

SB 104

(FILE 2)

**WRITTEN
TESTIMONY/
PRESENT-
ATIONS**



UNITED ASSOCIATION

of Journeymen and Apprentices of the
Plumbing and Pipe Fitting Industry of
the United States and Canada

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General President

Patrick R. Perno
General Secretary-Treasurer

Stephen F. Kelly
Assistant General President

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Letters should
be confined to
one subject

UA Local Union: **Plumbers & Pipefitters UA Local Union 262**
1751 Anka Street
Juneau, AK 99801

Subject:

April 12, 2007

Senator Hoilis French and Committee members
State Capitol
Juneau, AK 99801

RE: TESTIMONY FROM MAX MIELKE – A CLOSER LOOK AT PROJECT LABOR AGREEMENTS

Dear Mr. French:

If an idea has a proven track record of success, provides benefits for everyone involved and is a sound financial investment, why would anyone say no to such an idea? Good question, and it's one that gets asked every day all across America. The great idea is project labor agreements, and those saying no to it invariably come from the non-union sector – including contractors, owners and politicians. It seems they just don't like a good idea when they see it – or could it be that their anti-union bias has blinded them?

Project labor agreements, or PLAs as they are commonly known, have been around for many years and have worked well for everyone involved in them. Even the Supreme Court of the United States agrees PLAs are good for America, having unanimously upheld the project labor agreement on the massive Boston Harbor clean-up project.

In fact, Congress realized the value of PLAs 40 years ago, when such agreements were made legal under amendments to the Taft-Harley Act. While the terms of agreements vary from project to project, the goal is to bring together workers from different crafts under a common set of work rules, working conditions, hiring practices and methods for settling disputes. Often PLAs include a mutual agreement between labor and management that there will be no strikes and no lockouts.

In California, project labor agreements are making the state's energy system more secure and reliable, but PLAs are also at work in many other areas besides the utility industry. These agreements are in place in states from Maine to Washington, from New York to Alaska and everywhere in between. PLAs are being used to build schools, airports, water treatment plants, pharmaceutical facilities, highways, housing and of course, utilities.

PLAs not only provide employment for the UA and other building trades unions, they also save taxpayer money by streamlining bidding on projects and preventing future hidden costs and keeping the project on schedule-something that everybody wants, including workers.

Contrary to the claims of the non-union sector, PLAs are not automatically 'union-only' agreements. For PLAs negotiated in the public sector, it is unlawful to have union-only agreements, with the result that on public projects union and non-union employers are often found working side-by-side. For example, on the Boston Harbor Project-the largest environmental cleanup in history-more than 30 percent of the contractors were non-union.

Moreover, smart corporations in the private sector frequently use PLAs. For example, Toyota has build all its facilities in the U.S. under PLAs, and is starting a new \$800 million plant in Texas under a PLA as well. In all, UA members and all building-trades people have worked 30 million man-hours for Toyota alone.

It just so happens that union contractors, by virtue of the superior skills of their union trades people, often take center stage whenever a success story is being told.

PLAs have many benefits besides creating a more efficient workplace. Such agreements can help local communities by encouraging better training and providing apprenticeship opportunities for local residents. PLAs also ensure that higher standards are met, making job sites safer and promoting quality work.

Another popular claim by anti-PLA forces is that these agreements drive up wages and therefore raise the cost of a project. In many areas of the country where PLAs are prevalent, the agreements are used on public projects. As members of the United Association of Plumbers and Pipefitters know, on publicly funded projects the wages are determined by provisions of the federal Davis-Bacon Act, or by state versions of this enduring and sensible law. In other words, wages are based on whatever the prevailing wage is for that region, ensuring that unscrupulous contractors don't have a chance to "low ball" the bids by paying less than what workers in that area earn already, or by importing low-wage (and low-skilled) workers from other regions. Thus, on a PLA project, the playing field is made more level, ensuring that realistic bids are submitted.

Contrary to arguments by PLA opponents, there is just no evidence to support claims that the agreements drive up construction costs. In fact, the use of PLAs is on the rise because they stabilize labor costs, increase productivity and keep projects on schedule. Why else would big companies like Toyota, Merck and others routinely use PLAs in their construction projects? In addition, many of the new baseball and football stadiums and airports all across the country are presently being build under PLAs.

Despite the efforts of anti-union groups like the Associated Builders and Contractors (ABC), there is a lot of bi-partisan support for PLAs. Both Republican and Democratic governors-past and present-have used PLAs, including Governor John Rowland of Connecticut, Governor Jim McGreevey of New Jersey, and Governor George Pataki. In fact, Governor Pataki is quoted as

saying that a properly structured PLA can save money, ensure labor harmony and permit large scale projects to be completed on expedited timetables.

If the arguments in favor of PLAs are so powerful, who are those who oppose these agreements?

As noted, the ABC is fanatical in its opposition to PLAs. This group is joined in its campaign against PLAs by the Associated General Contractors of America (AGC), which went so far as to publish a paper (put out by the AGC's own law firm) back in the 1990s that was, in the words of the Building and Construction Trades Department, "misleading, biased and untruthful." In response, the BCTD published its own paper, a much more objective and balanced view of the pros and cons of PLAs.

In that document, the BCTD countered virtually every claim of the AGC, proving once and for all, we would think, that PLAs make good business sense. Unfortunately, anti-union groups continue to use every tactic they can think of to fight the use of these agreements.

In California, the state Building and Construction Trades Council has had to mount a continuing public information program in order to counter the campaign launched against the use of PLAs in building the dozens of power plants proposed as part of the solution to that state's energy woes. However, the BCTD has had some powerful and influential allies in the effort to get the word out about the benefits of PLAs-and some of this support came from surprising sources.

In 2001, the *Construction Labor Report* (a publication of the Bureau of National Affairs) reported the results of two studies demonstrating the success and value of the PLAs in California. The Report indicated that "the studies...provide a boost for project labor proponents at a time when Governor Gray Davis is considering increasing spending on public works." The PLAs were reported as being "valued by owners and construction firms alike" because the agreements aid "in resolving disputes over roles contractors and subcontractors play in large and complex projects." The Report also noted that PLAs promote "local economic development, workforce training and employment goals for women and minorities."

Another study conducted by the University of California at Los Angeles found that PLAs did not increase labor costs, encouraged competition, promoted job stability, and cooperation and productivity.

Later in 2001 support for PLAs came from one of the nation's most respected news sources, the *Kiplinger California Letter*, which stated that "project agreements are alive and well in California," and the *Letter* also predicted that PLAs would also be used on water projects, city halls, local schools and, of course, power plants-all this despite the fact that President George Bush had issued an executive order eliminating the use of PLAs on federal projects.

Despite such widespread support and extraordinary evidence the PLAs are good for the workplace, for consumers, taxpayers, and for business owners, groups like the ABC show no signs of letting up in their attacks on these agreements.

Nevertheless, the truth will ultimately prevail. Building trades people will continue to prove that project labor agreements lead to successful construction jobs. Our best weapon in this ongoing

battle is still the superior skill that union trades people have. As long as we continue to do the job right, we will triumph again and again.

Sincerely,



**Max Mielke
UA Local 262
Business Manager**

**United Association of Plumbers & Pipefitters
UA Local 262
1751 Anka St.
Juneau, AK 99801**

**Phone: (907) 586-2874
Fax: (907) 463-5116
Email: lu262bm@uanet.org**



THE ALLIANCE

...for responsible development of Alaska's Oil, Gas & Mineral Resources

360 West Benson Blvd., Suite 200 • Anchorage, AK 99503 • Phone (907) 563-2226 • Fax (907) 561-8870

SENATE JUDICIARY TESTIMONY

On SB 104

April 12, 2007

Thank you for this opportunity to testify on Senate Bill 104, the Alaska Gasline Inducement Act. My name is Paul Laird, and I'm general manager and testifying on behalf of the Alaska Support Industry Alliance.

We're the companies that provide the goods and services that make Alaska's oil, gas and mining industries possible, and our 400-plus member companies generate more than 30,000 jobs for Alaskans.

We believe upstream fiscal issues need to be resolved first if Alaska truly wants North Slope producers to make commitments to space in a gas pipeline. The Alaska Gasline Inducement Act puts too much emphasis on mitigating the short-term financial risks incurred by pipeline builders and does too little to address the much longer-term risks of gas shippers.

With few exceptions, Mr. Chairman and members of the committee, we aren't lawyers or experts in constitutional law. We can't tell you what fixes are needed in order to provide prospective shippers in a gas line with the fiscal confidence they need in order make commitments exceeding \$100 billion over the next 30 years while still complying with Alaska's Constitution.

For the sake of Alaska's future, Chairman French, the Alliance urges you not only to determine what terms aren't constitutional, but also to find a mutually beneficial solution that is.

The Alaska Gasline Inducement Act may represent our last and best chance at making a North Slope gas project a reality. We urge you to fix it and pass it, and we pledge our full support of your efforts to craft a bill that acknowledges the interests of Alaskans, of the developer and transporter and of North Slope producers and shippers.

Thank you.

Mr. Chairman, and members of the committee. My name is David Gottstein, and I represent Backbone as Co-Chair with Former Governor Walter Hickel.

I come today to you in support of AGIA. It may not have come to you in perfect shape, but it is an excellent platform to work from for, among others, the following reasons:

- 1. It provides for a competitive and fair process for all bidders to show what they can do for the State and, therefore, the people of Alaska. The more vibrant the bidding pool, the more the winning bidder will have to offer. That is common sense and good business. There are rumors that the producers are arguing that it is exclusive in that a competitive process results in one winner. In the first case, most competitive processes pressure the participants to put forth their best offer and therefore achieves better results, and secondly, this process will likely result in more than one significant player in a development team.**
- 2. In addition, the inducements, including reimbursement for up to \$500 million for permitting and related costs, will reduce the risk of the project, increase its value, and gain more for the State through a more profitable pipeline. By making the project less risky, it will attract more bidders, and will allow them to offer more in economic terms.**
- 3. Contrary to what the North Slope oil producers want you to believe, they are NOT the only companies qualified to build a pipeline. Gaslines throughout the country are mostly built and owned by independent pipeline companies, not producers. Warren Buffet, for example, is one of several major investors ready to offer billions of dollars of equity to get the project going.**
- 4. Once the best project is chosen, the producers must commit the North Slope gas they have under lease to that project. Or risk forfeiture. That's required by the terms of their leases. Exxon, for one, wants you to believe that they are the only ones who can decide when to market our gas. But they are required by law to sell our gas when the market is ready to purchase it. We are in a game of chicken, and the producers hope we take the bait and veer off the road of maximum opportunity for the State. Don't be afraid of offering Pt. Thomson gas, even under a slight cloud**

of litigation loss. There is a very high likelihood that our Supreme Court will affirm the administrative decision to cancel the leases. If we hold back offering the gas to a market, the producers win. Sound business judgments dictate taking the probable course, and mitigate the small chance of failure. In the worst case, sufficient gas will likely be made available even for a smaller project that is economic, which we are told could be as little as 1 BCF. It is most likely the producers will fall in line and offer our gas once a line is approved, in order to avoid not being left behind. It would further risk their leases to hold back, and generate the wrath of Congress and the American people for doing so. If the courts strike down the canceling of the lease, then a break-up fee could be paid to a winning bidder as a consolation. But the potential benefits of proceeding, along with the likelihood of success, far in away outweighs the likelihood of failure and the associated cost. Let's not be chicken. Let's be bold, rational business-wise and strong. Not doing so would be like entering a negotiating room with a labor union and announcing that we can't afford a strike, turning them into the automatic winner.

- 5. Getting our gas to market so that it benefits all Alaskans is what AGIA is all about. Alaskans will control our destiny as opposed to abdicating it to Outside corporations.**

Thank you for offering us the opportunity to make our case, and we, along with all Alaskans, are eager to get going. Thank you for your time today.

COMMENTS TO LEGISLATURE
on GAS CONTRACT and FISCAL INTEREST FINDINGS

June 14, 2006

Alaska Project Rank with Other Investment Opportunities

Dr. Anthony Finizza
Consultant
Econ One Research, Inc.

5th Floor
601 W 5th Street
Los Angeles, California 90071
213 624 9600

Suite 1170
1215 K Street
Sacramento, California 95814
916 449 2860

Suite 2825
Three Allen Center
333 Clay Street
Houston, Texas 77002
713 228 2700

Suite 230
106 E 6th Street
Austin, Texas 78701
512 476 3711

ONE

Methodology

- This analysis uses information from PFC's database of modeled projects with these criteria:
 - **Capex of at least \$ 1 billion**
 - **Production Start in 2006 or later**
 - **To make a level comparison, since projects starting prior to 2006 would have been advantaged by high prices of the last few years.**
 - Projects were split by type (Oil vs Gas)
 - Projects were split by country (OECD vs non-OECD)
- Analysis done in nominal dollar terms
- Financial metrics developed by PFC using Econ One assigned price decks at 2.5% inflation
- Projects are currently underway

Composition of PFC Database Used in Analysis

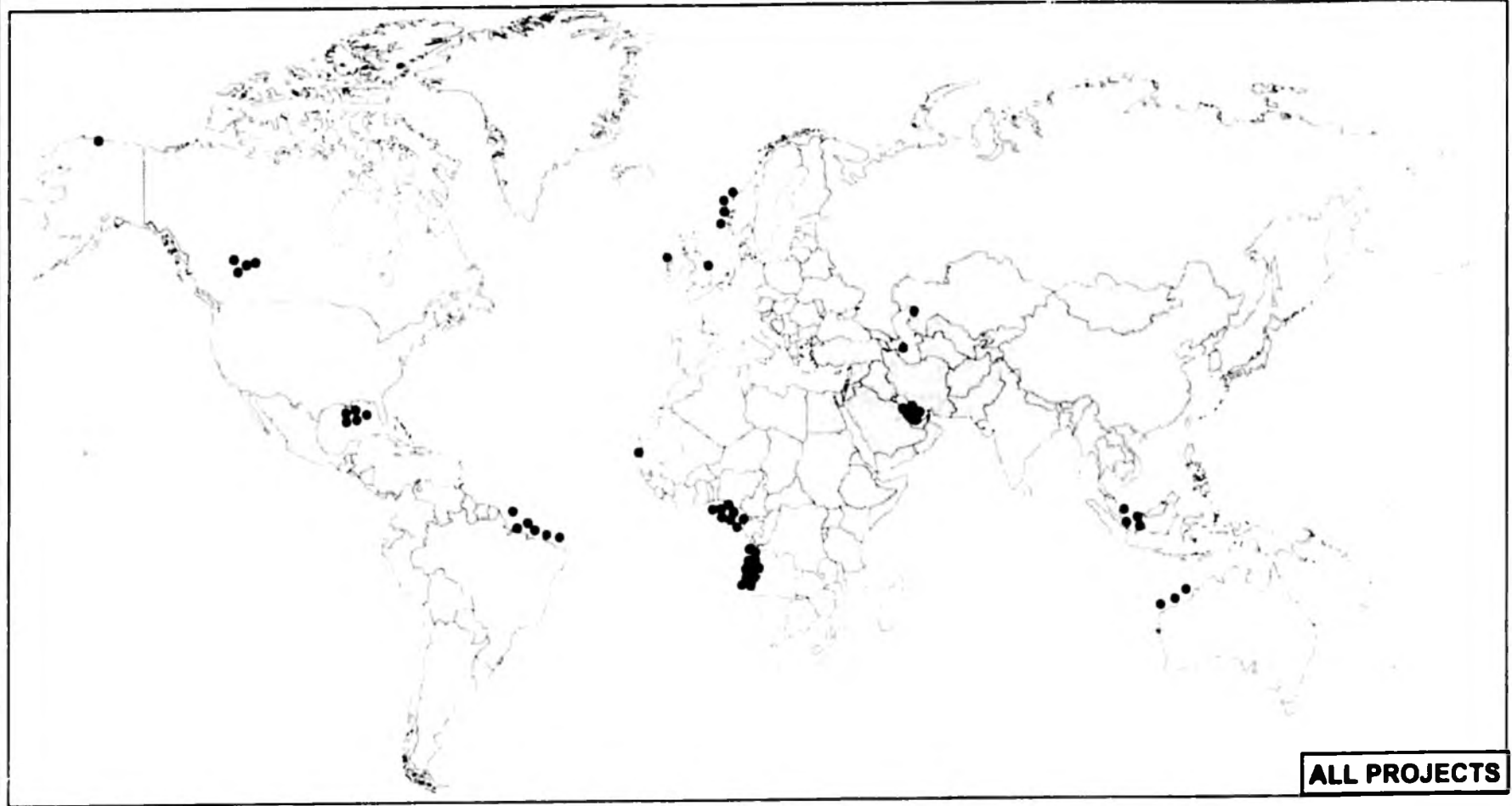
Projects Over \$1 Billion in CAPEX with Production Starting after 2005

	Total	of which OECD	of which Non-OECD
Total	55 (3 sponsors are in 32)	18 (10)	37 (22)
of which Oil	36 (21)	10 (6)	26 (15)
of which Gas	19 (11)	8 (4)	11 (7)

Some Issues with the PFC Analysis

- **Earlier work presented by P. Van Meurs in May 2006 using the same PFC database was done in real terms but discounted at 10%. This is equivalent to NPV 13.5 not NPV10 at 2.5% inflation. (This biases results against the Alaska gasline project since the comparisons were against NPV10 done in current dollars. This effect is not contained in Econ One's work.)**
- **For gas projects in the PFC database, transportation and regasification capital is excluded. (This biases the comparison of IRRs against the Alaska gasline project, which has pipeline capital in it.)**

Location of PFC Projects

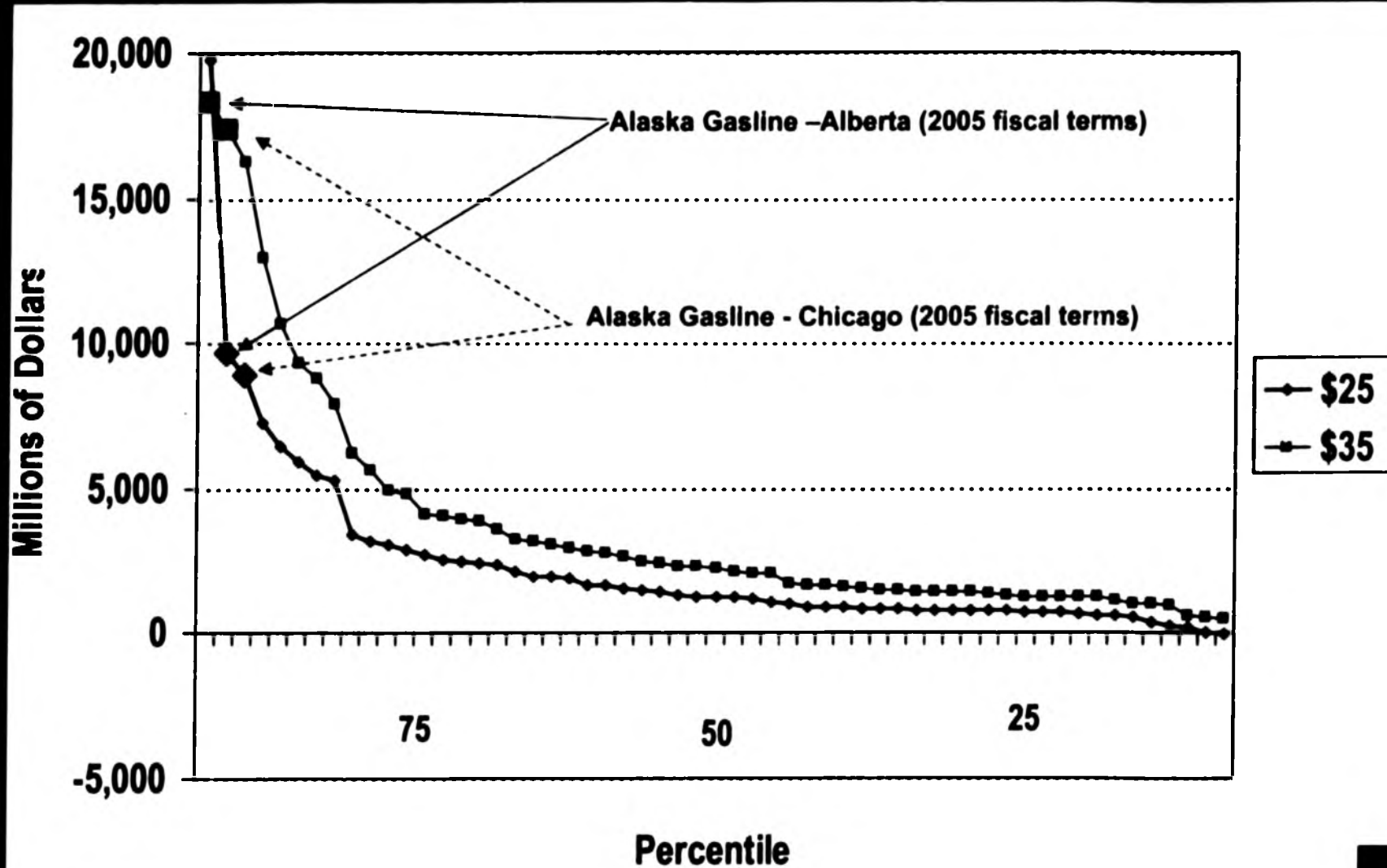


ALL PROJECTS

Project Comparison

Producer Net Cash Flow (NPV10)

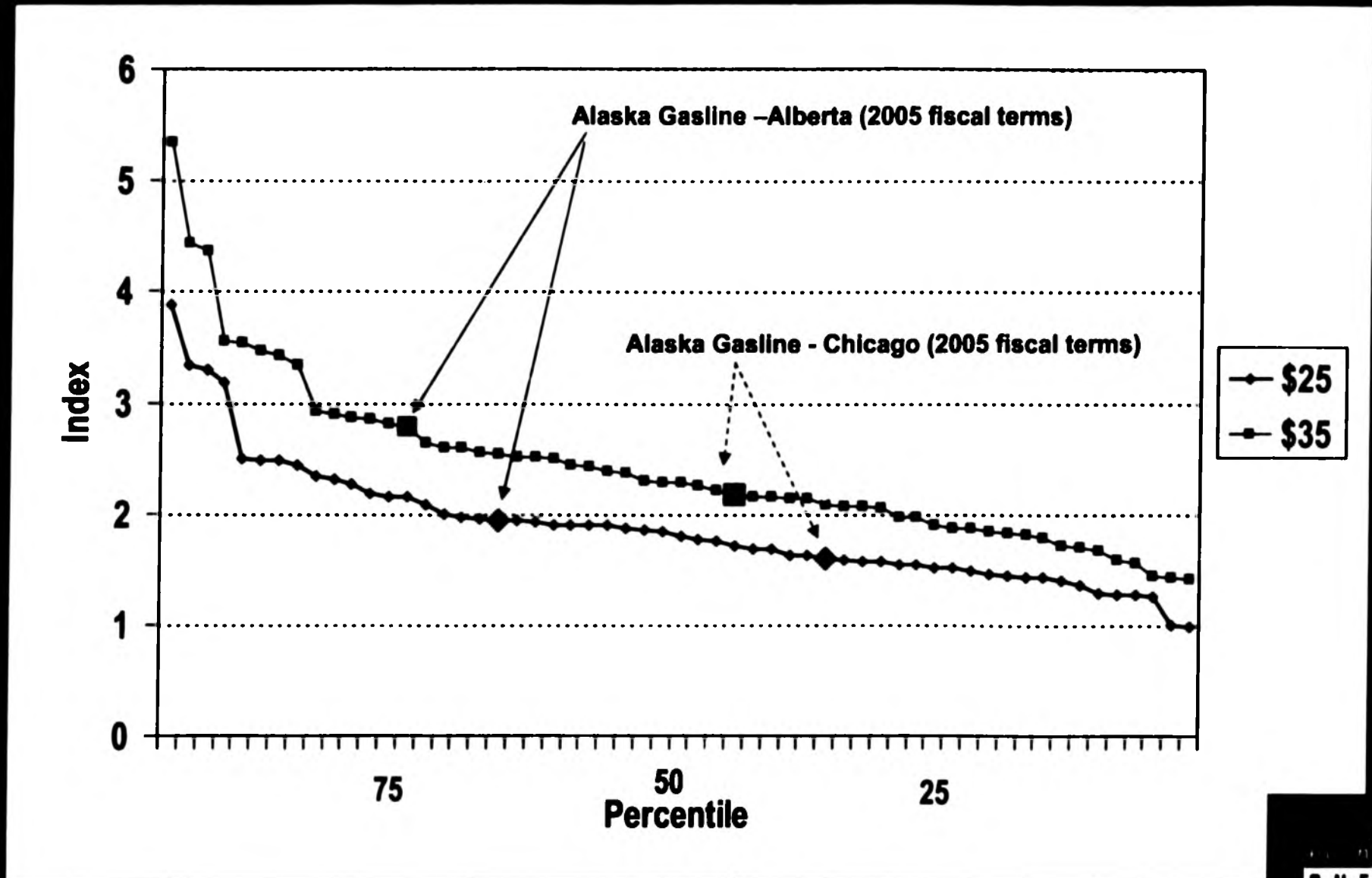
(\$35 and \$25 oil and 6-1 oil/gas price ratio)



Project Comparison

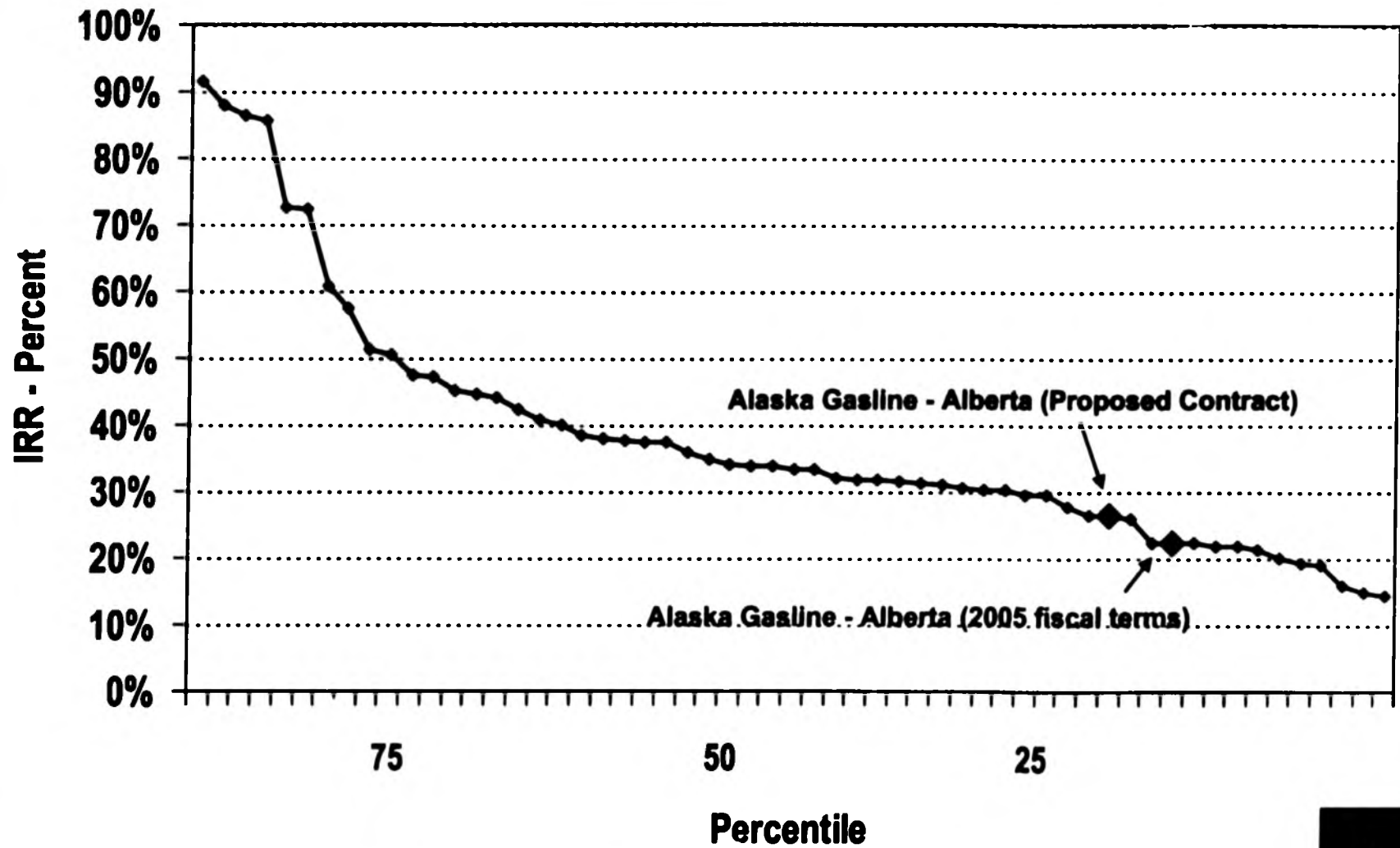
Profitability Index (PIR10)

(\$35 and \$25 oil and 6-1 oil/gas price ratio)



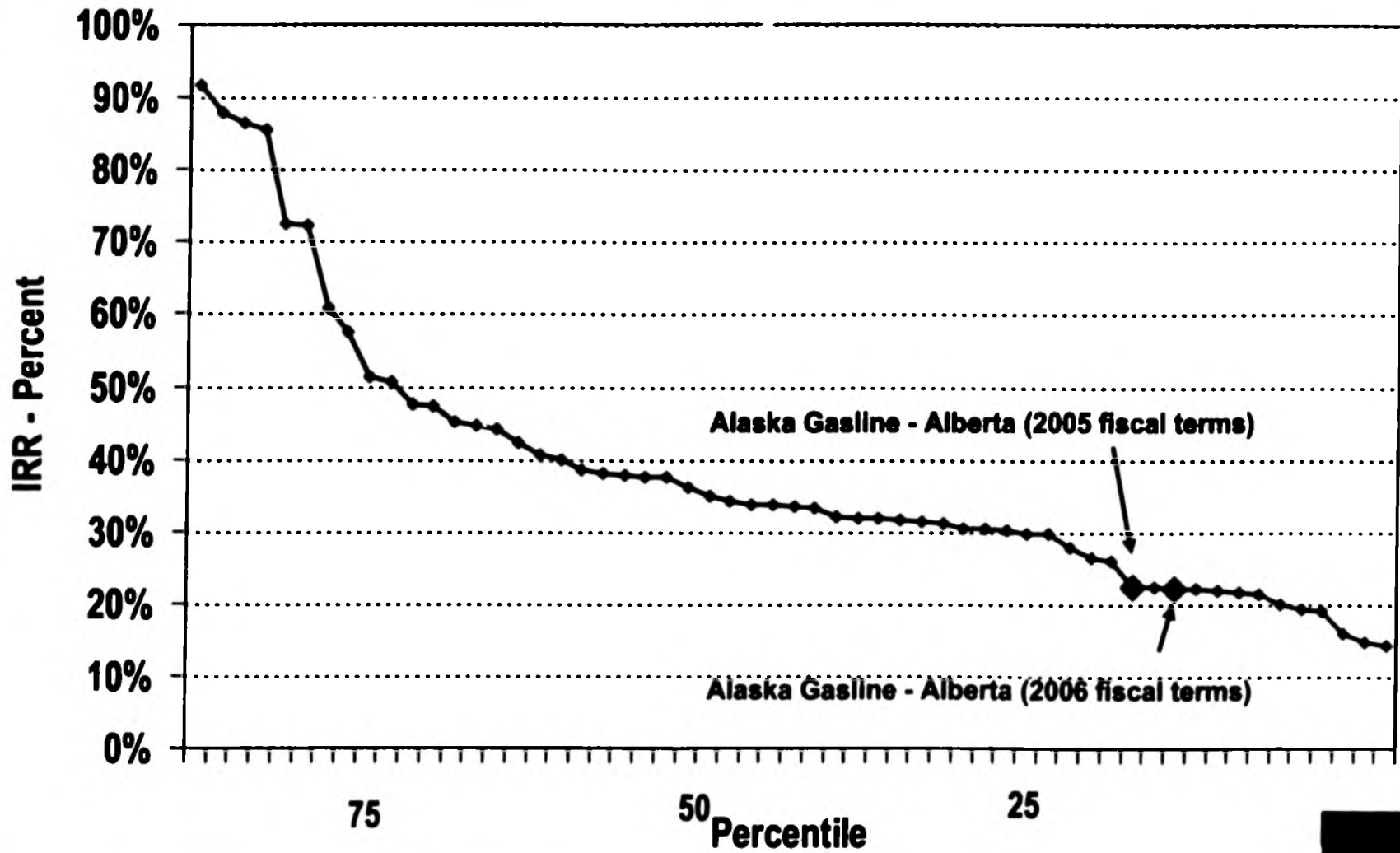
Effect of Proposed Contract on IRR

(\$35 oil and 6-1 oil/gas price ratio)



Effect of Fiscal Terms on IRR

(\$35 oil and 6-1 oil/gas price ratio)



Ranking of Alaska Gasline by Size Class

Gasline (Alberta) Ranking (\$35 oil and 6-1 oil/gas price ratio)

	Fiscal Terms	NPV10	PIR10	NPV10 per BOE	IRR
All Projects (including Alaska) (56)	2005 (ELF)	1/56	14/56	40/56	45/56
	2006 (PPT)	1/56	32/56	43/56	47/56
	Proposed Contract	1/56	8/56	35/56	43/56
Projects over \$3.5 Billion in CAPEX (16)	2005 (ELF)	1/16	5/16	8/16	11/16
	2006 (PPT)	1/16	5/16	9/16	12/16
	Proposed Contract	1/16	5/16	6/16	10/16

Project Ranking Summary

Ranking of Existing Projects (\$35 Oil and 6-1 Oil/Gas Price Ratio)

Category	Alaska Gasline Alberta 2005 Fiscal Terms	25%-tile	50%-tile (Median)	75%-tile	Ranking Quartile
Description					
Reserves (mmboe)	8,089	423	792	1852	4th 3rd 2nd 1st
CAPEX (\$mm)	28,123	1753	2806	3846	4th 3rd 2nd 1st
Financial Metrics					
NPV10 (\$M)	18,333	1404	2250	3865	4th 3rd 2nd 1st
NPV10/BOE	2.27	2.20	3.16	4.11	4th 3rd 2nd 1st
PIR10	2.78	1.90	2.28	2.63	4th 3rd 2nd 1st
IRR (%)	22.3	29.6	33.8	44.6	4th 3rd 2nd 1st

Source: PFC Energy and Econ One



Project Ranking Summary

Ranking of Existing Projects (\$25 Oil and 6-1 Oil/Gas Price Ratio)

Category	Alaska Gasline Alberta 2005 Fiscal Terms	25%-tile	50%-tile (Median)	75%-tile	Ranking Quartile
Description					
Reserves (mmboe)	8,089	423	792	1852	4th 3rd 2nd 1st
CAPEX (\$mm)	28,123	1753	2806	3846	4th 3rd 2nd 1st
Financial Metrics					
NPV10 (\$M)	9,667	435	1233	1635	4th 3rd 2nd 1st
NPV10/BOE	1.20	1.03	1.47	2.70	4th 3rd 2nd 1st
PIR10	1.94	1.51	1.83	2.16	4th 3rd 2nd 1st
IRR (%)	17.4	18.7	25.2	33.8	4th 3rd 2nd 1st

Source: PFC Energy and Econ One

Political Risk

- It is important to compare IRRs in relation to their risk-adjusted cost of capital.

IRR

(\$35 Oil and 6-1 Oil/Gas Price Ratio)

Project	IRR	Discount Rate?
Alaska Gasline (Alberta route)	22.3	10.0
Kashagan (Kazakhstan)	47.3	?
Shah Deniz (Azerbaijan)	21.7	?

Incorrect Ranking by IRR

- **Ranking projects on the basis of IRR in a capital constrained situation will often lead to suboptimal portfolio of projects**
- **This can be demonstrated in the PFC database**
- **Eliminated the top six projects and assumed a capital budget**
- **Ranked projects by PIR (preferred method) and by IRR (non-preferred method)**
 - **Used two examples for total capital available.**
- **The portfolio ranked by PIR provided higher NPV, monetized more Reserves, and used Less Capital**

Illustration of Incorrect Ranking by IRR

Projects Chosen from PFC List Excluding Largest Six

Project	Portfolio Sorted by PIR10					
	Capex	Capex NPV10	BOE	NPV10	PIR10	IRR
Gorgon	4,572	3,174	2,699	10,659	4.36	40.7%
Qatargas III	3,742	2,665	2,821	6,212	3.33	31.5%
Agbami	4,258	2,741	999	4,105	2.50	37.5%
Total	12,572	8,580	6,519	20,977		
	Portfolio Sorted by IRR					
Dalia	3,846	3,115	999	3,584	2.15	42.3%
Gorgon	4,572	3,174	2,699	10,659	4.36	40.7%
Agbami	4,258	2,741	999	4,105	2.50	37.5%
Total	12,676	9,030	4,697	18,348		

Illustration of Incorrect Ranking by IRR

Projects Chosen from PFC List Excluding Largest Six

Project	Portfolio Sorted by PIR10					
	Capex	Capex NPV10	BOE	NPV10	PIR10	IRR
Gorgon	4,572	3,174	2,699	10,659	4.36	40.7%
Qatargas III	3,742	2,665	2,821	6,212	3.33	31.5%
Agbami	4,258	2,741	999	4,105	2.50	37.5%
Ormen Lange	6,695	5,500	2,300	7,886	2.43	30.3%
Total	19,267	14,080	8,819	28,863		
	Portfolio Sorted by IRR					
Dalia	3,846	3,115	999	3,584	2.15	42.3%
Gorgon	4,572	3,174	2,699	10,659	4.36	40.7%
Agbami	4,258	2,741	999	4,105	2.50	37.5%
Greater Plutonia	4,318	3,025	1,195	3,189	2.05	31.8%
Qatargas III	3,742	2,665	2,821	6,212	3.33	31.5%
Total	20,737	14,720	8,713	27,749		

Conclusions

Among the projects in the PFC dataset used:

- **Alaska Gasline is LARGEST project in terms of CAPEX and Reserves added**
- **Gasline has BEST financial performance (NPV10) at “best estimate” prices and assumptions under 2005 fiscal terms**
 - **Gasline does NOT fall out of top quartile under lower price scenarios**
- **Gasline has PIR (“biggest bang for buck”) in top half of projects**
- **Gasline NPV10 per BOE is in third quartile under most price cases**
- **Gasline has low IRR, but as shown earlier, IRR is NOT USEFUL for comparison between projects that do not include all the capital, are of different scale, or of different risk. (All three conditions hold.)**

Greenberg Taurig

Memorandum

TO: Senator Therriault
Representative Samuels
Joe Balash
Henry Webb
Bonnie Robson

FROM: Donald C. Shepler

DATE: April 22, 2005

RE: Competitive Analysis of Producer-Owned Alaska Natural Gas Pipeline

At your request we have examined the competitive issues that might arise in the context of an Alaska natural gas pipeline if owned by the major North Slope producers. As you are aware, in 1977 the U.S. Attorney General recommended that such ownership be prohibited in implementing the Alaska Natural Gas Transportation Act ("ANGTA"). President Carter later forbade any producer ownership interest in the ANGTA pipeline. Recently, on January 28, 2005, those historical events were highlighted when the Chairman of the FERC wrote that the Commission would be mindful of competitive issues in reviewing any certificate application for a producer-owned line and noted that the antitrust concerns of the 1970's were "still valid and will be addressed" by the Commission.

Our analysis of the competitive issues is set forth in the accompanying memorandum by Ken Minesinger and Cecil Chung of Greenberg Taurig.¹ We conclude that the vertical integration arising from the largest North Slope producers also owning the only gas pipeline out of the state continues to raise serious competitive issues. Indeed, based on FTC precedent there is a significant chance that if the pipeline existed today the major producers would not be allowed to acquire it, largely because, and in contrast with an independent pipeline, the producer-owners would have the incentive and the ability to use their control over the pipeline to discriminate against rival producers and delay or defeat an expansion. Another concern relates

¹ Mr. Minesinger, who is a past Chairman of the Antitrust Committee of the Energy Bar Association, has a unique combination of antitrust experience, having worked on numerous mergers involving major natural gas pipelines and other energy companies before the Federal Trade Commission ("FTC") and Department of Justice, and FERC experience, including several major FERC market power cases involving natural gas pipelines. Mr. Chung worked for years on the staff of the FTC -- the federal antitrust agency that typically reviews natural gas pipeline as well as many other energy sector mergers and acquisitions. While at the FTC, Mr. Chung investigated numerous energy industry mergers and acquisitions, including several natural gas pipeline transactions, and has continued to work on energy matters in private practice.

to the ability of producer-owners to raise rates on the pipeline, thereby raising the real cost to their competitors of doing business in Alaska. Such discrimination and delay could potentially cause competing producers to sell their leases at distress prices or even surrender their leases. Thus, an independent pipeline would be notably superior to a producer-owned pipeline from a competitive perspective.

We would anticipate that if the North Slope producers file for FERC approval of a pipeline the Commission would be required to address these competitive problems. This could well require that FERC adopt remedies that go beyond its existing regulations recently promulgated in Order No. 2005, and under Order No. 2004 (dealing with treatment of affiliates who own capacity on interstate pipelines).² These new remedies would likely include "structural" remedies which FTC and DOJ, and in some instances FERC itself, favor as a more effective means of preventing anticompetitive conduct than regulatory remedies. Such remedies could include: (1) partial divestiture to an independent pipeline; (2) establishment of an independent system operator, with the power to require expansions; and, (3) creation of an independent market monitor. FERC has adopted some of these remedies in electric utility cases, although these remedies would essentially be "new ground" in the context of a FERC pipeline certificate proceeding.

Although we deem it unlikely that FERC would refuse to certificate a producer-owned pipeline, we believe that a producer application would encounter moderate to significant delay compared to an application by an independent pipeline company due to litigation of the competitive and remedial issues identified above. This process could well result in conditions being imposed on the certificate that will be unacceptable to the producer-owners, who, in the end, may elect not to build the pipeline after all. An independently owned pipeline, by contrast, would face the same rate, tariff, design and environmental review processes at the FERC, but none of the competitive concerns that would give rise to such delay and risk that the pipeline will not be built.

² Order No. 2005—dealing with open season rules for an Alaskan pipeline—is the subject of rehearing petitions filed by the North Slope producers. Further, ChevronTexaco has filed an appeal of Order No. 2005 in the U.S. Court of Appeals for the District of Columbia Circuit (Case No. 05-1111).

Greenberg Traurig

Memorandum

TO: Senator Therriault
Representative Samuels
Joe Balash
Henry Webb
Bonnie Robson

cc: Donald C. Shepler

FROM: Kenneth M. Minesinger
Cecil Chung

DATE: April 22, 2005

RE: Competitive Analysis of Producer-Owned Alaska Natural Gas Pipeline

Introduction and Executive Summary

In 1977 the United States Attorney General warned that producer ownership of the Alaska natural gas pipeline would raise serious competitive concerns. You have asked us to address whether similar concerns exist today, and in particular whether ownership of the Alaska natural gas pipeline by a joint venture formed by the three major oil and gas producers in Alaska – BP, ConocoPhillips, and Exxon (the “Big 3”) – would violate the federal antitrust laws or otherwise raise significant competitive issues. This memorandum concludes that the same or similar competitive issues identified by the Attorney General in 1977 continue to exist today and that time-consuming litigation regarding these issues and potential remedies is likely.

More specifically, a producer-owned pipeline would raise the following competitive issues, based on the available facts:

- A strong argument can be made that Big 3 ownership of the Alaska gas pipeline would raise serious competitive concerns, based on Federal Trade Commission

("FTC") and Department of Justice ("DOJ") consent decrees, and precedents of the Federal Energy Regulatory Commission ("FERC").

- For example, although we have not had the benefit of obtaining an expert economist's views on this subject, a significant risk exists that a pipeline owned by the Big 3 would have the incentive and the ability to discriminate against rival producers, including by delaying or defeating any pipeline expansion needed to serve rivals. An independent pipeline typically would not involve this or similar risks.
- FERC regulations that attempt to prevent this kind of anticompetitive conduct would not be dispositive in an FTC/DOJ antitrust analysis. Despite the existence of FERC regulation, the antitrust agencies have actively sought to prohibit anticompetitive mergers and activities in the energy industry, and have developed a strong preference for "structural" remedies such as divestiture over "behavioral" remedies such as FERC's "firewall" regulations. According to the antitrust agencies, a behavioral/regulatory remedy can be evaded and "does not eliminate the incentive and opportunity to engage in exclusionary behavior."¹
- FERC is, nevertheless, highly relevant because a separate FTC or DOJ investigation is, while not inconceivable, unlikely, and any dispute over the competitive issues posed by Big 3 ownership of the pipeline would likely be addressed in a FERC certificate or complaint proceeding. FERC Chairman Wood has recently stated that FERC will fully consider antitrust concerns, and it is possible that FERC would make its certificate decision with input from the FTC or DOJ.
- Although it is possible FERC could decide that its existing regulations sufficiently protect against the exercise of market power (contrary to the what the Big 3 themselves have argued in other cases), based on the unique facts associated with the Alaska pipeline we think there is a not insignificant chance that FERC could be convinced to impose remedies that go beyond its existing regulations, including, by way of example:
 - divestiture of an undivided ownership interest to a third-party so that the Big 3 could not thwart an expansion, and each pipeline owner would be forced to compete against the other pipeline owners;
 - establishment of an independent operator of the pipeline system, thus taking operational control away from the Big 3; and

¹ FTC Perspective on Competition Policy and Enforcement Initiatives in Electric Power. Prepared Remarks by William J. Baer, Bureau of Competition, FTC, before the Conference on the New Rules of the Game for Electric Power: Antitrust & Anticompetitive Behavior (December 4, 1997).

- establishment of a market monitor as a means of policing and deterring competitive abuses.
- Finally, although we believe it is unlikely that FERC would refuse to certificate a pipeline owned by the Big 3, smaller producers and perhaps others can be expected to ask to litigate the competitive issues raised by Big 3 ownership of the pipeline, and potential remedial solutions. These parties will likely urge FERC to solve these issues at the outset of the project – in contrast to the situation on TAPS, which some parties contend is infected with competitive problems similar to those discussed herein. As a result of such litigation, the potential exists for moderate or even significant delay in the FERC certificate process.

Background

Currently, the Big 3 hold 95 percent of Alaska's known natural gas reserves. The Big 3's reserves are concentrated in the Prudhoe Bay and Point Thomson production areas, and are adequate to support a pipeline with a capacity of approximately 4.5 Bcf/day. In addition, the total magnitude of the State's gas resources base is widely estimated to be many times the level of the known Prudhoe Bay and Point Thomson reserves. Third-party producers and explorers are seeking to develop these additional natural gas resources in competition with the Big 3. Currently, there is no pipeline that transports Alaska natural gas to the Lower 48 states, and it is anticipated that only one pipeline to the Lower 48 states will be constructed.

In addition to controlling most of Alaska's known reserves, the Big 3 also have a significant presence in natural gas sales markets in the Lower 48 states. According to one recent report, the Big 3 appear to account for 30-35 percent of the sales by natural gas marketers in the U.S. See "*E&P Firms Rule Revitalized Gas Wholesale Market*," *Gas Daily*, at 1, 5-6 (March 14, 2005).

Also relevant to this memorandum are, in addition to FERC's existing regulations under the Natural Gas Act ("NGA"), the recently enacted Alaska Natural Gas Pipeline ("ANGPA") and the regulations FERC recently issued in Order No. 2005 pursuant to ANGPA. Because Don Shepler has previously summarized these authorities in detail, we will not do so here other than to note FERC has observed that "the tremendous size, scope, and cost of an Alaskan pipeline, the long lead-time needed for such a project, environmental sensitivities, and the competitive conditions that are unique to such a project warrant *special consideration and oversight.*" Order No. 2005 at ¶ 9 (emphasis added). In our view, any competitive analysis of the Alaska natural gas pipeline should account for the unique circumstances of this project.

Finally, the history of prior legislative efforts to encourage the construction of an Alaska natural gas pipeline also bears mention. As Don Shepler mentioned in his memorandum to you dated February 11, 2005, in passing the Alaska Natural Gas Transportation Act ("ANGTA") in the 1970s, Congress directed the President to choose an applicant from among three parties who were pursuing competitive proposals at the Federal Power Commission, and required the Attorney General to analyze antitrust issues relating to the proposals. In 1977, based on his review of the relevant facts and antitrust principles, President Carter's attorney general recommended that the Commission not issue a certificate to a producer-owned pipeline, as a producer-owned pipeline "would seek to restrict access and throughput to take monopoly profits." Report at page v. The Attorney General also concluded that "producer-ownership of the pipeline creates incentives to deny or impede . . . future capacity expansion", *id.* at 39-41, and that "it will be in the interest of producer-owners to resist future expansion and thus discourage future entry into Alaskan gas production." *Id.* at 43. Based on the Attorney

General's report, President Carter prohibited producer ownership in any ANGTA pipeline. In 1981, President Reagan waived the prohibition on producer ownership, but only on the condition that FERC consider the views of DOJ on the issue "and upon a finding by the [FERC] that the agreement [on producer participation] will not (a) create or maintain a situation inconsistent with the antitrust laws or (b) in and of itself create restrictions on access to the Alaska segment of the [proposed pipeline]."

Recently, on January 4, 2005, an Alaska state legislator brought the Attorney General's 1977 report and President Reagan's conditional waiver to FERC's attention, and sought guidance from FERC regarding whether antitrust concerns will prevent the North Slope producers from owning the Alaska gas pipeline. In a letter dated January 28, 2005, FERC Chairman Wood responded by stating that in acting on any application to construct an Alaska natural gas pipeline, FERC "will be mindful of the congressional and presidential pronouncements" discussed above. In addition, Chairman Wood emphasized that "it would be prudent to conclude that the antitrust issues which concerned Congress and the President over twenty years ago are still valid and will be addressed by our Commission in our proceedings."

Discussion

Ownership of the Alaska gas pipeline by the Big 3 raises two separate but related competitive issues. First, the collaboration among the Big 3 to form a joint venture to build the pipeline should be examined as an agreement among competitors, also known as a horizontal agreement. Second, the Big 3's ownership of the pipeline constitutes a vertical integration of the pipeline and shippers that will use the pipeline's transportation services, and for that reason

vertical merger analysis provides an important analytical tool. We address each of these issues below.

I. A Big 3 Joint Venture To Own The Alaska Gas Pipeline Should Not Raise Horizontal Competitive Concerns.

As a general proposition, the idea of forming a joint venture to construct a gas pipeline that will transport huge quantities of previously untapped gas supplies from a remote production region to a consumption area is undoubtedly pro-competitive when viewed in isolation. It is often necessary and in fact efficient for horizontal competitors to pool resources to undertake a project that would be too large or risky for a single company.²

Nonetheless, "who" participates in such collaboration, in "what ways", and under "what conditions and terms" remain important questions in determining the legality of the proposed joint venture. Moreover, even a legitimate horizontal joint venture often raises the so-called "spillover effects" issue. Unless carefully structured and monitored, anticompetitive effects could occur outside the joint venture's legitimate area of horizontal collaboration. An examination of such potential issues should not be put aside until after the joint venture is already in operation. In the present context, this means that even though the formation of the joint venture would generally be lawful, if possible the joint venture should be structured in such a way that does not give rise to the competitive issues identified in the 1977 Attorney General's report, including incentives by the Big 3 to resist expansion, deter entry, and encourage

² In addition, sometimes what appears to be a legitimate, pro-competitive horizontal collaboration to offer a new product or service could be a carefully designed attempt to cover up an otherwise per se illegal output reduction or market allocation agreements by the joint venture partners. For purposes of this analysis we have assumed that the Big 3, under the guise of the joint venture, have not entered into a naked agreement to block construction or expansion of the pipeline or some other impermissible agreement not to compete.

competitors to abandon their leases and exit the market. We proceed to address those subjects in the next section.

II. A Big 3 Joint Venture To Own The Alaska Gas Pipeline Would Likely Raise Serious Vertical Competitive Concerns.

A. Vertical Merger Standards Currently Applied by the FTC, DOJ and FERC Echo the Concerns Expressed by the Attorney General In 1977 About a Producer-Owned Pipeline.

If the Alaska pipeline had already been built and then acquired by the Big 3 through a merger or acquisition, that would be considered a "vertical" merger, as it would combine a supplier (the pipeline) with certain of its customers (the producers who ship gas through the pipeline). As a result, our analysis begins with the vertical merger standards applied by the FTC and DOJ.

The federal antitrust enforcement agencies' vertical merger enforcement has gone through profound changes over the years. In the 1960's and 1970's, the agencies took an aggressive stance to block certain vertical mergers that would today easily pass muster as pro-competitive or competitively-neutral. In the 1980's and early 1990's, the agencies took a highly permissive attitude towards vertical mergers. In the recent past, however, the pendulum has swung back. Armed with modern theories of vertical merger analysis, such as a theory of raising rivals' costs ("RRC"), today's federal antitrust agencies have shown an increased level of attention to vertical mergers, especially involving those in the energy sector in the wake of deregulation in various aspects of gas and power businesses.

Currently, the FTC and DOJ have three principal concerns regarding vertical mergers. First, a vertical merger may give the merged firm the incentive and ability to foreclose rivals from competing, either by raising rivals' costs or through other forms of discrimination that may

harm rivals' ability to compete and either encourage them to exit the market or discourage potential rivals from entering the market. Second, a vertical merger may facilitate collusion. Third, a vertical merger may enable the merged firm to evade regulation.

Although most vertical mergers do not raise competitive concerns, in the past decade several transactions in the energy industry have been challenged by the FTC. For example:

- In *Dominion Resources*,³ the FTC maintained that the acquisition of Virginia Natural Gas ("VNG"), the primary natural gas pipeline distributor in southeastern Virginia, by Dominion Resources, a major electric power generator in southeastern Virginia, would likely deter or disadvantage entry by independent power generation companies because Dominion could use VNG to raise the costs of entry and/or electricity production to new entrants. As a result, the FTC required Dominion to divest VNG.
- In *Shell/Texaco*,⁴ the FTC found that Shell's proposal to form a joint venture with Texaco would have adverse vertical effects. Texaco owned the only pipeline carrying undiluted heavy crude oil to asphalt refineries in the San Francisco area, including Shell's refineries and refineries owned by third-parties that competed against Shell. The FTC alleged that the joint venture could raise rival asphalt refiners' cost of pipeline transportation, and therefore required a long-term fixed price supply agreement between the pipeline and the competing asphalt producers.
- In *Detroit Edison*, in order to address concerns that the acquisition of a major natural gas pipeline by a major electric generator could give the merged firm the incentive and ability to discriminate against competing generators, the FTC effectively required divestiture of an interest in the pipeline to an independent competitor, thereby essentially creating two independent, competing pipelines within one physical pipeline facility.⁵

³ FTC Dkt. No. C-3901 (1999).

⁴ FTC File No. 971-0026 (1997).

⁵ FTC File No. 001-0067 (2001). In addition to these and other mergers in the energy industry, the agencies also have challenged numerous vertical mergers in industries outside the energy industry. See, e.g., *Cytec/Digene*, FTC File No. 021-0098 (2002) (vertical merger abandoned after the FTC decision to block it in federal court; liquid Pap tests upstream and DNA-based test for the cervical cancer-causing HPV downstream); *Cadence Design Sys., Inc.*, 124 F.T.C. 131 (1997); *Time Warner Inc.*, 123 F.T.C. 171 (1997); *Silicon Graphics, Inc.*, 120 F.T.C. 928 (1995); *Alliant Techsystems, Inc.*, 941-0123 (1994); *Eli Lilly & Co.*, 120 F.T.C. 243 (1995); *Martin Marietta Corp.*, 117 F.T.C. 1039 (1994); *United States v. MCI Communications Corp.*, 1994-2 Trade Cas. (CCH) ¶ 70,730 (D.D.C. 1994) (DOJ consent; upstream market for international telecommunication services in U.S. by MCI and downstream market for international telecommunication services in U.K. by British Telecom; raising rivals' costs and regulatory evasion concerns); *AT&T/McCaw* (DOJ consent; upstream market for cellular infrastructure equipment

Following the lead of the antitrust agencies, in recent years FERC itself has carefully scrutinized vertical mergers pursuant to its authority under Section 203 of the Federal Power Act to review mergers and acquisitions of jurisdictional electric facilities. FERC has focused particularly on transactions that involve a bottleneck transportation line, *i.e.*, natural gas pipelines or electric transmission facilities. Similar to the approach utilized by the FTC and DOJ, FERC's concern has generally been that a vertical merger of this type would give the merged firm the incentive and ability to use a natural gas pipeline or electric transmission facility to discriminate against rival electric generators. Numerous FERC orders, including its Merger Policy Statement, reflect FERC's concern about the potential for anticompetitive effects resulting from vertical mergers. *See, e.g.*, Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement, Order No. 592, 61 Fed. Reg. 68,595 (1996), FERC Stats. & Regs. Regulations Preambles January 1991-June 1996 ¶ 31,044 (1996), order on reconsideration, Order No. 592-A, 62 Fed. Reg. 33,341 (1997), 79 FERC ¶ 61,321 (1997); *Oklahoma Gas and Electric Company, NRG McClain LLC*, 105 FERC ¶ 61,257 (2003); *Dominion Resources, Inc. and Consolidated Natural Gas Company*, 89 FERC ¶ 61,162 (1999); *San Diego Gas & Electric Company and Enova Energy, Inc., et al.*, 79 FERC ¶ 61,372 (1997), order denying reh'g, 85 FERC ¶ 61,037 (1998).

and downstream market for cellular services; raising rivals' costs and increased anticompetitive coordination concerns; 1994); *United States v. Tele-Communications Inc.*, 1994-2 Trade Cas. (CCH) ¶ 71,496 (D.D.C. 1994); *Tele-Communications Inc.*, 119 F.T.C. 593 (1993); *Atlantic Richfield Co.*, 113 F.T.C. 1050 (1990).

The scrutiny applied by the FTC, DOJ and FERC to vertical mergers over the past decade demonstrates that, in general, these agencies have the same concerns about vertical mergers that the Attorney General had in 1977 when he concluded that a producer-owned Alaska gas pipeline would create serious vertical issues. The common thread is the concern, then and now, that a bottleneck transportation facility could be used to foreclose rivals who depend on the facility to compete in selling various forms of energy, including electricity, oil and natural gas. Indeed, due to deregulation of many natural gas and electricity wholesale transactions, the recent vertical cases brought by the FTC, DOJ and FERC reflect a renewed concern that vertical mergers could cause increased prices for consumers and lead to less competition in deregulated markets if a transportation facility can be used to limit competition in those markets. Thus, any suggestion by the Big 3 that the basic principles on which the Attorney General relied in 1977 are outdated or no longer relevant would lack foundation, and would simply ignore the long line of recent vertical cases brought by these agencies.

B. Big 3 Ownership of the Alaska Gas Pipeline Would Raise Serious Competitive Concerns.

1. The Big 3 Would Likely Have the *Incentive To Use the Alaska Gas Pipeline To Discriminate Against Rivals.*

The challenge for the Big 3 will be to distinguish their situation from the numerous, recent cases in which the FTC, DOJ and/or FERC have identified vertical issues as a serious competitive concern, to explain why the concerns identified by the Attorney General in 1977 were either in error or no longer exist, and to demonstrate that the competitive problems which have allegedly occurred with regard to TAPS will not replicate themselves here. In analyzing this issue, we have assumed that only one pipeline will be constructed, that it will extend from

production areas in Alaska to a destination area or areas in the Lower 48 states, such as a market hub in the midwestern U.S., and that the Big 3 will hold the substantial majority of the pipeline's firm transportation rights and own approximately 95 percent of the gas reserves that initially will be transported through the pipeline.

Although we have not had the benefit of an expert economist's views, on its face the ownership of the Alaska pipeline by the Big 3 would appear to raise serious long-term competitive concerns. Indeed, FERC essentially said this already in Order No. 2005 (¶ 12): "we are well aware of the risks to competition imposed by a project that is owned or primarily sponsored by a small group." For competing producers, and perhaps for some downstream customers as well, there would be no realistic alternative to pipeline transportation of Alaska gas. Thus, whoever owns and controls the pipeline will have market power. A profit-maximizing firm should be presumed to pursue every possible lawful (and sometimes unlawful) means to maximize its profits, strengthen its competitive position in the marketplace, or weaken its rivals' competitive position. Having market power over the natural gas pipeline transportation segment of the overall natural gas business will further bolster the inherent incentive of the Big 3 to disadvantage their rivals in the production and sale of natural gas.

The Big 3 would vigorously dispute these conclusions. We have considered potential counterarguments that the Big 3 could offer, but none appears to satisfactorily address the competitive concerns created by their ownership of the pipeline.

For example, the Big 3 might argue that they lack market power in the downstream market for natural gas sales, and therefore lack any incentive to discriminate against rival sellers. In other words, the Big 3 would argue that they have such an insignificant share of the natural

gas sales market that they would lack any incentive to exercise market power over transportation, because the lost revenue from transportation would not be offset by increased gas sales revenue. To support this argument, the Big 3 would have to employ a broad definition of the market. Thus, they might argue that the entire United States and Canada, or the United States alone, constitute a single market and, under that market definition, they cannot possibly have market power in gas marketing and sales.

However, any argument by the Big 3 that the market includes the entire U.S., or the U.S. and Canada combined, would conflict with numerous cases that rely on a much narrower market definition. In case after case involving the natural gas industry, the FTC has typically relied on a geographic market definition that includes all alternatives within a fairly local area, such as a 50-mile radius. *See, e.g., Southern Union/CMS Energy*, FTC File No. 031-0068 (2003) (consent order) (pipeline transportation of natural gas to certain consuming areas in Missouri and Kansas); *El Paso/Coastal*, FTC Dkt. No. C-3996 (2001) (consent order) (two separate product markets—natural gas pipeline transportation and long term firm transportation of natural gas; several distinct geographic markets—natural gas consuming areas in certain counties in central Florida; consuming areas in several distinct metropolitan statistical areas in New York; consuming area in certain counties in Indiana; certain producing areas in the central Gulf of Mexico; certain producing areas in the west central Gulf of Mexico); *El Paso/Sonat*, FTC Dkt. No. C-3915 (2000) (consent order) (three separate markets for natural gas transportation alleged: transportation out of the producing fields in the east-central Gulf of Mexico; transportation out of the producing fields in the west-central Gulf of Mexico; and transportation into gas consuming areas in certain portions of eastern Tennessee and northern Georgia); *FTC v. Questar Corp.*, No.

2:95CV1137S (D. Utah 1995) (Questar's proposed acquisition of Kern River; natural gas market in Salt Lake City, Utah; transaction abandoned). FERC has also relied on a similarly narrow geographic market definition in analyzing market power issues involving natural gas pipelines. *See, e.g., Koch Gateway Pipeline Co.*, 89 FERC ¶ 61,046 (1999).

The narrower market definition employed in these cases is logical because the market for the delivery and sale of natural gas is constrained by the physical limitations of production areas and gas pipelines. A gas pipeline that delivers gas to Portland, Maine simply does not compete in any real sense with a gas pipeline that delivers gas to, say, San Diego, California. Similarly, gas marketers with pipeline capacity rights on a pipeline that delivers gas to Chicago do not realistically compete, for the sales they make in the Chicago area, with gas sold by marketers at a distant location such as Miami, Florida. Thus, any attempt by the Big 3 to use a broad U.S./Canada market definition would conflict with established precedent and with the fundamental realities of the natural gas business.

If the downstream market is defined more narrowly to constitute the sale of gas in, for example, Chicago and other "Mid-Continent" areas, it seems likely that the Big 3 will have a sufficient market share to give them an incentive to use the Alaska gas pipeline to discriminate against rivals.⁶ Ultimately, whether the Big 3 have market power (individually or collectively) in a relevant downstream gas sales/marketing market under accepted standards applied by the FTC,

⁶ In addition, it would be a mistake to think that there will be only one common consumption market served by the Alaska gas pipeline, even if the pipeline terminates at a single destination point. Actual pipeline interconnections to each local consumption market served along the route of the pipeline would determine how much gas from what producing areas could be available to consumers in a given area. While we have not undertaken a detailed analysis of what each of the potential relevant local consumption markets would look like, there likely would be some particular areas where the Big 3 or a member of the Big 3 have a substantial market share.

DOJ, or FERC is a fact-intensive question requiring an expert economic analysis. However, it is probably reasonable to assume that the Big 3, individually or collectively, have a major gas sales presence on Mid-Continent pipelines. Although a detailed factual investigation would be required to reach any final conclusion, it seems likely that further analysis will simply better define the extent of the Big 3's market share rather than demonstrate that the Big 3 lack a significant market share.⁷

Even if one ignores the precedents of the FTC and FERC and relies on a broad market definition, recent evidence indicates that the Big 3's market share would still be very substantial. According to one recent study, Amoco and Conoco are by far the largest natural gas marketers in the U.S. By one measure, the Big 3 appear to have a combined market share in the U.S. of approximately 30-35 percent. See "*E&P Firms Rule Revitalized Gas Wholesale Market*," *Gas Daily*, at 1, 5-6 (March 14, 2005) (Source: company SEC filings). Given a market share of that size, at a minimum a plausible argument can be made that the Big 3 would have an incentive to discourage other producers in Alaska from engaging in robust production of additional gas, causing a deluge of new gas to enter the market and depress the price that the Big 3 can receive for their sales in the lower 48 states.

The Big 3 may also argue that they would have no incentive to discriminate against third-party gas producers because it will cost third-parties more to explore for and produce gas than it will cost the Big 3, who have established fields whose production costs are presumably lower. However, if the third-party gas producers are already cost-disadvantaged, then the potential harm

⁷ Because the Big 3's pipeline project involves multiple competitors at each level rather than a single upstream company and a single downstream company, for purposes of a comprehensive analysis of vertical issues their market shares should be aggregated both in the upstream Alaska natural gas exploration and production market and the downstream natural gas local marketing and sales markets.

from foreclosure from meaningful access to the pipeline would seemingly be even more serious, because it would take even less effort for the integrated firm to successfully raise rivals' costs by directly or indirectly denying access to the pipeline. By engaging in such exclusionary conduct, the integrated firm may lose some revenue in the short term. However, such short-term transportation service revenue shortfalls will be offset by the rivals' exit from the market or reduced competitiveness. In addition, exclusionary actions by the Big 3 would tend to further discourage new entry into the upstream exploration and production market, including a reduction in competition for new leases, thereby hindering the development of new production areas.⁸

Any argument by the Big 3 that they lack an incentive to discriminate would also directly conflict with FERC precedent regarding pipeline/affiliate relationships. FERC orders recognize the inherent incentive for a vertically integrated company to use transmission facilities to harm rivals in upstream or downstream markets. In Order Nos. 136 and 636, FERC encouraged, and then required, pipelines to offer open access transportation to third-parties because of the strong incentive for a pipeline to favor gas owned by the pipeline or its affiliate. In addition, in Order Nos. 497 and 2004, FERC issued a series of regulations that attempt to address the competitive concerns raised by vertical integration between pipelines and their gas marketing affiliates. Here, the Big 3 presumably would hold an atypically large percentage of the capacity on the Alaska gas pipeline, more than 50 percent and probably up to 75 percent.⁹ On what would be the

⁸ See, e.g., *Atlantic Richfield Co.*, 113 F.T.C. 1050 (1990) (FTC alleged that the vertical merger involving chemicals would reduce the size of the merchant market for the upstream input product, making entry into that upstream market less likely and reducing the possibility of eventual deconcentration of that market).

⁹ We assume that the State of Alaska and third-parties will hold approximately 25 percent of the firm capacity rights on the pipeline.

largest gas pipeline project constructed in the U.S., the Big 3's marketing affiliates would hold a huge amount of capacity compared to what marketing affiliates typically hold on other onshore pipelines. Although FERC has not placed a limit on the amount of capacity that can be held by any one shipper, *see, e.g., El Paso Natural Gas Co.*, 88 FERC ¶ 61,139 (1999), any suggestion by the Big 3 that this situation would not raise significant competitive concerns would strain credulity.

In addition, any argument by the Big 3 that a producer-owned pipeline would lack an incentive to discriminate against rivals conflicts with statements by the Big 3 themselves. It is well known that in numerous FERC proceedings the Big 3 have complained that the pipeline has an incentive to exercise market power to favor its marketing affiliate, including by discriminating against rival marketers and producers. To cite just one example, in a recent filing addressing a discounting issue, BP stated:

The problem with affiliate capacity acquisition ... is related to the pipeline and its affiliate, in aggregate, accruing the ability to exercise market power. It relates to the combined incentive of the affiliate (once it has acquired capacity) and the pipeline to withhold capacity in order to drive up the delivered price of gas.¹⁰

The Big 3 also would have to address allegations by some that a similar anticompetitive situation has occurred on the TAPS oil pipeline. Independent producers have complained that the major producer-owners of TAPS have engaged in anticompetitive conduct causing the number of oil producers in Alaska to decline precipitously. *See, e.g., Protest and Complaint of Anadarko Petroleum Corp.*, filed in FERC Docket No. OR05-3, Dec. 16, 2004. Even Conoco itself made similar complaints—prior, that is, to becoming one of the TAPS owners (which

¹⁰ Initial Comments of BP America Production Co. and BP Energy Co., at 7, FERC Dkt. No. RM05-2 (March 4, 2005).

occurred when the FTC rejected the State's proposed remedy in the BP/Arco merger and required BP to divest Arco's entire interest in Alaska production to Phillips, and subsequently Phillips and Conoco merged). *See id.* at 12-13. The RCA also recently found that the TAPS owners have charged unreasonably high transportation rates for many years, over-recovering by \$9.9 billion, and thereby raising rival producers' costs. The TAPS experience should, in effect, impose a higher burden on the Big 3 to demonstrate that their ownership of the Alaska gas pipeline will not (1) encourage exit by third-party producers and explorers, (2) discourage entry and reduce production by third-parties, or (3) cause other anticompetitive problems.

The Big 3's exclusionary conduct or discriminatory practices could take various forms. For example, they could propose an artificially high tariff for all shippers. This type of inflated tariff (in that it would be higher than it would have been in a competitive market with multiple alternative pipelines) will be "uniformly" applied to all producer-shippers and thus still considered "nondiscriminatory" in a technical sense. However, in reality it would raise only the independent, third-party producers' transportation costs. The marketing affiliates of the Big 3 would pay the same inflated tariff, but in the view of third-party producers' that would be just like "moving money from one pocket to the other" for the Big 3. Moreover, from the State's perspective, increased transportation rates would reduce wellhead prices, royalties and production taxes.

The Big 3 may argue that an independently-owned pipeline would have the same incentive to charge the high possible transportation rate. It is true that even an independent pipeline would have the incentive to maximize its profits. However, it would have a different set of incentives, opportunities and abilities compared with a producer-owned pipeline. There

would be no inherent structural incentive for an independent pipeline to favor its affiliates. In addition, in FERC rate cases an independent pipeline would face the prospective of litigating against a much stronger group of intervenors – the Big 3 themselves – and this adversity could produce a lower transportation rate.

The Big 3's exclusionary conduct could also take the form of subtle differences in quality of services that are not easily quantifiable and detectable. The Big 3 could try to delay interconnection to independent third-party producers' wells or otherwise offer less prompt and effective services. They could also attempt to use FERC procedures to delay third-parties' requests, thereby further increasing rivals' costs. *Cf. Oklahoma Gas and Electric Company, NRG McClain LLC*, 105 FERC ¶ 61,297, at ¶ 35 (2003) ("when utilities control monopoly transmission facilities and also have power marketing interests, they have poor incentive to provide equal quality transmission service to their power marketing competitors"). At a minimum, such subtle tactics would delay the process and weaken rivals' competitive position.

Even more troubling, a pipeline owned by the Big 3 could have a strong incentive to block an expansion of the pipeline, whereas an independent pipeline would have a clear incentive to build an economically justified expansion. The main way for an independent pipeline to increase profits would be to build an expansion, thereby increasing rate base on which to earn a return. Thus, an independent pipeline would plainly want to expand if third-party producers and explorers were willing to fund the cost of an expansion. By contrast, a Big 3 pipeline would face a different set of incentives. The Big 3 would have an incentive to control the amount of new gas delivered to the downstream consumption areas. A sudden flood of new gas could depress downstream price of gas in a given market. Thus, in deciding whether to

expand, the Big 3 pipeline would have to consider whether the increased profits from an addition to rate base would be offset by reduced profits in the gas sales markets.

FERC identified this potential problem in Order No. 637, where it addressed the concern that pipelines would refuse to expand in order to keep gas prices artificially high for the benefit of their marketing affiliates. FERC stated:

[B]ecause of the possibility of affiliate abuse, the Commission will be particularly sensitive to complaints that pipelines, on which affiliates hold large amounts of transportation capacity, are refusing to undertake construction projects when demand for construction exists. In cases where such concerns are established, the Commission would need to take remedial measures. Depending on the circumstances, such remedies could include: requiring pipelines to put in taps to reduce capacity bottlenecks; requiring pipelines to build additional capacity when requested by customers willing to pay the costs of construction; limiting the rates at which the affiliate can release capacity; limiting the amount of capacity the affiliate can hold; or prohibiting the affiliate from holding capacity on its related pipeline.¹¹

Delaying or thwarting an expansion would have a significant adverse impact on royalty revenues received by the State of Alaska, in two ways. First, it would result in less gas produced than would be the case if the pipeline expanded, thereby resulting in fewer royalty payments (which also would result if the Big 3 charged higher transportation rates, reducing netbacks in Alaska). Second, blocking an expansion would tend to keep the basin price of gas in Alaska lower than it would be if the pipeline were expanded, again resulting in lower royalties.¹² Thus, in addition to the potential that the vertical concerns created by Big 3 ownership of the Alaska

¹¹ Order No. 637, at 31,287 (2000) (also stating that "there seems little indication that profits from scarcity exceed those that can be earned through construction, since pipeline construction applications have not noticeably declined").

¹² Experience on other pipelines shows that, when an expansion is constructed, the price of gas in the basin rises, all other things being equal. *See, e.g.*, Direct Testimony filed by Kern River Gas Transmission Co. in its pending FERC rate case, FERC Dkt. No. RP04-274 (explaining that Rockies gas prices increased and the Rockies to California basis spread narrowed significantly after the in-service date of Kern River's major expansion to California).

gas pipeline would have adverse effects on downstream consumption markets, they would also adversely impact Alaska.

In sum, if the Big 3 own the Alaska gas pipeline, the pipeline is likely to have a strong incentive to discriminate against third-party explorers and producers. This will likely discourage entry and encourage exit by the Big 3's rivals, reducing competition for the exploration and production of Alaska natural gas. Even the perception that a Big 3-owned pipeline would discriminate against rivals could discourage entry and encourage exit. In contrast, an independently-owned pipeline would not present any of these potential problems, assuming its marketing affiliate does not contract for a significant amount of capacity, and thus would be a competitively superior option to a Big 3 pipeline.

2. The Big 3 Would Likely Have the Ability To Use the Alaska Gas Pipeline To Discriminate Against Rivals.

Assuming that the Big 3 would have an incentive to discriminate against rivals, the remaining question in a vertical analysis is whether the Big 3 would have the ability to foreclose rivals and raise rivals' costs. Absent FERC regulation, the answer would almost certainly be yes, because the Big 3 would control the only gas pipeline shipping gas from Alaska, and perhaps the largest gas pipeline serving the destination points accessed by the pipeline. Indeed, natural gas pipelines are heavily regulated precisely because they have and presumably would exercise market power in the absence of regulation.

The Big 3 may argue that various aspects of FERC regulation, such as the ban on affiliate preferences, the requirement that the Alaska gas pipeline be properly sized, the ability of FERC to require expansion of the Alaska gas pipeline in certain circumstances, and the limit on charging more than a "just and reasonable" rate, would prevent a Big 3-owned pipeline from

exercising market power. Viewed strictly from an FTC/DOJ antitrust perspective, the Big 3's reliance on FERC regulation as a defense would be unlikely to succeed. In numerous merger cases involving regulated pipelines and other regulated entities, the FTC and DOJ have required divestitures even though regulation by FERC or by some other agency would arguably have deterred the merged firm's ability to exercise market power. For example, in the Dominion case discussed *supra*, the FTC required Dominion to divest its natural gas pipeline because of the potential the pipeline could be used to discriminate against rival electric generators, even though the pipeline was heavily regulated by the state public utilities commission. Similarly, in one gas pipeline merger case after another, the FTC has required pipeline divestitures despite the fact that the pipelines would have been heavily regulated by FERC after the merger.¹³

These precedents also reflect the strong preference of the antitrust enforcement agencies for structural remedies such as divestiture over behavioral, regulatory remedies. The FTC and DOJ prefer structural remedies over regulation because of the possibility that regulations can be evaded and due to the cost of policing regulatory-type remedies.

In this regard, lengthy FERC proceedings themselves would further weaken independent producers' competitive position. For example, loopholes and ambiguous language in FERC's Order No. 2005 would give the Big 3 ample opportunities to defeat or delay pro-competitive attempts to expand the pipeline. *See, e.g.*, Order No. 2005 at ¶ 123 (deferring decision on whether to approve rolled-in rate treatment for any expansion until the specific facts of a proposed expansion can be reviewed—and litigated). While the proceedings are ongoing, the

¹³ *See supra* (discussion of market definition in gas pipeline cases at the FTC).

Big 3 could continue to employ their subtle yet effective strategic behavior to raise their rivals' costs and further weaken their rivals' competitive position.

In sum, strictly from an antitrust perspective, the fact that FERC would regulate the Big 3-owned pipeline would not completely solve the potential vertical problems caused by Big 3 ownership.¹⁴ However, because the competitive issues will likely arise in the context of application by a Big 3 joint venture for a FERC certificate to construct an Alaska gas pipeline, perhaps in conjunction with a competing application by an independent gas pipeline company, we proceed in the next section to address the issue of what remedies are available at FERC to address the competitive issues raised by a producer-owned pipeline.

III. Potential Remedies To Address Vertical Concerns Posed by Producer-Ownership of the Alaska Natural Gas Pipeline

Although it is likely that a pipeline owned by the Big 3 would have the incentive and ability to foreclose rival producers, the fact that a producer-owned pipeline would raise serious competitive issues does not automatically mean that Big 3 ownership of the pipeline would violate the antitrust laws. Big 3 ownership may be necessary to get the pipeline built, which would be a more competitive result than if no pipeline is constructed. Still, for the reasons discussed above, an independent pipeline would be a competitively superior result over a producer-owned pipeline, and as a result the State may want to support and encourage an independent pipeline alternative in FERC proceedings and in Stranded Gas Act negotiations. If, however, the only alternative is a producer-owned pipeline, the question that must be addressed

¹⁴ In fact, FERC itself has sometimes recognized that its regulations are not always effective in preventing discrimination. *Oklahoma Gas and Electric Company, NRG McClain LLC*, 105 FERC ¶ 61,297, at ¶ 35 (2003).

is what remedies or mitigation measures FERC could adopt to address the vertical market power problem created by Big 3 ownership.¹⁵

A. FERC Can Select From a Broad Range of Remedies, Including Remedies That Go Beyond its Existing Regulations, To Address the Unique Situation Posed by a Producer-Owned Pipeline.

In an ordinary certificate proceeding, FERC would simply decide whether to issue a certificate based on the facts presented and would apply its existing regulations to any pipeline constructed under the certificate authority. It typically would not impose unique remedies on an ordinary pipeline.

The Alaska natural gas pipeline, however, will not be an ordinary pipeline, as Congress and FERC have recognized. Not only will it constitute the single largest gas pipeline project ever constructed in the U.S.—a fact that in and of itself might call for special treatment—but Big 3 ownership would create a unique vertical integration problem. The ownership by the Big 3 marketing affiliates of up to 75 percent of the pipeline's firm capacity rights would probably surpass the amount of capacity held by marketing affiliates on any other onshore gas pipeline in the U.S. The Big 3 also will own the vast majority of gas that will flow through the pipeline. Given the distinct incentive that a producer-owned Alaska pipeline would have to discriminate against rivals, and ANCPA's directive that FERC ensure access to the pipeline by third-party producers, FERC may strongly consider remedies that go beyond what it would consider in an ordinary pipeline certificate case. This possibility is strengthened even further by the perception by some that Big 3 ownership of the gas pipeline would make third-party producers vulnerable to

¹⁵ A danger exists that if there is no viable independent pipeline alternative, the Big 3 could simply refuse to build the pipeline if FERC requires any of the following remedies. Thus, from a negotiating standpoint, it would seemingly be very important to maintain at least the appearance of a viable independent pipeline alternative.

the sorts of abuses that have allegedly occurred on TAPS. In the following discussion we briefly discuss some of the remedies that third-party producers, consumer interests, and others could propose at FERC to address the unique circumstances posed by Big 3 ownership.¹⁶ FERC could impose one or more of these remedies.

1. Divestiture

It may be possible to require the Big 3 producers to sever their relationships with the upstream and further downstream affiliates through some form of divestiture or similar remedy. In other words, it may be possible to create a truly independent Alaska natural gas pipeline company. Even though the initial funding and personnel for the pipeline joint venture could come from the Big 3 producers, based on a pre-determined schedule, they could be required to spin it off or otherwise dispose of their financial interest. The FTC has used this method in the past.¹⁷ Moreover, FERC has recognized divestiture and similar remedies as an appropriate, yet rare, option in unique situations. *See, e.g.,* Order No. 497, FERC Stats. and Regs. ¶ 30,820, at 31,129 (1988) ("the Commission reserves the right to consider and impose such remedies as divorcement and divestiture in specific cases where the circumstances demonstrate they are required"); *see also* Order No. 637, at 31,287 (stating that where appropriate FERC could

¹⁶ It is possible that the Big 3 would contend that these remedies are not permitted under the Act. That issue is beyond the scope of this memorandum.

¹⁷ *See, e.g., Valspar Corporation*, FTC Docket No. C-3478 (1993) (coating resins for paints; divestiture of overlapping assets to a new independent corporation to be formed). The key difference between this method of spin-off and the more traditional method of selling a company to an existing company is that the former creates a new independent company. Alternatively, it can be viewed as divesting an overlapping business to the merging firm's shareholders. While the shareholders might be initially the same, management teams will be different. Moreover, Section 8 of the Clayton Act that deals with interlocking directorate situations would apply if the same individual attempts to sit on two competing firms' boards.

prohibit an affiliate from acquiring capacity on its affiliated pipeline). Because divestiture would eliminate the vertical concerns posed by Big 3 ownership of the gas pipeline, divestiture is the “cleanest” remedy available. However, it is possible the Big 3 would refuse to go forward with the project if they could not own the pipeline. Thus, other remedies must also be considered.

2. Partial Divestiture Through Creation of an Undivided Interest Pipeline

Another option is to allow the Big 3 producers to own the pipeline but as an undivided interest pipeline. In this case, each owner would be free to market its own share of the capacity. Thus, while physically there will be only one pipeline, from a competition perspective, it would be like having three separate, “virtual” pipelines competing against one another, with separate tariffs, separate rate schedules, and separate management and marketing employees.

If this option is pursued but the Big 3 are the only undivided interest owners, then it may not result in any material improvement of the competitive situation that would otherwise exist. Indeed, it would essentially replicate the situation that exists on TAPS, which at least arguably has not resulted in a vibrant competitive landscape in Alaskan oil exploration and production. The Big 3 would have common incentives, and tacit coordination of their activities would be a distinct possibility.

The real value in this option – and an improvement over the TAPS model – is if a third-party, such as the State of Alaska or an independent pipeline company, also acquires an undivided interest, with equal rights to expand the pipeline (and that cannot be vetoed by the Big 3). The State of Alaska or an independent pipeline company could play a pivotal role, akin to a maverick, disruptive competitor, possibly frustrating any attempt by the Big 3 to thwart pipeline expansion or otherwise foreclose upstream or downstream rivals. The FTC required the creation

of a similar "pipeline within a pipeline" in order to address vertical competition problems created by the merger of a gas pipeline and an electric generator in Michigan. *See, e.g., Detroit Edison, supra.* FERC has certificated similar undivided interest pipelines in the past, *see, e.g., Kern River Gas Transmission Co., 50 FERC ¶ 61,069 (1990)*, and requiring the Big 3 to divest an undivided interest in the pipeline would be consistent with FERC's past view that it has the power to require divestitures if necessary to address vertical problems.¹⁸

3. Establishment of an Independent System Operator

FERC has sought to encourage, and even require, vertically integrated electric utilities to transfer their transmission facilities to an independent system operator ("ISO"). FERC has relied on the ISO remedy to address the vertical integration problem that exists where an electric transmission provider's generation affiliates utilize a large percentage of the provider's transmission capacity. Through the creation of an independent operator, FERC seeks to ensure that transmission capacity will be operated and allocated in a way that does not discriminate against non-affiliates.

To our knowledge, FERC has never required a natural gas pipeline to transfer control of its pipeline facilities to an independent operator. However, because the Big 3 presumably will hold up to 75 percent of the Alaska pipeline's firm capacity rights, and will own most of the gas to be shipped through the pipeline, a plausible argument can be made that FERC should impose an ISO-type remedy on any pipeline owned by the Big 3, to address the unique vertical issues presented.

¹⁸ *See* Order No. 497, *supra*. Note that this option, which appears to dovetail with the State of Alaska's potential interest in owning part of the pipeline, will tend to minimize coordinated interaction as well.

Under this option, in essence, the Big 3 producers would own a passive ownership interest. To be most effective, the ISO should be given the power to propose capacity expansion and given the power to override any of the Big 3 producers' objections as long as certain pre-determined conditions are met. For instance, if the ISO secured a firm commitment from independent producers with newly discovered reserves that would justify a capacity expansion project, then the Big 3 producers would have to agree to capacity expansion. It also probably would be necessary to have a provision on admitting a new passive investor who is willing to share the cost of such capacity expansion, particularly in the event the Big 3 are unwilling to expand.

Obviously, the issue of expansion also would raise the controversial issue of rolled-in versus incremental rate treatment. How to resolve that issue – and numerous other details – would need to be addressed as part of proposing any ISO-type remedy.

4. Establishment of a Market Monitor

In FERC cases involving ISOs, FERC has also approved the establishment of a market monitor, as part of the ISO structure. One drawback of this remedy may be introducing yet another regulatory regime, in addition to FERC. On the other hand, appointing a market monitor or trustee to periodically audit the Big 3-owned pipeline for any anticompetitive behavior, and to investigate complaints and suspicious activities, could act as a useful constraint on the Big 3's abuse of market power over the pipeline transportation business. This option probably is most effective when it is used in conjunction with other checks and balances provided by the FERC's regulatory regime. One advantage of this option is that the market monitor would indirectly be funded primarily by the Big 3 by including the cost of the market monitor in the pipeline's

transportation rates. This would reduce the amount of costs that rivals would have to spend policing the Big 3's conduct, and essentially would require the Big 3 to pay part of the cost of monitoring their own behavior.

5. Other Potential Remedies

Other potential remedies could be considered, although those addressed here appear to have significant drawbacks. For example, in theory FERC could require the Big 3 to agree in advance on the terms under which they would expand the pipeline, including the circumstances in which they would agree to rolled-in rate treatment. However, unless the Big 3 made a blanket commitment to expansion and rolled-in rate treatment, it is difficult to see how this option could be implemented because of the myriad of different potential capacity expansion scenarios. Whether an expansion would make economic sense, and what rate treatment is appropriate, would depend on numerous factors that would be difficult to predict in advance.

Another option would be to require the Big 3 to provide "most favored nation" rate protection to third-party shippers. However, this could be rendered meaningless for the same reason that FERC's non-discrimination requirements would not prevent the Big 3 producers from charging a uniformly-inflated tariff or otherwise engaging in subtle forms of strategic behavior to raise their rivals' costs.

B. A Significant Potential for Delay Exists.

You have asked us to address whether the competitive issues raised by a producer-owned pipeline could delay the project, either because of a delay caused by FTC or DOJ review, or by protracted litigation at FERC. It is unlikely, but not inconceivable, that the FTC (or DOJ, although the FTC is the antitrust agency that typically reviews natural gas pipeline transactions)

would undertake a separate investigation and thereby delay the project. However, the FTC (or DOJ) may decide to express their position to FERC in context of a certificate proceeding or to Alaska in context of the Stranded Gas Act process. In the FERC context, this would fulfill the spirit of the Reagan directive that required FERC to consult with DOJ about antitrust issues raised by producer-ownership of any gas pipeline certificated under ANGTA. In addition, the FTC, as part of its competition advocacy program, often shares its views with other federal agencies such as the FERC or state agencies on a formal or informal basis. Thus, it may still be the case that the FTC will have an opportunity to share its non-binding views.

A significant potential for delay exists at FERC. It would not be surprising if third-party producers (such as Anadarko), competing pipelines, or consumer interests protest any certificate application by the Big 3 by raising the competitive concerns addressed in this memorandum, particularly in light of Chairman Wood's recent letter stating that the antitrust concerns which concerned Congress and the President over twenty years ago are still valid and will be addressed by FERC. This could cause a producer application to experience significant delay compared with an application by an independent producer. The competitive issues that a third-party could raise, including potential remedies to address those issues, would require FERC to conduct either a "paper" hearing or set the case for an evidentiary hearing before an ALJ. Although we believe a paper hearing is more likely in view of the goal of expedited treatment that Congress expressed in the Act, some precedent exists for setting these types of issues for hearing in somewhat analogous electric merger cases at FERC. *See, e.g., OG&E, supra.* In any event, even a paper hearing to litigate vertical competitive issues could take significant time (6-12 months),

depending on the number of filings and FERC's ability and willingness to deal with the issues expeditiously.

Conclusion

As discussed above, numerous and recent FTC, DOJ and FERC precedents indicate that the competitive concerns expressed by the U.S. Attorney General in 1977 about a producer-owned Alaska natural gas pipeline remain valid today. A significant risk exists that a pipeline owned by the Big 3 would have the incentive and ability to discriminate against rival producers, thwarting expansion of the pipeline, reducing competition for leases, and ultimately reducing royalties and taxes for the State of Alaska. A potential for significant delay at FERC also exists in order to litigate these competitive issues and to address whether FERC should impose a unique remedy due to the special circumstances posed by Big 3 ownership of the pipeline. In contrast, an independent pipeline typically would not present these or similar risks.

ExxonMobil AGIA Testimony Senate Judiciary Committee 4-14-07

SENATE JUDICIARY COMMITTEE:

Chairman: Hollis French

Vice-Chair: Charlie Huggins;

Members: Senators Lesil McGuire; Bill Wielechowski; Gene Therriault

INTRODUCTION

Good afternoon Chairman French, Vice-Chair Huggins and members of the Senate Judiciary Committee. My name is Bill McMahon. I am the Commercial Manager in the ExxonMobil Alaska Gas Development group, a position I have held since November 2000. I am involved in the effort to commercialize ExxonMobil's gas resources in Alaska.

ExxonMobil has been in Alaska for over 50 years and has been a key player in Alaska's oil industry development. We hold the largest working interest at Prudhoe Bay (36.4%) and our current net production in Alaska is approximately 150,000 barrels per day.

We have benefited from our involvement in the State of Alaska, and we believe that Alaska has benefited from this long-term relationship as well.

Commercializing Alaska's North Slope gas will allow us to continue this mutually beneficial relationship for another 50 years or more. Let me emphasize that ExxonMobil wants a successful gas pipeline project and we want to move it forward.

EXXONMOBIL READY TO PROGRESS PROJECT

The Alaska Gas Pipeline project is important to Alaska, to our nation, and to ExxonMobil. The Project has the potential to generate billions of dollars in revenues for the State of Alaska, the U.S. federal government, and Canada, and could provide a stable and secure source of clean energy for Alaska and North America for decades to come. For ExxonMobil, the project has the potential to add over 1 billion cubic feet per day (EM share) of gas sales, which would be more than a 10% increase to our current worldwide daily gas production. Given the significant impact this project could have on our business, we strongly support efforts to advance a pipeline project and we are ready to work with Governor Palin and her cabinet and with the Legislature to move the project forward.

As an illustration of our commitment, EM has spent more than \$180 million studying ways to commercialize Alaska gas. Since the 1970's we have evaluated LNG, gas to liquids and gas pipeline alternatives. Based on these studies we have determined that a Producer gas pipeline project will result in the best value for the State, the Producers and the nation. It is important for me to say ExxonMobil is aligned with the Governor, the legislature and the people of Alaska regarding the overall objective—we are committed to moving the Alaska Gas pipeline project forward.

GENERAL FEEDBACK ON AGIA

ExxonMobil embraces the concept of competition all over the world and is ready to participate in a fair market based competition. We understand the overarching goal of AGIA is to create open competition but due to the prescribed conditions included in AGIA it will not achieve this goal. A prescriptive bidding process will not allow the flexibility needed for individual applicants to weigh the risks associated with this basin opening mega-project and propose what is necessary to manage these risks.

It is important that AGIA allow applicants to define how they could achieve the State's objectives rather than prescribing specific requirements that must be met. To ensure the best result, AGIA should establish broad key objectives and allow applicants flexibility in meeting those objectives and in defining the requirements that are necessary to make the project commercially viable. If you were to amend AGIA to make it objective driven, it would result in an open competition, maximizing the number of applicants and allowing those applicants to propose innovative solutions.

As such, we suggest AGIA be modified to establish an objective driven process – define the state's broad objectives, request proposals as to how applicants intend to meet or not meet those objectives, evaluate the proposals and then select the one that best serves Alaska's needs. If none meet the State's overall objectives then you can always reject them or opt to negotiate with the party that most closely meets your needs.

To understand why it's important to use broad objectives as opposed to prescribing specific requirements it is helpful to review project risks and issues surrounding its development that will have to be addressed by an applicant.

PROJECT RISK / PRODUCER CAPABILITIES

Because there is a perception this is "simply" a gas treating / gas pipeline project, the tendency exists for many to underestimate the size, magnitude and risks associated with this undertaking. The Alaska Gas Pipeline Project is a world-scale undertaking with significant risks. In fact, the Project would be the largest private investment in North America – significantly larger than most "model" worldwide oil and gas "mega" projects. There is not really another project that compares.

Because of this size, many factors impact commercial viability.

First there is cost:

Our previous estimate of \$20 billion (\$2001) is now substantially higher. Since 2001, steel prices have nearly doubled. Industry and construction labor costs are experiencing hyperinflation. In addition, world-wide mega-projects are placing pressure on pricing and availability of global materials, and skilled manpower.

Next there is gas price:

Despite recent increases, natural gas prices remain highly volatile. The price of natural gas before 2000 was less than currently estimated gas treating and transportation costs.

Finally, there are many other risks.

These include cost overruns, schedule delays, construction conditions, and regulatory and State fiscal uncertainties. It is also important to note that project investments would have to be made over a period of 10 or more years before gas flows down the pipeline and is sold at the marketplace.

With size comes complexity, and an even greater premium on getting the design concept, contracting and marketing plans right...and then executing these plans efficiently and effectively. Most importantly, size also amplifies the consequences of poor execution. If a mistake is made on this project it would cost us all dearly.

The State of Alaska cannot anticipate how individual applicants will view these risks or how they may address them. Establishing a set of rigid prescribed terms will not allow the flexibility needed for individual applicants to weigh and manage those risks.

HOW PIPELINES ARE FINANCED AND WHO BEARS PROJECT RISKS

It is also important to understand how pipelines are financed which is a key reason why AGIA should allow flexibility in proposing upstream terms. Commercially-sound oil, gas, and pipeline projects traditionally have been able to obtain financing if they have strong sponsors with proven track records and the financial strength to both provide sponsor equity and to backstop key project commitments. For the Alaska gas pipeline project, key project commitments take the form of firm, long-term gas transportation commitments. Firm transportation commitments are binding obligations made by companies to pay for the cost of reserving a quantity of gas capacity as shippers on a pipeline over a specified period of time, typically many years. These commitments are made during an "open season", which, according to FERC Order 2005 for the Alaska gas pipeline, is a period of at least 90 days during which any and all prospective gas shippers can make binding commitments for a specific volume of transportation capacity.

Financial institutions generally require substantial, long-term, firm transportation commitments to provide funding for a gas pipeline project. These commitments must be provided by creditworthy shippers. In this case, the shippers will be the Producers, and, directly or indirectly, the State or the State's shipper. These firm transportation commitments are substantial, in the tens of billions of dollars and must be paid whether the shipper making those commitments actually transports gas through its reserved capacity. The shipper is also required to pay this commitment regardless of the price of gas in the market place.

Pipeline investors use these firm transportation commitments from shippers to show creditors they have capacity confirmed over a sufficient duration to secure financing and must rely on the financial strength of the companies backing the transportation commitments to secure project financing. Thus, the development costs and the associated over-run risk are ultimately borne by the shipper via this commitment. In other words, shippers must make long-term ship or pay transportation commitments and agree to pay transportation and treating rates that are based on the ultimate cost of the pipeline and treating facilities. The only information known in advance of making these commitments will be a projection based on each project entity's initial estimate of costs.

For that reason, the parties taking the risks need to be able to manage those risks. The Producers, as shippers, cannot make firm transportation commitments during an open season unless they are confident the gas pipeline project can be built cost effectively and operated on a long-term, commercially viable basis, including being competitive with other sources of gas supply. This is especially true for a project of this magnitude.

The existing prescriptive terms will preclude leaseholders from being able to make a conforming proposal which would deny the state the opportunity to even consider terms from the parties who hold the largest stake in the project's successful development.

IMPORTANCE OF STATE / PRODUCER ALIGNMENT AND BENEFITS OF THE PRODUCER PROJECT

Let me now talk about the importance of alignment between the State and the Producers and the benefits of a Producer project.

Maximizing the value to the State of Alaska and the resource holders means selecting the right design concept for this mega-project and then executing the project to deliver the lowest possible cost.

On a mega-project of this size and magnitude, project construction and operating experience should be a significant consideration. Only a limited number of companies have demonstrated the capabilities and financial strength to effectively participate in and manage world-scale mega-projects.

The Producers have mega-project experience on numerous projects world-wide and have demonstrated success in meeting project objectives. For example, ExxonMobil operates in nearly 200 countries and territories and on every continent except Antarctica. We are the world's largest non-government producer of both oil and natural gas. ExxonMobil's global project development company is unique within industry. This global development company leads the industry in project cost and schedule performance. Nearly 90% of ExxonMobil projects with costs greater than \$1 billion are delivered within 15% of estimated costs at the time of project funding and nearly 80% of those were delivered within 15% of the funding schedule. ExxonMobil's superior performance was independently validated in a report (dated September 21, 2005) published by Sanford C. Bernstein and Co. On the topic of project delays, the report stated "ExxonMobil came out on top of this analysis, with the lowest slippage rates, despite undertaking some of the largest projects. We believe this to be a direct result of its highly competent internal development company, which assumes full responsibility for monitoring a new project from idea to profit." Combining our capability with BP and ConocoPhillips will provide the best chance of delivering a successful project.

The Producers also have Arctic experience in Alaska and throughout the world. ExxonMobil's arctic experience is extensive - over 40 years - with developments in multiple types of arctic environments. Large projects with significant complexity are what we do and we are extremely qualified to take on this work.

Our successes in Arctic environments are the result of a long-term commitment to technology development which has played an important role in the advancement of oil and gas development in Alaska. ExxonMobil believes innovation is the key to meeting the world's energy challenges. Technology is the lifeblood of our industry, and it always has been. We are the leader in our industry in technology development. In 2006, we spent \$730 million on technology development and we have spent more than \$3 billion since 2002.

In addition, ExxonMobil has demonstrated world-class leadership in safety, health and environmental performance. ExxonMobil is a leader in operating efficiency and a pacesetter in operating safety. Our total recordable incident rates for employees and contractors are substantially below the average of US Petroleum Industry benchmark of participating American Petroleum Institute companies. We believe a company's commitment to the highest standards of safety, health and environmental care manifests itself in superior performance in all aspects of its operations.

In addition to our operational excellence, ExxonMobil has the financial strength to make this mega-project a reality. ExxonMobil has consistently maintained one of the strongest financial positions of any company in the world. We are one of just a few public companies to maintain the highest credit rating from Standard and Poor's (AAA) and Moody's (Aaa), and we have done so for each of the last 88 years. Our unparalleled access to financial resources gives us the flexibility to pursue opportunities worldwide throughout the economic cycle with the knowledge that they can be financed. Host governments recognize this strength and its importance as they look to develop their resources and economies. As an example of that strength, ExxonMobil's project financing experience exceeds \$30 billion in value for recently completed and ongoing activities. Our efficient management of large scale project financings is a critical piece in the overall success of ExxonMobil's project implementation record.

It is important to remember that the Alaska gas pipeline project is a basin-opening project that will benefit the State and the oil and gas industry in Alaska. Basin-opening projects throughout the world have progressed and been successful when there is alignment between the host government and the leaseholders. The Producers and the State both want a pipeline project to commercialize the known ANS gas resources and open the basin to gas exploration. So, at a very high level we are aligned.

We believe a Producer gas pipeline project will result in maximum value to the State and the Producers. The reason is the Producers and the State have maximum incentive to control costs. Low capital and operating costs, which result in lower treating and transportation costs, and access to premium market price, result in higher netback value on gas. It should be noted that the State will receive the majority of its revenue from the value of gas sales via revenue received under its lease royalty agreements and from production taxes, which are valued based on the netback received from the gas.

Third-party owners do not share the same incentives in that they actually benefit from increased capital costs.

Based on the demand for workers that this project will generate, Alaskans are obviously key to successful project execution. Both the State and the Producers want Alaskans to

benefit from the many job opportunities that will exist. When you consider carefully the options available, a Producer pipeline will provide maximum value to the State of Alaska.

We believe that financial strength, experience and the ability to get the job done should be critical components of any evaluation of proposals.

IMPORTANCE OF PREDICTABLE AND DURABLE FISCAL TERMS

For us to progress the project and mitigate its inherent risks, we will need some things from the State. Let me discuss the importance of predictable and durable fiscal terms for the upstream participants. Because of the nature and magnitude of the risks associated with this project – tens of billions of dollars of financial commitments, unprecedented cost and scope, potential for construction delays, as well as the inevitable risks associated with the commodity price of gas - fiscal terms that are predictable and durable are necessary. This is a common thread for all of our mega-project investments in basin opening developments. In all such cases, we are willing to take geologic risks, we are willing to take cost risks, and we are willing to take commodity price risks, but we cannot take the risk of fiscal terms changing. Let me expand on this important concept further. The first two risks, geologic and cost risk are risks for which we have developed an industry leading expertise to manage. This is what we do day after day at EM. Market risk is inevitable in a commodity business such as oil and gas and we manage that by attempting to ensure that we deliver those products into the highest value market at the lowest cost. Fiscal risk, however, is of a completely different nature and wholly outside of our control. We must have agreements that will allow us to develop this mega-project under predictable and durable terms, so that we can make an adequate investment decision. If fiscal terms can be changed in the future, then we are not able to make a well founded investment decision on behalf of our shareholders.

The Alaska Gas Pipeline Project will require massive investments to be made over a period of many years before any revenue is generated from those investments. As a result, increases in taxes on oil and gas related activities during the life of the project could significantly impact the commercial viability of the project and offset the benefits of taking on a project of this magnitude. Because fiscal terms could be modified under the proposed AGIA legislation, it does not provide the fiscal stability necessary to ensure a commercially viable project.

Development of a predictable and durable fiscal framework means that the terms agreed between the Producers and the State recognize the magnitude and risks associated with the project; balance State and Producer needs; and provide for the calculation of total State take in a transparent and predictable manner.

AGIA should allow market participants to put forward their best proposal on what is required to make the project viable, thereby creating a competitive process that will allow the State the opportunity to consider those proposals that have the best chance of actually delivering on the promise of an Alaska gas pipeline.

ADDITIONAL FEEDBACK ON AGIA

I would like to now give some specific feedback on AGIA which is based on the conclusions and principles I've mentioned. I will also outline some additional thoughts on how AGIA should be modified to provide the best chance of a successful result. For example, alignment between the State and the leaseholders is essential to a basin opening project of this magnitude. Therefore, establishing the right approach going forward is the most important activity for the project at this time. It is important that AGIA bring together the upstream and the midstream and provide for an integrated proposal. Let me expand on this point. The upstream and midstream at some point in time will have to come together. The reason is simple – the upstream pays for the midstream. When I say upstream I mean the revenue generated from sale of the gas and liquids from the pipeline project. To be able to calculate the revenue from the upstream we must have clarity on the taxes and royalty from our oil and gas operations and the taxes and royalties must be set at a level that makes the project viable. In order to ensure a viable project from the outset, we believe this must be done at the beginning. At a minimum, any proposal should demonstrate how a successful open season would be achieved.

As I discussed previously, with regard to upstream terms, the proposed upstream inducements would require significant modification to ensure a commercially viable project is obtained. It would be better to leave that issue open for now and allow an applicant to make a proposal to address those terms.

AGIA also prescribes activities that must be completed within a specific timeframe or date certain. Setting arbitrary target dates is not consistent with good project management practices. Further, milestones are not necessary if the project is commercially viable. The Producers' builder will progress the project at the maximum prudent pace, consistent with the industry proven "gate" process for project development.

In general, AGIA lacks specifics on key fiscal terms and other requirements. To address these gaps, AGIA gives commissioners broad authority to adopt additional requirements and establish regulations. Not knowing the requirements now creates significant uncertainty.

Finally, because of the complexity and risk associated with this project, the parties must have an efficient and impartial means of handling disagreements when they arise. We believe project related agreements should provide for binding neutral arbitration as the mechanism for resolving disputes. Binding neutral arbitration is widely utilized in U.S. and international commercial agreements and is not a new concept with the State of Alaska. Arbitration is the method used to resolve disputes under the State's Royalty Settlement Agreements. In addition, Alaska courts have recognized a strong public policy in favor of arbitration.

REACTIONS TO COMMITTEE AMENDMENTS

We also note that the House Oil & Gas Committee and the Senate Resources Committee made a number of amendments to AGIA. While substantial work needs to

be done to make AGIA truly objective, several of the proposed changes moved in the right direction, including making the state's entire capital contribution a bid variable, beefing up evaluation criteria, recognizing the need to include terms in a contract and requiring legislative approval of any license award. Unfortunately, steps were also taken that will likely limit the number of potential bidders by eliminating any confidentiality protection for a licensee's proprietary and trade secret data and imposing new prescriptive terms such as requiring any bidder to forego its legal rights to challenge an improper award. What we have at this stage is an AGIA bill that remains too prescriptive to solicit the quality market based bids necessary to move the project forward.

CONCLUSION

In closing, I would like to reiterate that ExxonMobil is committed to moving the gas pipeline project forward. Our company possesses the financial strength and project experience required to make this project a success. We are ready to work with the Administration and the Legislature to establish a framework that recognizes the integrated nature of the project and mitigates the risks I've discussed to allow the project to progress. We would suggest AGIA be amended to include a broad objective driven framework that sets out what the State wants to achieve. AGIA should allow each applicant to propose how best to meet those objectives and to identify what is required from the State to advance the project. This process will secure more viable applications, create more competition and afford the State the opportunity to secure the most value. We are ready to participate in a competitive, open and transparent process under the approach I've outlined.

Thank you for your attention and for the opportunity to address this important topic today. I look forward to addressing your questions.

RESPONSE TO QUESTION FROM SENATOR THERRIault ON POLITICAL RISK

Western democracies all have broadly diversified economies and when there is a need for more tax revenue, those governments have many options available to them as to how best to raise the needed additional revenue. For example, in the United States, changing the rate of personal income tax is often the vehicle that is selected. There is no need to target a particular industry.

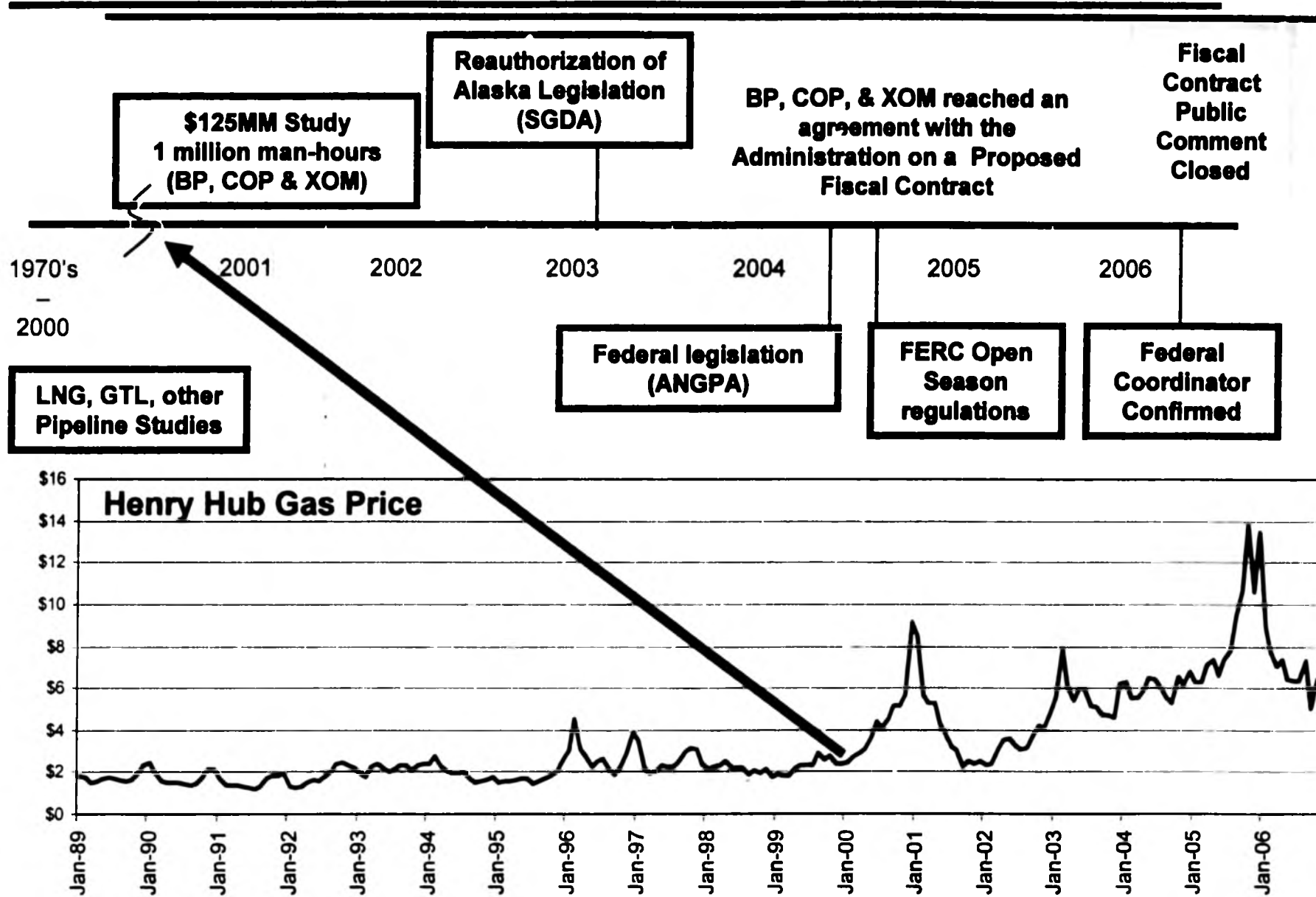
We need fiscal predictability in Alaska for exactly the same reason that we insist on fiscal stability in these other political jurisdictions. The temptation to target the predominant industry to provide additional revenue is always there and fiscal stability provisions prevent these other host governments from responding to that temptation.



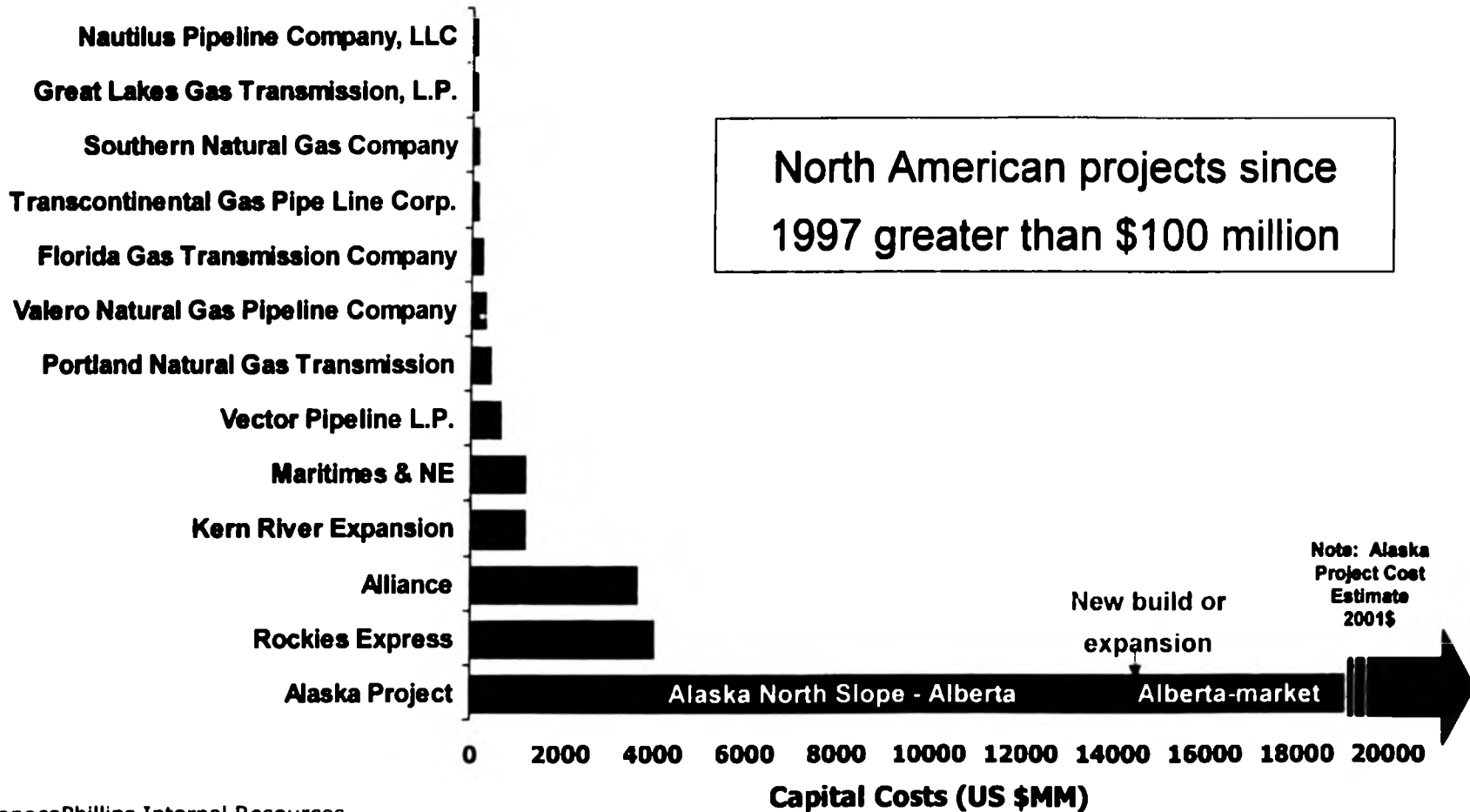
Senate Judiciary Committee
April 14, 2007

Wendy D. King
ANS Gas Development Team

Alaska Gas Pipeline Project



What makes the Alaska Project Different?



Source: ConocoPhillips Internal Resources

Alaska Gas Pipeline will be much larger / more difficult than other US/CAN pipelines. Size brings additional risk.

Alaska Gas Pipeline Project Risks

- **Cost**

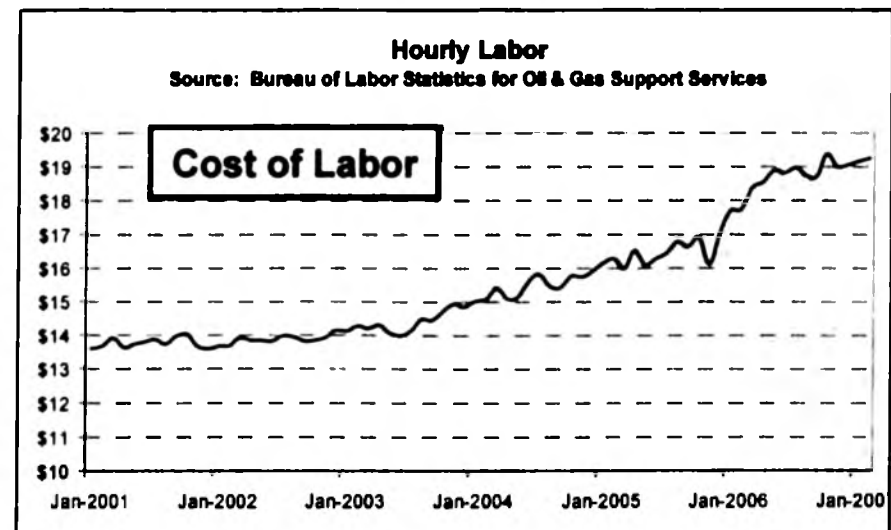
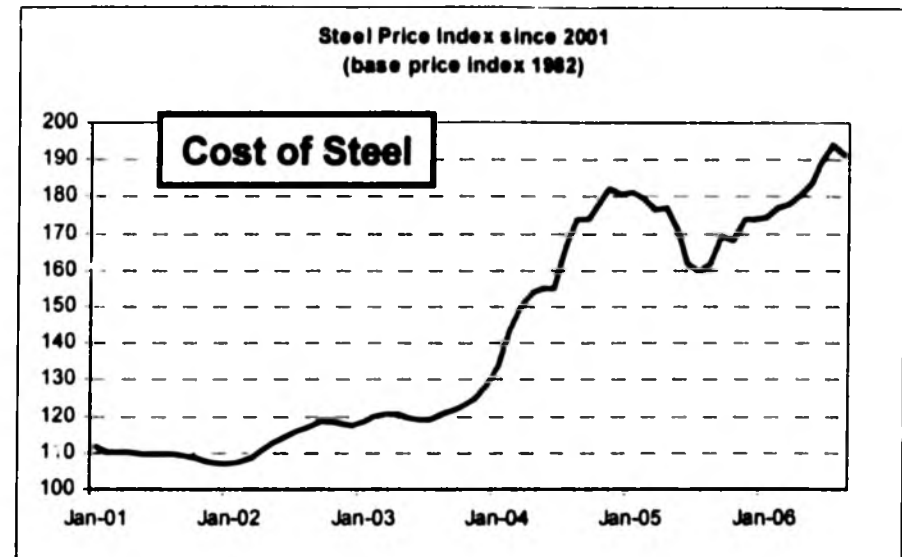
- Since 2001, steel prices have nearly doubled
- Labor costs continue to rise
- Previous \$20 billion cost estimate would be significantly higher today

- **Prices**

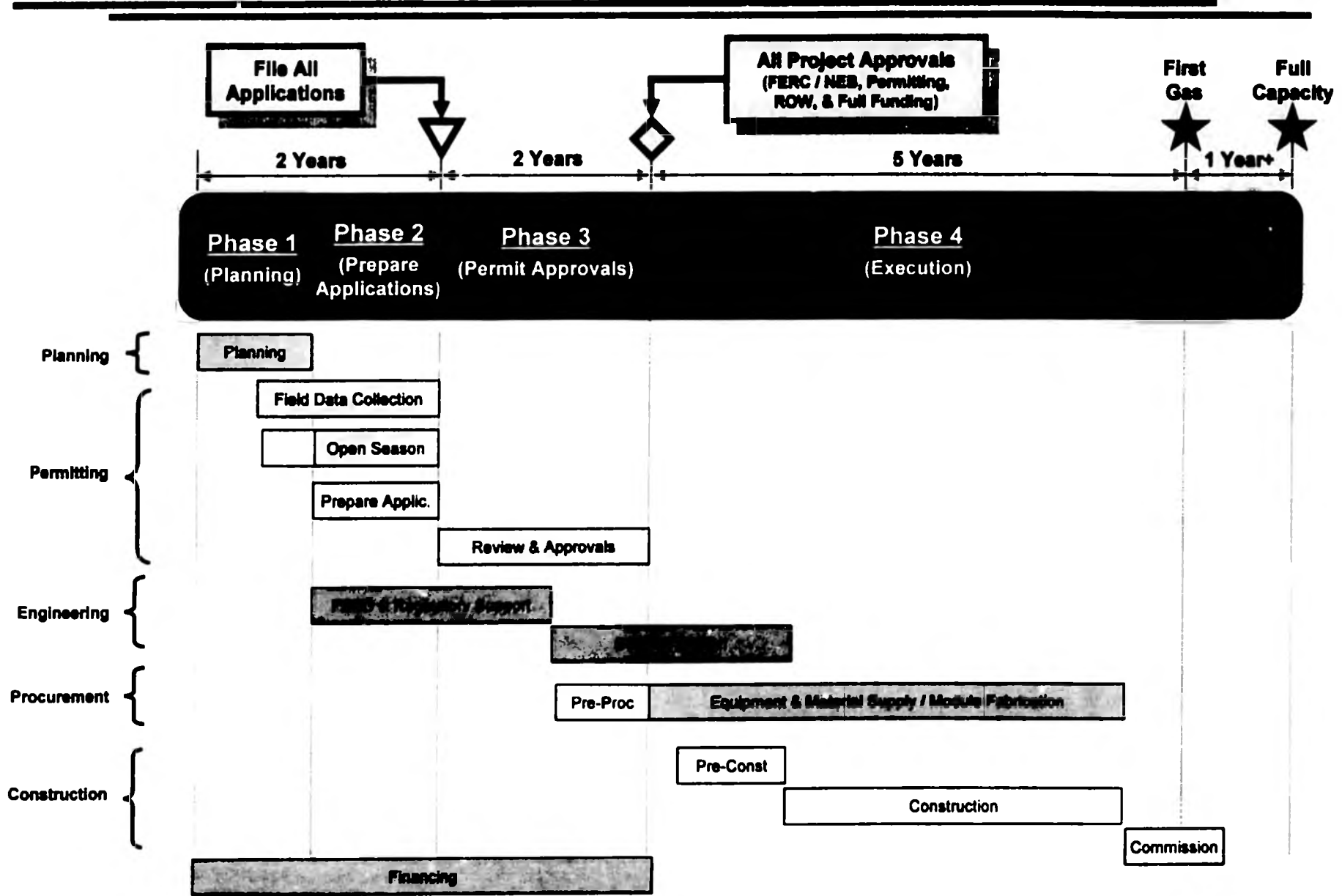
- Natural Gas Supply & Demand
- Volatility

- **Other Risks and Uncertainties**

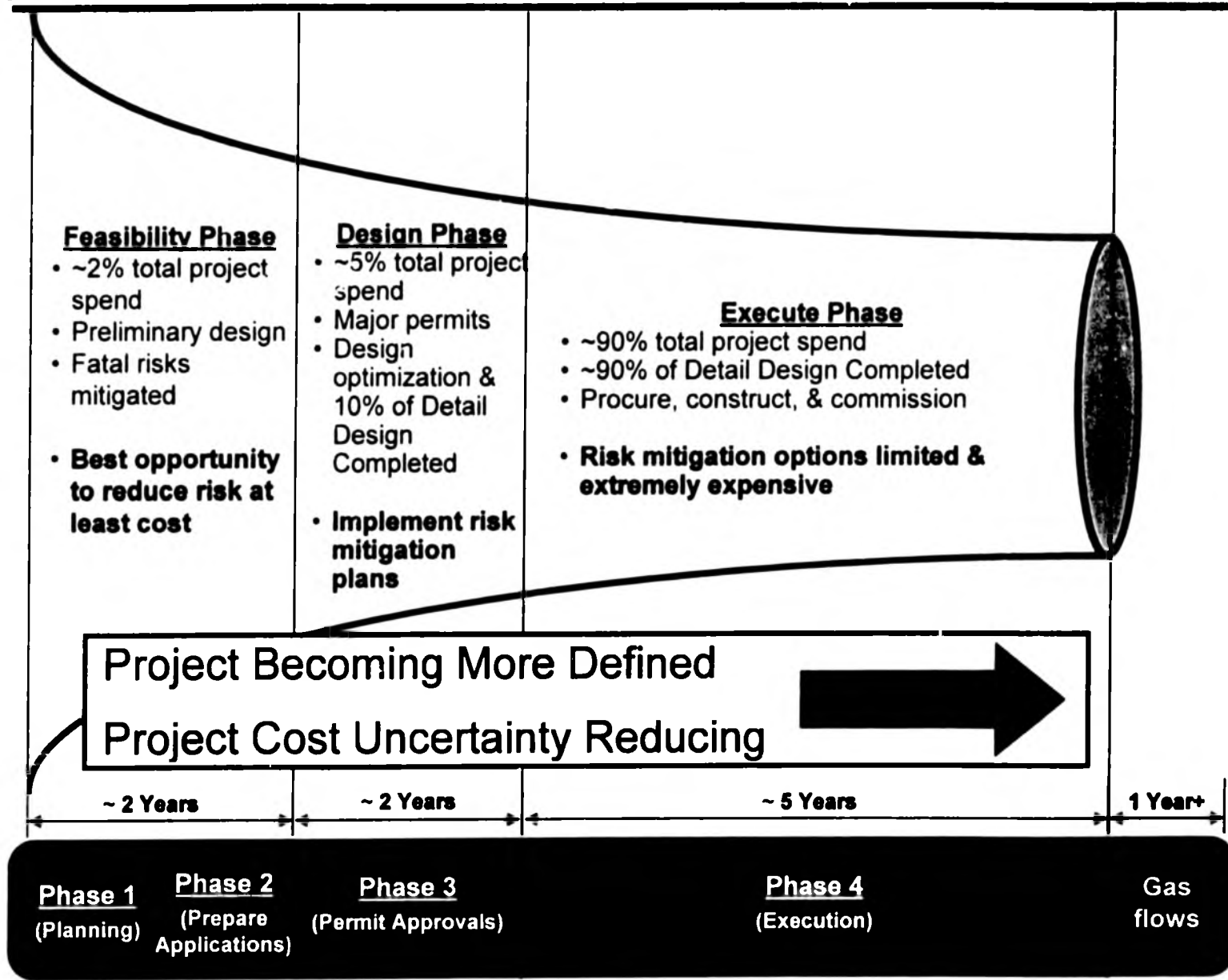
- World-scale logistics
- World-scale material procurement
- Labor availability
- Weather
- Reserves and Deliverability



Success Case Project Timeline



Front End Loading and Cost Estimates



Why an Open Season?

- **Why shipping commitments?**
 - Shippers agree to ship gas, or pay demand charges for fixed term
 - Allows pipeline company to repay its debt and obtain a return on its equity contribution
 - Commitments allow pipeline company to obtain financing – the commitments serve as collateral for the financing
- **Why is Open Season critical?**
 - Allows open access to pipeline
 - Demonstrates no discrimination
 - Required by ANGP – Sec. 103(e)
 - Establishes the demand for capacity, which impacts size, design, and cost of the pipeline
 - Also supports determination of whether project is viable commercially and can get financing

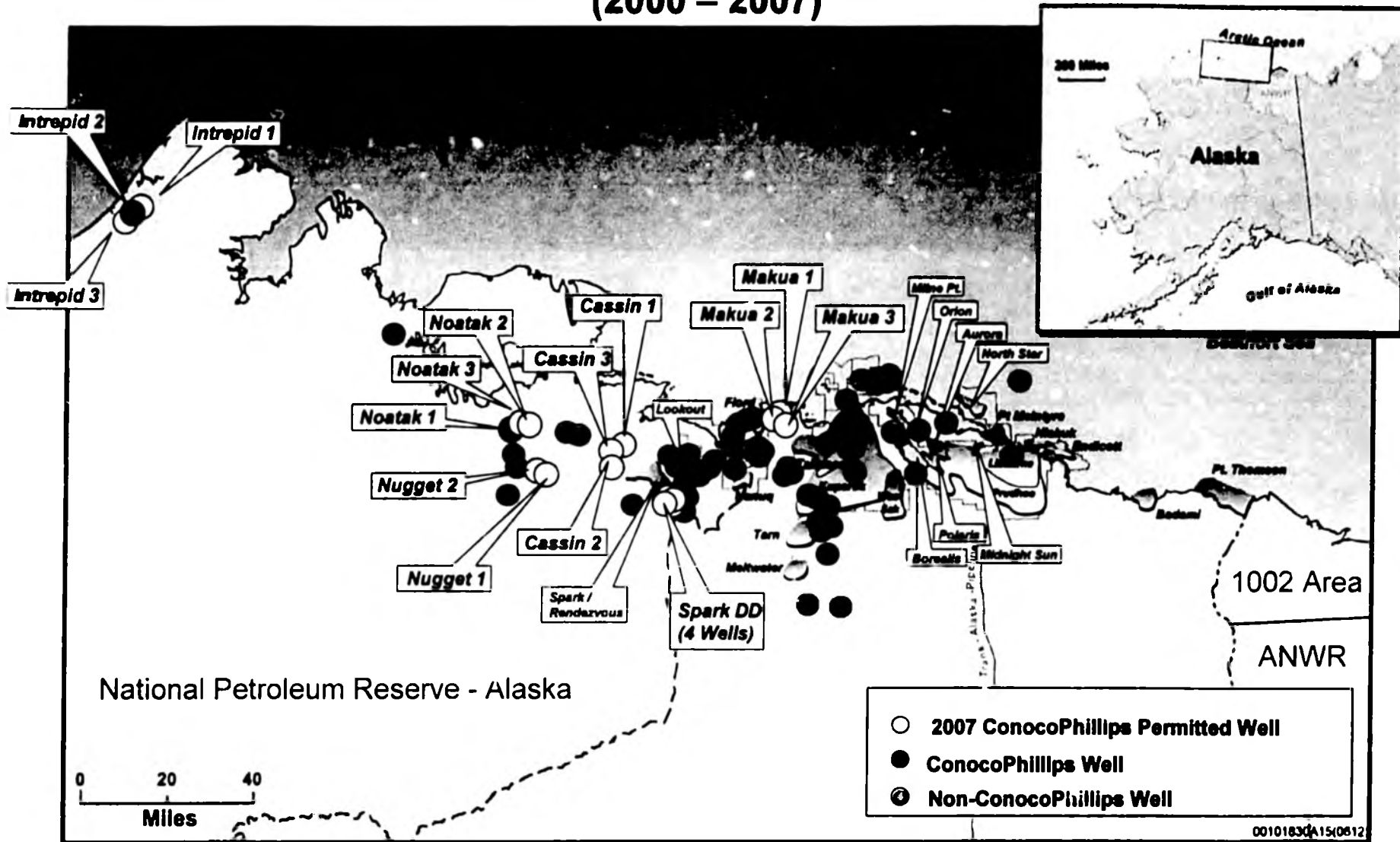
Proposed AGIA

Initial Concerns:

- **AGIA structure hinders competition and creative alternatives**
 - Licensed Project Assurances clause creates significant barriers to alternatives and competition
 - State could pick the wrong winner and be tied up for over a decade
 - AGIA 'bid requirements' are too narrow, prescriptive, and could result in subsidization that may not even be in the State's interests
- **Resource terms not adequately addressed - clearly 'not a negotiation'**
 - Long term firm shipping commitments are key to a successful pipeline project

ConocoPhillips Exploration on North Slope

(2000 - 2007)



Order 2005 on Rolled-in Rates

“In conclusion, to provide guidance to potential shippers in advance of the initial open season that is the subject of this rule, the Commission intends to harmonize both objectives (rate predictability for initial shippers and reductions of barriers to future exploration and production) in designing rates for future expansions of any Alaska natural gas transportation project. It is consistent with our guiding principle that competition favors all of the Commission’s customers, as well as with the objectives of the Act, to adopt rolled-in treatment up to the point that would cause there to be a subsidy of expansion shippers by initial shippers, if any subsidy were to be found.”

– page 44, 18 CFR Part 157, Order No. 2005, 2/9/05

ANS Exploration Potential

	Acres	Range (5 – 95%)	State Royalty?	State Taxes?
State lands* (onshore & offshore)	15 million	24 – 45 TCF unassociated	Yes	Yes
Private lands* (mostly native)		3 – 6 TCF associated		Yes
Federal onshore				
ANWR (1002 Area)	19 million (1.5 million)	0 – 20 TCF	Shared Federal Royalty	Yes
NPRA	23 million	39 – 83 TCF	Shared Federal Royalty	Yes
Federal OCS				
Beaufort Sea		1 – 72 TCF		
Chukchi Sea		10 – 210 TCF		

* Includes Foothills acreage

Source: USGS assessments for State (2005), ANWR (1998), NPRA (2002), Chukchi (2006), Beaufort (2006)

ConocoPhillips

Suggested Changes to AGIA

- **Convert AGIA 'bid requirements' to 'bid variables'**
 - Allow proposals to include other commitments and inducements
 - Allow resource-owner applicants to propose packages with resource terms
 - Foster greater quantity and quality of proposals

- **Amend exclusivity provisions to protect Alaska's options**
 - Avoid treble damages which might penalize Alaska for prudent actions
 - AGIA impairs State's ability to agree resource terms in the future
 - State coordinator/streamlined permitting should be available to any project
 - Similar structure to Alaska Natural Gas Pipeline Act (ANGPA)

Enbridge Inc.
3000 Fifth Avenue Place
425 - 1st Street S.W.
Calgary, AB T2P 3L8
Canada
www.enbridge.com

Rob Carpenter
Senior Legal Counsel,
Gas Strategy & Corporate Development
Tel: 403 231-5970
Fax: 403 231-7380
robert.carpenter@enbridge.com



April 25, 2007

VIA COURIER

State of Alaska
Senate Judiciary Committee
Alaska State Legislature
State Capitol Building, Room 417
Juneau, Alaska 99801

Attention: The Honorable Senator Hollis French, Chairman

Dear Sir:

Re: Speaking Notes from April 13, 2007 Testimony on Alaska Gas Pipeline Project

Enbridge Inc. wishes to thank you for the opportunity to present its testimony by conference call to the Senate Judiciary Committee on April 13, 2007 on the subject of Canadian rights-of-way in the context of the proposed development and construction of the Alaska Gas Pipeline Project. As you are aware, Enbridge is most interested in seeing this important project progress.

As you kindly offered at the end of my testimony, I am taking this opportunity to provide my speaking notes from the call. These notes outline the views of Enbridge respecting the right-of-way and regulatory regime in Canada under which such a natural gas pipeline would be required to proceed. They have been typed and acronyms defined so that they are more readable.

I have also taken the opportunity to attach for your information an Enbridge paper that provides our views on a number of matters in regards to the Northern Pipeline Act.

Again, Enbridge very much appreciates the opportunity to share its views on these matters with the State of Alaska and we would be pleased to provide any further assistance as may be required.

Yours truly,



Rob Carpenter
Senior Legal Counsel
Gas Strategy and Corporate Development
Enbridge Inc.
Encl.

Canadian Right-of-Way Issues

Speaking notes of Robert F. Carpenter
Prepared for testimony provided to Senate Judiciary Committee
State of Alaska
13 April 2007

- * Discuss difference between Northern Pipeline Act ("NPA") right-of-way process and a National Energy Board ("NEB") process
 - fact is, there isn't much difference
 - proceeding under either the NPA or the NEB would require similar steps for right-of-way ("ROW") acquisition for the Canadian portion of the pipeline
 - ROW needs to be acquired in three jurisdictions – Yukon Territory, Province of British Columbia and Province of Alberta
 - in B.C., right-of-way acquisition under either the NPA and NEB would start from very much the same point in terms of process
 - o TransCanada ("TC") does hold map notations in B.C. and Alberta, but these are not interests in land and allow no automatic right to be converted into a ROW
 - In the Yukon, TC does hold a federal ROW; however, that ROW currently only allows for investigatory activities such as geological investigations and surveying, it does not allow for construction. Construction cannot occur without prior written consent of the Canadian federal cabinet Minister who is designated for that purpose by the Canadian cabinet
 - o Approval by Minister allows construction
 - o it is unlikely that the Minister would provide consent to construction activities before all the requirements of the NPA had been met.
- e.g.
1. NPA Part III (17) – requires TC to provide proof that they have obtained all necessary regulatory approvals.
 - These approvals would include application for many permits and approvals in the Yukon, B.C. and Alberta, including (but not limited to) applications for land use permits, water use permits, fisheries authorizations, navigable waters authorizations and timber cutting permits
 - All of the types of applications listed above (and many that are not listed) would trigger provincial or federal environmental reviews, including a requirement for aboriginal consultation

2. Part III (13) – requires filing of contracts between shippers and pipeline (essentially, TARIFFS)

- in summary, ROW acquisition under either NEB or NPA would begin at the same starting point from a process perspective and would require the same permits and approvals
 - o proceeding under the NPA provides no advantage
- * discuss NEB process
 - there is nothing explicit in the NPA, the Certificates of Public Convenience and Necessity ("CPCNs") or the Yukon right-of-way agreement that states that whatever rights those documents may grant are exclusive
 - there is nothing in the National Energy Board Act that prohibits the NEB from looking at a new application
 - not claiming that the NEB process would be a piece of cake – would still require application for all the same permits and applications – would still require aboriginal consultation
 - Enbridge estimates permitting process would take up to 21 months between application and approval. Timing is dependent upon how much work is done before the application is made.
 - NEB process has worked well in the past for a number of projects, including the Alliance gas pipeline from B.C. to Chicago (of which Enbridge owns 50%)
 - NEB process will be used for several new crude oil pipelines that Enbridge is pursuing, and a major crude oil pipeline called Keystone that TC is pursuing
 - NEB process is well understood and supported by a variety of judicial decisions – less potential for challenge under an NEB process vs. the NPA
 - building the Canadian portion of the Alaska pipeline is anticipated to be undertaken in a different manner than the process used for the Mackenzie Gas Pipeline ("MGP"). For example, it is unlikely there would be a separate joint review panel. Instead, it is expected that the NEB and CEAA processes would be jointly undertaken, providing for greater efficiency and clarity.
- * potential challenges to NPA process
 - A. Aboriginal
 - Canadian laws have changed significantly since the NPA was enacted in 1978
 - Constitution Act (1982) recognized the existence of aboriginal rights

- since 1982, numerous court decisions have confirmed the requirement for extensive consultation with First Nations (regardless of whether treaty or non-treaty lands are being crossed)
- B. Environmental
- environmental standards in Canada (federal, provincial and territorial) have changed substantially since the NPA was passed
 - the environmental work done prior to the passage of the NPA would no longer be adequate (and was not believed adequate at the time)
- C. Challenges to changes in the scope of the project
- NPA authorized a very specific pipe, as described in the Treaty
 - the project is currently very different
 - whether one agrees that the NPA allows for flexibility for changing the scope of the project or not, the fact is that such changes would be yet another ground for challenging the CPCNs which were issued under the NPA
- D. North American Free Trade Agreement ("NAFTA")
- the NPA was not grandfathered under NAFTA
 - the Canadian preferences set out in the NPA and the CPCNs are inconsistent with Canada's free trade obligations under NAFTA
 - yet another ground for challenge

The bottom line: an advocate for an environmental group or a First Nation that didn't want this project built would likely prefer that it go ahead under the NPA as compared to the NEB. Proceeding under the NPA offers several strong arguments by which the project can be challenged.

- TC says there have been no successful challenges to the NPA – while technically this is correct, the examples they use to make this point are not comparable to building a major, high pressure gas pipeline from Alaska to Alberta
 - o up to now, the NPA has been used to build and expand facilities only in well developed areas like Southern Alberta in situations where the facilities were needed to carry gas from the Western Canadian Sedimentary Basin to markets
 - o the NPA has never been tested in a situation where it was being used to justify the construction of a major pipeline in a pristine, wilderness area with unsettled First Nations claims.

Alaska Natural Gas Pipeline

Enbridge Inc.'s views on issues regarding the Canadian portion of the Alaska Pipeline

Background Of The Northern Pipeline Act ("NPA")

In the mid-1970's the United States and Canada suffered from significant energy shortages and security concerns. The two countries agreed that greater energy supply and security could be achieved through the development and construction of a pipeline that would transport natural gas from Alaska's North Slope through Canada to the lower 48 states. This agreement was embodied in an exchange of diplomatic letters between Canada and the United States (collectively, the "Treaty"), which set out the size and pressure of the pipeline, the fiscal regime that was to apply and the route along which the pipeline was to be built.

In 1978 the Government of Canada passed the NPA in order to facilitate the planning and construction of the pipeline that Canada and the United States had agreed to in the Treaty; in fact, the Treaty is included as Annex I to the NPA.

In Enbridge's view, the NPA is specific to the pipeline contemplated in the agreement between Canada and the U.S. set out in the Treaty; indeed, the definition of "pipeline" in the NPA means "the pipeline for the transmission of natural gas from Alaska across Canada along the route set out in Annex I [the Treaty] to the Agreement..." Accordingly, the definition of "pipeline" in the NPA cannot be separated from the pipeline referred to in the Canada-U.S. agreement. They are one and the same.

It is important to recognize that this is all that the NPA does. It is not an omnibus statute dealing with the development of northern pipelines generally or even a general statute dealing with the transportation of Alaskan gas through Canada. Equally importantly, the NPA does not make any changes to the powers of Canada's National Energy Board ("NEB") to consider alternative international pipelines from Alaska into or through Canada.

In 1978, in contemplation of the construction of "the pipeline", several Certificates of Public Convenience and Necessity ("CPCNs") were issued pursuant to the NPA. Under the terms of the Treaty the pipeline was to be finished by 1983. However, because of changing economic circumstances, only the "Pre-build" portions of the project defined in the Treaty were built.

No Party Has Exclusive Rights To Build A Pipeline In Canada To Transport Alaskan Gas

There is no reference in the NPA (or in any other piece of Canadian legislation that we are aware of) that prohibits the development of an alternative pipeline to ship Alaskan gas through Canada.

Enbridge does not dispute that the rights granted under the NPA are exclusive, but those rights do not preclude progressing another project under the National Energy Board / Canadian Environmental Assessment Act.

The NPA Is Project Specific

The NPA was passed in order to give effect to the Treaty. The Treaty contemplates a very specific pipeline project, right down to specifying the fiscal regime, the route to be followed and the operating pressures and the diameter of pipe to be used. Reference to the pipeline specified in the Treaty is then used in the NPA to define the term "pipeline" for the purposes of the NPA. In Enbridge's view, the CPCNs are not a general authorization for the construction of "a" pipeline

from Alaska through Canada - the CPCNs are at most a partial authorization for the construction of the pipeline specified in the Treaty.

The project currently envisioned is not the pipeline specified in the Treaty. For example, the Treaty specifies a pipeline with an initial capacity of 2.4 bcf/d, while current proposals contemplate an initial capacity of about 4.5 bcf/d. The Treaty specifies 54" diameter pipe while current proposals contemplate 48" or 52" diameter pipe. The Treaty specifies 1120 psi pressure. Current proposals contemplate 2500 psi. In addition current proposals contemplate a different termination point and include liquids in the gas stream. In short, the current proposal is significantly different than the pipeline approved in the CPCNs.

Absent formal amendments, it is questionable whether variations could occur under the Treaty. History supports this view. For example in 1978 the Governments of Canada and the United States believed it necessary to execute an amendment to the Treaty when they decided to change the pipe diameter from 56" to 54".

In addition it should be noted that historically the NPA has not covered all necessary facilities. For example, the NPA did not apply to the decompression / recompression facility that was installed in the late 1990's at Empress Alberta, as part of the Pre-build system. That facility was approved under the NEB process.

CPCNs

While there is no "sunset clause" or expiry date in the NPA, it should be noted that such legislation in Canada rarely includes expiry dates.

CPCNs can lapse if not exercised in a timely fashion, or if other factors have intervened.

In this particular case:

- (i) The CPCNs are subject to conditions, including Schedule III of the NPA

Construction of the project cannot start tomorrow. Under Schedule III of the NPA, a number of conditions need to be satisfied before the CPCNs can be relied upon.

One of the conditions (s.13) of Schedule III requires the filing of contracts between producers and shippers and between shippers and the company [the holder of the CPCNs]. This makes shipper support critical to the holder of the CPCNs.

The conditions in Schedule III also include the requirement to apply for and receive all necessary regulatory approvals required for the work (s.17). Such approvals would include, for example, land use permits, water use permits, fisheries authorizations, navigable waters authorizations and timber cutting permits in the Yukon, British Columbia and Alberta.

The Northern Pipeline Agency, which administers the NPA, does not issue these necessary regulatory approvals; they are issued under any number of other Canadian Acts, including the Canadian Environmental Assessment Act and the Yukon Environmental and Socio-economic Assessment Act. Under the NPA, each approval would require its own panel. Unlike a modern NEB process, the NPA offers no opportunity to coordinate federal and provincial environmental reviews and does not include the statutory advantages of modern regulatory schemes. The NPA and the Northern Pipeline Agency have no authority to override provincial jurisdiction in environmental matters.

- (ii) The CPCNs were granted in an era of limited environmental review

The environmental review that was completed when the CPCNs were originally granted would not, in Enbridge's view, meet current standards for environmental reviews. Indeed, when the original environmental review was done it was completed under an Environmental Assessment Review Panel ("EARP"), a process that has since been replaced by processes under the Canadian Environmental Assessment Act. At the time, the EARP panel recommended rejection of certain routes and concluded that it did not have enough information on which to make a decision. As Enbridge understands it, it was only when the federal government finally overrode the panel and ordered it to reconsider its rejection of certain routes that approval was achieved.

Stricter standards are in place today.

- (iii) The CPCNs were granted prior to Canadian courts establishing rules requiring consultation with First Nations whenever activities take place in their traditional or treaty lands.

Canada's recognition and protection of the rights of its aboriginal people has changed. From the early 1980's a series of court decisions have recognized and upheld the constitutional rights of Canada's First Nations to be consulted in a comprehensive manner whenever development activities are proposed within their traditional lands or treaty areas.

- (iv) The NPA and the CPCNs are inconsistent with modern international trade agreements

The NPA pre-dates the North American Free Trade Agreement ("NAFTA") and was not exempted from the application of NAFTA when NAFTA was brought into force in 1994.

Schedule III of the NPA, which sets out the conditions which must be met prior to being able to rely on the CPCNs, requires (in Article 10) that Canadian content be maximized as far as practicable and that maximum advantage be taken of opportunities provided by the pipeline to establish and expand suppliers in Canada that can make a long term contribution to the Canadian industrial base. A report must be submitted specifying how the requirement will be complied with. This requirement is not discretionary, but mandatory.

Enbridge is advised that preferential requirements for Canadian products and services are contrary to NAFTA. In addition, Enbridge understands that the Canadian content preferences specified under the NPA could violate Canada's World Trade Organization obligations under Article III of the General Agreement on Tariffs and Trade ("GATT").

The pipeline will be the largest infrastructure project in North America. Accordingly, the economic stakes for suppliers are huge. If one were to accept the position that the NPA provides an exclusive opportunity to the holder of the CPCNs that is not available to other NAFTA investors, it could be argued that the NPA violates the provisions under Article 1102 of NAFTA. This opens the door for claims by other NAFTA investors.

Enbridge believes the Canadian Government would need to seek an exemption from the United States for the NPA to avoid the potential for litigation under NAFTA, but disputes under GATT may be unavoidable.

Rights-of-way ("ROW")

In B.C. and Alberta, right-of-way acquisition under either the NPA or an NEB process would start from the same point in the process. While there are existing map notations in B.C. and Alberta, map notations are not interests in land and allow no automatic right to be converted into a ROW.

To Enbridge's knowledge, the only ROW which exists is in the Yukon. That ROW only allows for investigatory activities such as geological investigations and surveying; it does not allow for construction. Construction cannot occur without prior written consent of the Canadian Federal Cabinet Minister designated for that purpose by the Canadian cabinet. It is unlikely that the Minister would approve construction prior to all the requirements set out in Part III of the NPA being met.

allowable gas offtake. The Prudhoe Working Interest Owners (WIO) and the Commission therefore agreed to principles allowing the Commission consultants and staff to access their reservoir simulation and other relevant engineering studies for the purpose of analyzing gas offtake rates and gas sales startup timing for the Prudhoe Oil Pool. Blaskovich Services, Inc. (BSI) was commissioned to provide reservoir engineering consultation in this study.

This work-study officially began in late January 2006. A brief summary follows:

Summary of 2006 Commission Audit Results

The Prudhoe WIO full field reservoir simulator was used as the primary tool in this evaluation. In addition to runs made assuming no gas sales, simulation runs were made at various gas sales rates (1.0-5.6 BSCF/D) and gas sales startup dates (2015, 2019, and 2024). Some simulation cases were run to test the impact of other factors such as changes in waterflood operation, fuel usage, CO₂ offtake, and some drilling/workover variations. We also evaluated the effect of varying assumptions for end of the field life (EOFL).

Throughout our analysis, we searched for major factors that would affect the trends in total hydrocarbon recovery as a function of gas offtake rates and timing. We were not searching for "the" optimum development strategy. We did not value one type of energy resource (e.g., liquids or gas) over another, but equated them using their relative energy content in units of barrels of oil equivalent (BOE). Based on our analysis of currently available data, we have reached the following major conclusions.

- A major gas sale at Prudhoe represents approximately an additional 4 billion BOE recovery.
- The latest WIO model needs improvements in its ability to predict future field performance. Model errors are increasing with time. Nevertheless, it is the best tool currently available. It should be suitable for comparing directional trends in energy recovery during a gas sale.
- Increased oil capture prior to gas sales can increase hydrocarbon recovery and result in recovery trends that are less sensitive to either gas offtake rates or gas sales startup dates. This was the only mitigation option evaluated that significantly improved trends in BOE recovery.
- End of field life (EOFL) is a major source of uncertainty in determining the gas sale strategies that will maximize energy recovery.
 - o Comparison of model reserves predictions at the same date for EOFL tended to favor an earlier, higher rate gas sale. We found the time limit EOFL approach to be inappropriate because ending energy production rates could be vastly different between the high rate, early startup case and the low rate, delayed startup case.

- o Model results based on equivalent EOFL rate limits consistently show that total energy recovery is substantially decreased with an earlier, higher rate gas sale. We believe that rate limits are more reasonable than time limits for comparison of gas sales model predictions. However, exclusive use of rate limits is flawed because the risks of wells and field infrastructure failures with age are ignored.
- Well, facilities and infrastructure failures can significantly increase the risk of lost hydrocarbons. The longer that gas sale is delayed, the greater the risk of well and facilities failure resulting in premature field shutdown. Furthermore, near term failures will defer production and may result in more reserves loss with early gas sales. Diligent efforts to maintain, repair, and replace aging wells and facilities will help to mitigate risks and maximize recovery under any sales scenario.

Recommendations

The Commission has not received a request for a new gas offtake rule. At this time, we cannot recommend a specific gas offtake rate and sales startup timing. The Prudhoe WIO model evaluations and studies that have been shared with us are not sufficient to justify an allowable above that specified in Rule 9, CO 341D. An early, high rate gas sale could result in the loss of a substantial volume of hydrocarbons. However, even greater volumes may be at risk if gas sales are indefinitely delayed and Prudhoe wells and infrastructure fail before these reserves can be recovered.

We are concerned that Rule 9 does not specifically require a plan for such a major change in the Prudhoe Oil Pool depletion strategy. The ultimate impact of gas sales on hydrocarbon recovery cannot be appraised in the absence of a proposed development plan that identifies the start date, sales rate and liquid loss mitigation efforts. Although the start-up for gas sales is a minimum of 8 years away, many decisions that affect the project will be made earlier. Depletion planning should be required prior to commitments to sell gas so that the Commission is adequately informed and assured that other factors do not exist that would justify or require action by the Commission.

Regardless of the timing of their submittal, the Prudhoe WIOs need to develop near-term strategies to prepare the field for gas sales with focus on methods to increase the capture of oil prior to gas sales and to ensure facility and well downtime is minimized. On a regular basis, the Commission needs to be kept informed of the progress of the depletion planning efforts, including review of study plans, reservoir study results and other relevant information that may impact the Commission's ultimate decisions concerning gas sales offtake. The exchange of information in the past year was very successful and a similar mechanism of exchange should be considered during the depletion planning stage.

We wholeheartedly appreciate the cooperation of the Working Interest Owners over the past year, particularly that of the BP technical representatives who worked with us in this endeavor.

This report reflects the evaluation and opinions only of the authors and does not necessarily reflect those of the Prudhoe Owners or other Commission staff.

Role of the Alaska Oil and Gas Conservation Commission in Establishing Allowable Gas Offtake Rate for Prudhoe Bay

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The Alaska Oil and Gas Conservation Commission ("AOGCC") has a very important role in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of both oil and gas. To fulfill this role, the AOGCC will decide what gas production rates should be allowed from Prudhoe Bay and other North Slope oil fields. Considering only the laws of science, these decisions are very simple; to prevent waste and insure a greater ultimate hydrocarbon recovery, produce all of the oil in a reservoir first and then "blow down" its gas cap only when there is no commercially recoverable oil left. The AOGCC recognizes, however, that many other factors will – and should – be considered in exercising its regulatory powers.

Before considering other factors, it is essential first to understand the science. Extracting gas from an oil field like Prudhoe Bay triggers a series of events. First, the pressure in the gas cap decreases and becomes lower than the pressure in the oil-bearing part of the reservoir. As driven by the laws of physics, the reservoir then works to get back to equilibrium, i.e., the same pressure throughout. To do this, some oil, which is at a higher pressure, moves up into the lower pressure gas cap and the pressure in the oil-bearing part of the reservoir drops. This process continues as the pressure throughout the reservoir equalizes at a lower pressure than before. And as more gas is withdrawn, the process repeats, causing more oil to move into the gas cap and also causing the reservoir pressure to decrease further.

Both the movement of oil into the gas cap and the decrease in reservoir pressure jeopardize oil reserves.

Let's look at movement of oil into the gas cap first. Think about what happens when you drain the oil from your car or when you pour cooking oil into a measuring cup. When you empty the container, some of the oil sticks to it and will not come off. That is what happens to oil when it moves into the gas cap, a part of the reservoir that has never contained oil but has always only held gas. However, because that container is porous rock rather than glass or plastic, the amount of oil that sticks is much greater. The previously "dry" reservoir rock becomes coated with oil. Although some of this oil can be produced, a substantial portion (in some fields over 20 to 30 per cent) sticks to the rock and will never come out. In short, producing gas without replacing the gas cap fluids will cause some oil to stick to the reservoir rock and result in a decrease of ultimate recovery of oil.

Now let's look at decreasing reservoir pressure. Think about an aerosol container. It starts out with high pressure inside; if you puncture it, it will explode. As you use it, more and more of the fluids – both the active product and the carrier gas -- are released and the pressure decreases until, eventually, you push the button and nothing happens. When you shake it, you might be able to hear that there is still hair spray or some other product inside, but you can no longer get it out. At this point the pressure has decreased so that you could even puncture the container and nothing would happen. Similarly, in an oil reservoir, the reservoir pressure provides the energy that allows the oil to flow through the reservoir and up the well bore. As fluids are produced, the

pressure decreases and the reservoir loses this energy. Eventually, as more and more gas is produced and the pressure continues to drop, there is insufficient energy to drive the oil from the reservoir. Typically operators of oil reservoirs maintain reservoir pressure and energy by re-injecting produced gas and injecting water to replace produced oil. They continue this process until they have recovered all the oil. Then, when no commercially recoverable oil is at risk, they "blow down" the gas cap. They do this because producing gas from an oil reservoir and not replacing it will result in a decrease of reservoir energy and, therefore, a decrease in oil recovery.

Another bad thing happens when the reservoir pressure decreases; some oil changes from liquid to gas. The remaining oil becomes thicker. Think about soup cooking; as water evaporates, the remaining liquid becomes thicker. In an oil field this thickening makes it harder for the oil to flow and, thus, decreases oil recovery. We all know that it is much easier to suck water up a straw than it is molasses.

In summary, looking simply at the reservoir engineering science, producing gas from an oil reservoir while there is still commercial oil remaining to be produced WILL cause a portion of the oil resources to be lost and, thus, the gas cap in an oil reservoir should only be "blown down" when no more commercially recoverable oil remains.

The explanation above assumes that all of the gas can be recovered after all of the oil has been produced, and for most Lower 48 scenarios this is a reasonable assumption. However, for the North Slope, there will be a trade-off between leaving oil in the ground and leaving gas stranded, and this trade-off will be influenced by several factors.

For example, the remaining useful life and increasing operating cost of the aging North Slope infrastructure will impact this balance between losing oil and stranding gas. Much of the North Slope infrastructure that was put in place thirty years ago for oil production will still be necessary for gas production. As this infrastructure ages, two things happen: 1) the cost to operate the equipment increases, and 2) components break and must be repaired or replaced. The later in time the gas is produced the higher the costs will be to operate, repair and replace equipment and, thus, the sooner the gas will become uneconomical to produce and the more gas will be left stranded.

The minimum rate at which TAPS can operate will also impact the balance between losing oil and stranding gas. Although the gas will have its own line which will operate independently of TAPS, continued operation of the TAPS line will impact the economic life of the gas production because, as long as TAPS is operating, many of the operating, repair and replacement costs will be shared by both the oil and gas production, thus extending the time before either becomes uneconomical.

These and other factors will complicate the gas off take rate and timing decisions for North Slope fields. The AOGCC is charged with preventing waste and insuring the greater ultimate recovery by making sure that the operators act in accordance with good oilfield engineering practices. In executing this responsibility, the AOGCC must be cognizant of the balance between oil recovery optimization and gas recovery optimization. This will be no trivial task.

Prudhoe Oil Pool Gas Offtake Reservoir Study

Public Summary

February 28, 2007

Presentation Summary

- Commission authority
- Historical perspective
- Reservoir concerns related to gas sales
- Study purpose and available information
- Observations
- Recommendations

AOGCC Major Gas Sales Reservoir Study Disclaimer

Evaluation and opinions reflect those of only BSI and AOGCC staff who worked directly on the project. These opinions do not necessarily reflect those of the WIO, Commissioners or other AOGCC staff

Prudhoe Gas Offtake Allowable Commission Authority

- **Commission Duties** (related to MGS decisions)
 - prevent physical waste of resource
 - promote greater ultimate recovery
- **Authorities**
 - require/approve development plans
 - set allowable offtake

Prudhoe Gas Offtake Allowable Historical

- Pool Rules CO 341D, Rule 9 (1977)
 - Offtake allowable set at 2.7 BCFD
 - Envisioned \approx 2.0 BCFD Pipeline Delivery
- Currently produced gas re-injected

Why do we care about gas offtake?

- Gas extraction lowers reservoir pressure
 - Decreases energy required for oil production
 - Oil recovery suffers; gas production benefits
- How is ultimate total hydrocarbon recovery affected by gas sales offtake?

Prudhoe Gas Offtake Allowable

Recent Activities

- 2002 WIO study
 - Tentative P/L design of 4.3 BCFD
 - Prudhoe major source for P/L (+24 TCF)
- Pipeline fiscal discussions/negotiations
- No Application for Rule 9 Amendment
- AOGCC 2005 inquiry
 - Concluded comprehensive revisit of Rule 9 needed
 - Proactive Approach
 - “Principles” for access to WIO reservoir studies

Prudhoe Gas Offtake Study

- Study begun January 2006
 - Engineering Consultant Blaskovich Services Inc. (BSI)
 - WIO provided Data Room with necessary information and studies
- WIO Full Field Reservoir Simulator Primary Tool
 - Access/Electronic copies of reservoir simulation results
 - Additional simulation runs on request
- Good Cooperation from WIO staff, management

Study Approach

- Simulation runs variables
 - Gas Startup Times (2015-2024) Offtake Rates (1-5.6 BCFD)
 - Other field operating strategies
- Compared on basis of total energy content
 - Units of Barrel Oil Equivalent (BOE)
- Concentrated on trends in recovery, not absolutes
 - Not looking for “the” optimum development strategy

Conclusions

- Major Gas Sales adds \approx 4 Billion BOE (+/- 24 TCF)
 - 11.4 BSTB Oil/Condensate/NGLs produced to date
 - 1977 projections of less than 9 Billion Barrel Oil
 - Initial projections assumed 1982 Gas Sales
 - End of Field life estimated 2003

Conclusions - Model

- **WIO model best currently available**
 - Years in development
 - Should be good for evaluation of directional trends
 - Some improvements needed in predictive mode

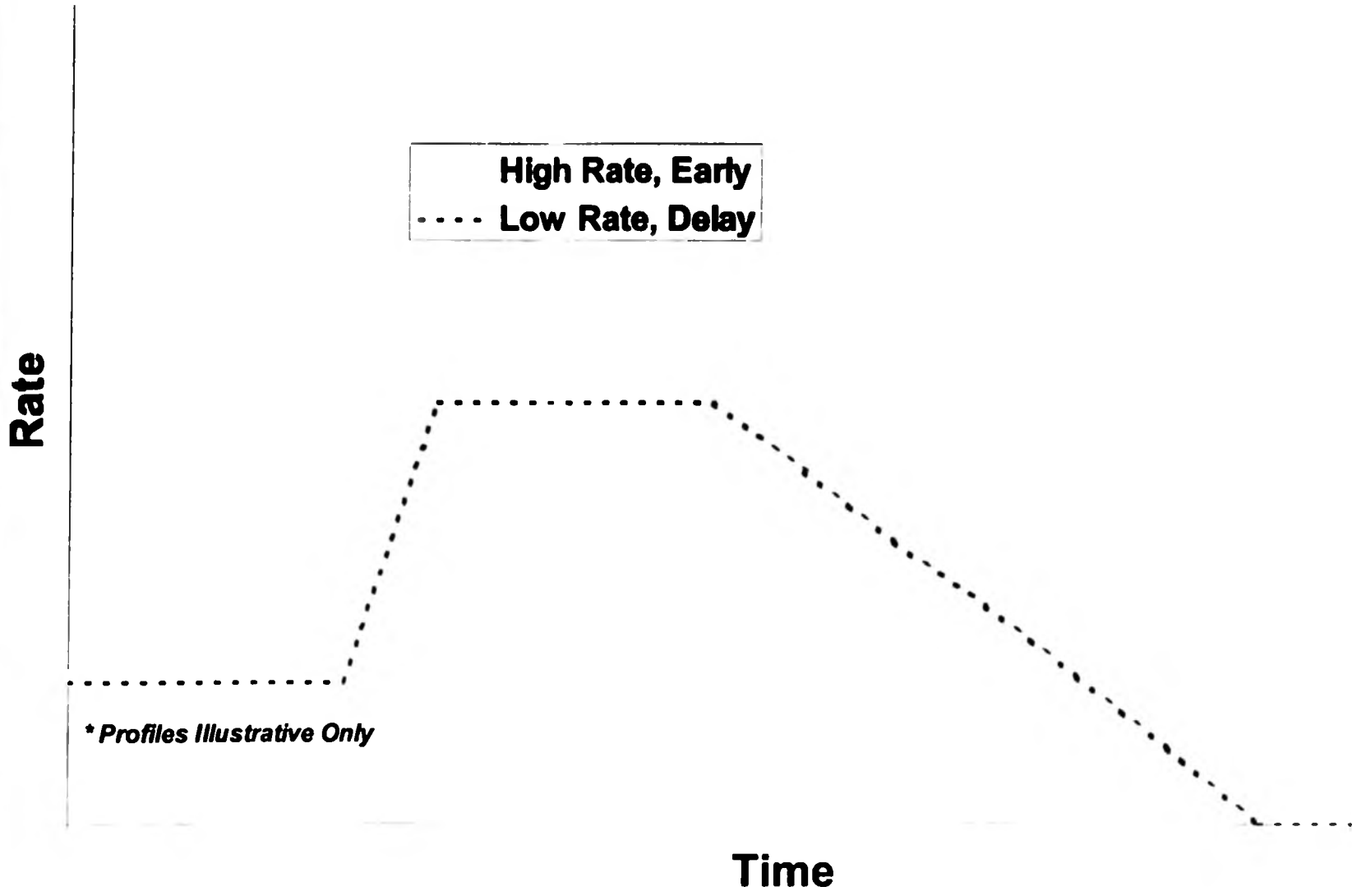
Conclusions

- *Increased oil capture prior to Gas Sales*
Improved recovery trends
 - Most encouraging strategy
 - Recovery trends less sensitive to gas offtake or S/U Rate
 - Allows for more flexibility

End of Field Life (EOFL)

- End of Field Life (EOFL) is when costs exceed revenue from continued production.
 - Reserves are evaluated at an assumed EOFL
 - Unknown – but important to compare all cases at same assumed EOFL
- Major effect upon predicted recovery outcomes
- Date Limit favors earlier, higher rate MGS
- Rate Limit favors later, lower rate MGS

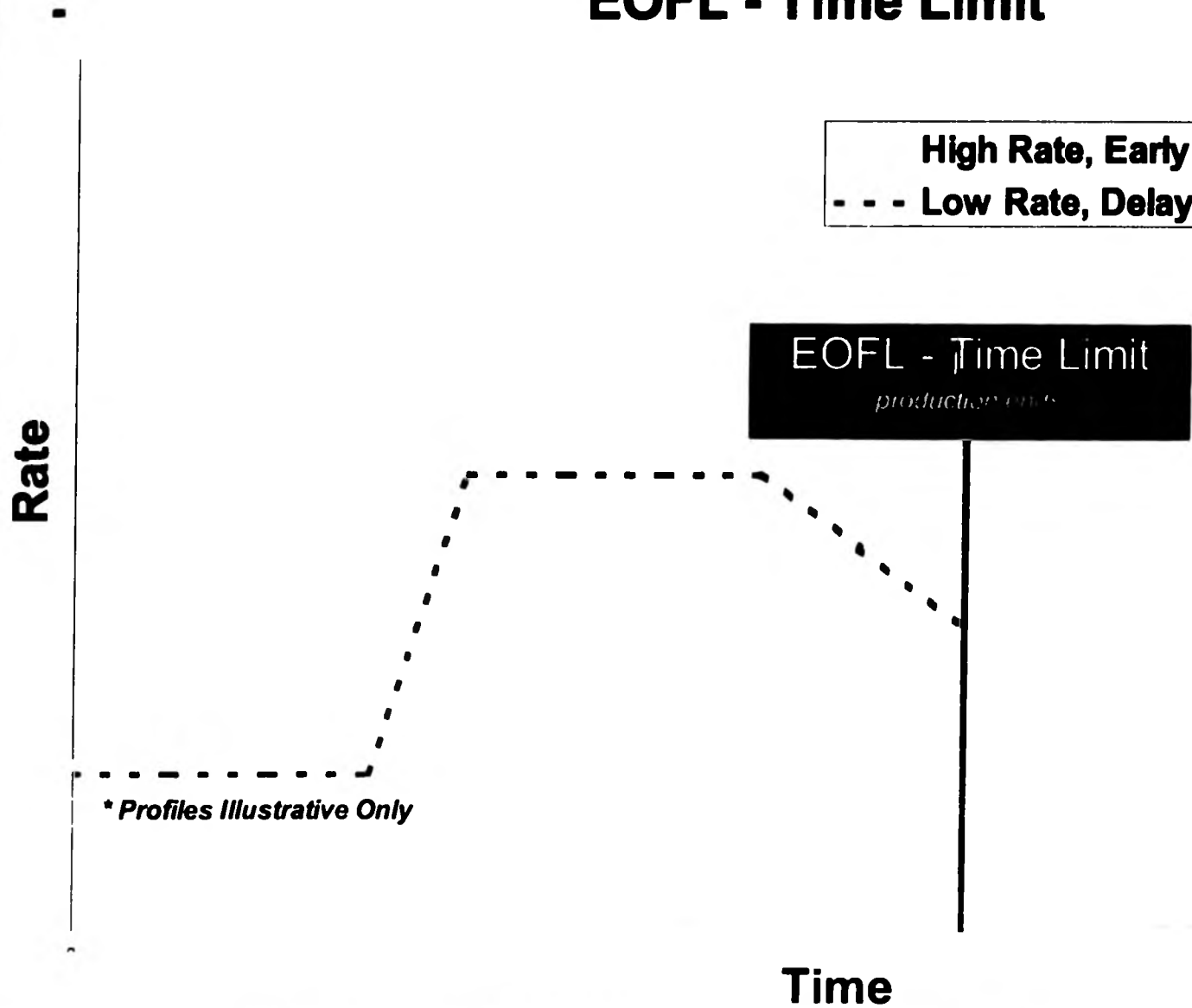
Hypothetical Profiles*



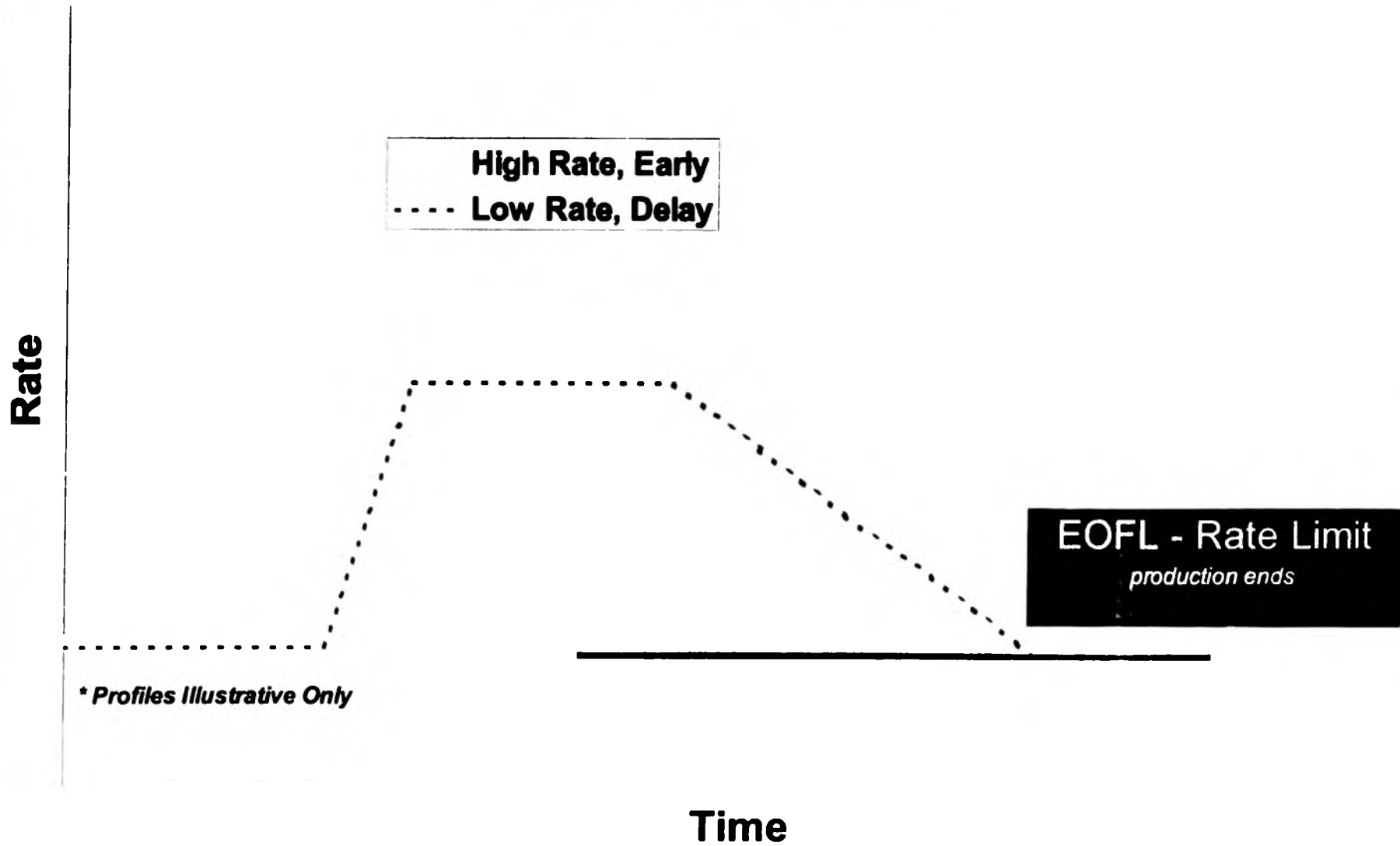
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AOGCC Public Meeting - MGS
Reservoir Study

Hypothetical Profiles* EOFL - Time Limit



Hypothetical Profiles* EOFL - Rate Limit



EOFL Summary

- Time limits do not treat production (revenue) fairly.
- Rate limits do not treat future risk (costs) fairly.
- We believe rate limits are more correct but we need to consider risk with age.
- Use rate limits and risk analysis

Field Well/Infrastructure Failures

- Failures increase reserves risk
 - If MGS delayed
 - Higher risk with age– impact field life
 - Near Term failures
 - Deferred oil production prior to MGS risks reserves

Recommendations

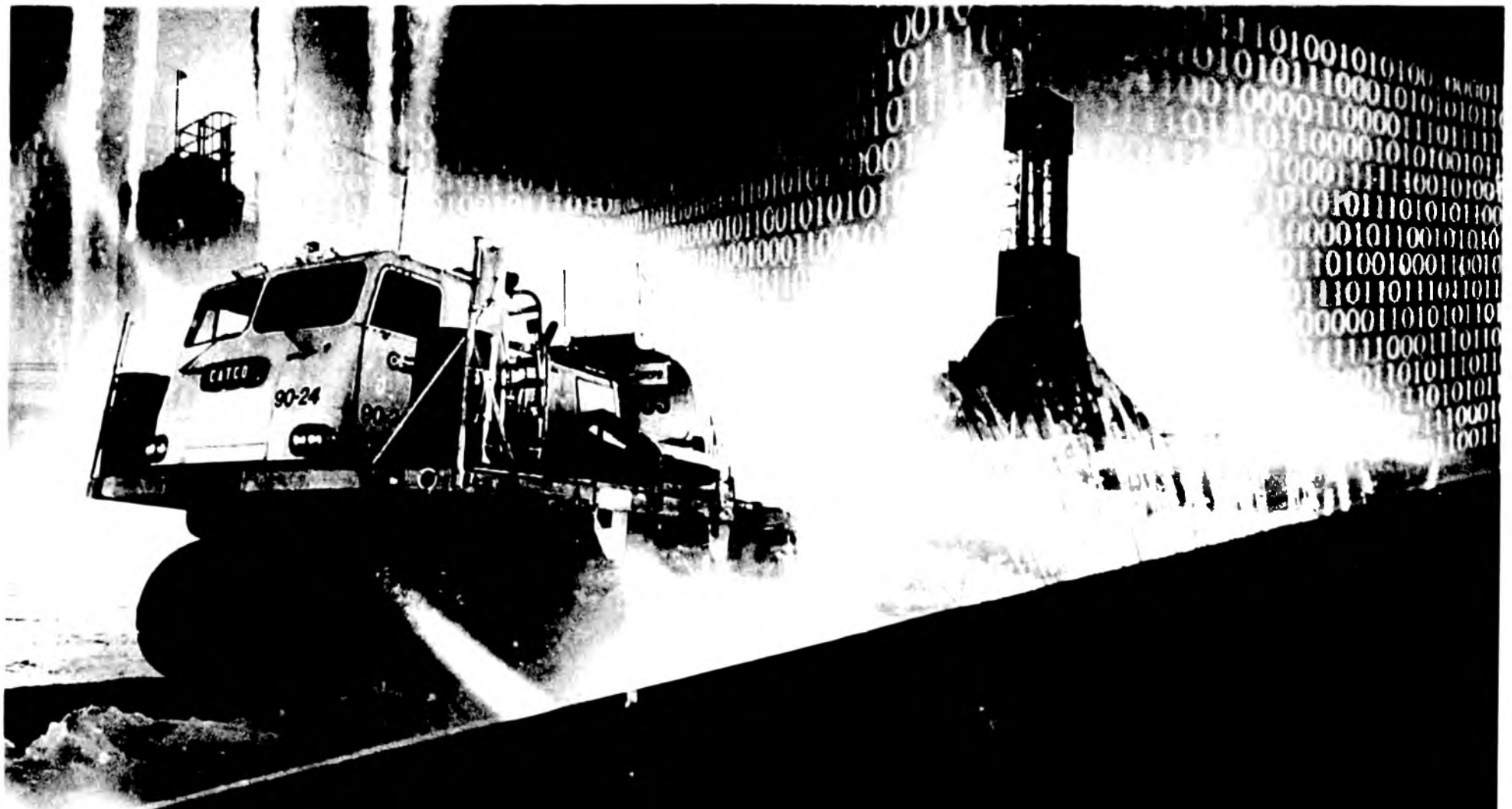
MGS Offtake

- There is insufficient evidence at this time to recommend increasing Rule 9 Offtake
- No request for modification of Rule 9
- Depletion planning should be required prior to commitments to sell gas

Recommendations

Pre-MGS Strategies/Plans

- **Regardless of timing of request for modification near term strategies needed to prepare for MGS**
 - **Increase oil capture prior to MGS**
 - **Minimize well and facility downtime**
- **Mechanism needed for exchanging information during the depletion planning stage**



Alaska Gasline Inducement Act

Anadarko
Petroleum Corporation

Senate Judiciary

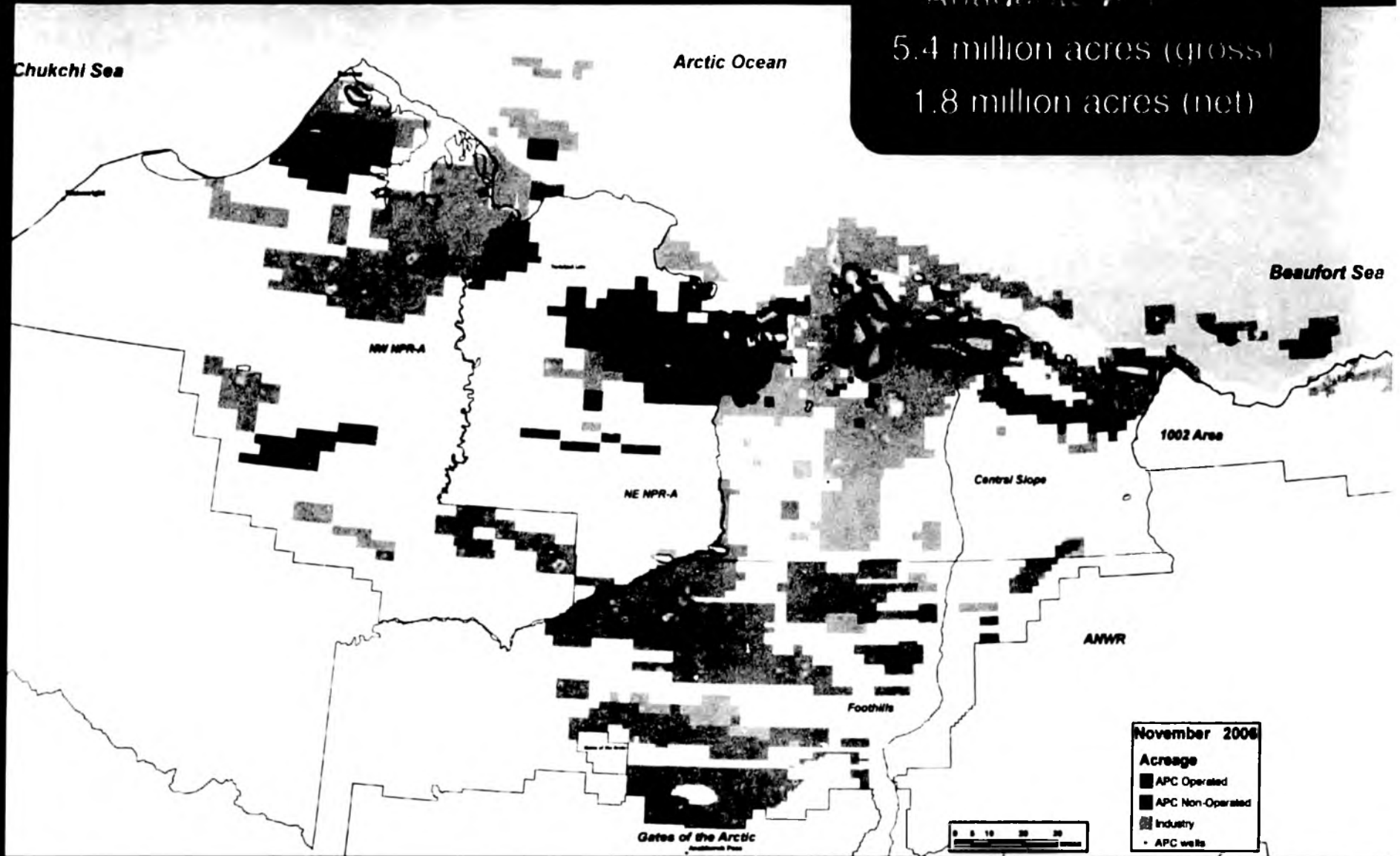
April 14, 2007

Anadarko's Investment in Alaska-Land

Anadarko's Investment in Alaska-Land

5.4 million acres (gross)

1.8 million acres (net)



Support AGIA

▲ Support Alaska Gasline Inducement Act

– *We like the process*

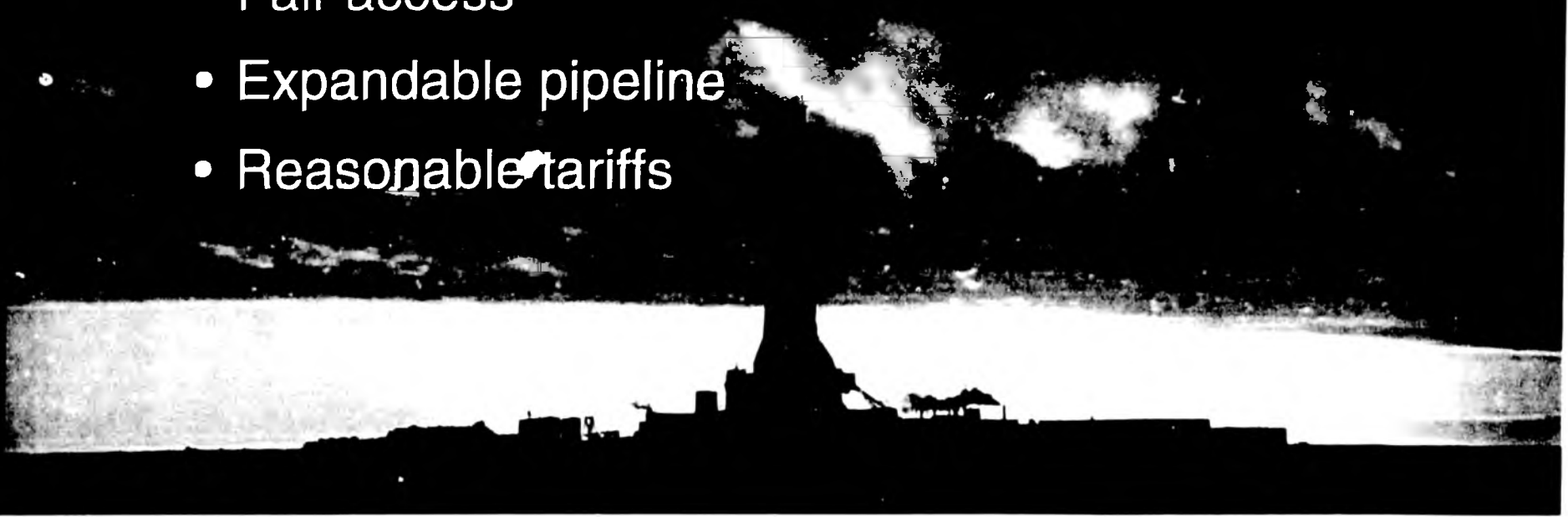
– *We support the specifics*

– *Addresses Key Explorer Concerns*

- Fair access

- Expandable pipeline

- Reasonable tariffs



Support AGIA Process

▲ We like the process

- *Three opportunities for input and for key policy makers to consider issues before a deal is done*
 - Initial legislation
 - Public comment on submitted applications
 - Legislative review of selected application
- *Creates competitive process*
- *Lays out “must haves” that the state will require of any applicant*

Support Specifics in AGIA

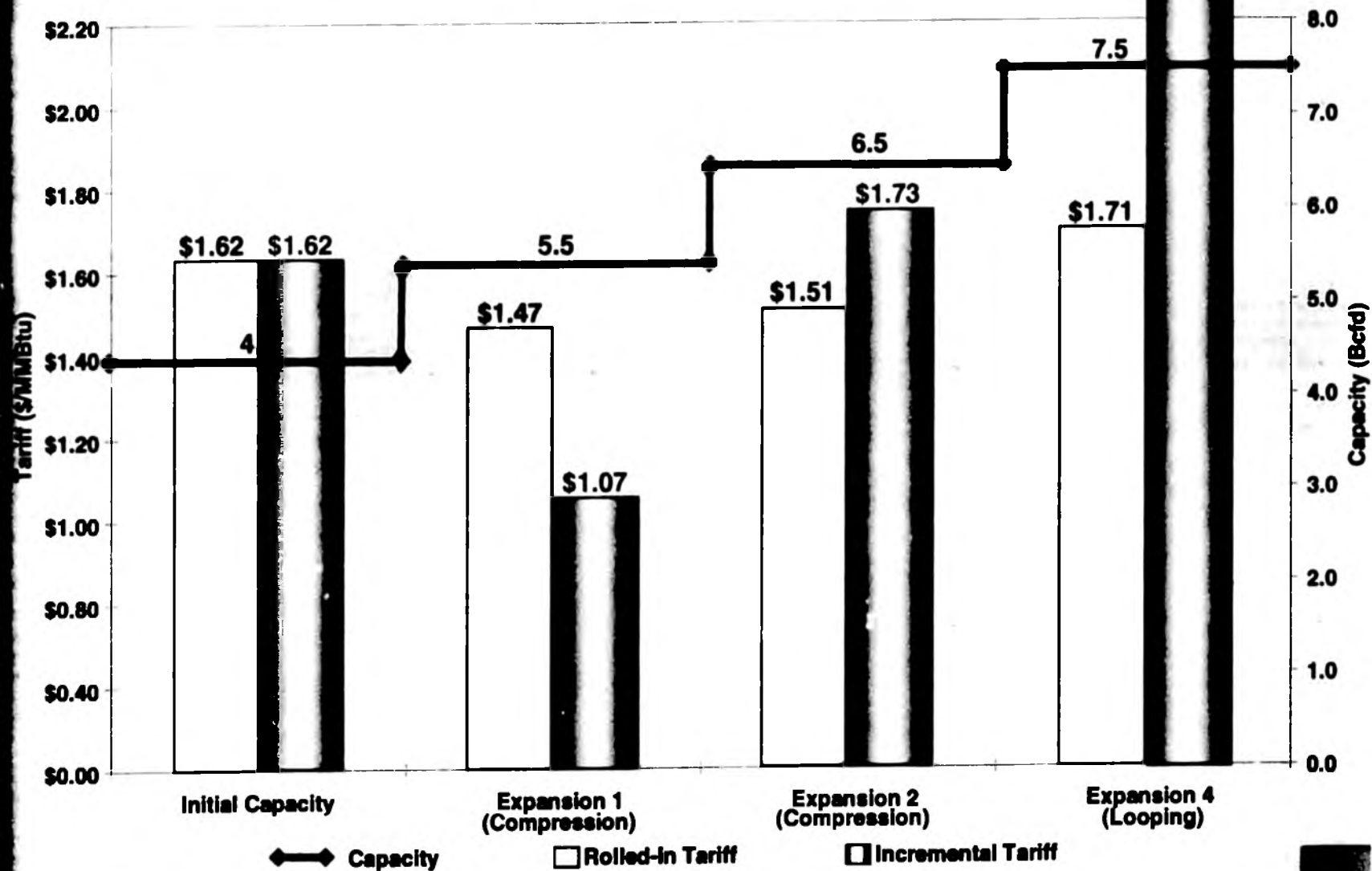
▸ We support mandatory provisions on access and rates

– *Pipeline (licensee) must:*

- Assess market demand for expansions every 2 years
- Commit to expand in reasonable increments on reasonable terms
- Propose and support rolled in rates up to 15% above initial rate and agree not to enter into negotiated rate agreements that would preclude the rolled in rates.

Indicative Expansion Tariffs

Numbers from P. 25, State AGIA Presentation, March 12, 2007



AGIA helps mitigate challenge of FERC rules

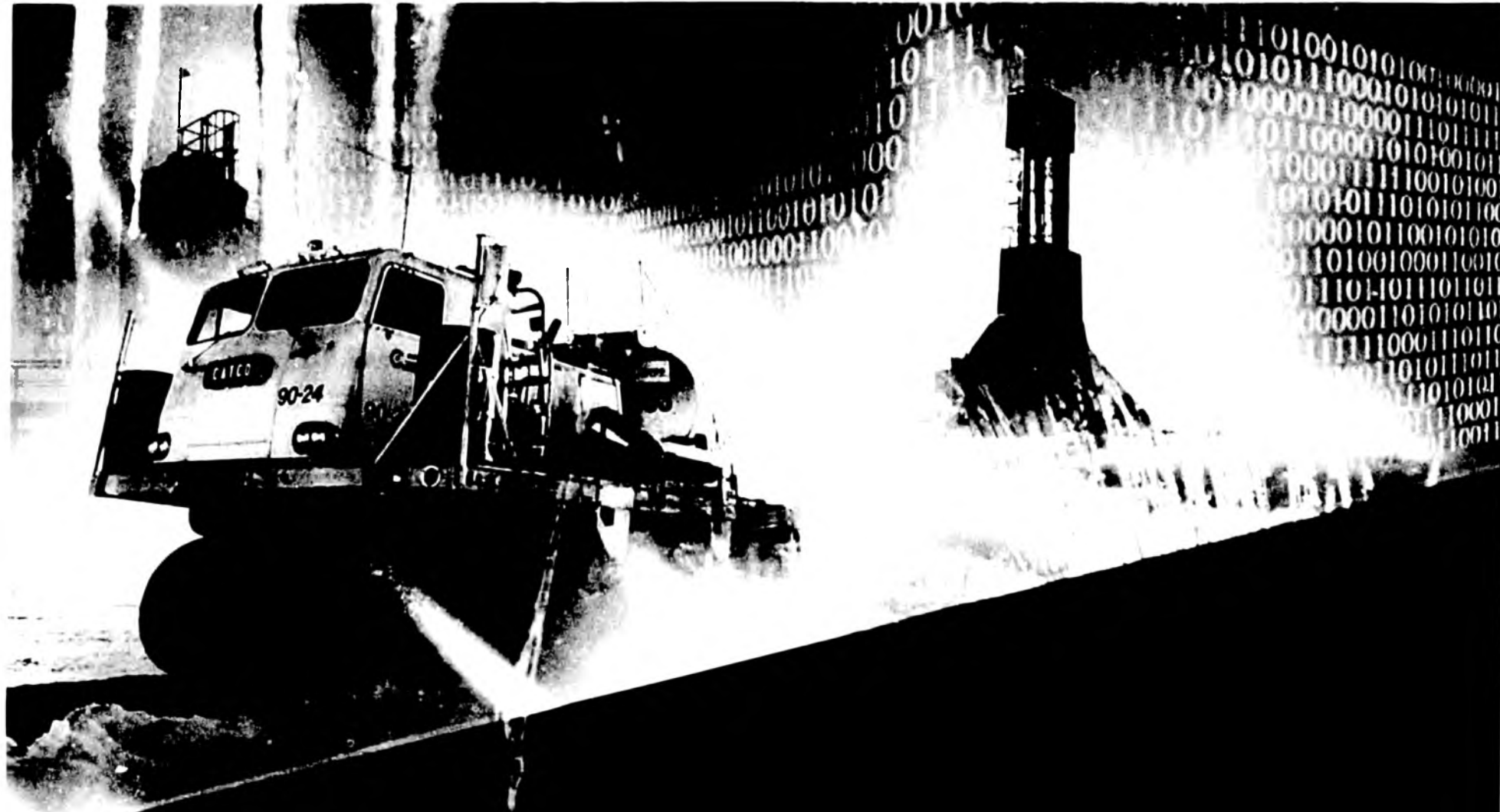
- Producers in court challenging FERC authority to ensure adequate pipeline capacity and low cost expansions
- Producers attempting to invalidate Sections 157.36 & 157.37
- 18 C.F.R. 157 Subpart B
- Section 157.36 Open seasons for expansions.
- Any open season for capacity exceeding the initial capacity of an Alaska natural gas transportation project must provide the opportunity for the transportation of gas other than Prudhoe Bay or Point Thomson production. In considering a proposed voluntary expansion of an Alaska natural gas pipeline project, the Commission will consider the extent to which the expansion will be utilized by shippers other than those who are the initial shippers on the project and, in order to promote competition and open access to the project, may require design changes to ensure that some portion of the expansion capacity be allocated to new shippers willing to sign long-term firm transportation contracts, including shippers seeking to transport natural gas from areas other than Prudhoe Bay and Point Thomson.
- Section 157.37 Project design.
- In reviewing any application for an Alaska natural gas pipeline project, the Commission will consider the extent to which a proposed project has been designed to accommodate the needs of shippers who have made conforming bids during an open season, as well as the extent to which the project can accommodate low-cost expansion, and may require changes in project design necessary to promote competition and offer a reasonable opportunity for access to the project.

Support AGIA

▸ Support Alaska Gasline Inducement Act

- *We like the process*
- *We support the specifics*
- *Addresses Key Explorer Concerns*
 - Fair access
 - Expandable pipeline
 - Reasonable tariffs





**Bringing Excellence
to the Surface**

Anadarko PLC
Petroleum Corporation

Alaska Natural Gas Pipeline Project

Testimony on AGIA

Senate Judiciary Committee

April 14, 2007

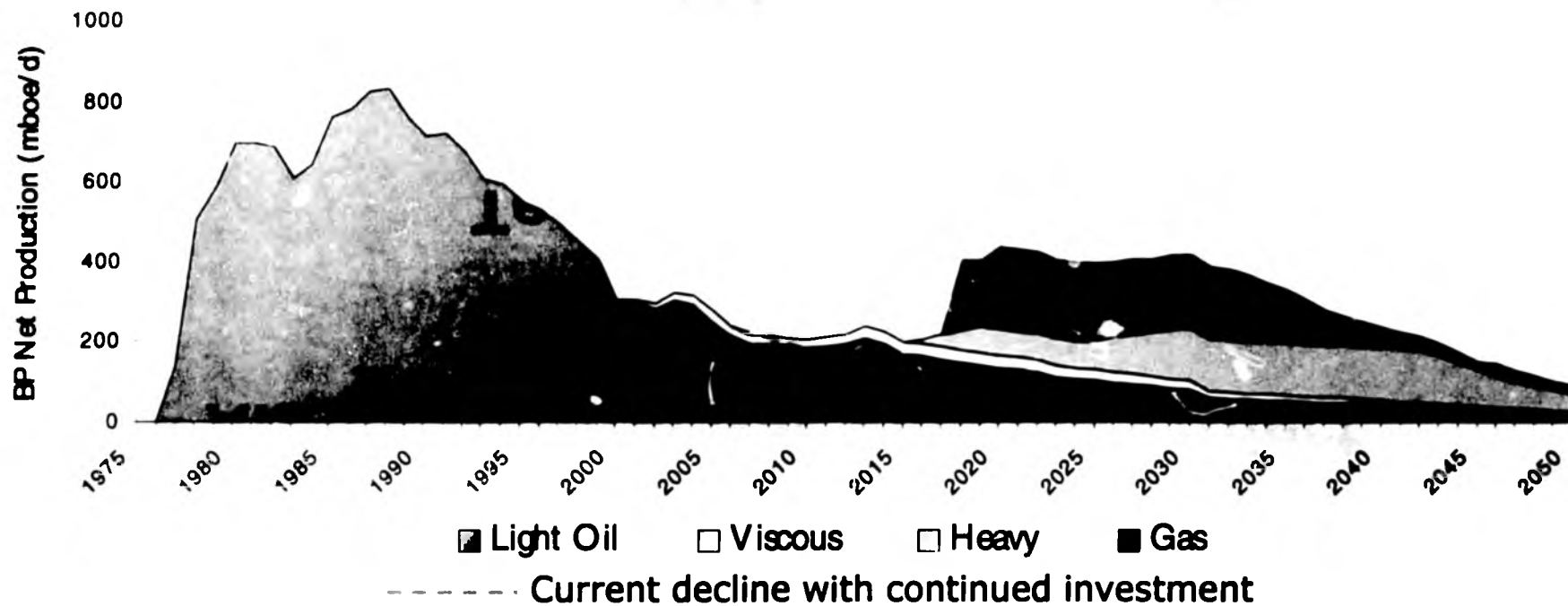
bp





BP's Vision for Alaska

- BP has a long history in Alaska....
-and we look forward to a 50-year future
- That future is only possible with a gas pipeline



BP Key Messages



- BP wants and needs a successful gas pipeline
- BP supports Gov. Palin's desire to get Alaska's gas to market
- AGIA can help deliver a successful gasline project provided key issues are addressed
 - Encourage best solution by offering objectives, rather than requirements
 - Don't require initial shippers to subsidize others
 - Encourage competition by allowing the market to determine the "winner"
 - Resource rules should be clearly defined and not be subject to change

What A Successful Gasline Means



- **Jobs** for Alaskans
- Additional **revenue** for future generations

- Increased **economic activity**
- **New businesses** created



**AGIA can help deliver a successful gas pipeline if we....
Use Objectives instead of Prescriptive Requirements**



- Prescribing solutions will not result in the best project
 - A better project will result from allowing the market to respond to the State's objectives

- Subsidization is contrary to FERC regulation

"It is consistent with our guiding principle...to adopt rolled-in rate treatment up to the point that would cause there to be a subsidy of expansion shippers by initial shippers, if any subsidy were to be found." [FERC Order 2005, para. 125]

- Agree that evaluation should be done in an open and transparent way

AGIA can help deliver a successful gas pipeline if we....

Avoid Exclusivity to Ensure a Pipeline Gets Built



- **AGIA may preclude a successful project from moving forward**
 - expedited regulatory handling offered only to licensed project
 - State can be penalized for assisting other project
 - AGIA may conflict with Federal law and regulation

- **Should the State pick an exclusive winner based only on a proposal?**

- **The market will determine the best solution through actual performance**

- **Alaska Natural Gas Pipeline Act is a good model**
 - Provides expedited regulatory handling to any project

AGIA can help deliver a successful gas pipeline if we....
Address Resource Terms to Allow a Project to Proceed



- The resource terms in AGIA will not encourage the firm transportation commitments needed for a successful project
- Solving resource issues with clarity will enable a successful open season which is the key to advancing the project
- BP wants to develop mutually agreeable resource terms



What is so important about FT?

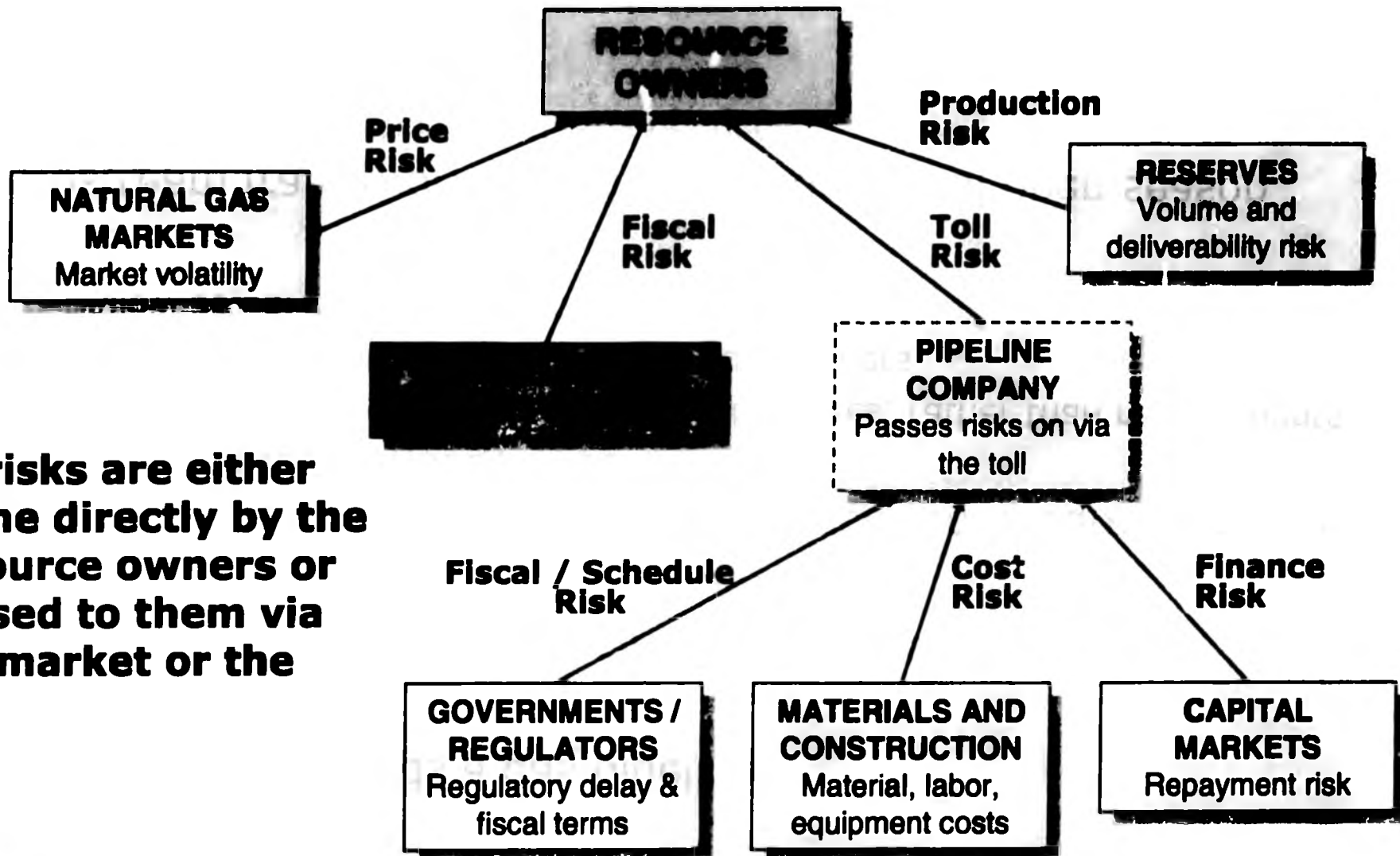
- Firm Transportation commitments (FT) by the resource owners are needed for a gas pipeline company to get financing
 - "No customers, no credit, no pipeline" (TransCanada)
 - "No producers, no pipeline" (Enbridge)

- FT is a binding financial obligation
 - not simply "committing gas to a pipeline"

- Requires multi-billion dollar commitments by resource owners
 - Assuming 4.5 bcfd, \$3.50/mcf, 25 year term.....**\$144 billion**

- Long term commitments represent real risk
 - Risk is borne by resource owners

Project Risk Resides with the Resource Owners



All risks are either borne directly by the resource owners or passed to them via the market or the toll.

➔ Those bearing a risk are commercially motivated to manage that risk

Summary



- BP wants and needs a gas pipeline
- BP supports an open and transparent process
- Key midstream issues must be addressed to ensure there are no unintended consequences
 - Encourage best solution by offering objectives, rather than requirements
 - Don't require initial shippers to subsidize others
 - Allow actual performance to determine the "winner"
- Upstream framework is critical for successful open season
 - Resource terms must be clearly defined



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 198612
Anchorage, Alaska 99519-8612
(907) 561-5111

April 30, 2007

The Honorable Hollis French, Chair
Senate Judiciary Committee
State Capitol, MS 3100
Juneau, AK 99801

Senator French:

Thank you for the opportunity to provide testimony to the Senate Judiciary Committee. During testimony I was not able to fully answer a question regarding the Canadian policy on rate subsidization resulting from rolled-in rate treatment. I have provided a written response below.

What is the Canadian policy on subsidization as it relates to rolled-in rates?

I am not aware of any statement being made by the Canadian National Energy Board regarding subsidization resulting from rolled-in rate treatment. However, in Canada the NEB has determined that rolled in toll treatment for pipeline expansions is generally in the public interest.

An important decision on the matter of rolled-in rate treatment in Canada was made by the NEB on the Iroquois project (GH-5-89 Decision), in which the NEB found, among other things, that "tollpayers have no acquired rights", and that "when new facilities are completed they will become an integral part of [the] pipeline system and will not be associated with or dedicated to any individual shipper's gas."

I have also enclosed a copy of the public testimony BP provided on SB104. Thank you again for the opportunity to participate in your deliberations.

Sincerely,

David Van Tuyl
Gas Commercialization Manager, BP Alaska

Attachment
cc: Committee Members

**BP Testimony on AGIA (SB104)
Senate Judiciary Committee
April 14, 2007**

- Mr. Chairman, members of the committee, for the record my name is Dave Van Tuyl. I am the Gas Commercialization Manager for BP Alaska. Thank you for the opportunity to testify before you this morning.
- My testimony will start with some general comments about the importance gas pipeline project, then I'll provide some specific suggestions on the AGIA bill, then I'll turn to a brief discussion of financing and risk, and then I'll conclude with a summary.

BP's Vision for Alaska

- I'd like to spend a moment to look into the future and consider the opportunities we have before us.
- BP has a **long history in Alaska**. BP has been actively involved in the exploration, development and production of Alaska's North Slope energy resources for decades.
- And we see the opportunity for a bright future ahead. In fact, we envision our **50-year future in Alaska**. It's not just a slogan.
- So how might that vision look to our company?
- I'd like to turn your attention to the graph at the bottom of slide 2, which shows the **possibility of the future that BP sees** in Alaska, depicting BP's share of production through time.
- There are a few key points to draw from the graph.

- The days of **high plateau** production are behind us.
- We still have a significant level of production today, but that **production will continue to decline** with time. That's what the dotted red line depicts.
- That shows production declining at historic levels, which already would require **significant investment**.
- We can make up that decline in production with new investment that would result in new production from **heavy oil resources and from gas**.
- But it's not a given. It's a view of what's **POSSIBLE**.
- That future is only made possible with an Alaska gas pipeline project.

BP Key Messages

- So **BP wants and needs a gas pipeline**. And we need that pipeline to be built for a low capital cost and then operated cost efficiently. We believe that is what is required to make the project happen and be successful. Low costs are good for both BP and the State because it results in lower tariffs, higher netbacks and more revenues for the State and BP.
- Also, a low cost project will provide incentive to explore for more gas to keep the pipeline full into the future. That is also good for the State and for BP.
- The best way to ensure there is gas exploration in the future is to get a gas pipeline built in the first place, and to get it built for a low cost.

- This is a **hugely important project to BP, to Alaska and to the nation**. It represents the largest, known, undeveloped gas resource in the United States, and in BP's global portfolio. The gas project is important in its own right – but it also extends the economic life of Alaska's oil production for decades. Extending oil production is good for the State, the nation and for BP.
- We **share the governor's and the legislature's desire** to get a successful gas project moving, and **BP stands ready** to engage with the administration and legislature to reach a balanced fiscal framework that works for all the parties.
- And finally, a successful framework will set the foundation for **a stable, healthy, and viable oil and gas business for decades** to come. BP's future in Alaska is directly linked to the gas pipeline project.
- That's why we are very encouraged by the Governor's and the legislature's enthusiasm about getting Alaska's gas to market. That is also our vision, and so we share your enthusiasm. It's the key to Alaska's future, and to BP's future in Alaska.
- Therefore, it's important that we get it right.
- BP sees AGIA as the Administration's expression of its commitment to advance the gas pipeline project in an open and transparent way. We applaud that good faith expression.
- Developing the right process is difficult. Since first seeing AGIA at its roll out to the legislature and the public on March 2nd, we have identified a number of important areas of concern for you to consider.

- We believe AGIA CAN be successful if some key issues are addressed, and I've summarized those concerns here, and will discuss them in more detail shortly.
- We believe AGIA may create some unintended consequences that could jeopardize the vision of getting Alaska's gas to market quickly, and at low cost. We believe it is important for the Legislature to consider these areas of concern as you deliberate on AGIA.
- Why do we feel these changes are so important? It's because we want the project to be a success, because there is much at stake for BP and for Alaskans.

What A Successful Gasline Means

- It's worth a brief reminder of the importance of a successful project. And I'd like to emphasize that what we need is a SUCCESSFUL gas pipeline, not just ANY gasline.
- As we've said, this is a project of tremendous scope and scale and that's what the picture reminds us of. Because of this it presents tremendous risk. But if it's done right, it also presents the opportunity for great benefits as well.
- Because there is much at stake, we need to get it right.
- The project creates the opportunity for jobs for Alaskans, and if we deliver a successful, low cost project, for revenues to the State and to BP well into the future.

- We can create a whole new industry of gas exploration with a successful, low cost project. Gas exploration and expansion are only possible if the pipeline gets built in the first place, and if it's built for a low capital and operating cost. That will make it attractive for bringing new volumes into the project, which benefits the State, gas explorers, and initial shippers as well.
- A successful gas pipeline project will provide the opportunity to bring a long term gas supply source for use by Alaskans.
- And finally, gas sales will diversify Alaska's economy for decades into the future.
- As I said, there's a lot at stake, so we need to get it right.
- Now I'll turn specifically to our suggestions on AGIA that would help AGIA deliver a success gas pipeline.
- Each of the next three slides starts out with the statement, "AGIA can help deliver a successful gas pipeline if...", and I'll describe modifications we recommend to AGIA on each slide.

Use Objectives Instead of Prescriptive Requirements

- First, AGIA can help deliver a successful gas pipeline if we use objectives, instead of prescriptive requirements
- We fully support the State clearly providing its objectives for a successful gas pipeline project
- The concern we have is that AGIA as drafted presupposes solutions to those objectives, such as those contained in Section .140 starting on page 4 of the bill.

- We think that prescribing solutions up front will not result in the best project. We've heard the administration state their intent that "we need to let industry do what they do best". We fully agree with that intent, and think it only gets met if industry is allowed to offer its own unique, creative solutions.
- One specific example of prescribing a solution we find particularly troubling is the issue of toll subsidization.
- AGIA as drafted can result in one party subsidizing another. Now I'm referring to the language in Section .140(7) of the bill on page 7-8. AGIA specifically requires initial shippers - who financially underpin the project and who already bear most of the risk associated with the project - to bear yet another risk and additional cost: the risk of tariff increases of 15% or more **by subsidizing expansion shippers**
 - First I want to make clear that the issue is not just the potential for a 15% rise in the tariff. And by the way, the "15% cap" as I've heard this language characterized is not 15%, and it's not a cap. In reality it could result in a significantly higher increase than 15%.
 - But the more fundamental issue is that we believe the issue of subsidization is contrary to FERC policy.
 - We understand and we fully share the State's desire for a pipeline to be expandable - it's absolutely good business.
 - However, we believe that the **State should carefully consider** the potential adverse consequences of requiring pipeline owners to increase rates on their initial customers to subsidize expansion shippers.
 - A policy of subsidization places additional risk on the initial shippers, making the project less attractive, and therefore puts the project at risk.

- Now if the **State wants to subsidize others**, it can certainly do so itself, directly, as a policy choice. But we don't believe it's good policy to do so with other peoples' money.
- Congress made clear in the Alaska Natural Gas Pipeline Act of 2004 that rates for initial shippers should NOT increase if a mandatory expansion was ordered. In fact, the language of the Federal Law states that

"the [FERC] shall...ensure that the rates do not require existing shippers on the Alaska natural gas transportation project to subsidize expansion shippers." - ANGPA, Sect. 105(b)

- Also, in Order 2005, FERC put in place a rebuttable presumption of rolled in rates for expansions provided it did not require subsidization by initial shippers [and I'd like to read paragraph 125 of the Preamble]:

"In conclusion, to provide guidance to potential shippers in advance of the initial open season that is the subject of this rule, the Commission intends to harmonize both objectives (rate predictability for initial shippers and reduction of barriers to future exploration and production) in designing rates for future expansions of any Alaska natural gas transportation project. It is consistent with our guiding principle that competition favors all of the Commission's customers, as well as with the objectives of the Act, to adopt rolled-in rate treatment up to the point that would cause there to be a subsidy of expansion shippers by initial shippers, if any subsidy were to be found." [Order 2005, paragraph 125]

- These two excerpts from Federal law and regulation, suggest that .140(7) of AGIA and Federal law could be in conflict. This conflict

issue actually becomes quite complicated, and we are continuing to study it. If indeed there is a conflict, resolving it would add delay and uncertainty. We do not see how that is in any of our interests.

- So we remain concerned about this conflict.

- In any case, we believe that this type of provision, requiring a subsidy for not-yet-ready shippers at the expense of initial shippers, would be a disincentive for potential shippers participating in an open season. That's not in any of our interest.

Avoid Exclusivity to Ensure a Pipeline Gets Built

- The second modification that would enable AGIA to help deliver a successful gas pipeline relates to the issue of exclusivity.

- Under Sections .410 and .540 of the bill on pages 20 and 22, AGIA would result in an **exclusive winner** before any real work is done and awards State funds based on promises, not results

- We are concerned that this feature may actually **PRECLUDE** a successful project from moving forward. That's clearly not anyone's intent, but could be an unfortunate unintended consequence.
 - Our understanding of AGIA is that expedited regulatory handling is offered only to the licensed project, and that the State can be penalized for assisting another competing project
 - We're concerned that this approach may actually conflict with Federal law and regulation, which favor competition among various project proposals and market involvement in the choice.
 - We think it wise that the State consider **avoiding any notion of exclusivity** or the government 'picking a winner'; I'm not aware of any example where that has worked successfully.

- We recognize that the Administration has, in good faith, laid out selection criteria under Section .180 to enable the selection of the exclusive winner in as transparent a way as possible.
 - So that leaves a fundamental question: Should the State pick an exclusive “winner” based only on a proposal?
 - That approach gives us concern.
 - We believe that the **State can help to advance the project by setting out a clear framework for investors** - from there the market will work to identify the most effective project
 - And we support open competition in the **marketplace**, rather than in advance of actual performance or before the competition actually starts
 - In fact, the FERC requires that the **market demonstrate that it wants that application** before awarding a certificate to an applicant. That's what happens in a successful open season.
 - We believe the Federal law under ANGPA offers a good model, in which expedited regulatory handling is provided to ANY project.
 - We certainly understand that from the State's perspective, there are a number of **specific things desired from ANY project** (jobs and training for Alaskans, gas access for Alaskans, pipeline expansions).
 - We support all of these objectives.
 - Those objectives can and will be addressed by a successful project through open competition in the marketplace.
- A third area we suggest be considered carefully is that, although AGIA seeks to get a project moving, and we fully support that objective, **it does not sufficiently address the resource framework, which is the key enabler for a financeable project**
 - That said, **we are encouraged that AGIA recognizes at least in part, the importance of some of these key resource issues.**
 - In Section .310 on page 16, AGIA seeks to address the issue of **royalty valuation**, which has been an historic source of conflict

between industry and the State. But we are concerned that these terms **do not provide sufficient clarity** to justify making the firm transportation commitments required to underpin the project.

- The royalty valuation provisions depend on future regulations; neither the shippers nor the legislature know what those regulations might say.
 - The valuation regulations would allow for retroactive adjustments, and the regulations associated with RIV/RIK switching imply that “reasonable” disproportionate costs and “reasonable” interference with marketing is okay. I don’t know what that means or how to evaluate that.
 - Also, these regulations may change every two years.
- In Section .310(a)(3) on page 17 of the bill, AGIA seeks to address royalty issues associated with **RIV/RIK switching** which is incompatible with the long-term arrangements required to make a gas pipeline project happen (RIV = “royalty in value”; RIK = “royalty in kind”). RIV/RIK switching is problematic for at least two reasons:
 - 1) One is that if the State chooses to switch let’s say from in-value to in-kind, the **shipper would have to come up with additional gas to satisfy its customers** in the marketplace.
 - 2) The second problem is associated with obtaining the capacity on the pipeline if the State switches. For instance, if the State had originally elected to take gas in value, the shipper would have obtained the associated capacity to ship the State’s associated share of gas. If the State then switched from in-value to in-kind, this could result in **stranding downstream capacity**, raising the question of who would pay for that cost of unused capacity.
 - Under AGIA, the specific solution to RIV/RIK switching is **left to future regulation** that, as I mentioned earlier, would allow for the lessee to bear disproportionate costs, and potentially interfere with long-term marketing.

- AGIA includes a provision related to gas production tax in Section .320(a) on page 19. However, the gas production tax rate is not established, and **only becomes known after the conclusion of the open season**. A shipper would not know what the production tax is before having to make the FT commitment, which would be an incredible risk.
 - The gas production tax rate is then only established for a period of 10 years, which for reference is a **fraction of the period that shippers will likely be required to make their firm transportation commitments**.
 - **AGIA is silent as to the many other payments** made to the State, which constitute the majority of industry payments.
- It is widely understood that the resource owners will pay the cost and bear the risk in building a pipeline **whether they own it or not**
 - Resource owners will pay all the costs of the pipeline, either directly or indirectly by reimbursing the pipeline owner through the tariff for the costs they incur
 - It's the RESOURCE that drives the construction of a basin-opening pipeline like this project, NOT the PIPELINE that drives the resource!
 - Therefore, solving the resource issues with clarity is key to allowing a project to move forward.
 - Multi-billion dollar commitments spanning decades are needed to financially underpin this project;
 - Just like Wall Street needs to know the rules before lending money, resource owners need to know the fiscal rules that will govern the project before making commitments that will enable the pipeline to be financed.

- Although this is widely known, the details of an upstream framework are complex and will take time and effort by both the State and the producers to agree - but unless they are addressed, a project won't secure financing; it won't advance
 - The provisions of Sections .310 and .320 do not adequately address these upstream issues. To do so requires robust interaction.

- Thus far, there have been some high level discussions between our senior management and the Governor.

- But we've been disappointed in the level of interaction with the Commissioners and their staff. That's where the problem will ultimately be solved.

- Over the last three weeks we've had three constructive discussions with one deputy Commissioner. That's a start.

- We would welcome the opportunity to increase the frequency and depth of dialogue with the Administration.
 - BP remains ready to engage at any time

What Is So Important About FT?

- We've heard a fair amount, in this committee and others, about this term called "FT" which is short for firm transportation commitments
 - In listening to many of these hearings it seems to me that the nature of these commitments is not fully understood
 - However, these commitments are absolutely critical for a gas pipeline to be successful
 - Therefore, I thought I'd spend a moment hopefully adding a bit of clarity to the understanding of FT

- **These commitments, typically obligations to “ship or pay” made by the resource owners or “shippers”, are needed by the pipeline company to get financing**
 - **validating just how important they are, we've heard some very simple and straightforward comments from pipeline companies who have testified in the past couple of weeks**
 - **TransCanada has said “No customers, no credit, no pipeline” (and in this context customers means shippers)**
 - **Enbridge put it even more simply by saying “No producers, no pipeline”**

- **Those aren't “political” statements. They are statements about the simple financial truths of gas pipeline projects**

- **FT is a binding FINANCIAL obligation. I've sometimes heard FT described as “committing gas to a pipeline”. I've heard that quote from industry as well as others, so I'm not pointing any fingers here. But I just wanted to make it clear that FT is an actual financial obligation**
 - **Typically, FT is known as a “ship or pay” obligation**
 - **That means that a shipper commits to pay the pipeline company for use of its service whether or not the shipper actually delivers gas to the line**
 - **And it's also important to note that a company does not need to have ANY gas resources to enter into a firm transportation commitment. Any company who meets the creditworthiness standards set by the pipeline company is free to bid for capacity. Gas pipelines are “open access”. Anyone is free to obtain capacity if they make the requisite commitments.**
 - **These FT commitments are real financial obligations. We are required to disclose these commitments as additional information with our filing with the SEC.**

- Clearly, an FT of this magnitude will be taken into consideration by financial entities like banks when evaluating our company. That's because it's a real obligation.
 - Once these commitments are made to the pipeline, they are used by the pipeline to obtain financing from the financial markets, provide coverage for that financing, and a return for the pipeline.
 - Maybe an example to explain the nature of these commitments would help. Let's say we've had a successful open season, the pipeline gets project financed, is built and it's in operation. Then, heaven forbid, for some reason the pipeline company goes bankrupt. Not what we're hoping for, for sure. But what would the lenders do? So they would turn to the FT commitments made by the shippers to get their repayment. And these FT commitments would indeed be paid to the lenders. That's because they are a **REAL FINANCIAL COMMITMENT**. They have to be properly taken into consideration when evaluating project economics.
- The scale of these commitments is often oversimplified. It's not "just" the capital cost of the project, if that weren't in itself a large enough commitment.
 - the commitment is for what is known as the "demand charge" which is the cost of service the pipeline will charge through time
 - Capital is one major component
 - But for illustration, I've provided some broad assumptions to put the scale of these commitments in perspective.
 - assuming a 4.5 bcfd project, at a unit cost of \$3.50/mcf for 25 years results in a total FT commitment of \$144 billion
 - That's a huge sum, even for a company the size of BP
- These long term commitments are just that – commitments. Therefore, they represent real risk. And the size of these commitments magnifies the risk. And that risk is borne by those making the commitments,

Risk Diagram

- This next slide attempts to show how **risk is ultimately allocated** in a major resource development project like the Alaska Gas Pipeline Project
- I'm going to **step through it one bit at a time.**
- First, we start with the **Resource Owners** – that's of course the State of Alaska, and it includes the lessees, like BP, CP, EM, Chevron and others.
- There are certain risks that are inherent to the resource itself.
 - There is always price risk associated with selling a commodity like gas
 - that's the risk that the price of gas will fall in the future, possibly below the tariff
 - There's also production risk
 - Keeping the pipeline full for project life
 - Being able to deliver the full volume every day
 - These risks are important considerations when a resource owner has to make the firm transportation commitments necessary to underpin the project
- Next, there's fiscal risk for a lessee; that's the risk that the fiscal terms on the upstream business might change. On major infrastructure projects like this around the world, it's not uncommon for host governments to address fiscal risk with a mutually agreed framework.
- There are also a whole host of risks associated with constructing the pipeline itself
 - Regulatory process could change → schedule risk
 - Material, labor and equipment costs → cost risk, which includes project management and execution
 - Need for finances from the capital markets → finance risk

- **What is critical to appreciate** is that all these project-related risks that are taken by the pipeline company are ultimately passed through to the resource owners through the toll
 - The Pipeline company receives a regulated rate of return
 - Gets a reasonable return on investment commensurate with the risks
 - That's the pipeline's reward
 - In exchange for this regulated rate of return, the regulators ensure that the pipeline does not take on certain risks
 - These instead are passed through to the resource owners, provided that the pipeline owner delivers the project on time and operated efficiently
 - That's how the risk / reward balance is struck by the pipeline regulators

- So ultimately, **ALL RISKS** are either borne directly by the resource owners, or are passed through to the resource owners through the toll

- To ensure a low cost project, it's important that those that are bearing a risk are able to manage that risk
 - They are commercially motivated to manage that risk downwards

- To reiterate, it's critical that the fiscal system is established in such a way that the risks associated with the resource or "upstream" are adequately addressed to ensure the risk / reward balance is right.
 - That will maximize the likelihood of having a successful open season and a successful project.
 - The State is uniquely positioned to address this risk

Summary

- So in summary, I'd like to leave you with four messages.
- First, BP wants and needs a gas pipeline. It's critical to our vision of the 50-year future in Alaska.
- Second, BP fully supports an **open process** that leads to a mutually agreed fiscal framework with the State that **allows a project to advance and attract financing**
- We think there should be an **open and transparent public review** of the resulting framework
 - The Governor has already committed to keep the legislature and the public apprised - we fully support her in that.
 - It is critical that the legislature supports and endorses that framework
 - The judicial branch should review that framework to ensure constitutionality
 - The people of Alaska and all 3 branches of government should and will be consulted.
- We think that the resulting framework should be **available to all investors** to ensure competition
- Third, we believe that a number of midstream details in AGIA should be fixed.
 - We think the best project will come about if the State allows industry to offer solutions, rather than prescribing them up front.
 - The provisions which result in rate subsidies of one party to another should be eliminated
 - **any notion of exclusivity** or the government 'picking a winner' like those contained in Sections .410 and .540 should be avoided
 - Any process should allow competition in the marketplace to work

- It is easy to make hopeful promises but it is harder, and vitally important, to deliver performance
 - That is what we believe the State should require. **Delivery, not promises.**

 - And finally, a mutually agreeing an upstream framework is critical.

 - The resource issues must be resolved for the project to proceed and to ensure the resource owners have sufficient confidence to make the necessary long term financial commitments in an open season required to advance the project. Section .310 and .320 of AGIA do not accomplish this objective.

 - We are ready to engage on developing that upstream framework.

 - Thank you for the opportunity to testify today. I'd be happy to answer any questions you might have.
-



Senate Judiciary Committee

April 14, 2007

- **Alaska Gasline Inducement Act (AGIA) Process**
 - Open, transparent and competitive
 - Identifies clear evaluation criteria
 - Inducements to project applicants in exchange for specific commitments
 - Empowers selected applicant to build successful consortium, leading to open season

- **Return to Stranded Gas Development Act Process?**
 - No identified criteria
 - No requirement to justify need for 30-45 years of concessions in excess of \$10 billion
 - State in compromised negotiating position
 - No project commitments other than spending levels – due diligence only criteria
 - Oil tax concessions beginning now for 30 years with no commitment to build a line

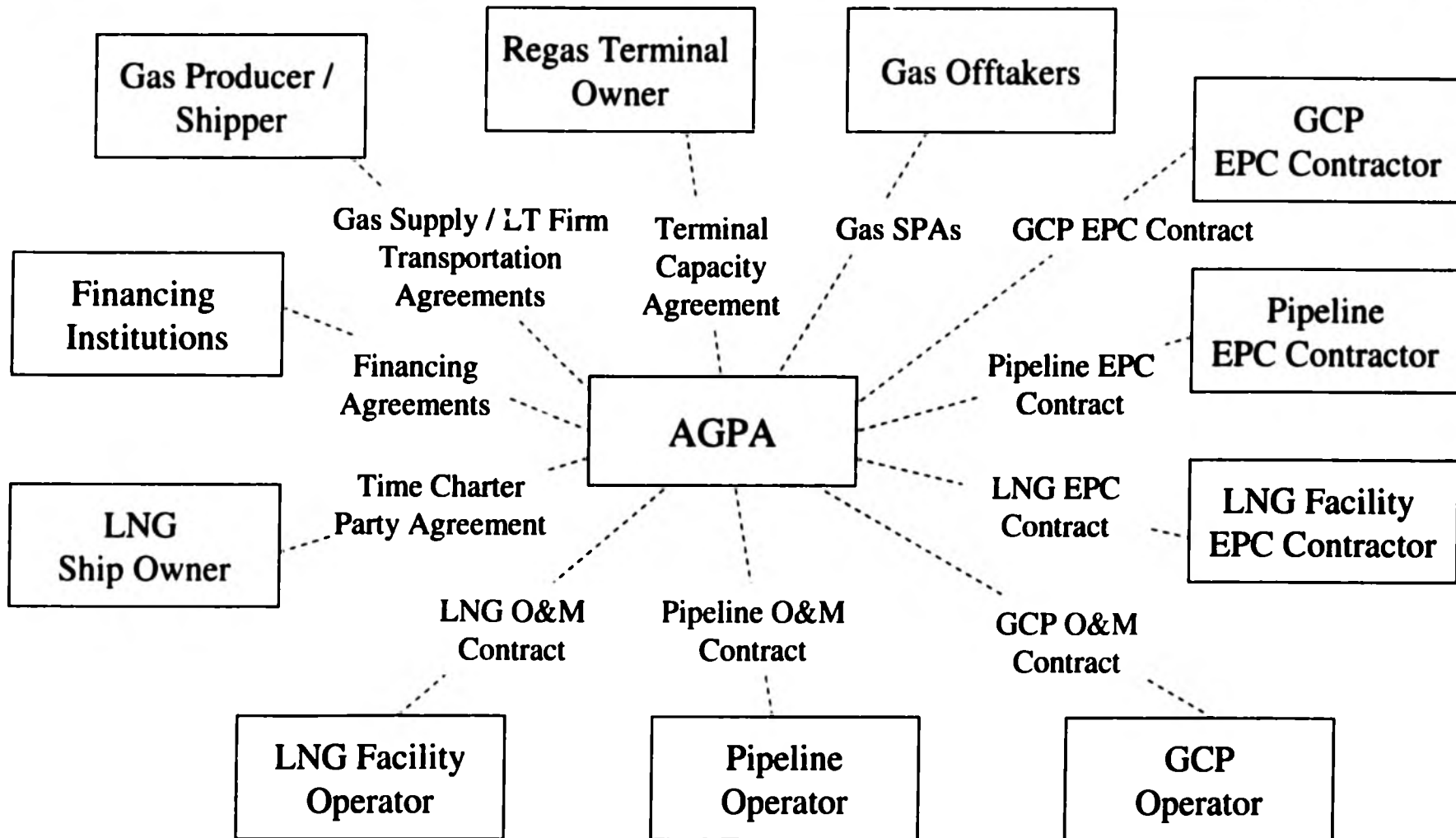
The Alaska Gasline Port Authority ("AGPA")



Formed to ensure:

1. A gasline is built
2. Stable source of energy to Alaskans not tied to Lower 48 price index (Henry Hub, etc.)
3. All pipeline and liquefaction associated jobs are within the state of Alaska; including construction, operation, and maintenance
4. Direct net-project revenue sharing – 60% to State – 30% to every Alaska municipality – 10% in energy related benefits to rural Alaska
5. Earliest opportunity for in-state gas availability
6. Greatest opportunity to supply gas liquids to in-state markets
7. Market optionality for Alaska's gas

Indicative AGPA Project Structure



- Industry leaders will be involved in all components of AGPA's project

AGPA Project Description



Gas Conditioning Plant in Prudhoe Bay

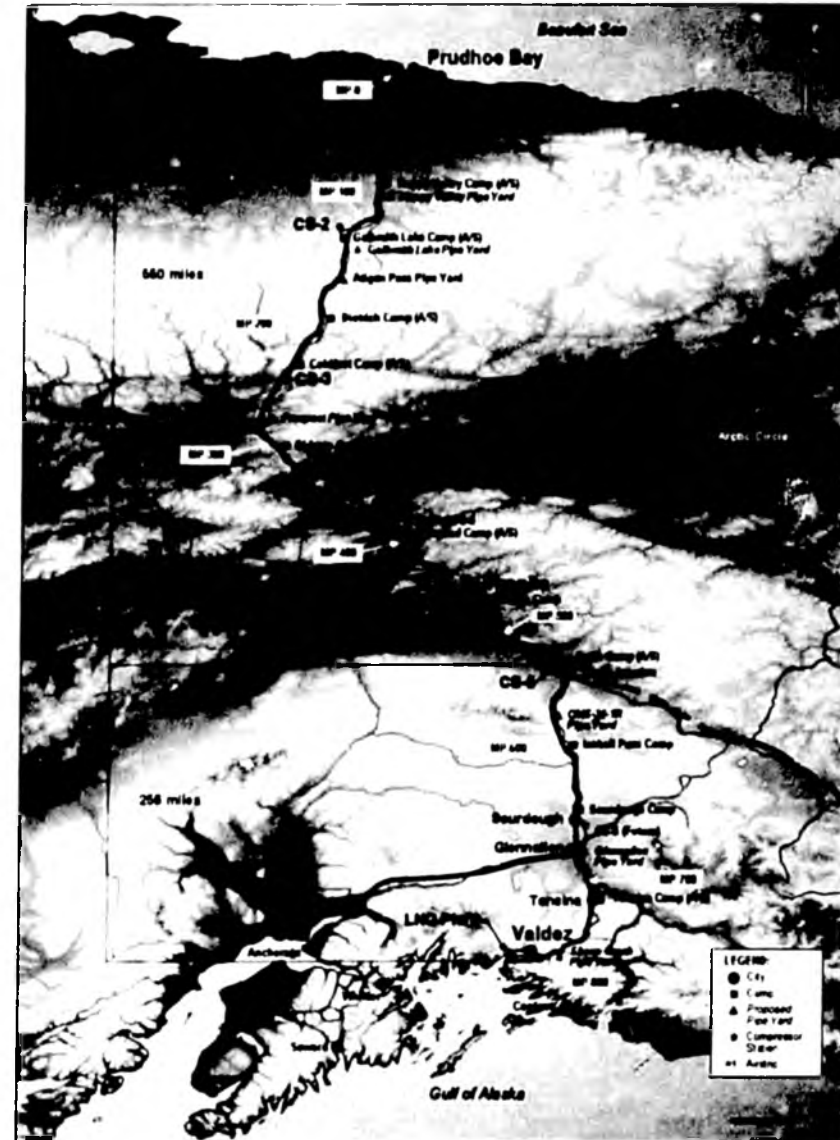
- removes impurities
- compresses and chills the gas to pipeline specifications

Pipeline from Prudhoe Bay to Valdez

- parallel to TAPS
- pre-build to Delta Junction for later tie-in for the Alaska/Canada Highway Project
- tie-in at Glennallen for a spur line to Alaska South Central natural gas grid

LNG Facility in Valdez

- integrated LNG liquefaction and LPG extraction facilities
- includes storage and vessel loading facilities



Project Status



1. Project Route Permitted
2. The 12 Senior Permits Acquired
 - Yukon Pacific Corporation
 - \$100 million expended
 - Right-of-way
 - Project FEIS
 - LNG terminal permit
3. Bechtel Cost Estimates
 - Complete & Updated
4. Marine Transportation / Jones Act
 - MOU with the largest LNG shipping company in the world – Mitsui OSK Lines
5. Access to Multiple Markets
 - Only West Coast receiving terminal under construction
 - West Coast Alternatives
 - Hawaii
 - Pacific Rim
6. Anticipated Financing
 - 80% debt (Federal loan guarantee available)
 - 20% private funding

Financing Approach



- **Limited recourse project financing**
 - well-established financing approach for capital-intensive energy or infrastructure projects around the world
 - Project is sole source of repayment of loans – limited or no recourse to sponsors and other Project participants

- **The key factors for financeability**
 - commercial and contractual structure
 - project economics; ability to generate cash flows sufficient to repay the debt
 - experience and track record of the various project participants, including: engineering and construction contractors, facility operators, offtakers, suppliers, etc.
 - appropriate risk allocation under project and financing agreements
 - credit worthiness of the counterparties under Project agreements

Risk Mitigation



- 800 mile pipeline is 100% adjacent to TAPS, 100% in Alaska
- Infrastructure in place for entire line – roads, bridges, camp pads, etc.
- LNG project: lower overall cost overrun risk:
 - liquefaction facilities utilize proven technology and well-tested design, resulting in a relatively low level of uncertainty in cost estimate
 - low level of cost uncertainty for LNG marine transportation and regasification
 - pipeline component has the highest capital cost uncertainty – for LNG project the pipeline is only a portion of overall cost to market
- LNG Project with 2/3 less cost = 2/3 less risk

- Alaska loses U.S. markets to LNG projects from elsewhere
- Expiration of \$18 billion Federal Loan Guarantee
- Increased cost of construction (steel, etc.) as years of study and negotiation goes by

LNG Project is Economic



- Robust economics with a forecast of internal rate of return in excess of 30% to upstream producers with no tax concession by State

- Greatest benefits to the State of Alaska

- Favorable economics takes into consideration AlCan Highway pre-build to Delta Junction

- Win-Win for Alaska for LNG:
 - Capture West Coast market now plus enable a later AlCan Highway project to proceed when ready

Advantages of LNG from Alaska



- The Alaska LNG project will benefit from an efficient, low-cost liquefaction operation:
 - ambient conditions (low average temperatures) in Valdez result in significant unit cost savings in comparison with liquefaction facilities located in tropical climate
 - efficiency gains estimated in the range of 30 – 40%
- Most other LNG projects have significantly higher marine transportation costs to market due to longer shipping distances
- Many other LNG projects involve higher upstream costs due to complex, expensive field development
 - Alaska benefits from substantial existing North Slope infrastructure and developed fields (Prudhoe Bay)

Advantage of LNG for Alaska – Right Sized Project



- **Gas requirements:**
 - **Current ANS discovered gas resource: 35 Tcf**
 - **Alaska LNG project initial phase gas requirements: 15-25 Tcf (1.5-2.5 bcf/d)**

- **Maximum current offtake allowed for PBU is 2.7 bcf/d (AOGCC Rule 9)**
 - **LNG: approximately 2 bcf/d offtake**

- **The Alaska LNG project will enable Alaska's gas to reach Alaskan's and the market sooner, while exploration efforts are underway for the larger pipeline projects**

- **AGPA provides Alaska's vast gas resources the significant benefit of market optionality**

AGIA Suggested Amendments



- More detail required from Canadian line applicants
- If offtake amounts exceed AOGCC Rule 9 limitations (2.7 bcf/d less field use), must have already filed an application with AOGCC for increased offtake limits
- Additional gas reserves needed? Budget and timeline for exploration program
- Analysis of anticipated oil loss from PBU if volume exceeds AOGCC Rule 9 limitations
- Analysis of liquids availability in Alaska for value added processing
- Timeline for project start up and completion for present value analysis
- Current project cost estimate required with application

AGIA benefits towards advancing gas pipeline

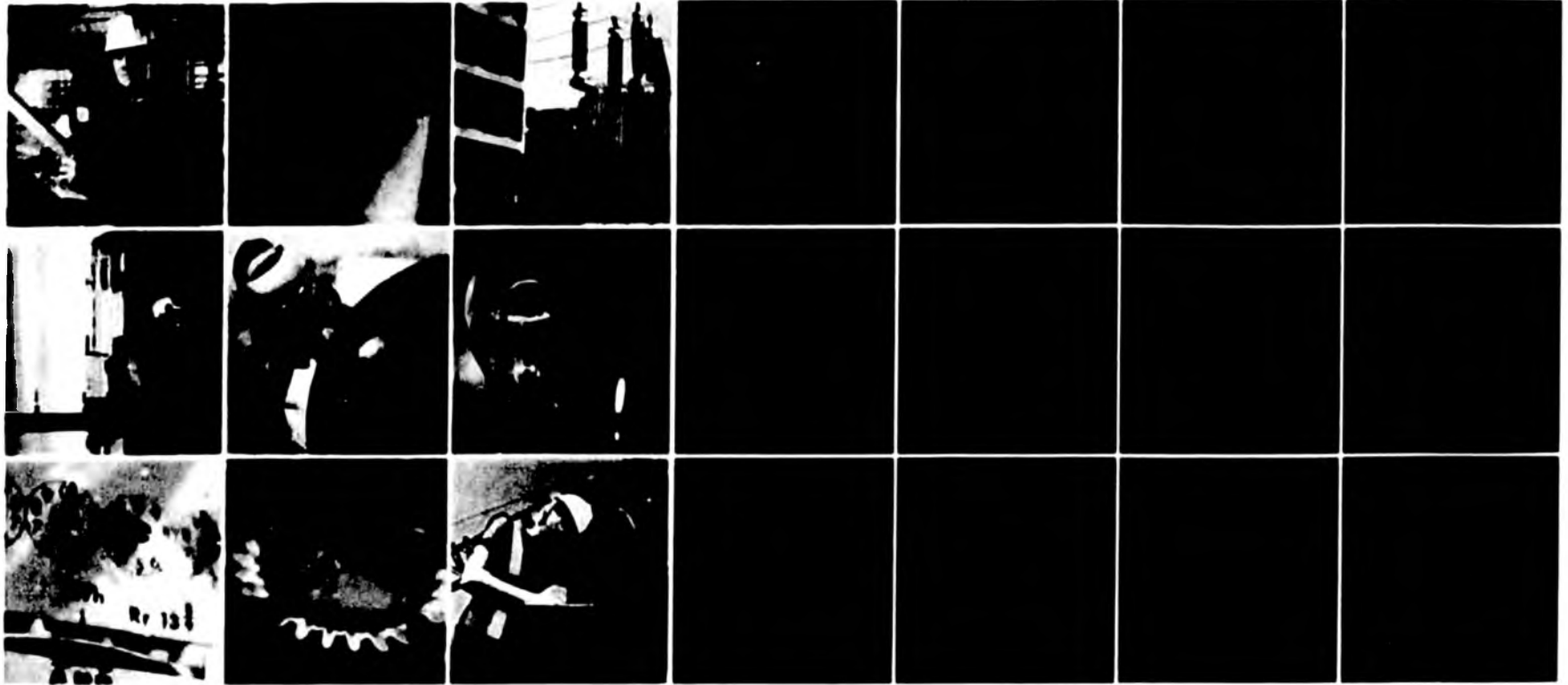
- Rolled in rates – good for Alaska’s future
- Allows for independently owned infrastructure
- Follows successful model used in other countries who also use rolled in rates and independently owned pipelines.
- \$500 million skin in the game – sends very positive message about Alaska’s desire to commercialize Alaska’s gas

The All-Alaska Gasline. The future is on the line.



Alaska Gasline
PORT AUTHORITY

Right Sized – Right Now!



State of Alaska

Senate Judiciary / House Resources Testimony

April 13/14, 2007



TransCanada

In business to deliver

TransCanada Natural Gas Pipeline Network

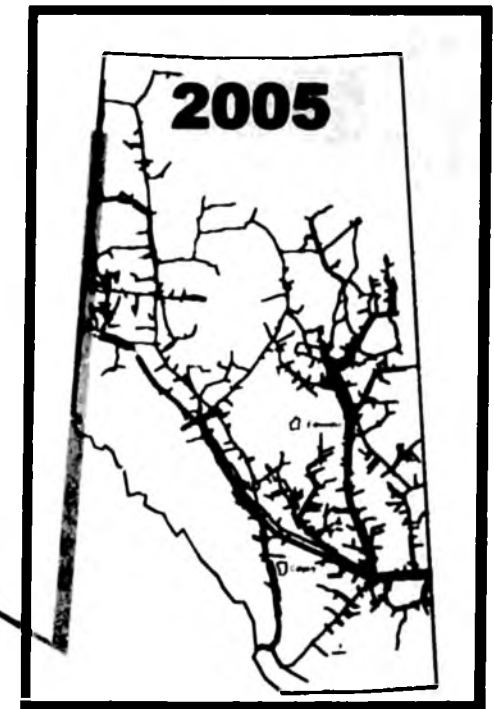


- **36,500 miles of wholly-owned pipeline**
- **Interests in an additional 4,600 miles of pipeline**
- **Unparalleled connections from traditional and emerging basins to growing North American markets**
- **Average daily volume of approximately 15 Bcf**

TransCanada's Pipeline Assets

- TC is North America's largest gas transmission company, owning approximately 2/3 of the take-away capacity from Alberta hub to North American markets.
- TC owns 36,500 miles of natural gas transmission pipelines and provides service to Northeast, Midwest, Pacific NW, California, Eastern Canada and Western Canadian markets WCSB markets.
- TC also owns 360 Bcf of natural gas storage capacity.
- One-third of the Alaska Highway Pipeline Project is in the ground and transporting approximately 3 Bcf/d every day (Foothills Prebuild, Northern Border and GTN loops).
- TC has strong cash-flows (C\$2.4 B in 2006) and growing financial capacity from its pipeline assets and 7700 MW of power generation assets (in-service or under development).
- TC has 50 years experience as a builder/owner/operator of cold-weather North American regulated pipelines.

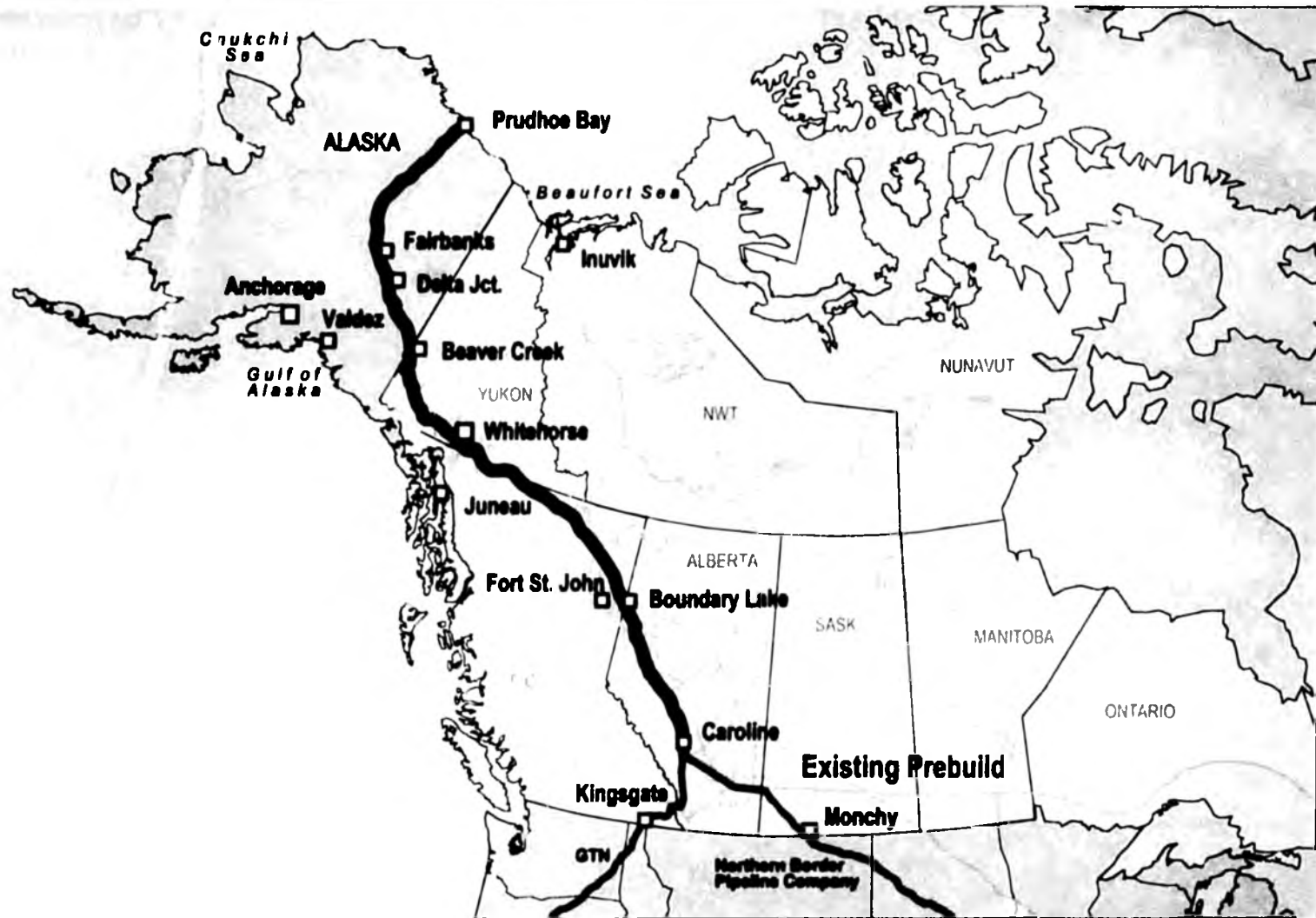
TransCanada - Proven Basin Developer



Regulatory Structure

- Independent pipeline model
- Rolled-in tolls

Alaska Highway Pipeline



TransCanada's Interest

- TransCanada (TC) has been a lead player in the project since its inception. We have more than \$2B and 30 years invested in bringing Alaskan gas to market.
- TC's subsidiary, Foothills, holds valid and exclusive certificates issued under the Northern Pipeline Act (NPA) for Canadian section of the project – these certificates do not have a sunset or expiry date.
- Foothills is named Canadian Project Sponsor in Canada/U.S. Treaty.
- TC has an easement under NPA for entire route in Yukon recognized in Umbrella Final Agreement between Government of Canada, Government of Yukon and Yukon First Nations.
- TC holds key land and environmental permits in Alaska.

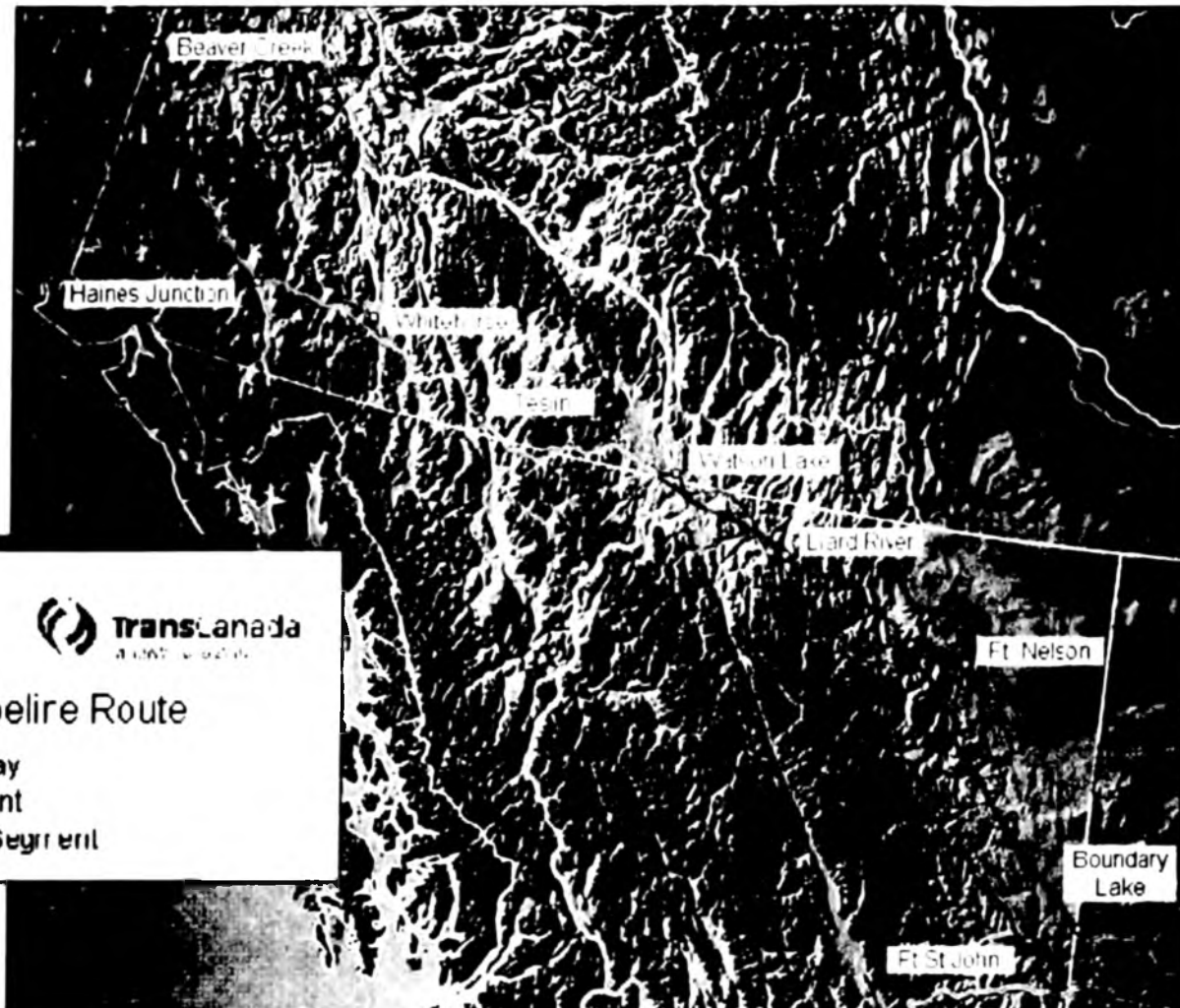
Legislative/Regulatory Structure - Competition Held, and Canadian Project Sponsor Selected


- NEB held competitive hearings, open to all parties
 - Selected Foothills as Canadian project sponsor
 - Rejected other applications (Arctic Gas)
- Canada / U.S. negotiated Treaty for Alaskan gas project
 - Canada obtained benefits in exchange for access across Canada for Alaskan gas
 - Foothills named Canadian sponsor in Treaty
- Canada enacted Northern Pipeline Act (NPA)
 - Enshrined Foothills rights and obligations
 - Established single-window regulator, complement to NEB
- Foothills granted exclusive rights – only reasonable interpretation.
 - Project expedition not achievable unless exclusive
 - No commercial party would invest necessary billions without exclusivity.
 - No expiry or “sunset” date in Foothills certificates.

TransCanada's Land Status - Alaska

- TransCanada holds key land and environmental permits
 - Conditional FERC certificate granted under ANGTA
 - Clean Water Act wetlands permits
 - Federal ROW
 - Completed State ROW application (pending final State decision since Q1, 2005)

Canadian Section



 **TransCanada**
A CANADIAN COMPANY

Alaska Highway Pipeline Route

- Alaska Highway
- Yukon Segment
- Northern BC Segment

TransCanada's Land Status - Canada

- **Yukon Easement**
 - Received in 1983
 - Confirmed in 1993 in Umbrella Final Agreement
 - Width: 240 metres
 - Easement is Federal
 - Yukon Govt. publicly stated this cannot be replicated
 - Access already granted
 - NPA holds other Reservations by Notation
- **BC Map Reserve**
 - Registered in 1981
 - Pipeline corridor is largely Provincial Crown
 - Width: 1600-metre corridor
 - Process to perfect through BC/Alberta Lands
 - No term or rental fee until interest perfected
 - Few private land interests
- **Key difference from Mackenzie: Easement and Reserve/Notation corridor are Federal/Provincial – not subject to FN title**

**First Nations in
Yukon and North BC**

White River

Kluane

Champagne & Aishihik

Kwanlin Dun

Ta'an Kwach'an

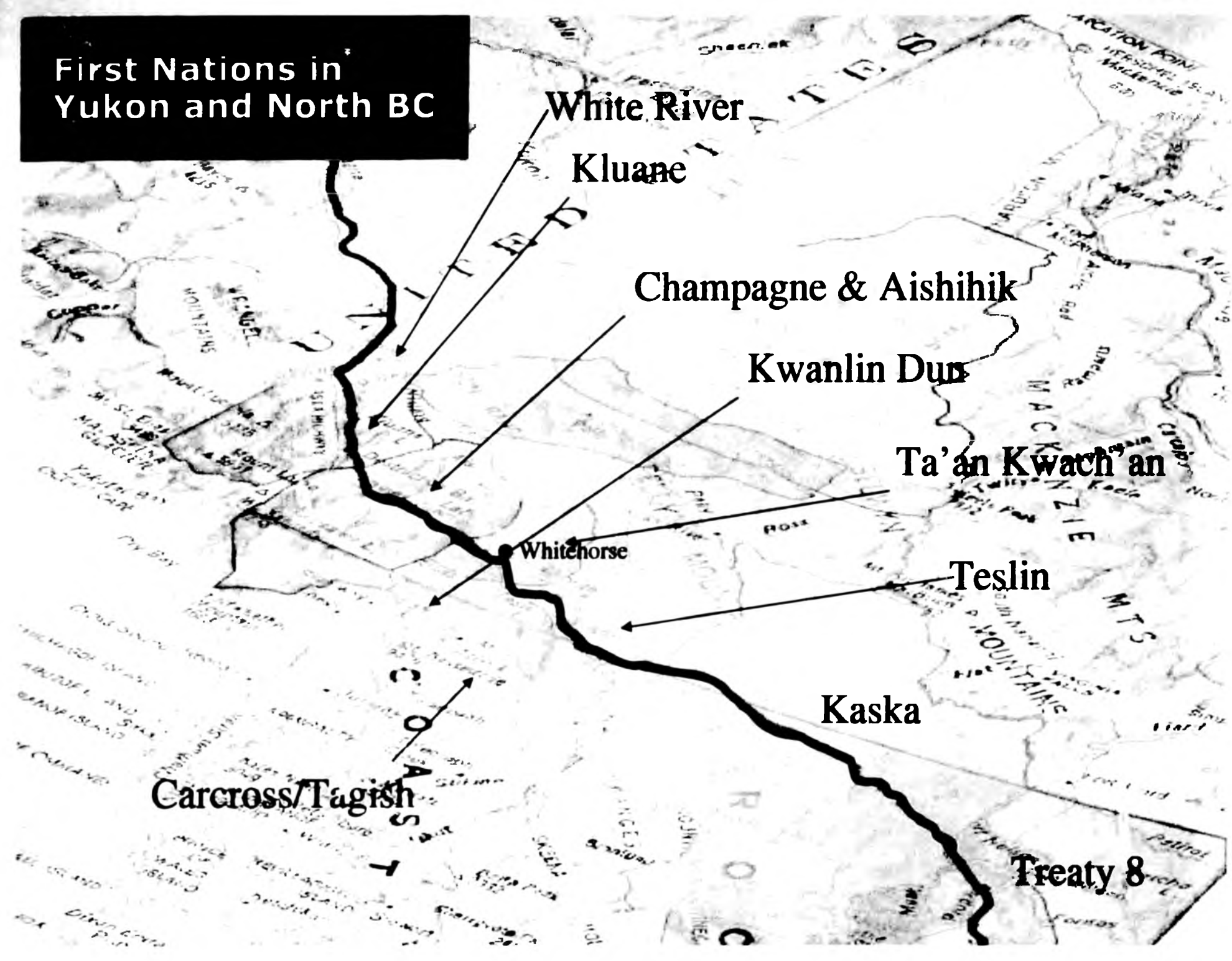
Whitehorse

Teslin

Kaska

Carcross/Tagish

Treaty 8



First Nations Land Claim Agreement Status

- Yukon: (First Nation pop. of ~ 2,600 along AHPP)
 - All right of way First Nations have settled except Kaska and White River.
 - Kaska did not complete negotiations
 - White River completed negotiations but have not held a ratification vote
- BC: (First Nation pop. of ~ 5,800 along AHPP)
 - Kaska FN – AIP stage pursuant to the BC Treaty process.
 - Taku River Tlingit – AIP stage in BC Treaty process
 - Treaty 8 – signed in 1899

TransCanada's Benefits to First Nations

- Benefits of the NPA for First Nations derive from:
 - Terms and Conditions (obligations which are attached to Foothills' Certificates of Public Convenience and Necessity)
 - Undertakings from the project hearings
- Foothills is required to deliver significant benefits and minimize impacts of the project.
- Benefits are already secured.
- Government of Canada can impose penalties on Foothills should it fail to comply with Terms and Conditions of the NPA.

TransCanada's Benefits to First Nations (cont'd)

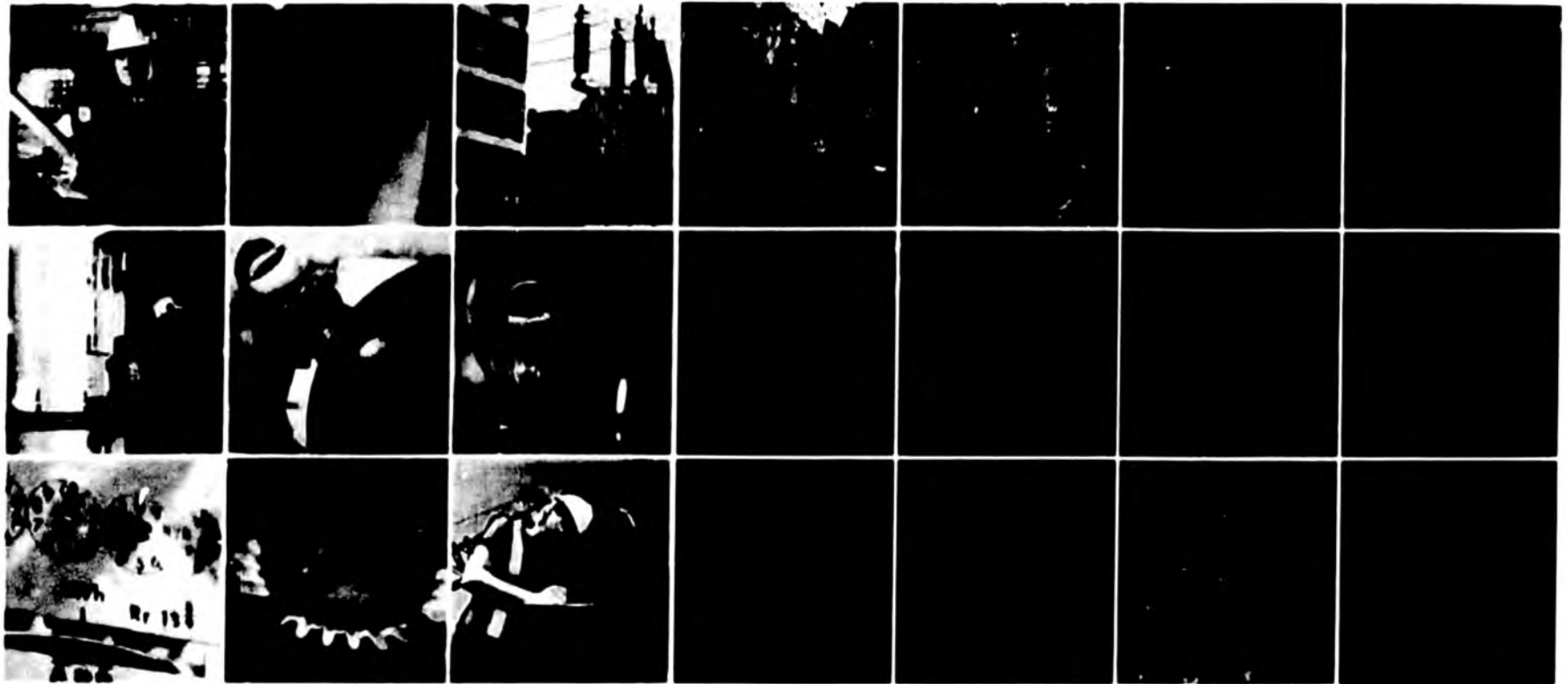
- **NPA Benefits for all Northern Residents:**
 - Training and employment opportunities for construction and operations of the pipeline.
 - Northern business opportunities.
 - Opportunity for equity participation.
 - Natural gas supply to communities
 - Beaver Creek, Burwash Landing, Destruction Bay, Haines Junction, Whitehorse, Teslin, Upper Liard and Watson Lake (many are First Nation communities)
 - Foothills has an obligation to provide specified financial assistance for gas off-takes.
 - Zonal tolls
 - Lower tolls for Whitehorse or Ft. Nelson versus Alberta deliveries.

TransCanada's Benefits to First Nations (cont'd)

- **NPA Specific Benefits for First Nations:**
 - Fair and competitive opportunity to participate in the supply of goods and services.
 - Representation on the Board of Directors for Foothills South Yukon.
 - 3 of 11 directors for First Nations/Women
 - Foothills must enhance First Nations participation in project employment, training, and entrepreneurial opportunities through detailed socio-economic plans.
 - Terms and Conditions require Foothills to establish and maintain a consultation process with First Nations.
 - Terms and Conditions or Undertakings (from hearings) establish protection for biophysical, socio-cultural, and socio-economic environment of the communities and traditional lands.
- The Umbrella Final Agreement and Yukon First Nation Final Agreements acknowledge and respect the validity of Foothills' pipeline easement.
 - Setting aside new lands for a Greenfield project would be a difficult and slow process.

Summary

- **TransCanada holds critical assets for the project in Alaska and Canada**
 - **Alaska**
 - Conditional FERC Certificate
 - Clean Water Permits and Federal ROW
 - Pending State ROW
 - **Canada**
 - NPA Certificates
 - Canada / U.S. Treaty
 - Single-window regulatory agency
 - Yukon ROW
 - Specific benefits for First Nations and extensive history of consultation.



Thank You



TransCanada
In business to deliver

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

Senate Judiciary

4/4/2007

AGIA Overview



AGIA:

- **Is a commercial vehicle that creates a competitive playing field**
- **Provides a pipeline sooner and on Alaska's terms**
- **Is a transparent process, with transparent inducements.**

Commercial Vehicle

AGIA

The Alaska Gasline Inducement Act

- **AGIA is not a negotiation**
- **Successful bidding process requires AGIA's inducements**
 - **Inducements provide for a level playing field and all the players are in the game**
 - **Without inducements, no bidders**
 - **Without bidders, state has no ability to get a pipeline on its desired terms**

Commercial Vehicle

AGIA

The Alaska Gasline Inducement Act

AGIA's inducements:

- Known, clearly quantified, and transparent
- Midstream inducement of \$500 million:
 - *reduces licensee's project development risks, especially an independent pipeline licensee*
- Upstream tax and royalty inducements:
 - *coupled to the licensed midstream project to make license more valuable, by*
 - Encouraging open season participation
 - Ensuring that state will stick with its licensed partner
- Requirement to obtain pipeline certificate reduces overall project risks, increases opportunity for success

A Project on the State's Terms



- State's "must haves" focus on the future:
 - A competitive and vibrant oil and gas industry
 - Jobs and careers, not only from the pipeline itself, but also from a vibrant support industry
 - Gas for Alaskans

A Project on the State's Terms



The state “must haves”

- **Minimum 70/30 debt/equity ratio ensures reasonable base tariffs**
- **Expansion requirements ensure explorer's gas can access the pipeline**
- **Rolled-in rates ensure all parties have an economic incentive to explore for gas**

Transparent Public policy



- AGIA creates a competitive process, not a negotiated process
- Bids commented upon by the public
- Winner chosen by the Commissioners
- Legislative review and approval
- Value of AGIA's inducements are up-front and transparent

Summary

AGIA
The Alaska Gasline Inducement Act

- AGIA levels the playing field.
- AGIA is a **commercial vehicle** that provides a **pipeline sooner on Alaska's terms**, in a **transparent manner**.

Increasing Predictability for Producers



Constitution of Alaska

Article 9 - Finance and Taxation

§ 1. Taxing Power

The power of taxation shall never be surrendered. This power shall not be suspended or contracted away, except as provided in this article.

Increasing Predictability for Producers



Constitution of Alaska

Article 9 - § 4. Exemptions

The real and personal property of the State or its political subdivisions shall be exempt from taxation [P]roperty used exclusively for non-profit religious, charitable, cemetery, or educational purposes, ... shall be exempt from taxation. Other exemptions of like or different kind may be granted by general law. All valid existing exemptions shall be retained until otherwise provided by law.

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

**Economics of AGIA's role in the pipeline
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.***

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

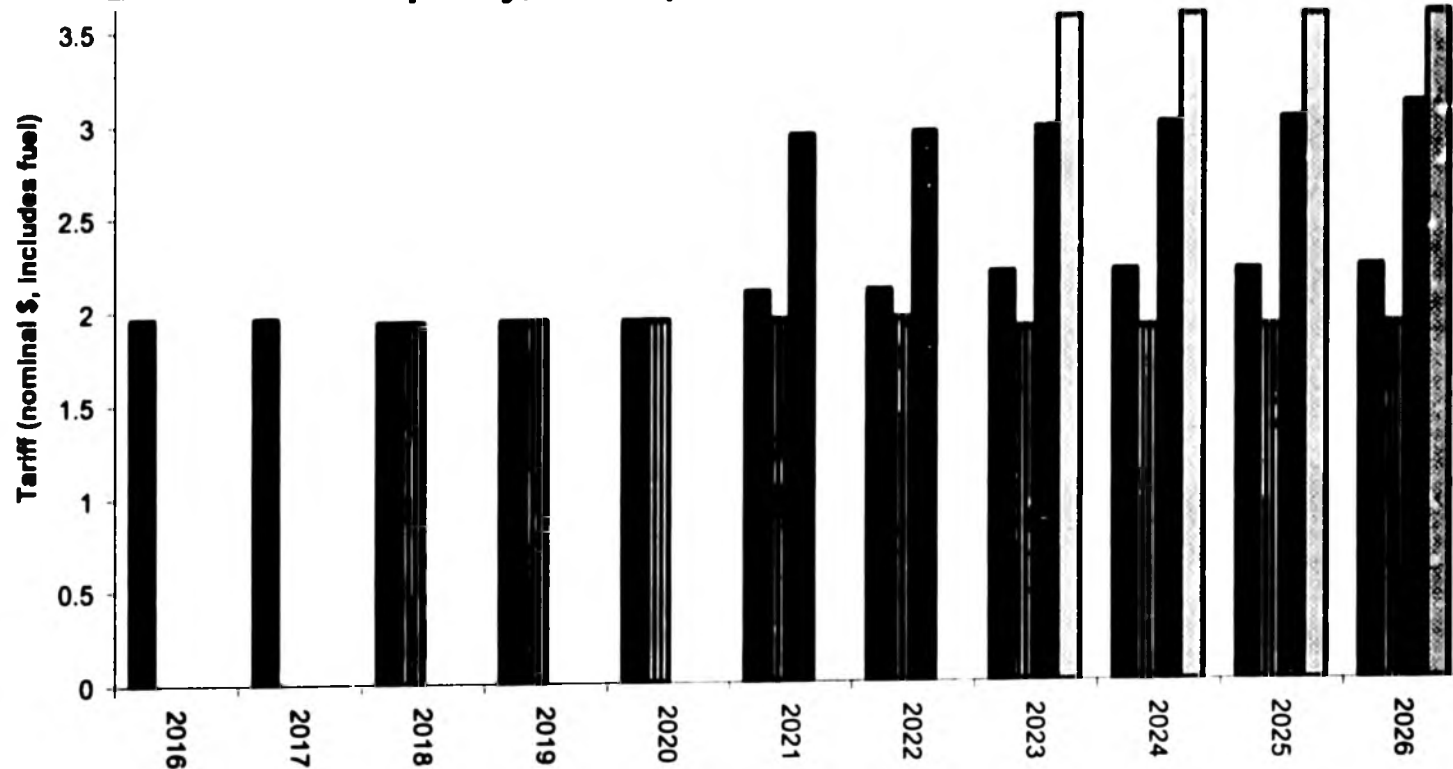
Note: Volumes here reported at pipe inlet

Effects of AGIA vs. FERC-L48 Rate Policy

AGIA

The Alaska Gasline Inducement Act

- AGIA policy; Initial, 1st and 2nd Expansion Shippers' Rates
- ▨ Lower-48 FERC policy, 1st Expansion (2018) Shippers' Rates
- Lower-48 FERC policy, 2nd Expansion Shippers' Rates (2021)
- ▩ Lower-48 FERC policy, 3rd Expansion Shippers' Rates (2023)

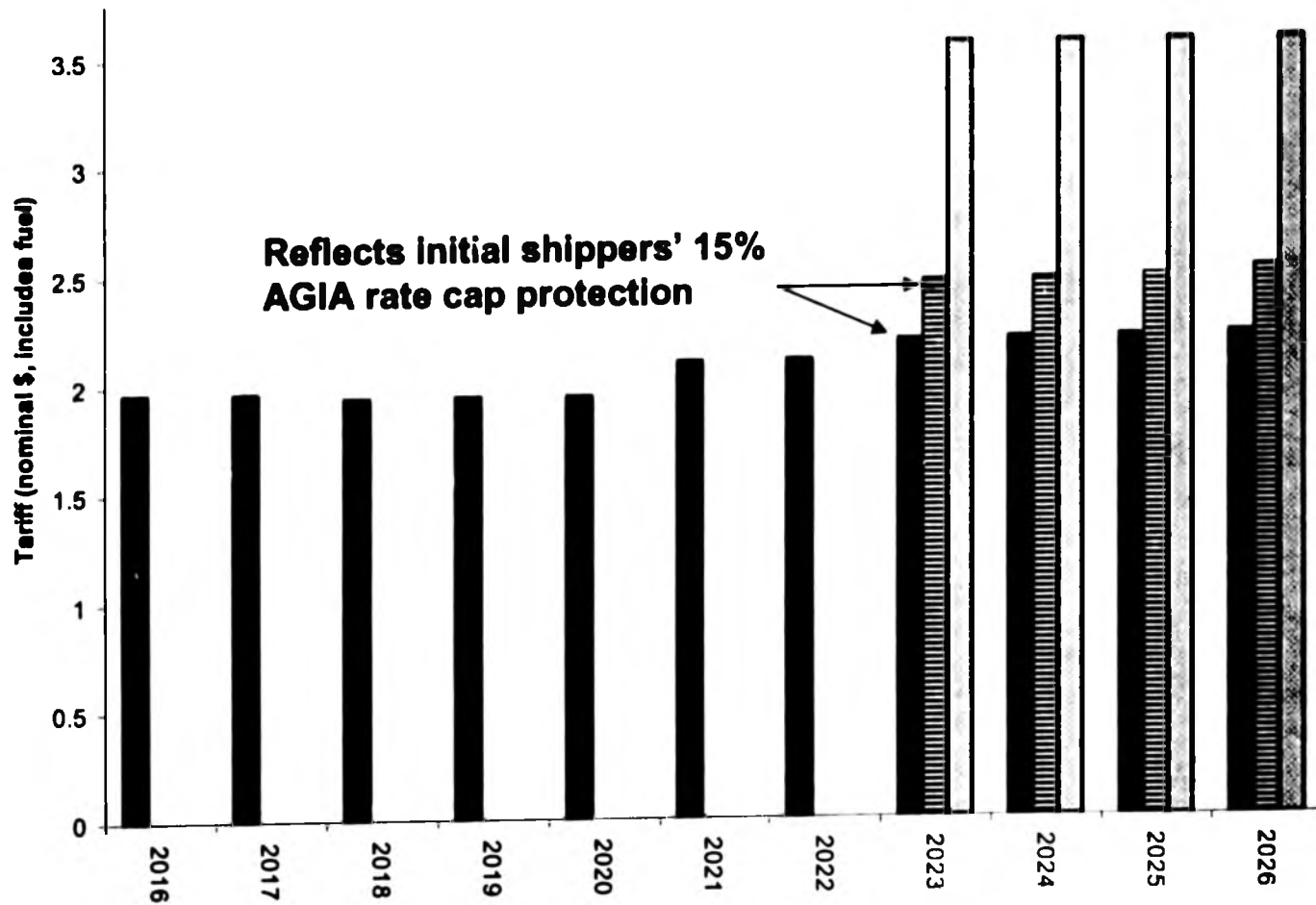


tax freeze

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



- AGIA policy, Initial, 1st and 2nd Shippers' Rates
- ▨ AGIA policy, 3rd Expansion Shippers' Rates (2023)
- ▩ Lower-48 FERC policy, 3rd Expansion Shippers' Rates (2023)



- 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.

Case A: "State gas first"

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

Case B: "State gas second"

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

Case C: "State gas last"

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

**State Revenue, AGIA Rates:
All Expansions Occur**



- Without rolled-in rates it is **very unlikely** all expansions would occur. But if they did:
 $[AGIA \text{ revenue}] - [L48 \text{ FERC revenue}] =$

	State NPV₅ difference, \$2007 (billion)			
	<u>Case A</u>	<u>Case B</u>	<u>Case C</u>	<u>Expected</u>
	State gas first	State gas 2nd	State gas last	<u>Value</u>
\$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)

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)			
	<u>Case A</u>	<u>Case B</u>	<u>Case C</u>	<u>Expected</u>
	State gas first	State gas 2nd	State gas last	<u>Value</u>
\$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

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

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- 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)			
	<u>Case A</u>	<u>Case B</u>	<u>Case C</u>	<u>Expected</u>
	State gas first	State gas 2nd	State gas last	<u>Value</u>
\$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**

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- 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 NPV₅ difference, \$2007 (billions)			
	<u>All Three Exp.</u>	<u>1st Two Exp.</u>	<u>Only 1st Exp.</u>	<u>Avg of Cases</u>
\$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

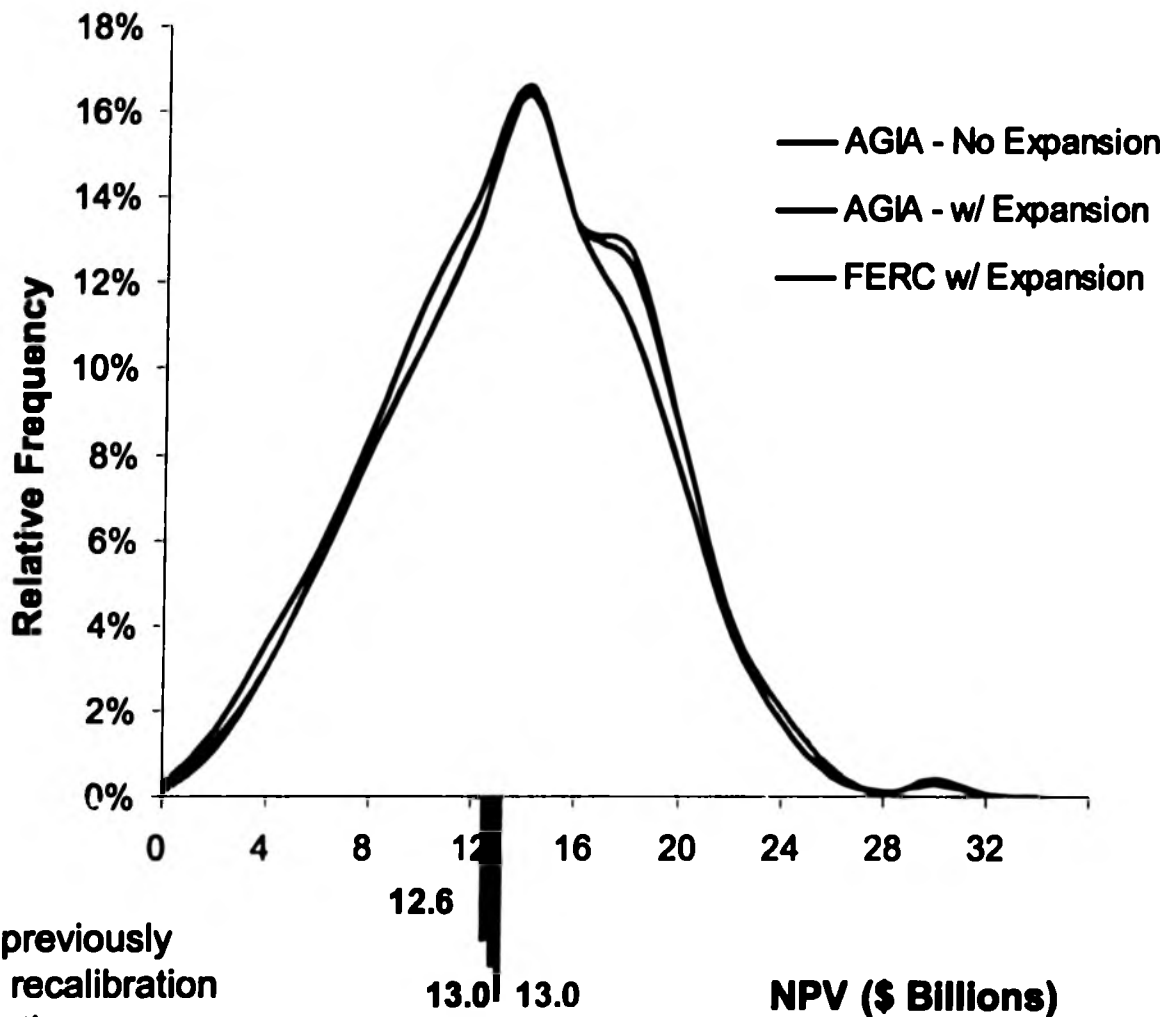
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- The following shows Producer upstream investment measures given the three expansions under the “worst case” of no producer gas in any of the expansions.

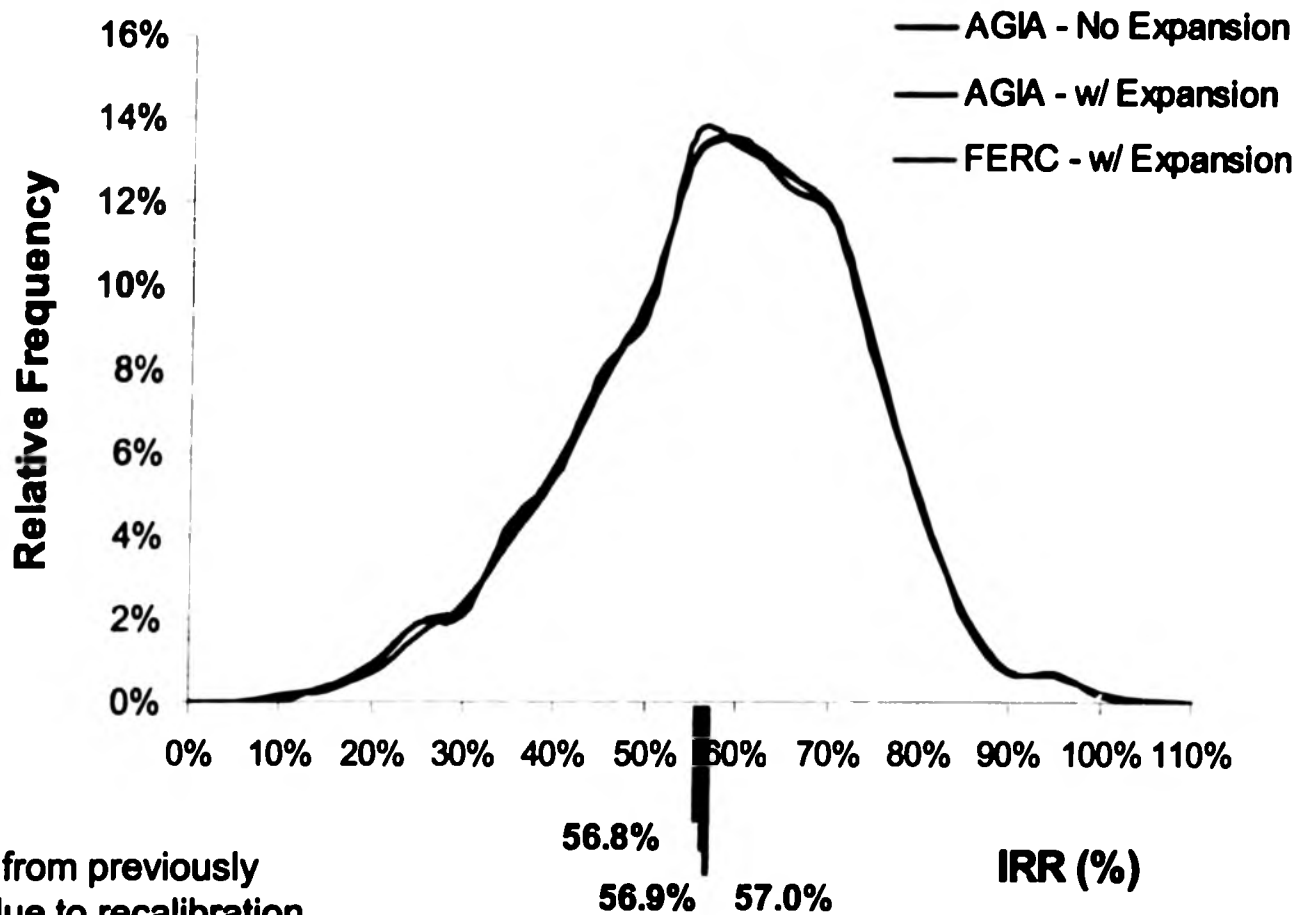
	NPV	IRR	P/I	NPV per BOE	% Δ NPV	Δ IRR	% Δ P/I
\$3.50	3.8	29.5%	3.0	\$0.46	-7.0%	-0.22%	-4.8%
\$5.50	11.7	62.8%	7.3	\$1.41	-3.3%	-0.10%	-2.9%
\$7.00	17.4	79.0%	10.3	\$2.10	-2.3%	-0.13%	-2.1%

Frequency Distribution Producer Upstream NPV₁₀



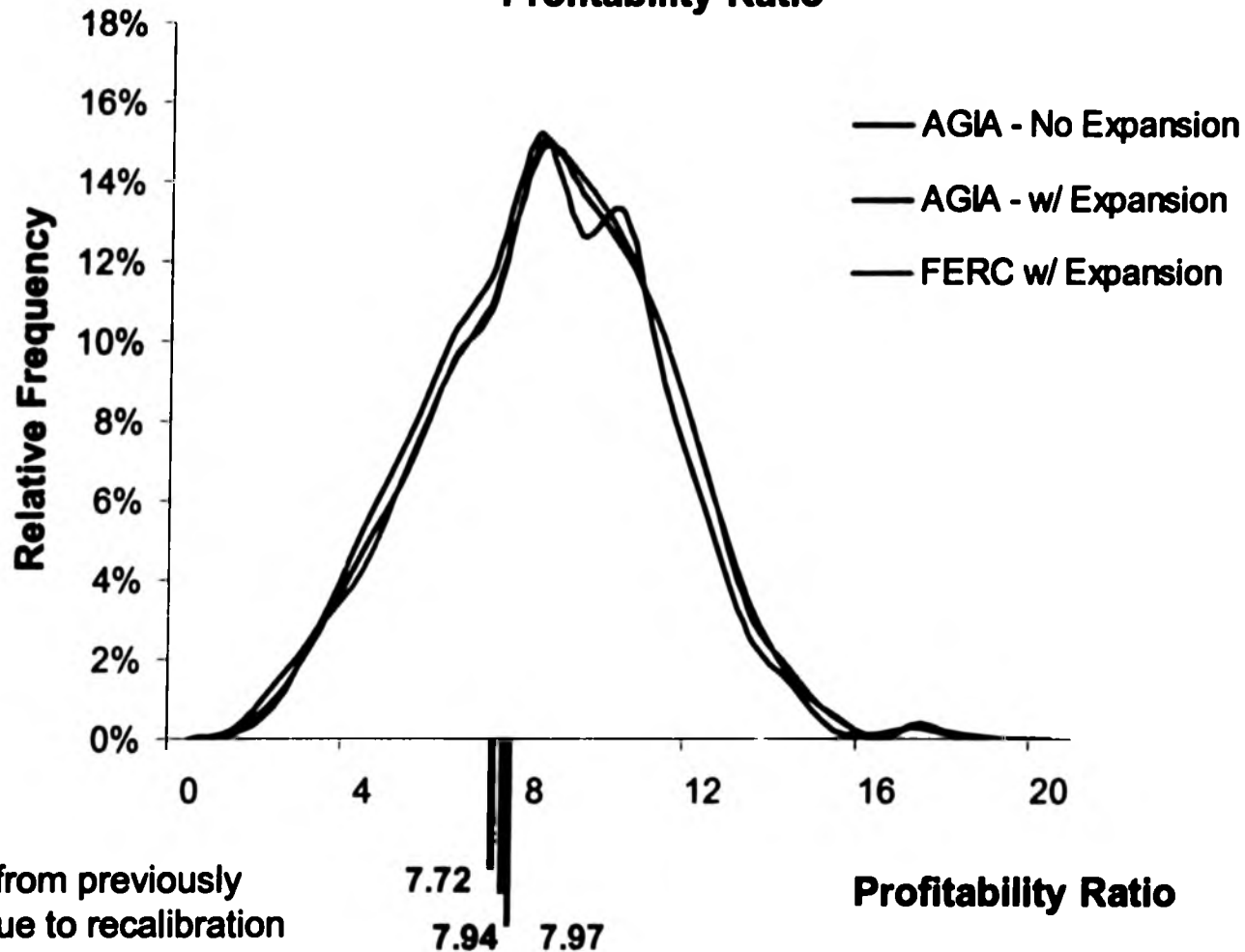
Note: Results differ from previously reported estimates due to recalibration of \$2004 to \$2006 price paths.

Frequency Distribution Producer Upstream IRR



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

Frequency Distribution Producer UpStream Profitability Ratio



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

Summary

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- 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

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The Alaska Gasline Inducement Act

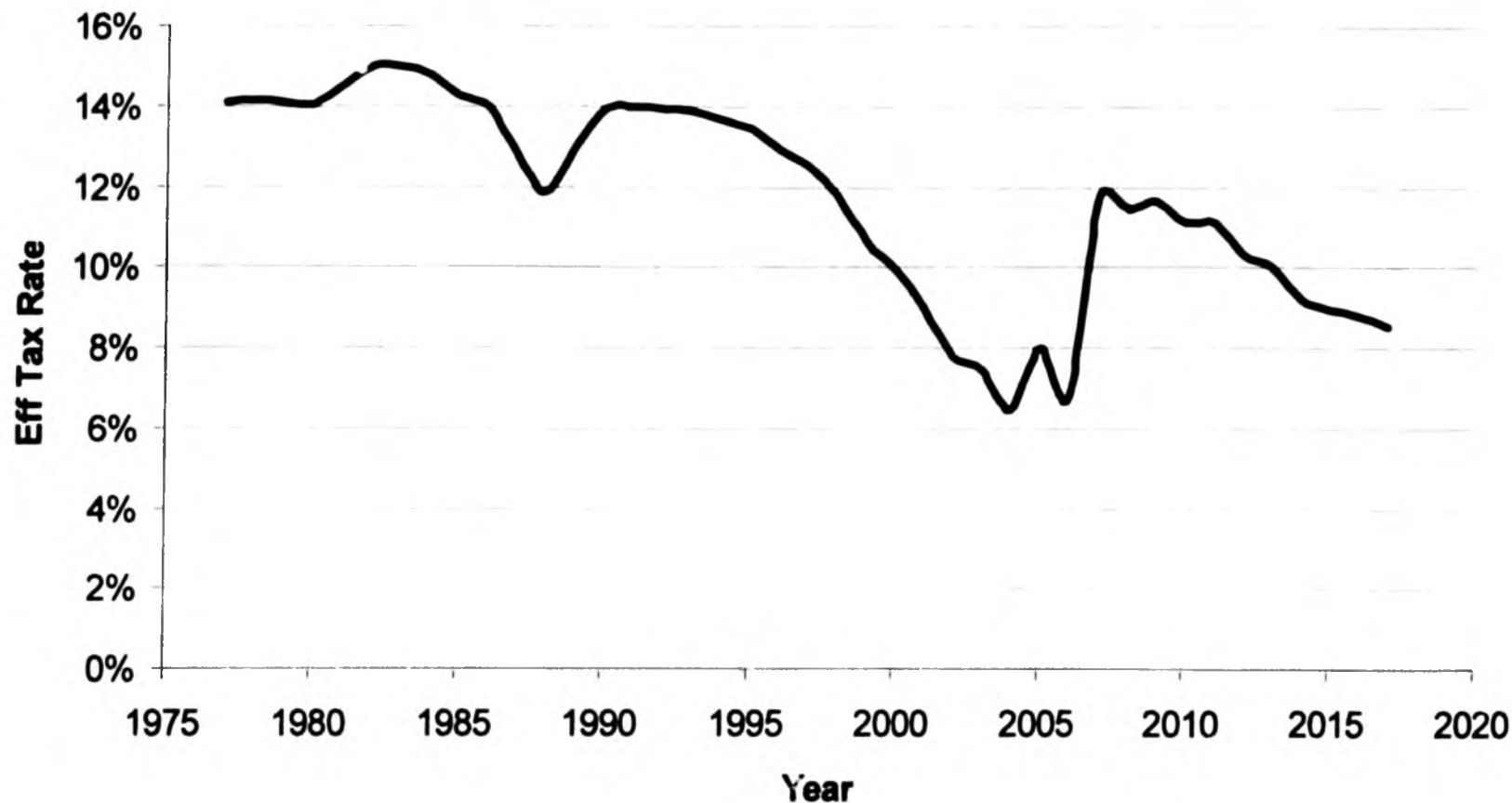
**Presentation to Senate Judiciary
4/11/2007**

oil production tax

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Effective Production Tax Rate- Oil

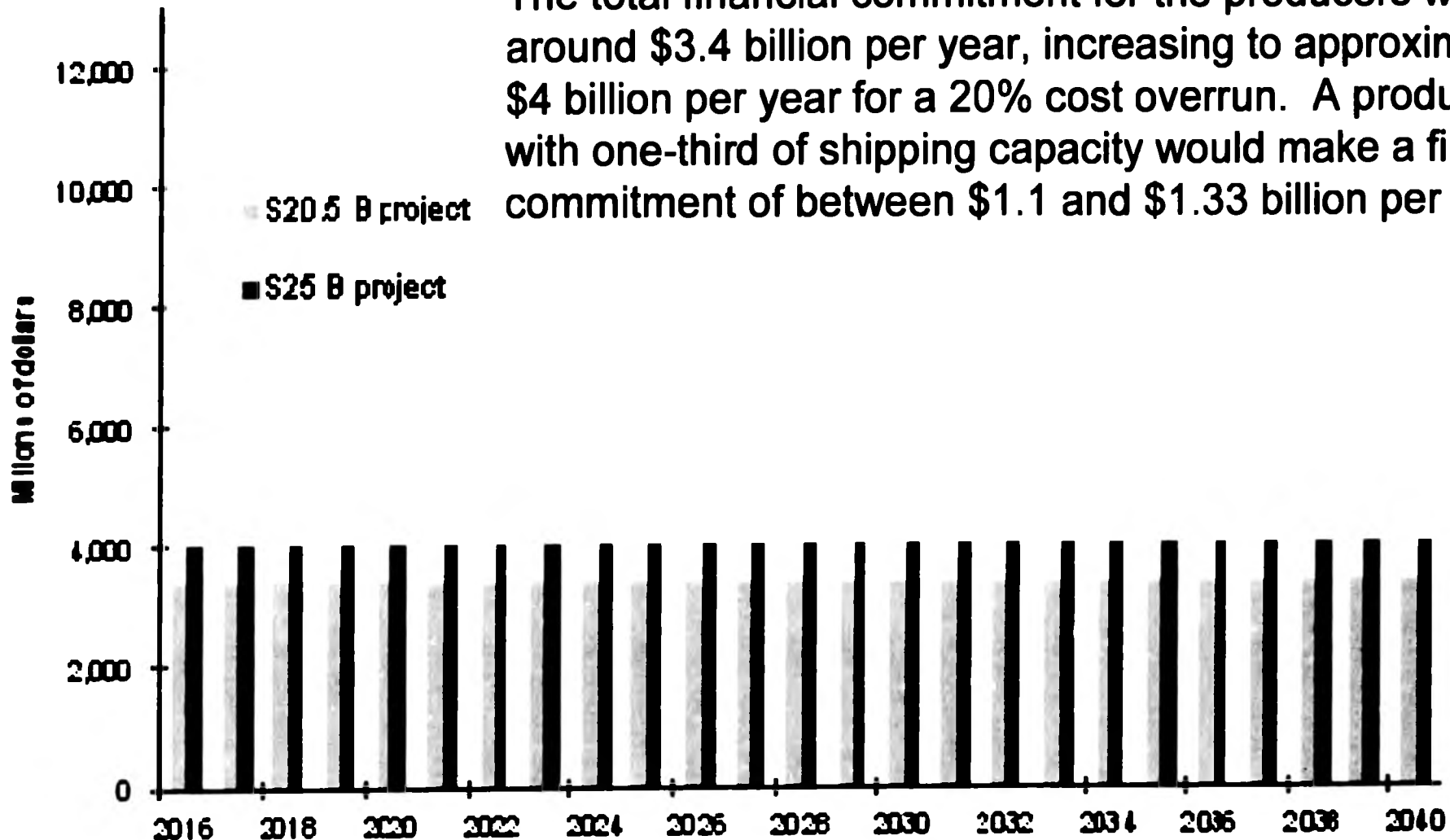


Q3. FT contracts: nominal dollar size of obligation

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The total financial commitment for the producers would be around \$3.4 billion per year, increasing to approximately \$4 billion per year for a 20% cost overrun. A producer with one-third of shipping capacity would make a financial commitment of between \$1.1 and \$1.33 billion per year.

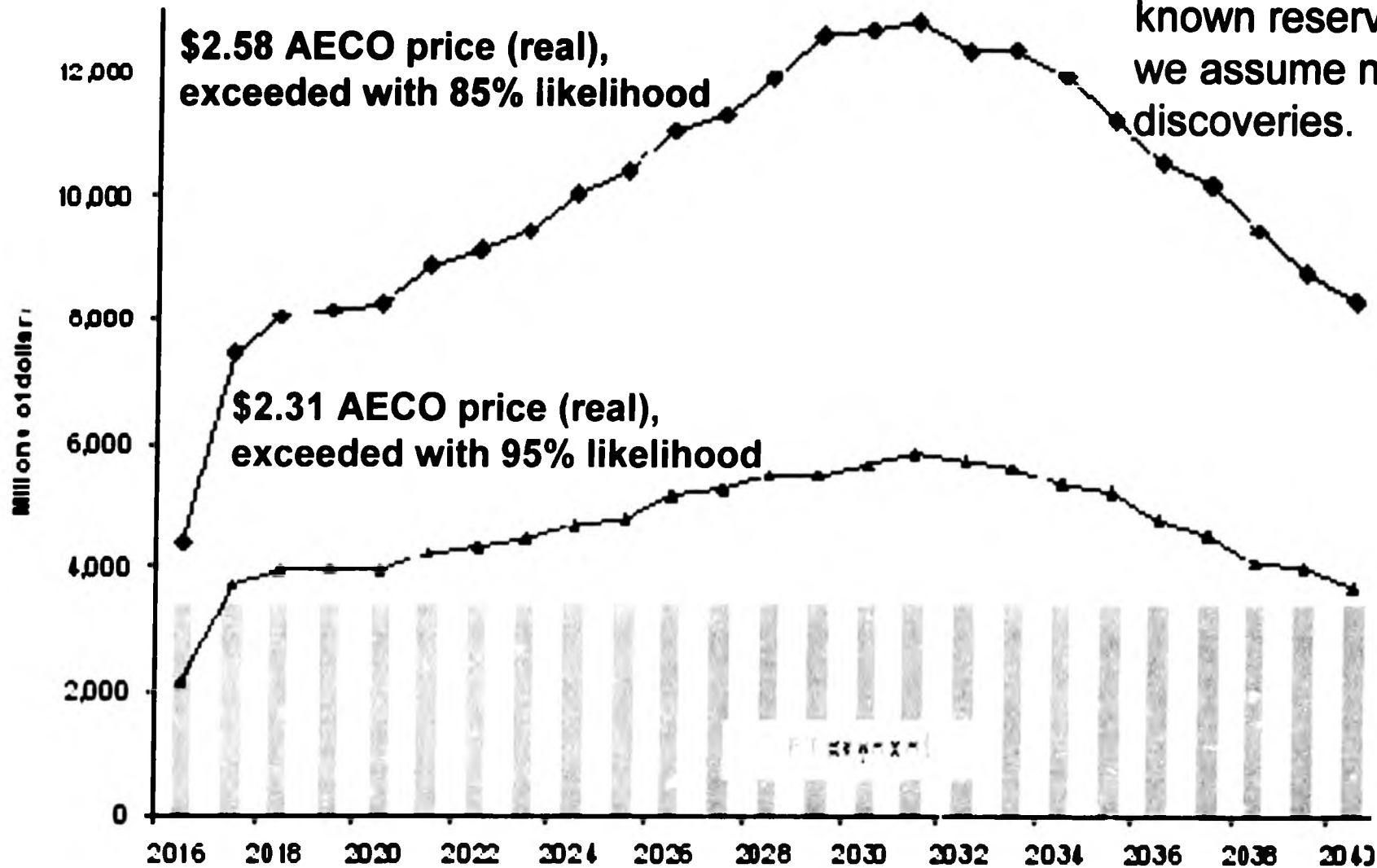


Q3. FT contracts (cont.): tariff in context of revenues

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Revenues declines as known reserves decline; we assume no new discoveries.



Analysis of Producer Returns, Investment Attractiveness, and Fiscal Certainty

Response to questions
4-5, 9-11, 16

How to measure investment attractiveness?

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- NPV = “net present value”
 - The current value of future profits
- IRR = “internal rate of return”
 - The discount rate that makes $NPV = 0$
- P/I = “profitability index”
 - $\frac{\text{[present value of cash inflows]}}{\text{[present value of outflows]}}$
- NPV/Boe = “NPV per barrel oil equivalent”
 - Measure of how much cash flow is generated from reserves

Producer Upstream Returns

Base case cost = \$20.5B

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	NPV	IRR	P/I	NPV per BOE
\$3.50	4.1	29.8%	3.2	\$0.49
\$4.00	6.1	39.7%	4.3	\$0.74
\$4.50	8.1	48.7%	5.3	\$0.98
\$5.00	10.1	56.3%	6.4	\$1.22
\$5.50	12.1	62.9%	7.5	\$1.46
\$6.00	14.0	68.9%	8.5	\$1.70
\$6.50	16.0	74.2%	9.5	\$1.93
\$7.00	17.8	79.2%	10.5	\$2.15
\$7.50	19.6	83.9%	11.5	\$2.37
\$8.00	21.3	90.4%	12.4	\$2.57
\$8.50	22.9	95.6%	13.2	\$2.76

Producer Upstream Returns

50% cost overrun = \$30.1B



The Alaska Gasline Inducement Act

	NPV	IRR	P/I	NPV per BOE
\$3.50	1.2	13.8%	1.5	\$0.14
\$4.00	3.2	20.9%	2.2	\$0.39
\$4.50	5.2	28.0%	3.0	\$0.63
\$5.00	7.2	35.0%	3.8	\$0.87
\$5.50	9.2	41.4%	4.6	\$1.12
\$6.00	11.2	47.2%	5.4	\$1.35
\$6.50	13.1	52.4%	6.1	\$1.59
\$7.00	15.1	57.2%	6.9	\$1.82
\$7.50	16.9	61.9%	7.6	\$2.05
\$8.00	18.8	67.8%	8.3	\$2.27
\$8.50	20.5	72.7%	9.0	\$2.47

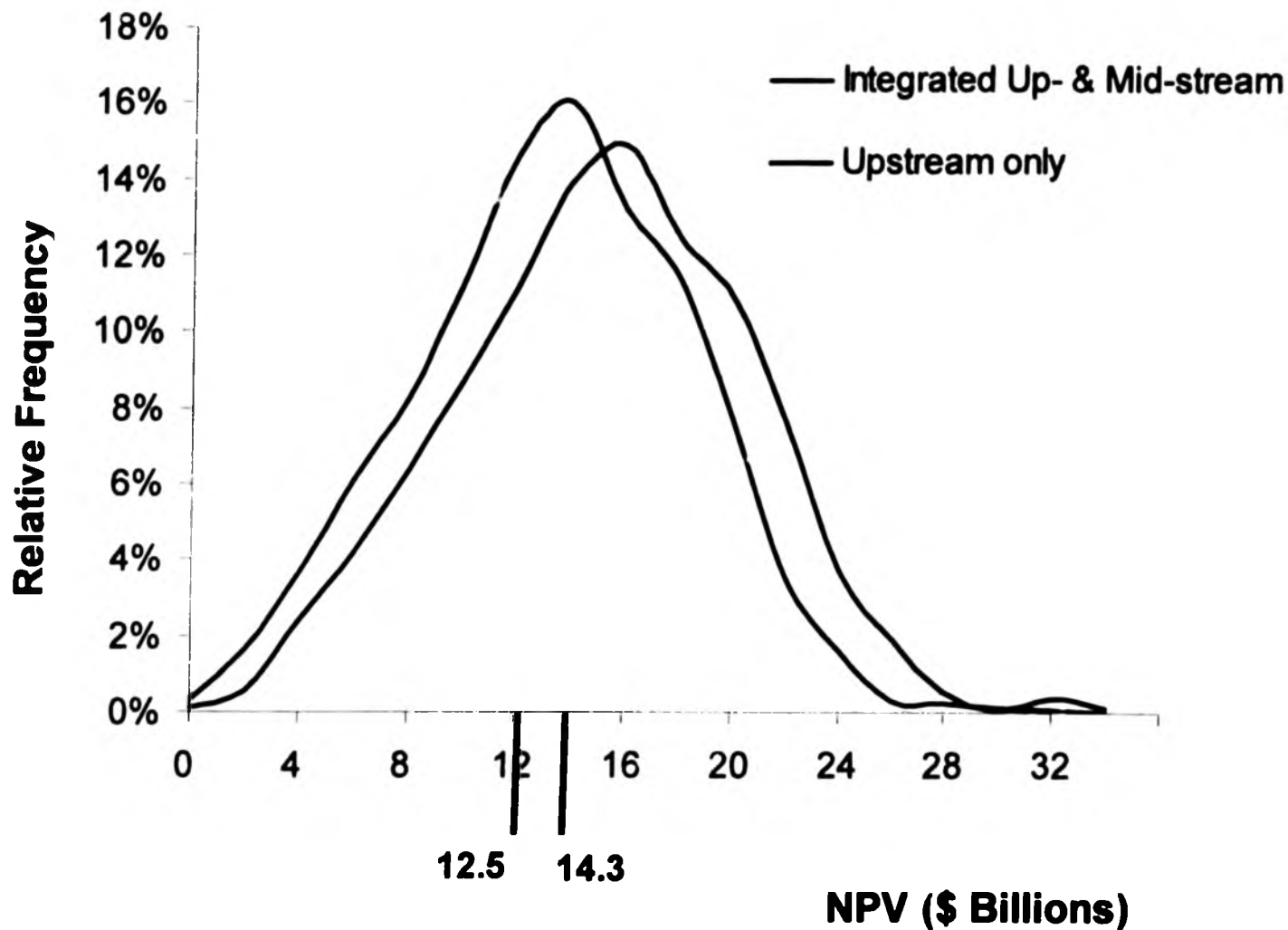
Producers' returns as both shippers + pipeline owners

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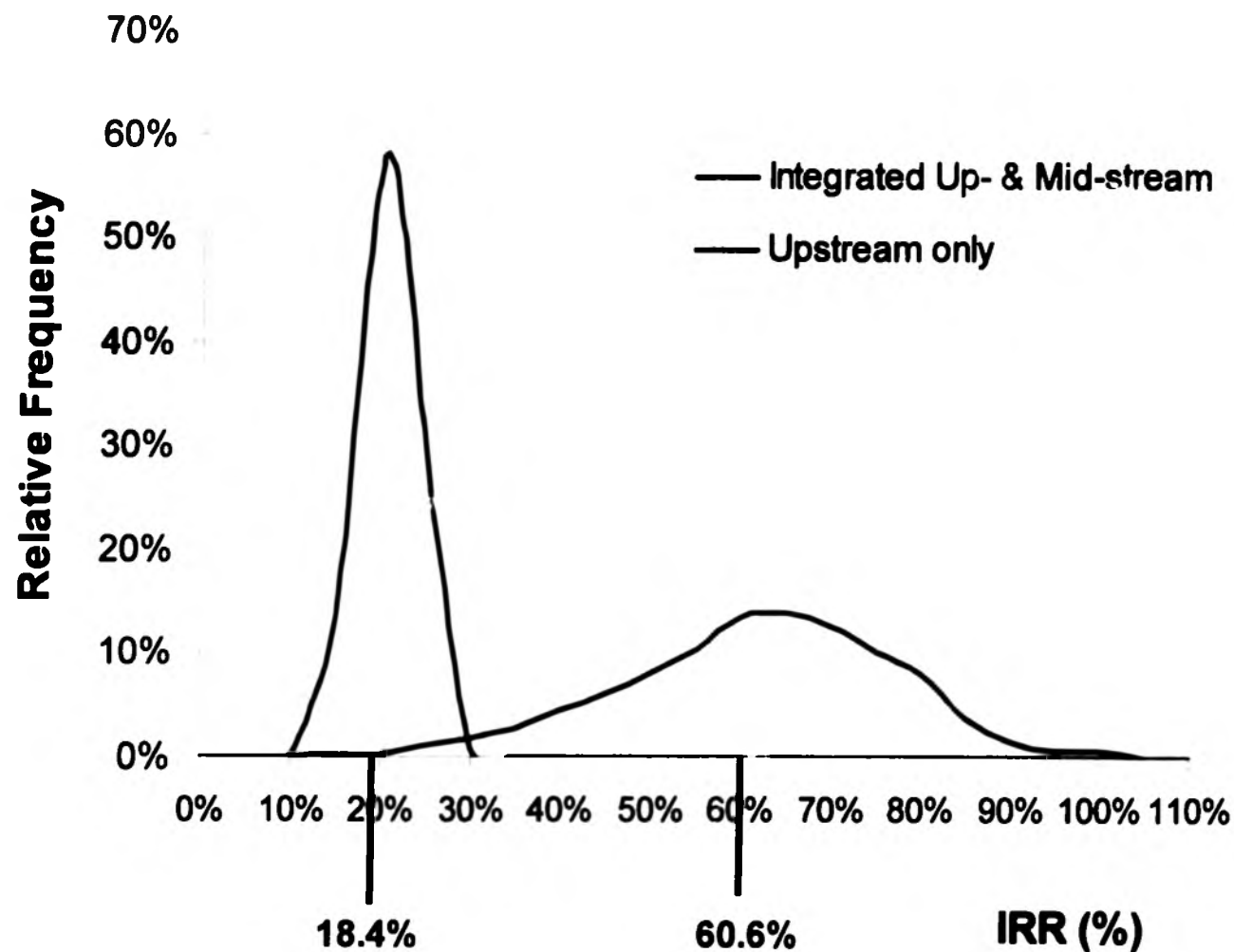
The Alaska Gasline Inducement Act

	NPV	IRR	P/I	NPV per BOE
\$3.50	3.0	12.6%	1.3	\$0.37
\$4.00	5.0	14.0%	1.4	\$0.60
\$4.50	6.9	15.4%	1.6	\$0.83
\$5.00	8.7	16.7%	1.7	\$1.06
\$5.50	10.6	17.9%	1.9	\$1.28
\$6.00	12.4	19.0%	2.0	\$1.50
\$6.50	14.2	20.1%	2.2	\$1.72
\$7.00	16.0	21.1%	2.3	\$1.93
\$7.50	17.7	22.1%	2.5	\$2.14
\$8.00	19.3	23.0%	2.6	\$2.33
\$8.50	20.8	23.9%	2.7	\$2.51

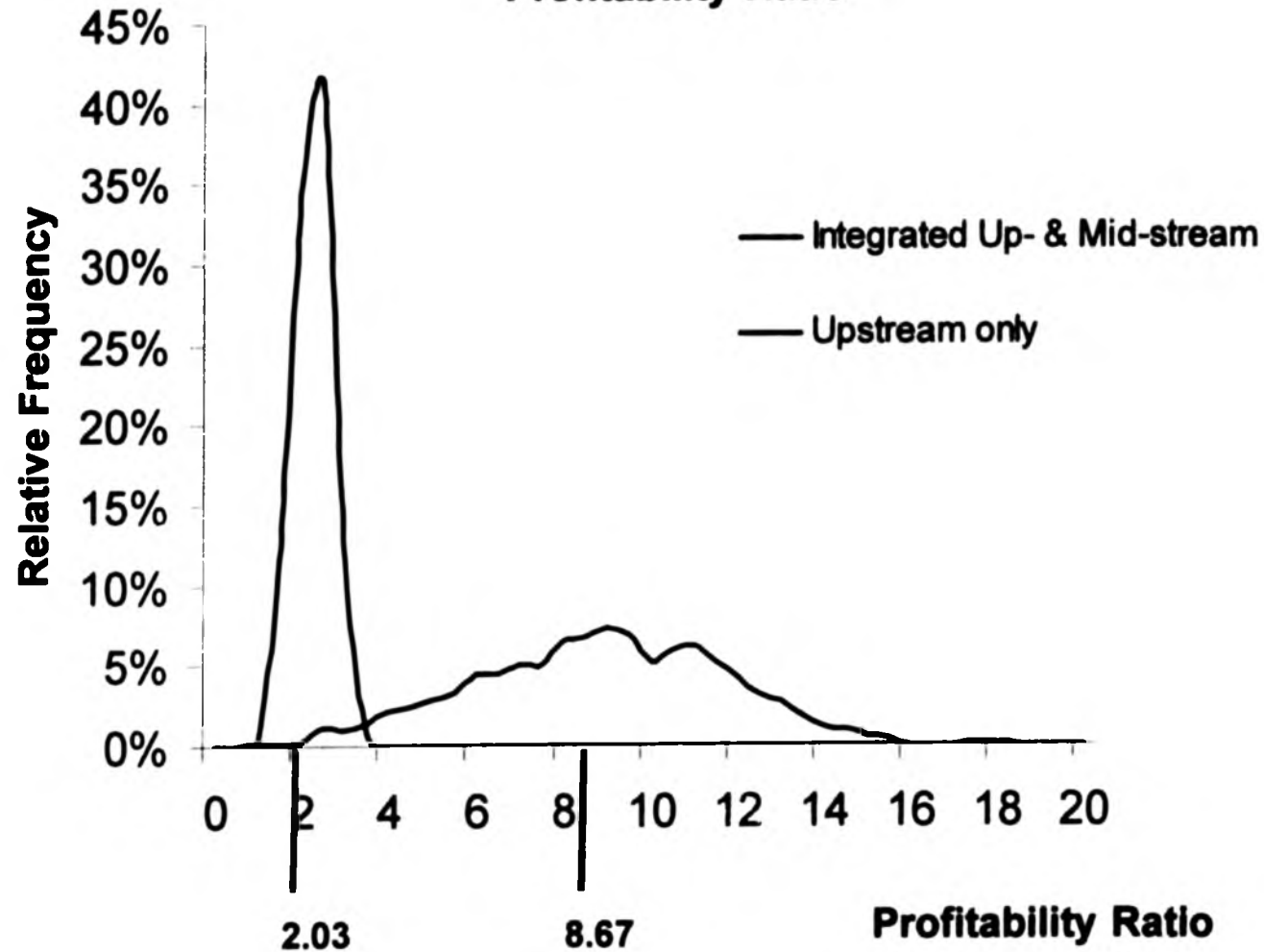
Frequency Distribution of Producer NPV₁₀



Frequency Distribution of Producer IRR



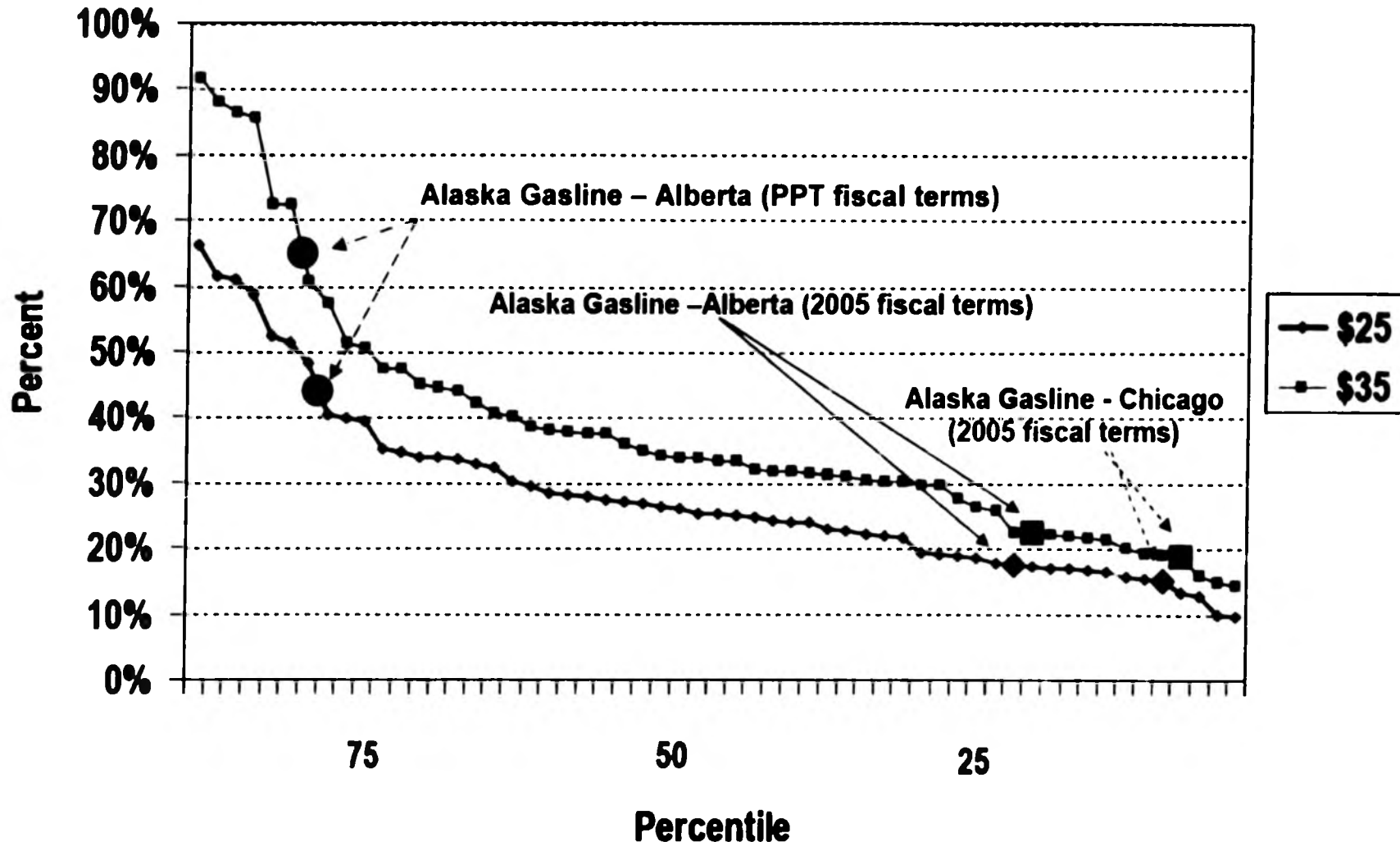
Frequency Distribution of Producer Profitability Ratio



**Internal Rate of Return (IRR)
(\$35 and \$25 oil and 6/1 oil/gas ratio)**

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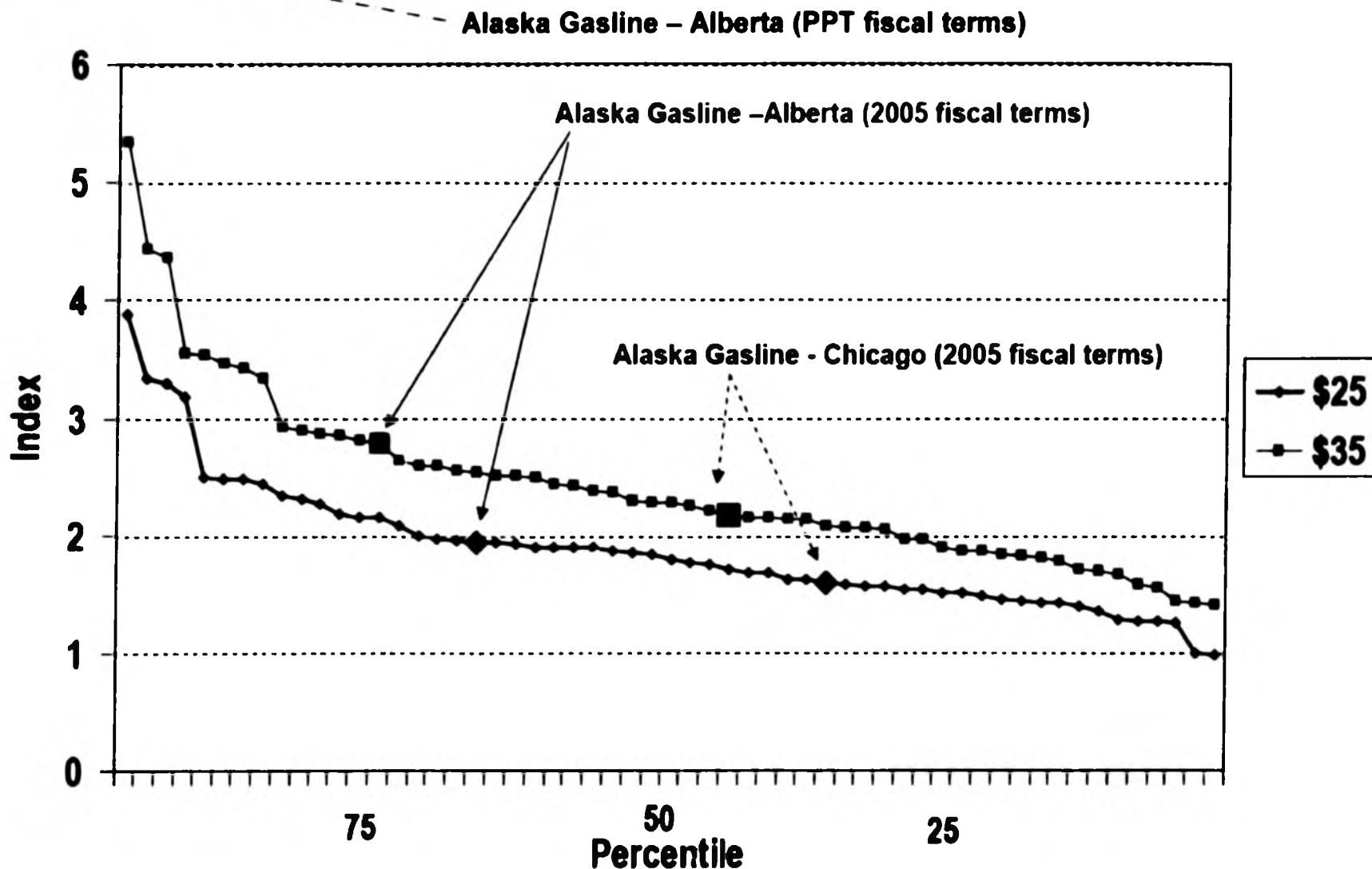


Project comparison data from EconOne presentation to LB&A Committee, 6/14/06. EconOne data 13
assumes 100% Producer pipeline ownership; upstream return data assumes 0% pipeline ownership.

Profitability Index Ratio (PIR10) (\$35 and \$25 oil and 6/1 oil/gas ratio)

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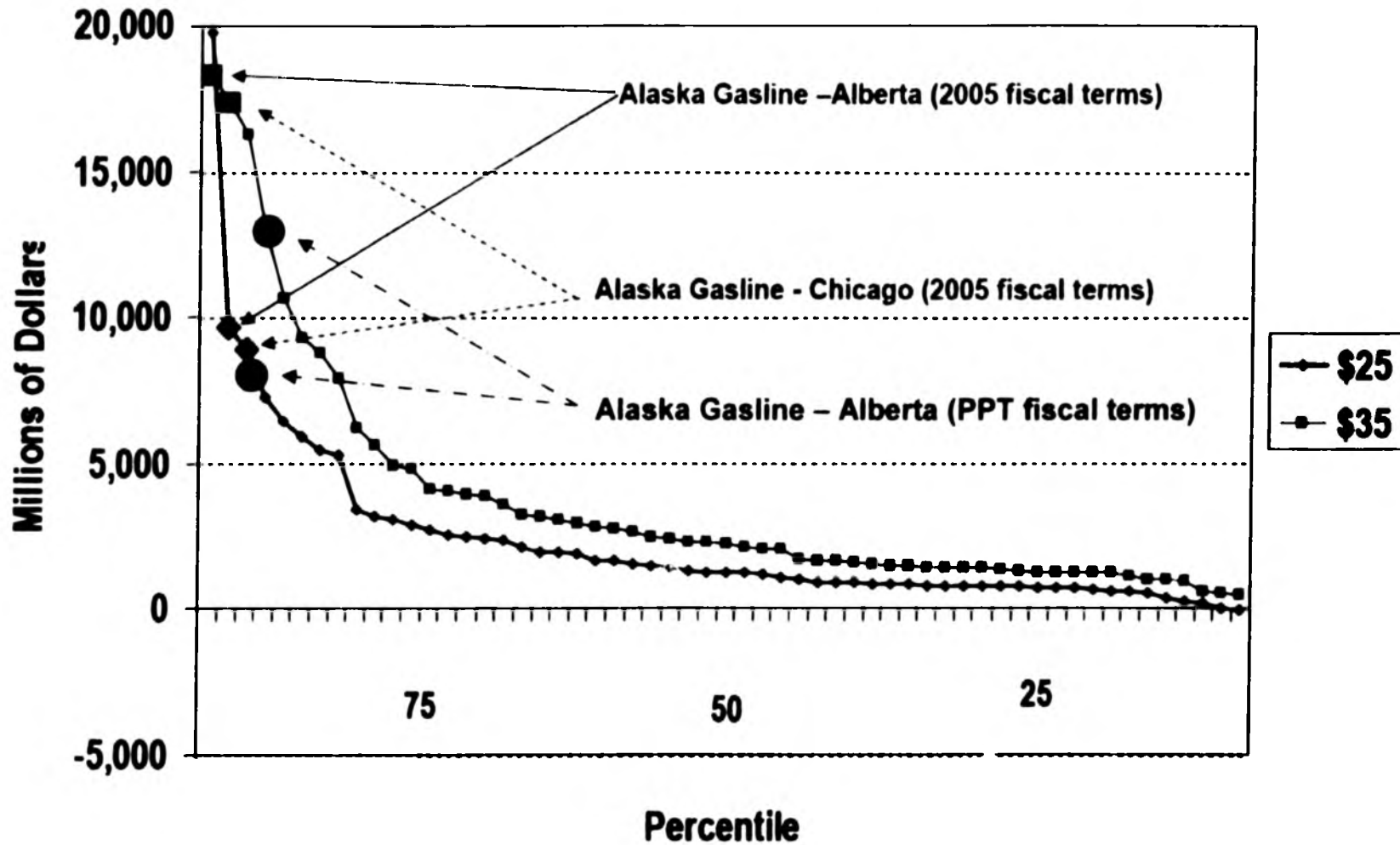


Project comparison data from EconOne presentation to LB&A Committee, 6/14/06. EconOne data assumes 100% Producer pipeline ownership; upstream return data assumes 0% pipeline ownership.

Project Comparison
Producer Net Cash Flow (NPV10)
(\$35 and \$25 oil and 6/1 oil/gas ratio)



The Alaska Gasline Inducement Act

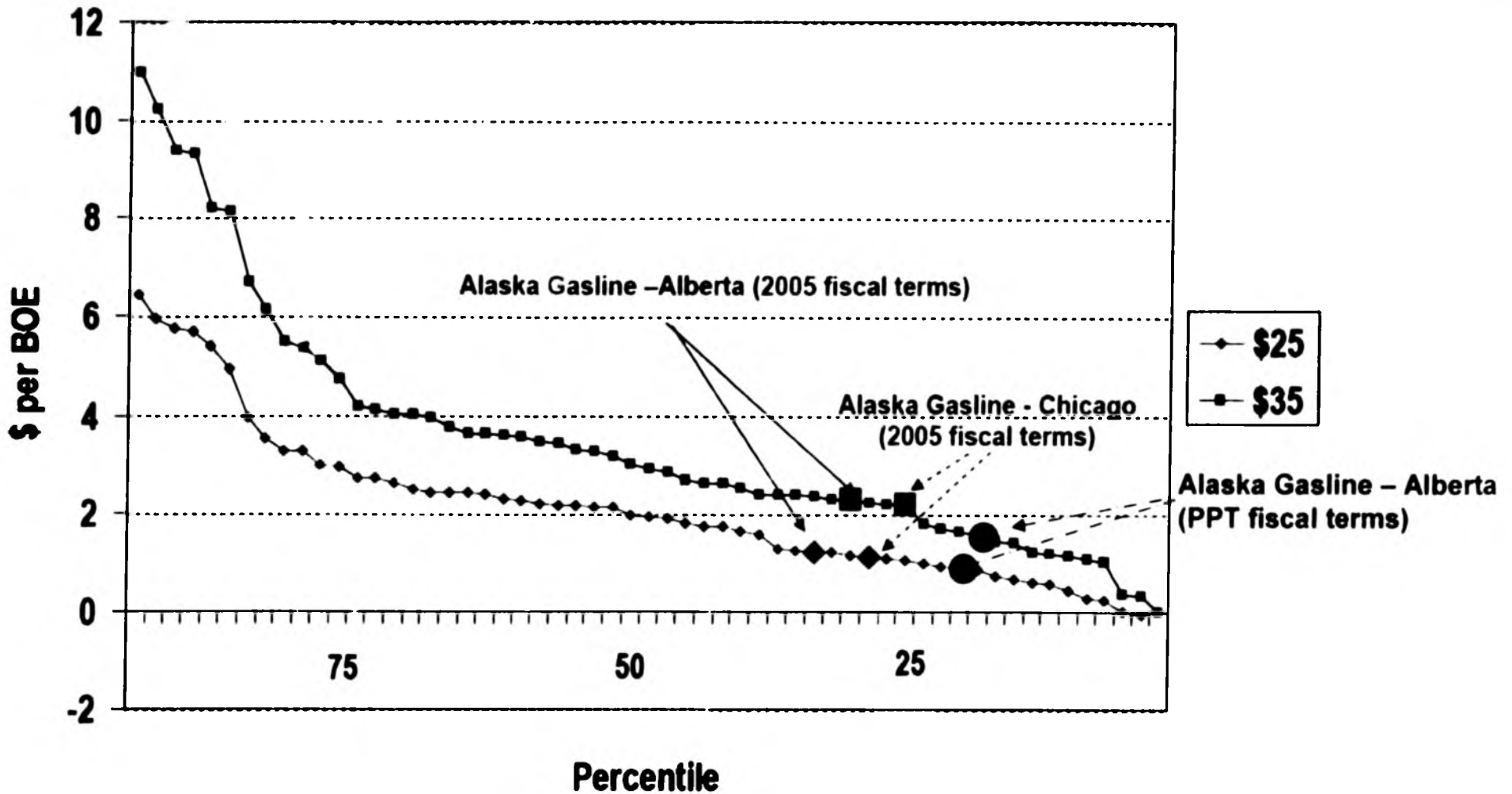


Project comparison data from EconOne presentation to LB&A Committee, 6/14/06. EconOne data assumes 100% Producer pipeline ownership; upstream return data assumes 0% pipeline ownership. 15

**NPV per BOE
(\$35 and \$25 oil and 6/1 oil/gas ratio)**



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Project comparison data from EconOne presentation to LB&A Committee, 6/14/06. EconOne data 16 assumes 100% Producer pipeline ownership; upstream return data assumes 0% pipeline ownership.

Tax increases effects on NPV

→ No fiscal certainty

AGIA

The Alaska Gasline Inducement Act

Producer NPV₁₀ in billions of dollars with increase in production tax rate at start of project

	NPV ₁₀				% change		
	<u>0%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>
\$3.50	3.8	3.6	3.3	3.0	-6.4%	-12.8%	-21.3%
\$4.00	5.7	5.4	5.0	4.6	-5.8%	-11.6%	-19.3%
\$4.50	7.6	7.2	6.7	6.2	-5.5%	-11.0%	-18.4%
\$5.00	9.4	8.9	8.4	7.8	-5.4%	-10.7%	-17.8%
\$5.50	11.3	10.7	10.1	9.3	-5.2%	-10.5%	-17.5%
\$6.00	13.1	12.5	11.8	10.9	-5.2%	-10.3%	-17.2%
\$6.50	14.9	14.2	13.4	12.4	-5.1%	-10.2%	-17.1%
\$7.00	16.7	15.8	15.0	13.8	-5.1%	-10.2%	-17.0%
\$7.50	18.3	17.4	16.5	15.2	-5.1%	-10.2%	-17.1%
\$8.00	19.9	18.9	17.8	16.5	-5.1%	-10.3%	-17.2%
\$8.50	21.4	20.3	19.2	17.7	-5.2%	-10.4%	-17.3%

Note: Oil effects excluded

Tax increases effects on NPV

→ Fiscal certainty 10 years

AGIA

The Alaska Gasline Inducement Act

Producer NPV₁₀ in billions of dollars with increase in production tax rate at 11th year of project

	NPV ₁₀				% change		
	<u>0%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>
\$3.50	3.8	3.7	3.6	3.5	-2.9%	-5.8%	-9.7%
\$4.00	5.7	5.6	5.4	5.2	-2.5%	-5.0%	-8.4%
\$4.50	7.6	7.4	7.2	7.0	-2.3%	-4.7%	-7.8%
\$5.00	9.4	9.2	9.0	8.7	-2.2%	-4.4%	-7.4%
\$5.50	11.3	11.1	10.8	10.5	-2.1%	-4.3%	-7.1%
\$6.00	13.1	12.9	12.6	12.2	-2.1%	-4.2%	-6.9%
\$6.50	14.9	14.6	14.3	13.9	-2.0%	-4.1%	-6.8%
\$7.00	16.7	16.3	16.0	15.5	-2.0%	-4.1%	-6.8%
\$7.50	18.3	18.0	17.6	17.1	-2.0%	-4.0%	-6.7%
\$8.00	19.9	19.5	19.1	18.6	-2.0%	-4.0%	-6.7%
\$8.50	21.4	21.0	20.5	19.9	-2.0%	-4.1%	-6.8%

Tax increases effects on NPV

→ Fiscal certainty 5 years

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The Alaska Gasline Inducement Act

Producer NPV₁₀ in billions of dollars with increase in production tax rate at 6th year of project

	NPV ₁₀				% charge		
	<u>0%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>
\$3.50	3.8	3.7	3.5	3.2	-4.7%	-9.3%	-15.4%
\$4.00	5.7	5.5	5.2	4.9	-4.1%	-8.2%	-13.6%
\$4.50	7.6	7.3	7.0	6.6	-3.8%	-7.6%	-12.7%
\$5.00	9.4	9.1	8.7	8.3	-3.7%	-7.3%	-12.2%
\$5.50	11.3	10.9	10.5	10.0	-3.5%	-7.1%	-11.8%
\$6.00	13.1	12.7	12.2	11.6	-3.5%	-6.9%	-11.6%
\$6.50	14.9	14.4	13.9	13.2	-3.4%	-6.8%	-11.4%
\$7.00	16.7	16.1	15.5	14.8	-3.4%	-6.8%	-11.3%
\$7.50	18.3	17.7	17.1	16.3	-3.4%	-6.8%	-11.3%
\$8.00	19.9	19.2	18.5	17.6	-3.4%	-6.8%	-11.4%
\$8.50	21.4	20.7	19.9	18.9	-3.4%	-6.9%	-11.4%

Tax increases effects on NPV
→ Fiscal certainty 15 years

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Producer NPV₁₀ in billions of dollars with increase in production tax rate at 16th year of project

	NPV ₁₀				% charge		
	<u>0%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>
\$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%

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		
	<u>0%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>
\$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%	-2.1%	-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%

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		
	<u>0%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>
\$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%

Tax increases effects on IRR
→ Fiscal certainty 5 years



The Alaska Gasline Inducement Act

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

	IRR				difference		
	<u>0%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>
\$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%

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						
	<u>0%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>
\$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%

Tax increases effects on PI

→ 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

Tax increases effects on PI
→ 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		
	<u>0%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>
\$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

Tax increases effects on PI

→ 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		
	<u>0%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>
\$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

Tax increases effects on PI
→ Fiscal certainty 15 years

AGIA

The Alaska Gasline Inducement Act

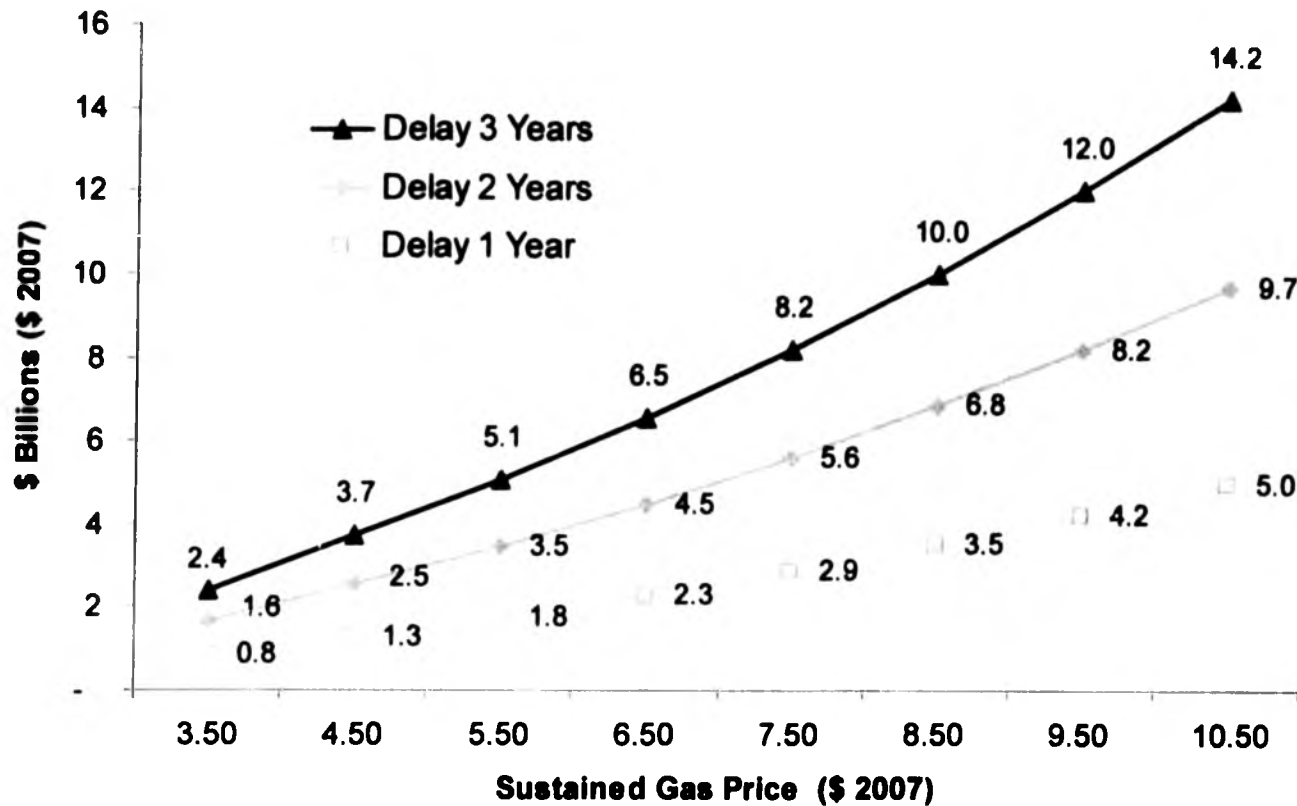
Producer PI with increase in production tax rate at 16th year of project

	PI				difference		
	<u>0%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>	<u>15%</u>	<u>30%</u>	<u>50%</u>
\$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

Discounted at 5% per year

AGIA

The Alaska Gasline Inducement Act



AGIA designed to ensure that litigation over fiscal certainty does not delay project. Chart assumes 38 years of gas flow.

Q13. TAPS tariffs recovered all costs in first 13 years

AGIA

The Alaska Gasline Inducement Act

- The answer depends on determinations of appropriate rates of return, capital structure, etc.
- The Regulatory Commission of Alaska in its investigation of TAPS rates determined that TAPS was fully paid for by 1989. (See Order 151, Docket P-97-4, Exhibit 6 Schedule 1).

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



**ALASKA DEPARTMENT OF LABOR
& WORKFORCE DEVELOPMENT**

Alaska Gasline Inducement Act Project Labor Agreement

Presented to the Senate Judiciary
Committee by

Click Bishop, Commissioner

April 13, 2007

Jobs are Alaska's Future



**ALASKA DEPARTMENT OF LABOR
& WORKFORCE DEVELOPMENT**



What is a PLA?

A comprehensive collective bargaining agreement that sets the terms and conditions of employment on a project, for that project only.

Jobs are Alaska's Future



**ALASKA DEPARTMENT OF LABOR
& WORKFORCE DEVELOPMENT**

Project Labor Agreement

Licensee/General Contractor Negotiates Directly with an Appropriate Entity

The PLA is a collective bargaining agreement between the licensee, or its agent, and an appropriate entity setting out the terms and conditions of employment on the project, typically including wages and benefits, and setting out other work conditions including no-strike, no lockout provisions, dispute resolution procedures, and use of hiring facilities in Alaska.

Contractors

All contractors, union or nonunion, interested in bidding on project work, must follow the terms and conditions set out in the PLA.

Jobs are Alaska's Future



**ALASKA DEPARTMENT OF LABOR
& WORKFORCE DEVELOPMENT**



PLA History

- First used in the 1930's
- Currently used widely in the private and public sectors.

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& WORKFORCE DEVELOPMENT**



Jobs are Alaska's Future

PLA Precedents

- **Legal**
 - U.S. Supreme Court (Boston Harbor) 1993
 - AK Supreme Court (Laborers Local 942 v. Lampkin) 1998
- **PLA-based Public and Private Projects**
 - Grand Coulee and Hoover Dams
 - TAPS
 - San Francisco BART
 - Puget Sound Transit
 - Sutter and Sunrise Power Plants in California
 - Seattle Airport



**ALASKA DEPARTMENT OF LABOR
& WORKFORCE DEVELOPMENT**



Why Have a PLA?



- Stable workforce—no strikes or lockouts
- Meets project scheduling challenges.
- Eliminates need to negotiate numerous separate contracts.
- Assures consistent terms and conditions for all contractors
- Vehicle for:
 - Alaska hire.
 - Apprenticeship Opportunities.
 - Preference for underutilized groups.

Jobs are Alaska's Future

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

**Government contract to test
presentation to Senate Justice Committee
4/16/2007**

Effects of Government Subsidies on Rates

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The Alaska Gasline Inducement Act

Base rate: All subsidies 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, worth \$600 million if GTP costs \$4 billion
- If this subsidy is included then total government subsidies exceed 15%

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

**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

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

Senate Judiciary

4/16/07

FERC Policy- Rolled in Rates- In Alaska



- **2004 ANGPA mandate to FERC:**
 - “promote competition in the exploration, development and production of Alaska natural gas.” (§103(e)(2)(b)).
 - “provide the opportunity for the transportation of natural gas other than from the Prudhoe Bay and Point Thomson units” for any open season for capacity exceeding the initial capacity of the line. (§103(e)(2)(c)).

FERC Policy- Rolled in Rates- In Alaska

AGIA

The Alaska Gasline Inducement Act

- **FERC Concluded:**

“incremental pricing of expansion could put expansion shippers at a significant rate disadvantage compared with initial shippers, and accordingly could discourage exploration, development and production of Alaska natural gas.” (Order 2005 at ¶ 123)

FERC Policy- Rolled in Rates- Lower 48

AGIA

The Alaska Gasline Inducement Act

- From 1960's until 1999 FERC preferred rolled-in pricing. (Statement of Policy, 71 FERC ¶ 61,231 (1995)).
- Changed in 1999 because, "it no longer fits well with an industry that is increasingly characterized by competition between pipelines." (Statement of Policy, 88 FERC ¶ 61,227 (1999)).

**FERC Policy -
Rolled in Rates -
Lower 48/Alaska**



- “Our existing lower-48 states policy favoring incremental rates for expansions does not apply in the case of an Alaska natural gas project. There is likely to be only one Alaska pipeline so there will be little or no opportunity for competition between pipelines.” (Order 2005 at ¶ 123).

**FERC Policy-
Rolled in Rates-
Lower 48/Alaska**



A rate increase is not necessarily a subsidy. (see, order 2005-A at ¶ 50).

“An alternative ...definition of subsidization could be whether the expansion rate is no higher than the actual initial rate or of an initial rate without built in subsidies.” (Order 2005-A at ¶ 49)

FERC Policy- Rolled in Rates- Alaska



“Whether a rolled-in expansion rate that is higher than original rates is a ‘subsidy’ is a question that necessarily would have to be reviewed in the context of a future NGA section 7 filing. At that time, Pacific Star’s argument relating to whether the federal government’s loan guarantees and accelerated depreciation amount to a ‘subsidy’ of initial shippers’ rate may be raised.” (Order 2005 at ¶ 124, emphasis in original).

Governmental Contribution to Rates

AGIA

The Alaska Gasline Inducement Act

Government Contributions reduce rates by more than 15%:

- **Loan Guarantee up to \$18 billion**
- **7-year accelerated depreciation**
- **Federal income tax credit for GTP**
- **AGIA \$500 million**

AGIA Policy- Rolled in Rates

AGIA

The Alaska Gasline Inducement Act

- **AGIA caps roll-in filing commitment roughly at level of governmental contributions to the project.**
- **Permits 2d or 3d generation of expansion shippers also to enjoy the benefit of governmental contributions made available to initial shippers.**

FERC Process

AGIA

The Alaska Gasline Inducement Act

“A pipeline company

PROPOSES

But the FERC

DISPOSES.”

(an old industry adage)

- AGIA does not intrude on FERC's authority.
- AGIA requires that the licensee **PROPOSE** rolled-in rates
- FERC will **DISPOSE.**