Poors does recommend a balance sheet adjustment. Such adjustment is calculated using the NPV of fixed cost commitments (calculated at 10% discount rate) and then adding a fraction of that amount (30% in the example provided by S&P) to debt for financial analysis purposes.

4. Project risks should be incorporated in the analysis be an explicit considerations of such risks, not through adjustments to the discount rate.

II. NPV ARITHMETIC

A. Three alternative views of the same project

1. Table 1 shows three alternative representations of the same financial analysis of the Alaska Project.[1] All of the assumptions regarding future gas prices, project construction costs, variable operating costs, and pipeline tariffs are the same in all three columns of the Table. There are only two differences. In Case 1 the pipeline capacity payments are treated as a variable operating cost, while in Cases 2&3 the pipeline costs are capitalized and treated as a cash outflow at the time of first gas flow (2012). Cases 2 & 3 differ from one another in that in Case 2 the pipeline tariff is discounted at 10% (used as a proxy for the opportunity cost of funds invested in the Project) while in Case 3 the pipeline tariff is discounted at 6.5% (a proxy for the cost of debt to the Project.) More information on the assumptions underlying Table 1 are shown in Appendix 1.

Table 1: Alaska Pipeline Project NPV & IRR Analysis
($,millions)

	Case 1 FT Costs as a variable operating cost over contract life	Case 2 FT Costs recognized up front, with discount rate equal to 10%	Case 3 FT Costs recognized up front, with discount rate equal to 6.5%
NPV(10%) of Revenue	$ 52,859.5	$ 52,859.5	$ 52,859.5
NPV(10%) of Variable Operating Costs	$ (16,422.2)	$ (4,425.7)	$ (4,425.7)
NPV(10%) CapEx (GTP & Pt. Thompson)	$ (2,376.6)	$ (2,376.6)	$ (2,376.6)
NPV(10% or 6.5%) of FT Fixed Pipeline Costs	$ -	$ (11,996.5)	$ (19,572.8)
Project EBIT NPV	$ 34,060.7	$ 34,060.7	$ 26,484.4
Project IRR	91.4%	20.2%	16.1%

[1] The numbers in Table 1 are purely for illustrative purposes. While the assumptions underlying the project cash flows used here are believed to be reasonably representative of the order of magnitude of actual project costs and revenues, it is incorrect to rely on the project NPVs or IRRs shown for any purpose other than as illustrative examples.

B. Net Present Values

1. Comparing the Project NPV in Cases 1 & 2 one sees that they are identical. If the same discount rate is used to NPV the pipeline capacity payments as is used to discount the Project, it makes no difference to the Project NPV whether you NPV the pipeline payments or not. This is the logical result. The purpose of calculating an NPV is to weight costs and benefits that occur at different points in time to make them comparable in terms of economic value. The Project NPV is negatively affected if one uses a discount rate to NPV the pipeline capacity payments that is lower than the discount rate used to evaluate the overall Project. The merits of using a lower discount rate will be discussed below.

2. The argument for capitalizing the pipeline capacity payments for the purpose of evaluating Project economics runs along the following lines: By signing a long-term contract for capacity, the Producers have effectively committed a share of future cash flows to the pipeline owners. Capital markets will recognize that such a commitment has been made and will require the Producers to recognize the opportunity costs associated with it. The opportunity costs may take the form of less borrowing capacity, or the form of equity reserves held to safeguard against potential risks associated with capacity contracts. According to this argument, by capitalizing the pipeline capacity costs and treating them as an up-front payment in the Project economics, the Producers will evaluate the Project investment decision recognizing all the relevant costs.

3. The lesson from Table 1 is that if the pipeline capacity payments are NPVed at the same discount rate as used to calculate the Project NPV, then Project NPV is unchanged by the decision to capitalize. The decision to NPV capacity payments only effects the Project NPV if a different discount rate is used to calculate the up-front cost. The equivalence of the NPVs using the same discount rate makes the sense in a world of perfect certainty. If future costs and benefits are known with certainty then the discount rate functions solely to put quantities at different points in time on an economically equivalent basis. If the future is uncertain, however, we need to find a way to incorporate risk into the analysis.

4. The arguments for capitalizing pipeline capacity costs using a discount rate lower than other components of Project cash flows, although expressed in different ways, are all grounded on an attempt to reflect in the Project economics the effects of uncertainty in future cash flows. Because pipeline capacity payments can be predicted with greater accuracy than future gas prices, some project analysts would recommend using a lower discount rate for capitalizing pipeline capacity payments than Project revenues. While this practice has an intuitive appeal and can lead to adjustments in the cash flow Nap's that are directionally correct, there is a consensus among economists that to account for uncertainty in cash flows by adjusting discount rates is at best imprecise and at worst can lead to incorrect investment decisions.[2]

5. While there is consensus that adjusting discount rates is the wrong way to incorporate uncertainty into a cash flow analysis, there is none regarding a preferred alternative method to accomplish that objective. I consider below several alternative approaches to quantifying the economic effects of risks associated with the pipeline capacity contracts.

III. CALCULATING THE INTERNAL RATE OF RETURN

A. General comments on IRRs

1. Businesses continue to use internal rate of return calculations despite over 50 years of college textbooks telling students that NPV calculations are more reliable guides to investment decisions. I will not rehash all of the pros and cons of IRR vs. NPV here. Generally, in my experience, I have found the IRR to be a useful in situations where it is reasonably close to discount rate used by the business for NPV calculations. Problems arise when the calculated IRR is significantly different from the opportunity cost of capital.

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[2] The discount rate used in the NPV calculation should reflect the opportunity cost of capital to the Producers. In other words, it should reflect the rate of return available to the Producers (and to capital markets more generally) on *other projects* of comparable risk. Uncertainty in the components of the cash flows should be analyzed directly through scenario or Monte Carlo simulation analysis.

2. A source of trouble for the IRR calculation is what the textbooks call the "reinvestment rate of return." The assumptions underlying the IRR calculation imply that funds generated by the project of interest can be reinvested at the same rate of return as the project. This assumption is reasonable for projects that yield IRRs roughly equal to the cost of capital. It is not reasonable when the calculated IRRs are significantly greater than or less than reasonable returns on alternative investments.

B. Review of IRRs in Table 1

1. Looking back on Table 1 we see that the IRRs fall consistently from Case 1 to Case 3. This is an unavoidable consequence of the IRR calculation. By definition, the IRR is the discount rate that equates negative cash flows in the early years of the project with the positive cash flows in the later years. The greater the magnitude of the negative cash flows in the early years of the project, the greater the weight (lower discount rate) that must be given to later period positive cash flows. While the mechanics that result in falling IRRs is clear, the meaning to ascribe to this result is less apparent. The pipeline capacity payments are actually made over time, and are only moved forward in the context of the financial model. Hence the falling IRRs are purely an artifact of the modeling assumptions and provide no useful information regarding the real project economics.

IV. VIEWS OF THE FINANCIAL COMMUNITY REGARDING PIPELINE CAPACITY RISKS

In order to form a basis for my opinion on how to incorporate pipeline capacity risks into the Project economics I directed my staff to research the perspectives of debt rating agencies and equity analysts. I also asked them to review public SEC filings by energy companies to understand how pipeline commitments were disclosed to the public. My staff researched Moody's and Standard & Poors published ratings criteria, spoke with company equity analysts, and researched SEC filings to determine the role of pipeline commitments in company valuations. Companies researched included Anadarko Petroleum, Burlington Resources, ConocoPhillips, Mirant, and XTO Energy. The conclusion of my staff's research is that the analysts do not consider long-term pipeline contract commitments as debt, but rather as just one potential risk element in the array of valuation components. Both credit analysts and equity analysts, in evaluating a company that has entered into a pipeline commitment, look primarily at the strength of gas reserves, destination-market prices and hedging of destination price risk in evaluating the risks associated with pipeline capacity contracts.

A. Debt rating agencies

1. Standard & Poor's Corp: My staff reviewed S&P's ratings criteria for Industrials and Utilities to determine how S&P may assess off-balance sheet pipeline commitments. S&P includes the following items in a leverage analysis of a company:[3]

   - Operating leases;
   - Debt of joint ventures and unconsolidated subsidiaries;
   - Guarantees;
   - Take-or-pay contracts and obligations under throughput and deficiency agreements.

   S&P indicates that it uses various methodologies to determine the proper adjustment value for each off-balance-sheet item.

[3] S&P Ratings Methodology, Evaluating the Issuer, Corporate Ratings Criteria, page 25

2. My staff spoke with Standard & Poor's analyst Jeff Wolinsky, CFA, author of "Buy or Build"[4], a paper focused on valuation, from a credit perspective, of purchased power commitments entered into by electric utilities. S&P accords power purchase commitments of electric utilities debt treatment by calculating the NPV of the future cash stream (at 10% discount rate) and apply a risk-factor rate *to lower* the NPV, and adding the resulting total to corporate debt.[5] However, for a transportation commitment for an integrated energy or industrial firm, Mr. Wolinsky indicated that it is not standard practice to treat such contracts in the same manner as power purchase agreements. Assessment of pipeline commitments is on a case by case basis, where reserves and destination price risk is the focal points of concern and review.

3. Moody's Investors Service: In its guide to off-balance sheet exposures, Moody's indicates that it views take or pay pipeline commitments as problematic if market conditions and raw prices change or if the price of the end product drops. Moody's states that it factors payments under take-or-pay contracts into the analysis of future cash flows and may also adjust the balance sheet, if appropriate. [6]

4. In Moody's petroleum industry ratings criteria publication, Moody's indicates that it looks at a producer's transportation arrangements, but such arrangements are one of only a dozen or more qualitative issues it reviews in evaluating petroleum firms.[7]

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[4] "Buy Versus Build": Debt Aspects of Purchased-Power Agreements, Standard & Poor's Ratings Services, May 2003.

[5] In the example shown in the paper the risk factor applied was 30%, i.e., the NPV of the purchased power contract commitment was lowered by 70% to get S&P's estimate of a "debt equivalent." The paper explains that historically the risk factors were in the range of 5-10%.

[6] The Analysis of Off-Balance Sheet Exposures, July 2004.

[7] Moody's Approach to Rating the Petroleum Industry, Moody's Investor Service, December 2003.

5. For gas pipelines, Moody's looks gas supply and demand.[8] Moody's indicates that it looks at the gas supply feeding a pipeline, stating that is important that the pipeline be connected a gas supply with a long expected life. Moody's published criteria also state that they look for a diverse supply of creditworthy shippers, and look for an indication that the shippers would be motivated to continue to ship on the pipeline.

B. Equity Analysts

1. Raymond James: Mr. Wayne Andrews, Raymond James analyst covering Anadarko, Apache, Burlington, Forest Oil and XTO Energy, among others, stated that the existence of a pipeline contract can be viewed as a positive or negative factor in evaluating a stock. Such a commitment indicates that a company has gas supplies and customers. Mr. Andrews looks at the following issues:

   a) How long will the gas reserves run?

   b) Has the shipper hedged themselves for price differentials between the source and the destination market?

C. Disclosure Research

1. My staff selected a variety of companies to determine disclosure of transportation commitments. My staff found that most if not all companies generally disclose their gas transportation commitments in their SEC 10Ks and notes to financial statements.

2. Anadarko Petroleum: Anadarko's SEC filings indicate that it has entered into various transportation and storage agreements in order to access markets and provide flexibility for the sale of its natural gas and crude oil in certain areas. Anadarko states that as of 12/31/2004 it had transportation and storage commitments of $423 million, comprise ' of $304 million in the United States and $119 million in Canada.

[8] Moody's Approach to Rating Gas Transmission and Distribution Companies, An Update. June 2000. Moody's Investor Service, Global Credit Research.

Anadarko also lists its future pipeline commitments not included in the tabulation above. "During 2004, Anadarko and a group of energy companies...executed agreements with a third party to design, construct, install and own Independence Hub, a semi-submersible platform in the deepwater Gulf of Mexico. The agreements require a monthly demand charge of about $2 million for five years beginning at the time of mechanical completion, a processing fee based upon production throughput and a transportation fee based upon pipeline throughput."

3. Burlington Resources: Burlington indicates in its 2004 SEC 10K that it "has entered into contracts which provide firm transportation capacity rights on pipeline systems. The remaining terms on these contracts range from 1 to 19 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company." [9]

4. Conoco Phillips: Conoco Phillips lists its long-term agreements and take-or-pay agreements. "We have certain throughput agreements and take-or-pay agreements that are in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company's business. The aggregate amounts of estimated payments under these various agreements are 2005—$92 million; 2006—$98 million; 2007—$98 million; 2008—$98 million; 2009—$98 million; and 2010 and after—$553 million."[10]

5. Mirant: As an example of an energy marketer with generation assets, Mirant's 2004 SEC 10K indicates that as of December 31, 2004, Mirant has approximately $95 million in purchase commitments under fuel purchase and transportation agreements, which are in effect through 2029.[11]

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[9] Burlington Resources 2004 SEC 10k, page 62

[10] ConocoPhillips 2004 SEC 10-K, page 139

[11] Mirant 2004 10-K, page F-67

6. XTO Energy: XTO's SEC 10K indicates that it has firm transportation contracts with various pipelines, and it is obligated to transport minimum daily gas volumes or pay for any deficiencies at a specified reservation fee rate. The 10K states: "As calculated on a monthly basis, our failure to deliver these minimum volumes to the pipeline requires us to pay the pipeline for any deficiency. Our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. We have generally delivered at least minimum volumes under our firm transportation contracts, therefore avoiding payment for deficiencies"[12] The XTO 10K lists transportation commitments on an annual basis for the 2005-2009 and for the period beyond 2009.

V. MODELING RISKS OF PIPELINE CAPACITY CONTRACTS

1. The illustrative example in Table 1 shows that use of a 6.5% discount rate to NPV pipeline capacity payments lowers the Project NPV by over $7.5 billion vs. the case where the10% discount rate is applied to all Project cash flows. If this is an adjustment to reflect uncertainty, is it reasonable? Based on the foregoing review of practices adopted by the financial community, I considered two primary sources of potential risk related to the commitment to the pipeline capacity contract. The first, which I call "price risk" is the risk that the price of gas in Alberta will not be sufficient to cover the variable costs associated with gas production, treating and pipeline transportation.[13] Second, I considered what I call "volume risk," which is the risk that there will not be sufficient reserves to keep the pipeline full for a 25 year pipeline capacity contract term.

2. In order to quantify price risk I considered the value of a hypothetical put option designed to protect the shippers on the pipeline from price risk. Calculating the value of this option is one way to approximate the economic cost of the uncertainty surrounding the transportation contract. As such it is comparable to the $7.5 billion reduction in NPV associated with the use of a lower discount rate to NPV pipeline capacity payments.

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[12] XTO Energy, 2004 SEC 10K, page 58.

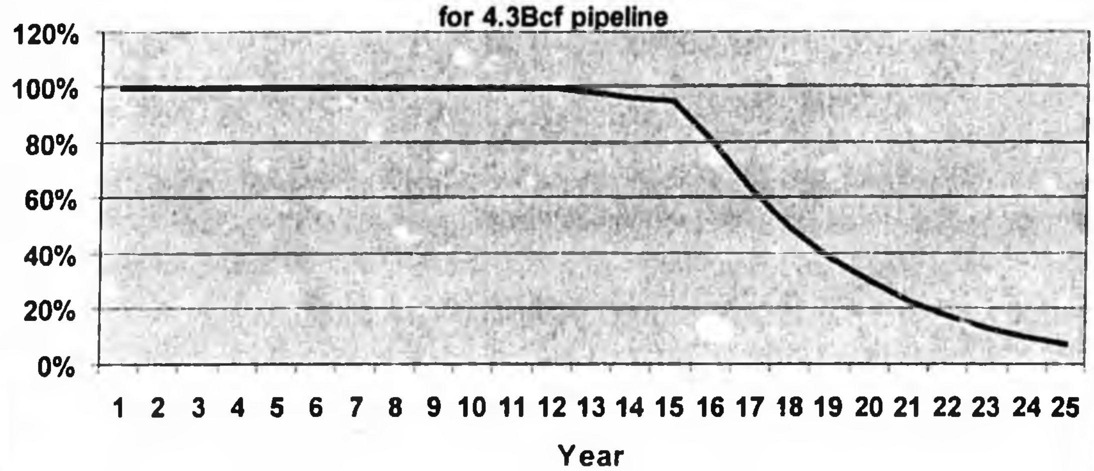
[13] The pipeline transportation cost is incorporated in the analysis as a variable cost at the 100% load factor equivalent of the capacity payment.

a) In this hypothetical the strike price of the option is equal to the 100 percent load factor equivalent of the pipeline capacity contract (including fuel and commodity costs), plus the variable costs associated with lifting and the gas treating plant. The option would give the producers the right to sell their gas in Alberta at the strike price, in other words, the option would protect the Producers from a situation where the selling price of the gas in Alberta was not sufficient to cover the variable lifting, treating and pipeline transportation costs. As discussed in greater detail in Appendix 2, I calculate the initial strike price to be $1.94 in 2005 dollars.

b) Using a gas price projection and Monte Carlo simulation model that Lukens Energy Group had developed for the State of Alaska, I calculate the net present value of the option premium to be approximately $265 million in the case where there is sufficient gas supply to fill the pipeline for 25 years, and $190 million using a production profile based on currently proved reserves.[14] More details on the assumptions underlying this calculation are in Appendix 2.

3. In order to quantify the volume risk I considered a 25 year gas production profile based on current estimates of proved reserves as shown in Figure 1.

FIGURE 1
Alaska Gas Reserve Profile
for 4.3Bcf pipeline



[14] The NPV of the option premium is the NPV of gains the holder of the option would receive, i.e., it is the NPV of the expected value of the positives differences between the strike price and the actual price of gas delivered in Alberta.

a) I calculated the net present value of a payment stream to the producers to compensate them for capacity that had been reserved but could not be utilized because of production shortfalls. The payment required to eliminate volume risk is about $1,220 million.

4. My analysis shows that derivative contracts could be created at a cost of less than $1.5 billion that would substantially eliminate the risks associated with holding the pipeline capacity contracts. In my opinion, an adjustment to the Project NPV of an amount significantly greater than that obtained by using lower discount rates to NPV certain costs, such as the $7.5 billion reduction shown in the illustrative example of Table 1, cannot be justified based on sound economic reasoning.

VI. RECOMMENDATION

1. Based on the foregoing discussions, I have developed two recommendations for how to calculate NPVs and IRRs for the Project economics as reflected in Tables 2&3.

2. The analysis shown on Table 2 incorporates pipeline capacity costs as an operating cost. A balance sheet adjustment was estimated using the Standard & Poors method for purchased power agreements described above, as was included in the Project economics as an up-front cost.

3. Table 3 shows an alternative method based on hedging costs.

Table 2: Alaska Pipeline Project NPV & IRR Analysis

($,millions)

Incorporating S&P's PPA Method		FT Costs as a variable operating cost over contract life
NPV(10%) of Revenue	$	52,859.5
NPV(10%) of Variable Operating Costs	$	(16,422.2)
NPV(10%) CapEx (GTP & Pt. Thompson)	$	(2,376.6)
30% of NPV(10%) of FT Fixed Pipeline Costs	$	(3,598.9)
Hedging Costs	$	-
Project EBIT NPV	$	30,461.8
Project IRR		27.6%

Table 3: Alaska Pipeline Project NPV & IRR Analysis		
($,millions)		
Incorporating Hedging Costs	FT Costs as a variable operating cost over contract life	
NPV(10%) of Revenue	$	52,859.5
NPV(10%) of Variable Operating Costs	$	(16,422.2)
NPV(10%) CapEx (GTP & Pt. Thompson)	$	(2,376.6)
30% of NPV(10%) of FT Fixed Pipeline Costs	$	-
Hedging Costs	$	(1,500.0)
Project EBIT NPV	$	32,560.7
Project IRR		36.8%

Alaska State Legislature

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Representative Carl Gatto

TO: Representative Ralph Samuels, Chair - LB&A Committee
FROM: Rep. Gatto, Co-Chair – Resources Committee

DATE: May 10, 2007

RE: House Resources Consultant Request
CC: Representative Craig Johnson, Co-Chair – Resources Committee
Representative Vic Kohring
Representative Bob Roses
Representative Paul Seaton
Representative Peggy Wilson
Representative Bryce Edgmon
Representative David Guttenberg
Representative Scott Kawasaki

Thank you for your timely response to the request of the House Resources Committee for access to consultants authorized by LB&A.

I am concerned about statements you make in your letter and feel that it is necessary to draw attention to disagreements as to content. I recall that you and I have previously discussed the exact issue of hearing from consultants as have our staff members but that does not seem to be your interpretation. Let me clarify my position.

In your memo, you state that, "In the three weeks that AGIA was in the House Resources Committee, I never received any request on any subject from the Chairman." This is untrue and I am attaching a copy of the memo that I personally provided to your staff on April 13th, 2007 entitled, "Consultants for House Resources hearings on CSHB 177(O&G)." Additionally we have had at least a few conversations on this subject and so you must have known of my memo as well as my intentions. Furthermore you have written that:

> "If presentations are to be done, our consultants would have to have been advised on what subject. They have not done an analysis of the legislation, because the committee chair chose not to ask. There is not enough time for anyone to do a thorough analysis of the bill by tomorrow."

I find it disturbing and surprising that consultants on contract to the LB&A Committee could possibly not be completely familiar with all aspects of the AGIA. This is especially egregious in light of my April 13th request to you.

You gave calculations on the cost to the state for these presentations: Again I disagree with your analysis. I quote:

> "The total cost per hour of the five gentlemen you have listed is $1975/hour. If they testify in person, we would also pick up transportation and expenses. If they had to work two days, the cost to the State would be close to $40,000."

Earlier in the same memo you explain that Mr. Finizza is not available at all, yet you included the cost per hour for his time too. I have calculated the cost below and it appears closer to $25,000 than $40,000. It seems unreasonable to me to nit pick this issue but you have brought it up and so I feel obligated to respond.

$1975/5 = $395 per person average cost
$395 * 4 = $1580/hour, cost of the remaining four consultants
$1580 *8 = $12,640 per day (8 hr/day-this appears to be your assumption)
$12,640 *2 = $25,280 for two days for the true cost less travel.
$40,000 - $25,280 or $14,720 less than your estimate

Additionally, estimates for travel for Rick Harper should not be included since he is currently in Juneau as per my personal request. Bill Mogel was also recently in Juneau as well and it would seem unreasonable that he would incur travel expenses as well. Obviously Mr. Finizza would not incur any travel expenses if he is not available to speak. This leaves travel expenses for two of the five consultants originally mentioned in the memo with signatures from all nine members of the House Resources Committee.

I disagree with you that the amount of money for consultants is high. Its importance to the committee is invaluable and presentations from independent consultants are of great value to those who must bulwark their vote with the best information available. The AGIA is arguably the most important bill we will discuss ever and the costs of the project, not to mention the substantial potential revenues, are measured in tens of billions of dollars. It is my opinion that the expenditure of roughly $25 thousand plus relevant expenses is an excellent investment in assuring we uphold our sworn duty to ensure the State receives the maximum benefit of its resources.

Interestingly you mention Mr. Dickenson who is not on the request list. That was my intention and Mr. Dickinson is not included in the request from the Resources Committee members. This is what you stated:

> The presentation by Mr. Dickinson came from the subject raised in House Resources. The question was if there were differing views in the Administration on the economics' presentation given by Dr. Scott. Commissioner Galvin replied that there were disagreements, but that the views and presentations given by Dr. Scott were the views of the Administration. Since it is good to have the legislature hear all views, we hired Mr. Dickinson to give another point of view on the use of FT commitments as debt or debt-like entities.

This suggests the impetus for Mr. Dickinson being hired came from the House Resources Committee. As the Co-Chair I am not aware of any formal request from any committee members and am further cautioned by the enthusiasm you have shown in attempting to answer certain questions apparently discussed in committee. Your concern for the importance of hearing all views is noted and appreciated. This is, in fact, the exact reason I am requesting personal access for myself and members of the Committee to the consultants mentioned in my request.

You mention that you "...regret that I did not receive any requests from the committee chair while the bill was in the Resources Committee, and indeed did not get a request until yesterday afternoon." As I have stated earlier in this memo, that is untrue and the memo you received yesterday signed by all nine members of the House Resources Committee was actually the second request on the subject from my office. Again, the memo is attached.

You mention that "We also have a call in to Mr. Harper requesting a copy of the material he intends to present to the committee." Mr. Harper has remained in Juneau to testify before the House Resources Committee at my personal request and any call to request his presence would certainly confirm that he has been here for several days. As far as any materials Mr. Harper intends to present to the committee, I will direct my staff to share them with your office. Additionally, as is my practice, they will be available in electronic format on our committee website as soon as possible.

Thank you for addressing our concerns about personal access to consultants hired by the LB&A and available to elected representatives. Access to the consultants and the knowledge they can provide encourages robust debate, and that I believe, is in the best interest of the Alaskans who depend on us to make the most informed decisions possible.

We see each other several times each day where all of this could have been discussed with back and forth comments. Correspondence deserves like reply and so I have written this letter even though it is consuming more time than a conversation would. Nonetheless I thank you for taking your time to write.

ALASKA STATE LEGISLATURE
House Resources Committee

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MEMORANDUM

TO: Rep. Ralph Samuels, Chair – Legislative Budget and Audit

FROM: Rep. Carl Gatto – Co-Chair, House Resources
Rep. Craig Johnson – Co-Chair, House Resources

RE: Consultants for House Resource hearings on CSHB 177(O&G)

DATE: April 13th, 2007

The House Resources Committee formally requests the Legislative Budget and Audit Committee engage the necessary legal, economic, and technical consultants to assist in their deliberations on CSHB 177(O&G).

Committee members have requested specialized consultation to adequately assess the accuracy of the testimony we have received and the testimony we will receive. In addition, we believe the consultants will assist the members in understanding the respective weight of the technical issues arising from testimony.

It is my intent to conclude House Resources hearings on this bill by late April. I recognize this provides only a very short window for consultation, but I believe consultants will prove valuable to the Finance Committee as well.

Thank you.

LEGISLATIVE BUDGET & AUDIT COMMITTEE

REPRESENTATIVE RALPH SAMUELS, CHAIRMAN

MEMORANDUM

TO: Representative Carl Gatto, Co-chair
✓Representative Craig Johnson, Co-chair
Representative Vic Kohring, Member
Representative Bob Roses, Member
Representative Paul Seaton, Member
Representative Peggy Wilson, Memb r
Representative Bryce Edgmon, Member
Representative David Guttenberg, Member
Representative Scott Kawasaki, Member
House Resources Committee

FROM: Representative Ralph Samuels, Chair
Legislative Budget and Audit Committee

DATE: May 10, 2007

RE: House Resources Consultant Request

Regarding your letter requesting LB&A to provide consultants for the House Resources Committee, we can attempt to provide some testimony for the committee.

As I requested from the Senate Judiciary Committee, I would like to know what topics you wish to talk about.

In the three weeks that AGIA was in the House Resources Committee, I never received any request on any subject from the Chairman. If presentations are to be done, our consultants would have to have been advised on what subject. They have not done an analysis of the legislation, because the committee chair chose not to ask. There is not enough time for anyone to do a thorough analysis of the bill by tomorrow.

Mr. Finizza is not available at all. We have checked on the availability of Mr. Mogel and he will be able to provide testimony telephonically. He has a prepared Power Point that

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