SCOMM

148:8

AGIA Testimony

INTRODUCTION

Good morning Representative Kohring and members of the House Oil and Gas Committee. My name is Marty Massey. I am the U.S. Joint Interest Manager for ExxonMobil, a position I have held since November 2001, and I am responsible for the commercialization of 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 of hydrocarbons 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 relationship for another 50 years or more.

EXXONMOBIL READY TO PROGRESS PROJECT

With that introduction, I would like take a moment to emphasize the importance of the Alaska Gas Pipeline project to Alaska, to ExxonMobil, and to our nation. 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. ExxonMobil supports efforts to advance a pipeline project and we are ready to work with Governor Palin and her cabinet and with the Legislature to move forward the Alaska gas pipeline project.

Let me demonstrate the importance of this project to ExxonMobil. It 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 are obviously very interested in progressing it.

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.

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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 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.

HOW PIPELINES ARE FINANCED AND WHO BEARS PROJECT RISKS

Let me now make a few comments on how projects are financed and who bears the risks. 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 (often abbreviated and called FT) are binding obligations made by companies (known as "shippers") to pay for the cost of reserving a quantity of gas capacity 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.

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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 transportation 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.

IMPORTANCE OF STATE / PRODUCER ALIGNMENT AND BENEFITS OF THE 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. Over time, development costs are 25% lower than industry average on a $/barrel basis. 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)

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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. Our Arctic offshore activity started in 1966 with the installation of the ice resistant Granite Point platform in Alaska's Cook Inlet, which is still producing oil. In the 1970's we provided a significant amount of research and engineering for the Prudhoe Bay project, where our completion designs for permafrost were of key importance to the project. We also developed the combined hydraulic flow model and thermal simulator on which the design of TAPS was based. In 1984, we installed the Concrete Island Drilling System (CIDS) to drill exploration wells in the Alaska Beaufort Sea. This was the first mobile drilling platform to operate in the ice covered waters of the Beaufort. In addition to our Arctic experience in Alaska, ExxonMobil also has extensive Arctic experience in Canada, developing the Norman Wells Field in the Mackenzie River area near the Arctic Circle. Offshore Newfoundland, we completed the Hibernia platform, the first and only iceberg resistant offshore structure in the world. In Russia, we recently started up the Sakhalin 1 development which involved an offshore drilling platform where CIDS was reused and renamed Orlan, an onshore drillsite where we have set new industry limits for extended reach drilling, an onshore oil and gas plant with a capacity of 250,000 barrels per day, and purpose built tankers which are used year-round. All of this work is being done in an arctic and seismically-active area. At Sakhalin we are currently producing 250,000 barrels of oil per day.. I hope you see from these examples that large projects with significant complexity are what we do and we are extremely qualified to take on this work.

These successful efforts were 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.

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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, results 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.

IMPORTANCE OF FISCAL STABILITY

For us to progress the project and mitigate its inherent risks, we do need some things from the State. Because of the nature and magnitude of the risks associated with this project – 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. As with all of our other mega-project investments, and we share this with the resource owners where those investments are to be made, 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 hub. 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 ten or more 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

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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.

SPECIFIC FEEDBACK ON AGIA

With that background, I would like to now give some feedback on AGIA which is based on the conclusions and principles I've mentioned. I will also outline our 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.

Also, it is important that AGIA allow applicants to define how they could achieve the State's key 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 by providing requirements they feel are necessary to make the project commercially viable. For example, we think it would be better to let the applicant determine whether or not they require any capital contribution from the State.

ExxonMobil recognizes the importance to the State, explorers and others of having access to the project so their gas can be treated and transported to markets. To ensure that a project is constructed, it must be commercially attractive to shippers at the time they make their initial firm transportation commitments. Shippers, particularly those who must invest substantially to explore for, develop and produce gas resources, will not be willing to enter into long-term financial commitments for the transportation of gas if they believe there is a substantial likelihood that their initial rates will be significantly increased in the future in order to accommodate expansions.

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Under the Alaska Natural Gas Pipeline Act, Congress struck what it determined was the proper balance between encouraging investment by those willing to commit to pay for initial capacity and encouraging exploration by providing an opportunity for future access to the pipeline. Because of the unique nature of the Alaska gas pipeline project, FERC approved unprecedented policies to enable a FERC-mandated expansion to benefit explorers.

The issue of how potential future shippers may access initial capacity and future expansion capacity, if needed, should be administered by the FERC for all elements of the project in the United States. For example, shippers (producers) should not be required to subsidize other expansion gas holders (competitors) at 115% of initial maximum rates due to a mandated roll-in of expansion costs. For example this 15% increase could increase my FT commitment by 30 to 50 cents per MBTU on gas shipped. This is an increased cost of $500 to $800 million per year on the initial shippers. You could also consider this a subsidy to the expansion shipper. We are not in the business of subsidizing our competitors. This is too high of a risk to take. In addition, the pipeline entity should not be required to accept a FERC certificate irrespective of FERC imposed conditions.

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 necessary 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 producer's 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 their requirements now creates significant uncertainty. AGIA also does not establish criteria for evaluating proposals and selecting the successful bidder, which is likely to lead to litigation from project proponents not selected for inducements.

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.

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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 the broad objectives the State wants to achieve and allow each applicant to decide how best to meet those objectives and to identify what is required from the State to advance the project. The State can then accept the proposal that delivers the most value. We are ready to participate in a competitive open 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.

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BERNSTEIN RESEARCH

Global Integrated Oils: Project Slippage - the reason why future optimistic oil supply outlooks are likely to be wrong

Ticker	Rating	CUR	20/09/2005 Closing Price	Target Price	YTD Rel. Perf.	EPS 2004A	EPS 2005E	EPS 2006E	P/E 2004A	P/E 2005E	P/E 2006E	Yield
BP/.LN	O	GBp	661.00	725.00	29.3%	39.00	61.82	56.81	16.9	10.7	11.6	2.6%
BP	O	USD	71.40	78.00	21.5%	4.47	6.77	6.10	16.0	10.5	11.7	2.4%
COP	O	USD	68.90	76.00	57.9%	5.95	8.15	7.72	11.6	8.5	8.9	2.9%
CVX	O	USD	64.04	73.00	21.2%	5.47	7.02	6.55	11.7	9.1	9.8	2.5%
ENI.IM	M	EUR	24.85	27.00	34.1%	1.80	2.69	2. 3	13.8	9.2	9.3	3.0%
E	M	USD	150.70	167.00	19.0%	12.50	16.91	16.34	12.1	8.9	9.2	3.0%
FP.FP	O	EUR	222.80	262.00	37.9%	14.07	21.22	20.64	15.8	10.5	10.8	2.2%
TOT	O	USD	134.77	160.00	21.9%	9.31	13.36	12.59	14.5	10.1	10.7	2.3%
RDSA.LN	M	GBp	1838.00	2070.00	0.0%	0	185.50	194.16	NM	9.9	9.5	3.5%
RDSB.LN	M	GBp	1915.00	2070.00	0.0%	0	185.50	194.16	NM	10.3	9.9	3.3%
RDSA.NA	M	EUR	27.26	30.00	0.0%	0	2.69	2.85	NM	10.1	9.6	3.4%
RDSB.NA	M	EUR	28.65	30.00	0.0%	0	2.69	2.85	NM	10.7	10.1	3.2%
RDS/A	M	USD	65.76	76.00	0.0%	0	6.77	6.96	NM	9.7	9.4	3.4%
RDS/B	M	USD	68.83	76.00	0.0%	0	6.77	6.96	NM	10.2	9.9	3.2%
XOM	O	USD	64.53	75.00	25.1%	3.69	5.20	4.90	17.5	12.4	13.2	1.7%
SPX			1221.34			57.10	74.00	76.50	18.2	16.5	16.0	2.0%

O – Outperform, M – Market-Perform, U – Underperform

Highlights

- Our project slippage analysis suggests that oil supply forecasts from industry consultants and industry bodies are far too optimistic, as they fail to take project delays into account. Additionally, if this trend continues, it is likely that these same analysts will always be waiting for significant new supply to come onto the market "next year", while in reality annual oil supply growth is likely to slow to just over 1% in the next decade.
- Additionally, this concept of project slippage will inevitably lead to the continued production and capex target misses for most of the Majors. This could lead to changes in production forecasts and earnings estimates following upcoming oil company strategy presentations. Furthermore, future projects in new regions or parts of existing developing basins (such as the deepwater), as well as projects using new technology aids, are more likely to slip going forward.
- Project slippage is also a global issue, as the slippage associated with the 40 oil projects we have analyzed will cumulatively account for a production "miss" of over 2Mbbl/d by 2007. This will be

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equivalent to 2.3% of global production in that year. Indeed it also goes a long way to explaining why the IEA supply forecasts have been overly optimistic in recent years.

- As the number of large volume projects increases within a Majors portfolio, the potential exists for longer delays in ultimate first oil. This is especially true for BP, and such a trend could put future oil production targets at risk. However, within the Majors' group there are significant differences. Overall the key theme is that a lack of detailed organization for development and management of multiple key projects will unquestionably cause slippage and potentially cost overruns.
- ExxonMobil come 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.

Investment Conclusion

Have you ever wondered why in recent years actual oil industry production has consistently fallen short of the industry's, consultants' and analysts' forecasts? Sure, the industry and the oil price bears can make excuses for the production growth shortfall due to the odd war, hurricane or strike, but in reality we think the answer is a lot simpler than that.

This industry is truly dreadful at project management, or at least at predicting the timing of project start-ups. The amount of production growth that has been lost to projects being delayed over the past few years is stunning, over 2Mbbl/d in 2007. It is also not a specific company problem either, although Shell with its highly published delays to Sakhalin and Bonga appears to be grabbing a lot of the headlines. BP appear to have a consistent delivery problem too, although you would never realize it from their strategy presentation until you dig deeper; Chevron is also gaining ground on it larger rivals around the world, and in a story sure to develop over the coming week ENI is likely to announce potential delays to the Kashagan project, pushing first production at least into 2009.

How many people believe a builder's estimate of when they will be finish a job on your house? The answer is no one, so maybe we are being too hard on the industry, maybe it is the investors and the analysts that are to blame for the slippage, or at least in part. One company stands out above all others on the slippage ranking, and for those that have not guessed already, it is ExxonMobil. ExxonMobil are not renowned for flashy presentations or stretched targets, and openly admit that, and because these projects are complex and large, they are conservative in their estimates of start-up time, hence less slippage. It appears that apart from ExxonMobil, companies appear all too eager to please the market rather than face reality. When a new, large development project is located in harsh terrain, or in the deepwater, and new technology is being piloted, it is pretty much guaranteed the project will take longer than the engineers think.

Putting this all together it appears that there is both a serious lack of project engineers in this industry and a significant move towards extreme projects using new technology. Coupled, this is a recipe for continued project slippage, continued optimistic oil production forecasts from the IEA and some industry "consultants", and inevitably, continued production and capex target misses from most of the Majors.

Details

Despite a number of well published delays and cost overruns to major oil industry projects recently, many other projects have had their planned start-up dates subtlety moved backwards. This intrigued us, as we

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thought if this was an industry issue it may go someway to explaining why the forecast growth of global oil supply and the production targets of the Majors have not lived up to expectations.

What we found, from the analysis of over 40 major projects that were originally meant to start production between 2003 and 2007, shocked us. Not only is project slippage as a concept damaging the production targets of oil companies, it is also a major global issue during such tight oil supply and demand conditions.

The data within this report is based on an extensive analysis of historic and recent company strategy presentations, press releases and industry papers. We do not attempt to capture all oil projects that came onstream, or are planned to come onstream, over the 2003-2007 period, but we have focused our attention on the large oil projects that should have the most impact on the industry. Secondly, we have concentrated on oil projects rather than on gas projects in this analysis, which may be unfair to a number of companies that have delivered significant gas projects on time, and on budget. Thirdly, in some cases we have had to use data, other than that officially supplied by the operator, for specific quarterly start-up times and production profiles.

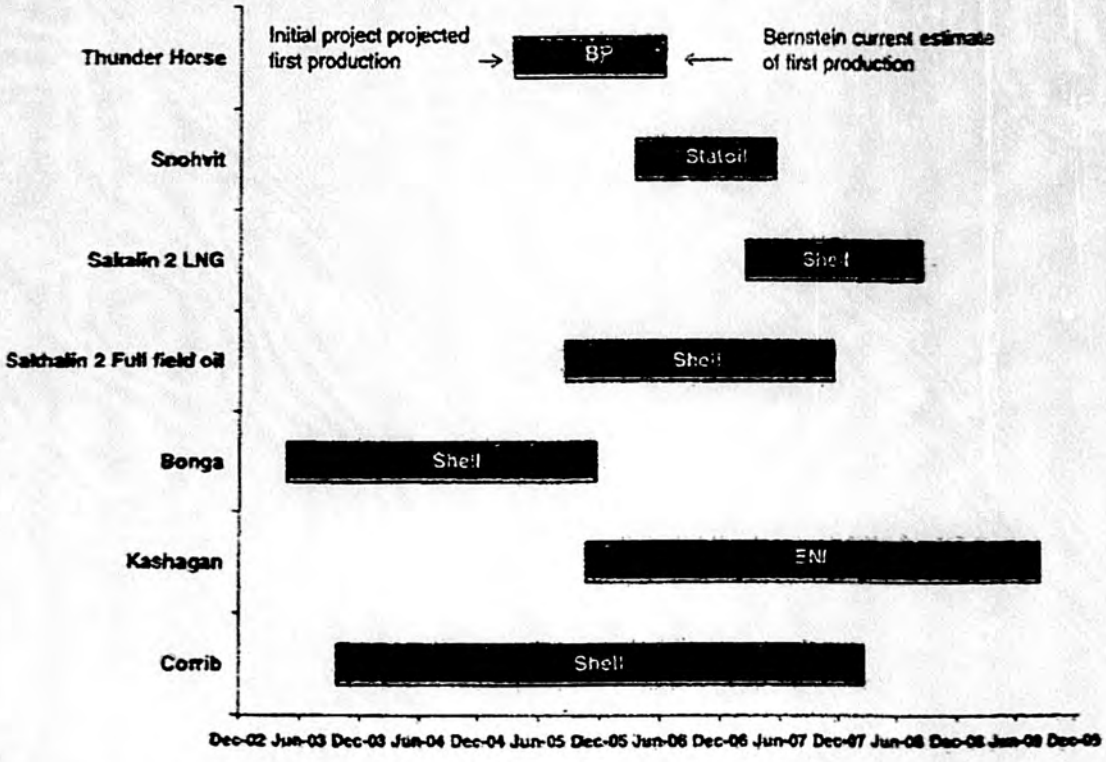
Oil companies, in particular, may feel that it is not fair associating the company with project delays that were caused by factors outside their control, such as weather conditions or political bureaucracy, but we would argue that this is simply the nature of the business. Therefore, although we may have many discussions following this report on the timing we have assigned to projects, based on the available company data, the bigger picture for the industry is very clear. Despite all these caveats the issue of project slippage is real and its impact will be especially felt over the coming two years when the world could well have used the oil production, which now has slipped into the future.

Project slippage is not a one-off story but an industry epidemic

We have all been guilty at some point of over promising and under delivering. Sometimes we get away with it, other times we do not. So far there have been a number of instances in the oil industry were production forecasts, based on the scheduling of large projects, have also led to substantial revisions to oil company production targets (or strategic indicators in BPs case!). Notably, BP's downward production forecast in 2002, which dogged the stock through most of 2003, was based on the timing of project start-ups. However, recently major project delays to Shell's Bonga and Sakhalin 2 projects have made the headlines, as could ENI's Kashagan project this week based on partners comments (**Exhibit 1**).

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Exhibit 1
Initial and revised startup times and degree of slippage for some recent that have slipped



Source: Company reports, press releases, Bernstein Estimates

We looked at 40 oil projects that were meant to start up originally between 2003 and 2007 (**Exhibit 2**). In this analysis we have concentrated on large oil projects that should have the most impact on production growth rates in the industry and on global supply. Although many of the projects have only slipped less than a year, due to the seasonality of oil demand and the time taken for production ramp-up even a six month slippage on a large project can have implications for the growth or decline rates within a basin.

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Exhibit 2
Delays to key projects being undertaken by the Majors

Projects which have significant slippage

Project name	Operator	Project name	Operator
Sakhalin 2 Full field oil	Shell	Tengiz Extension	Chevron
Bonga	Shell	Usan	TOTAL
Agbami	Chevron	Banyu Urip (Cepu)	ExxonMobil
Thunder Horse	BP	Elephant	ENI
Greater Plutonio	BP	Moho Bilondo	TOTAL
Kashagan	ENI	Bonga SW/Aparo area	Shell
In Amenas	BP	Akpo	TOTAL
Skarv	BP		
Shah Deniz	BP		
Rhum	BP		
Rosa	TOTAL		

Projects on time or slippage < 1 year

Project name	Operator	Project name	Operator
Erha	ExxonMobil	Sunrnont	ConocoPhillips
ACG 1	BP	Athabasca	Shell
Atlantis	BP	Abo	ENI
Clair	BP	Sakhalin 1 oil	ExxonMobil
Holstein	BP	Kizomba C	ExxonMobil
Kizomba A	ExxonMobil	Full Field Doba	ExxonMobil
Kizomba B	ExxonMobil	Grane	Norsk Hydro
Mad Dog	BP	Kristen	Statoil
Nakika	Shell	Bemboco/Sanha	Chevron
Dalia	TOTAL	BBLT	Chevron
Kizomba	ExxonMobil	Bayu Undan	ConocoPhillips

Source: Company reports, press releases, Bernstein Estimates

Additionally, although we have tried to use the operator's current estimate of start-up, or in a number of cases our estimate if it is clear from the presentations of partners that the project is no longer going to be delivered on time, we suspect many large projects will slip further, building on the current problem. In future reports we will update this slippage database and also look into the slippage in significant gas projects as well as the specific impact of slippage on oil company production targets and earnings forecasts.

Project slippage has not only impacted company targets but also global oil production growth

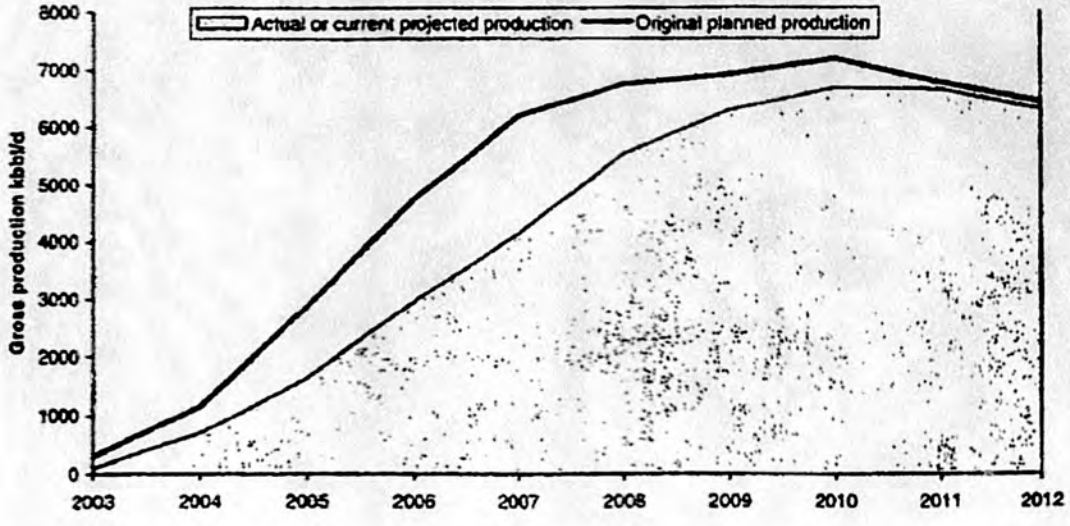
Due to the piecemeal way in which news of project delays are released to the market, it is easy to dismiss the impact of each individual news event on the global supply balance. However, our analysis suggests that project slippage is, in aggregate, having a dramatic impact on global supply and can to a large extent help explain consistently disappointing global supply growth relative to expectations over the last few years.

The slippage associated with the 40 projects we have analyzed will cumulatively account for a production "miss" of over 2Mbbl/d by 2007 (**Exhibit 3**). This will be equivalent to 2.3% of global production in that year (**Exhibit 4**). This figure is even more startling when placed in the context of global spare production capacity. We estimate that OPEC spare capacity will have fallen to 2.5Mbbl/d in 2007 from 4Mbbl/d in 2003, presuming we see a drop in demand caused by high prices between now and 2007. Had these 40 projects been delivered on time, there is the possibility that spare capacity could actually have expanded over that time frame to 4.5Mbbl/d. More to the point, if that had been the case, spare capacity would currently be at a far more comfortable level of 2.6Mbbl/d versus the actual cushion of just 1.3Mbbl/d. Thus, it could be argued that this effect has been a direct, contributory driver of current oil prices.

As an aside, it is worth noting that exhibits 3 and 4 do not imply that this is a temporary effect. We have only considered projects which were originally slated to start production some time between 2003 and 2007. While we estimate that the cumulative slippage associated with these projects will start to reverse from 2008 onwards, there will, by this time, be new slippage in evidence associated with projects originally slated to start in 2008 and beyond. Consequently, if we were able to track slippage on all future projects, and if current slippage trends continue on future developments, exhibit 3 would show an ever expanding divergence between production expectations and actual production.

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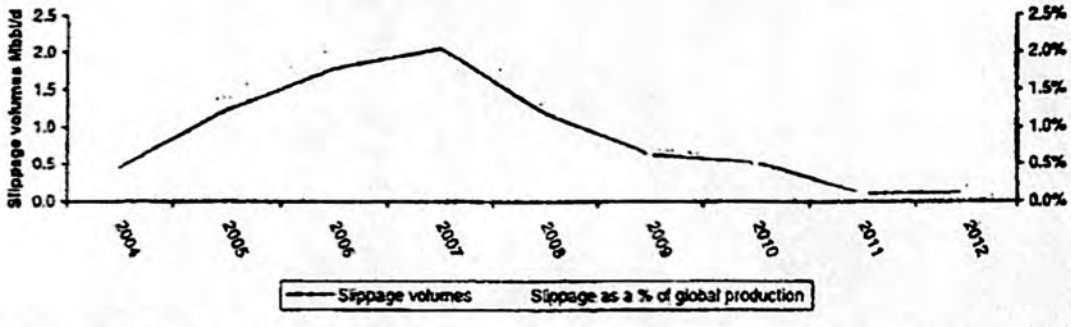
Exhibit 3
Cumulative production discrepancy between original expectations and actual delivery of the 40 projects analyzed



Source: Company reports, press releases, Bernstein Estimates

This analysis suggests that recent publication from industry consultants and industry bodies are far too optimistic as they have both failed to take this effect into account. Additionally, if this trend continues, it is likely that these same analysts will always be waiting for significant new supply to come onto the market "next year", while in reality annual oil supply growth is likely to slow to just over 1% in the next decade.

Exhibit 4
Cumulative production discrepancy and as a % of global production



Source: Company reports, press releases, Bernstein Estimates

The IEA provides us with good evidence that supply forecasts have indeed been overly optimistic in recent years, and that this is a relatively new phenomenon. In particular, this trend is evidenced through an analysis of IEA revisions over time. In the past, revisions made by the IEA to forecasts of non-OPEC supply have been directly driven by the oil price as would be logical (Exhibit 5). As prices went up, so future supply estimates were revised up and vice-versa. This relationship was particularly strong in the 1990's and held, although to a lesser extent, up until 2003. Since then the IEA has consistently had to revise

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down its estimates of future supply despite a steadily increasing oil price. This effect is even more visible when restricting the forecast to non-OPEC, non-FSU supply (Exhibit 5).

Poor exploration success cannot account for this discrepancy due to the long lag time from discovery to first production, and the fact that the IEA forecasts only look out as far as a year and a half. Instead, we believe that project slippage has been a large driver of this divergence.

Exhibit 5
IEA Non-OPEC supply revisions versus WTI price



Source: IEA, Bloomberg, Bernstein Estimates

Key observations surrounding project slippage

From our analysis of some of the key oil projects being undertaken by the Majors it appears that a concerning theme is apparent. The crux of the problem is the susceptibility of previously un-chartered projects to delays. Indeed, slippage is now occurring across the spectrum of projects types, but in particular, projects in new regions or parts of existing developing basins (such as the deepwater), as well as projects using new technology aids, are more likely to slip.

There is no doubt that projects such as Kashagan or Bonga are significantly challenging projects, which take years of design time before they are sanctioned by various internal management levels. However, while attempting to get projects sanctioned to maintain strong project pipelines, we believe that oversights are being made. Specifically, projects which have not been the subject of rigorous review during the FEED (Front End Engineering and Design) phase are prone to poor project definition prior to sanction and hence are subject to delays. This is evident in the announced delay to Statoil's Snøhvit field last week, which cited engineering design changes as partly to blame for the cost extensions and time delays.

Before considering reasons why slippage of key projects is occurring it is worth noting that slippage on individual projects does tend to vary widely (Exhibit 6) and there is no clear trend that slippage increase with project size. However, slippage does trends upward with the increased number of managed projects or volumes (Exhibit 7). As a result we can now look at the problem to see what is causing these effects and which of the Majors is more impacted than others.

Developments costs are particularly affected by the experience of the lead operator. Specifically, a lead operator exposed to a new region, testing a new design solution with a high level of front end loading

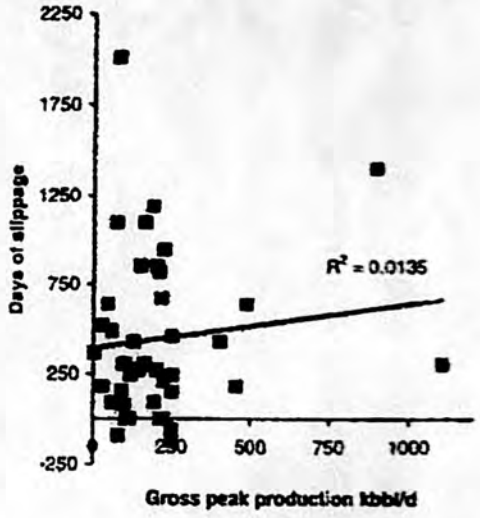
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without sufficient learning time, notoriously ends up with project slippage in the form of increased cost and time.

Furthermore, unique FPSO project solutions, such as the Bonga field tend to have a higher slippage levels than other deepwater concept types, unless ExxonMobil's design one, build many approach is used. Indeed, FPSO solutions appear to be used where rapid projected production growth was targeted, and if not properly managed with a clear plan of what the shipbuilder is meant to do, they can go badly wrong.

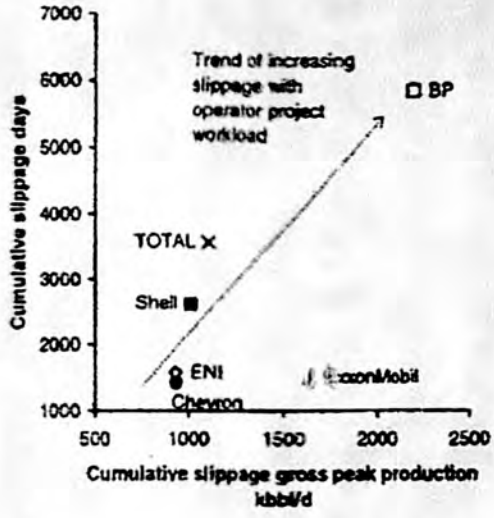
Moreover, project definition and management throughout the lifetime of a project has a significant effect on schedule slippage and cost overruns on new projects, with centrally managed projects, using a development organization, often outperforming those where disperse regional teams are solely responsible for delivery.

Exhibit 6
Slippage days on individual projects can vary widely ...



Source: Bernstein Estimates

Exhibit 7
... but cumulative projects by individual companies tend to equate to longer slippage delays



Source: Bernstein Estimates

Also evident in our analysis is the fact that projects in emerging oil regions such as West Africa, Caspian, Sakhalin are also more likely to slip primarily due to the government interference, with subsequent delays over which the company's have no control. With the recent tax changes in Russia, Venezuela and Bolivia this problem is likely to manifest itself in additional costs as well as time delays, while we expect increasing involvement by the state-owned oil companies of host nations in key projects. Furthermore, this does not bode well for the major deepwater projects in development off Brazil, Indonesia, Nigeria, Angola and Equatorial Guinea. It also appears that the governments of many countries with production sharing agreements are slowing down the pace of project approval, as with high oil prices their budgets are not under pressure and they want to make sure the oil company is not over spending on the project leading to less tax revenue.

Who are the best ... and the worst at project management?

As we have seen above, as the number of large volume projects increases within a Majors portfolio, the potential exists for longer delays in ultimate first oil, this is especially true for BP and such a trend could put future oil production targets at risk (**Exhibit 7**). However, within the Majors group there are significant

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differences. Overall the key theme is that a lack of detailed organization for development and management of multiple key projects will unquestionably cause slippage, as is the case within BP's portfolio. Specifically, in projects where BP acts as lead operator, we see an increased occurrence of project slippage, which is likely to turn into cost overruns as well.

ExxonMobil come 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, utilizing all ExxonMobil business functions along the way. With a tried and tested project plan which progresses ideas through technology, finance, execution, operations and marketing, the company manages to avoid costly delays. Noteworthy is how this series of project steps successfully allowed ExxonMobil to win a key $7Bn GTL project with the Qatari government in July 2004, one of the few projects in that year which were not subject to government imposed delays!

Key lessons that need to be learned by the industry

We see a number of key lessons to be learned from this analysis which could help diminish the potential for project slippage. Primarily they reside in the setting up of internal development organization who assume responsibility for delivery and ensuring that realistic front end loading, project execution planning and implementation are conducted and not fast tracked. As a result, realistic targets are set which investors can grasp and accept.

Additionally, the Majors are being forced into increasingly riskier environments which require risk and financing to be shared. However, in these environments management must ensure their risk management simulations conducted at the outset are inclusive of how conservative a potential partner is historically. We believe this and a joint concerted planning phase will lead to an improvement in the successful delivery of today's and tomorrows critical projects.

Finally, when communicating project start-up times externally companies should be more realistic with project schedules both to avoid slippage and changes to production targets, and allow industry observers a chance at predicting forward oil supply growth more accurately.

Valuation Methodology

The Global Integrated Oils preferred year forward target price methodology is derived from 12 months forward relative PE multiples versus through cycle ROACE. The relative PE multiple to the S&P is calculated off our 2006 estimated earnings and the through cycle ROACE, assuming investors continue to reward companies with higher returns as has been the case historically. Based on this methodology all companies have upside potential, as they lie below the industry through cycle valuation line. We use $58/bbl WTI and $8.41/mcf for US gas in 2005, with $55/bbl and $7.97/mcf for US gas in 2006, and $45/bbl in 2007 inflated at 8-14% thereafter.

Risks

It is possible that a larger sample size of projects may reveal slightly different results than presented here, although we believe we have selected the largest oil projects that should have the most impact on the industry. Further alternative interpretations of our conclusions are described in the details section above.

Disclosure Appendix

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Alaska Natural Gas Pipeline Project

Getting Alaska's Gas to Market

House Oil and Gas Committee

March 26, 2007

bp

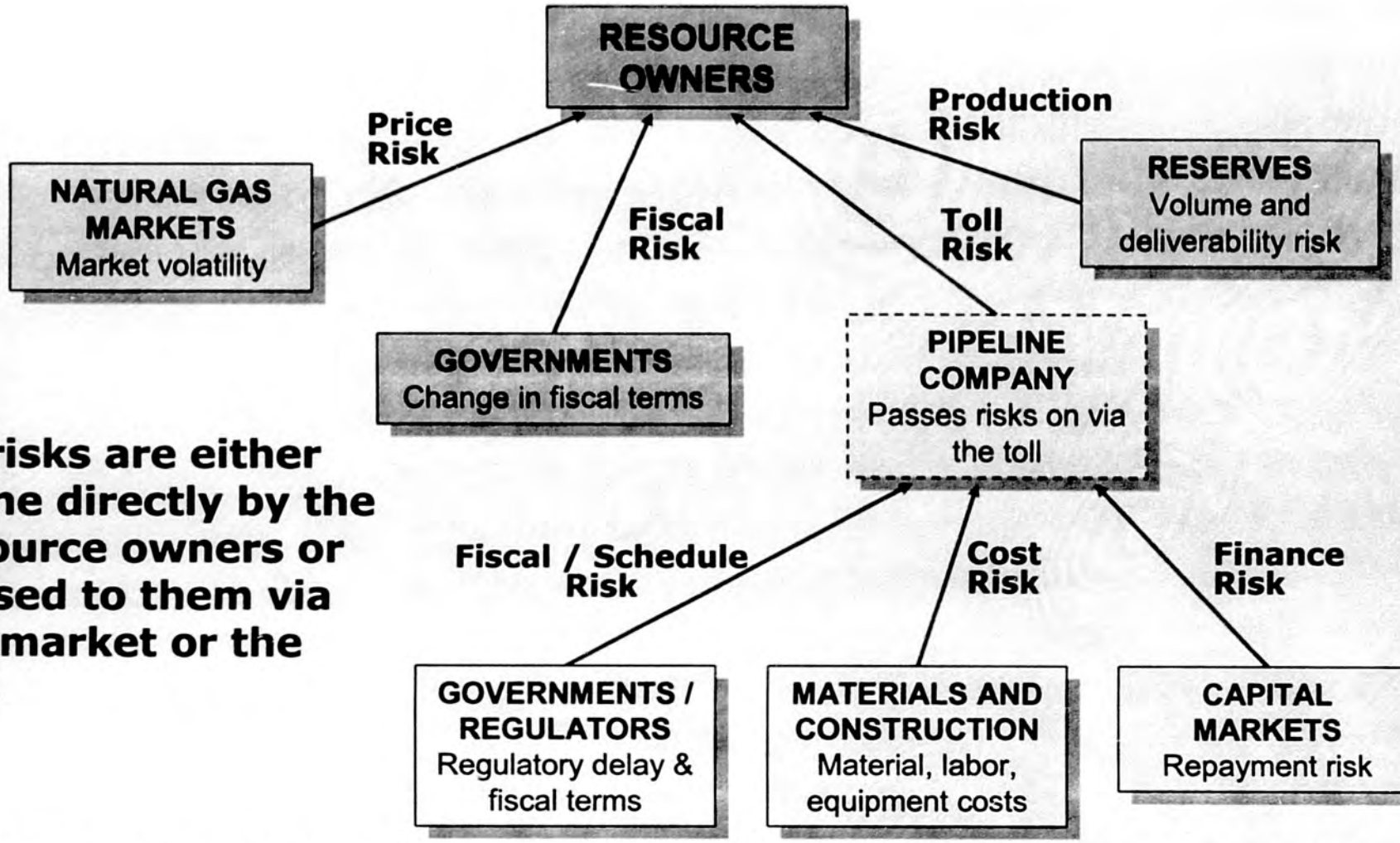
BP Key Messages

- BP wants and needs a gas pipeline
- We support Governor Palin's desire to get Alaska's gas to market
- We are concerned that AGIA as drafted creates some unintended consequences

Key Concerns to Address

- AGIA would result in an exclusive winner before any work is done; based on promises, not performance
- AGIA requires base shippers to subsidize expansion shippers, which adds risk to the pipeline
- Inducements could be suggested by project sponsors, rather than stipulated in advance
  - $500m may attract underfinanced sponsors
- Solving resource issues with clarity enables a successful open season which is the key to advancing the project

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
- Upstream framework is critical
  - Must be addressed for a successful open season
- Key midstream issues must be addressed to ensure there are no unintended consequences
  - Granting an exclusive license before any work is performed prevents participation of others and reduces competition
  - "Inducements" should be based on performance, not promises

AGIA Testimony

INTRODUCTION

Good morning Representative Kohring and members of the House Oil and Gas Committee. My name is Marty Massey. I am the U.S. Joint Interest Manager for ExxonMobil, a position I have held since November 2001, and I am responsible for the commercialization of 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 of hydrocarbons 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 relationship for another 50 years or more.

EXXONMOBIL READY TO PROGRESS PROJECT

With that introduction, I would like take a moment to emphasize the importance of the Alaska Gas Pipeline project to Alaska, to ExxonMobil, and to our nation. 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. ExxonMobil supports efforts to advance a pipeline project and we are ready to work with Governor Palin and her cabinet and with the Legislature to move forward the Alaska gas pipeline project.

Let me demonstrate the importance of this project to ExxonMobil. It 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 are obviously very interested in progressing it.

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.

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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 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.

HOW PIPELINES ARE FINANCED AND WHO BEARS PROJECT RISKS

Let me now make a few comments on how projects are financed and who bears the risks. 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 (often abbreviated and called FT) are binding obligations made by companies (known as "shippers") to pay for the cost of reserving a quantity of gas capacity 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.

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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 transportation 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.

IMPORTANCE OF STATE / PRODUCER ALIGNMENT AND BENEFITS OF THE 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. Over time, development costs are 25% lower than industry average on a $/barrel basis. 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)

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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. Our Arctic offshore activity started in 1966 with the installation of the ice resistant Granite Point platform in Alaska's Cook Inlet, which is still producing oil. In the 1970's we provided a significant amount of research and engineering for the Prudhoe Bay project, where our completion designs for permafrost were of key importance to the project. We also developed the combined hydraulic flow model and thermal simulator on which the design of TAPS was based. In 1984, we installed the Concrete Island Drilling System (CIDS) to drill exploration wells in the Alaska Beaufort Sea. This was the first mobile drilling platform to operate in the ice covered waters of the Beaufort. In addition to our Arctic experience in Alaska, ExxonMobil also has extensive Arctic experience in Canada, developing the Norman Wells Field in the Mackenzie River area near the Arctic Circle. Offshore Newfoundland, we completed the Hibernia platform, the first and only iceberg resistant offshore structure in the world. In Russia, we recently started up the Sakhalin 1 development which involved an offshore drilling platform where CIDS was reused and renamed Orlan, an onshore drillsite where we have set new industry limits for extended reach drilling, an onshore oil and gas plant with a capacity of 250,000 barrels per day, and purpose built tankers which are used year-round. All of this work is being done in an arctic and seismically-active area. At Sakhalin we are currently producing 250,000 barrels of oil per day.. I hope you see from these examples that large projects with significant complexity are what we do and we are extremely qualified to take on this work.

These successful efforts were 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.

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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, results 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.

IMPORTANCE OF FISCAL STABILITY

For us to progress the project and mitigate its inherent risks, we do need some things from the State. Because of the nature and magnitude of the risks associated with this project – 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. As with all of our other mega-project investments, and we share this with the resource owners where those investments are to be made, 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 hub. 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 ten or more 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

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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.

SPECIFIC FEEDBACK ON AGIA

With that background, I would like to now give some feedback on AGIA which is based on the conclusions and principles I've mentioned. I will also outline our 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.

Also, it is important that AGIA allow applicants to define how they could achieve the State's key objectives rather than prescribing specific requirements that must be met. To ensure the best result, AGIA should establish br ad key objectives and allow applicants flexibility in meeting those objectives by providing requirements they feel are necessary to make the project commercially viable. For example, we think it would be better to let the applicant determine whether or not they require any capital contribution from the State.

ExxonMobil recognizes the importance to the State, explorers and others of having access to the project so their gas can be treated and transported to markets. To ensure that a project is constructed, it must be commercially attractive to shippers at the time they make their initial firm transportation commitments. Shippers, particularly those who must invest substantially to explore for, develop and produce gas resources, will not be willing to enter into long-term financial commitments for the transportation of gas if they believe there is a substantial likelihood that their initial rates will be significantly increased in the future in order to accommodate expansions.

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Under the Alaska Natural Gas Pipeline Act, Congress struck what it determined was the proper balance between encouraging investment by those willing to commit to pay for initial capacity and encouraging exploration by providing an opportunity for future access to the pipeline. Because of the unique nature of the Alaska gas pipeline project, FERC approved unprecedented policies to enable a FERC-mandated expansion to benefit explorers.

The issue of how potential future shippers may access initial capacity and future expansion capacity, if needed, should be administered by the FERC for all elements of the project in the United States. For example, shippers (producers) should not be required to subsidize other expansion gas holders (competitors) at 115% of initial maximum rates due to a mandated roll-in of expansion costs. For example this 15% increase could increase my FT commitment by 30 to 50 cents per MBTU on gas shipped. This is an increased cost of $500 to $800 million per year on the initial shippers. You could also consider this a subsidy to the expansion shipper. We are not in the business of subsidizing our competitors. This is too high of a risk to take. In addition, the pipeline entity should not be required to accept a FERC certificate irrespective of FERC imposed conditions.

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 necessary 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 producer's 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 their requirements now creates significant uncertainty. AGIA also does not establish criteria for evaluating proposals and selecting the successful bidder, which is likely to lead to litigation from project proponents not selected for inducements.

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.

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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 the broad objectives the State wants to achieve and allow each applicant to decide how best to meet those objectives and to identify what is required from the State to advance the project. The State can then accept the proposal that delivers the most value. We are ready to participate in a competitive open 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.

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BERNSTEIN RESEARCH CALL

Global Integrated Oils: Project Slippage - the reason why future optimistic oil supply outlooks are likely to be wrong

Ticker	Rating	CUR	20/09/2005 Closing Price	Target Price	YTD Rel. Perf.	EPS 2004A	EPS 2005E	EPS 2006E	P/E 2004A	P/E 2005E	P/E 2006E	Yield
BP/.LN	O	GBp	661.00	725.00	29.3%	39.00	61.82	56.81	16.9	10.7	11.6	2.6%
BP	O	USD	71.40	78.00	21.5%	4.47	6.77	6.10	16.0	10.5	11.7	2.4%
COP	O	USD	68.90	76.00	57.9%	5.95	8.15	7.72	11.6	8.5	8.9	2.9%
CVX	O	USD	64.04	73.00	21.2%	5.47	7.02	6.55	11.7	9.1	9.8	2.5%
ENI.IM	M	EUR	24.85	27.00	34.1%	1.80	2.69	2.68	13.8	9.2	9.3	3.0%
E	M	USD	150.70	167.00	19.0%	12.50	16.91	16.34	12.1	8.9	9.2	3.0%
FP.FP	O	EUR	222.80	262.00	37.9%	14.07	21.22	20.64	15.8	10.5	10.8	2.2%
TOT	O	USD	134.77	160.00	21.9%	9.31	13.36	12.59	14.5	10.1	10.7	2.3%
RDSA.LN	M	GBp	1838.00	2070.00	0.0%	0	185.50	194.16	NM	9.9	9.5	3.5%
RDSB.LN	M	GBp	1915.00	2070.00	0.0%	0	185.50	194.16	NM	10.3	9.9	3.3%
RDSA.NA	M	EUR	27.26	30.00	0.0%	0	2.69	2.85	NM	10.1	9.6	3.4%
RDSB.NA	M	EUR	28.65	30.00	0.0%	0	2.69	2.85	NM	10.7	10.1	3.2%
RDS/A	M	USD	65.76	76.00	0.0%	0	6.77	6.96	NM	9.7	9.4	3.4%
RDS/B	M	USD	68.83	76.00	0.0%	0	6.77	6.96	NM	10.2	9.9	3.2%
XOM	O	USD	64.53	75.00	25.1%	3.69	5.20	4.90	17.5	12.4	13.2	1.7%
SPX			1221.34			67.10	74.00	76.50	18.2	16.5	16.0	2.0%

O – Outperform, M – Market-Perform, U – Underperform

Highlights

- Our project slippage analysis suggests that oil supply forecasts from industry consultants and industry bodies are far too optimistic, as they fail to take project delays into account. Additionally, if this trend continues, it is likely that these same analysts will always be waiting for significant new supply to come onto the market "next year", while in reality annual oil supply growth is likely to slow to just over 1% in the next decade.
- Additionally, this concept of project slippage will inevitably lead to the continued production and capex target misses for most of the Majors. This could lead to changes in production forecasts and earnings estimates following upcoming oil company strategy presentations. Furthermore, future projects in new regions or parts of existing developing basins (such as the deepwater), as well as projects using new technology aids, are more likely to slip going forward.
- Project slippage is also a global issue, as the slippage associated with the 40 oil projects we have analyzed will cumulatively account for a production "miss" of over 2Mbbl/d by 2007. This will be

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equivalent to 2.3% of global production in that year. Indeed it also goes a long way to explaining why the IEA supply forecasts have been overly optimistic in recent years.

- As the number of large volume projects increases within a Majors portfolio, the potential exists for longer delays in ultimate first oil. This is especially true for BP, and such a trend could put future oil production targets at risk. However, within the Majors' group there are significant differences. Overall the key theme is that a lack of detailed organization for development and management of multiple key projects will unquestionably cause slippage and potentially cost overruns.
- ExxonMobil come 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.

Investment Conclusion

Have you ever wondered why in recent years actual oil industry production has consistently fallen short of the industry's, consultants' and analysts' forecasts? Sure, the industry and the oil price bears can make excuses for the production growth shortfall due to the odd war, hurricane or strike, but in reality we think the answer is a lot simpler than that.

This industry is truly dreadful at project management, or at least at predicting the timing of project start-ups. The amount of production growth that has been lost to projects being delayed over the past few years is stunning, over 2Mbbl/d in 2007. It is also not a specific company problem either, although Shell with its highly published delays to Sakhalin and Bonga appears to be grabbing a lot of the headlines. BP appear to have a consistent delivery problem too, although you would never realize it from their strategy presentation until you dig deeper; Chevron is also gaining ground on it larger rivals around the world, and in a story sure to develop over the coming week ENI is likely to announce potential delays to the Kashagan project, pushing first production at least into 2009.

How many people believe a builder's estimate of when they will be finish a job on your house? The answer is no one, so maybe we are being too hard on the industry, maybe it is the investors and the analysts that are to blame for the slippage, or at least in part. One company stands out above all others on the slippage ranking, and for those that have not guessed already, it is ExxonMobil. ExxonMobil are not renowned for flashy presentations or stretched targets, and openly admit that, and because these projects are complex and large, they are conservative in their estimates of start-up time, hence less slippage. It appears that apart from ExxonMobil, companies appear all too eager to please the market rather than face reality. When a new, large development project is located in harsh terrain, or in the deepwater, and new technology is being piloted, it is pretty much guaranteed the project will take longer than the engineers think.

Putting this all together it appears that there is both a serious lack of project engineers in this industry and a significant move towards extreme projects using new technology. Coupled, this is a recipe for continued project slippage, continued optimistic oil production forecasts from the IEA and some industry "consultants", and inevitably, continued production and capex target misses from most of the Majors.

Details

Despite a number of well published delays and cost overruns to major oil industry projects recently, many other projects have had their planned start-up dates subtlety moved backwards. This intrigued us, as we

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thought if this was an industry issue it may go someway to explaining why the forecast growth of global oil supply and the production targets of the Majors have not lived up to expectations.

What we found, from the analysis of over 40 major projects that were originally meant to start production between 2003 and 2007, shocked us. Not only is project slippage as a concept damaging the production targets of oil companies, it is also a major global issue during such tight oil supply and demand conditions.

The data within this report is based on an extensive analysis of historic and recent company strategy presentations, press releases and industry papers. We do not attempt to capture all oil projects that came onstream, or are planned to come onstream, over the 2003-2007 period, but we have focused our attention on the large oil projects that should have the most impact on the industry. Secondly, we have concentrated on oil projects rather than on gas projects in this analysis, which may be unfair to a number of companies that have delivered significant gas projects on time, and on budget. Thirdly, in some cases we have had to use data, other than that officially supplied by the operator, for specific quarterly start-up times and production profiles.

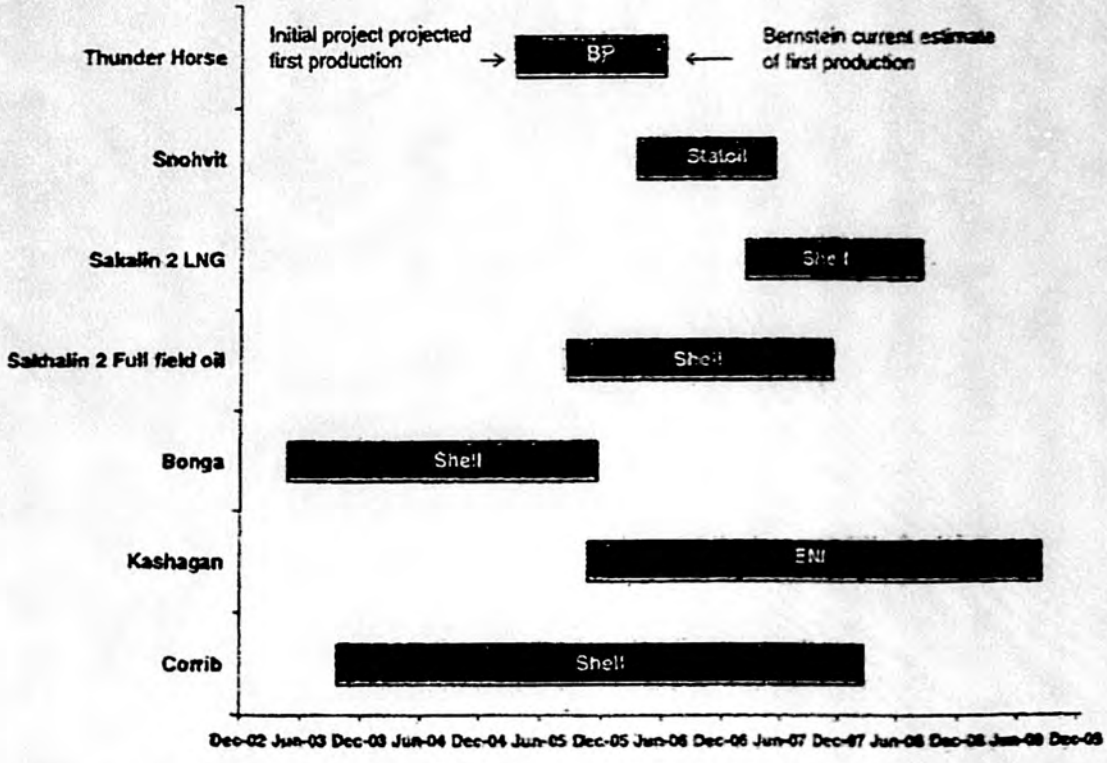
Oil companies, in particular, may feel that it is not fair associating the company with project delays that were caused by factors outside their control, such as weather conditions or political bureaucracy, but we would argue that this is simply the nature of the business. Therefore, although we may have many discussions following this report on the timing we have assigned to projects, based on the available company data, the bigger picture for the industry is very clear. Despite all these caveats the issue of project slippage is real and its impact will be especially felt over the coming two years when the world could well have used the oil production, which now has slipped into the future.

Project slippage is not a one-off story but an industry epidemic

We have all been guilty at some point of over promising and under delivering. Sometimes we get away with it, other times we do not. So far there have been a number of instances in the oil industry were production forecasts, based on the scheduling of large projects, have also led to substantial revisions to oil company production targets (or strategic indicators in BPs case!). Notably, BP's downward production forecast in 2002, which dogged the stock through most of 2003, was based on the timing of project start-ups. However, recently major project delays to Shell's Bonga and Sakhalin 2 projects have made the headlines, as could ENI's Kashagan project this week based on partners comments (**Exhibit 1**).

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Exhibit 1
Initial and revised startup times and degree of slippage for some recent that have slipped



Source: Company reports, press releases, Bernstein Estimates

We looked at 40 oil projects that were meant to start up originally between 2003 and 2007 (**Exhibit 2**). In this analysis we have concentrated on large oil projects that should have the most impact on production growth rates in the industry and on global supply. Although many of the projects have only slipped less than a year, due to the seasonality of oil demand and the time taken for production ramp-up even a six month slippage on a large project can have implications for the growth or decline rates within a basin.

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Exhibit 2
Delays to key projects being undertaken by the Majors

Projects which have significant slippage

Project name	Operator	Project name	Operator
Sakhalin 2 Full field oil	Shell	Tengiz Extension	Chevron
Bonga	Shell	Usan	TOTAL
Agbami	Chevron	Banyu Urip (Cepu)	ExxonMobil
Thunder Horse	BP	Elephant	ENI
Greater Plutonio	BP	Moho Bilondo	TOTAL
Kashagan	ENI	Bonga SW/Aparo area	Shell
In Amenas	BP	Akpo	TOTAL
Skarv	BP		
Shah Deniz	BP		
Rhum	BP		
Rosa	TOTAL		

Projects on time or slippage < 1 year

Project name	Operator	Project name	Operator
Erha	ExxonMobil	Sturmont	ConocoPhillips
ACG 1	BP	Athabasca	Shell
Atlantis	BP	Abo	ENI
Clair	BP	Sakhalin 1 oil	ExxonMobil
Holstein	BP	Kizomba C	ExxonMobil
Kizomba A	ExxonMobil	Full Field Doba	ExxonMobil
Kizomba B	ExxonMobil	Grane	Norsk Hydro
Mad Dog	BP	Kristen	Statoil
Nakika	Shell	Bemboca/Sanha	Chevron
Dalia	TOTAL	BBLT	Chevron
Xikomba	ExxonMobil	Bayu Undan	ConocoPhillips

Source: Company reports, press releases, Bernstein Estimates

Additionally, although we have tried to use the operator's current estimate of start-up, or in a number of cases our estimate if it is clear from the presentations of partners that the project is no longer going to be delivered on time, we suspect many large projects will slip further, building on the current problem. In future reports we will update this slippage database and also look into the slippage in significant gas projects as well as the specific impact of slippage on oil company production targets and earnings forecasts.

Project slippage has not only impacted company targets but also global oil production growth

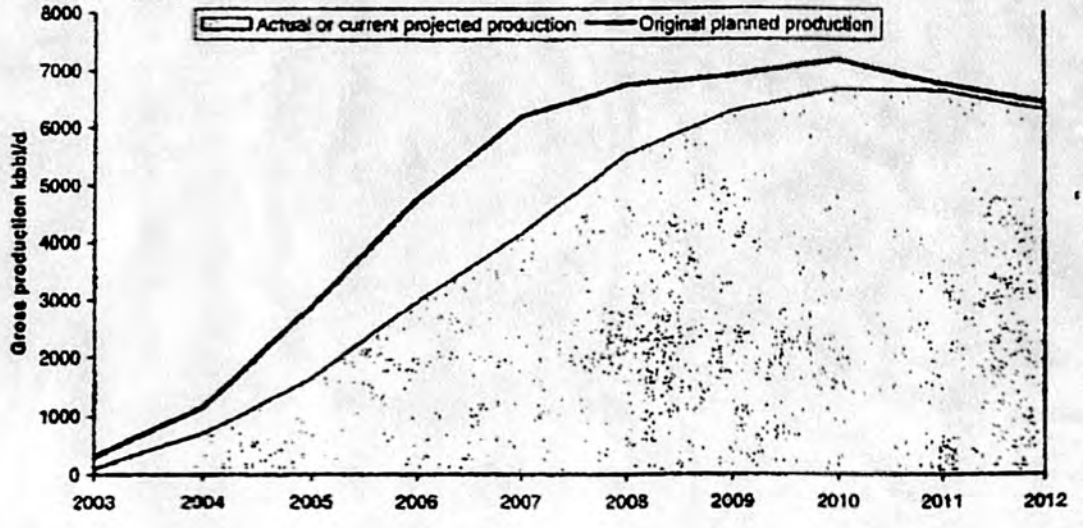
Due to the piecemeal way in which news of project delays are released to the market, it is easy to dismiss the impact of each individual news event on the global supply balance. However, our analysis suggests that project slippage is, in aggregate, having a dramatic impact on global supply and can to a large extent help explain consistently disappointing global supply growth relative to expectations over the last few years.

The slippage associated with the 40 projects we have analyzed will cumulatively account for a production "miss" of over 2Mbbl/d by 2007 (**Exhibit 3**). This will be equivalent to 2.3% of global production in that year (**Exhibit 4**). This figure is even more startling when placed in the context of global spare production capacity. We estimate that OPEC spare capacity will have fallen to 2.5Mbbl/d in 2007 from 4Mbbl/d in 2003, presuming we see a drop in demand caused by high prices between now and 2007. Had these 40 projects been delivered on time, there is the possibility that spare capacity could actually have expanded over that time frame to 4.5Mbbl/d. More to the point, if that had been the case, spare capacity would currently be at a far more comfortable level of 2.6Mbbl/d versus the actual cushion of just 1.3Mbbl/d. Thus, it could be argued that this effect has been a direct, contributory driver of current oil prices.

As an aside, it is worth noting that exhibits 3 and 4 do not imply that this is a temporary effect. We have only considered projects which were originally slated to start production some time between 2003 and 2007. While we estimate that the cumulative slippage associated with these projects will start to reverse from 2008 onwards, there will, by this time, be new slippage in evidence associated with projects originally slated to start in 2008 and beyond. Consequently, if we were able to track slippage on all future projects, and if current slippage trends continue on future developments, exhibit 3 would show an ever expanding divergence between production expectations and actual production.

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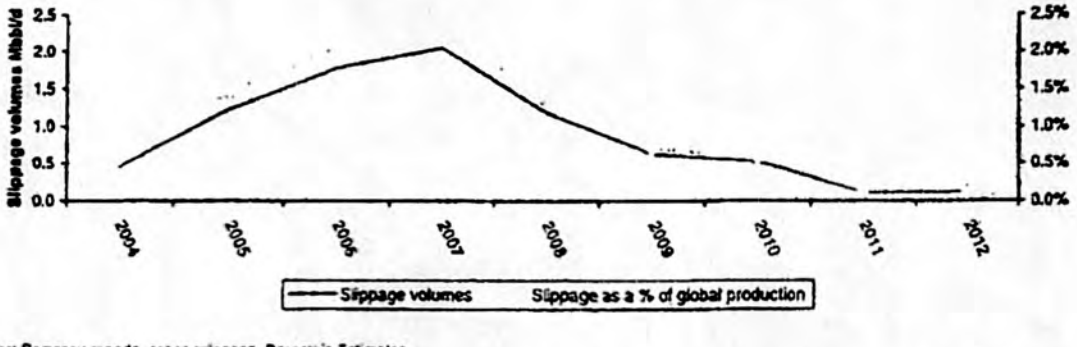
Exhibit 3
Cumulative production discrepancy between original expectations and actual delivery of the 40 projects analyzed



Source: Company reports, press releases, Bernstein Estimates

This analysis suggests that recent publication from industry consultants and industry bodies are far too optimistic as they have both failed to take this effect into account. Additionally, if this trend continues, it is likely that these same analysts will always be waiting for significant new supply to come onto the market "next year", while in reality annual oil supply growth is likely to slow to just over 1% in the next decade.

Exhibit 4
Cumulative production discrepancy and as a % of global production



Source: Company reports, press releases, Bernstein Estimates

The IEA provides us with good evidence that supply forecasts have indeed been overly optimistic in recent years, and that this is a relatively new phenomenon. In particular, this trend is evidenced through an analysis of IEA revisions over time. In the past, revisions made by the IEA to forecasts of non-OPEC supply have been directly driven by the oil price as would be logical (Exhibit 5). As prices went up, so future supply estimates were revised up and vice-versa. This relationship was particularly strong in the 1990's and held, although to a lesser extent, up until 2003. Since then the IEA has consistently had to revise

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down its estimates of future supply despite a steadily increasing oil price. This effect is even more visible when restricting the forecast to non-OPEC, non-FSU supply (Exhibit 5).

Poor exploration success cannot account for this discrepancy due to the long lag time from discovery to first production, and the fact that the IEA forecasts only look out as far as a year and a half. Instead, we believe that project slippage has been a large driver of this divergence.

Exhibit 5
IEA Non-OPEC supply revisions versus WTI price



Source: IEA, Bloomberg, Bernstein Estimates

Key observations surrounding project slippage

From our analysis of some of the key oil projects being undertaken by the Majors it appears that a concerning theme is apparent. The crux of the problem is the susceptibility of previously un-chartered projects to delays. Indeed, slippage is now occurring across the spectrum of projects types, but in particular, projects in new regions or parts of existing developing basins (such as the deepwater), as well as projects using new technology aids, are more likely to slip.

There is no doubt that projects such as Kashagan or Bonga are significantly challenging projects, which take years of design time before they are sanctioned by various internal management levels. However, while attempting to get projects sanctioned to maintain strong project pipelines, we believe that oversights are being made. Specifically, projects which have not been the subject of rigorous review during the FEED (Front End Engineering and Design) phase are prone to poor project definition prior to sanction and hence are subject to delays. This is evident in the announced delay to Statoil's Snohvit field last week, which cited engineering design changes as partly to blame for the cost extensions and time delays.

Before considering reasons why slippage of key projects is occurring it is worth noting that slippage on individual projects does tend to vary widely (Exhibit 6) and there is no clear trend that slippage increase with project size. However, slippage does trends upward with the increased number of managed projects or volumes (Exhibit 7). As a result we can now look at the problem to see what is causing these effects and which of the Majors is more impacted than others.

Developments costs are particularly affected by the experience of the lead operator. Specifically, a lead operator exposed to a new region, testing a new design solution with a high level of front end loading

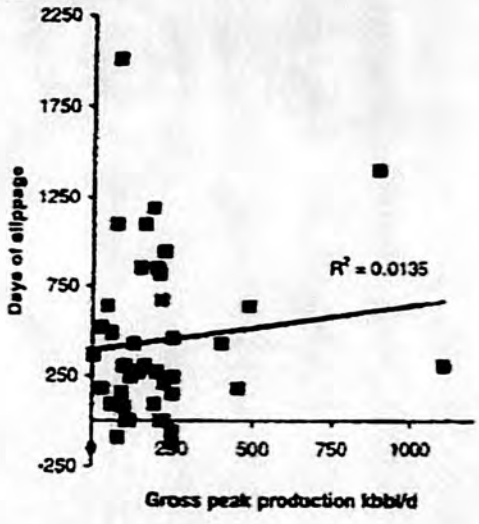
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without sufficient learning time, notoriously ends up with project slippage in the form of increased cost and time.

Furthermore, unique FPSO project solutions, such as the Bonga field tend to have a higher slippage levels than other deepwater concept types, unless ExxonMobil's design one, build many approach is used. Indeed, FPSO solutions appear to be used where rapid projected production growth was targeted, and if not properly managed with a clear plan of what the shipbuilder is meant to do, they can go badly wrong.

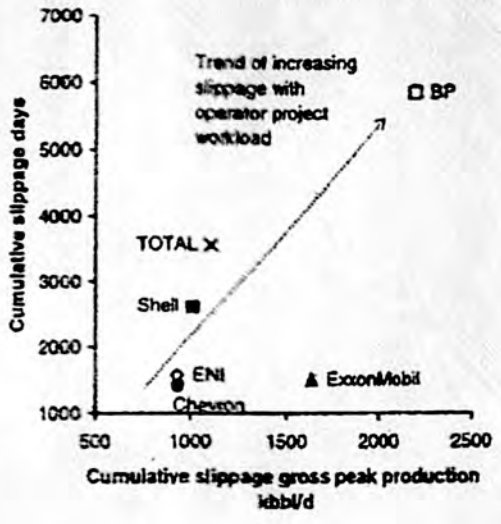
Moreover, project definition and management throughout the lifetime of a project has a significant effect on schedule slippage and cost overruns on new projects, with centrally managed projects, using a development organization, often outperforming those where disperse regional teams are solely responsible for delivery.

Exhibit 6
Slippage days on individual projects can vary widely ...



Source: Bernstein Estimates

Exhibit 7
... but cumulative projects by individual companies tend to equate to longer slippage delays



Source: Bernstein Estimates

Also evident in our analysis is the fact that projects in emerging oil regions such as West Africa, Caspian, Sakhalin are also more likely to slip primarily due to the government interference, with subsequent delays over which the company's have no control. With the recent tax changes in Russia, Venezuela and Bolivia this problem is likely to manifest itself in additional costs as well as time delays, while we expect increasing involvement by the state-owned oil companies of host nations in key projects. Furthermore, this does not bode well for the major deepwater projects in development off Brazil, Indonesia, Nigeria, Angola and Equatorial Guinea. It also appears that the governments of many countries with production sharing agreements are slowing down the pace of project approval, as with high oil prices their budgets are not under pressure and they want to make sure the oil company is not over spending on the project leading to less tax revenue.

Who are the best ... and the worst at project management?

As we have seen above, as the number of large volume projects increases within a Majors portfolio, the potential exists for longer delays in ultimate first oil, this is especially true for BP and such a trend could put future oil production targets at risk (Exhibit 7). However, within the Majors group there are significant

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differences. Overall the key theme is that a lack of detailed organization for development and management of multiple key projects will unquestionably cause slippage, as is the case within BP's portfolio. Specifically, in projects where BP acts as lead operator, we see an increased occurrence of project slippage, which is likely to turn into cost overruns as well.

ExxonMobil come 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, utilizing all ExxonMobil business functions along the way. With a tried and tested project plan which progresses ideas through technology, finance, execution, operations and marketing, the company manages to avoid costly delays. Noteworthy is how this series of project steps successfully allowed ExxonMobil to win a key $7Bn GTL project with the Qatari government in July 2004, one of the few projects in that year which were not subject to government imposed delays!

Key lessons that need to be learned by the industry

We see a number of key lessons to be learned from this analysis which could help diminish the potential for project slippage. Primarily they reside in the setting up of internal development organization who assume responsibility for delivery and ensuring that realistic front end loading, project execution planning and implementation are conducted and not fast tracked. As a result, realistic targets are set which investors can grasp and accept.

Additionally, the Majors are being forced into increasingly riskier environments which require risk and financing to be shared. However, in these environments management must ensure their risk management simulations conducted at the outset are inclusive of how conservative a potential partner is historically. We believe this and a joint concerted planning phase will lead to an improvement in the successful delivery of today's and tomorrows critical projects.

Finally, when communicating project start-up times externally companies should be more realistic with project schedules both to avoid slippage and changes to production targets, and allow industry observers a chance at predicting forward oil supply growth more accurately.

Valuation Methodology

The Global Integrated Oils preferred year-forward target price methodology is derived from 12 months forward relative PE multiples versus through cycle ROACE. The relative PE multiple to the S&P is calculated off our 2006 estimated earnings and the through cycle ROACE, assuming investors continue to reward companies with higher returns as has been the case historically. Based on this methodology all companies have upside potential, as they lie below the industry through cycle valuation line. We use $58/bbl WTI and $8.41/mcf for US gas in 2005, with $55/bbl and $7.97/mcf for US gas in 2006, and $45/bbl in 2007 inflated at 8-14% thereafter.

Risks

It is possible that a larger sample size of projects may reveal slightly different results than presented here, although we believe we have selected the largest oil projects that should have the most impact on the industry. Further alternative interpretations of our conclusions are described in the details section above.

Disclosure Appendix

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Alaska Natural Gas Pipeline Project

Getting Alaska's Gas to Market

House Oil and Gas Committee

March 26, 2007

bp

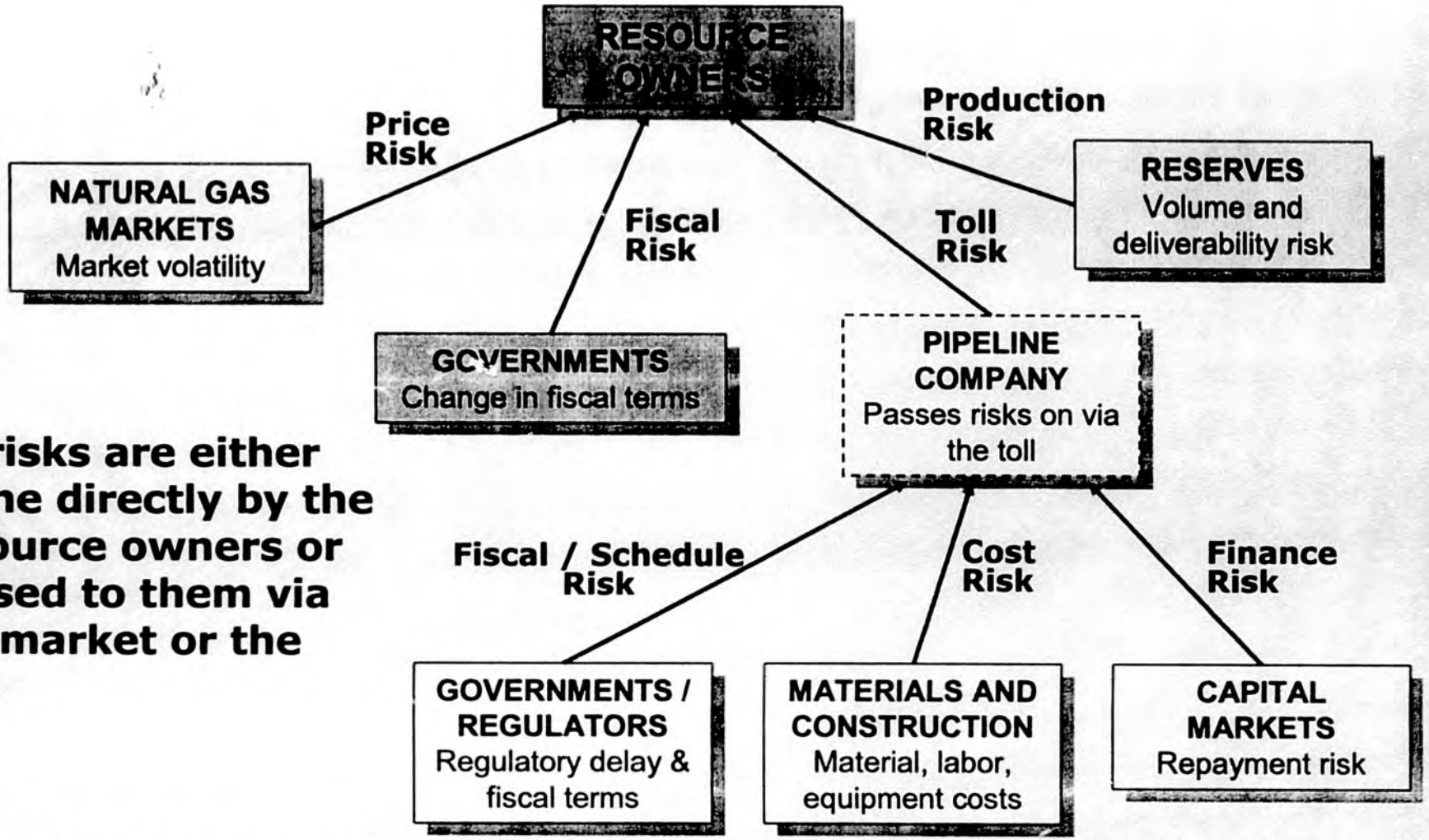
BP Key Messages

- BP wants and needs a gas pipeline
- We support Governor Palin's desire to get Alaska's gas to market
- We are concerned that AGIA as drafted creates some unintended consequences

Key Concerns to Address

- AGIA would result in an exclusive winner before any work is done; based on promises, not performance
- AGIA requires base shippers to subsidize expansion shippers, which adds risk to the pipeline
- Inducements could be suggested by project sponsors, rather than stipulated in advance
  - $500m may attract underfinanced sponsors
- Solving resource issues with clarity enables a successful open season which is the key to advancing the project

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
- Upstream framework is critical
  - Must be addressed for a successful open season
- Key midstream issues must be addressed to ensure there are no unintended consequences
  - Granting an exclusive license before any work is performed prevents participation of others and reduces competition
  - "Inducements" should be based on performance, not promises

BP Testimony on SB 104 (AGIA)
Senate Resources Committee
March 23, 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 additional time to prepare our testimony, and for the opportunity to testify before you this afternoon.

BP Key Messages

- I'd like to start by emphasizing a few general points.

- First, **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 et 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.

- Second, we **share the governor's and the legislature's desire** to get a 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 on March 2nd, we have identified a number of important areas of concern for you to consider.

- 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.

- Next I'd like to turn your attention to a few of those key areas of concern with the current AGIA bill.

Key Concerns

- The first concern is that AGIA would result in an **exclusive winner** before any real work is done and awards State funds based on promises, not results
    - 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 to enable the selection of the exclusive winner in as transparent a way as possible.
    - 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 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.

- The second concern is that AGIA as drafted can result in one party subsidizing another. 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**
    - 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 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.

- We heard FERC testify yesterday and speak very favorably about the bill, but this area of conflict was not specifically addressed. So in fact, we plan to consult with FERC in the very near future just to ensure there is not a conflict problem in the future.

- 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 also not in any of our interest.

- And for the record, I just wanted to ensure that the nature of the producers' challenge to Order 2005-A was clear. We are only challenging the issue of whether or not FERC should be able to dictate design changes after the conclusion of an open season. We are not challenging the rebuttable presumption of rolled-in rates provided it does not result in a subsidy. A contrary statement was made earlier in the week, and we wanted to ensure that we made that point clear.

- Our motivation for the challenge is to prevent cost increases, and to avoid unnecessary project delay.

- A third area for careful consideration, and perhaps the centerpiece of AGIA, is the **$500 million grant**
    - I would like to be clear, this was not requested by BP
    - It may be attractive to underfinanced project sponsors or companies not willing to risk all of their own money
    - **Rather than specifying in advance what inducements are needed, the State could ask project sponsors to propose specific midstream inducements – this gives the free market opportunity to do what it does best**
    - The State could then determine what inducements to offer and make them available to all parties
    - We've heard the Administration say that the $500m is provided up front because this is the riskiest phase of the project. We have a very different view.
    - The up-front phase is risky for a non-resource owner who is not confident that it will have customers participate in its open season; we heard Enbridge share this view last week. But the riskiest phase for the ultimate shippers in fact is the construction period – where cost control is critical, and will be the key determiner of what the ultimate toll will be.
    - In fact, as we've previously shared, ALL project risks ultimately flow to the resource owners who make those initial firm transportation commitments, which I'll discuss in more detail shortly.

- A fourth 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**
    - 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
- 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 take time and effort to agree - but unless they are addressed, a project won't secure financing; it won't advance

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
    - Need for finances from the capital markets → finance risk

- Just to put the finance risk in perspective, I have this **handout** that my finance folks sent me yesterday that summarizes the 10 largest oil and gas pipeline project financings ever.

- You'll notice that the largest financing to date is $3.7 billion, which is a fraction of the anticipated cost of this project. I thought this might be useful context for the committee.

- 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 limited but reasonable return on investment, come rain or shine
    - 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
- 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, **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. We are ready to engage on developing that upstream framework.

- And fourth, we believe that a number of midstream details in AGIA should be fixed.
    - **any notion of exclusivity** or the government 'picking a winner' should be avoided
    - Any process should allow competition in the marketplace to work
    - Finally, **any payment of State 'inducements' should be made after promises are delivered, not before**
        - For example, we think it would be appropriate that a sponsor earn inducements by actually conducting a successful open season that results in firm transportation commitments, rather than before actual results are delivered.
        - It is easy to make hopeful promises
        - but it is harder, and vitally important, to deliver performance

Response to Questions Raised by Senate Resources Committee Following Testimony Provided by BP Exploration's Gas Commercialization Manager David Van Tuyl at March 23, 2007 SB 104 AGIA Hearing

1. **Is there anything in the PBUOA that would prevent one owner from participating in an open season if the others didn't choose to?**

   No. Strictly speaking, at an open season a company makes a financial commitment to pay demand charges for firm transportation services, and is not committing gas directly to the pipeline. No provision of a unit agreement would prevent a company from choosing to commit its funds at an open season. However, it is reasonable to expect that that company would only make that commitment if it was sufficiently certain that it could actually deliver the volume of gas that corresponds to the firm transportation services it was seeking to acquire.

   Although one owner could participate in an open season if the other owners did not, the owner would not likely participate unless the owner could actually deliver gas to the proposed project in compliance with the applicable unit operating agreement and any applicable other agreements. Whether the owner could comply with those agreements would depend on the terms of those agreements, which vary unit by unit, and the circumstances surrounding the delivery of gas. For example, the provisions for taking gas under the Prudhoe Bay Unit Operating Agreement (PBUOA) are quite complex and, before any owner in that unit would participate in a binding open season, an exhaustive analysis of the entire agreement would be undertaken as well as analysis of any other applicable agreement. In short, before an owner could take gas for a major gas sale, some agreements among the owners would likely be required.

   In sum, before an owner individually would participate in an open season, the owner would want to ensure that all conditions necessary in the applicable operating agreement and other agreements for the taking of gas production and delivery of that gas to a pipeline may be satisfied. That may require additional agreements among the owners depending on the circumstances.

   We plan to conduct a more complete analysis of the PBUOA and offer a response when that analysis has been completed.

2. **What percentage of your total company's gas production would this project represent?**

   In 2006, BP produced 1.45 million barrels of oil equivalent in gas (~8.4 bcfd). Therefore, if BP's share of gas provided to a 4.5 bcfd Alaska gas pipeline project was 1 bcfd BP net, Alaska gas would represent just over 10% of BP's total worldwide gas production.

3. What does Order 2005 say about regulation of the GTP? Would the rate resulting from a GTP expansion be rolled-in or incremental?

In Order 2005, FERC requires that regulations for a GTP provide for an "unbundled" service, that is, that the gas treatment service must be offered separate from the gas transportation service. This would allow a shipper to choose between the services offered. The FERC's statement is summarized in paragraph 128 of the preamble to Order 2005:

> *"The Commission is stating in the final rule at section 157.34(c)(6) that the open season notice must contain an unbundled transportation rate. Moreover, section 157.34(c)(10) prohibits a prospective applicant from requiring prospective shippers to process or treat their gas at any designated facility. The Commission is satisfied that it can address any other discriminatory conduct in connection with gas quality requirements or other ancillary services through the provisions of section 157.35 in conjunction with existing Commission policies and procedures."*

Additional details as to the FERC's requirements related to a gas treatment plant are specified under Order 2005-A. Specifically, under paragraph 87:

> *"The Commission did not intend to preclude the inclusion of jurisdictional natural gas conditioning facilities from the open season. If, pursuant to ANGPA section 103, a project sponsor intends to file an application under section 7 of the NGA for authorization of a project that includes a jurisdictional natural gas conditioning service, we will review the open season plan and notice to ensure that such service is offered in its open season notice, subject to the same requirements as apply to transportation service. However, the prospective applicant must offer a separate rate for the gas treatment service and separate rate for the transportation service. Furthermore, the prospective applicant can neither require bidders to bid on both services, nor evaluate the bids based on whether bidders requested one or both services. Moreover, while the prospective applicant can require specific natural gas quality specifications such as would be met by using the conditioning services offered, it cannot reject an otherwise qualified bidder that states that it will deliver to the pipeline facilities gas that meets the stated quality specifications."*

The Order continues, in paragraph 88, to address the inclusion of a gas treatment plant into the ANGTS design, which originally excluded a GTP:

> *"On the other hand, if a prospective applicant is proposing to apply to revise the Alaska Natural Gas Transportation System (ANGTS) application now held*

in abeyance, then a conditioning service will have to be included as a part of the open season, but again, with all services offered priced separately."

The FERC does not specifically address the issue of the rate treatment of a GTP expansion (that is, whether the rate would be incremental or rolled-in).

4. **Please provide additional information on the "Top 10 Oil and Gas Pipeline Project Financings" chart provided to the Committee, including dates of projects and cost information if available. Also, why is TAPS not included on the list?**

The summary provided to the Committee is a listing of the 10 largest oil and gas pipeline **project financings**, not necessarily the largest projects. TAPS is not included in the table because it was not project-financed. For reference, project financing is when lenders look to the revenues generated by the project itself for repayment of monies loaned.

We are continuing to attempt to compile the additional details requested by the Committee and will provide a more detailed response once that information is available.

5. **What is the volume of liquids that will be carried in the gas pipeline?**

The total volume of liquids carried in the Alaska gas pipeline project at any point in time is dependent on a number of factors, including the inlet volume of gas delivered to the pipeline, the heating value or "richness" of the gas delivered, the disposition of ethane (which can be marketed as either gas or liquid) and the operating temperature and pressure of the system.

Assuming an inlet gas rate of 4 bcfd, heating value of 1080 btu/mcf, with the pipeline operating at 2500 psi with a 30 degree compressor discharge temperature, the total liquids potential is approximately 180,000 barrels per day, of which approximately 100,000 barrels per day is ethane.

10 Largest Oil and Gas Pipeline Project Financings

(greenfield and expansion only – excludes acquisition financing and refinancings)[1]

	Project Name, Location	Total Capital Cost (Senior Debt Portion)	Sponsors
1.	Alliance Pipeline Project (Gas), Canada/US (3,000 km)	$3.73 billion ($2.59 billion debt)	Coastal, IPL, Williams, Fort Chicago Energy, Westcoast Energy
2.	BTC Pipeline (Oil), Caspian Basin (1,730 km)	$3.6 billion ($2.59 billion debt)	Amerada Hess, BP, ConocoPhillips, Eni, INPEX, Itochu, SOCAR, Statoil, Unocal,
3.	Cusiana – Cupiagua Pipeline (Oil), Colombia (800 km)	$2.2 billion ($1.54 billion debt)	Ecopetrol, BP, Total, Triton, TransCanada, IPL
4.	Chad – Cameroon Pipeline (Oil), Chad (1,070 km)	$2.0 billion (pipeline only) ($700 million debt)	ExxonMobil, Petronas, Chevron
5.	Bolivia-Brazil Pipeline Project (Gas) Bolivia / Brazil (3,075 km)	$2.23 billion ($1.4 billion debt)	Petrobras, BG, El Paso, YPFB, BHP, Enron, Shell

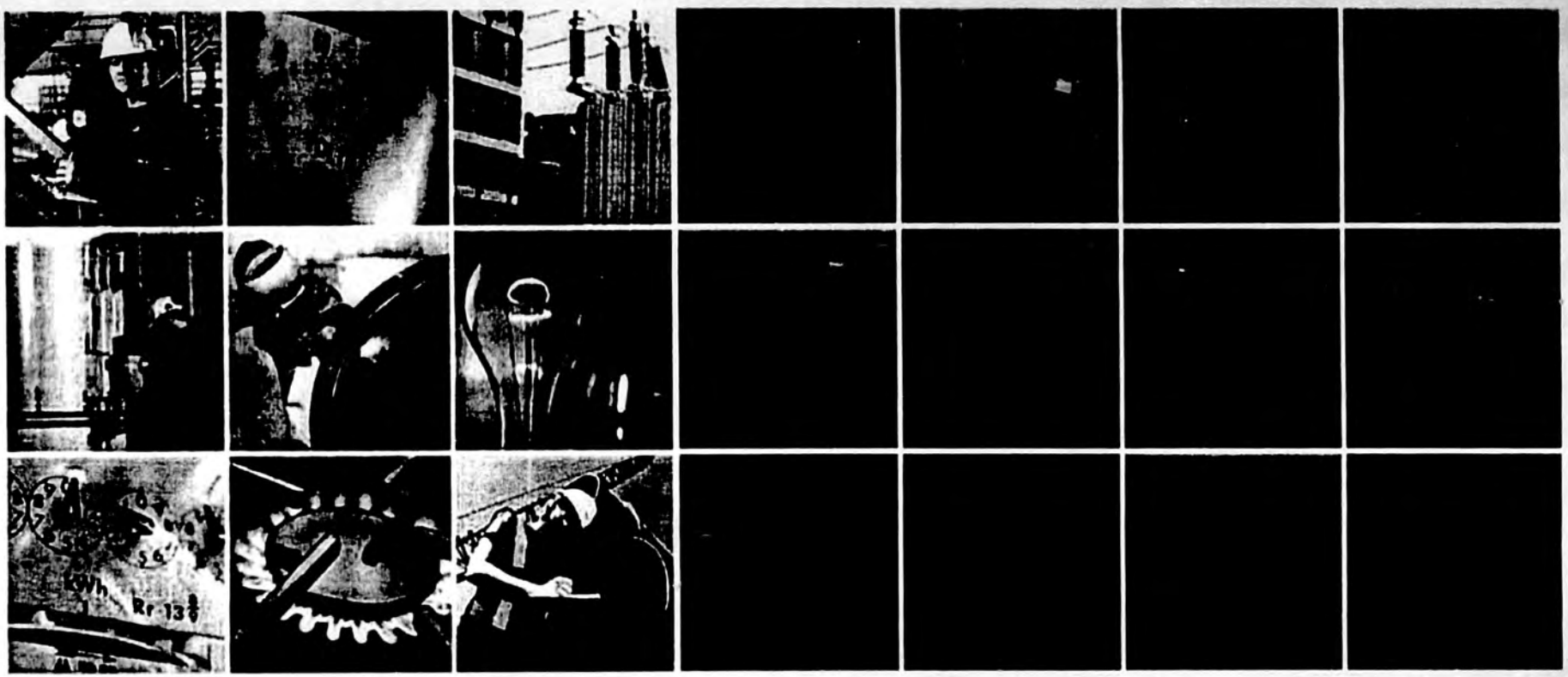
[1] Also excludes primarily upstream projects with an integrated pipeline component. Based on Dealogic database.

10 Largest Oil and Gas Pipeline Project Financings

(greenfield and expansion only – excludes acquisition financing and refinancings)[1]

	Project Name, Location	Total Capital Cost (Senior Debt Portion)	Sponsors
6.	OCP Heavy Crude Pipeline (Oil) Ecuador (503 km)	$1.2 billion ($900 million debt)	Alberta Energy, Repsol, YPF, Occidental, Agip, Pecom Energia, Techint, Kerr-McGee
7.	Mozambique-South Africa Pipeline Project (Gas), Mozambique (865 km)	$1.2 billion ($543 million debt)	Republic of South Africa, Republic of Mozambique, Sasol Polymers
8.	Malhas Project (Gas), Brazil (expansion)	$1.0 billion ($900 million debt)	Petrobras, Mitsui, Itochu, Mitsubishi
9.	Kern River Expansion II (Gas), United States (part refinancing)	$875 million loan	Williams, Tenneco
10.	Camisea (Gas), Peru	$865 million ($480 million debt)	Techint, Sonatrach, PlusPetrol, SK, Hunt Oil, Tractebel

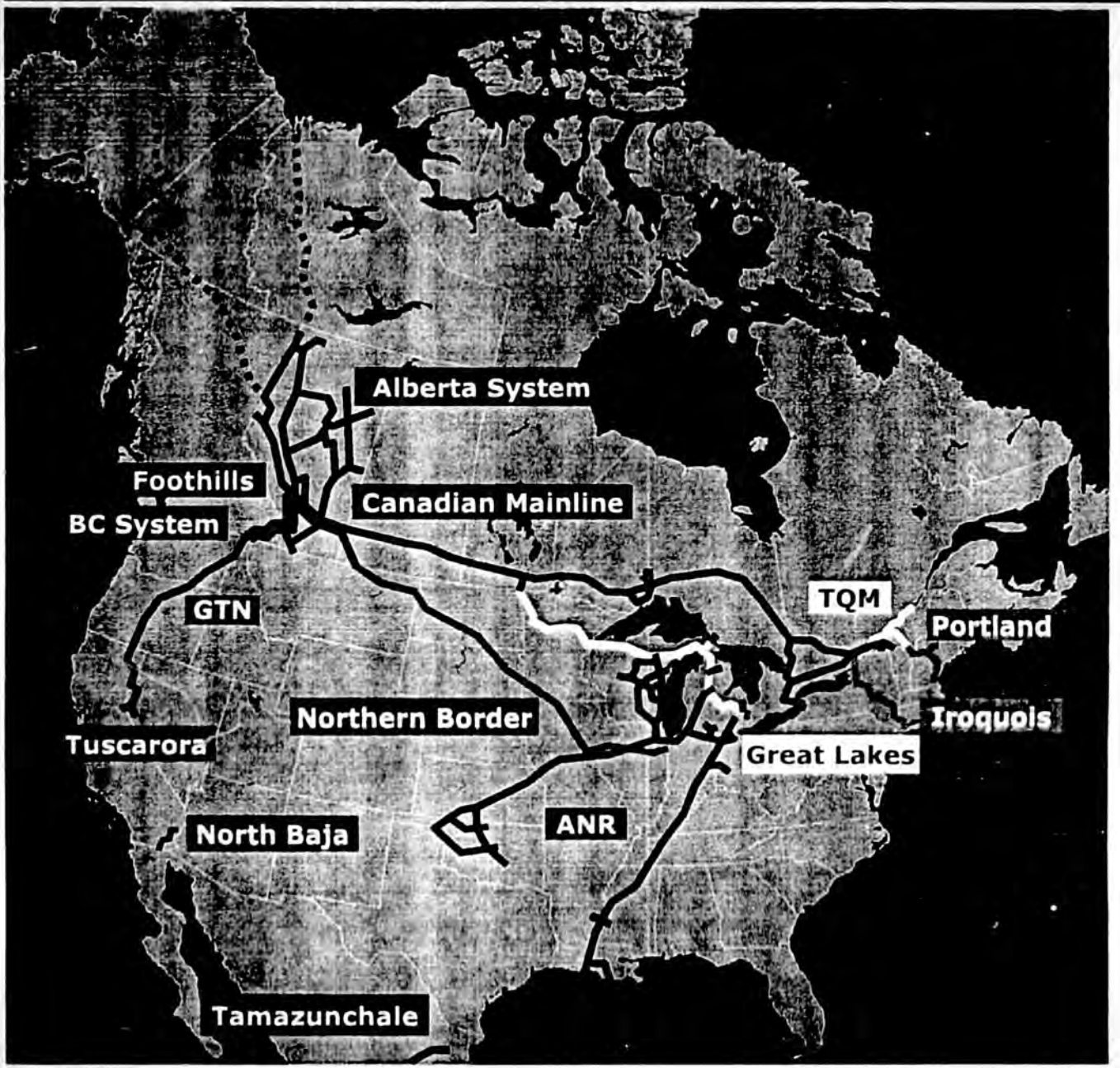
[1] Also excludes primarily upstream projects with an integrated pipeline component. Based on Dealogic database.



Alaska Legislature Testimony
Alaska Highway Gas Pipeline Project

Juneau, Alaska
March 26/27, 2007

TransCanada
In business to deliver



- 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

TransCanada's Pipeline Assets

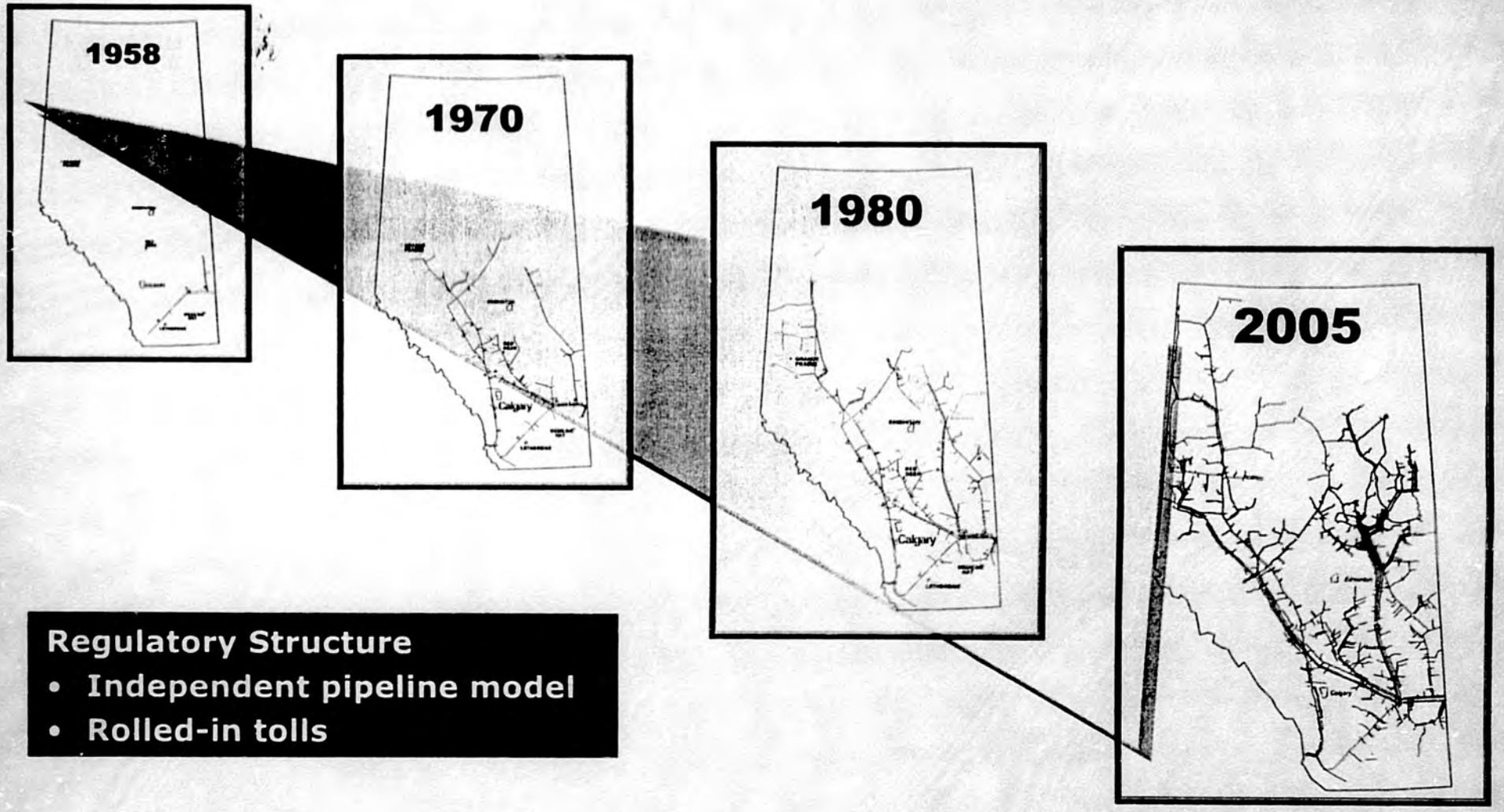


- TC is North America's largest gas transmission company, owning approximately 2/3 of the take-away capacity from Alberta hub to North American markets.
- TC owns 36,500 miles of natural gas transmission pipelines and provides service to Northeast, Midwest, Pacific NW, California, Eastern Canada and 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

TransCanada - Proven Basin Developer





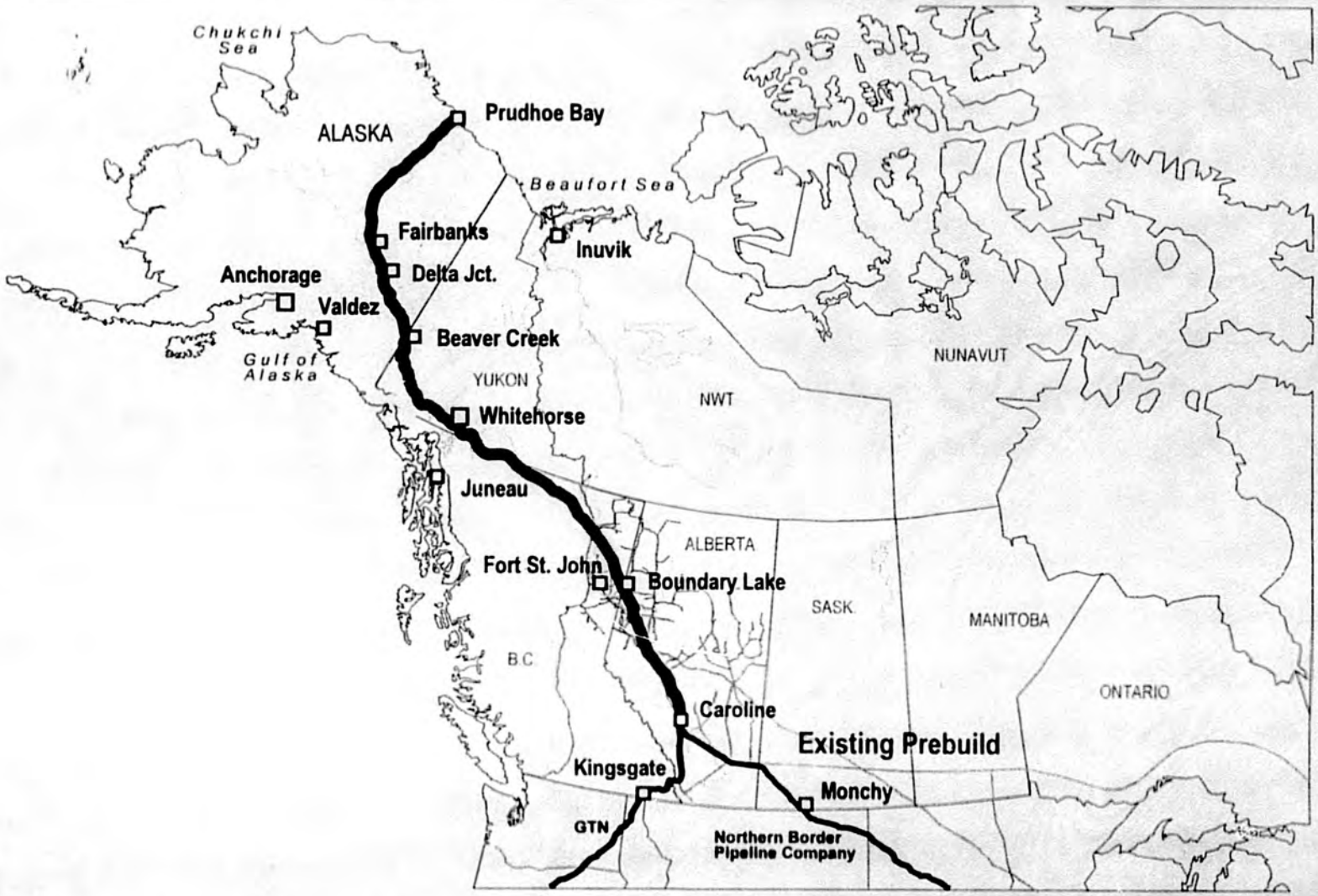
Regulatory Structure

- **Independent pipeline model**
- **Rolled-in tolls**

TransCanada

Alaska Highway Pipeline





TransCanada

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.

TransCanada

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

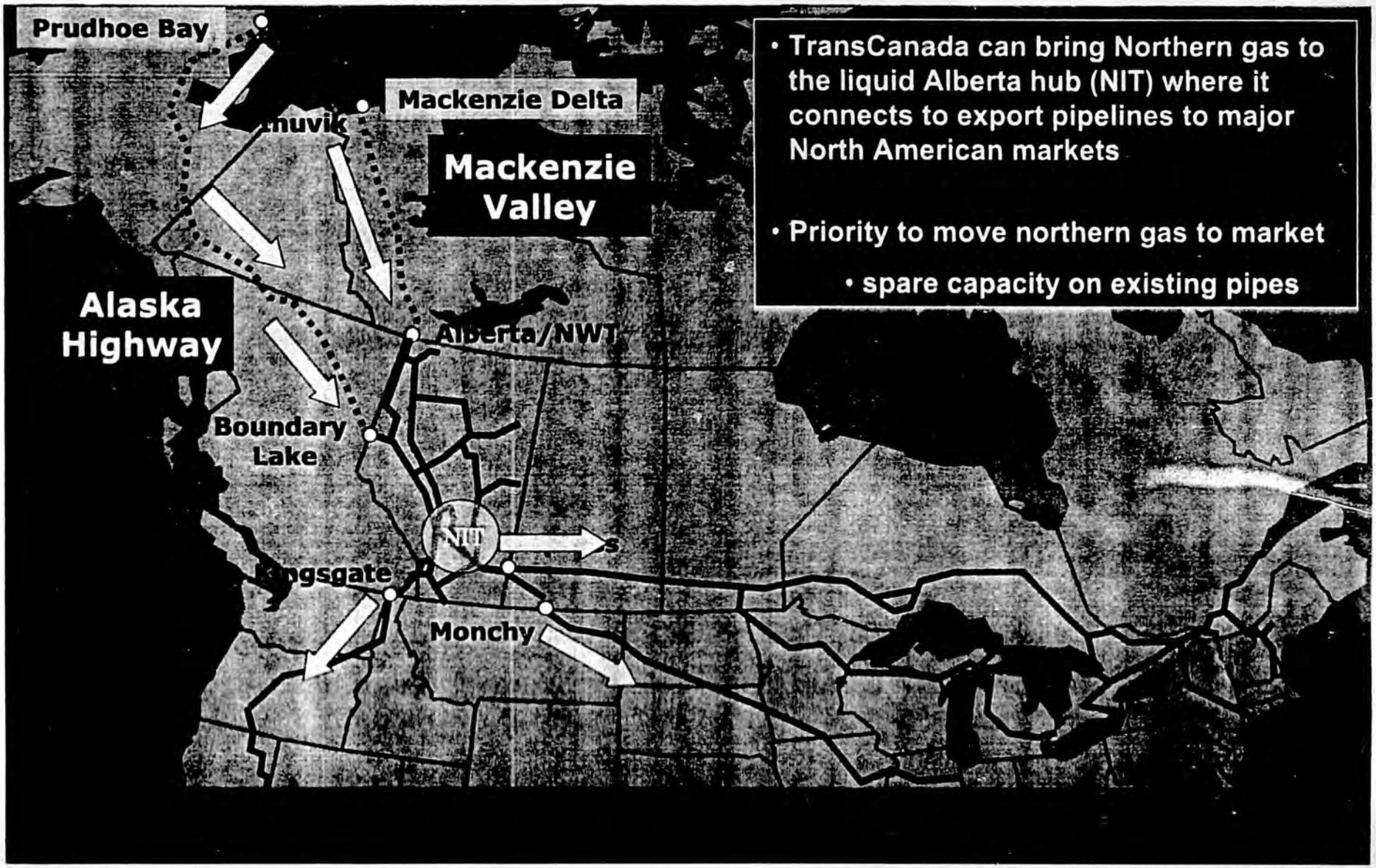


- NEB held competitive hearings, open to all parties
  - Selected Foothills as Canadian project sponsor
  - Rejected other applications (Arctic Gas)
- Canada / U.S. negotiated Treaty for Alaskan gas project
  - Canada obtained benefits in exchange for access across Canada for Alaskan gas
  - Foothills 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

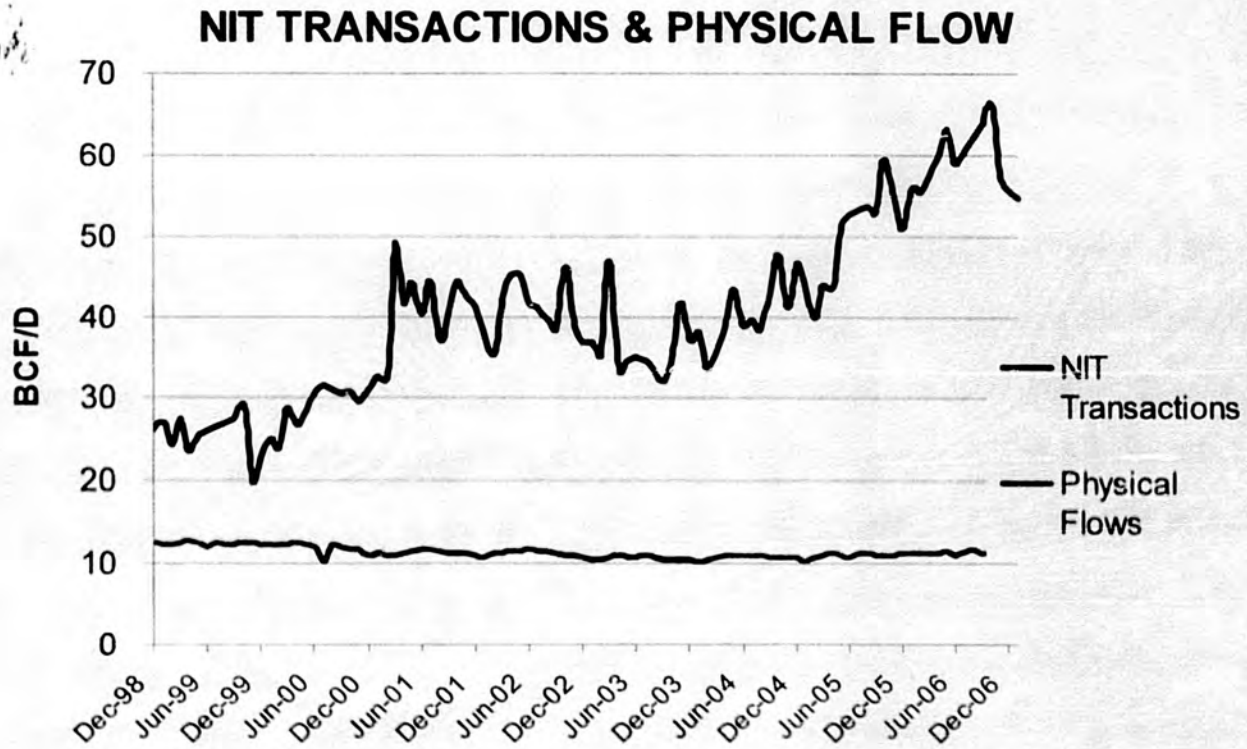
TransCanada is ready to move Northern Gas to North American markets





The Alberta Hub (NIT) is the most liquid natural gas market in North America

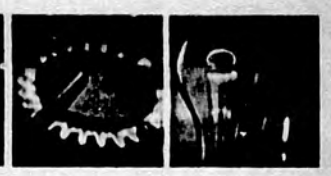


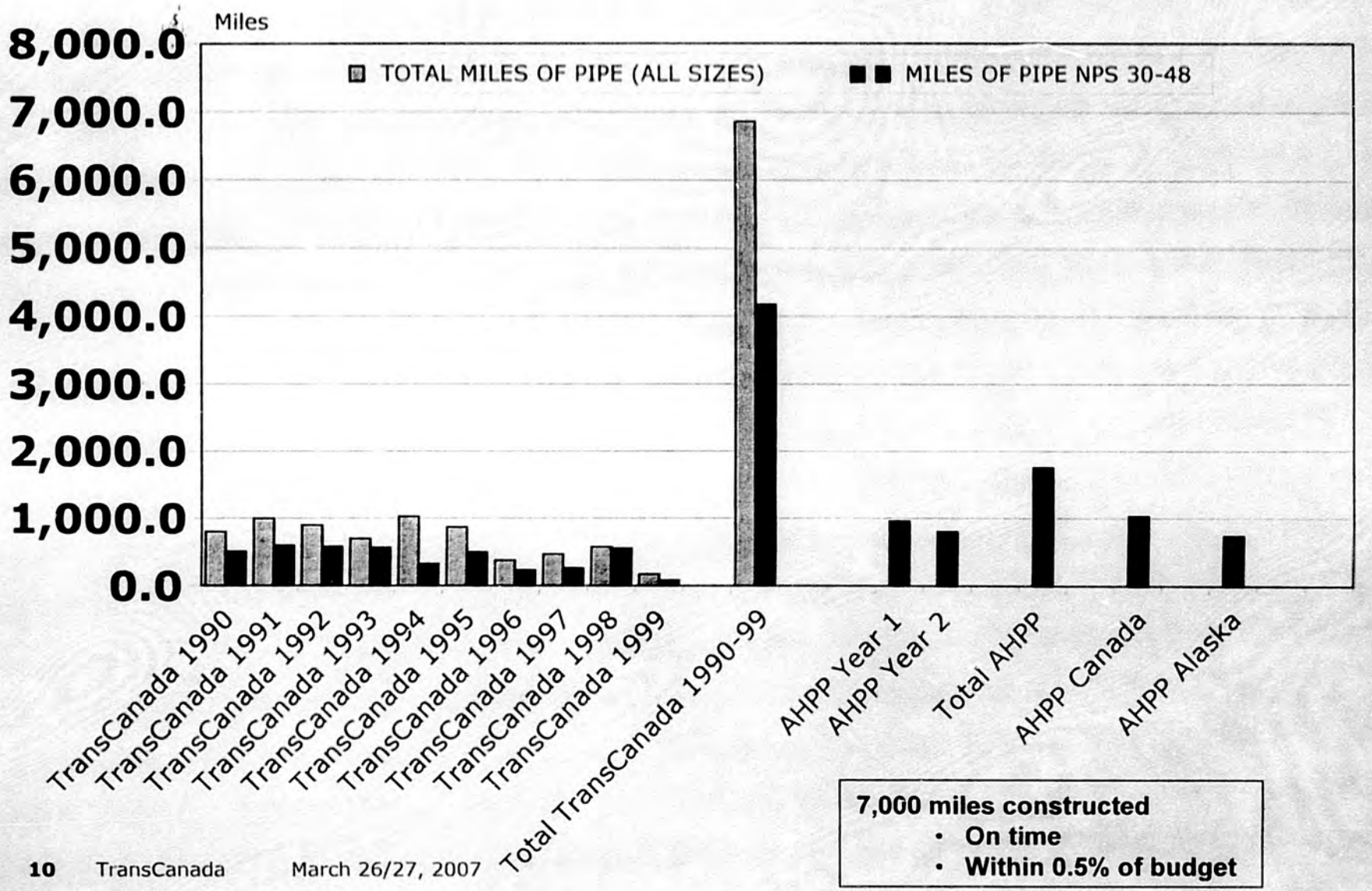


- **Alberta liquidity continues to grow**
- **Transaction statistics suggest that NIT is the most iiquid market in North America**

TransCanada

Our Western Canada Track Record: 1990s Miles Constructed

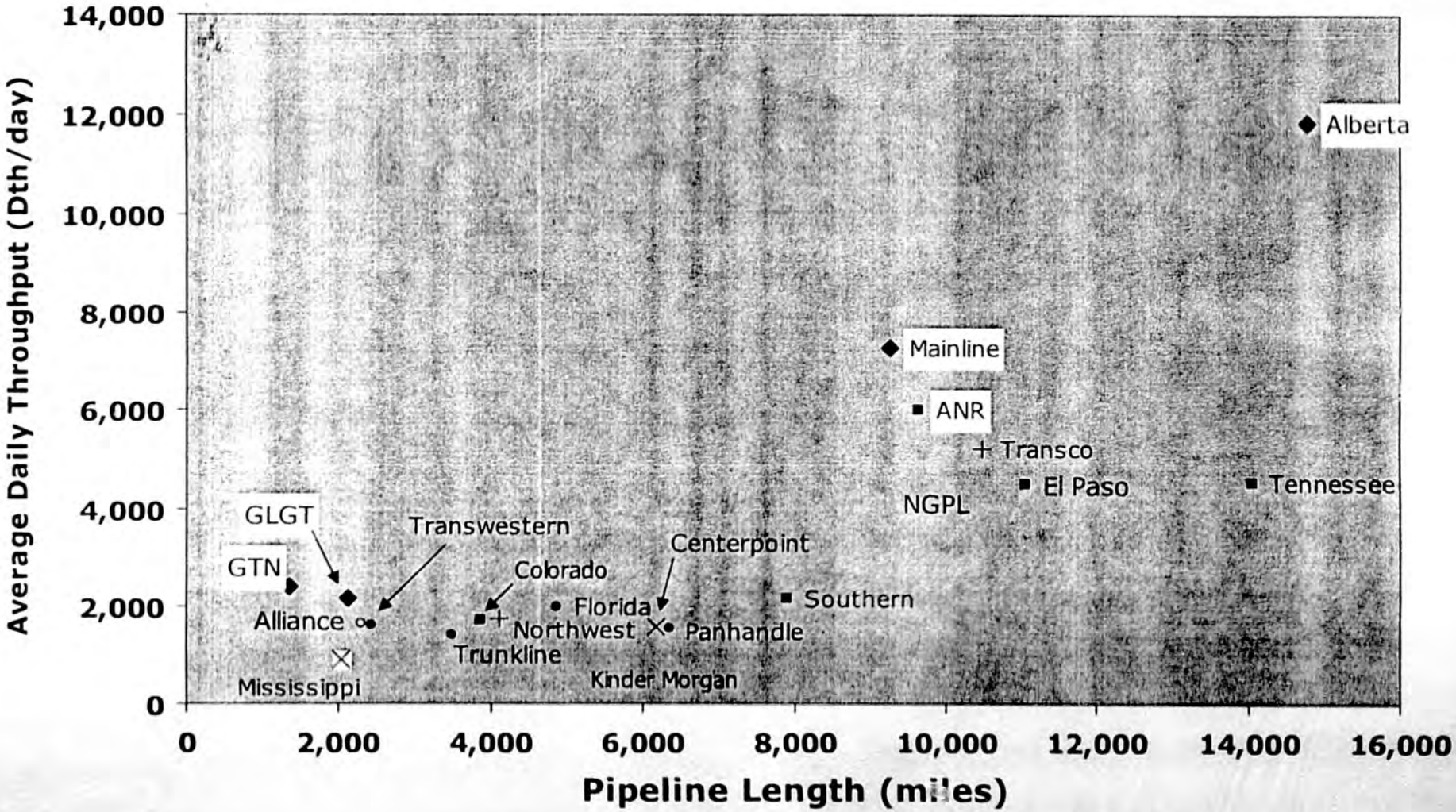




7,000 miles constructed
- **On time**
- **Within 0.5% of budget**

Operating Costs & Reliability – Study Participants



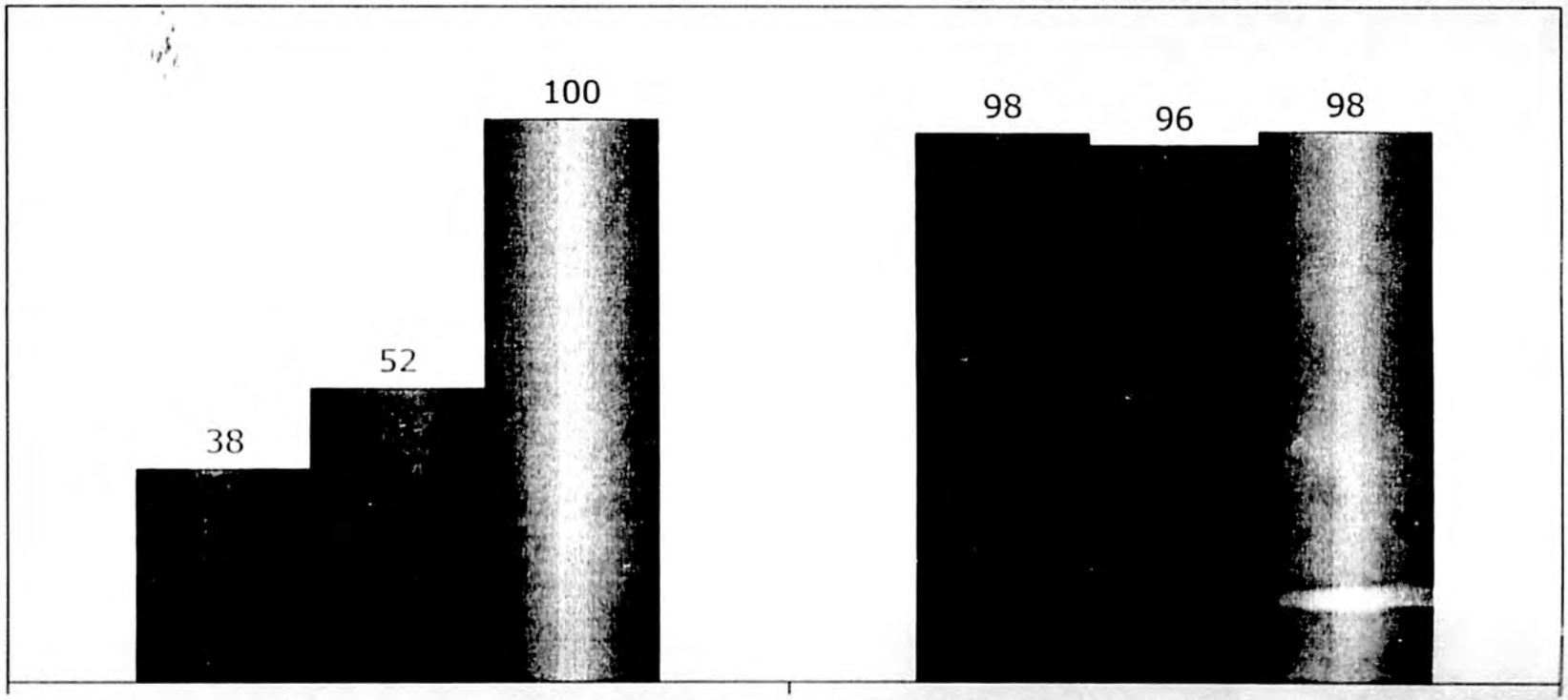


Source (Operating data): ***"Major Interstate Pipelines" (2004, Foster Associates)***

TransCanada

Compression Maintenance Comparisons



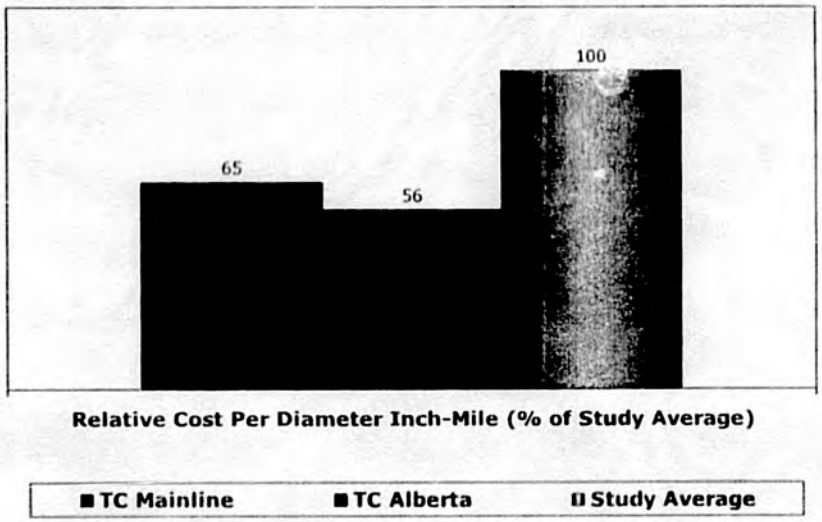


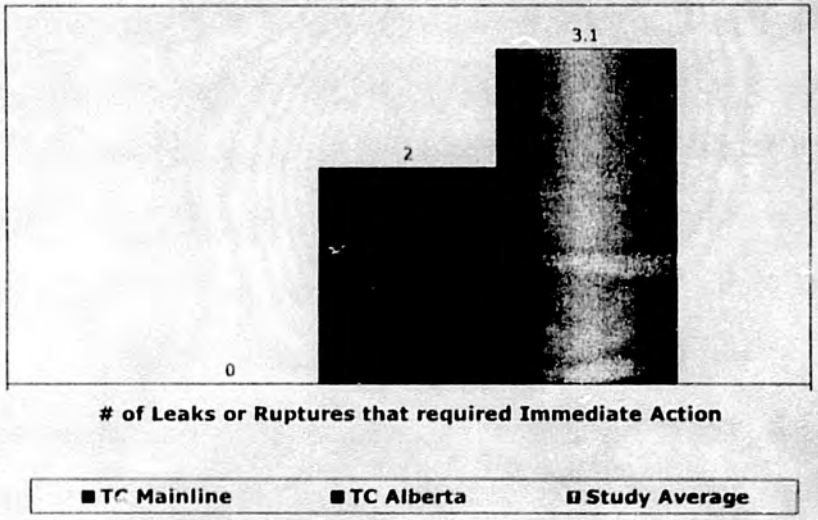
Source: Solomon Associates Natural Gas Transmission System Performance Analysis for Operating Year 2004

TransCanada

Pipeline Maintenance Comparisons





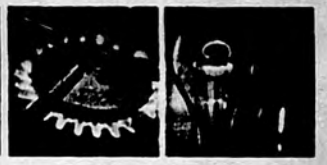


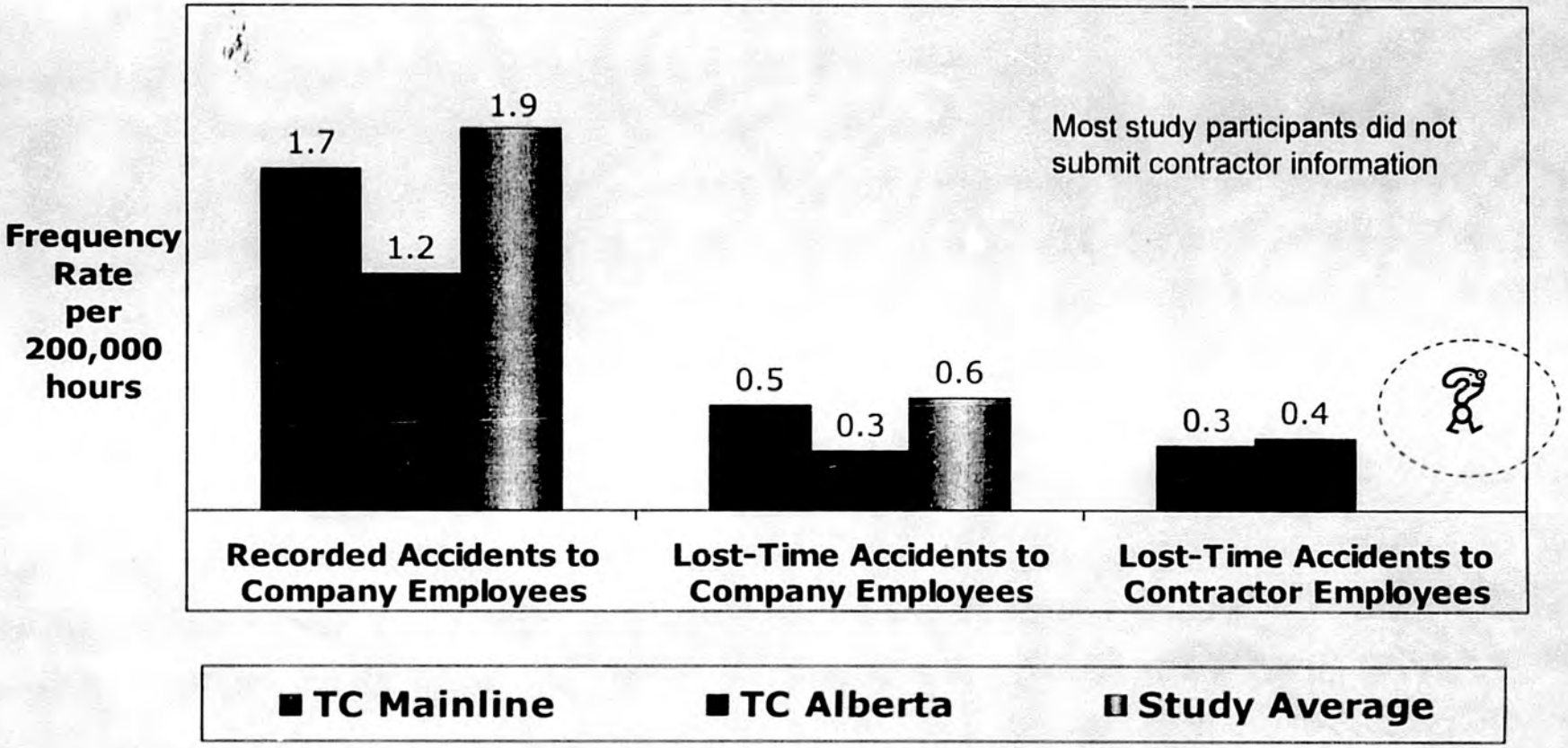
Note: Diameter Inch-Mile (DIM) is calculated by multiplying each pipe diameter by its length and summing the products

Source: Solomon Associates Natural Gas Transmission System Performance Analysis for Operating Year 2004

TransCanada

Safety Performance



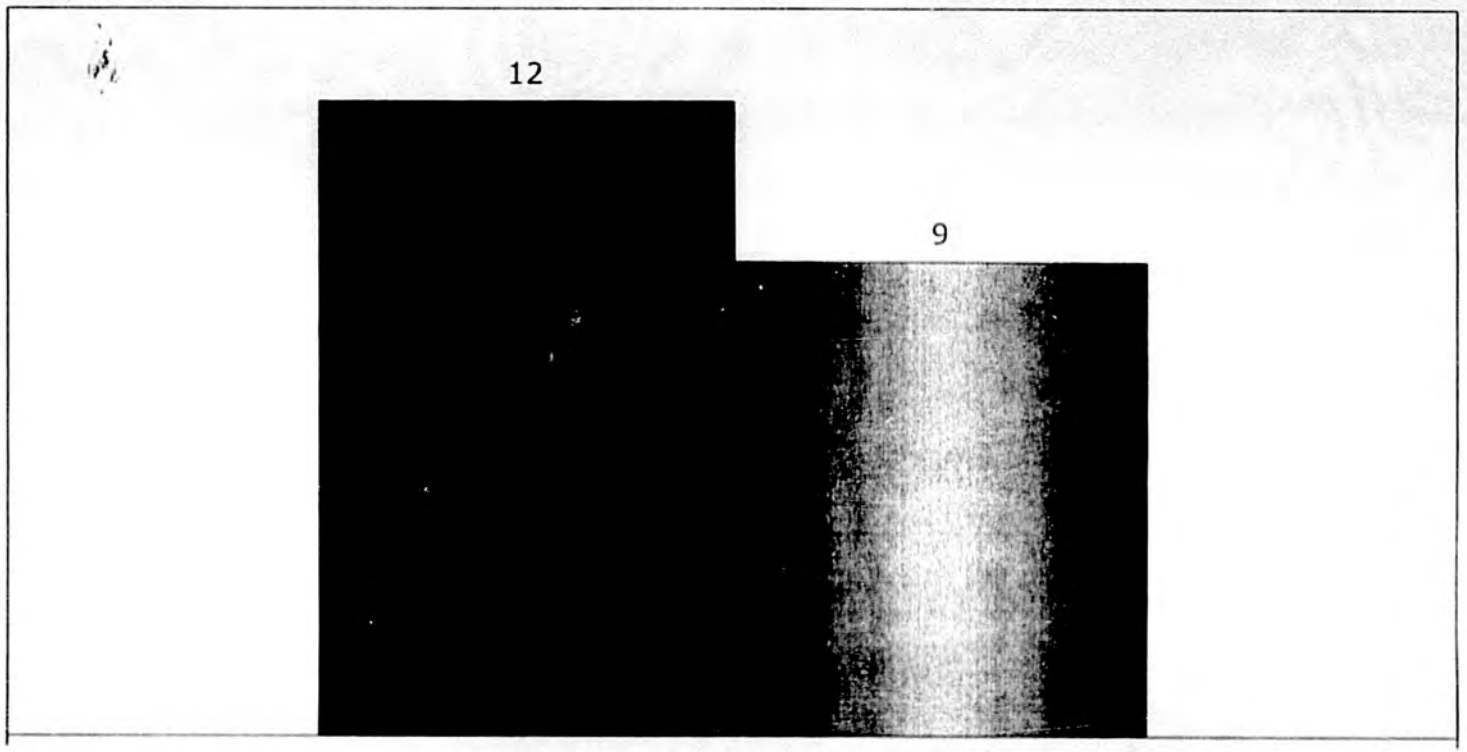


TransCanada expects the same high standards of Health, Safety and Environmental (HSE) performance from its contractors as from its employees

Source: Solomon Associates Natural Gas Transmission System Performance Analysis for Operating Year 2004

TransCanada

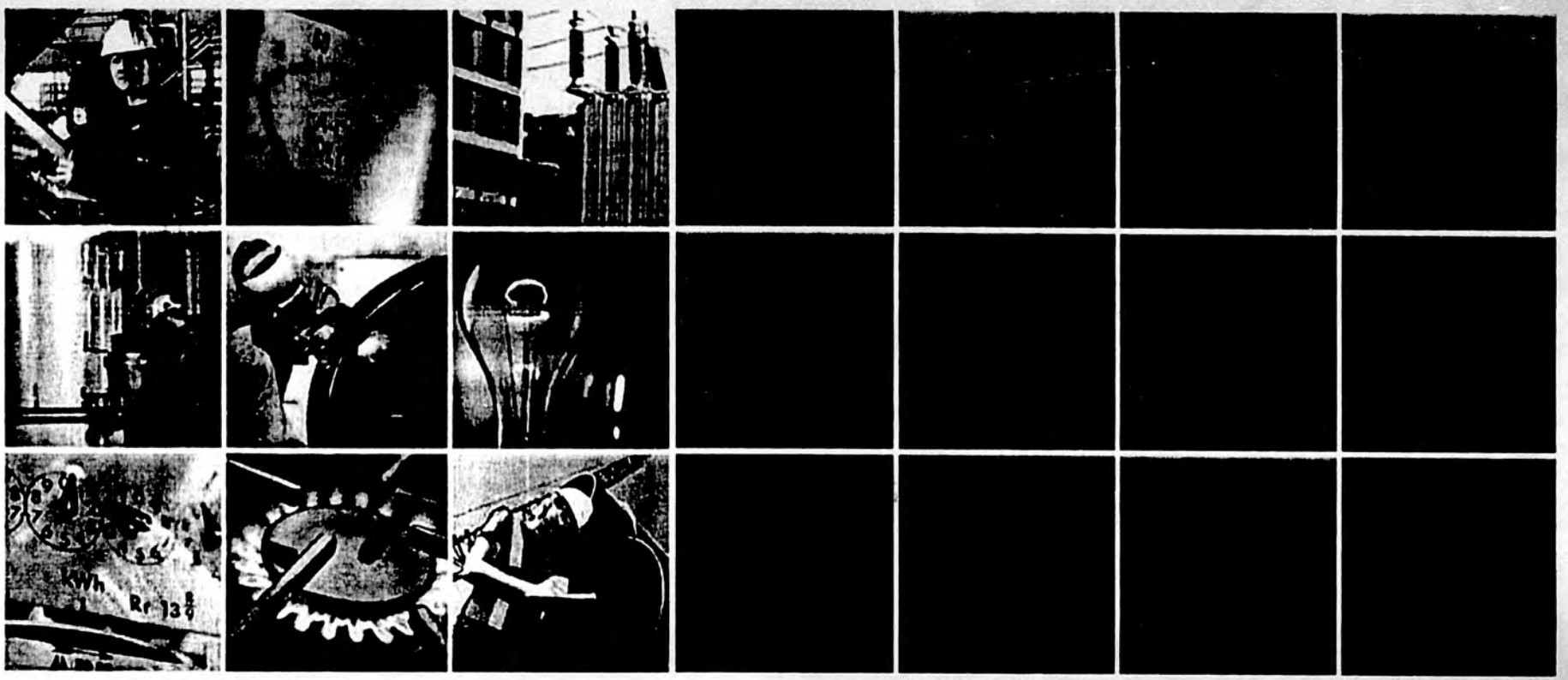
% of Total Pipeline Length Inspected Annually



Mainline is a similar type of pipeline as the proposed Alaska project

Source: Solomon Associates Natural Gas Transmission System Performance Analysis for Operating Year 2004

TransCanada



Thank You

TransCanada
In business to deliver



ENBRIDGE

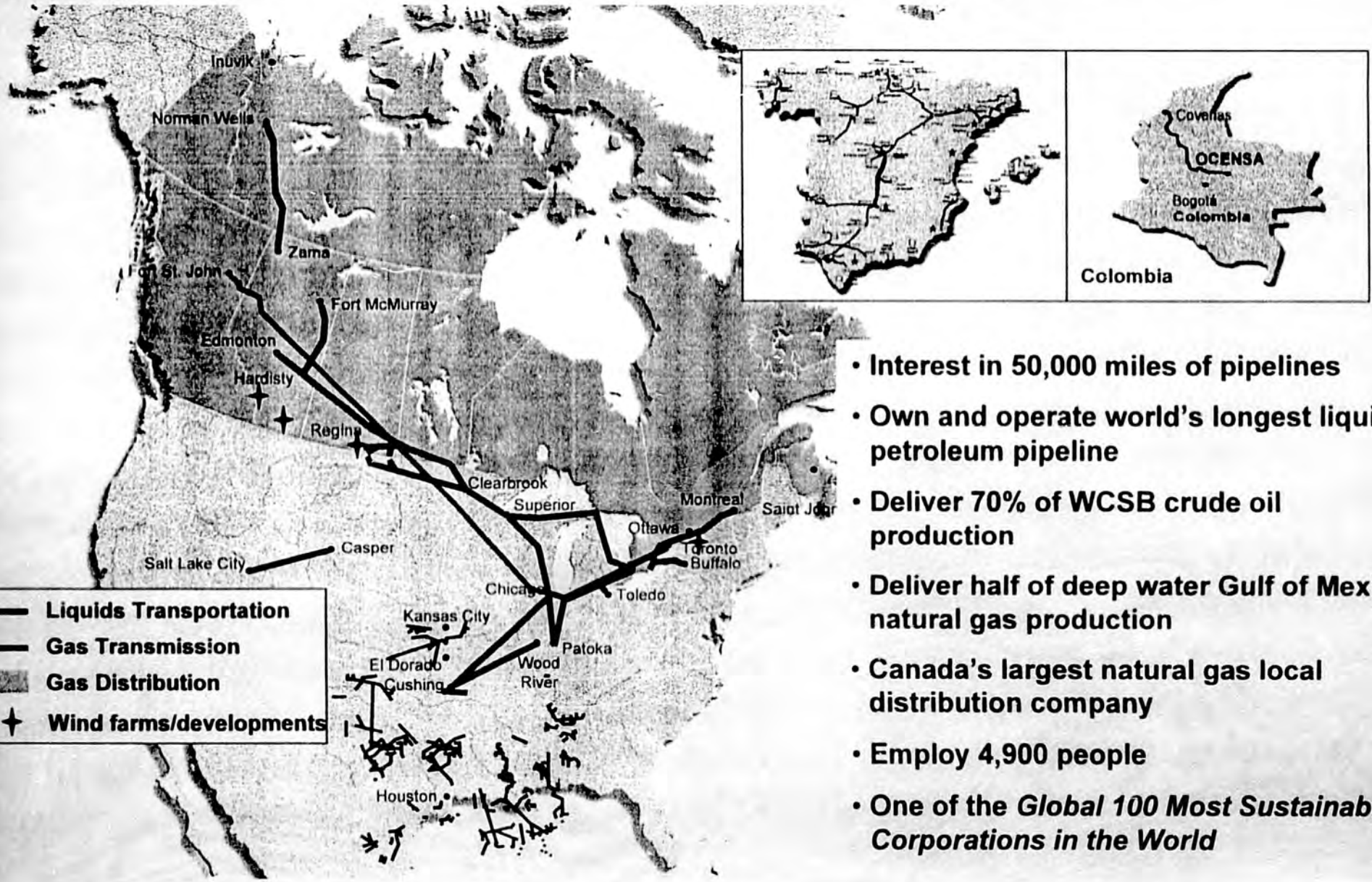
Alaska Natural Gas Pipeline

The Path Forward ....

....An Enbridge Perspective

March 27, 2007

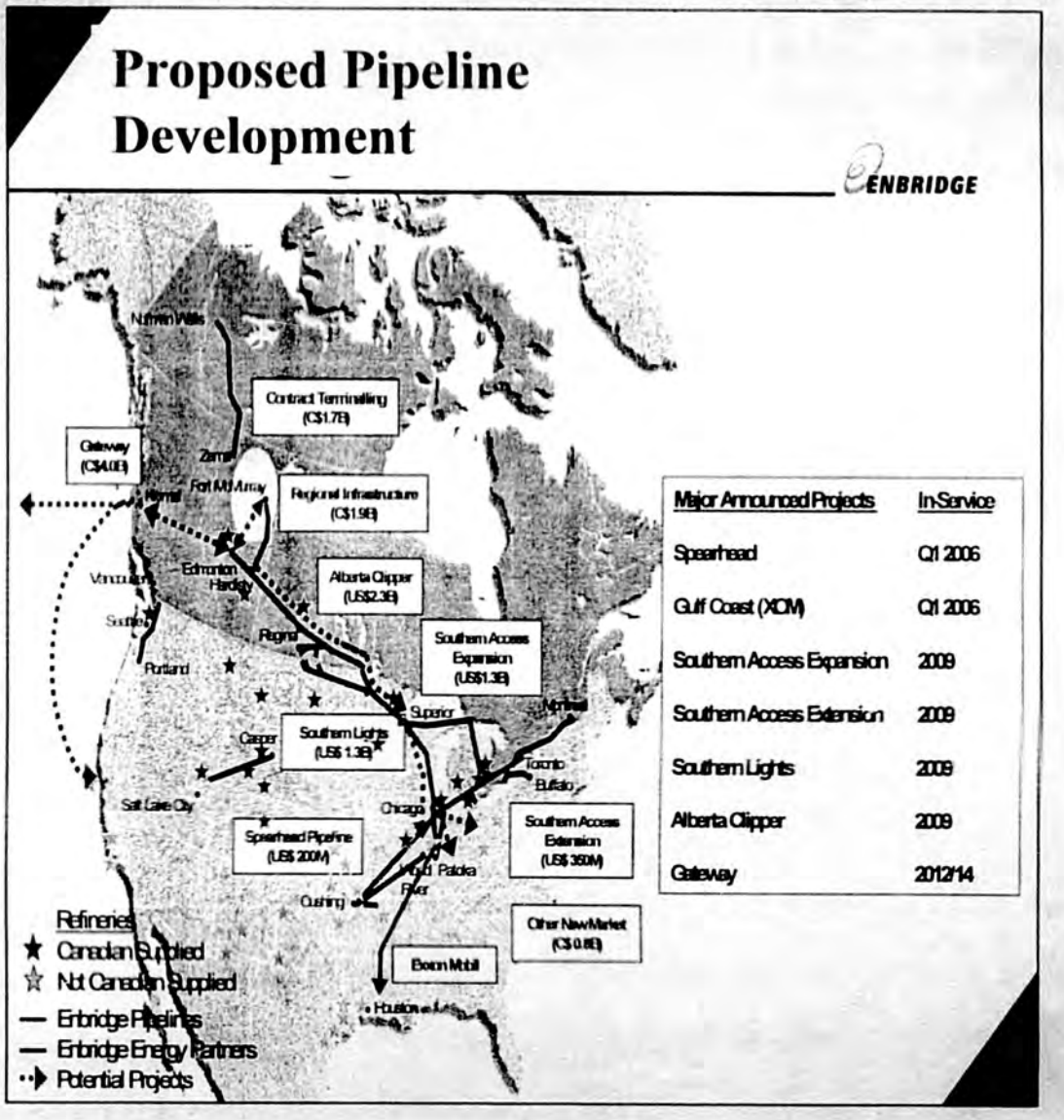
Enbridge Overview



- Interest in 50,000 miles of pipelines
- Own and operate world's longest liquid petroleum pipeline
- Deliver 70% of WCSB crude oil production
- Deliver half of deep water Gulf of Mexico natural gas production
- Canada's largest natural gas local distribution company
- Employ 4,900 people
- One of the *Global 100 Most Sustainable Corporations in the World*

Unparalleled Recent Pipeline Development

- $15 billion over the next 10 years
  - Unmatched recent experience managing labor, construction, procurement, environment, regulatory and cost-control challenges
  - Today's development environment is substantially different than 10 years ago
- Alliance Pipeline
  - Technical and commercial similarities



Moving the Pipeline Forward

ENBRIDGE

- Process ***Requires State – Producer alignment***
  - No producers No pipeline
    - Timing is Key – market degredation/capital competition
    - Focus on what is essential vs. what is desirable
      - Producers' goals / motivations
      - North American supply / demand fundamentals make timing critical
      - The FERC Regulatory process is well defined and will work

Moving the Pipeline Forward

- AGIA introduced as a catalyst to expedite the construction of a natural gas pipeline
  - Applaud the new Administration's high priority given to moving the pipeline development forward
- AGIA process will likely not produce the desired results because:
  - AGIA focus is on the pipeline and not Producer alignment
  - Project is too risky to move forward without Producer commitment
    - Enbridge will not participate in AGIA or any other similar process unless we are part of a consortium that includes producer commitment
- AGIA adds unnecessary regulatory layer
  - FERC process well defined and effective

Why Producer Involvement is Important

ENBRIDGE

- Promotes efficient development through:
  - Alignment
  - Financial resources
  - Previous experience

- Most importantly they will bear lion's share of risk

Project Progression

ENBRIDGE

- Binding shipper commitment is required prior to spending significant $'s on regulatory applications
  - Not commercially prudent to assume producers will show, or that gas can be "acquired"
  - Risk too high even with government cost sharing
- Even binding shipper/pipeline agreements will have conditions including:
  - An acceptable FERC Certificate
  - Acceptable Financing
  - Shipper resolution of Alaska state taxation issues
  - Defined project milestones / timing
- An unconditional commitment to proceed will not happen
  - Regulatory certificates may have conditions making project uneconomic
  - Events between application and certificate could make project uneconomic

Regulatory Application

ENBRIDGE

- FERC and NEB (Canadian) applications require:
  - Detailed project cost evaluation
  - Project management plan
  - Environmental assessment
  - Stakeholder engagement
  - Finalization of tariff structure (Cost of Service / Incentives)
  - Environmental assessment

In Conclusion

ENBRIDGE

Enbridge believes:

- AGIA does not resolve producer fiscal (tax) concerns
- Producers unlikely to commit to pipeline brought forward by another company under AGIA unless and until fiscal issues resolved
- Producer support is required and achievable without AGIA
- Government financial assistance not essential
- Government can achieve key goals without adding to regulatory process
- An unconditional commitment to proceed with project is not achievable

ConocoPhillips

House Oil and Gas Committee
March 28, 2007

Wendy D. King
ANS Gas Development Team

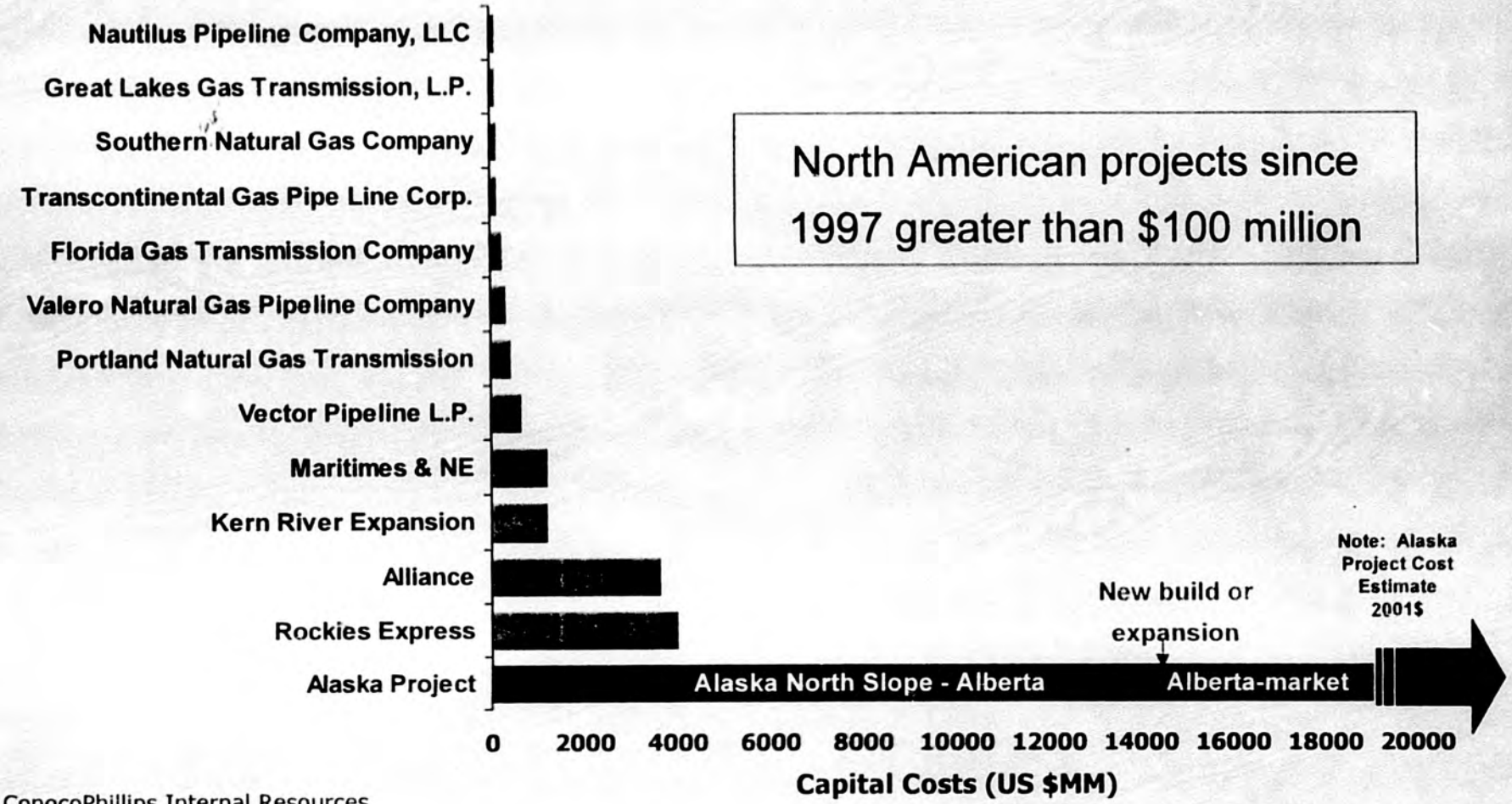
Investing in Alaska Today



- Alaska's #1 Oil Producer
  - 2006 production: 280,000 barrels of oil per day
- Alaska's #1 Gas Producer
  - 2006 production: 145 million cubic feet per day
  - Kenai LNG ~1200 uninterrupted LNG shipments since 1969
- Alaska's Leading Explorer
  - Largest acreage holder on ANS*, 1.7MM net undeveloped acres
  - 60 wells since 1999, including 16 wells in NPRA
- Largest Industry Community Supporter
  - 2006 > $12 Million Contributions
- 1,093 Employees
  - Annual Payroll over $122 Million
  - Thousands of Induced and Indirect Jobs
- Largest Royalty and Taxpayer
  - 2006 Estimated Taxes and Royalties: $2.1 Billion
- Alaska Capital and Operating Budget
  - More than $12 Billion invested over past 10 years

*Note: Federal and State Lands

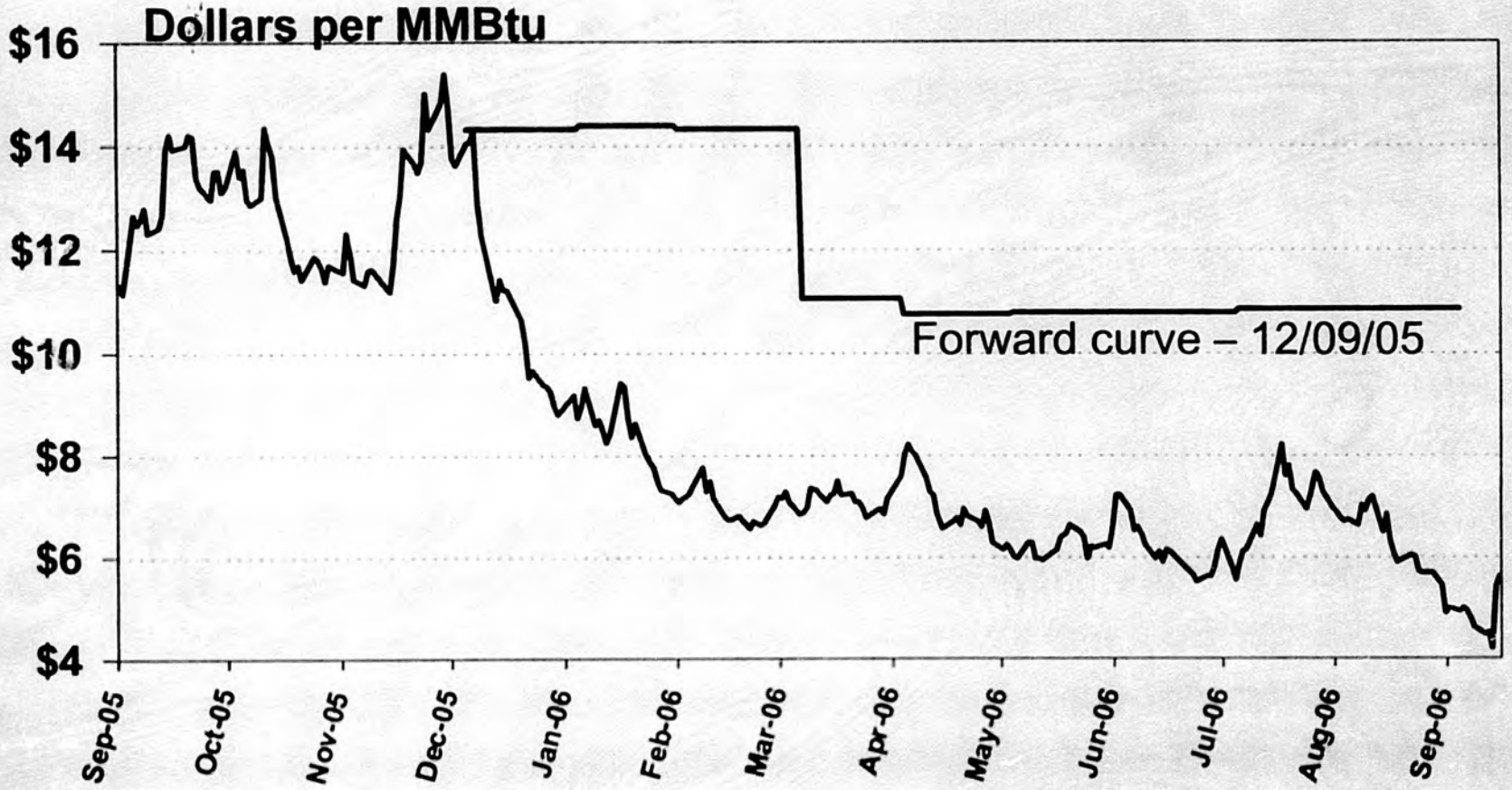
What makes the Alaska Project Different?



Source: ConocoPhillips Internal Resources

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

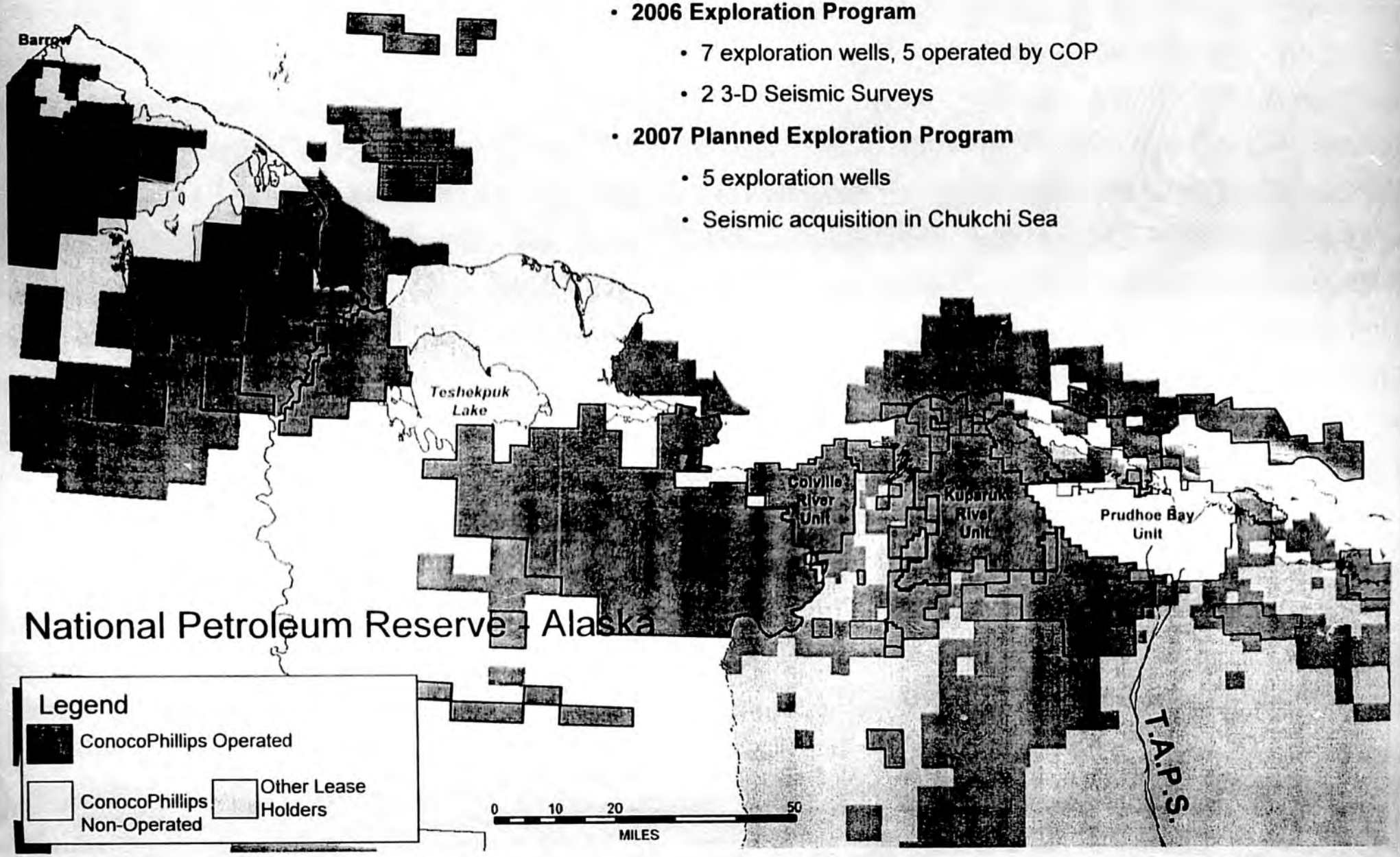
Predicting Natural Gas Prices



Source: New York Mercantile Exchange, Henry Hub Basis

Largest Base for North Slope Development

- **2006 Exploration Program**
  - 7 exploration wells, 5 operated by COP
  - 2 3-D Seismic Surveys
- **2007 Planned Exploration Program**
  - 5 exploration wells
  - Seismic acquisition in Chukchi Sea

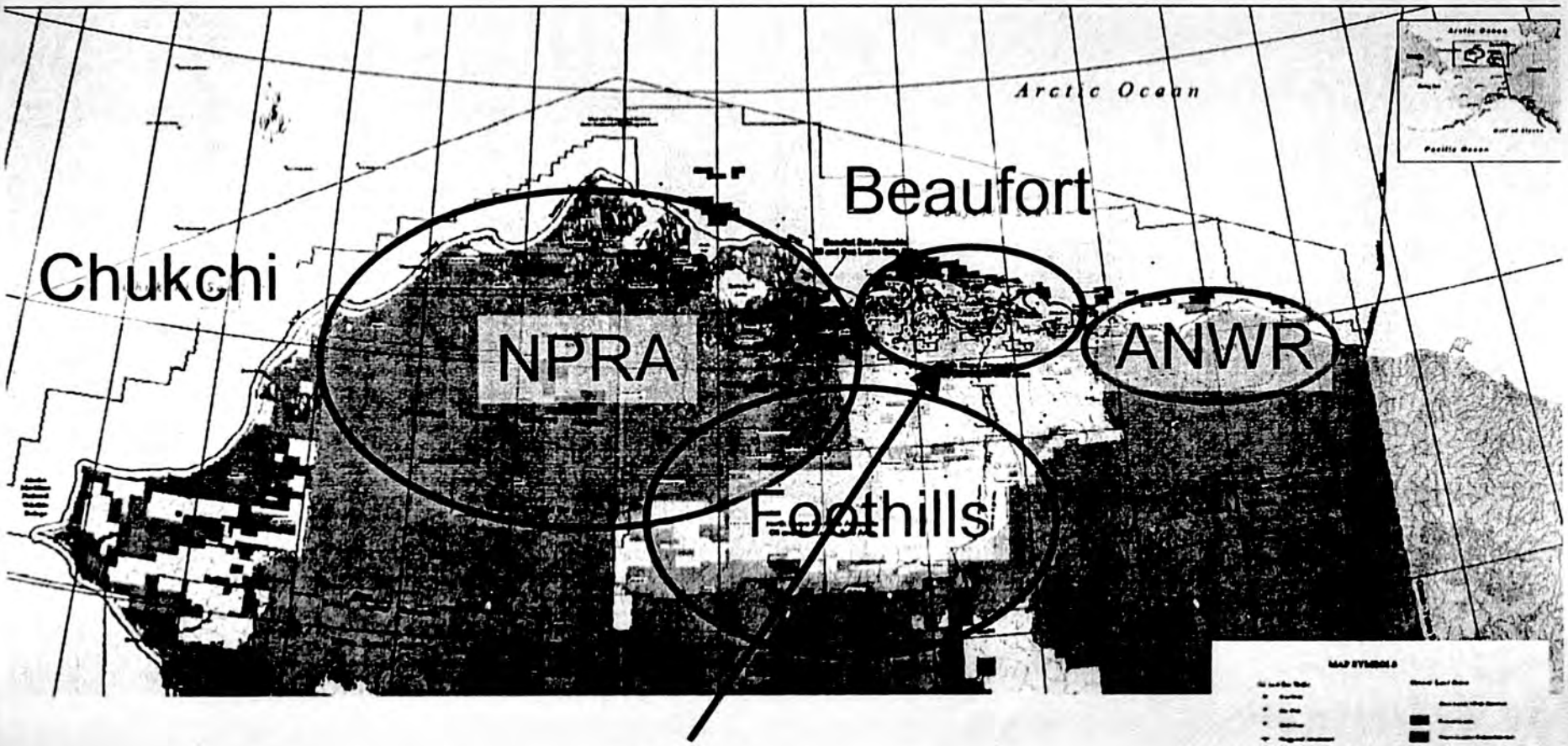


AGIA Project Risk Allocation

Project Risk	Pipeline Entity	Initial Shipper	Late Shipper
Upstream development and operating costs		XX	X
Gas reserves and deliverability		XX	XX
Increased State take over period of FT		XX	X
Increased tariffs from rolled-in rates on expansions		XX	X
Project delay causing increased costs	X	XX	X
Obtaining shipping commitments from creditworthy parties	X		

Risks are greater for initial shippers

Alaska's North Slope



Existing infrastructure
predominantly on State Lands

ConocoPhillips

ANS Exploration Potential

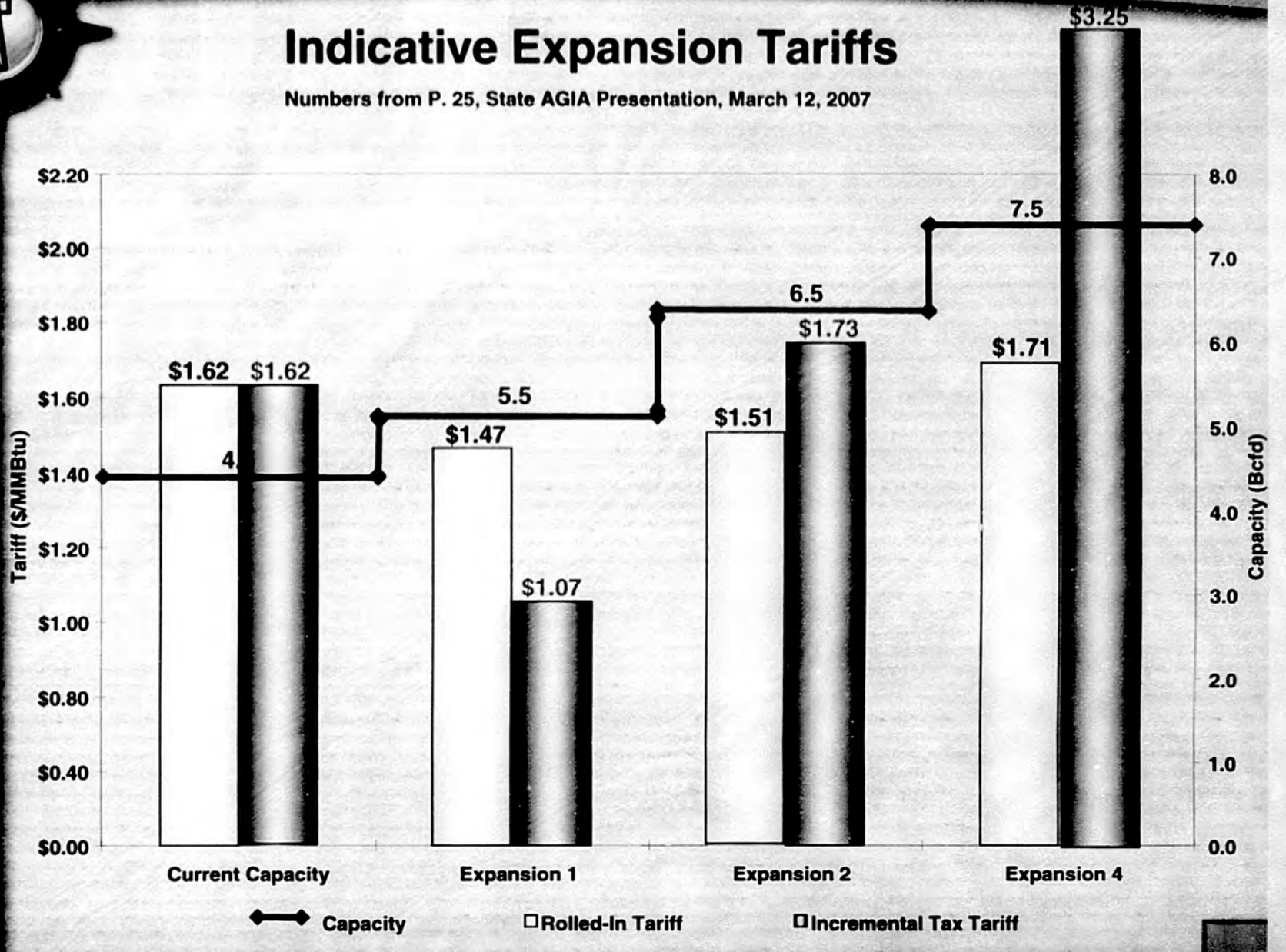
	Acres	Range (5 – 95%)	State Royalty?	State Taxes?
State lands* (onshore & offshore)	15 million	24 – 45 TCF unassociated	**Yes**	**Yes**
Private lands* (mostly native)		3 – 6 TCF associated		**Yes**
Federal onshore				
1002 Area of ANWR	19 million	0 – 20 TCF	Shared Federal Royalty	**Yes**
NPRA	23 million	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)

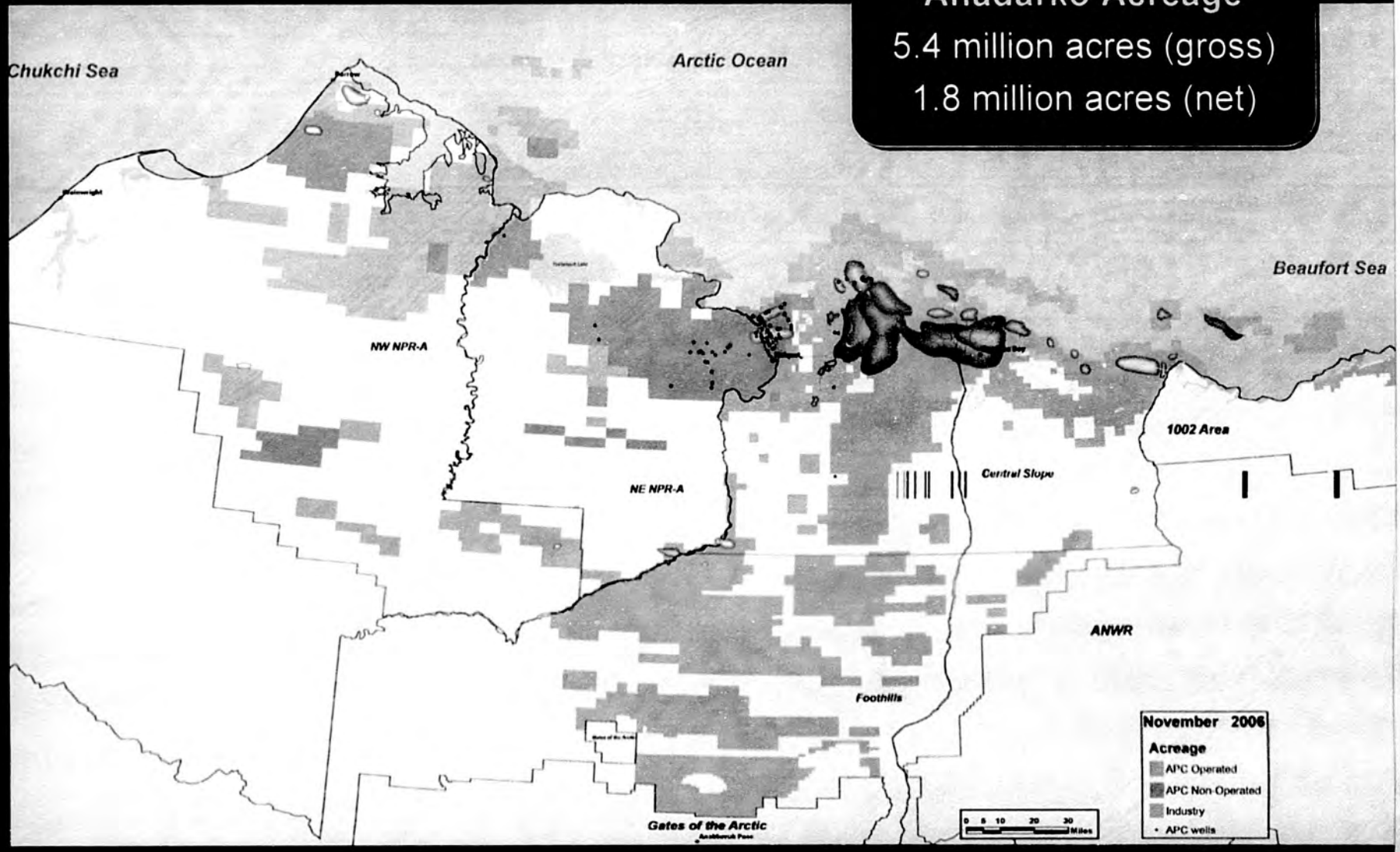
Indicative Expansion Tariffs

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



Anadarko's Investment in Alaska-Land

Anadarko Acreage
5.4 million acres (gross)
1.8 million acres (net)



Testimony of Kirk Morgan, President Kern River Gas Transmission Company
to the House Oil & Gas Committee
Alaska House of Representatives
March 29, 2007

Good afternoon.

Thank you Mr. Chairman, I appreciate the opportunity to testify to this committee on behalf of MidAmerican Energy Holdings Company concerning the proposed Alaska Gasline Inducement Act.

My name is Kirk Morgan. I am president of Kern River Gas Transmission Company, a wholly owned subsidiary of MidAmerican Energy Holdings Company. MidAmerican has assets totaling $37 billion and an employee base of 18,000. MidAmerican, through Kern River and its sister company, Northern Natural Gas, owns and operates more than 17,500 miles of interstate natural gas transmission pipelines with a combined capacity exceeding 6.4 Bcf/d. MidAmerican's pipelines deliver approximately 8.3% of the natural gas delivered in the United States. The Kern River pipeline, which our company built in 1991, brings natural gas from the Rocky Mountain supply basins across 926 miles of rugged mountainous and remote desert terrain to customers in Utah, Nevada and California. Kern River was the largest gas pipeline project to have been built in the United States in more than a decade. In 2003, Kern River expanded the pipeline, more than doubling its capacity, adding 717 miles of 36-inch and 42-inch diameter pipeline. The $1.2 billion project was completed on time, $87 million under budget, and helped restore stability to energy markets in the Western United States.

MidAmerican is a subsidiary of Berkshire Hathaway, Inc. Berkshire is one of only a few companies in the world with a AAA credit rating. Berkshire has a market capitalization in excess of $160 billion. It is recognized world-wide for financial strength, investment acumen and integrity.

The development of Alaska's huge natural gas reserves is essential to both Alaska and the United States. Projected market growth, combined with a decline in North American production, has created a growing supply/demand imbalance that cannot be adequately addressed by traditional gas supply basins alone. Alaska's natural gas is needed to help ensure energy security, reliability and price stability in the United States.

The Alaska natural gas pipeline project is unprecedented in its scale and complexity. The successful development of the project will require an alignment of stakeholder interests, including the state of Alaska, the North Slope producers, future North Slope explorers and producers, a pipeline developer, shippers and the federal government.

Projects of this scale can be easily delayed. (That has been the history of this project.) Only through proper planning, organization and execution can the project achieve its goals to accelerate development of Alaska's natural gas resources and transport gas to lower 48 markets at the lowest reasonable cost. To do otherwise will relegate this project and development of this resource to reacting to the next energy crisis where goals are frequently compromised in the interest of expediency.

MidAmerican has a serious interest in developing this project in a manner that is consistent with the state of Alaska's interests. From our perspective, the negotiations conducted by the pervious administration under the Stranded Gas Act were not fruitful for many reasons. Foremost among these were that they produced proposals not supported by the people of the state; they failed to give serious consideration to alternative proposals for development; and they consumed years without advancing the project.

We believe AGIA is a positive step toward revitalizing the gas pipeline development process in a way that will move the project forward. The bill will allow consideration of competing proposals and ideas for developing the pipeline. The state benefits from such competition. The bill offers positive inducements to those who already have discovered gas to commit to the pipeline, while defining tariff provisions that will encourage new exploration. And the bill offers inducements to a pipeline developer to advance the project in a manner that the state defines as in its best interest. Perhaps most importantly, the bill establishes a process where each party that proposes to develop the line must make meaningful commitments to development milestones for the legislature and the public to see what it will and will not do and by what dates.

AGIA is a good first step. AGIA is an open, transparent and competitive process designed to advance the project on a deliberate schedule and in a manner that achieves the overarching goals of the State which are to 1) encourage new exploration on the North Slope, 2) provide for expansion of the pipeline as new reserves are brought into production, 3) achieve the lowest cost commercially reasonable tariff, 4) create jobs for Alaskans, and 5) provide natural gas to Alaskans for in-state use.

AGIA recognizes the magnitude of front-end development risks and offers to share that risk, in a significant way, by offering dollar-for-dollar matching of initial development expenditures, by offering worker training for Alaskans, and by committing to expedite state permitting requirements. These, plus separate inducements offered to resource owners, are significant commitments which signal to the marketplace that the project is moving on a serious and credible path to completion. In the absence of such progress, markets will have no alternative than to seek other means to meet market demand. The most significant alternative would be to allow imported LNG even greater market access, uncontested by development of Alaska's natural gas resources.

While LNG is certainly a necessary part of the natural gas resource mix, it makes little policy sense to unnecessarily increase our reliance on foreign energy from many unstable and unpredictable regions around the world. This project, in MidAmerican's view, is undeniably necessary and the time is now to push it forward. The key to moving the project forward is to determine the appropriate balance of risks and rewards for all stakeholders.

There is an alternate approach. The North Slope producers have for years articulated their "must haves" before advancing the project. You have heard these prerequisites before including: 1) tax and royalty certainty on gas and on oil, 2) regulatory certainty in both the U.S. and Canada, 3) cost reductions through technological advancements, and 4) federal enabling legislation.

This approach is effectively saying that the project will get started if and when all of the pre-conditions have been met and all concessions have been extracted. This approach has proven to be ineffective in advancing the project.

MidAmerican's approach is different. We believe the project can be advanced concurrent with resolution of issues that today remain outstanding. I want to emphasize MidAmerican's view that alignment of stakeholder interests is essential. Parties will understandably act in their self-interest and in their own business interest. That is why stakeholder interest alignment is critical to a successful project. That alignment must clearly set forth the roles and responsibilities of each party, as well as the commercial structure which will balance the risks and rewards, such that investment expectations will be known up front. Our approach does not exclude interested parties or discount new ideas which may be offered to help manage project risks. We know that even if the pipeline is developed by an independent developer, the North Slope producers will play the crucial role as shippers on the line and sellers of gas to other shippers. MidAmerican, as an independent pipeline, is impartial and in a unique position to help facilitate solutions when stakeholders' interests diverge. We are confident that an appropriate capital structure and rate design, coupled with our low cost of capital and project experience, can result in a project structure with appropriate allocations of risk and reward for all stakeholders, including the state of Alaska and the producers.

Indeed, MidAmerican believes that an independent pipeline provides the best alignment of interests. National energy policy promotes, in fact requires, competition and the unbundling of market segments. For example, the market structure in the United States typically requires that exploration and production, interstate transportation, marketing and distribution be performed by separate companies. Competition, not market concentration, will lead to efficient markets. MidAmerican has no upstream, downstream or global commercial interest that would create any conflicts of interest or raise any type of market power concern with respect to this project. Accordingly, MidAmerican's interests align extremely well with the state of Alaska and include:

1) Accelerating development of this critically important project;
2) Achieving the lowest cost commercially reasonable tariff;
3) Offering a commercial structure that encourages new exploration and production to both expand and extend the life of the pipeline. Thirty-five Tcf implies only a 22-year project life, and new discoveries are critical to fill the pipeline over its useful life;
4) Providing open-access, non-discriminatory transportation services to ensure both receipts and deliveries are provided for in-state use; and
5) Ensuring Alaskan jobs and workforce development. The state's commitment to workforce training and development is extremely important. Skilled labor shortage is one of the contributing factors in construction cost increases throughout the industry. A skilled Alaskan workforce will not only ensure jobs for Alaskans, but will help address an industry-wide demand for these workers.

The process set forth in AGIA will allow these ideas, and all parties' ideas and proposals, to be advanced and tested in an open and transparent manner. We support that process and while we can understand debate over what constitutes the best pipeline development proposal, it is harder to understand why parties would object to a process that calls for an open and transparent comparison of proposals. We urge the legislature to approve this legislation this session, so that a pipeline developer can be selected in a time frame that will allow a productive 2008 field season for engineering and environmental programs to be conducted.

That concludes my prepared testimony. Thank you for the opportunity to appear before you today. I would be happy to address any questions.

ALASKA GASLINE
PORT AUTHORITY

COMMENTS AND RECOMMENDATIONS FOR ALASKA GASLINE INDUCEMENT ACT

While the Port Authority would be willing to submit an application under the AGIA in it's current form, we believe the bill can be improved through the legislative process and make the following suggestions for improvements to this legislation:

1. Section 43.90.140(2) (D) ii requires approximately 10 specific areas of information for an LNG project applicant, however if you are an applicant for a project through Canada there are little specifics required as to that route. We would suggest a Canadian line project applicant include (a) a detailed description of all access and tariffs for downstream elements (b) if it is a project to Alberta, how does it get from there to the Midwest (tariffs and terms) (c) where do they intend to offtake the liquids and at what terms (d) who will own and control the facilities. Basically, the same things that they are asking from the LNG project should be included for a Canadian line.
2. Applicants requiring an initial offtake from PBU in an amount greater than that presently allowed by the Alaska Oil and Gas Conservation Commission (AOGCC) should be required to have already filed an application with the AOGCC for a determination that the amount of offtake in excess of the current Rule 9 limit on Prudhoe Bay offtake will be allowed.
3. If the appplicant's project requires the discovery of additional gas, they should include a cost estimate and timeline for the additional gas exploration.

4. The applicant should be required to provide an analysis of how their project would affect oil loss and ultimate oil recovery of a field.
5. An additional criterion should be added which would identify if the applicant is making gas liquids available within Alaska for value added processing.
6. Timeliness of project construction should be given a high priority in the evaluation. Alaskans need access to our gas now. Previous net present value analyses have shown that an earlier project brings substantial value to the state.

Alaska Gasline
PORT AUTHORITY

Alaska Legislature Testimony

March, 2007

The Alaska Gasline Port Authority ("AGPA")

- A municipal port authority established by the voters of the Fairbanks North Star Borough, the North Slope Borough and the City of Valdez on October 5, 1999
    - in accordance with AS 29.35.600 the Alaska Municipal Port Authority Act

- Formed to build or cause to be built a project that will commercialize Alaska's North Slope gas

The Alaska Gasline Port Authority ("AGPA") (cont'd)

- Formed to ensure:
  1. A gasline is built
  2. Lowest tariff for Alaska's gas to Alaskans and marketplace
  3. Stable source of energy to Alaskans not tied to Lower 48 price index (Henry Hub, etc.)
  4. All pipeline and liquefaction associated jobs are within the state of Alaska; including construction, operation, and maintenance
  5. Direct net-project revenue sharing – 60% to State / 40% to every Alaska municipality
  6. Earliest opportunity for in-state gas availability
  7. Greatest opportunity to supply gas liquids to in-state petrochemical industries

AGPA Project Description

Alaska Gasline Port Authority

Pipeline from Prudhoe Bay to Valdez

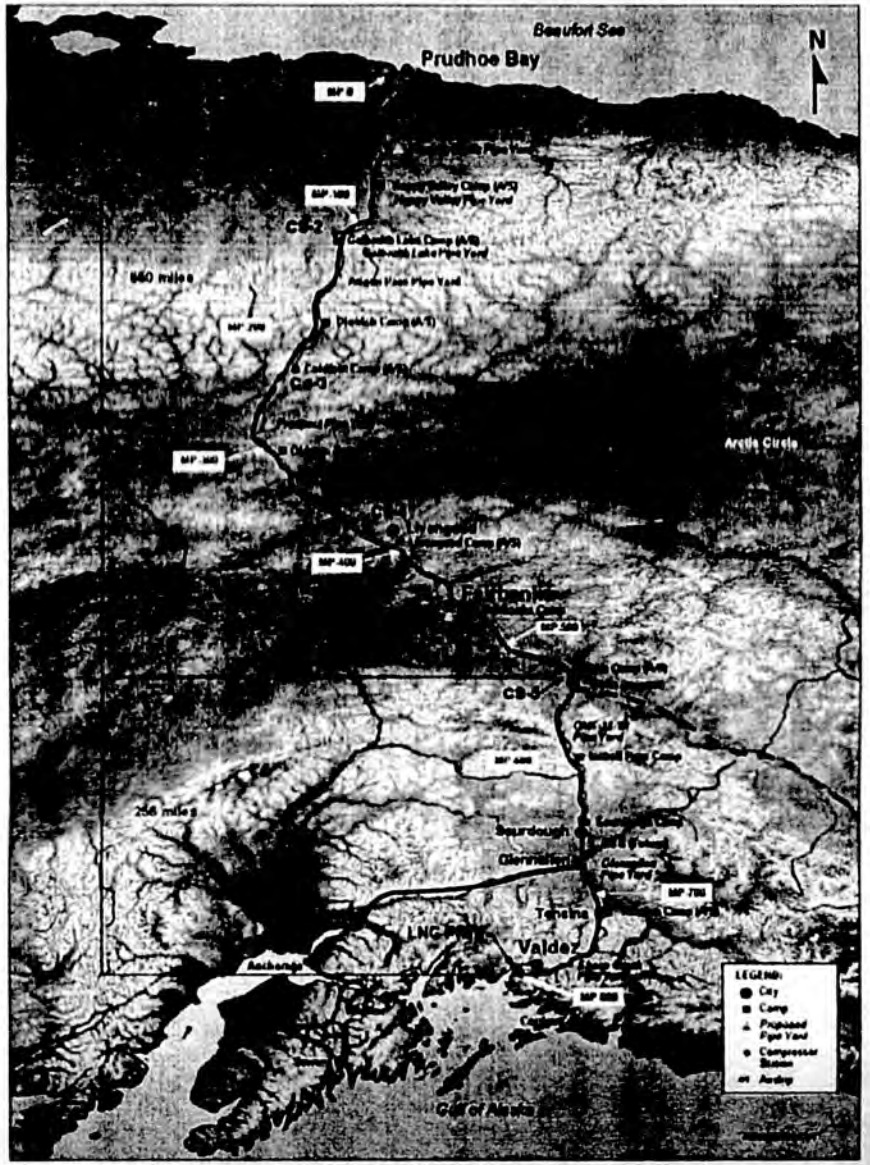
- parallel to TAPS
- pre-build to Delta Junction for later tie-in for the Alaska/Canada Highway Project
- tie-in at Glennallen for a spur line to Alaska South Central natural gas grid

LNG Facility in Valdez

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

Gas Conditioning Plant in Prudhoe Bay

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



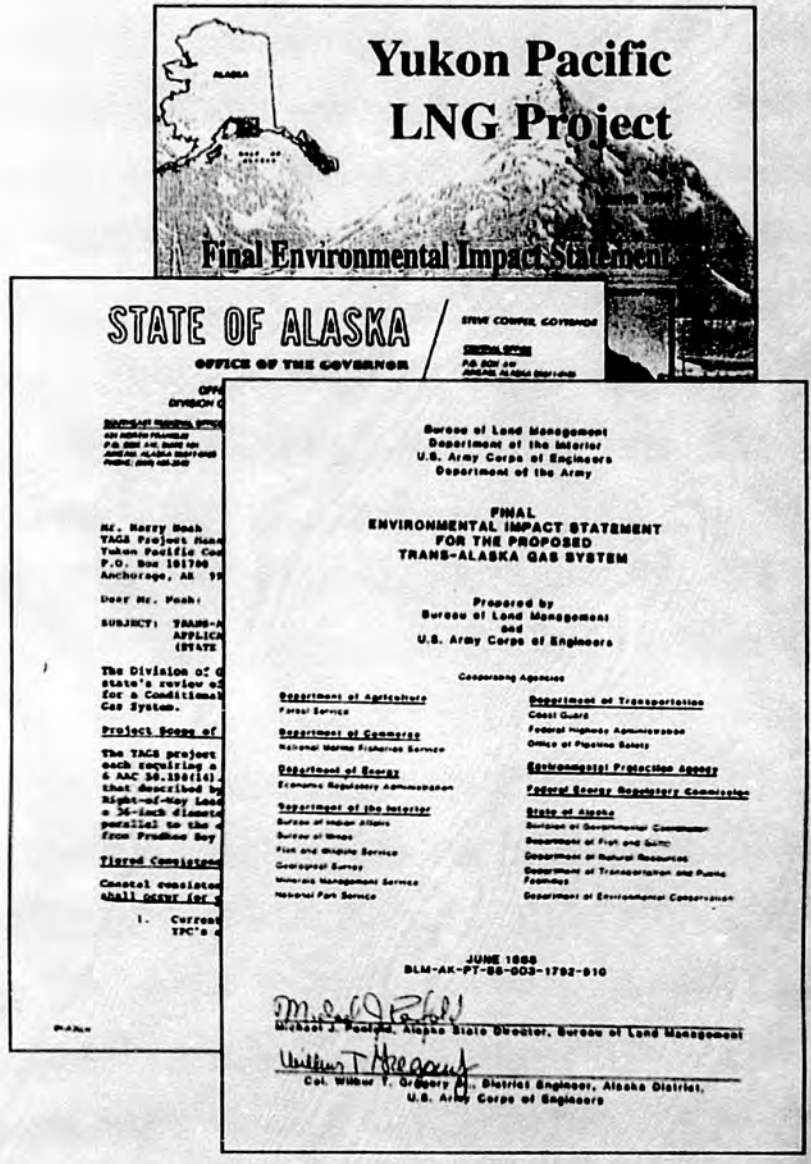
AGPA Project: Permits

Yukon Pacific Corporation ("YPC")

- Formed in 1982 by William Egan and Walter Hickel, former Governors of Alaska
- Sole purpose: to build a trans-Alaska gas pipeline to Valdez for the export of LNG
- Parent company is the CSX Corporation

YPC Permits

- YPC has obtained numerous State and Federal permits and rights associated with a Trans-Alaska gas pipeline and Alaska LNG project
- Over $100 million of expenditures in obtaining of environmental data and regulatory and environmental permits
- CSX has entered into an exclusive option agreement with AGPA to sell YPC and the permits



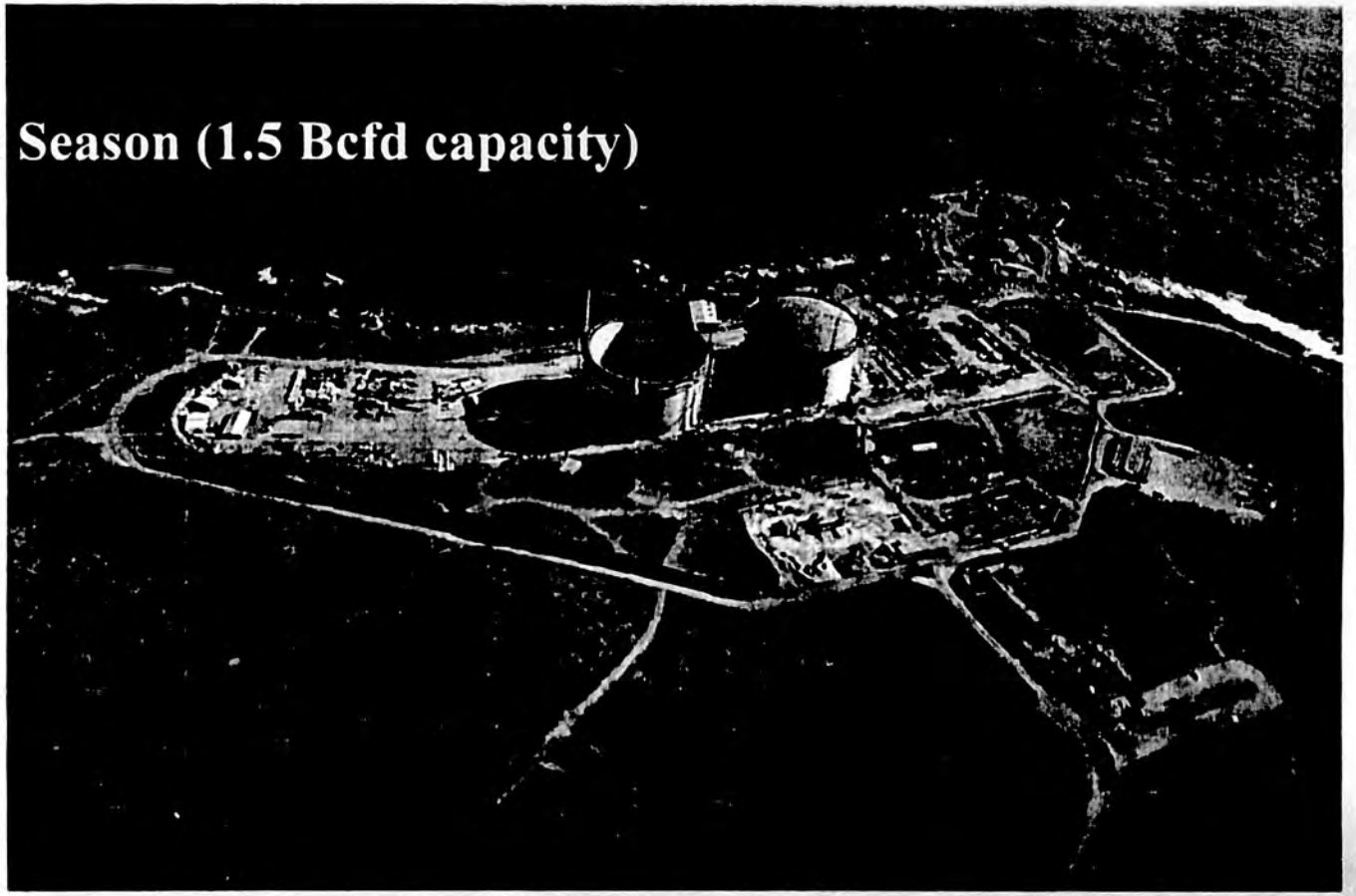
Energia Costa Azul / Sempra LNG

i. **Currently Under Construction**

ii. **Initial LNG Supply:**

- **50% from British Petroleum**
- **50 % Shell**

iii. **Expansion Open Season (1.5 Bcfd capacity)**



AGPA Project: Progress To Date

- ☑ Established by public vote
- ☑ Positive IRS ruling on exemption from federal income taxes
- ☑ EPC study performed by Bechtel
- ☑ EPC cost update in 2005
- ☑ Detailed economic and financial analysis and modeling
- ☑ Secured exclusive option on existing project permits
- ☑ Act of Congress to add LNG project to $18 billion federal loan guarantee
- ☑ Strong interest from N. American gas market participants
- ☑ Participation in the Open Season for the expansion of the Energia Costa Azul regasification terminal in Baja California, Mexico
- ☑ MOU with Mitsui OSK Lines and BGT Ltd regarding marine transportation requirements
- ☑ MOU with the Alaska Natural Gas Development Authority (ANGDA) for Glenallen to Palmer spurline

ANS Gas Commercialization

- AGPA's objective is to promote the timely commercialization of Alaska's North Slope gas resources

- AGPA is actively developing the LNG concept as the first step towards full commercialization of ANS gas:
  - initial phase: in-state gas distribution to maximum extent practical, LNG project
  - full ANS gas commercialization: pipeline projects through Canada, LNG expansion

- AGPA's goal: obtain gas supply to enable commercial operation within the 2013–2014 timeframe

ANS Gas Commercialization: (cont'd)

- Gas requirements:
  - Current ANS discovered gas resource: 35 Tcf
  - Alaska LNG project initial phase gas requirements: 15-25 Tcf
  - Proposed AlCan Highway pipeline project through Canada: 50-65 Tcf

- It is expected that with further exploration, the ANS gas resource will be increased to over 100 Tcf

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

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

ANS Gas Commercialization: (cont'd)

- In anticipation of full ANS gas commercialization, AGPA has proposed to pre-build the pipeline section from Prudhoe Bay to Delta Junction to accommodate eventual larger gas volumes to Canada
  - pipeline diameter to allow expansion to 6 Bscf/d of capacity
  - Canadian pipeline could tie in at Delta Junction
  - phased development reduces pressure on steel/pipe markets
  - shared line to Delta Junction reduces unit cost for both projects

- AGPA is prepared to work in a partnership with a project developer of the Canadian Highway route
  - timetable will be coordinated with Canadian pipeline project developer

Advantages of LNG from Alaska

- Alaska LNG will be competitive with other gas suppliers in the North American gas market, including international LNG suppliers

- 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

Advantages of LNG from Alaska (cont'd)

- Valdez Port:
  - ice free, deep water port
  - most advanced vessel tracking system in US
- 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)
- Low-risk political environment in comparison with some international suppliers

AGIA Suggested Amendments

- More detail required from Canadian line applicants
- If offtake amounts outside AOGCC Rule 9 limitations (2.7 bcf/d), 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

AGIA benefits towards advancing gas pipeline

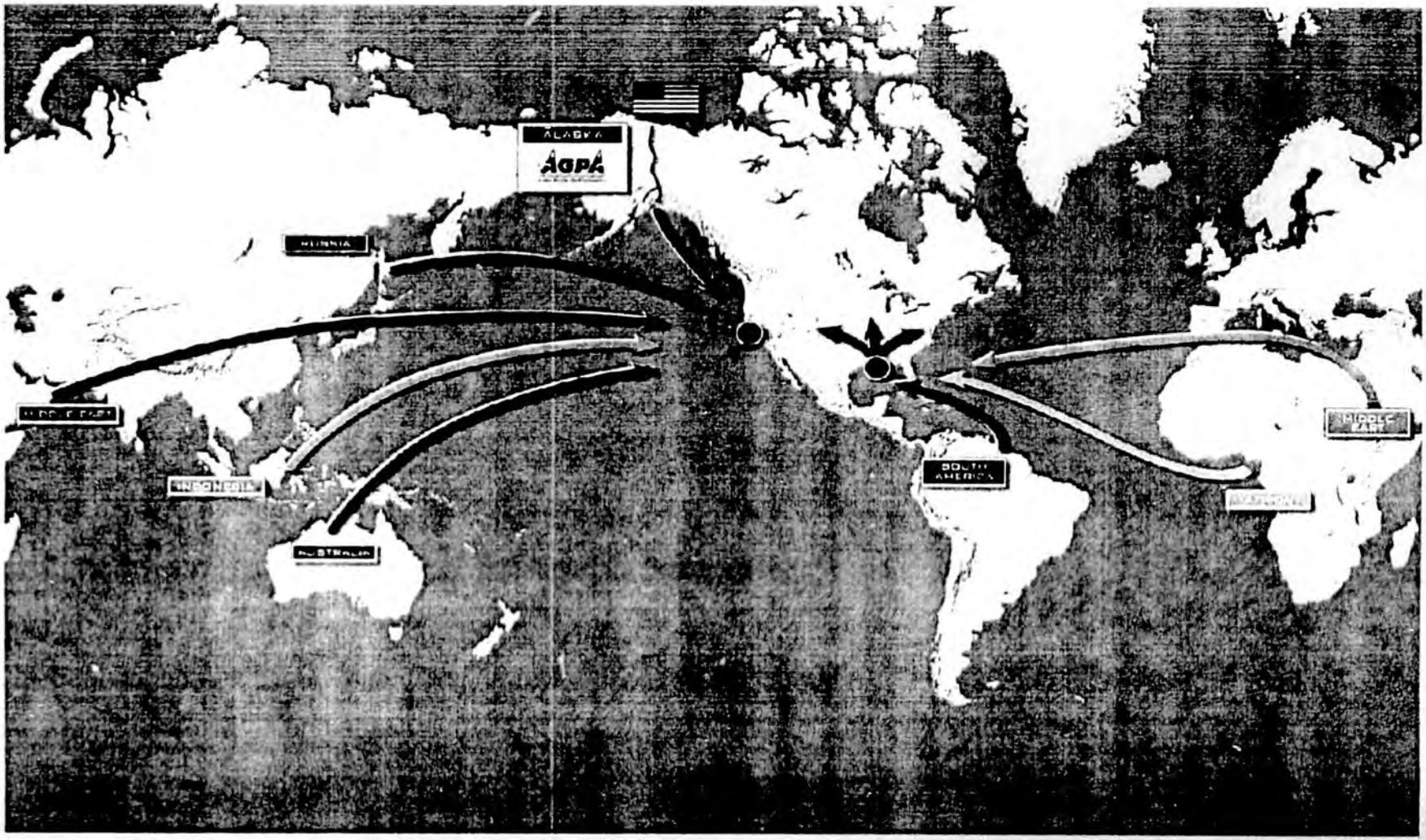
- Rolled in rates – good for Alaska's future
- Allows for independently owned infrastructure
- $500 million skin in the game – sends very positive message about Alaska's desire to commercialize Alaska's gas

Alaska at Strategic Crossroads

- **AGIA**
  - Open and transparent
  - Identified evaluation criteria
  - Inducements in exchange for specific commitments
  - Empowers selected applicant to build successful consortium, leading to open season

- **Return to Stranded Gas Act**
  - No identified criteria
  - No requirement to justify need for concessions
  - State in compromised negotiating position
  - No commitments other than spending levels

Competition for U.S. Gas Markets – Alaska's Risk



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



Alaska Gasline
PORT AUTHORITY

Chevron

AGIA Testimony
HB 177

John Zager
General Manager, Alaska

Tim Houston
Alaska Commercial Manager

Juneau, Alaska
March 29, 2007

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AGIA Observations

- Chevron's stake in the outcome
- Various stakeholders have different objectives
- Recognition that we either succeed or fail together
- It's all about alignment and risk allocation
- Participants are disciplined investors

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Gasline Objectives Vary

State of Alaska	Pipelines	Producers	Explorers
• Long Term Revenue • Low tariffs – High Netbacks, but willing to accept higher tariffs for other benefits ■ Guaranteed access & expandability ■ Gas for Alaska ■ Rapid schedule ■ Jobs ■ Economic Activity	• Earnings • Financeable project ■ Long-term FT Contracts ■ Assured cost recovery ■ Limited completion risk • Low tariff to attract more gas to expand or extend life of pipeline	• Earnings • Low tariff for those providing initial FT- High Netbacks • Project that meets plan ■ No cost overruns ■ No schedule slips • Lowest cost pipeline • More gas for expansions that lower overall rate	• Earnings • Assured access for new discoveries - Expandable Pipeline • Low tariffs for expansion - High Netbacks

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AGIA Observations

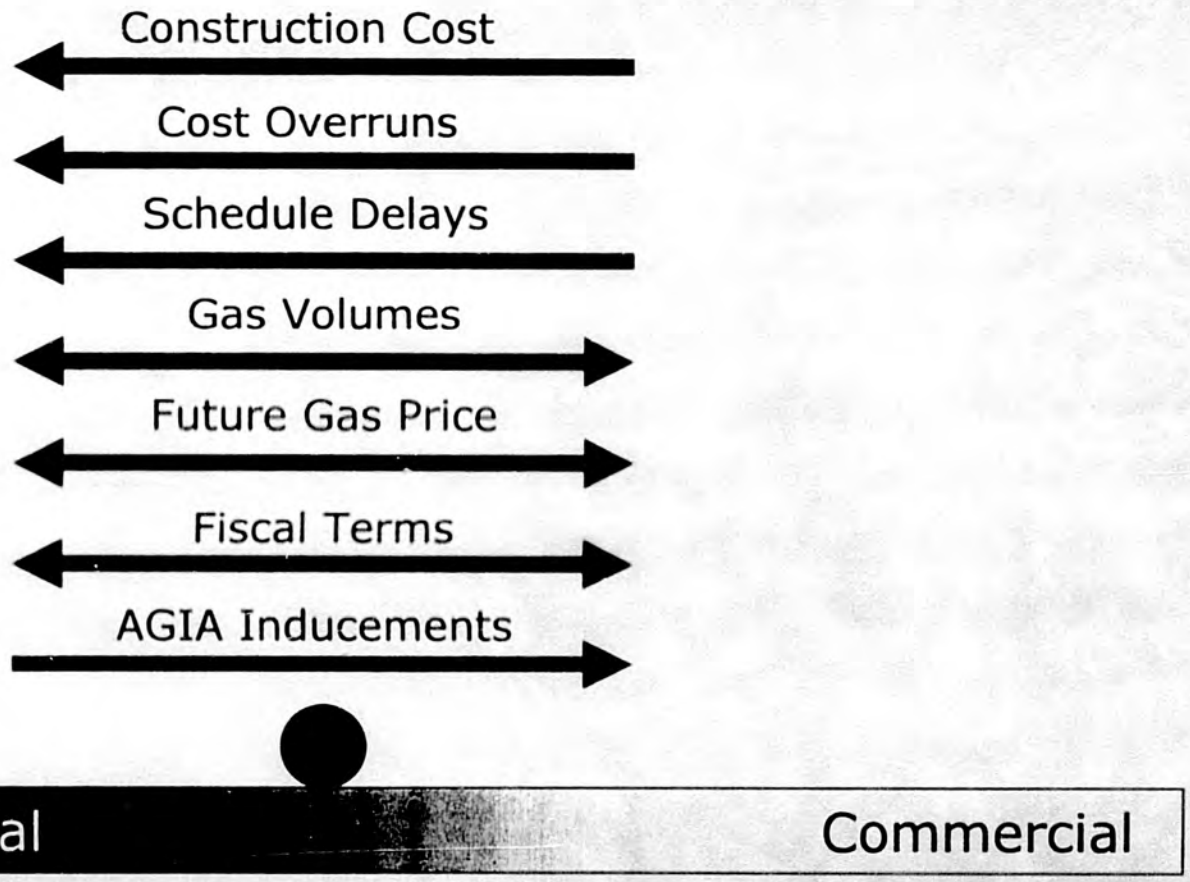
- AGIA provides inducements for key risks in two segments
  - Midstream
    - $500 million of upfront development costs
    - Exclusivity & streamlined processes
    - Upstream inducements apply only to selected project
  - Upstream
    - Royalty "higher of" language
    - State "take in kind" or "take in value"
    - Gas tax rates "locked" for 10 years

- Are these sufficient for a successful open season?

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Key Commercial Influences

- Cost and allocation of risk will effect the commercial viability of the project
  - Where is the ball? How can we "move the ball" forward?



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AGIA – What will help "move the ball"?

- Longer and more comprehensive fiscal stability
  - "The exemption under this section may be applied within 10 years …" [Sec 43.90.320 (b) page 16]
- Limit cumulative impact of rolled-in rates
  - "… recovery of all expansion costs … increase existing shippers' rates by no more than 15 percent of the initial maximum recourse rate …" [Sec 43.90.140 (7) p.6]
  - "… in order to exercise an election under this section, … will not protest or appeal a filing by the licensee to roll in expansion costs … required in AS 43.90.140.(7);" [Sec 43.90.310 (b)(4) page 15]
- Remove future uncertainties where possible
  - "… The commissioner of natural resources shall … at least every two years … determine whether the regulations continue to meet the requirements of this section under current conditions; the commissioner shall amend the regulations as necessary.;" [Sec 43.90.310 (c) page 15]

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Summary

Chevron's driver is to monetize our gas on the slope.

To be successful alignment must be created, the participants need to work together to realize a solution. Chevron will work to the best of our ability to help make that happen.

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