

**SB**

**104**

**(FILE 3)**

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**FILE**

# STATE PRESENTATIONS

AGIA

4/23/07

The Palin-Parnell Administration presents

# AGIA

The Alaska Gasline Inducement Act

Senate Finance

4/23/2007

# AGIA Overview



The Alaska Gasline Inducement Act

## AGIA:

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

# Commercial Vehicle



- AGIA uses competitive bidding, not negotiation.
- Successful bidding process requires AGIA's inducements
  - Without inducements, no third-party bidders
  - Without third-party bidders, state has no ability to get a pipeline on its desired terms

# Commercial Vehicle



## AGIA's inducements:

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

# A Project on the State's Terms



- By creating a more competitive playing field, state can specify some “must haves”
- State’s “must haves” focus on its future:
  - A pipeline sooner
  - A competitive and vibrant oil and gas industry
  - Jobs and careers, not only from the pipeline itself, but also from a competitive oil patch
  - Gas for Alaskans

# A Project on the State's Terms



- State's "must haves" all obtained through pipeline tariff and access terms that ensure a competitive oil and gas industry
  - Competitive oil and gas industry can flower if pipeline ownership gives no upstream competitive advantage
  - Jobs and careers for Alaskans will be maximized by ensuring a competitive upstream industry
  - Cheap gas for Alaskans will be enjoyed if pipeline regularly expands

# A Project on the State's terms

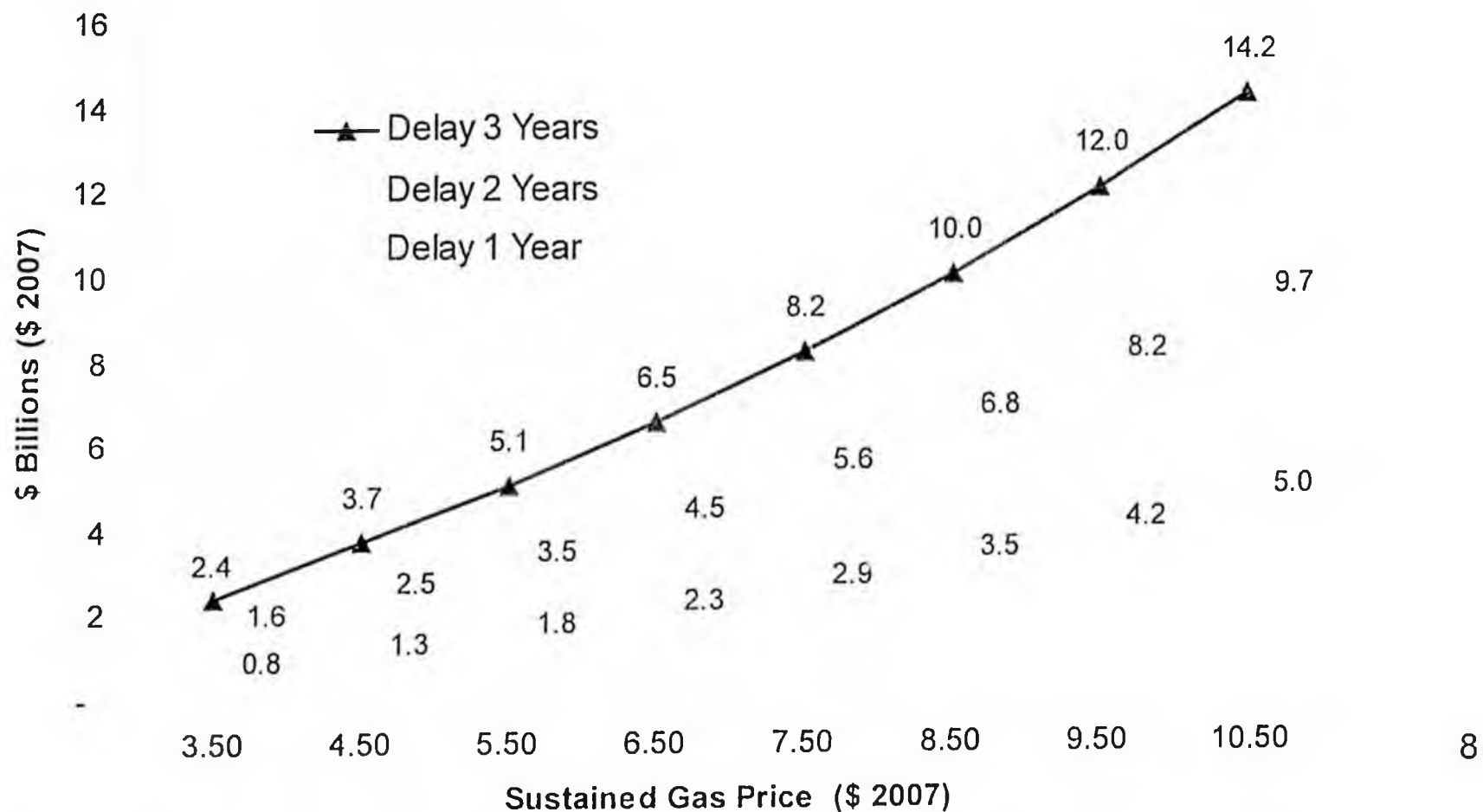


- A pipeline sooner
- Required minimum 70/30 debt/equity ratio ensures reasonable base tariffs
- Expansion requirements ensure that gas found by any party can access the pipeline
- Rolled-in rate requirements ensure that all parties have an economic incentive to explore for gas, competition for oil and gas, and all of Alaska's gas can get into the pipeline

# Gets a Pipeline Sooner



## Losses to State for Each Year Delay Discounted at 5% per Year



# Tariff and State Revenue Effects of Debt-Equity Structure



The Alaska Gasline Inducement Act

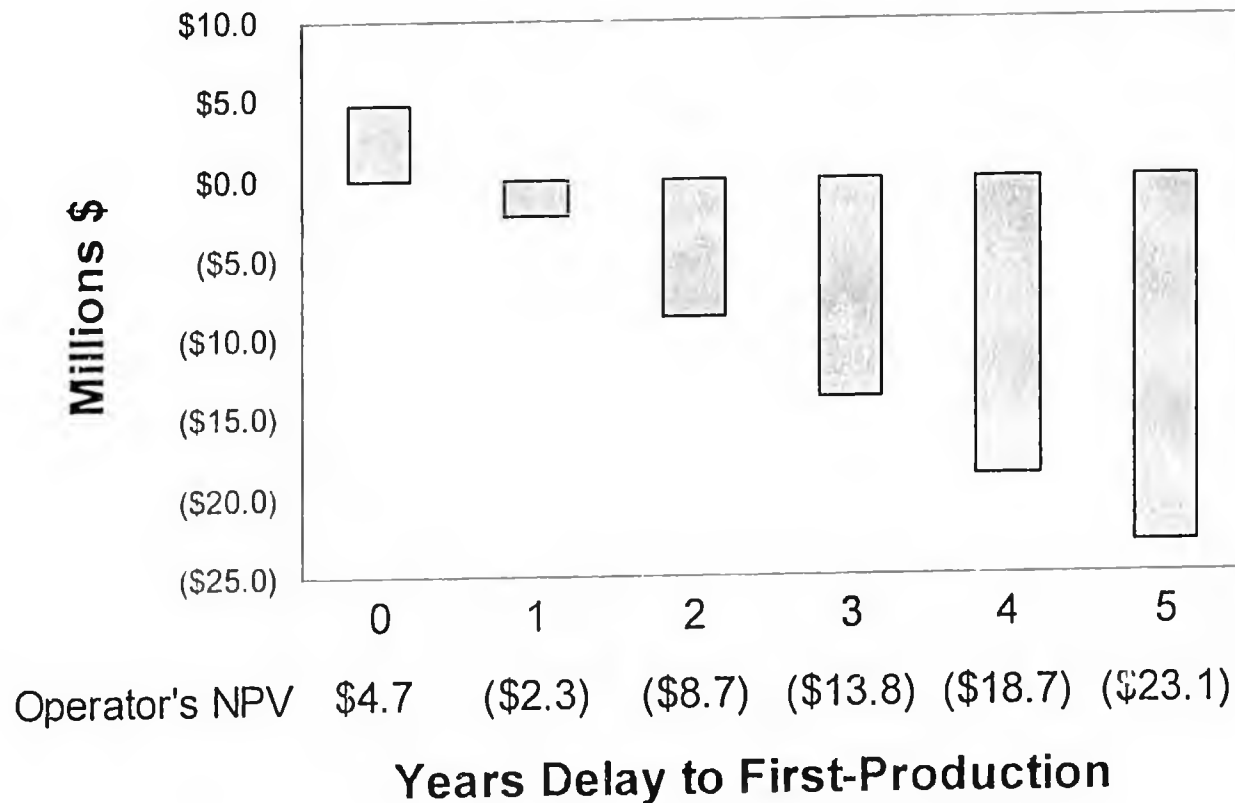
Debt%	Equity%	Tariff	Present Value State Revenue \$ Billions
80%	20%	\$1.47	37.4
75%	25%	\$1.56	36.9
70%	30%	\$1.65	36.3
65%	35%	\$1.74	35.7
60%	40%	\$1.84	35.1
55%	45%	\$1.95	34.5
50%	50%	\$2.06	33.8
45%	55%	\$2.18	33.1

AGIA protects the states interest in low tariffs. It ensures that no less than 70/30 will be used rather than 50/50, with associated tariff benefits of 41 cents and state revenue benefits of \$2.5 billion.

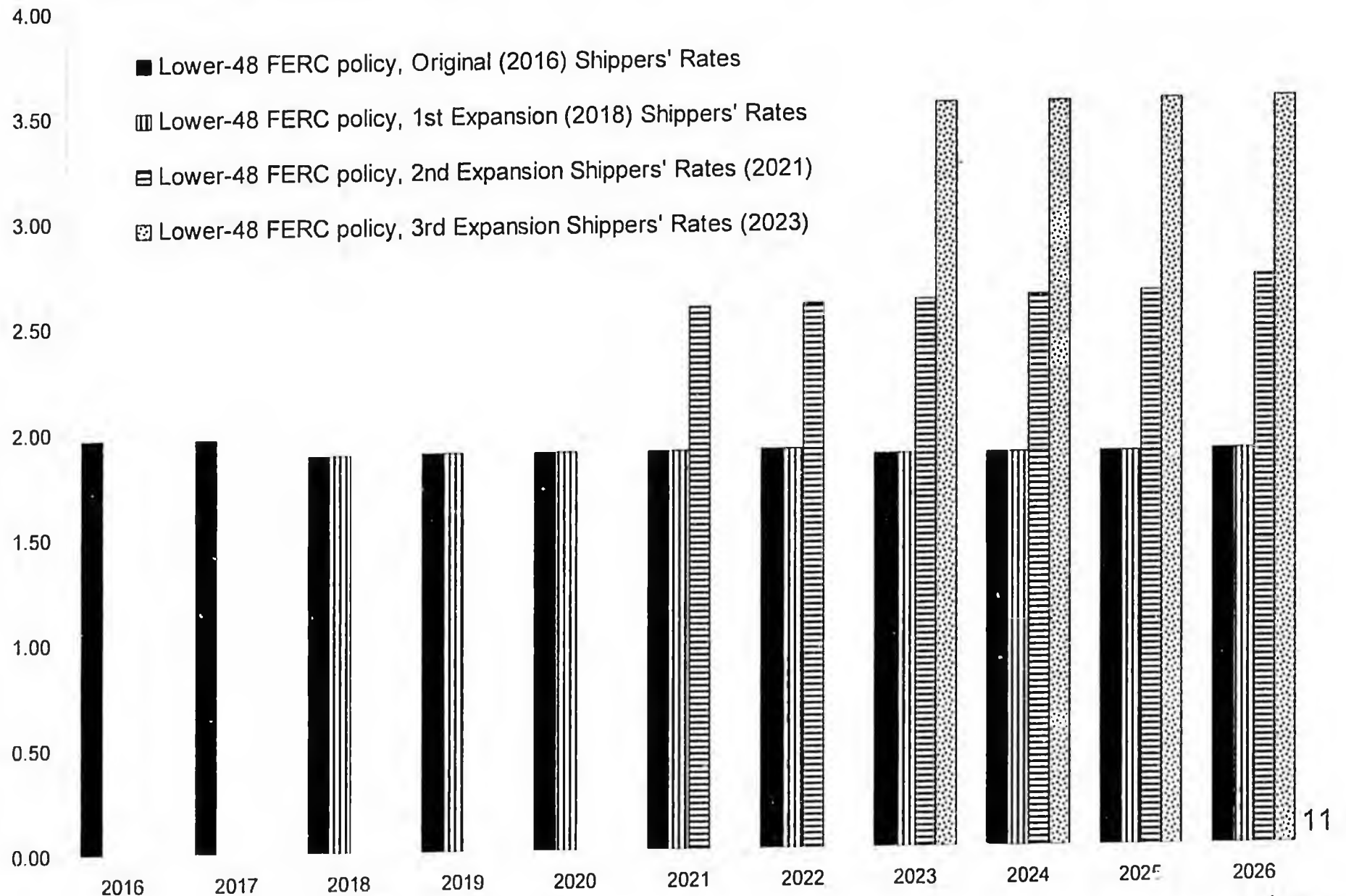
# Expansion Provisions Cost-of-Delay To Explorer



**Expected Net Present Value (NPV 12)**  
Generic North Slope Prospect



# FERC Lower 48 Expansion rate policy

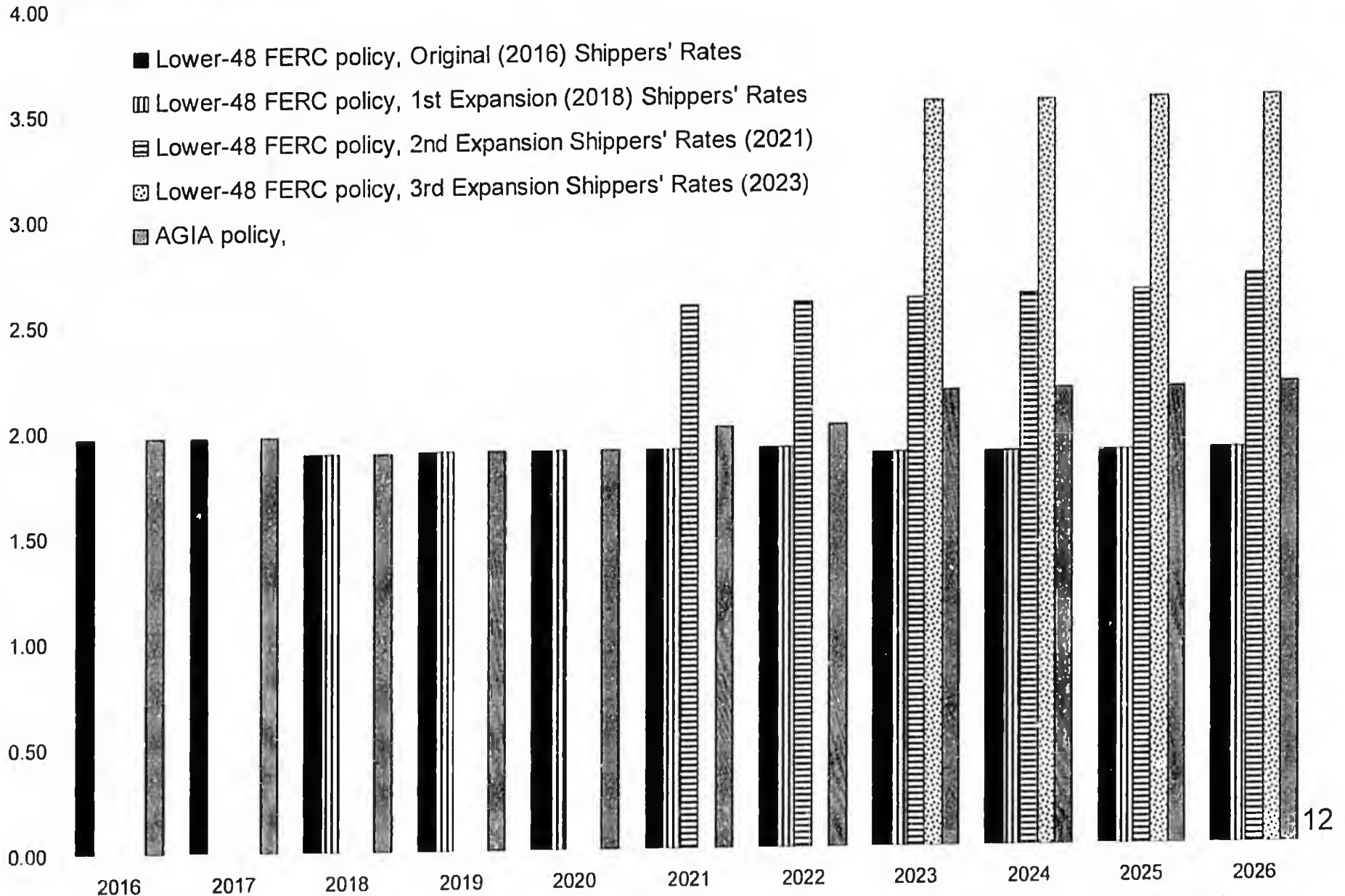


# AGIA

## Expansion rate policy

# AGIA

The Alaska Gasline Inducement Act



# Rolled-in Rates Encourage Exploration



## Examples:

Scenario 1: Add 1 Bcf/day with compression (from 4.5 to 5.5 Bcf/day)

<i>Rolled-in</i>	<i>Incremental</i>
<b>\$6.0 million</b>	<b>\$6.5 million</b>

Scenario 2: Add 1 Bcf/day with compression (from 5.5 to 6.5 Bcf/day)

<i>Rolled-in</i>	<i>Incremental</i>
<b>\$4.3 million</b>	<b>-\$5.4 million</b>

Scenario 3: Add 700 MMcf/day with looping (from 6.8 to 7.5 Bcf/day)

<i>Rolled-in</i>	<i>Incremental</i>
<b>\$ .9 million</b>	<b>-\$25.5 million</b>

# Transparent Public policy



- AGIA creates a competitive process, not a negotiated process
- Bids will be submitted, commented upon by the public, and evaluated
- A winner will be chosen by the Commissioners
- The Commissioners' decision will be reviewed by the Legislature

# Transparent Public policy



- The value of AGIA's inducements are up front and transparent
- Contrast: AGIA's \$500 million versus SGDA contract \$10 billion+
  - Much of SGDA contract value was hidden and unquantifiable
  - AGIA's benefits are explicit and quantifiable

# Summary



- Without competition, and the forward movement that AGIA provides, Alaskans will have to wait, and watch, until the Producers do the pipeline on their timeline and on their terms.
- AGIA changes the playing field.
- AGIA is a **commercial vehicle** that creates a competitive playing field, provides a **pipeline on Alaska's terms**, in a **transparent manner**.

OIL + GAS

INCENTIVES

4/25/07



# Oil and Gas Incentives\*

## ■ Royalty Reduction (DNR)

- AS 38.05.180(j) allows reduction to as low as 5 percent royalty for new production or as low as 3 percent for producing or shut-in fields.
- Reduction in royalties to as low as 5 percent for oil produced from certain Cook Inlet platforms should production fall below specified levels (AS 38.05.180(f)(6)).

## ■ Exploration Incentive Credits (DNR)

- AS 38.05.180(i) allows up to 50 percent of drilling costs on conventional leases; up to 50 percent of seismic costs on unleased state land.
- AS 41.09.010 allows up to 50 percent of drilling and seismic costs on unleased and licensed lands; up to 25 percent on federal and private lands.

## ■ Discovery Royalty (DNR)

- AS 38.05.180(f)(4) Cook Inlet Sedimentary Basin. Five percent royalty for 10 years.
- AS 38.05.180(f)(5) applies to the following Cook Inlet fields: Falls Creek, Nicolai Creek, Starichkof, North Fork, Redoubt Shoals, and West Forelands. Five percent royalty on first 25 MM bbls for 10 years or 5 percent royalty on first 35 BCF for 10 years.

## ■ Exploration Incentive Credits; AS 43.55.025 (DOR)

- Tax credit on wells drilled >25 miles from existing unit boundary (N. Slope\*); up to 20%
- Tax credit on wells drilled >3 miles from any existing oil or gas well (N. Slope\*); up to 20%
- Tax credit on wells drilled >3 miles from any existing oil or gas well *and* >25 miles from an existing unit boundary (N. Slope\*); up to 40%
- Tax credit on seismic exploration activity; up to 40%

## ■ PPT (DOR)

- AS 43.55.023(a) provides for tax credit for Alaska capex (reinvestment) at 20% rate (may be transferred or carried-forward)
- AS 43.55.023(b) provides for tax credit for 20% of net losses (may be transferred or carried-forward)
- AS 43.55.024 provides a tax credit up to \$12 million for small volume producers, phases out on a sliding scale for large volume producers (not transferable)

\*Cook Inlet requirements vary

<u>CURRENT INCENTIVES</u>	<u>CONVENTIONAL LEASES</u>	<u>UNLEASED STATE LAND</u>	<u>LICENSED LAND</u>	<u>SNG LEASES</u>	<u>FEDERAL &amp; PRIVATE LAND</u>
<b>Exploration Incentive Credits (EIC)</b> AS38.05.180(i)	up to 50% of drilling costs	up to 50% of seismic costs	N/A	up to 50% of drilling costs	N/A
AS41.09.010 -- expires 7-1-2007	N/A	up to 50% of drilling & seismic costs	up to 50% of drilling & seismic costs	N/A	up to 25% of drilling & seismic costs
<b>Exploration Tax Credit</b> AS43.55.025 (03.185) Expires 7-1-2007 for NS (C-5-286) Expires 7-1-2010 for non-NS	As much as 40% of drilling costs, or As much as 40% of seismic costs	As much as 40% of drilling costs, or As much as 40% of seismic costs	As much as 40% of drilling costs, or As much as 40% of seismic costs	As much as 40% of drilling costs, or As much as 40% of seismic costs N/A	As much as 40% of drilling costs, or As much as 40% of seismic costs
AS43.20.043 -- expires 1-1-2013 (03.61) for below 68° latitude*** (see note at bottom)	10% of capital investment 10% of annual cost	10% of capital investment 10% of annual cost	10% of capital investment 10% of annual cost	10% of capital investment 10% of annual cost	10% of capital investment 10% of annual cost
<b>Royalty Reduction</b> AS38.05.180(j) (03.28)	as low as 5% if new production as low as 3% if producing or shut-in	N/A	(Applies after conversion to Lease) (Applies after conversion to lease)	as low as 5% if new production as low as 3% if producing or shut-in	N/A
AS38.05.180(f)(6) (03.185)	As low as 5% for oil production from CI platforms if production falls below specified levels	N/A	N/A	N/A	N/A
<b>Discovery Royalty</b> AS38.05.180(f)(4) for Cook Inlet only	5% royalty for 10 yrs	N/A	In limited area after conversion: T18N	(Applies to limited area: T18N)	N/A
Pre-1969 leases only, statewide	5% royalty for 10 yrs	N/A	N/A	N/A	N/A
AS38.05.180(f)(5) for following fields only: Falls Creek, Nicolai Creek, Starichkof, North Fork, Redoubt Shoals, & West Foreland field must be in production by 1-1-2004	5% on 1st 25 MM bbls for 10 yrs 5% on 1st 35 BCF for 10 yrs	N/A	N/A	N/A	N/A
<b>Economic Limit Factor based Ceiling--</b> AS43.55.011(j)(k)	Yes	N/A	(Applies after conversion to Lease)	Yes	Yes
<b>Contract Gas Price With a Utility vs Royalty Value -- AS38.05.180(aa)</b>	Value of state's royalty share equals gas contract price	N/A	(Applies after conversion to Lease)	Value of state's royalty share equals gas contract price	Value of state's royalty share equals gas contract price
<b>Value of state's royalty gas used for ag products -- AS38.05.180(cc) (03.57)</b>	Negotiated Value	N/A	(Applies after conversion to Lease)	Negotiated Value	Negotiated Value
*** If requesting this credit, not eligible for any other tax credits or royalty modifications					

<u>CURRENT INCENTIVES</u>	<u>CONVENTIONAL LEASES</u>	<u>UNLEASED STATE LAND</u>	<u>LICENSED LAND</u>	<u>SNG LEASES</u>	<u>FEDERAL &amp; PRIVATE LAND</u>
Qualified CapEx Credits (PPT) -- AS 43.55.023(a) <i>transferrable</i> credit against PPT	up to 20% of capital expenditures	N/A	up to 20% of capital expenditures	up to 20% of capital expenditures	up to 20% of capital expenditures
Loss Carry-Forward Credits (PPT) -- AS 43.55.023(b) <i>transferrable</i> credit against PPT	up to 20% of capital expenditures	N/A	up to 20% of capital expenditures	up to 20% of capital expenditures	up to 20% of capital expenditures
Transition Investment Expenditure Credits (PPT) -- AS 43.55.023(i) <i>non-transferrable</i> credit against PPT Expires at the end of 2013	up to 20% of 2001-2006 capital expenditures	N/A	up to 20% of 2001-2006 capital expenditures	up to 20% of 2001-2006 capital expenditures	up to 20% of 2001-2006 capital expenditures
Frontier Basin Production Credit -- AS 43.55.023(a) <i>non-transferrable</i> credit against PPT (for production south of 68 latitude and outside Cook Inlet basin) Expires at the end of 2016	up to \$6MM	N/A	(Applies after conversion to Lease)	up to \$6MM	up to \$6MM
Small Producer Credit -- AS 43.55.023(c) <i>non-transferrable</i> credit against PPT (\$12 MM for production <50,000 BOE/day, declining on a sliding scale to \$0 for production >100,000 BOE/day)	up to \$12MM	N/A	(Applies after conversion to Lease)	up to \$12MM	up to \$12MM
<b><u>INCENTIVES AS PART OF A PROGRAM</u></b>	<b><u>CONVENTIONAL LEASES</u></b>	<b><u>UNLEASED STATE LAND</u></b>	<b><u>LICENSED LAND</u></b>	<b><u>SNG LEASES</u></b>	<b><u>FEDERAL &amp; PRIVATE LAND</u></b>
Exploration Licensing AS38.05.132	N/A	N/A	Up to 500,000 acres per license One-time \$1/acre license fee No bonus bid No annual rental sole right to convert to O & G leases	N/A	N/A
Nonconventional Gas Incentive-- AS 38.05.180(n)(2) (04.531)	reduced rental 6.25% royalty if no competition with 12.5% leasee	N/A	(Applies after conversion to Lease)	N/A	

# NATURAL RESOURCES

GAS

RESERVES

4/26/07

# Alaska Department of Natural Resources



Briefing for  
**Senate Finance**  
Current Gas Reserves & Resource Estimates  
ANS & Offshore

Robert Swenson  
State Geologist & Acting Director  
Division of Geological & Geophysical Surveys

*<http://www.dggs.dnr.state.ak.us>*

*<http://akgeology.info>*

April 26, 2007

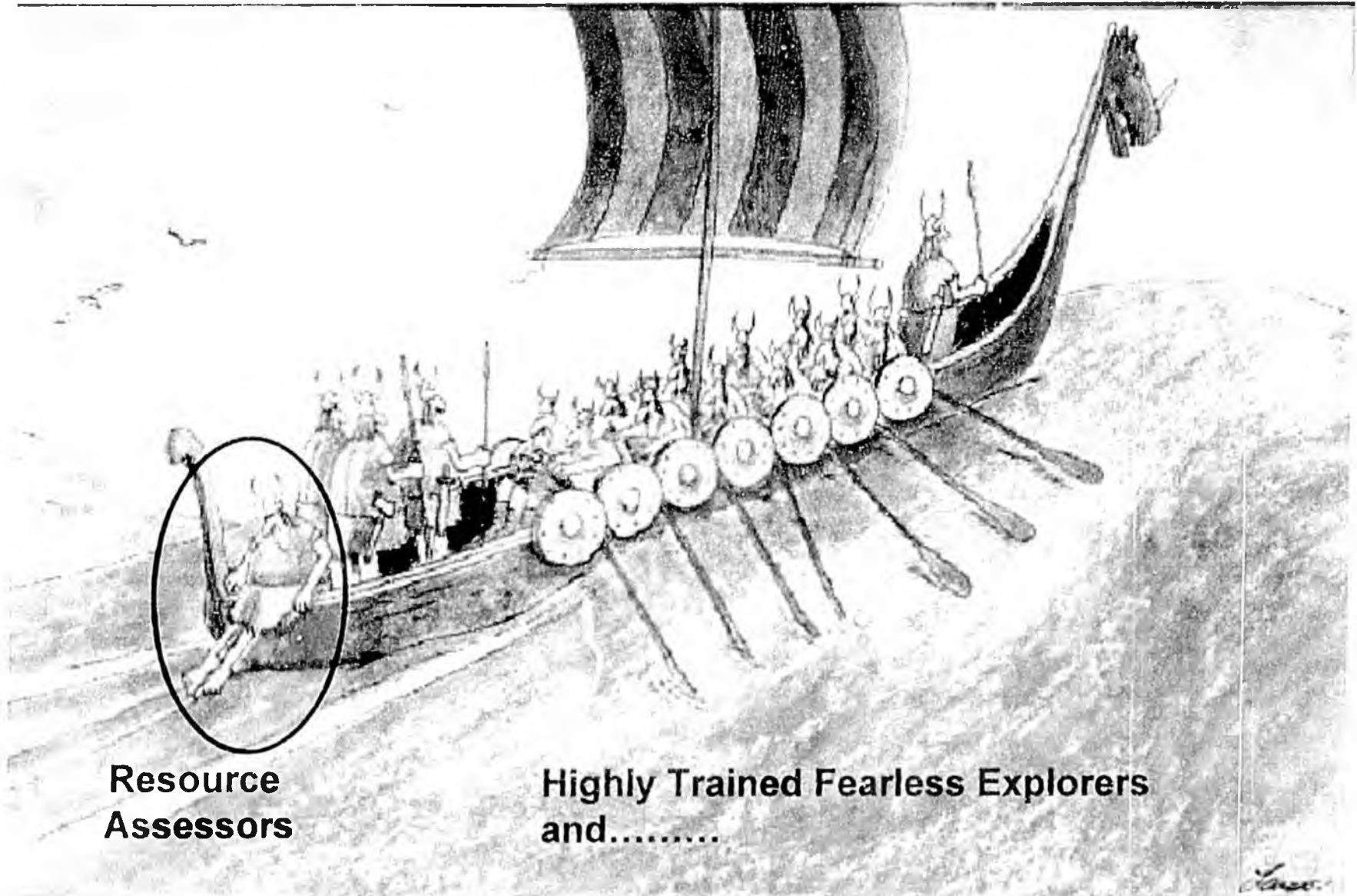


# Overview



- The State of Alaska does not perform quantitative, probabilistic resource assessments, but works closely with the agencies that do
- All numbers presented here are from US Geological Survey & MMS resource assessments published between 1999 and 2005.
- All estimates provided are based on rigorous analysis of all available data, geology, existing accumulations, and basin analogies
- All non-reserve estimates are presented as technically recoverable resources (as contrasted with economically recoverable or gross in-place estimates).
- Resource estimates used represent the mean of a probabilistic distribution with associated P5 & P95

# Oil & Gas Resources Team

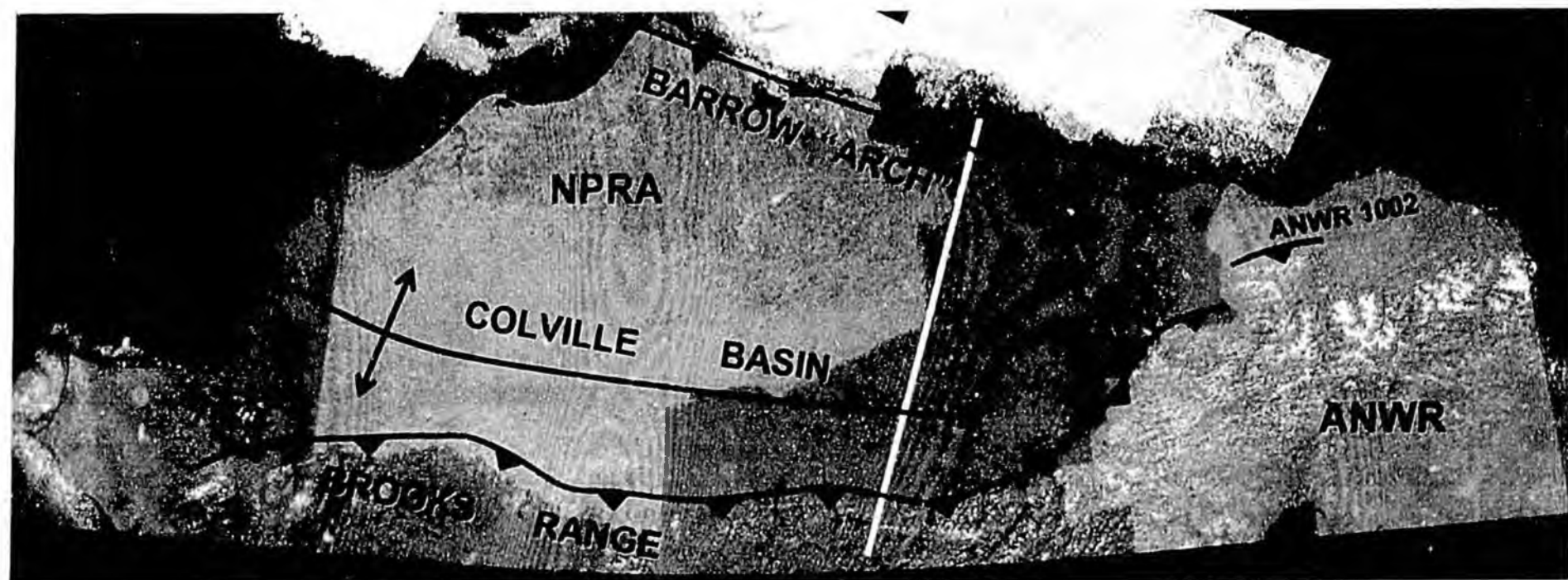


**Resource  
Assessors**

**Highly Trained Fearless Explorers  
and.....**

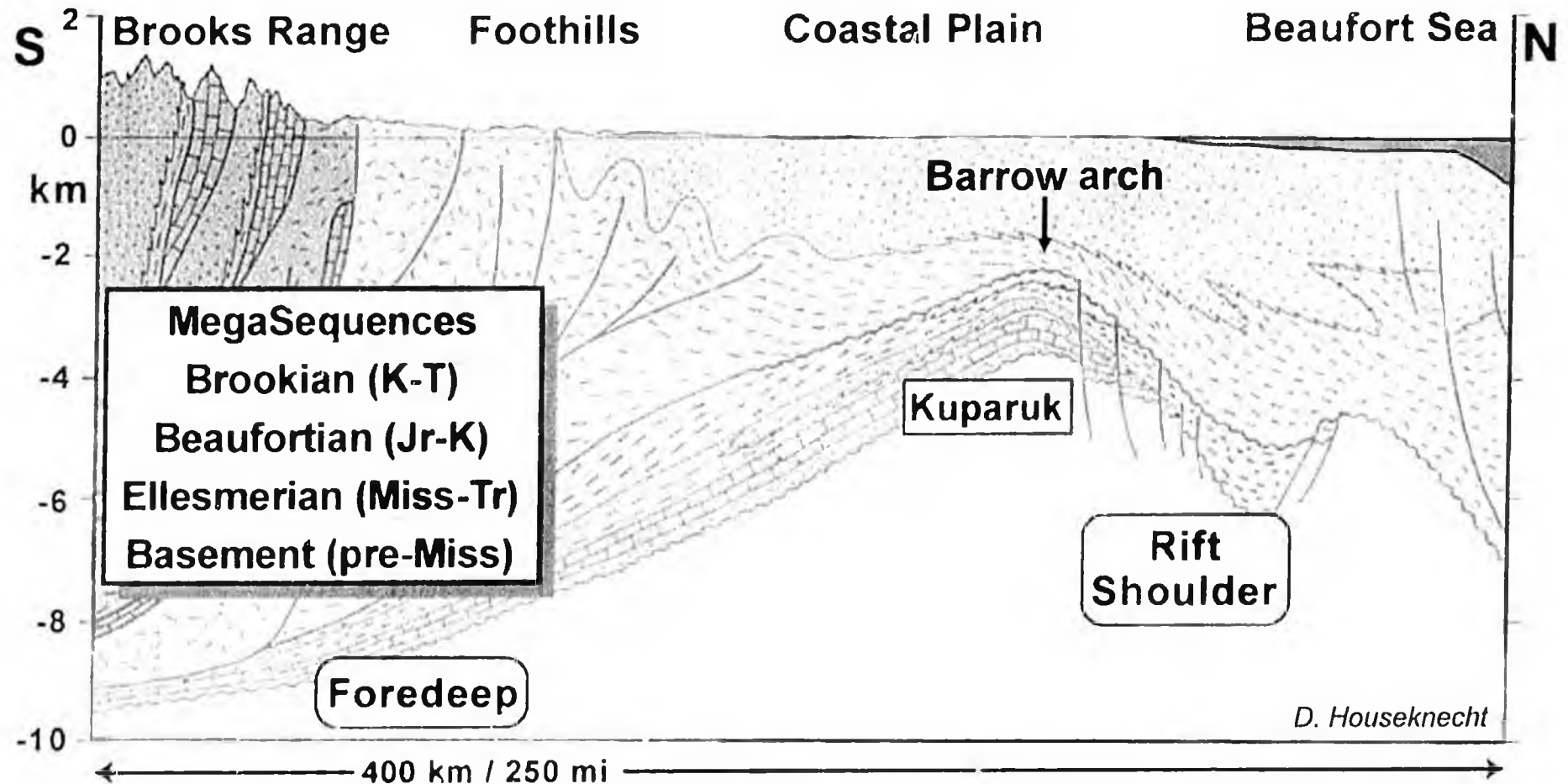
# *North Slope*

## Overview of Regional Geology



# Overview of Regional Geology

## Central North Slope



- Late Devonian-Triassic south-facing passive continental margin
- Jurassic-Hauterivian extensional episode superimposed on older passive margin succession

- Jurassic-Barremian arc-continent collision resulting in Cret. foreland basin
- Latter two tectonic settings overlap

# North Alaska Stratigraphy & Petroleum Plays

As used in USGS NPRA  
Assessment

Play definitions will vary  
slightly among  
assessment provinces...

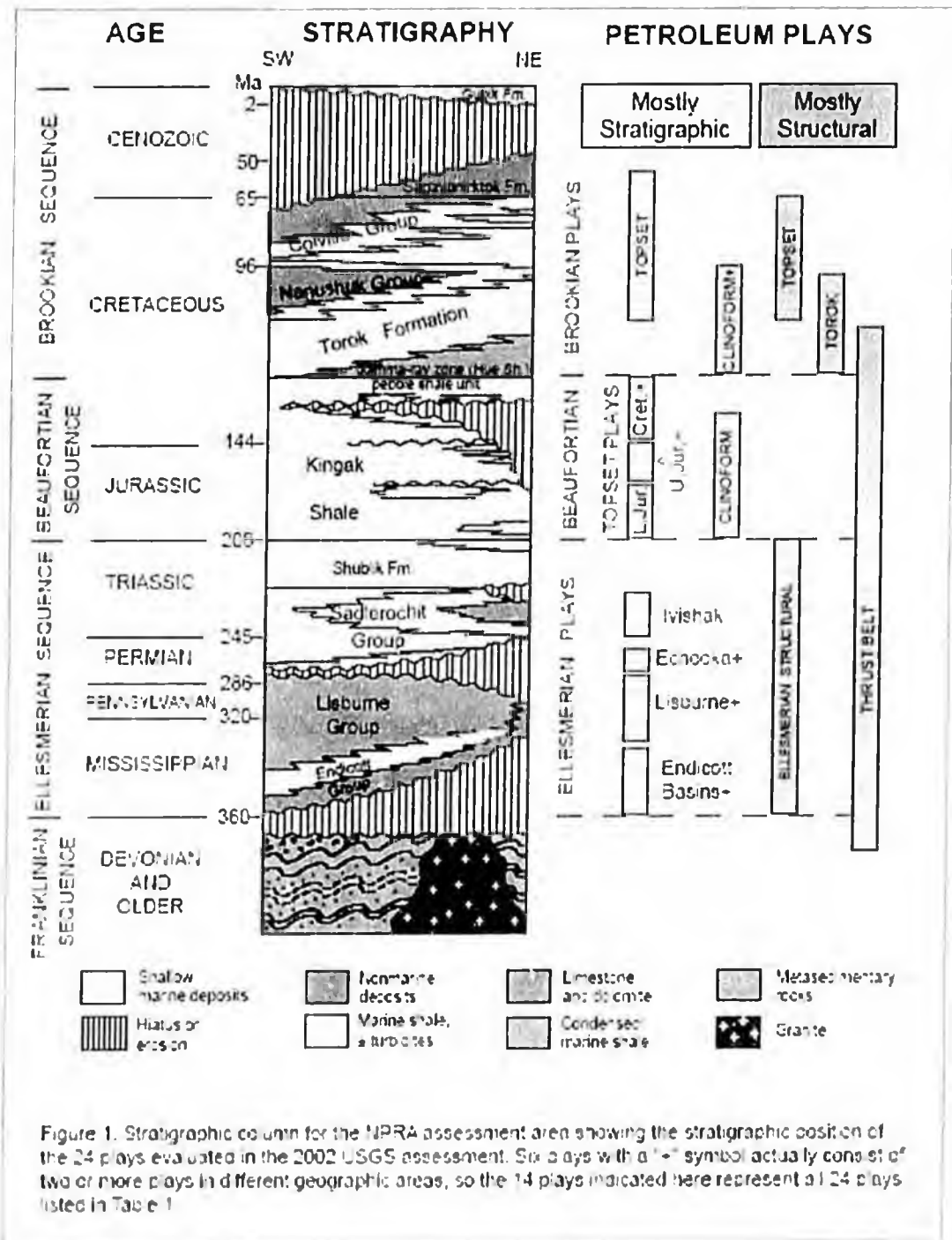
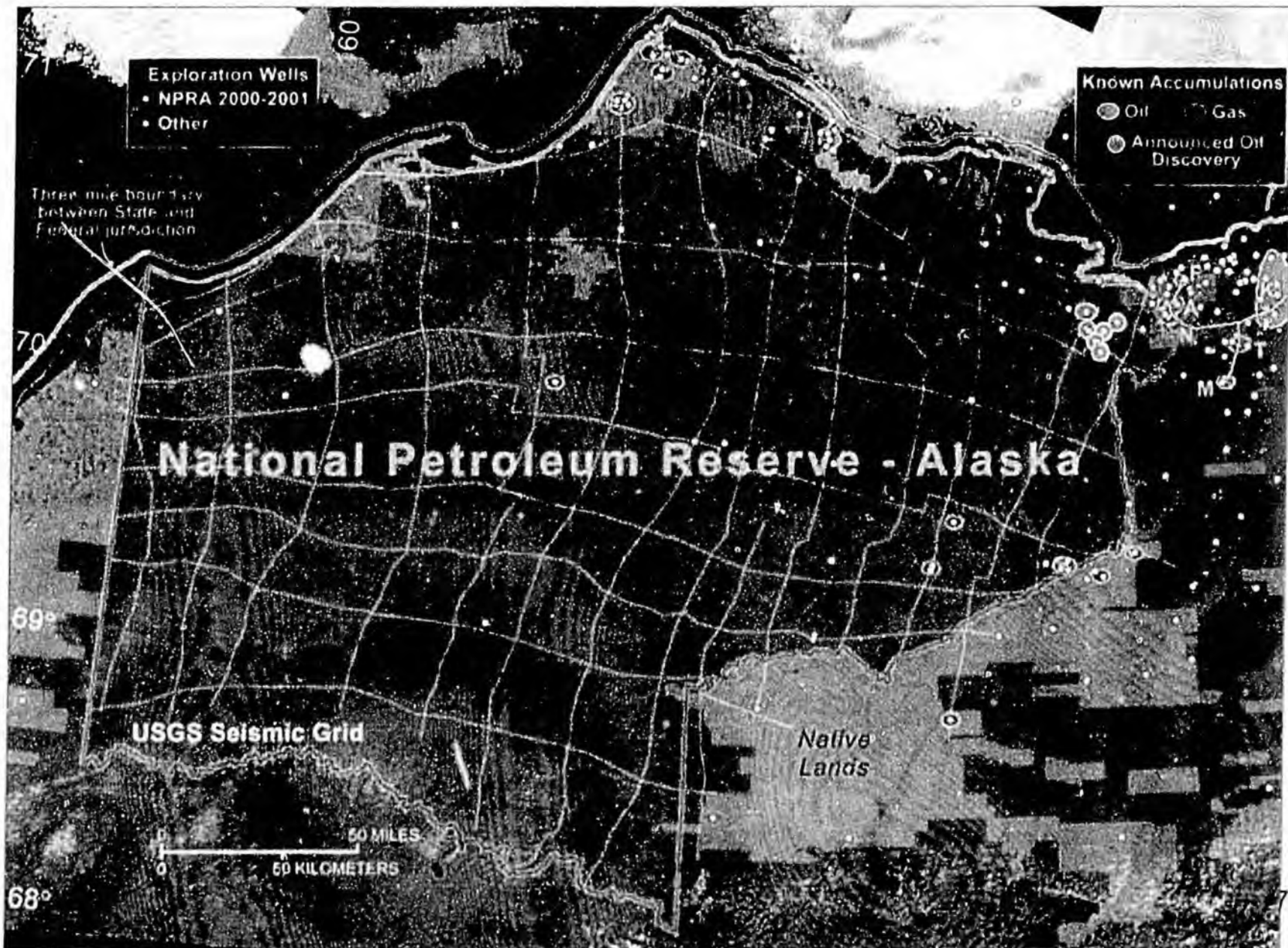
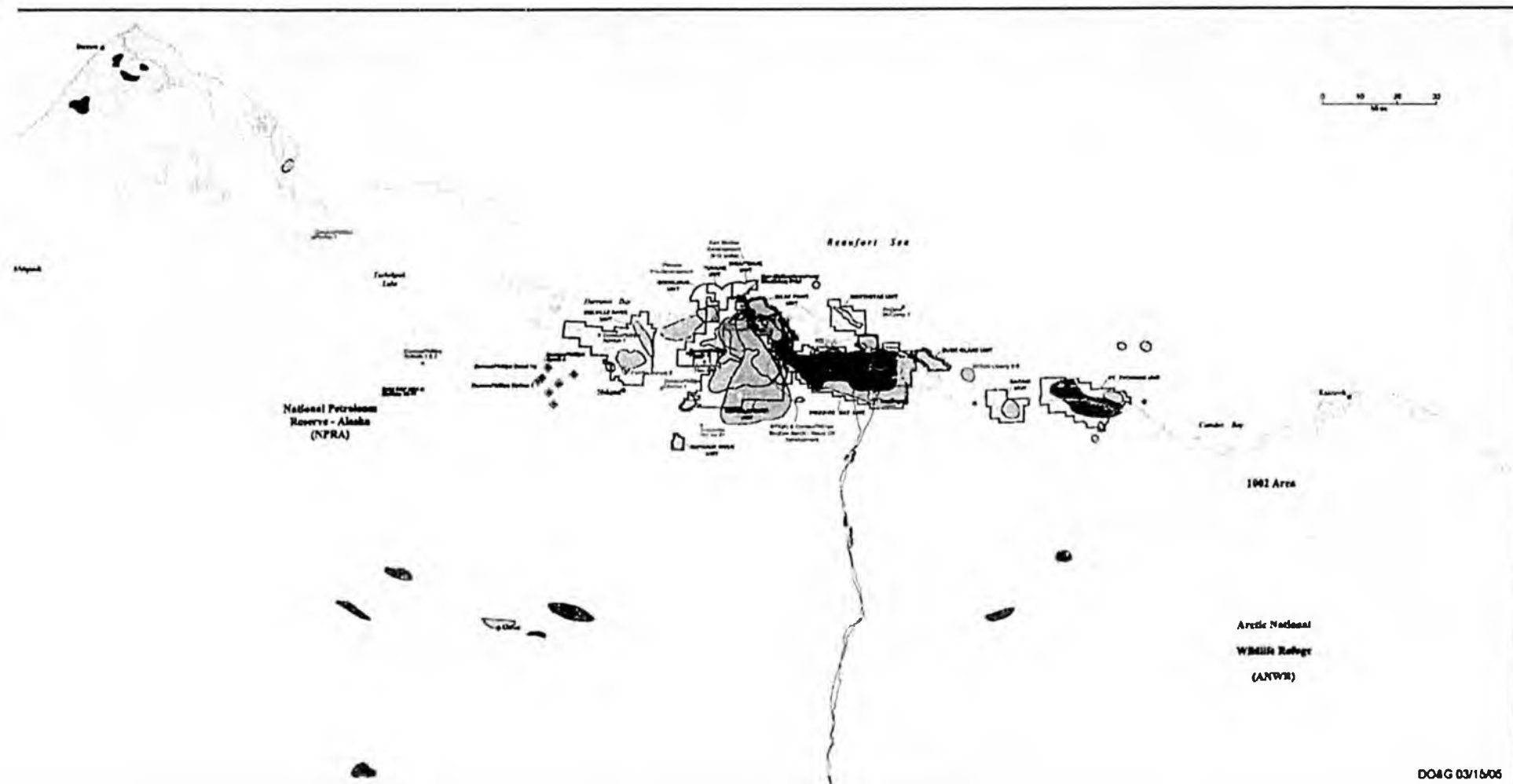


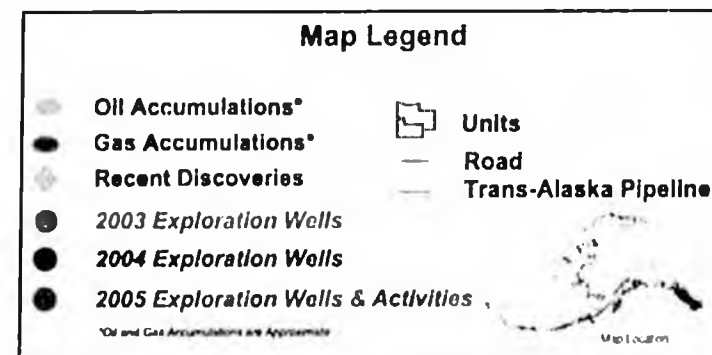
Figure 1. Stratigraphic column for the NPRA assessment area showing the stratigraphic position of the 24 plays evaluated in the 2002 USGS assessment. Six plays with a "+" symbol actually consist of two or more plays in different geographic areas, so the 14 plays indicated here represent a total of 24 plays listed in Table 1.

# NPRA Assessment Area





# North Slope Oil & Gas Activities & Discoveries March 2005



# Proven Gas Reserves

## Does not Include Probable

( reserves growth through continued development)

*(BCF)*

### North Slope

Badami Unit	0
Barrow	34
Colville River Unit	400
Duck Island Unit	843
Kuparuk River Unit	1150
Milne Point Unit	14
North Star	450
Prudhoe Bay Unit	24,526
Other Undeveloped	<u>8,000</u>
<b>TOTAL North Slope</b>	<b>35,417</b>
<b>Cook Inlet</b>	<b>1,650</b>
<b>TOTAL STATE</b>	<b>37,067</b>



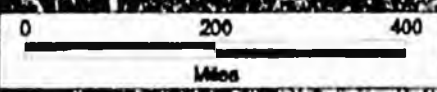
**Explanation**  
Sedimentary Basins  
Assessment Boundaries  
USGS  
MMS

# Alaska Natural Gas Resources

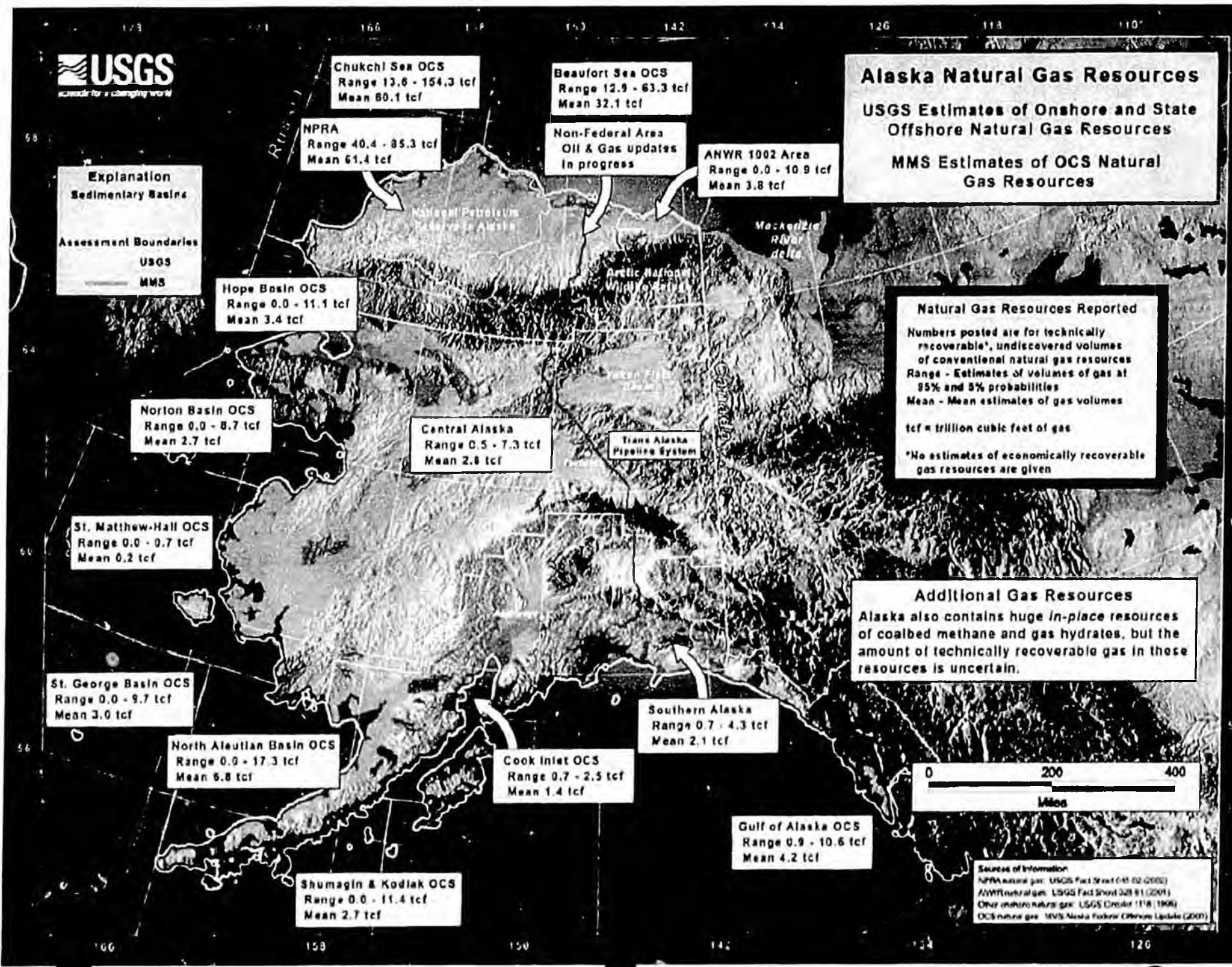
USGS Estimates of Onshore and State Offshore Natural Gas Resources  
MMS Estimates of OCS Natural Gas Resources

**Natural Gas Resources Reported**  
Numbers posted are for technically recoverable, undiscovered volumes of conventional natural gas resources  
Range - Estimates of volumes of gas at 95% and 5% probabilities  
Mean - Mean estimates of gas volumes  
tcf = trillion cubic feet of gas  
  
\*No estimates of economically recoverable gas resources are given

**Additional Gas Resources**  
Alaska also contains huge *in-place* resources of coalbed methane and gas hydrates, but the amount of technically recoverable gas in these resources is uncertain.



**Source of Information**  
NPRA natural gas: USGS Fact Sheet 645 (2-2000)  
ANWR natural gas: USGS Fact Sheet 328 (1-2001)  
Other onshore natural gas: USGS Circular 1118 (1996)  
OCS natural gas: MMS Alaska Federal Offshore License (2001)



# Technically Recoverable ANS Reserve Estimates

Does not include economic thresholds

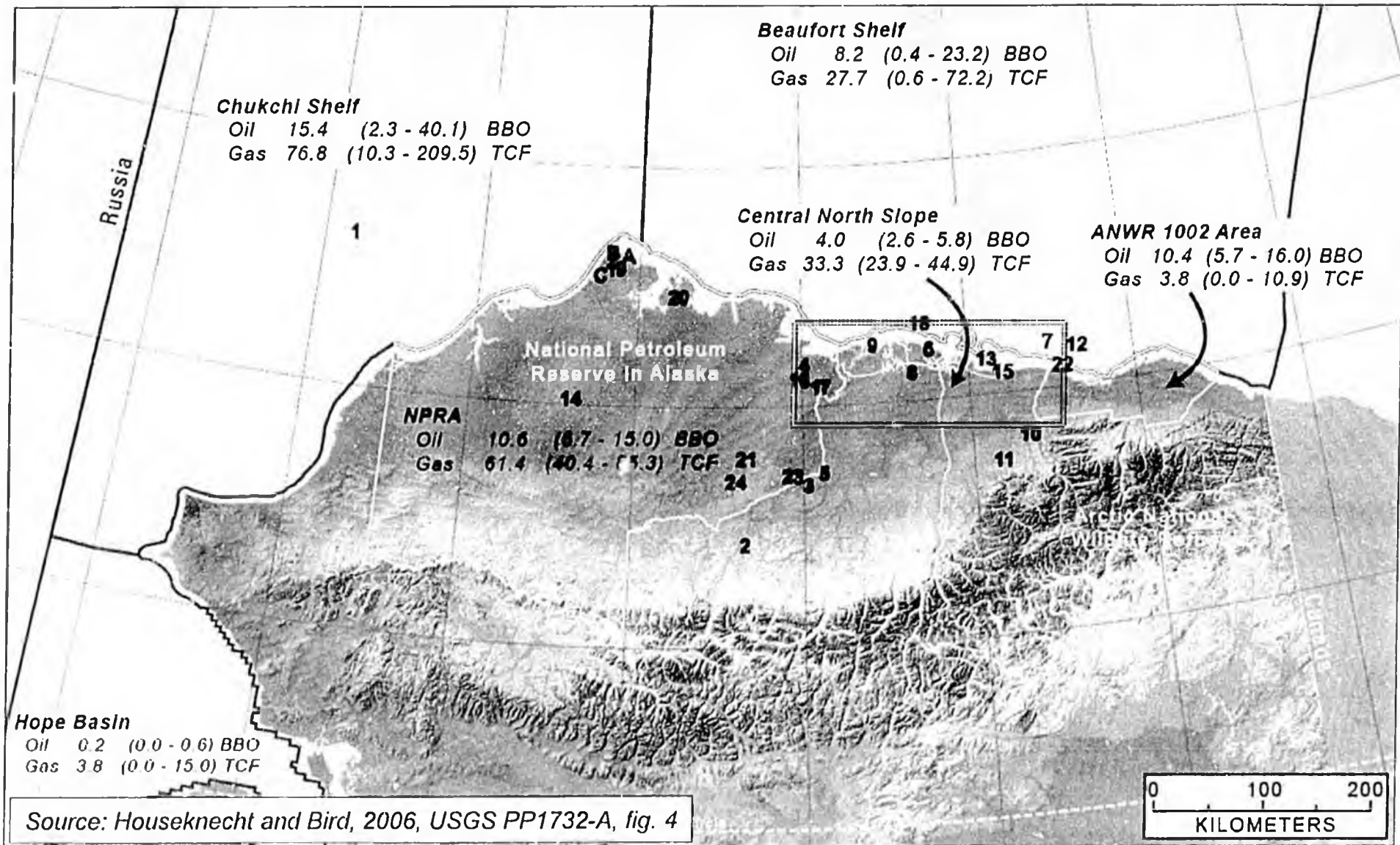
## North Alaska Assessments of Undiscovered, Technically Recoverable Gas<sup>1</sup>

<u>USGS Assessment Segment</u>	<u>Year</u>	<u>F95</u>	<u>Mean</u>	<u>F05</u>
State Lands oil-associated gas, BCF	2005	2,681	4,198	6,092
State Lands non-associated gas, BCF	2005	23,939	33,318	44,873
NPRA non-associated gas, BCF	2002	40,372	61,351	85,317
ANWR non-associated gas, BCF	1999	0	949	3,660
<b>Total Arctic Onshore</b>		-- <sup>2</sup>	<b>99,816</b>	-- <sup>2</sup>
<u>MMS Assessment Segment</u>				
Chukchi Shelf gas, BCF	2006	10,320	76,770	209,530
Beaufort Shelf gas, BCF	2006	650	27,650	72,180
Hope Basin gas, BCF	2006	0	3,770	14,980
<b>Total Arctic OCS</b>	2006	<b>16,410</b>	<b>108,190</b>	<b>183,530</b>
<b>Total Onshore &amp; OCS</b>		-- <sup>2</sup>	<b>208,006</b>	-- <sup>2</sup>

**Notes:**

<sup>1</sup> All numbers are probabilistic estimates of undiscovered, technically recoverable gas in billions of cubic feet (BCF). Because these estimates include gas resources in small, non-economic accumulations, these mean volumes of gas are unlikely to ever be produced.

# Arctic Alaska Province Resource Estimates Summary



Numbers for each assessment province include mean and range (95- to 5-percent-confidence-level volumes) of undiscovered oil (in billions of barrels [BBO]) and gas (in trillions of cubic feet [TCF]). Red numbers correspond to discovered accumulations.<sup>1,2</sup> Central North Slope assessment figures include both foothills and coastal plain areas, not just area within dashed rectangle.

**Table 4.** Estimated mean volumes of undiscovered, technically recoverable petroleum in conventional accumulations for areas in the Arctic Alaska Petroleum Province.

[Estimates for onshore and State offshore areas versus Federal offshore area are listed separately because of differences in the assessment methods used by the U.S. Geological Survey and U.S. Minerals Management Service. See figure 4 for 95- and 5-percent-confidence-level volumes. ANWR, Arctic National Wildlife Refuge; NPRA, National Petroleum Reserve in Alaska]

	Oil and natural-gas liquids (billion bbl)			Natural gas (trillion ft <sup>3</sup> )		
	Crude oil	Natural- gas liquids	Total liquids	Nonassociated gas	Associated gas	Total gas
Onshore and State offshore areas						
NPRA <sup>1</sup>	10.56	1.43	11.99	61.35	11.68	73.03
Central North Slope <sup>2</sup>	3.98	0.48	4.46	33.32	4.20	37.52
ANWR, 1002 Area <sup>3</sup>	10.36	0.19	10.55	3.84	4.76	8.60
Subtotal	24.90	2.10	27.00	98.51	20.64	119.15
Federal offshore area						
Chukchi Shelf <sup>4</sup>	--	--	15.38	--	--	76.77
Beaufort Shelf <sup>4</sup>	--	--	8.22	--	--	27.65
Hope Basin <sup>4</sup>	--	--	0.15	--	--	3.77
Subtotal	--	--	23.75	--	--	108.19
Arctic Alaska Petroleum Province onshore and offshore areas						
Total	--	--	50.75	--	--	227.34

<sup>1</sup>Bird and Houseknecht (2002).

<sup>2</sup>Bird and others (2005).

<sup>3</sup>Bird and Houseknecht (2001).

<sup>4</sup>U.S. Minerals Management Service (2006).

**+ 35.42 (known fields)**

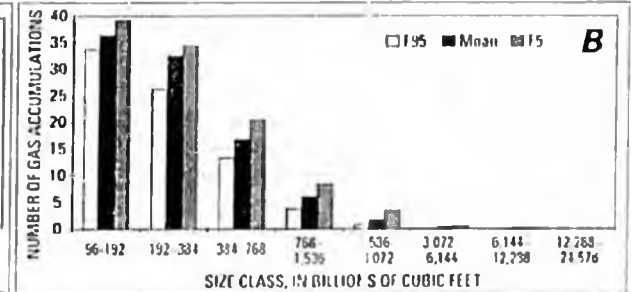
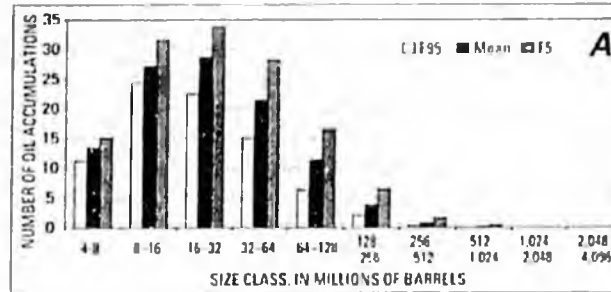
**262.74 TCF total**

13

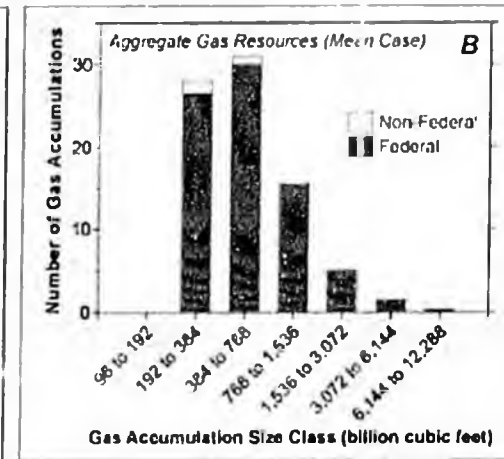
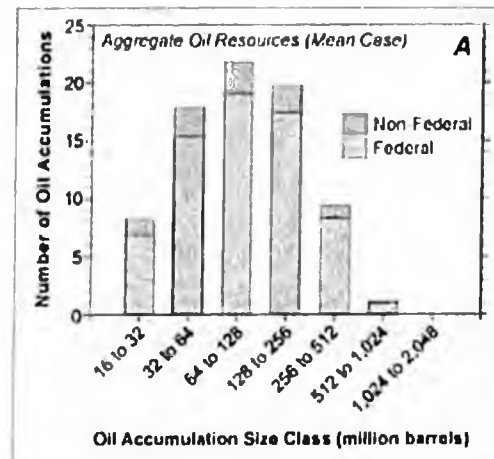
Source: Houseknecht and Bird, 2006, USGS PP1732-A

# Undiscovered Mean Field Size Distributions - USGS

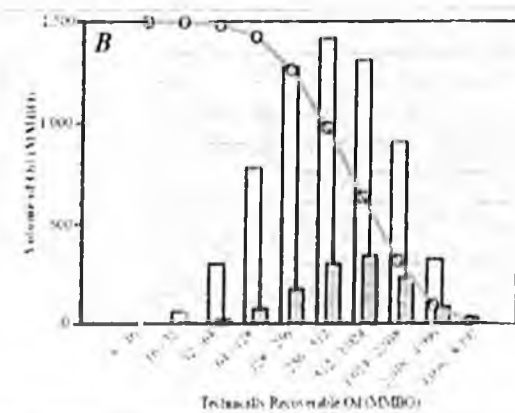
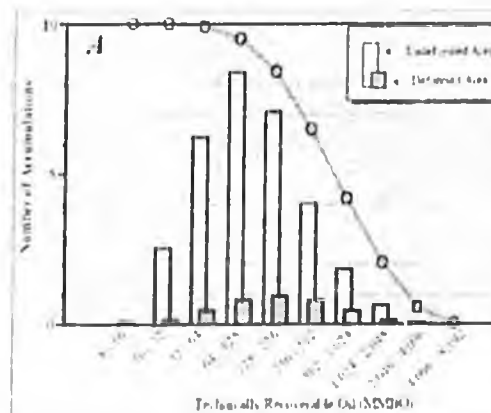
**State Lands:** ~1 undiscovered oil accumulation > 250 MMBO recoverable. ~ 2 undiscovered gas accumulations > 1.5 TCF recoverable.



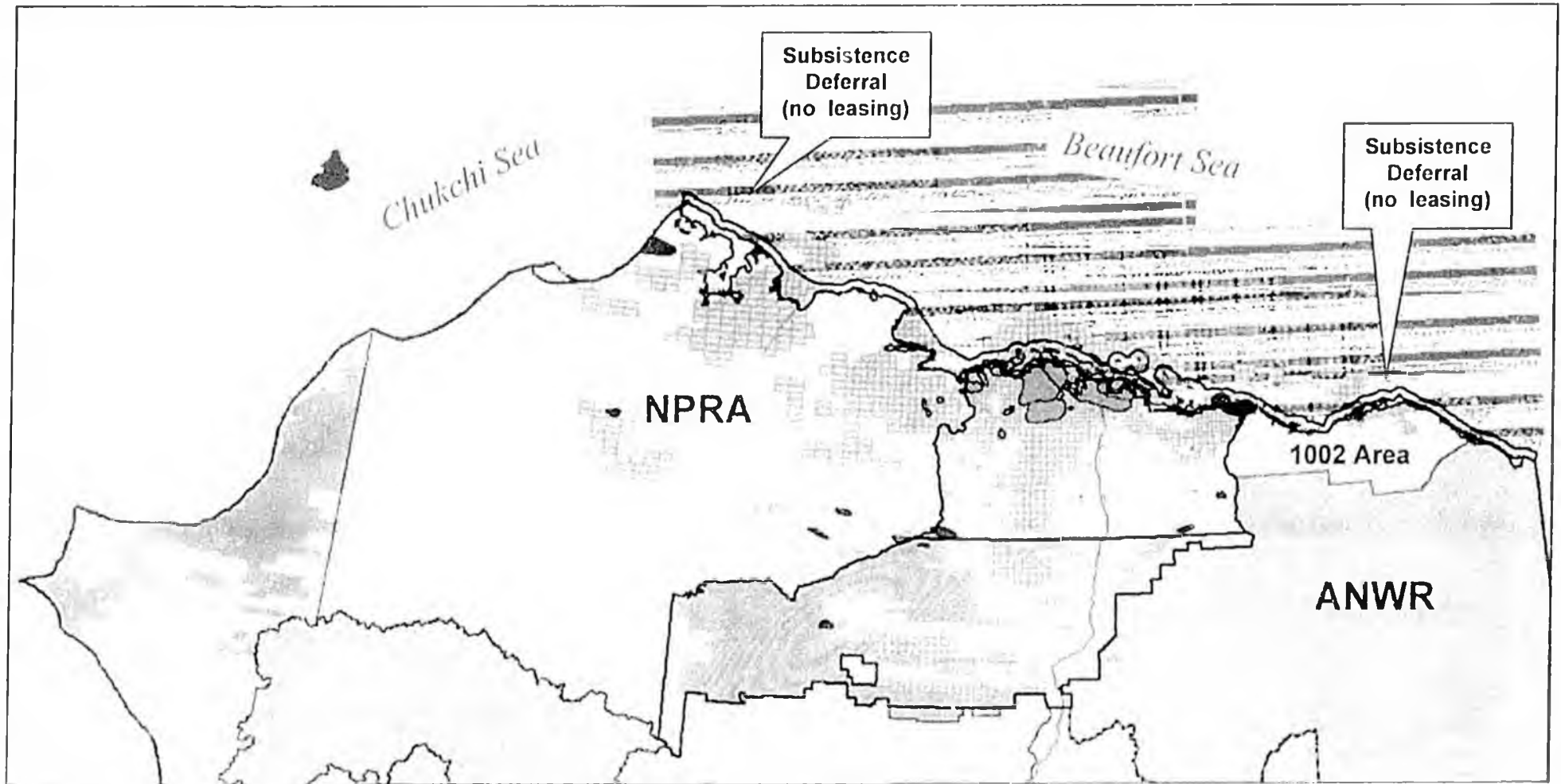
**NPRA:** ~11 undiscovered oil accumulations > 250 MMBO recoverable. ~7 undiscovered gas accumulations > 1.5 TCF recoverable.



**ANWR 1002:** ~9 undiscovered oil accumulations > 250 MMBO recoverable (~65% of estimated total recoverable oil volume); gas resource not shown.



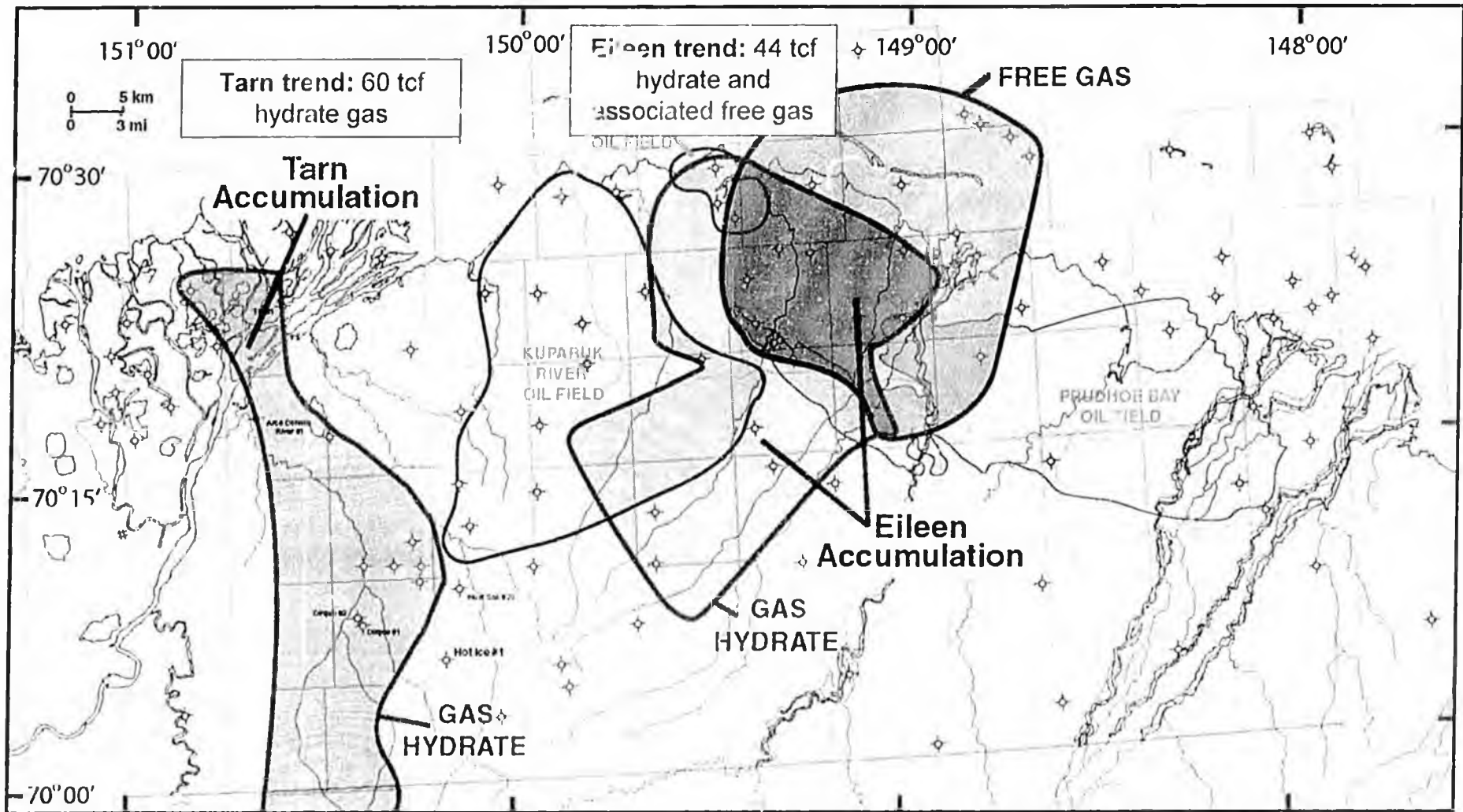
# Arctic Alaska Province Leased Acreage



- Existing leases in dark yellow
- High bid tracts from April 18, 2007 Beaufort Sea OCS sale shown in turquoise, orange, purple, etc.

# Unconventional Gas Potential

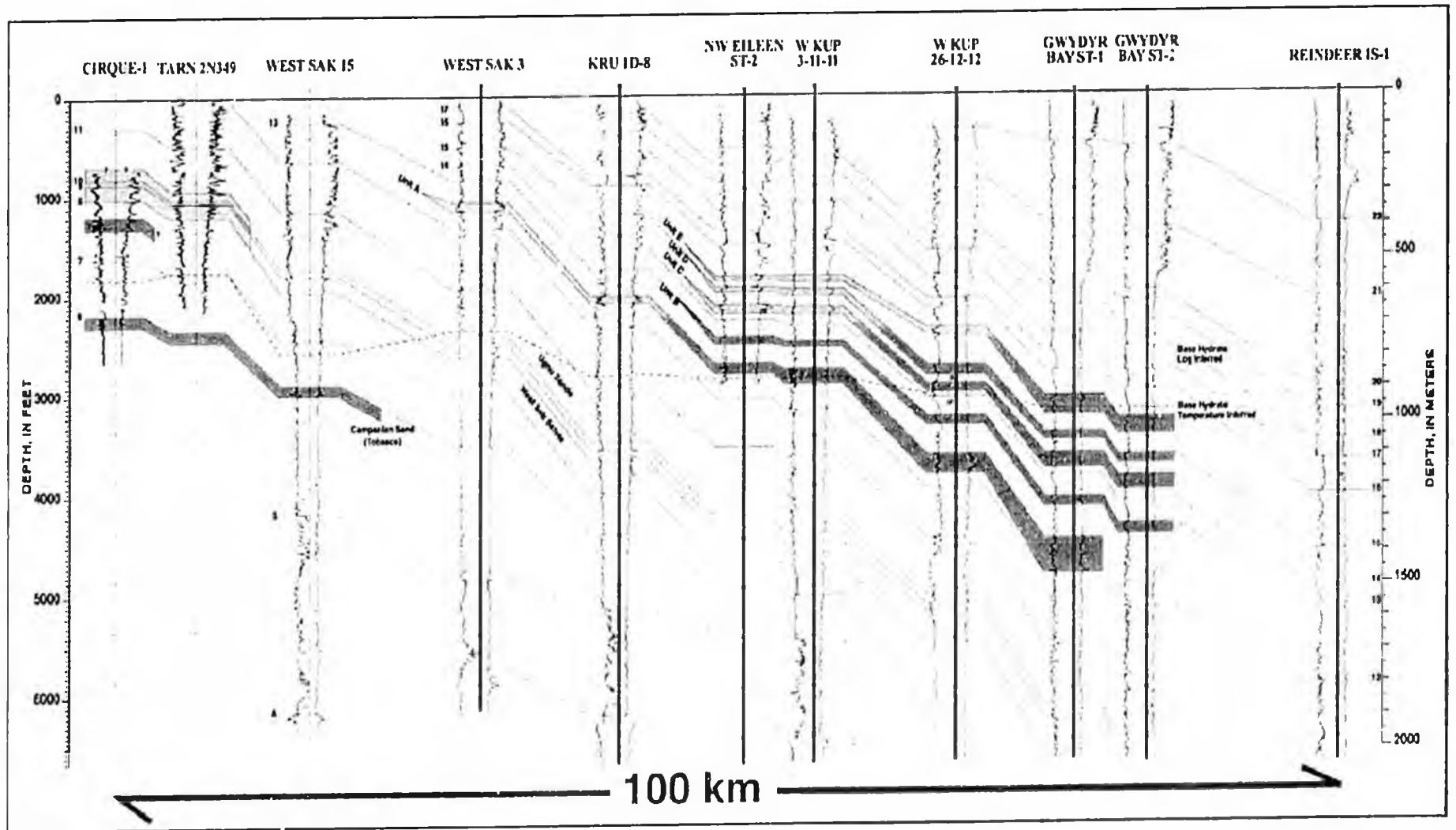
# Known Gas Hydrate Accumulations



Known gas hydrate accumulations (blue) and hydrate-associated free gas accumulations (orange) in the vicinity of the major North Slope oil fields (green). The USGS estimates up to 100 tcf in place of hydrate in the Eileen and Tarn trends combined. From T.S. Collett, 10/01 and Hunter and Collett, (2004).

Modified from T.S. Collett, USGS Open File Report 2004-1-152

# Eileen and Tarn Gas Hydrate Accumulations



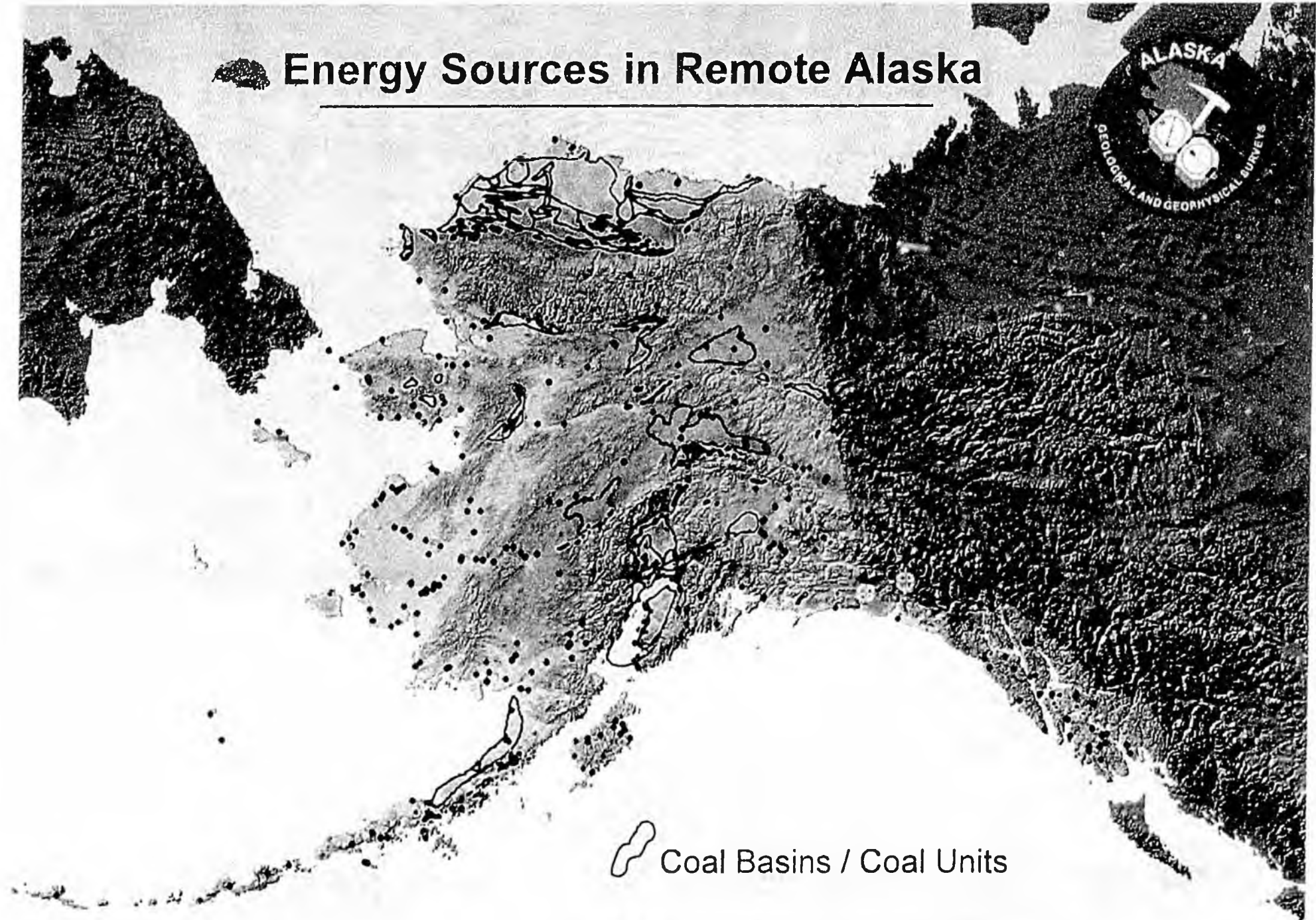
# ANS Potential Hydrates Resource

All Values Trillions of Cubic Feet (TCF)

- **32,965 Tcf** - Gas Hydrates In Place Resource<sup>3</sup>
- **104 Tcf** - Gas Hydrates In Place Prudhoe-Tarn area
- Technically Recoverable Numbers cannot be determined at this time

<sup>3</sup>Collett, personal communication, 11/26/04.

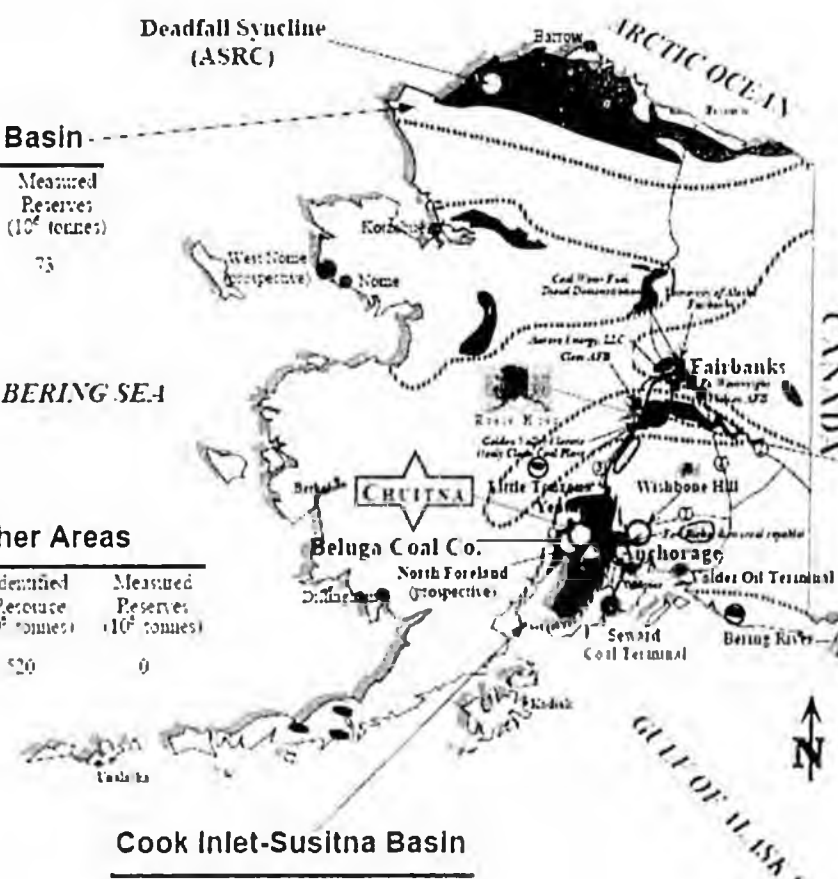
# Energy Sources in Remote Alaska



 Coal Basins / Coal Units

 Villages/ Population Centers





- Exploration Prospective Phase
- Pre-Development Phase
- PRODUCING MINE
- Major Port
- Alaska Railroad
- |— Highways
- Coal Fired Power Plants & Coal Technology Projects

**Northern Alaska Basin**

Hypothetical Resource (10 <sup>9</sup> tonnes)	Identified Resource (10 <sup>6</sup> tonnes)	Measured Reserves (10 <sup>6</sup> tonnes)
3,650,000	136,100	73

**All Other Areas**

Hypothetical Resource (10 <sup>6</sup> tonnes)	Identified Resource (10 <sup>6</sup> tonnes)	Measured Reserves (10 <sup>6</sup> tonnes)
8,660	520	0

**Nenana Province**

Hypothetical Resource (10 <sup>9</sup> tonnes)	Identified Resource (10 <sup>9</sup> tonnes)	Measured Reserves (10 <sup>9</sup> tonnes)
13,320	7,800	227

**Key to Coal Rank**

- Bituminous
- Subbituminous
- Lignite

**Cook Inlet-Susitna Basin**

Hypothetical Resource (10 <sup>6</sup> tonnes)	Identified Resource (10 <sup>6</sup> tonnes)	Measured Reserves (10 <sup>6</sup> tonnes)
64,250	10,550	1,450

Major Basin Margins

REVENUE

FISCAL

OUTLOOK

4/26/07



STATE OF ALASKA  
DEPARTMENT OF  
**REVENUE**

# **Alaska's Long Run Fiscal Outlook**

Senate Finance Committee, April 25, 2007

Alaska Department of Revenue

Patrick Galvin, Commissioner and

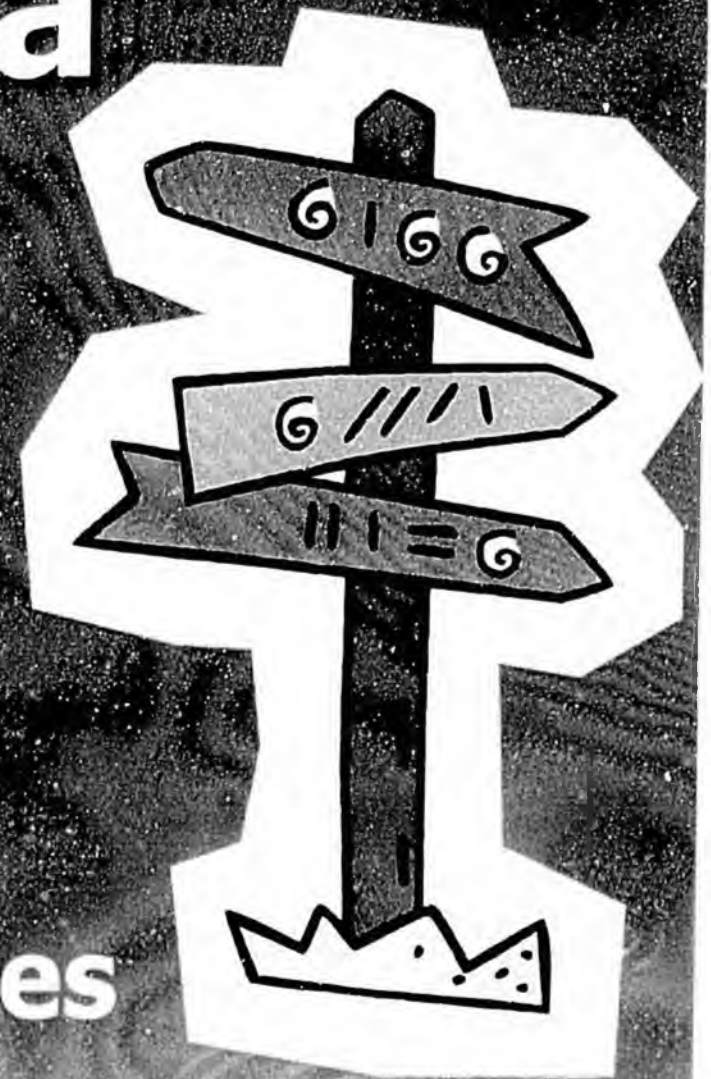
Michael D. Williams, Chief Economist

Presented 4/26/07 PM

# Agenda

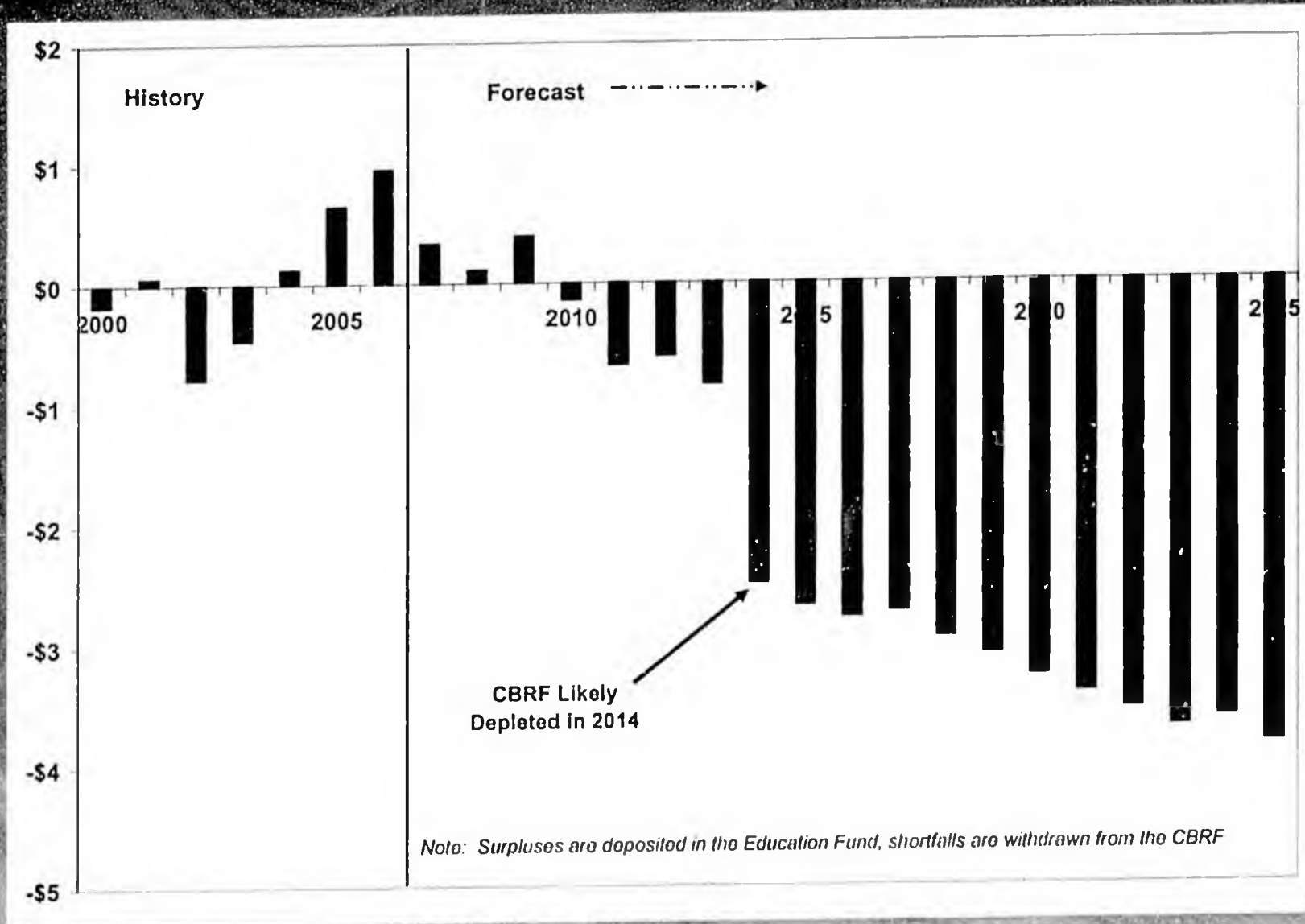
- **Surplus / Deficit**
- **State Oil Revenue**
- **Appropriations**
- **Revenue, Expenditures**

**and use of Balancing Funds**



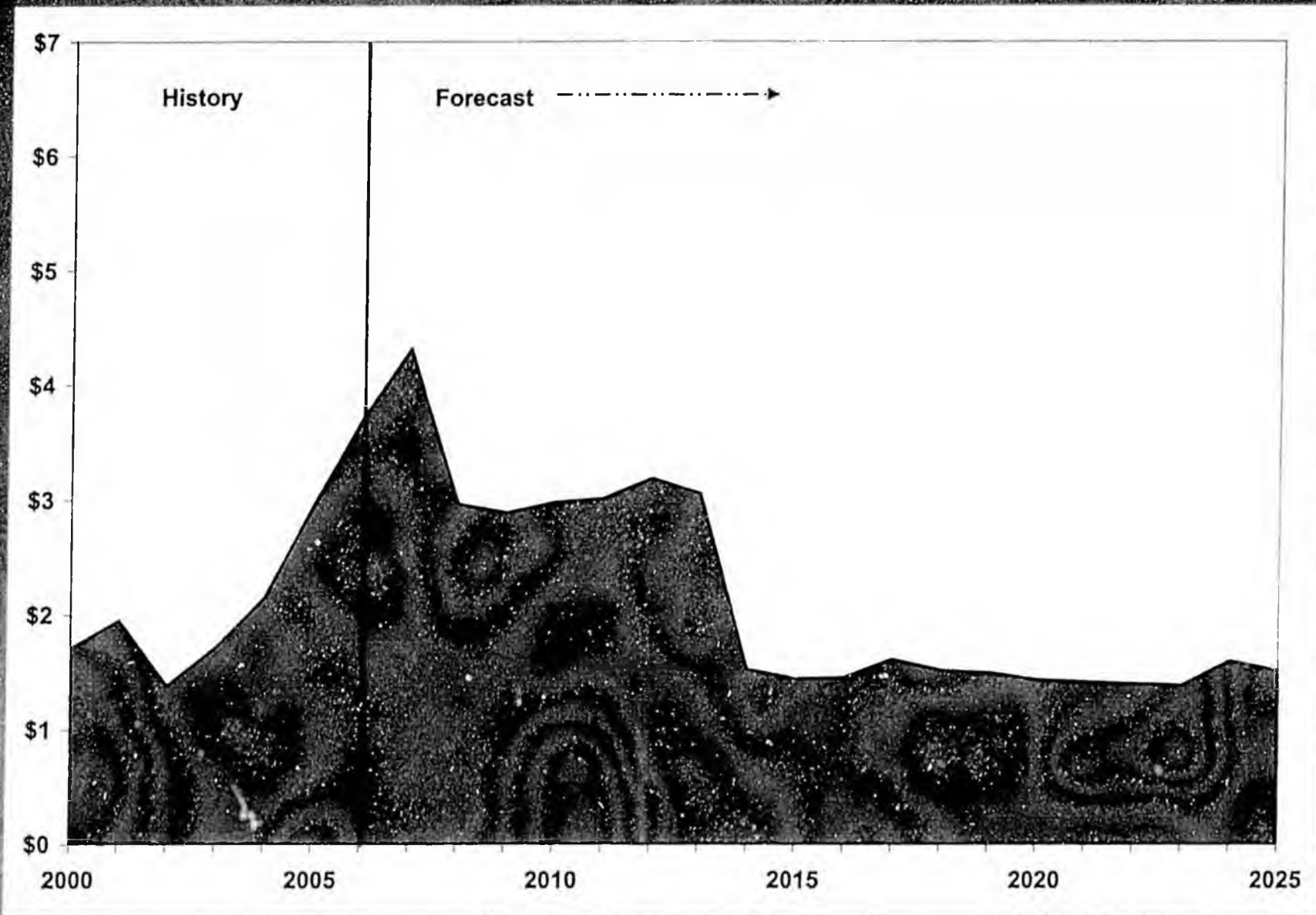
# State Surplus & Deficit

Unrestricted General Fund, Billions of Nominal Dollars



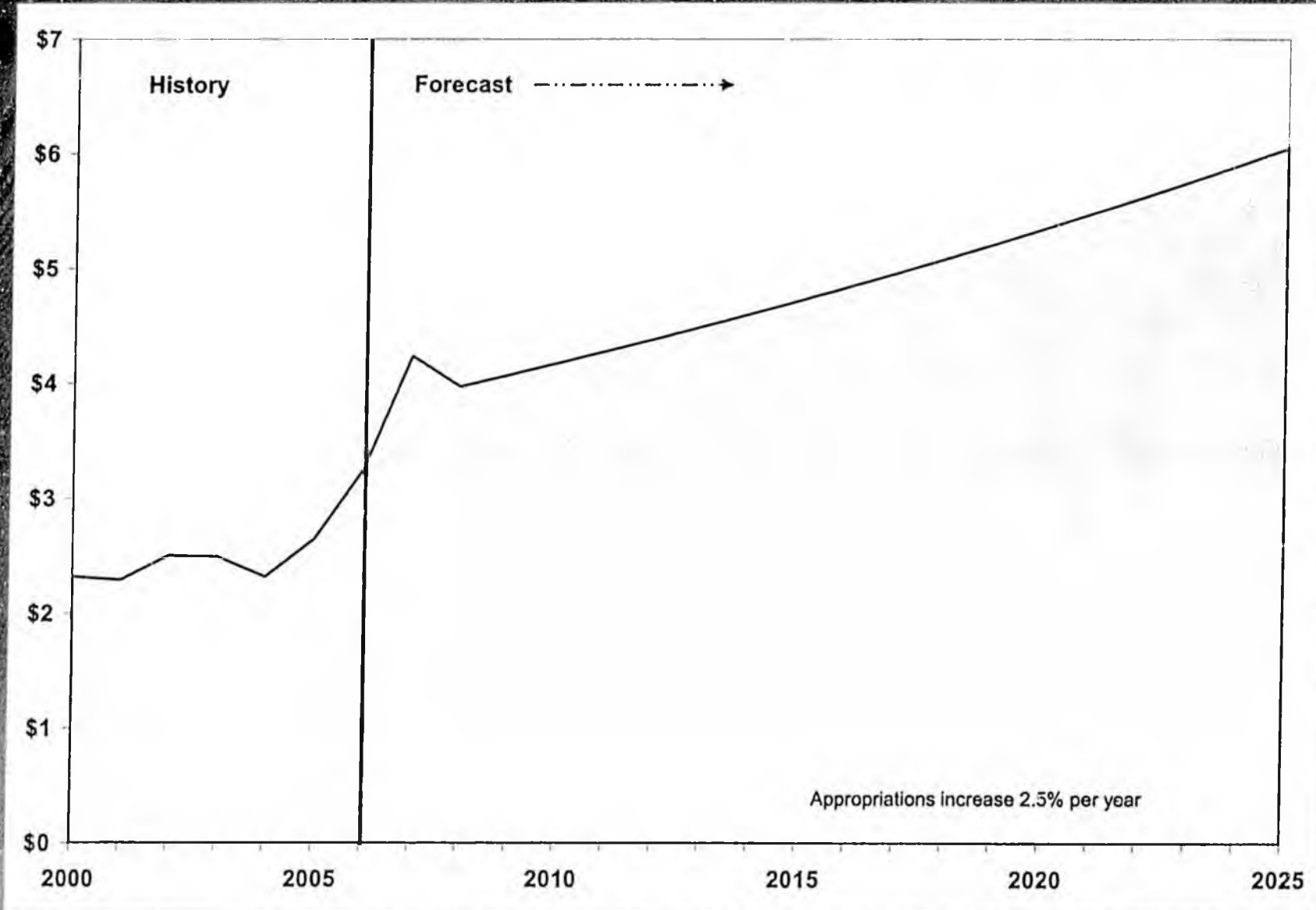
# State Oil Revenue

General Fund Unrestricted Revenue, Billions of Nominal Dollars



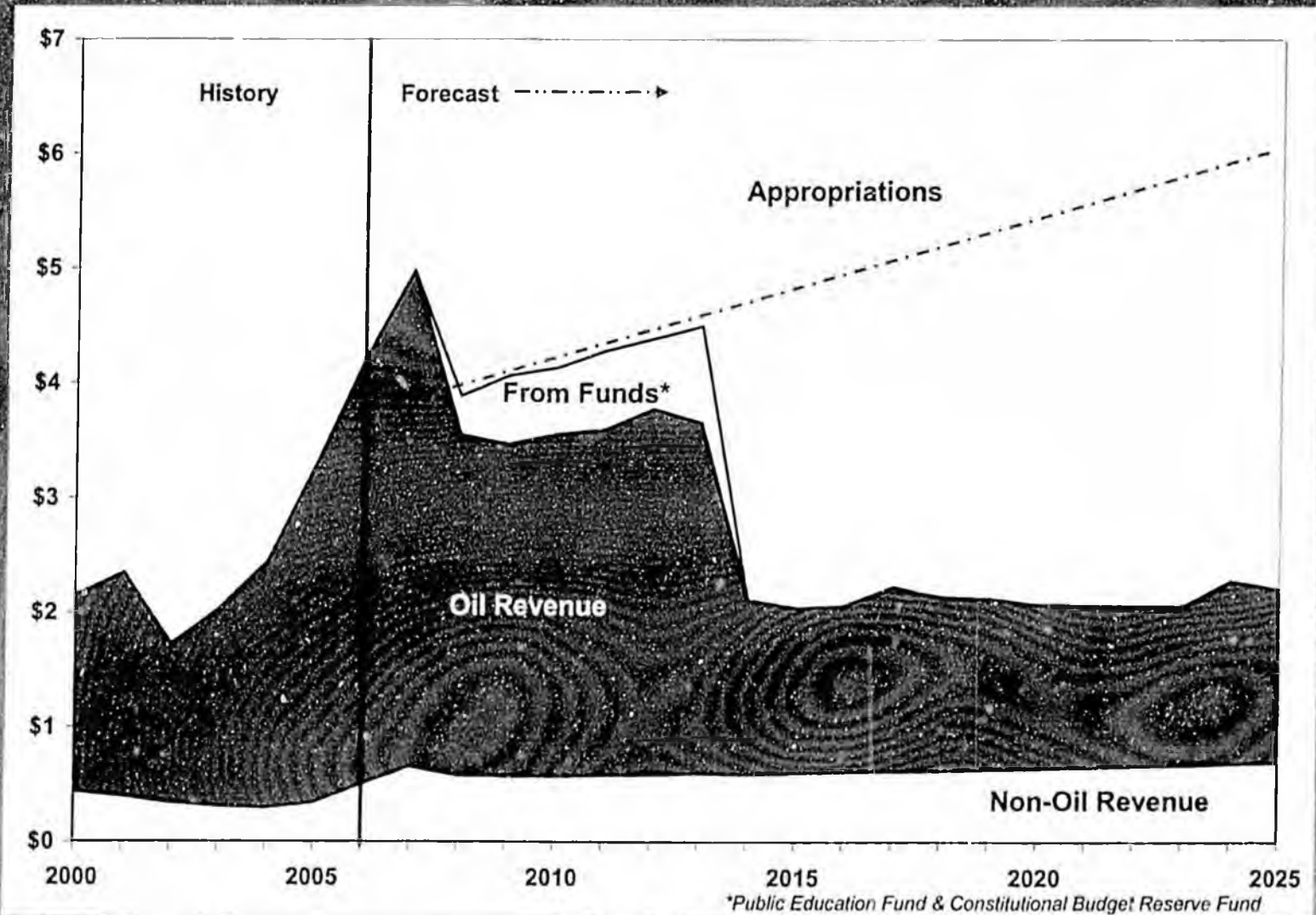
# General Fund Appropriations

Billions of Nominal Dollars



# Revenue, Appropriations & Monies from Special Funds

Billions of Nominal Dollars



\*Public Education Fund & Constitutional Budget Reserve Fund



STATE OF ALASKA  
DEPARTMENT OF  
**REVENUE**

**Patrick Galvin & Michael D. Williams**

[patrick\\_galvin@revenue.state.ak.us](mailto:patrick_galvin@revenue.state.ak.us) & [m\\_w@revenue.state.ak.us](mailto:m_w@revenue.state.ak.us)

**Alaska Department of Revenue**

NATURAL

GAS

PRICES

4/27/07

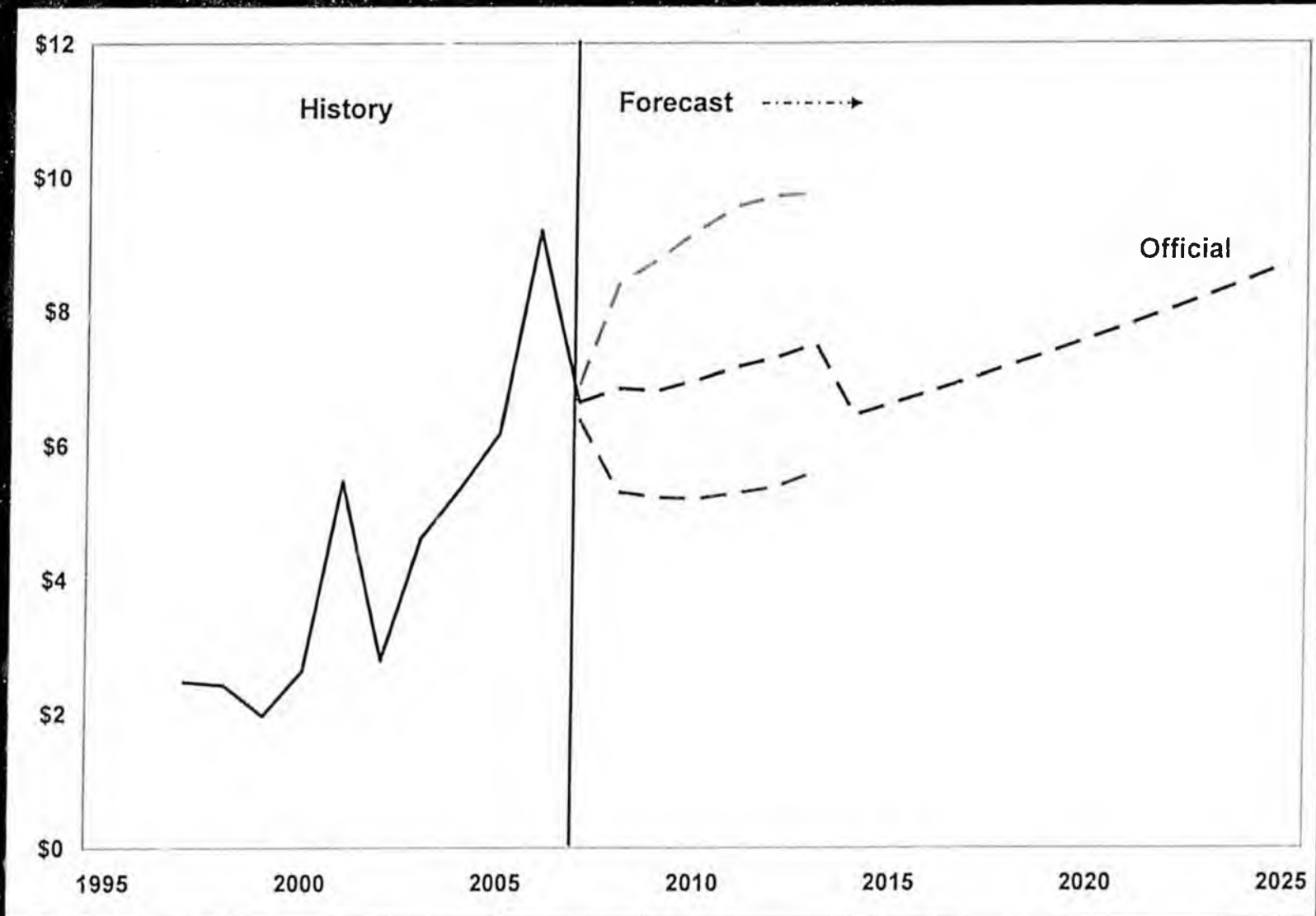
# Natural Gas Prices



**Senate Finance**  
**Department of Revenue, April 26, 2007**  
**Michael D. Williams, Chief Economist**

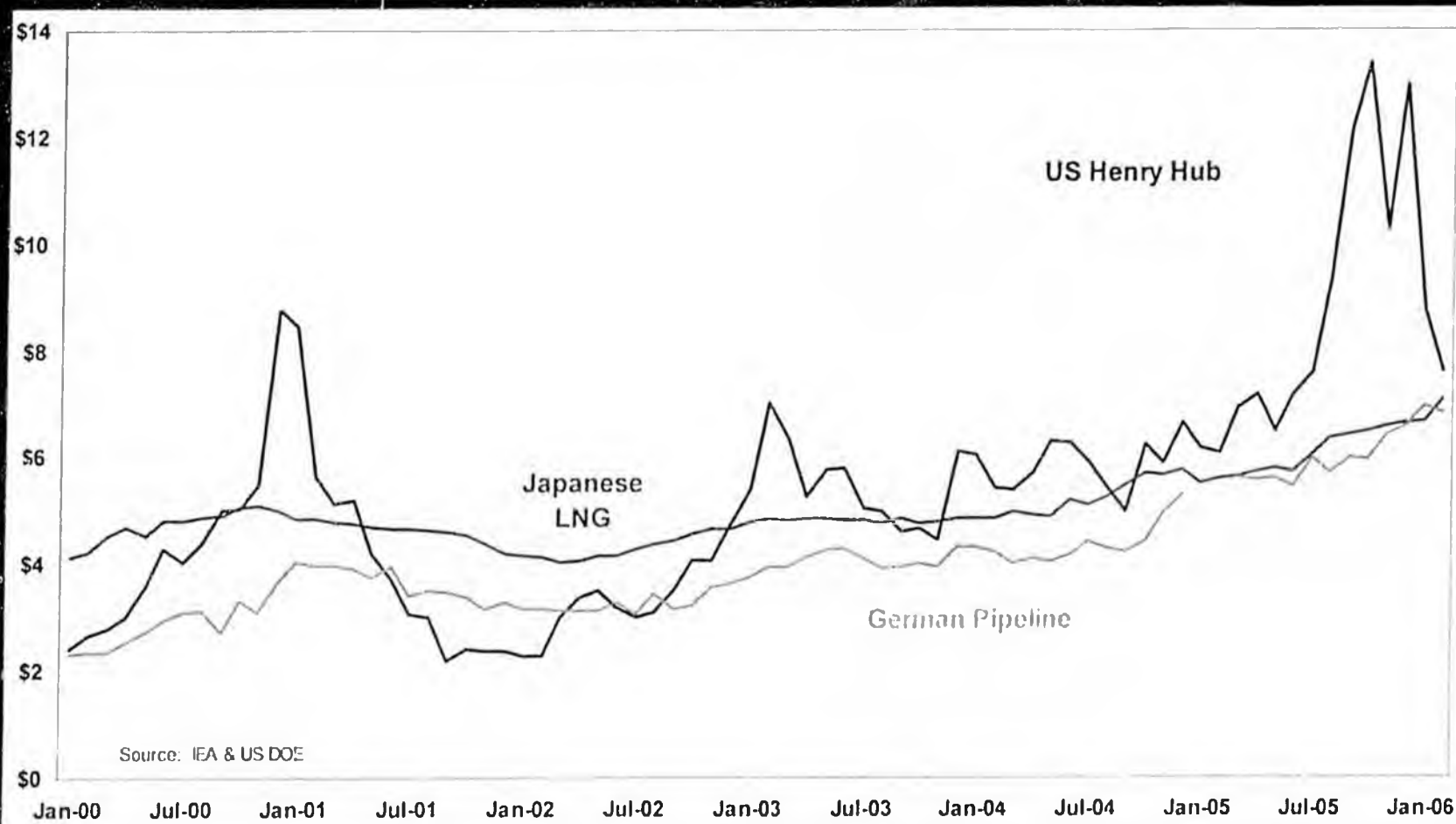
# Natural Gas Prices

Nominal Dollars per million BTU at Henry Hub



# Monthly International Gas Prices

US Dollars per Million British Thermal Units



ROLLED-IN

RATES

5/1/07

The Palin-Parnell Administration presents

# AGIA

The Alaska Gasline Inducement Act

**Rolled-in rates—from the FERC Perspective**

**Senate Finance Committee**

**5/01/07**

# FERC Policy- Rolled in Rates- In Alaska



- 2004 ANGPA mandate to FERC:
  - “promote competition in the exploration, development and production of Alaska natural gas.” (§103(e)(2)(b)).

# ● FERC Policy- ● Rolled in Rates- In Alaska



- FERC Concluded:

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

# FERC Policy- Rolled in Rates- Lower 48



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

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



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

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



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

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

# FERC Policy- Rolled in Rates- Alaska



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

# Governmental Contribution to Rates



Government Contributions reduce rates by more than 15%:

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

# AGIA Policy- Rolled in Rates



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

# FERC Process

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“A pipeline company

**PROPOSES**

But the FERC

**DISPOSES.**”

(an old industry adage)

# FERC Process



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

AGOCCE

**TESTIMONY OF JOHN K. NORMAN, CHAIR AOGCC  
SENATE FINANCE COMMITTEE  
APRIL 27, 2007**

This afternoon I'll discuss the AOGCC's role in North Slope gas sales and give you a status report.

Most knowledgeable Alaskans know the significance of 35 TCF of natural gas. However, very few people realize that hundreds of millions of barrels of oil and condensate could be lost if gas offtake is not correctly managed.

Oil is Alaska's bird in the hand and gas is our bird in the bush. The AOGCC is responsible for setting the gas offtake allowables from the North Slope oil fields to ensure that we do not harm our bird in the hand while aspiring to grasp our bird in the bush.

In general, maintaining reservoir pressure enhances oil recovery, but producing gas depletes reservoir pressure. Therefore, gas reserves in most fields are usually sold only after most of the oil has been produced. Until then, the gas that is produced with the oil is used to promote increased liquid production in various ways.

For example, gas might be reinjected into the reservoir to provide the energy needed to get the liquid hydrocarbons to the surface, or the gas might be used for enhanced oil recovery operations.

Both of those are happening right now at Prudhoe Bay and other North Slope fields.

Therefore, North Slope gas sales will involve trade-offs between oil and gas recovery. It's not practical to get every drop of oil out of the ground before starting gas sales, and the AOGCC certainly does not take that position. We just want to ensure that the trade-

offs that inevitably will occur result in greater ultimate recovery of both gas and oil

Prudhoe Bay has an existing gas offtake allowable. It is 2.7 BCF per day and it was set in 1977.

The AOGCC usually waits for an application from the operator to apply or modify pool rules. However, in 2005 we recognized that:

- (1) North Slope gas sales discussions were heating up,
- (2) the 2.7 BCF per day gas offtake allowable for Prudhoe Bay was set in 1977, about the time the field began to produce; and, although that offtake rate was based on the best available information at the time, we now have 30 years and 11 billion barrels of production and production-related data to help determine a better number
- (3) most of the publicly discussed pipeline options could require more than 2.7 BCF per day offtake from Prudhoe Bay
- (4) performing the necessary studies to determine an appropriate offtake could take a lot of time, and
- (5) the AOGCC did NOT want to cause any project delays.

To give us the most current information, BP and the other Prudhoe Bay working interest owners agreed to provide the AOGCC staff and consultants access to their simulators including the underlying engineering, geologic, and geophysical information. They voluntarily set up a data room in BP's Anchorage offices, equipped with computers and software allowing review of the simulator results.

It is very important to note that the data and information offered meet the standards of AS 31.05.035(d) and 20 AAC 25.537(b) governing confidentiality of information.

In simple terms, the data made available to us was not something we were otherwise entitled to, it belonged solely to the Prudhoe Bay working interest owners, we needed it to perform our study, and the only way for us to get access to it would be to agree to keep it confidential.

The study began in January 2006, and ended in late 2006. BP and its partners were helpful and provided us all that we needed.

This past February, we published a summary report, approved by BP and its partners. The report is available on the AOGCC website.

As soon as we announced that we had completed our study, everyone wanted to know the magic number, but it's not that easy.

First, it's a multi-variable equation. The right offtake volume will depend on when sales start, how aggressively the oil has been produced in the meantime, and what mitigating steps are in place and planned. And second, there are legal restrictions on what results of the study we can share and how we share them.

As soon as we have enough information to make a meaningful determination, we will hold public hearings and make as much information available as is needed and legally allowed to support the assigned offtake allowable.

We intend to complete our evaluations and make our final rulings on gas offtake allowables for both Prudhoe Bay and Pt Thomson well in time for the "open season" process.

That said, here's what we can say:

- (1) The later gas sales begin, the smaller the oil losses.
- (2) Depending on the life of the North Slope infrastructure, delaying too long could result in decreased gas recovery.
- (3) The lower the offtake rate, the smaller the oil losses.
- (4) The more the oil production is accelerated before gas sales start, the smaller the oil losses.
- (5) The more that is done to mitigate the detrimental effects of gas sales, the smaller the oil losses.
- (6) Oil loss is more sensitive to the acceleration of oil production and the mitigating steps than it is to start-up timing or offtake rate.

By the time we get a pipeline built, selling gas from Prudhoe Bay will likely be okay at a higher offtake rate than the current 2.7 BCF per day, provided BP and its partners continue working: (1) to accelerate oil production (for example: aggressive infield drilling and operational vigilance to minimize production interruptions) and (2) to mitigate for gas losses (gas cap water injection and using CO2 for EOR, for example).

We are comfortable that, unless a substantial delay occurs (which could make our analysis stale and require additional analytical work), we will be adequately prepared to determine the Prudhoe Bay gas offtake allowable when an application comes before us.

Now I would like to talk about Pt Thomson, where we can't make such a confident statement.

One year ago the AOGCC, Exxon, and its partners agreed upon a similar process for studying the allowable gas offtake from Pt Thomson. The AOGCC contracted reservoir evaluation consultants to assist its technical staff in performing the Pt Thomson study. Exxon and its partners agreed to give AOGCC staff and consultants access to a data room in Exxon's Houston offices. It was agreed that the data room would include reservoir engineering, geologic and simulation information and would be equipped with computers and software allowing review of the simulator results. The study was supposed to begin before September 2006 and last up to six months. Exxon and its partners indicated that they planned to apply to the Commission in late 2006 or early 2007 for Pool Rules and a gas offtake allowable rate for Pt Thomson.

Unfortunately we were not able to follow that time line. Exxon had delays in preparing the data room and information. The process was finally slated to begin late last year, about the same time that the DNR found Exxon and its partners to be in default on their leases. We attended one meeting where Exxon presented a small portion of the information we would need, but since then the study has been on hold pending resolution of legal issues.

Without a thorough study, it will be very difficult for the AOGCC to have sufficient information to make a gas offtake ruling on Pt Thomson. So that one remains a wild card – in many ways.

So, in summary:

- (1) There are hundreds of millions of barrels of oil and condensate at risk if Alaska doesn't manage gas sales properly.

- (2) The AOGCC is charged with setting gas offtake allowables that will protect Alaska's valuable hydrocarbon resources.
- (3) The AOGCC intends to perform its function so that it does not delay the project, i.e., before an open season.
- (4) We've done the technical work to prepare us to address Prudhoe Bay's offtake without causing that delay.
- (5) There's still a lot to be done for Pt Thomson; so delay is possible there.

Thank you and we would be happy to take your questions.

**BIOGRAPHICAL INFORMATION**

***John K. Norman***

***Chairman***

**State of Alaska**

**Oil & Gas Conservation Commission**

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- Education:** University of Missouri (J.D. 1964; A.B. (Geology) 1962).
- Admitted to Bar:** Missouri (1964); Alaska (1969); U.S. District Court, District of Alaska (1969); U.S. Court of Appeals, Ninth Circuit (1972); U.S. Supreme Court (1972).
- Member:** Greater Anchorage Area Board of Health (1973-1975); State Division of Lands Advisory Committee (1976-1977); Federal Bureau of Land Management Advisory Council (1982-1985); President, Common Sense for Alaska, Inc. (1981-1982); Vice President, Anchorage Chamber of Commerce (1983-1985); Chairman, Commonwealth North, Hartig Research Fellowship Trust (1981 - present); Board of Directors, Resource Development Council (1988 - 2004); Trustee, Iditarod Trail Race Foundation (1976-present); U.S. Department of Commerce, Alaska District Export Council (1992 - present); American Institute of Professional Geologists (2003 - present); Outstanding Lawyers of America (2003 - present); The Best Lawyers in America (2004-present); Alaska Bar Association (Chairman, Natural Resource Law Committee (1977-79), Fee Arbitration Panel (1977-1981), Environmental/Natural Resource Law Section (1980-present), Discipline Hearing Committee (1983-1987); American Bar Association (Member, Environment, Energy and Resources Section; State Chairman, Committee on Environmental Quality, Young Lawyers Section, 1971-1973); Official Alaska Representative and Vice Chairman, Interstate Oil and Gas Compact Commission (2004-present) (Chairman Steering, Nominating and Split Estates Committees).
- Positions Held:** Chairman, State of Alaska Oil & Gas Conservation Commission (2004-present); Founding Partner and Shareholder, Harig Rhodes Hoge & Lekisch, P.C. (1971-2004); Assistant Attorney General, State of Alaska, Department of Law, Natural Resources Section (1969-1971); Exploration Representative, Skelly Oil Company, Alaska/Texas (1967-1968); 1st Lt., United States Army, Germany (1964-1966).
- Published Works:** "Section Line Dedications for Construction of Highways," Alaska Law Journal (Feb. 1970); "Production, Conservation and Utilization of Natural Gas in Alaska," Natural Resources Lawyer (Nov. 1970); "Alaska's D-2 Lands," Alaska Mineral Development Institute Paper No. 5, Rocky Mountain Mineral Law Foundation (Aug. 1978); "Legal Considerations When Entering the Alaska Energy Market," IBC Global Conferences (Sept. 2002); Alaska Oil & Gas Law Reporter, Rocky Mountain Mineral Law Newsletter (1984 - 2004).
- Reported Cases:** *Swindel v. Kelly*, 499 P.2d 291 (Alaska 1972); *Zamarello v. Yale*, 514 P.2d 228 (Alaska 1973); *Thomas v. Bailey*, 595 P.2d 1 (Alaska 1979).

**MEMORANDUM****STATE OF ALASKA****ALASKA OIL AND GAS CONSERVATION COMMISSION**

TO: Chair John K. Norman                      DATE: February 28, 2007  
Commissioner Daniel Seamont  
Commissioner Cathy P. Foerster

FROM: Jane Williamson *Jane Williamson*                      SUBJECT: Prudhoe Major Gas Sales  
Sr. Reservoir Engineer                      Study

Blaskovich Services, Inc. (BSI) and Commission staff recently completed a study of the impact of a future Major Gas Sale (MGS) on oil and gas recovery from the Prudhoe Oil Pool. The following is provided as a summary of major findings and conclusions from this study.

**Foreward – Historical Review and Study Purpose**

In 1977, the Commission set the maximum allowable Prudhoe Oil Pool annual gas offtake rate at 2.7 billion standard cubic feet per day (BSCF/D), which contemplated an annual average gas pipeline delivery sales rate of 2.0 BSCF/D. This allowable, set out in Rule 9 of Conservation Order 341D, was approved without benefit of production history. The Commission recognized that the rates may be changed as production data and additional reservoir data became available.

Over the past five years, there has been significant activity concerning a potential major gas sale. BPXA, Exxon-Mobil, and ConocoPhillips commissioned a \$125 million dollar study to determine the conceptual feasibility of a gas pipeline. The tentative plan resulting from this study was for a 4.3 BSCF/D pipeline, with capacity to expand to 5.6 BSCF/D. The Prudhoe Bay Unit, Prudhoe Oil Pool is the only North Slope developed field with significant gas reserves (estimated at more than 24 trillion cubic feet (TCF)) and is of primary importance for any decision concerning the pipeline. Pt. Thomson, with over 8 TCF of gas and several hundred million barrels of gas condensate and oil, was assumed to also provide a supply of gas for the pipeline. The companies and the State of Alaska have devoted significant resources to negotiate fiscal terms to build the pipeline. Based on these efforts, the Commission became concerned that no application for modification to the Prudhoe gas offtake rule had been submitted.

As a result of a Commission inquiry and several public hearings, the Commission published a report on December 5, 2005 concluding that there was a need to comprehensively revisit the question of the appropriate gas offtake limits in light of several decades of reservoir development and information that has become available since 1977. Because delay in the Commission's decision-making could disrupt the timetable for a potential gas pipeline project, the Commission adopted a proactive approach to ensure there would be an adequate factual basis for its eventual decision on

1:51:01 PM

AOGCC  
page 8

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

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

### Summary of 2006 Commission Audit Results

The Prudhoe WIO full field reservoir simulator was used as the primary tool in this evaluation. In addition to runs made assuming no gas sales, simulation runs were made at various gas sales rates (1.0-5.6 BSCF/D) and gas sales startup dates (2015, 2019, and 2024). Some simulation cases were run to test the impact of other factors such as changes in waterflood operation, fuel usage, CO<sub>2</sub> offtake, and some drilling/workover variations. We also evaluated the effect of varying assumptions for end of the field life (EOFIL).

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

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

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

### Recommendations

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

## Role of the Alaska Oil and Gas Conservation Commission in Approving Pool Rules for the Point Thomson Field

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The Alaska Oil and Gas Conservation Commission ("AOGCC") has a very important role in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of oil and gas. To fulfill this role, the AOGCC must determine what gas production rates should be allowed from North Slope oil fields. As part of this process, the AOGCC will evaluate ExxonMobil's proposed plan to develop the Point Thomson Field as a gas field rather than as an oil field. Generally, the most total hydrocarbon recovery from a retrograde condensate field would be achieved by conducting gas cycling operations to produce condensate (a liquid hydrocarbon that is considered "oil" under the Commission's governing law) until all of the economically recoverable liquid hydrocarbons have been produced. Only then should the gas be sold. The AOGCC recognizes, however, that many other factors will – and should – be considered in exercising its regulatory powers.

Point Thomson is the largest proven yet still undeveloped field in Alaska. It is also one of the most difficult to develop and manage properly because the majority of the resources are contained in what is called a retrograde condensate reservoir. Retrograde condensate reservoirs around the world tend to be deeper and have higher pressures and temperatures than conventional reservoirs. These abnormally high temperatures and pressures cause the fluids in the reservoir to have unusual properties. Thus, a retrograde condensate reservoir acts differently than a typical oil field such as Prudhoe Bay or a typical gas field such as the Kenai Gas Field. The differences in behavior are technically complex and difficult to describe, understand, and address; yet understanding and addressing these differences are essential to evaluating whether a plan of development satisfies the conservation requirements administered by the Commission.

A conventional oil reservoir is typically filled with a liquid hydrocarbon that has some solution gas in it. In such a reservoir all the fluid exists as a liquid, but as it is brought to the surface its pressure drops and some of its solution gas is released. The same thing happens underground. As the pressure decreases in the reservoir, gas in the oil comes out of solution. To understand how this works, think of a bottle of soda. Before the bottle is opened, its contents are under pressure and it appears that there is just liquid in the bottle. However when the cap is removed, the pressure in the bottle is reduced and bubbles will start to form and float to the surface of the soda.

Conversely, a conventional gas reservoir is typically filled with hydrocarbon gas. The gas may have a small amount of hydrocarbon liquid, called condensate, vaporized in it. This condensate will not drop out as a liquid in the reservoir because the temperature is too high. However it will separate from the gas when the gas is brought to the surface where the temperature is lower. This is similar to what happens when someone blows warm breath onto a cold window and watches it fog up. The water that exists as a vapor inside the warm lungs turns to condensation as it hits the cold window.

Retrograde condensate reservoirs do not behave in the same ways that conventional oil and gas reservoirs do. Dropping the pressure in the reservoir does not cause gas to form from oil, as is the case in a conventional oil reservoir. Nor does vaporized condensate remain a vapor, as is the case in a conventional gas reservoir. Rather, for a retrograde condensate reservoir, as the pressure decreases, liquids drop out of the gas in the reservoir.

When a retrograde condensate field is produced like a conventional gas field, the gas is produced and sold at high rates. Initially a large amount of condensate is produced with the gas. However the reservoir pressure drops quickly and condensate production drops dramatically because condensate is dropping out in the reservoir instead of at the surface. To further the problem, condensate that drops out in the reservoir is much more difficult to produce than that which remains entrained as a vapor in the gas. The liquid tends to build up and clog the pore spaces in the reservoir rock. Also, since this reservoir has never been exposed to liquid before, the rock acts as a sponge and some of the condensate will be immobilized and never come out. To make things worse, once the condensate comes out of the gas, very little of it will return to a gaseous state even if the reservoir pressure is later increased. In other words this is a problem that you can't fix after you cause it; it's like unringing a bell.

In addition to lost condensate recovery, if the reservoir pressure is reduced too quickly, the gas recovery will also decrease. The condensate that clogs up the reservoir and won't come out also blocks the gas from coming out. This is similar to an air filter on a car. When the filter is new, air will flow through it freely, but as it gets older the pores in the filter begin to clog with dirt (as the pores in the reservoir would clog with condensate) and the air will not flow through as well. Eventually no air at all will flow.

So what's the answer? To maximize condensate production from a retrograde condensate reservoir, it is necessary to keep the reservoir pressure high until the condensate has been recovered. Often this is accomplished through a process known as "gas cycling." In this process hydrocarbon gas is produced, the condensate is removed and sold, and the now-lean gas is injected back into the reservoir to maintain pressure and to sweep more condensate to the surface. As this process continues, the gas produced slowly becomes leaner and the yield of condensate decreases. Eventually the gas is stripped of most of the liquids and it is safe to sell the gas. This method delays gas sales, but it results in greater ultimate recovery of both liquid and gaseous hydrocarbons.

Another method used to develop retrograde condensate fields is to inject a substitute gas such as nitrogen or carbon dioxide either to replace or to supplement the produced gas for pressure maintenance. Unfortunately, there is currently no substitute gas available to Point Thomson.

These are just a few of the more common methods used for developing retrograde condensate fields and each has advantages and disadvantages that must be considered. Primary depletion as a gas field is the least efficient and results in the lowest hydrocarbon recovery. However, it is the simplest and cheapest method for the operator since it does

not require an investment in equipment to recycle the gas. Gas cycling yields greater hydrocarbon recovery but may be less attractive to the operator because it has a higher up-front development cost for compression and it has low up-front cash flow due to the deferral of gas sales. Injection of outside substances has the possibility of maximizing both condensate recovery and cash flow, but it is the most expensive method because in addition to compression equipment it requires the purchase of a substitute gas.

Selection of an optimal method of development must consider all of the unique aspects of the reservoir in question, as well as the practicality and applicability of the various development methods.

The operator of the Point Thomson Unit has indicated that the only development scenario that makes sense is to develop Point Thomson as if it were a normal gas field, which would likely result in significant loss of condensate. Since the AOGCC must determine whether this development option is consistent with good oilfield engineering practices and will result in greater ultimate recovery, the agency is working with an outside consultant who has extensive retrograde condensate reservoir expertise. The AOGCC and its consultant are evaluating different development options and developing a sound technical basis for conservation orders relative to the development plan that is ultimately proposed by the operator of the Point Thomson Unit.

## Role of the Alaska Oil and Gas Conservation Commission in North Slope Gas Sales

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope natural gas to market. The Alaska Oil and Gas Conservation Commission ("AOGCC") has an important responsibility in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of oil and gas. To fulfill this role, the AOGCC must determine what gas offtake rates should be allowed from North Slope fields, most notably the Prudhoe Oil Pool and the Pt. Thomson gas condensate reservoirs.

There are over 35 trillion cubic feet of gas reserves within these two fields. However, hundreds of millions of barrels of oil and condensate could be lost if gas offtake from these fields is not correctly managed.

In general, maintaining reservoir pressure enhances oil recovery, but producing gas depletes reservoir pressure. Therefore, gas reserves in most fields are usually sold only after the liquid hydrocarbon reserves have been depleted. Until then, the gas that is produced is used to promote liquid production in various ways (including being reinjected so that it can provide the energy needed to get the liquid hydrocarbons to the surface and providing a source of gas for miscible injectant used in enhanced oil recovery operations). And that is exactly what is happening right now at Prudhoe Bay and other North Slope fields.

The North Slope gas sales project will ultimately involve trade-offs between oil and gas recovery. The documents *Role of the Alaska Oil and Gas Conservation Commission in Establishing an Allowable Gas Offtake Rate for Prudhoe Bay* and *Role of the Alaska Oil and Gas Conservation Commission in Managing Development of the Point Thomson Field* explain these trade-offs. This document explains the process the AOGCC is using to insure greater ultimate total hydrocarbon recovery, i.e., recovery of both oil and gas, as the North Slope gas project moves forward.

Normally, the operator of an oil or gas field applies to the AOGCC for "Pool Rules." These are specific rules that stipulate how to develop the reservoir in a way that maximizes oil and gas recovery. However, the Point Thomson Owners have not yet applied to the AOGCC for Pool Rules.

Nor have the Prudhoe Owners applied for amendment of current pool rules to allow for a higher gas offtake rate. The existing Prudhoe gas offtake rate was set in 1977 at 2.7 billion standard cubic feet (BCF) of gas per day. After deducting gas used as fuel and in enhanced recovery operations, this leaves about 2 BCF of gas per day available for sales. However, the gas sales scenarios that are being discussed publicly could require increasing the Prudhoe gas offtake allowable.

Normally the AOGCC would wait for an application from the Owners before performing the reservoir studies necessary to establish or increase gas offtake rates. However, that would delay the AOGCC's decision-making such that it could disrupt the timetable for a potential gas pipeline project. (The AOGCC needs to complete its evaluations and make its rulings for both

Prudhoe Bay and Pt Thomson so the Owners have approved gas offtake allowables that they can use in the "open season" process that is required under the Federal Energy Regulatory Commission ("FERC") regulations. The current draft version of the Alaska Stranded Gas Fiscal Contract requires the Producers to apply to the AOGCC within 6 months of the effective date of the contract for issuance of pool rules to authorize the field gas offtake rate for Point Thompson.)

Therefore, the AOGCC has chosen a proactive approach. There are two ways the Commission might take a proactive role with respect to such studies. One would be to conduct or arrange for consultants to conduct independent reservoir studies. The other would be to participate with the Owners and operators in their reservoir simulation studies, so that questions can be answered and adjustments can be made up front. Assuming adequate cooperation on the part of the Owners, the latter approach has significant advantages: lower cost to the State of Alaska, less time required to complete evaluation of the studies, more complete and accurate input data, and use of proven, probably more sophisticated reservoir evaluation tools.

In 2005 the Commission held hearings to inquire whether the gas offtake rate from Prudhoe should be updated. The AOGCC decided that, although the 1977 allowable was based on the best available data at the time, the appropriate gas offtake allowable must now be redetermined using the almost thirty years worth of reservoir description and performance information that has become available since 1977. Further, the Prudhoe Owners and the AOGCC established principles by which to perform collaborative studies. The report of the inquiry and the resultant study principles were issued by the AOGCC on December 5, 2005.

The AOGCC has contracted reservoir evaluation consultants to assist its technical staff in performing the Prudhoe study. The Prudhoe Owners have agreed to provide the AOGCC staff and consultants access to their simulators including the underlying engineering, geologic, and geophysical information. A data room has been set up in BP's Anchorage offices, equipped with computers and software allowing review of the simulator results. The Owners have voluntarily offered to make the data room information available. The information meets the standards of AS 31.05.035(d) and 20 AAC 25.537(b) entitling it to be held confidential during this study period.

This study process began in January 2006, and is anticipated to be complete by the end of this year. Following this study period, either the Owners will submit an application to amend the Prudhoe gas offtake allowable or the AOGCC will call for a hearing. In either case, the AOGCC will hold public hearings to review the development plans associated with the proposed gas sales. The Owners will be required to submit for the record reservoir studies that best reflect a reasonable range of offtake options and their effects. The AOGCC may request (including by subpoena) any other pertinent information that has been used in the study but is not included in the Owners' submission of evidence in the hearings. Claims of confidentiality for evidence in the hearings will be determined by the AOGCC during the course of the hearings under governing law.

On April 26, 2006 the AOGCC and the Pt. Thomson Owners agreed upon a similar process for studying the allowable gas offtake from that field. The AOGCC has contracted reservoir evaluation consultants to assist its technical staff in performing the Pt Thomson study. AOGCC staff and consultants will have access to a data room in ExxonMobil's Houston offices. The data

room will include reservoir engineering, geologic and simulation information and will be equipped with computers and software allowing review of the simulator results. The study will begin before September 2006 and will last up to six months. The Point Thomson Owners have indicated they plan to apply to the Commission in late 2006 or early 2007 for Pool Rules and a gas offtake allowable rate.



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AK GASLINE

PORT

AUTHORITY



## Senate Finance Committee

April 28, 2007

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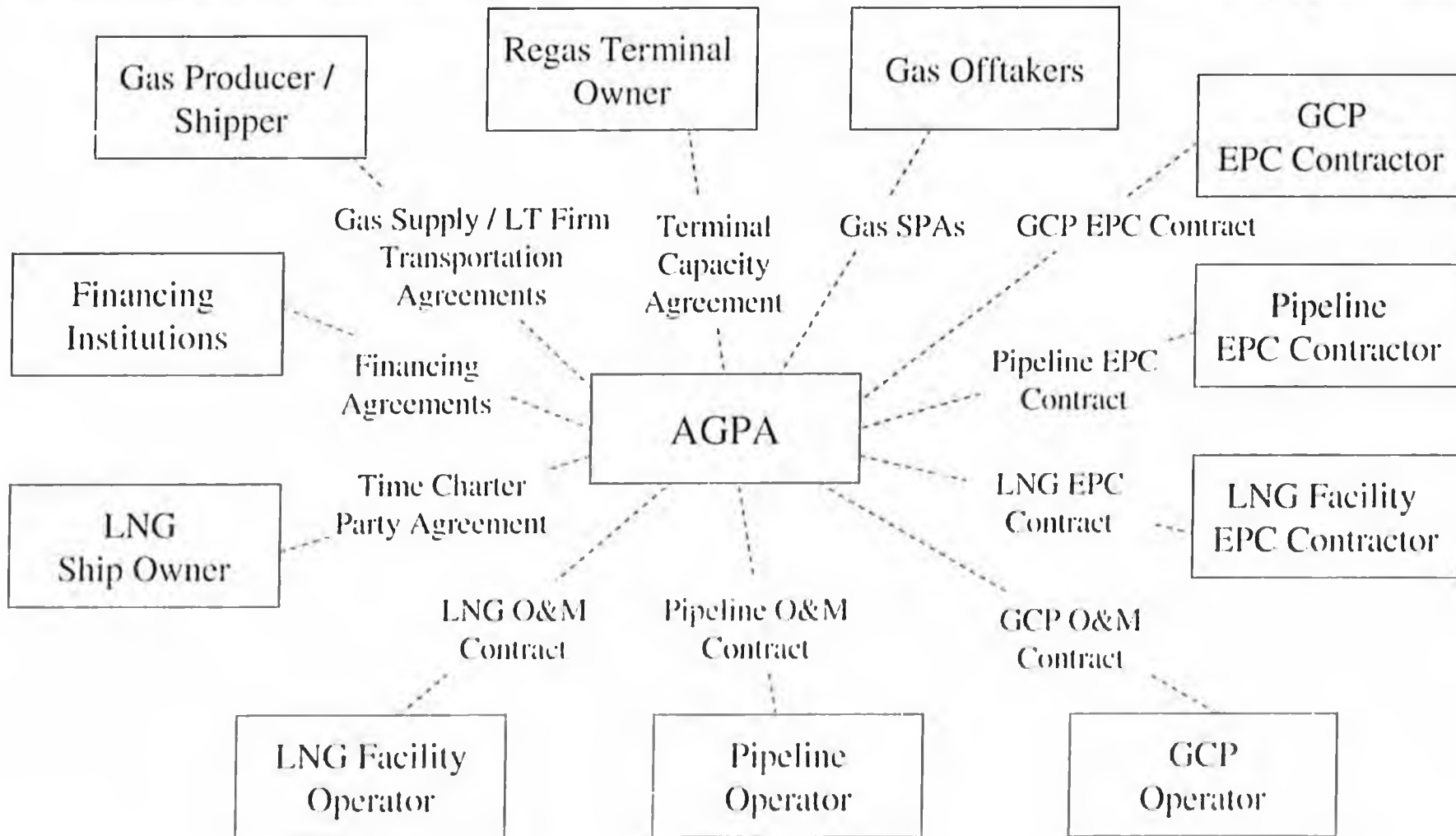
## AGIA is Good for Alaska



### Alaska Gasline Inducement Act (AGIA) Process:

- Open, transparent and competitive
- Identifies clear evaluation criteria
- Inducements to project applicants in exchange for specific commitments
- Empowers selected applicant to build successful consortium, leading to open season

# Indicative AGPA Project Structure



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

# AGPA Project Description



## Gas Conditioning Plant in Prudhoe Bay

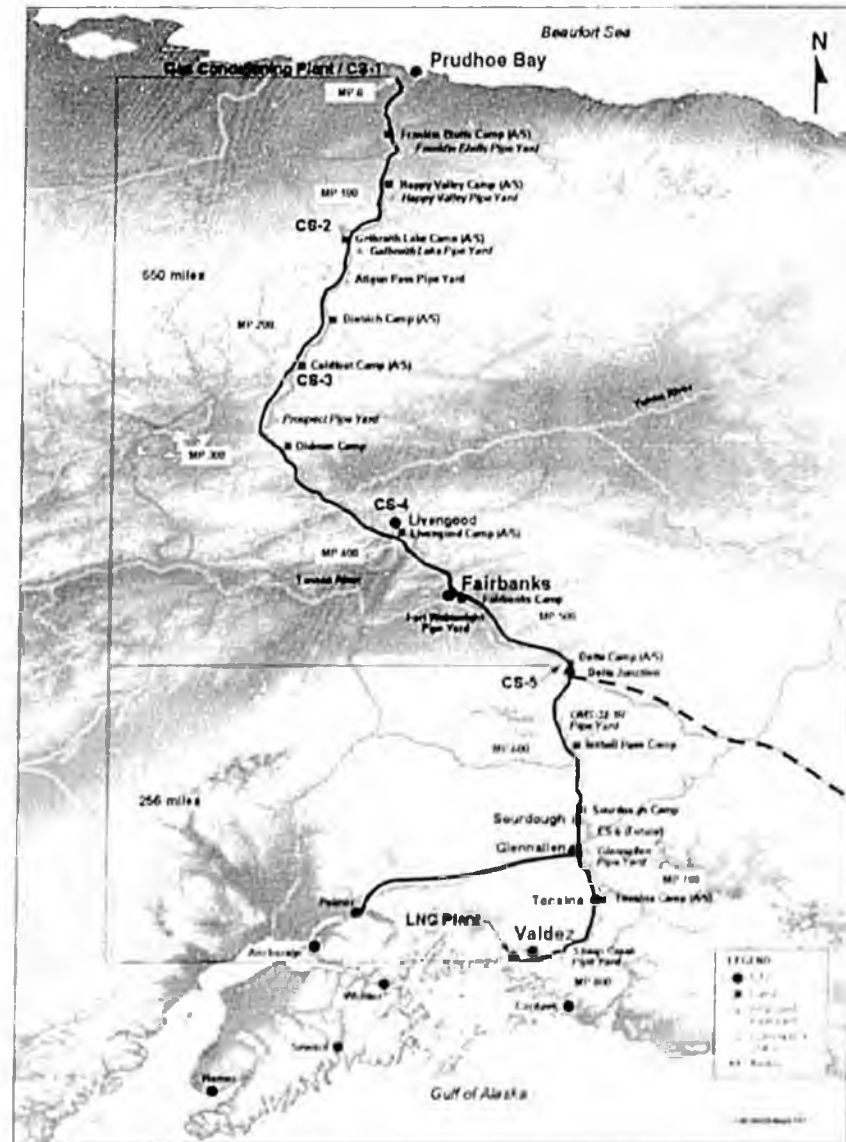
- removes impurities
- compresses and chills the gas to pipeline specifications

## Pipeline from Prudhoe Bay to Valdez

- parallel to TAPS (max. capacity: 6 Bcfd)
- pre-build to Delta Junction for later tie-in for the Alaska/Canada Highway Project
- tie-in at Glennallen for a spur line to Alaska South Central natural gas grid

## LNG Facility in Valdez

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



## Project Status



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

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## Phased Project = Better Cost Overrun Risk Management



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

## LNG Project is Economic



- Robust economics with projected strong returns to upstream producers (with no tax concession by State)
  
- Favorable economics takes into consideration pre-build to Delta Junction for a future AlCan Highway
  
- Win-Win for Alaska with LNG:
  - Capture West Coast market now plus enable a later AlCan Highway project to proceed when ready
  - Earliest in-State gas availability

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## Advantages of LNG from Alaska



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

## Advantage of LNG for Alaska – Phased Project



- Better mitigation of cost overrun risk
- Open North Slope to commercialization of gas; encourage further exploration
- Commercialize discovered gas resources, while allowing exploration for expansion to proceed
  - initial offtake for LNG project – within existing AOGCC Rule 9 limitation
- Better positioned to accommodate early in-State offtake:
  - economics of project components downstream of Alaska do not suffer diseconomies of scale due to reduced export volume – offtake at Glennallen affects only 100 miles of pipeline to Valdez
- Pre-build for expansion affects only the pipeline in Alaska
  - expansion either through addition of new LNG trains or by interconnection at Delta Junction with an AICan Highway project
  - Availability of gas liquids in Alaska for value added processing

## AGIA Suggested Project Evaluation Criteria

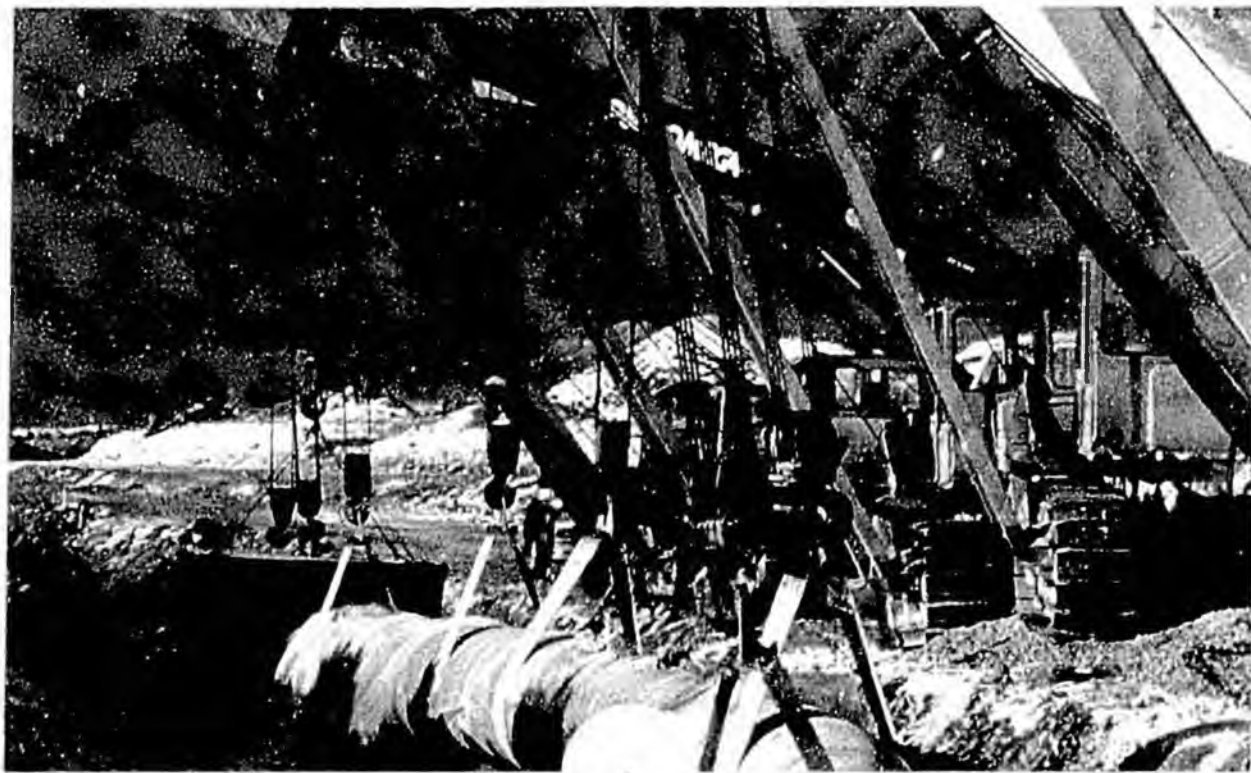


- If applicant's offtake amounts exceed AOGCC Rule 9 limitations (2.7 bcf/d less field use), must have already filed an application with AOGCC for increased offtake limits
- Additional gas reserves needed? Budget and timeline for exploration program
- Analysis of liquids availability in Alaska for value added processing
- Current project cost estimate required with application

### AGIA benefits towards advancing gas pipeline

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

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



*Alaska Gasline*  
PORT AUTHORITY

**Right Sized – Right Now!**

LB+A

CONSULTANTS


DAN

DICKINSON

5/3/07

Presentation to the Alaska  
Legislature  
Senate Finance Committee  
May 3, 2007

Dan E. Dickinson  
CPA, CMA

- 
- How is gas generally taxed under the PPT? What are the PPT credit implications of gasline work?
  - Same as oil (almost) – on net value
  - Investment downstream of the point of production not eligible for credits

# How is gas taxed under the PPT


- 43.55.011
- (e) 22.5% of net value
- (f) North Slope floor triggered by oil price
- (g) & (h) Progressivity triggered by single taxpayer net value
- (i) Private royalty 1.67% for gas – 1/3 of oil
- (j) Cook Inlet Ceiling

## AS 43.55.011 (e) 22.% of net value

- Total upstream costs are deducted from the revenue streams from oil and gas sales.
- Gas Revenue Exclusion (GRE) mechanism discussed in 2006 is an administratively simple way of adjusting the effective rate without changing the nominal rate or making lots of allocations.

# 43.55.011(f) North Slope floor triggered by oil price

- Alternative floor just applicable to North Slope Oil and Gas is triggered by oil price.
  - Consider future if Prudhoe Bay is producing 250,000 bbls oil and 3 bcf of gas.
  - If the heating value is 1,000,000 btu per mcf, that translates to the equivalent of 500,000 bbls a day – so 1/3 of the field's production will be used to set the trigger.

- 
- Question 3. How does PPT progressivity work on gas and what is it's link to oil?

# AS 43.55.011 (g) & (h) Progressivity triggered by single taxpayer net value

- Progressivity is determined for each taxpayer on its total mix of oil and gas and all upstream costs
- Calculated on a monthly basis – monthly upstream costs are 1/12 of total annual costs
- Example – Next slide
  - Prices April 27 2007,
  - 1,000 btu per mcf,
  - equal mix of boe gas and oil

# AS 43.55.011(g) & (h) progressivity triggered by single taxpayer net value

	Oil		Gas		Gas BOE		Taxpyr Ave
Dest Price	63.76		7.32				
Downstream Adj	(5.00)		(3.00)				
Gross Value	58.76		4.32	6.00	25.92		
Upstream Adj	(7.00)				(7.00)		
Net Value	51.76				18.92		35.34
.011(h) limit	(40.00)				(40.00)		(40.00)
Price Index	11.76				N/a		N/a
.011(g) factor	0.0025				0.0025		0.0025
Progressivity %	2.940%				N/a		N/a

# Dollar/bbl progressivity Charge at various Destination values and net deductions


Per barrel Progressivity Charge							
Per Barrel Costs	Monthly Average Destination Value per bbl in Dollars						
	50	55	60	65	70	75	80
5	0.56	1.25	2.06	3.00	4.06	5.25	6.56
6	0.44	1.10	1.89	2.80	3.84	5.00	6.29
7	0.32	0.96	1.72	2.61	3.62	4.76	6.02
8	0.21	0.82	1.56	2.42	3.41	4.52	5.76
9	0.10	0.69	1.40	2.24	3.20	4.29	5.50
10		0.56	1.25	2.06	3.00	4.06	5.25
11		0.44	1.10	1.89	2.80	3.84	5.00
12		0.32	0.96	1.72	2.61	3.62	4.76
13		0.21	0.82	1.56	2.42	3.41	4.52
14		0.10	0.69	1.40	2.24	3.20	4.29
15			0.56	1.25	2.06	3.00	4.06
16			0.44	1.10	1.89	2.80	3.84
17			0.32	0.96	1.72	2.61	3.62
18			0.21	0.82	1.56	2.42	3.41
19			0.10	0.69	1.40	2.24	3.20
20				0.56	1.25	2.06	3.00

# AS 55.43.011 (i) Private Royalty 1.67% of gross for gas

- This is one third the rate for oil which is 5% of gross.

## AS 43.55.011(j) Cook Inlet Ceiling

- No direct effect on North Slope gas
- Expires in 2022
- If gas line is built from North Slope to Cook Inlet may want to consider effect of differential rates of taxation
- Ceiling potentially different for each producer:
  - Average (15 AAC 55.440) 4.947% of \$3.585 per mcf.

- 
- Are PPT gas credits applicable to the GTP in the AGIA bill?
  - Under PPT – the GTP is not eligible for credits.

# Only Upstream Costs Qualify as Credits

- AS 43.55.023 (a) “...may take a tax credit for a qualified capital expenditure... in the amount of 20 percent of that expenditure;”
- AS 43.55.023 (k)”...’qualified capital expenditure’...means...an expenditure that is a lease expenditure under AS 43.55.165 and is...treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code)

# Only Upstream Costs Qualify as Credits

- AS 43.55.165 (a) "...a producer's lease expenditures for a calendar year are the ordinary and necessary costs upstream of the point of production of oil and gas ...and that are the direct costs of exploring for developing, or producing oil or gas..."

# Where is the point of Production?

- In AS 43.55.900
- (21) gas processing
- (23) gas treatment
- (27) point of production
- Are defined so that gas processing is upstream of the point of production and gas treatment is downstream of the point of production.

# PPT Definitions: Point of Production

- AS 43.55.011(27) “point of production” means
- (A) for oil...
- (B) for gas, other than gas described in (c) of this paragraph that is
- (i) not subjected to or recovered by mechanical separation or run through a gas processing plant, the first point where the gas is accurately metered;
- (ii) subjected to or recovered by mechanical separation but not run through a gas processing plant, the first point where the gas is accurately metered after completion of mechanical separation;

# PPT Definitions: Point of Production

- AS 43.55.011(27) “point of production” means
- (B) for gas...
- (iii) run through a gas processing plant, the first point where the gas is accurately metered downstream of the plant;
- (C) for gas run through an integrated gas processing plant and gas treatment facility that does not accurately meter the gas after the gas processing and before the gas treatment, the first point where the gas processing is completed or where gas treatment begins, whichever is further upstream.

# PPT Definitions: Gas Processing

- AS 43.55.011 (21) “gas processing”
- (A) means processing a gaseous mixture of hydrocarbons
- (i) by means of absorption, adsorption, externally applied refrigeration, artificial compression followed by adiabatic expansion using the Joule-Thomson effect, or another physical process that is not mechanical separation; and
- (ii) for the purpose of extracting and recovering liquid hydrocarbons [producing ngl's/oil];
- (B) does not include gas treatment

# PPT Definitions: Gas Treatment

- AS 43.55.011 (23) “gas treatment”
- (A) means conditioning gas and removing from gas nonhydrocarbon substances for the purpose of rendering the gas acceptable for tender and acceptance into a gas pipeline system.
- (B) includes incidentally removing liquid hydrocarbons from the gas

# PPT Definitions: Gas Treatment

- AS 43.55.011 (23) “gas treatment” (cont.)
- (C) does not include
  - (i) dehydration required to facilitate the movement of gas from the well to the point where gas processing takes place;
  - (ii) the scrubbing of liquids from gas to facilitate gas processing.

# Under Current law:

- Gas Processing
- Starts with gaseous mixture of hydrocarbons, and produces natural gas liquids and gas by removing the hydrocarbon liquids.
- Gas treatment
- Starts with produced gas and removes nonhydrocarbons (including incidental hydrocarbons) to prepare the gas for tender to the pipeline. Nothing is produced.

# AGIA Definitions: Gas Processing

- AS 43.55.900 (7) “gas processing” means the treatment of gas downstream of the point of production to extract natural gas liquids. CSHB 177(RES)
- AS 43.55.900 (7) “gas processing” means post-production treatment of gas to extract natural gas liquids. CSSB 104(JUD)

# AGIA Definitions: Gas Processing

- Suggested Definition
- AS 43.55.900 (7) “gas processing” has the same meaning as “gas processing” in AS 43.55.900 (21)

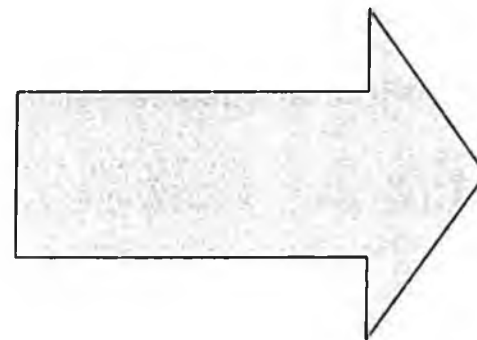
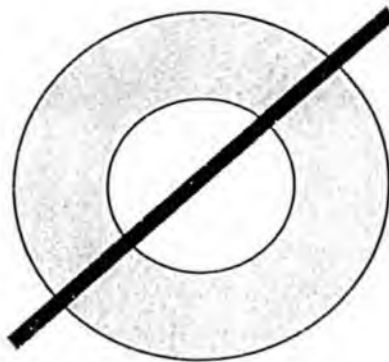
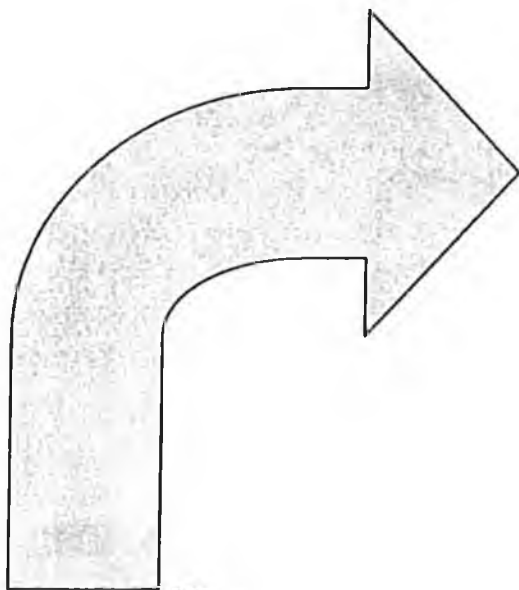
# PPT Point of Production for Gas

Is the gas run through an integrated gas processing plant and gas treatment facility that does not accurately meter the gas after the gas processing and before the gas treatment?		no	Is the gas subjected to or recovered by mechanical separation or run through a gas processing plant?		yes	Is the gas subjected to or recovered by mechanical separation but not run through a gas processing plant?		no	Is the gas run through a gas processing plant?	
yes			no			yes			yes	
Point of Production = the first point where gas processing is completed or where the gas treatment begins, whichever is further upstream			Point of Production = the first point where gas is accurately metered			Point of Production = the first point where gas is accurately metered after completion of mechanical separation			Point of Production = the first point where gas is accurately metered downstream of the plant	

# Gas Point of Production

Gas not run through a gas processing point or subject to mechanical separation

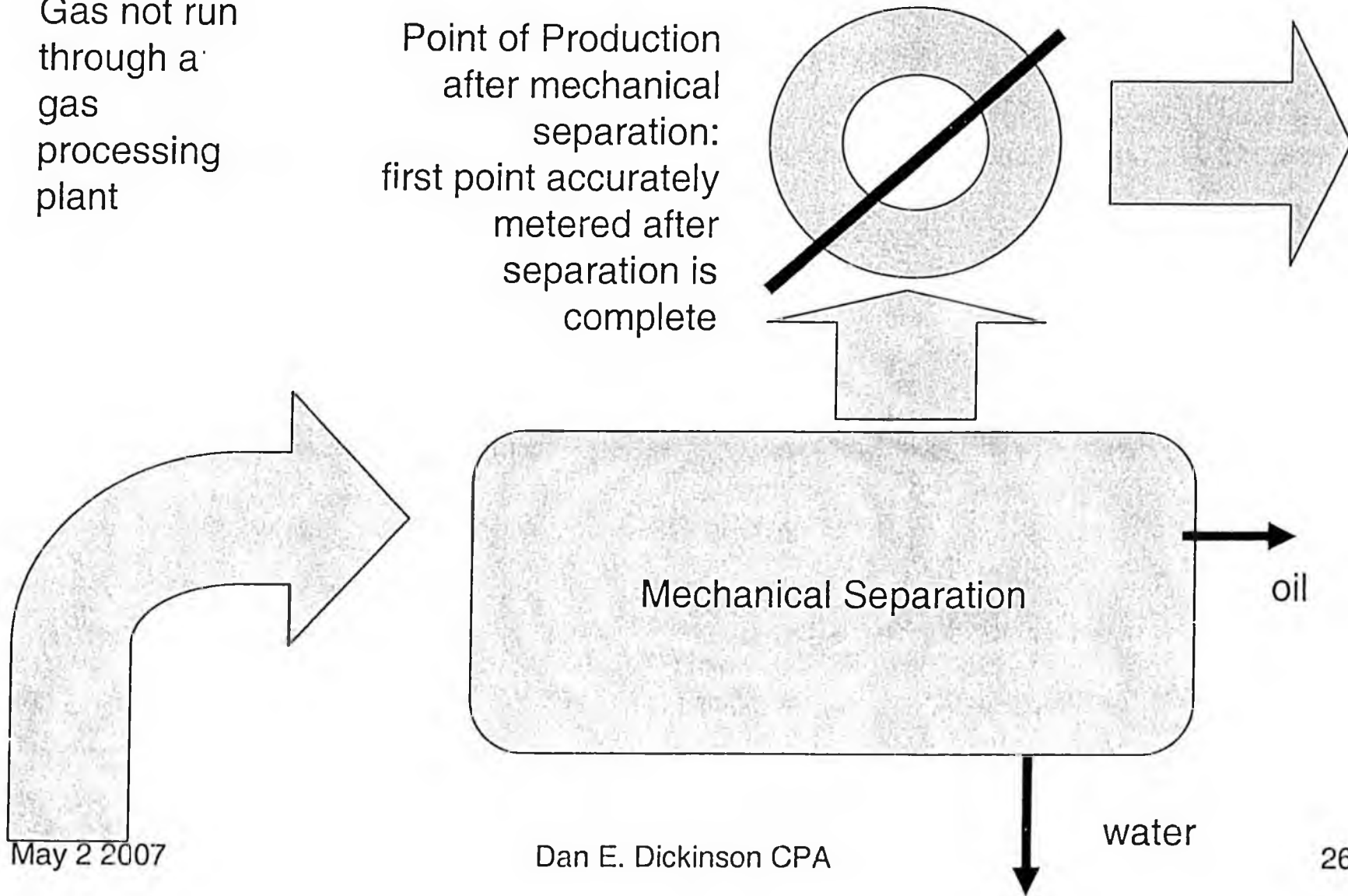
Point of Production: first point accurately metered



# Gas Point of Production

Gas not run through a gas processing plant

Point of Production after mechanical separation:  
first point accurately metered after separation is complete



May 2 2007

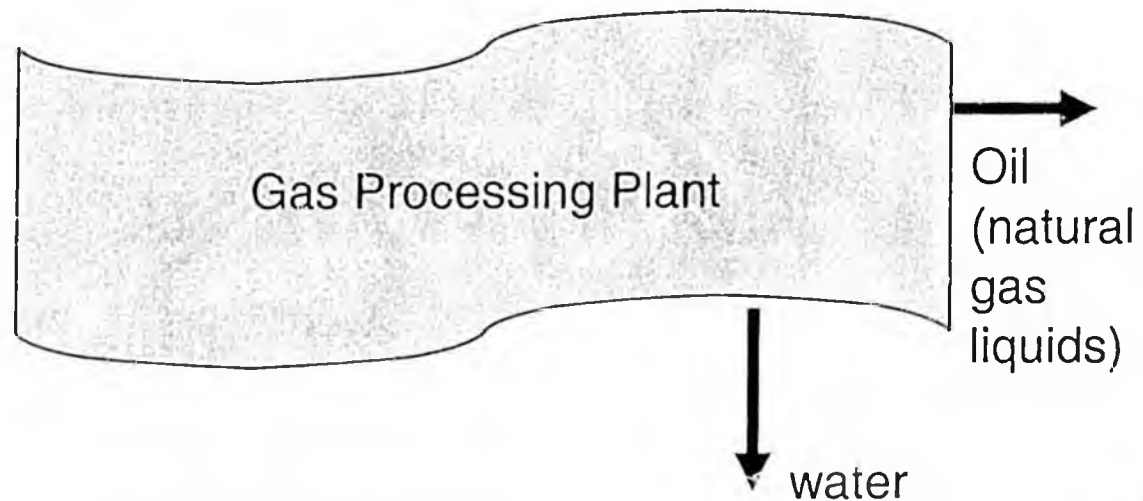
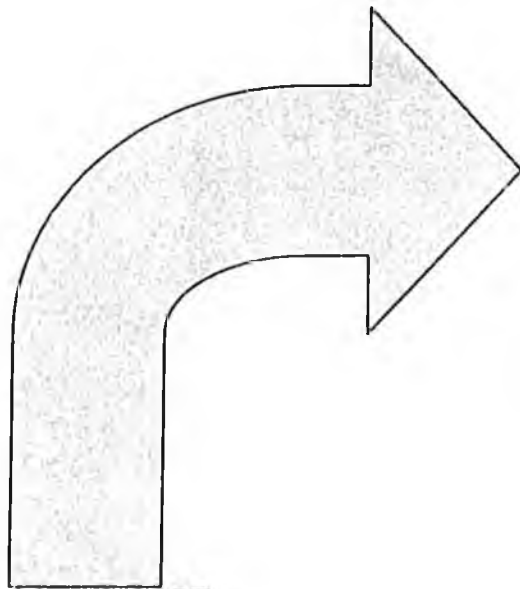
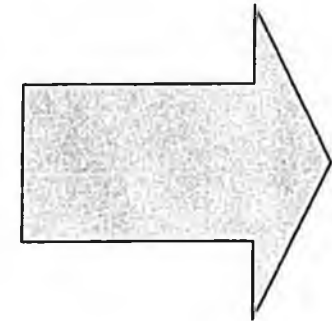
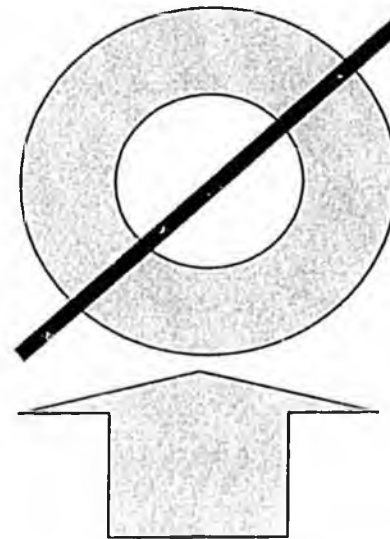
Dan E. Dickinson CPA

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# Gas Point of Production

Gas not run through an integrated gas processing plant and gas treatment plant

Point of Production after gas processing: first point accurately metered downstream of plant



May 2 2007

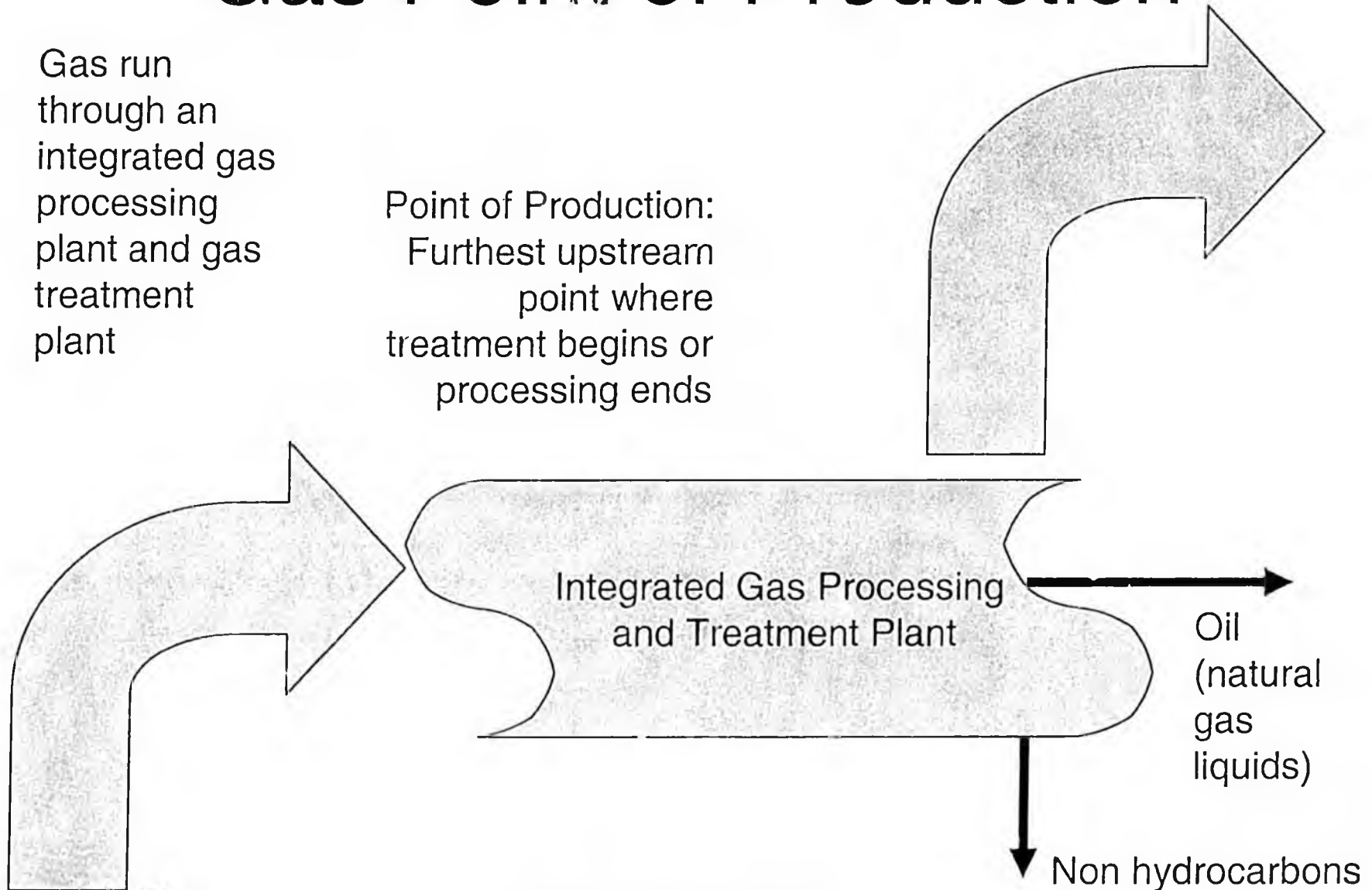
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27

# Gas Point of Production

Gas run through an integrated gas processing plant and gas treatment plant

Point of Production:  
Furthest upstream point where treatment begins or processing ends

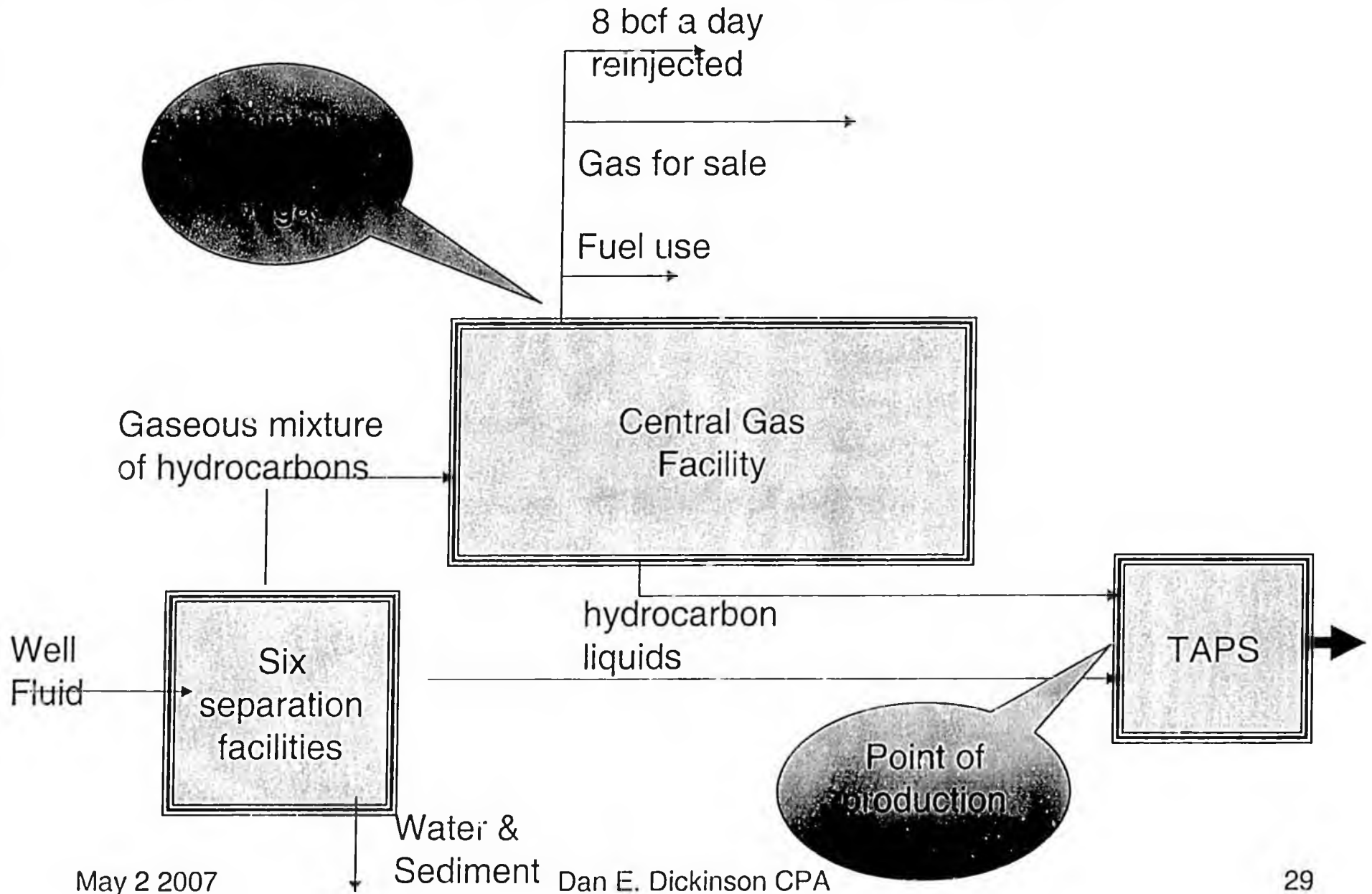


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# Prudhoe Bay: Point of Production under the PPT



May 2 2007

Dan E. Dickinson CPA

# North Slope Central Gas Facility

- On the Alaska North Slope the Central Gas Facility is a gas processing plant, which sends natural gas liquids which are produced at the TAPS inlet:
- AS 43.55.009 (27) “point of production” means (A) for oil ... the device through which the oil enters into the facilities of a carrier pipeline...in a condition of pipeline quality...”
- AS 43.55.009 (10) “oil” means (A) crude petroleum oil: and (b) all liquid hydrocarbons that are recovered...by gas processing in a gas processing plant.

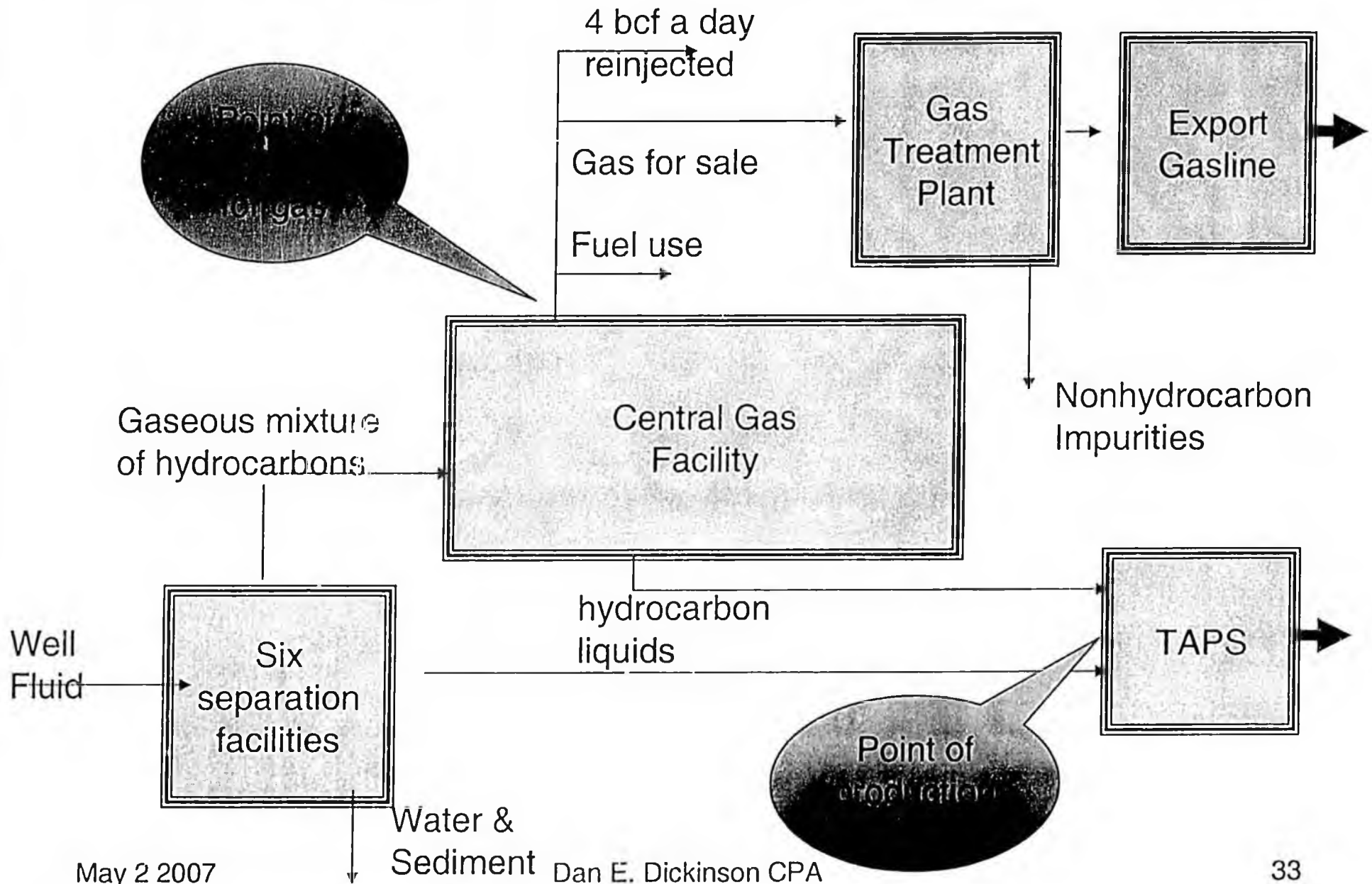
# North Slope Central Gas Facility

- On the Alaska North Slope the Central Gas Facility is a gas processing plant,
- AS 43.55.020 (e) “... gas used in the operation of a lease or property in the state in drilling for or producing oil or gas or for repressuring...is not considered...as ... gas produced from a lease or property.”

## Answer to the Question:

- If CGF remains a separate plant and sends gas to a Gas Treatment Plant (GTP), gas would be produced as it is metered out of plant. The GTP would be downstream of the point of production for the gas and thus associated operating and capital costs would not qualify as lease expenditures under AS 43.55.165 (a) nor would capital costs qualify for credit treatment under AS 43.55023 (a).

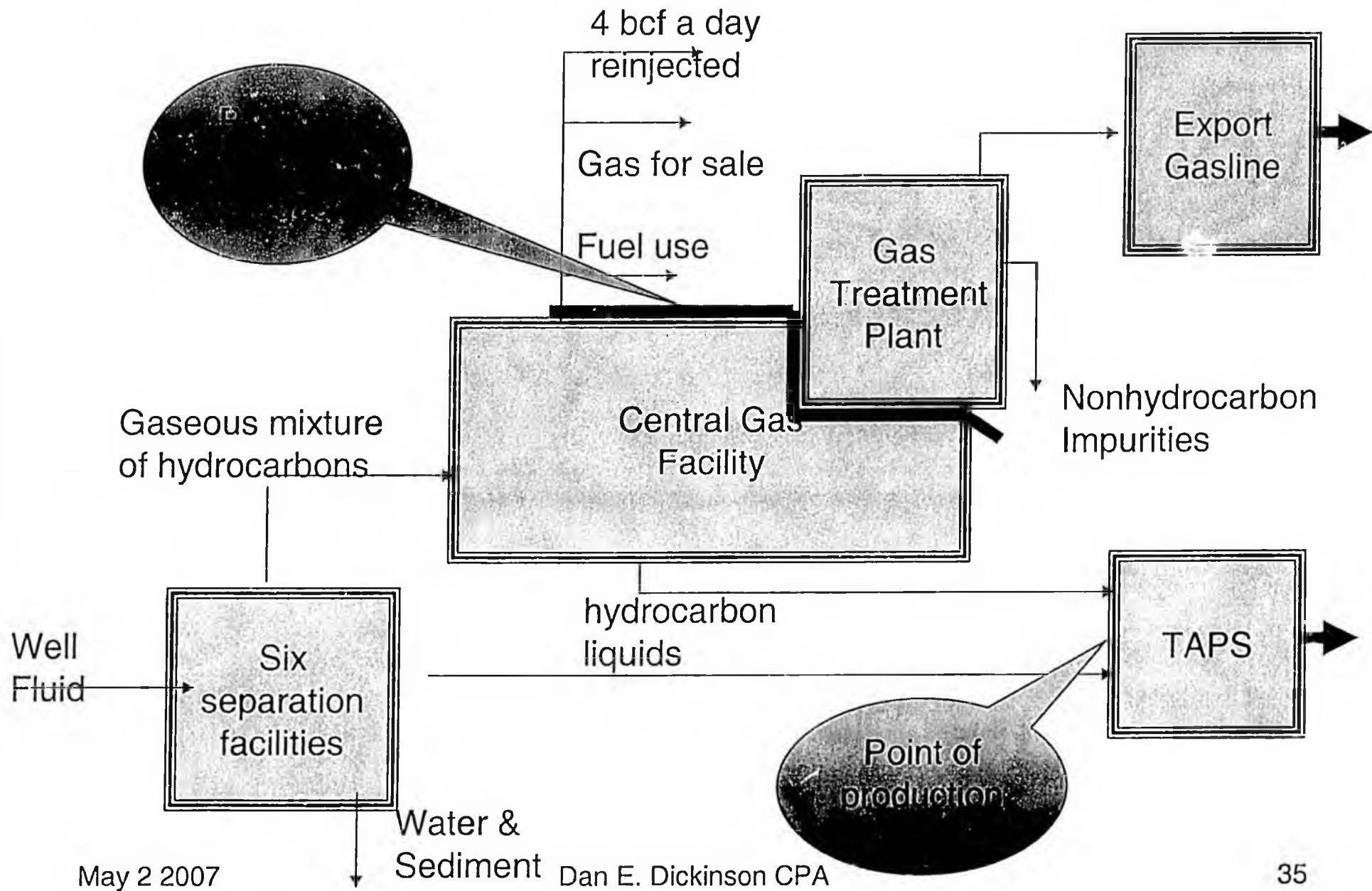
# Prudhoe Bay: Point of Production under the PPT with a GTP




# Answer to the Question:

- If CGF becomes integrated into a Gas Treatment Plant (GTP) (produced gas is not metered), then the gas would be produced within that integrated facility, at the furthest point upstream of the beginning of gas treatment or the end of gas processing. If the plants are integrated, the risk is that some gas processing will move downstream of the point of production, not that gas treatment will move upstream of the point of production.

# Prudhoe Bay: Point of Production under the PPT w/integrated GTP



- 
- We are trying to determine how attractive an investment this pipeline is. Antony Scott, Commercial Analyst, DNR, Oil and Gas, in his April 11, 2007 presentation shows that using the IRR metric this project can have very high rates of return, particularly with a third party line. However we believe he does not include the cost of shippers' firm transportation commitments in his numbers when comparing an independent pipeline with a producer owned pipeline. How might this affect his results?

# Firm Transportation

- Shipper makes a Firm Transportation commitment (FT) to pay the capital portion of the tariff whether it uses the pipeline or not.
- It is that financial commitment that underwrites the pipeline:
  - Required by FERC before approving a project
  - Required by lenders before lending money to a project.

# Producers' returns as both shippers + pipeline owners



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

# Producer Upstream Returns

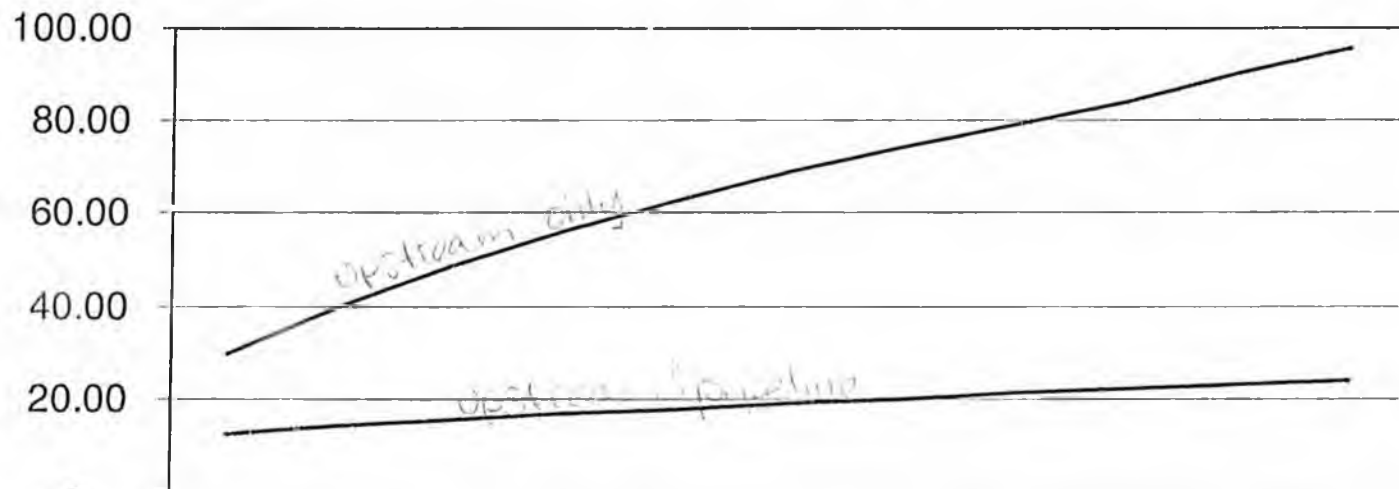
Base case cost = \$20.5B

# AGIA

The Alaska Gasline Inducement Act

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

### Calculated IRR at various price levels



	3.5	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8.5
— Upstream & Pipeline	12.6	14.0	15.4	16.7	17.9	19.0	20.1	21.1	22.1	23.0	23.9
— Upstream Only	29.8	39.7	48.7	56.3	62.9	68.9	74.2	79.2	83.9	90.4	95.6

# Internal Rate of return

Step One: Model An Owned Project				
	CapCosts	Op Costs	Revenues	Cash Flows
Units:		1000	1000	
Dollars		0.1	5	
Product		100	5000	
Year				
0	(20,000)			(20,000)
1		(100)	5,000	4,900
2		(100)	5,000	4,900
3		(100)	5,000	4,900
4		(100)	5,000	4,900
5		(100)	5,000	4,900
6		(100)	5,000	4,900
7		(100)	5,000	4,900
8		(100)	5,000	4,900
9		(100)	5,000	4,900
10		(100)	5,000	4,900
			IRR:	21%

# Internal Rate of Return

Step Two: Model Capital Component of Tariff				
Using PAYMENT function				
Units:				
Dollars	Balance	Interest	Payment	Balance
Product		10%		
Year				
0				20,000.00
1	20,000.00	2,000.00	(3,254.91)	18,745.09
2	18,745.09	1,874.51	(3,254.91)	17,364.69
3	17,364.69	1,736.47	(3,254.91)	15,846.25
4	15,846.25	1,584.63	(3,254.91)	14,175.97
5	14,175.97	1,417.60	(3,254.91)	12,338.66
6	12,338.66	1,233.87	(3,254.91)	10,317.62
7	10,317.62	1,031.76	(3,254.91)	8,094.47
8	8,094.47	809.45	(3,254.91)	5,649.01
9	5,649.01	564.90	(3,254.91)	2,959.01
10	2,959.01	295.90	(3,254.91)	0.00

# Internal Rate of Return

Step Three: Model Third Party Line with no FT but with tariff			
	Tariff	Revenues	Cash Flows
Units:			
Dollars			
Product			
Year			
0			
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
		IRR:	#NUM!

# Internal Rate of Return

Step Four: Model Third Party Line with some additional capital			
	Tariff	Revenues	Cash Flows
Year			
0			(100.0)
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
			1645%

# Internal Rate of Return

Step Five: Model Third Party Line with some more additional capital			
	Tariff	Revenues	Cash Flows
Year			
0			(2,000.0)
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
			82%

# Internal Rate of Return

Step Six: Model Third Party Line with yet more additional capital			
	Tariff	Revenues	Cash Flows
Year			
0			(6,750.0)
1	(3,354.9)	5,000.0	1,645.1
2	(3,354.9)	5,000.0	1,645.1
3	(3,354.9)	5,000.0	1,645.1
4	(3,354.9)	5,000.0	1,645.1
5	(3,354.9)	5,000.0	1,645.1
6	(3,354.9)	5,000.0	1,645.1
7	(3,354.9)	5,000.0	1,645.1
8	(3,354.9)	5,000.0	1,645.1
9	(3,354.9)	5,000.0	1,645.1
10	(3,354.9)	5,000.0	1,645.1
	IRR:		21%

# FASB 47 Disclosure of Long Term Obligations (1981)

- This statement requires that an enterprise disclose its commitments under unconditional obligations that are associated with suppliers' financing arrangements. Such obligations often are in the form of take-or-pay contracts and throughput contracts.

# FASB 47 Disclosure of Long Term Obligations (1981)

- Example 2
- 27. C Company has entered into a throughput agreement with a natural gas pipeline providing that C will provide specified quantities of natural gas (representing a portion of capacity) for transportation through the pipeline each period while the debt used to finance the pipeline remains outstanding. The tariff approved by the Federal Energy Regulatory Commission contains two provisions, a demand charge and a commodity charge. The demand charge is computed to cover debt service, depreciation, and certain expected expenses.

# FASB 47 Disclosure of Long Term Obligations (1981)

- 27. (cont.) The commodity charge is intended to cover other expenses and provide a return on the pipeline company's investment. C Company must pay the demand charge based on the contract quantity regardless of actual quantities shipped, while the commodity charge is applied to actual quantities shipped. Accordingly, the demand charge multiplied by the contracted quantity represents a fixed and determinable amount.

# FASB 47 Disclosure of Long Term Obligations (1981)

- 28. C' disclosure might be as follows:
  - C company has signed an agreement providing for the availability of needed transportation capacity through 1990. Under that agreement, the company must make specified minimum payments monthly. The aggregate amounts of such required payments at December 31, 19X1 is as follows (in thousands):

# FASB 47 Disclosure of Long Term Obligations (1981)

# FASB 47 Disclosure of Long Term Obligations (1981)

- 28 (cont).
- In addition the company is required to pay additional amount depending on actual quantities shipped under the agreement. The companies total payments under the agreement were (in thousands) \$6,000 in 19W9 and \$5,000 both in 19X0 and in 19X1.

### Contractual Commitments

The following table summarizes the Group's principal contractual obligations at December 31, 2003. Further information on borrowings and capital leases is given in Item 18 — Financial Statements — Note 29 on page F-47 and further information on operating leases is given in Item 18 — Financial Statements — Note 17 on page F-29.

Expected payments by period under contractual obligations and commercial commitments	Payments due by period						2009 and thereafter
	Total	2004	2005	2006	2007	2008	
				(\$ million)			
Borrowings (a)	20,143	9,366	2,674	2,786	1,299	945	3,073
Finance lease obligations	4,634	127	243	248	240	248	3,528
Operating leases	8,115	1,275	1,066	895	799	728	3,352
Decommissioning liabilities	7,504	86	156	173	154	156	6,779
Environmental liabilities	2,430	465	441	402	276	186	660
Pensions (b)	26,682	633	649	652	659	666	23,423
Other post-employment benefits (c)	11,768	242	252	259	263	264	10,488
Unconditional purchase obligations (d)	67,828	45,491	7,076	3,133	1,388	1,655	3,585

(a) Expected payments exclude interest payments on borrowings.

(b) Represents the expected future contributions to funded pension plans and payments by unfunded pension plans.

(c) Represents the expected future payments for postretirement benefits.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2004 include purchase commitments existing at December 31, 2003 entered into principally to meet the Group's short term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Item 11 — Quantitative and Qualitative Disclosures about Market Risk on page 170.

The following table summarizes the nature of the Group's unconditional purchase obligations.

Unconditional purchase obligations payments due by period	Payments due by period						2009 and thereafter
	Total	2004	2005	2006	2007	2008	
				(\$ million)			
Crude oil and oil products	22,043	19,350	844	452	422	374	601
Natural gas	19,439	13,189	2,575	1,141	489	398	1,647
Chemicals and other refinery feedstocks	10,049	2,277	1,666	753	563	545	4,245
Utilities	11,612	9,622	1,231	289	62	54	354
Transportation	2,814	738	510	365	247	204	750
Use of facilities and services	1,871	315	250	133	105	80	988
Total	67,828	45,491	7,076	3,133	1,888	1,655	8,585

# BPs 2003 20(f)

- Unconditional purchase obligations (d)
- (d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas feedstocks and pipeline systems.
- Obligations set out for five years, after five years and in total

# Why does this matter?

- Moody' Investors Service
- Authors (or "Contacts"):
- Barbara Havlicek, Kevin Stoklosa, Greg Jonas, Laura Levenstein, Pamela Stumpp, Michel Madelain, Trevor Pijper, Wolfgang Draak, Waylon Iserhoff, Brian Cahill, Thomas Keller, Takohiro Morita
- The Analysis of Off-Balance Sheet Exposures, A Global Perspective
- July 2004

# Moody's Rating Methodology

- Take-Or-Pay Contracts
- Take or pay contracts are another form of purchase commitment typically found in the ... energy industry. ... Such contracts can be problematic if market conditions and raw material prices change or if the price of the end product drops. Regardless of whether or not the contract becomes problematic, Moody's factors payments under take-or-pay contracts into the analysis of future cash flows and may also adjust the balance sheet if necessary. (Havlicek page 7)

# Why does this matter?

- Standard & Poor's
- Authors (and "Analytical Contacts"):
- Solomon B. Samson, Scott Sprinzen, Emmanuel Dubois-Pelerin, Kenneth C. Pfeil
- Corporate Ratings Criteria
- 2006

# Standard and Poor's Rating Methodology

- Off balance-sheet financing
  - Analysis of liabilities is not limited to those shown on the company's balance sheet. Off balance-sheet items factored into the leverage analysis include the following:
    - Operating leases
    - Guarantees, debt of joint ventures and unconsolidated subsidiaries
    - Take-or-pay contracts and obligations under throughput and deficiency agreements...
  - (Samson pgs. 28-29)

# Standard and Poor's Rating Methodology

- Various methodologies are used to determine the proper adjustment value for each off-balance-sheet item. In some cases, the adjustment is straightforward. For example, the amount of guaranteed debt can simply be added to the guarantor's liabilities. Other adjustments are more complex or less precise. (Samson pg. 29)

# Closing Thought:

- E.C. Capen and D.F. Casey The Economics of Creative Financing

Society of Petroleum Engineers 11664  
(1983)

# Closing Thought:

- Now and then, someone comes in and announces that he has discovered the business man's equivalent to the Fountain of Youth – a corporate money tree. The person will instruct us that his pet project (PP) need not compete for cash in the budgeting process because he has found a benefactor, Mr. S. Claus, willing to put up the money at no cost save some “small monthly payments” to be worked out later. These payments should come from PP's profits and represent no real drain on the company.

# Close of Closing Thought

- To be sure we seldom see requests as blatant as portrayed above, but we nevertheless sense some misunderstandings about how to evaluate projects that have alternatives to outright purchase of goods and equipment. Has the old maxim prohibiting free lunches somehow been set aside with regard to so called creative financing? No, more likely the lunch costs more than normal, but we're not always sure who pays. (Capen & Casey pg. 241)

MOGEL /

EWING

5/9/07



# FERC's Regulation of Interstate Natural Gas Pipelines


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**William A Mogel**

**Saul Ewing LLP**

Senate Finance Committee

May 8, 2007



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THE FERCS REGULATORY REGIME,  
WHICH IS DESIGNED TO PROTECT  
CONSUMERS, PROHIBITS AN  
INTERSTATE NATURAL GAS PIPELINE  
FROM ACTING IN AN ANTI-  
COMPETITIVE, DISCRIMINATORY OR  
PREFERENTIAL MANNER TO ANY  
SHIPPER.



# QUALIFICATIONS

---

- 30 years as a FERC practitioner.
- Author/Editor of 17 books on energy law.
- Writings cited as authority by the US Supreme Court.
- Adjunct lecturer at law school on energy law.
- Regulatory practice includes energy projects in foreign countries.



# CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

---

- Unlike oil pipelines, before a natural gas pipeline can commence construction and operation it must first obtain a certificate after making a showing of public benefit.
- FERC can condition the certificate on numerous matters, including when construction must be completed.
- A pipeline cannot expand, terminate or “abandon” service without prior approval of FERC.



# RATES AND TERMS AND CONDITIONS OF SERVICE

---

- FERC must approve all rates, rate changes and terms and conditions in a natural gas pipeline's tariff.
- FERC has authority to investigate existing rates of a natural gas pipeline.
- Rates that are not "just and reasonable" may be rejected and refunds can be ordered.



## INTERSTATE NATURAL GAS PIPELINES ARE REQUIRED TO BE “OPEN ACCESS”

---

- Capacity must be allocated on a non-discriminatory basis to affiliated and non-affiliated shippers.
- Rates charged and terms and conditions for capacity must be just and reasonable and may not discriminate or grant a preference to shippers similarly situated.
- Capacity release programs must be non-discriminatory and transparent.



INTERSTATE PIPELINES ARE REQUIRED  
TO ADHERE TO COMPREHENSIVE  
STANDARDS OF CONDUCT

---

- No preference in sharing of information, setting rates, and terms and conditions between the pipeline and its affiliated marketing company.



## FERC HAS BEEN GRANTED ADDITIONAL PUNITIVE AUTHORITY BY THE EAct of 2005

---

- To punish violations of its statutes and regulations by:
  - Fines of up to \$1 million per violation per day.
  - Disgorgement of unjust profits.
  - Referrals to the Justice Department for criminal prosecution.



---

The FERC's regulatory regime for interstate natural gas pipelines is significantly different from oil pipelines and changes since 1985 insure that pipeline's will not act unlawfully or discriminate against shippers.

INDUSTRY

PRESENTATIONS

SULLIVAN +  
CROMWELL

**SULLIVAN & CROMWELL LLP**

# **Project Finance Workshop**

**An Introduction to Project Finance  
for Oil, Gas and Pipelines**

*April 25, 2007*

*Presented 4/26/07 am*

# Introduction

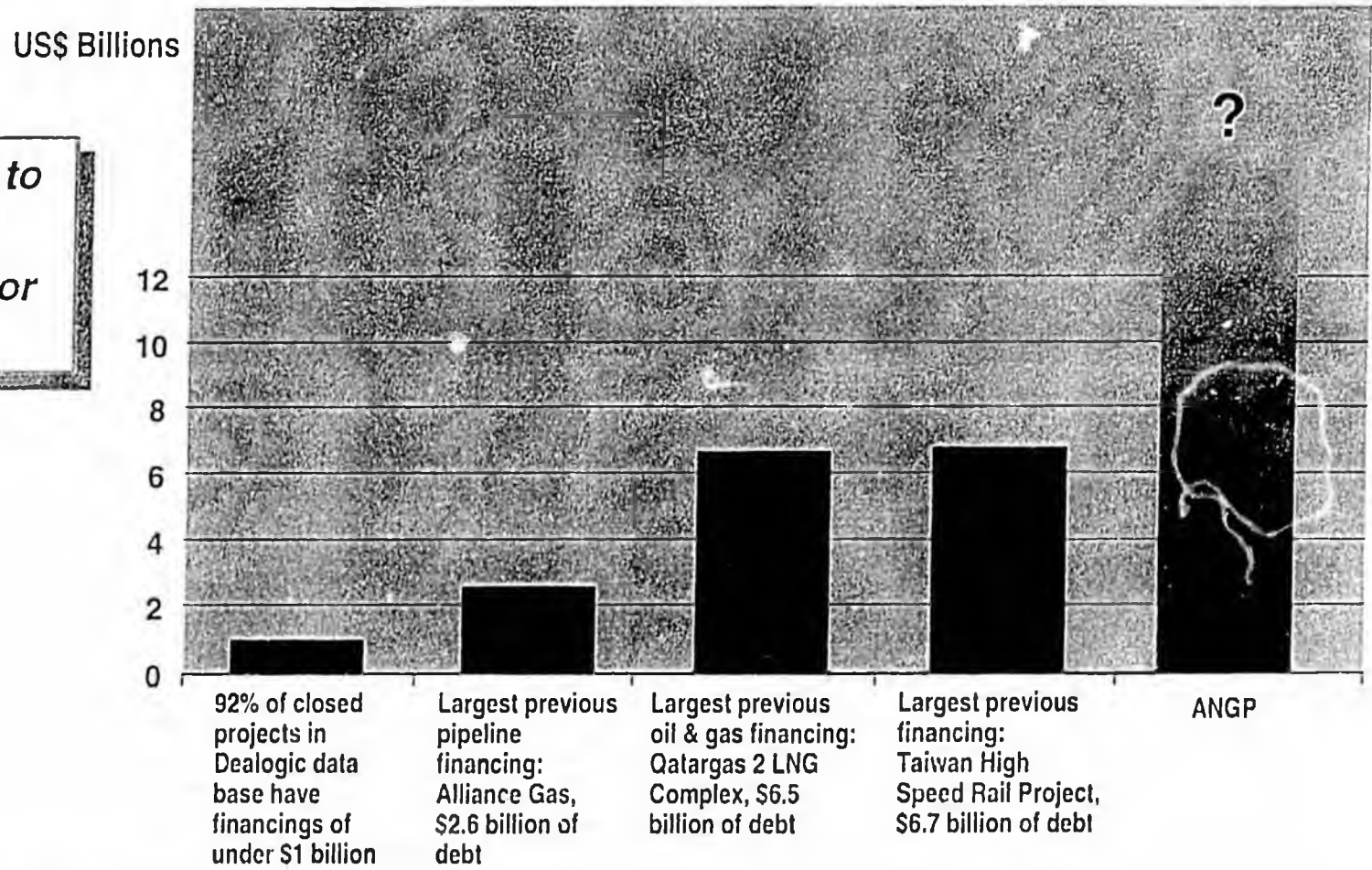
## Outline

- What is Project Finance?
- Risk Allocation and Mitigation
- The Current Project Finance Market
- Building Blocks of a Typical Project Financing
- Project Finance for Oil, Gas and Pipelines

# Introduction

- Introductory level
- The problem of precedent

*Premature to talk about specific financing for ANGP*



# Introduction

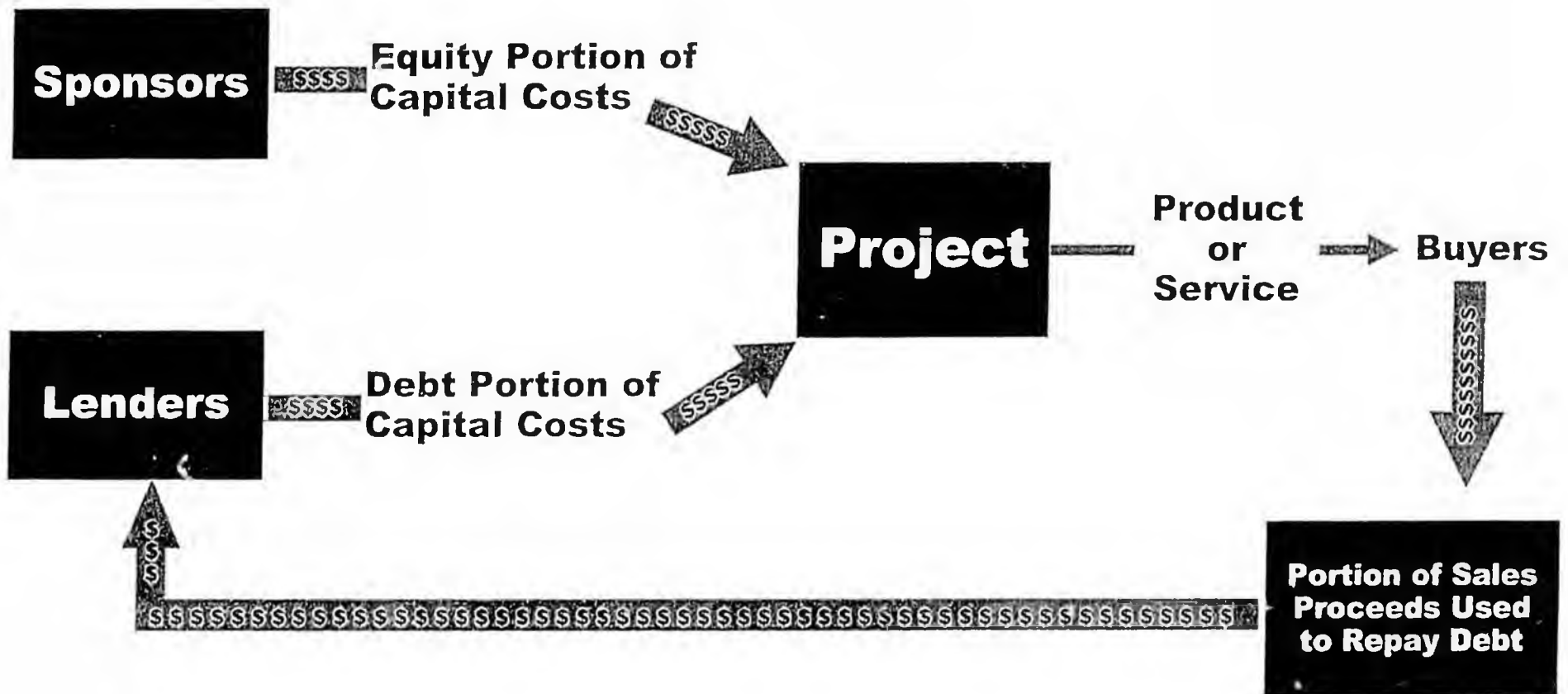
## Key Points

- Premature to discuss any specific ANGP financing because project design and scope, identity of sponsors, nature of commercial contracts, sponsor financing objectives, rules for use of Federal guarantees, market conditions at time of financing and other factors are all unknown
- Can talk about main drivers of oil, gas and pipeline financing generally, to assist understanding of how development of ANGP might influence financing

*Section 1*

**What is Project Finance?**

# 1. What is Project Finance?



# 1. What is Project Finance?

- At one point virtually synonymous with power plant financing
- Today, project finance is not a single financial product, but different products for different markets:
  - e.g., airplanes, toll-roads, upstream oil, power plants – all very different products, markets and practices

*Beware of generalizations*

# 1. What is Project Finance?

- What do these different “project finance” products and markets have in common?

**NOT** corporate finance

- In corporate finance:
  - The borrower is usually a diversified enterprise whose future net cash flows can be difficult to predict
  - The lender has full recourse to all present and future assets and revenues of the borrowing group
  - The structure and covenants of the major corporate finance debt products are highly standardized

## Instead, Project Finance is ...

- A tailored product
- A highly structured product
- A non-diversified credit
- Often “greenfield”
- A cash-flow-based credit
- Usually based on contractual commitments
- Limited recourse
- A tool whose purpose is sometimes risk-sharing and risk-mitigation, as well as fund-raising

# Project Finance is ...

- ***A tailored product***
  - Debt structure and terms crafted to reflect the risk and economic profile of the specific project
  - In contrast, most other financial products (e.g., high yield debt, investment grade bonds, private placement debt) have highly standardized features and covenants

*Even in the most active parts of market, e.g. U.S. private power, all attempts to standardize terms and conditions have failed.*

# Project Finance is ...

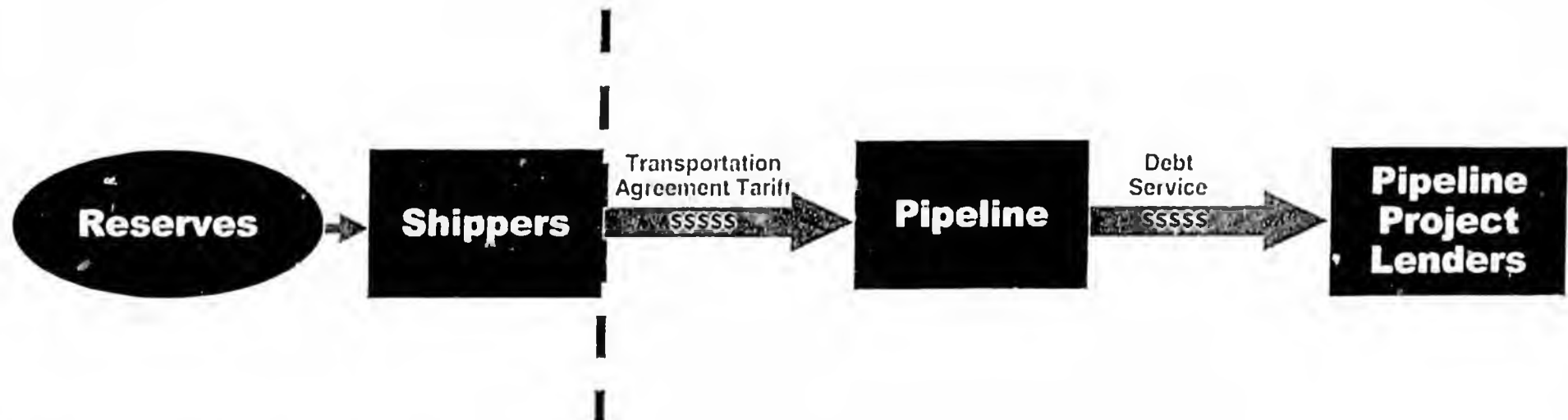


- ***A highly structured product***
    - Project loans typically involve structural elements such as
      - completion support
      - account structures
      - off-take commitments
      - security interests
      - project covenants and
      - structured remedies
- that differ from those commonly found in corporate credits.
- These structural elements are crafted to satisfy sponsor objectives and credit concerns and to match the risk profile of the specific project

# Project Finance is ...

- *A non-diversified credit*

- One business, one product, one committed source of cash flows
- But, also indirectly a function of the value chain that lies “behind” the project:
  - contractual commitments by customers
  - and all the real-world factors that determine if those commitments will be met



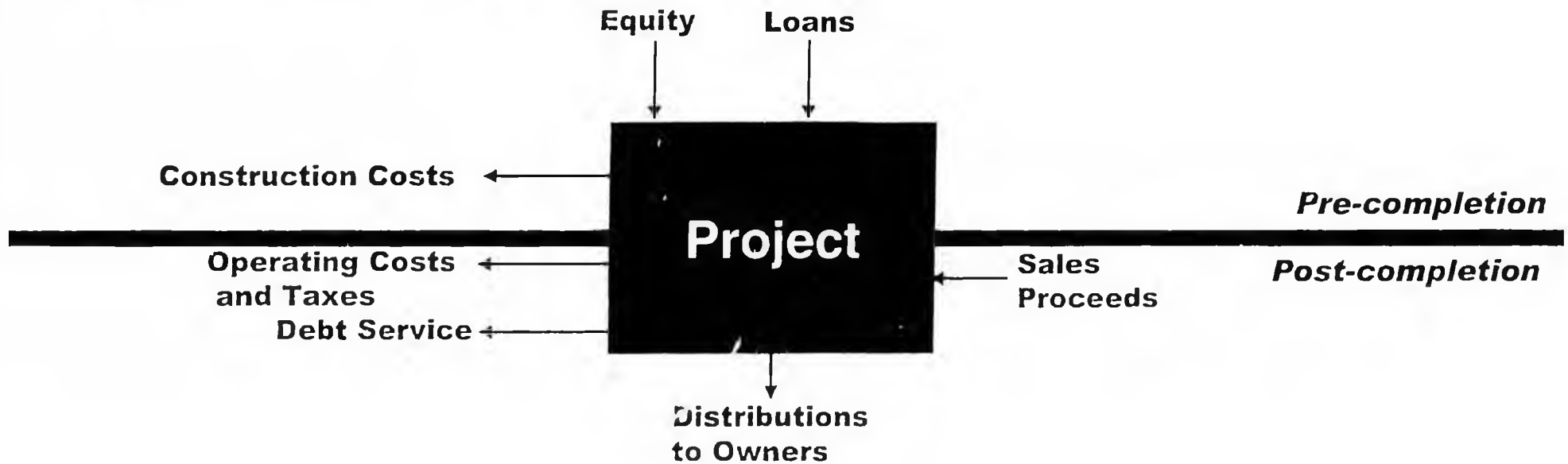
# Project Finance is ...

- *Often “greenfield”*
  - When loan is disbursed, business does not exist
  - In “greenfield” project — threshold risk is whether the project can get
    - built on time,
    - within budget, and
    - will work as promised, minimizing likelihood of force majeure events
  - Lenders generally unwilling to take entire unmitigated completion risk — sponsors always bear primary, or “first layer” of risk through equity and/or completion support
  - Many projects fail because adequate completion support is not available

# Project Finance is ...



- *A cash-flow-based credit*



- Primary credit metrics are cash-based:  
ratio of "cashflow available for debt service" to debt service

# Project Finance is ...



- *Usually based on contractual commitments*
  - Contractual commitments are generally in an amount sufficient to cover debt service and an agreed “cushion,” and for a term no shorter than term of debt
    - Examples
      - Power plant: power purchase agreement
      - Pipeline: transportation agreements
    - Exceptions
      - Projects that produce “terminal market” commodities (copper, market crude oil)
      - There is a limited appetite for “merchant risk” (market risk) in deep and well understood markets (principally electric power)
  - *Contractual commitments are only as good as the parties behind them.*

# Project Finance is ...



## ■ *Limited recourse*

- “**General Recourse**” – means all of the present and future assets and revenues of the borrowing group are available to satisfy the debt.
- “**Limited Recourse**” – means that only specified assets or revenue streams are available to satisfy the debt – neither borrower nor its affiliates “owes” the debt if it cannot be satisfied from the agreed assets or revenue stream.

# Project Finance is ...



- *A tool whose purpose is sometimes risk-mitigation and risk-allocation, as well as fund-raising*
- As such, it sometimes enables the project by
  - providing some partners with necessary funds,
  - lowering financing costs,
  - mitigating or sharing risks,
  - strengthening the project through involvement of financing “partners”

Section 1: What is Project Finance?

## Summary of Main Points

- Hard to generalize – different for different types of projects
- Tailored and structured for the particular project
- Following completion, loans for repayment look only to project cash flows, typically based on contractual commitments
- Often serves important purposes in addition to simply raising funds

*Section 2*

**Risk Allocation and Mitigation**

## Key point

- Sponsors always bear all risks on equity investment
- Sponsors bear primary risk of loss – 100% loss of equity investment before first dollar of loss on debt

*The sponsors' economic stake is the foundation of the credit — not just a cushion against loss, but the basis for the lenders' expectation that the sponsors will be well-motivated to make the project a success*

## Key point (cont'd)

- Traditional maxim: “Project finance is a bet on the sponsors.”
  - Lenders expect “voluntary” fix of post-completion problems because of financial (equity) stake, strategic factors and/or reputational risk.
  - This leads to lender focus on
    - Size of equity stake and leverage
    - Operating experience
    - Financial strength
    - Strategic story

## 2. Risk Allocation and Mitigation

- Within the debt portion of the investment, project finance sometimes allocates risk of loss to those best able to bear it
- Examples:
  - **Price/market risk** — often borne by buyers under committed off-take contracts, then borne by lenders
  - **Political** — sometimes borne by political risk insurers
  - **Tax/regulatory** — often mitigated by host government through stability assurances
  - **Construction/completion** — primarily borne by project sponsors
  - **Operational** — primarily borne by project company

*Consistent with general market practice, the legislation authorizing federal guarantees for the Alaska Natural Gas Pipeline specifically contemplates some form of completion support from project sponsors*

## 2. Risk Allocation and Mitigation

### ■ Examples: Mitigation and Allocation of Completion Risk

Quality of feasibility/budget work



Contracting strategy (if available)



Quality of project execution



Budgeted contingency



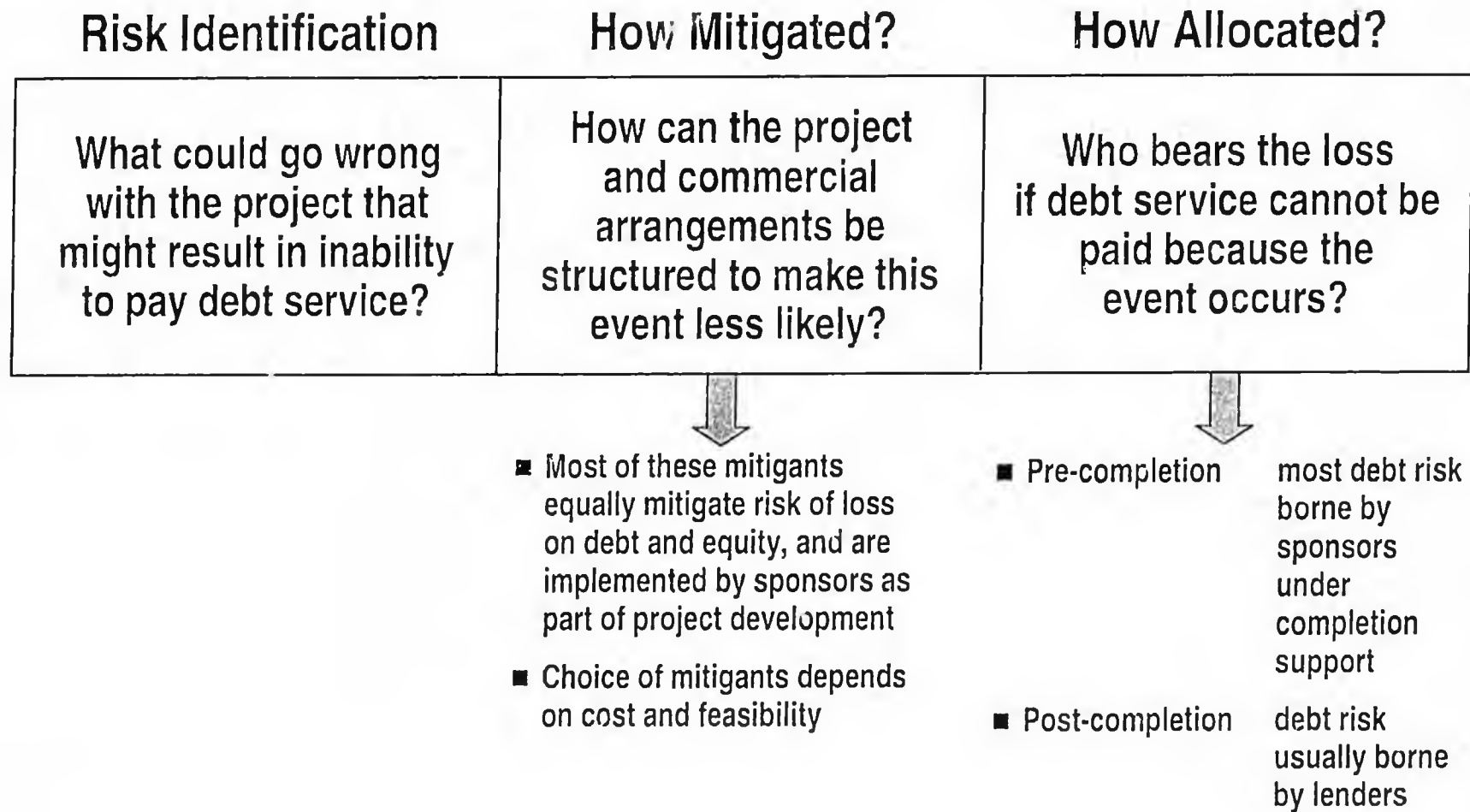
Any third-party pre-committed over-run financing

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Sponsor completion support

MITIGATION  
ALLOCATION

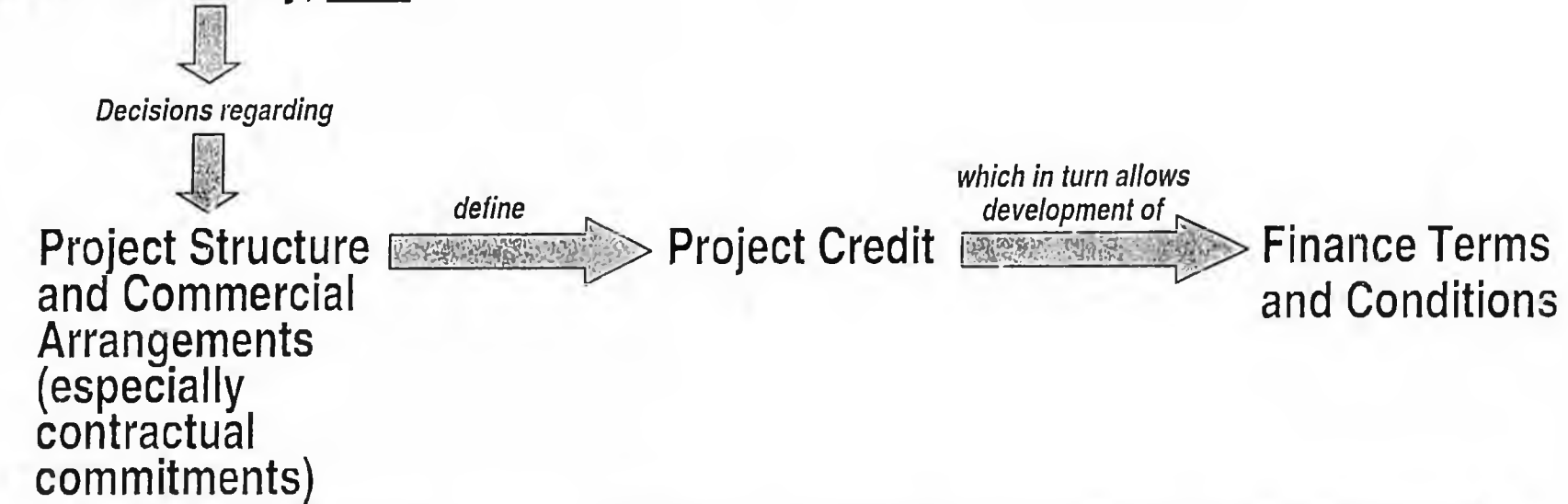
# The Project Finance Risk Matrix



# Risk Allocation Takes Place in a Three Step Process

## In A Properly Structured Project:

Reserves and Market  
Are Necessary, BUT



*The Federal guarantee legislation recognizes primacy of commercial decisions by providing that no credit supports shall be required other than those resulting from commercial requirements of project owners.*

## Summary of Main Points

- Project finance involves sharing risk of project failure, but equity sponsors always bear first risk of loss
- Project development and operating experience of sponsors, strength of their balance sheets, strategic importance of the project, size of the sponsor equity investment, and strength of contractual commitments are most important factors considered by lenders
- Some risks are mitigated or allocated to others through project agreements
- Finance terms and conditions must follow, and not precede, project structure and commercial arrangements

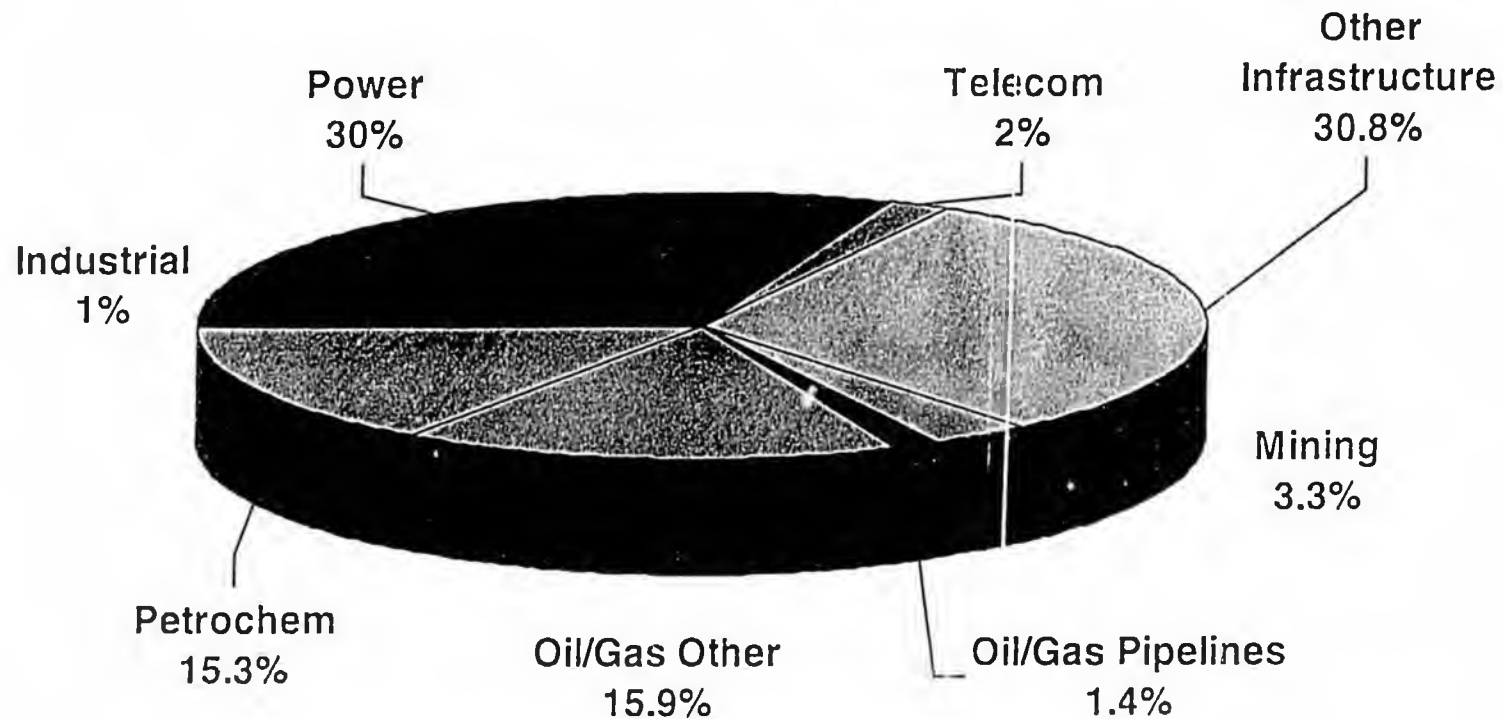
*Section* 3

**The Current Project Finance Market**

# Who uses PF?

## Project Debt by Industry: 2006

*2006 Global Volume of Project Debt:  
US\$ 186.8 billion*

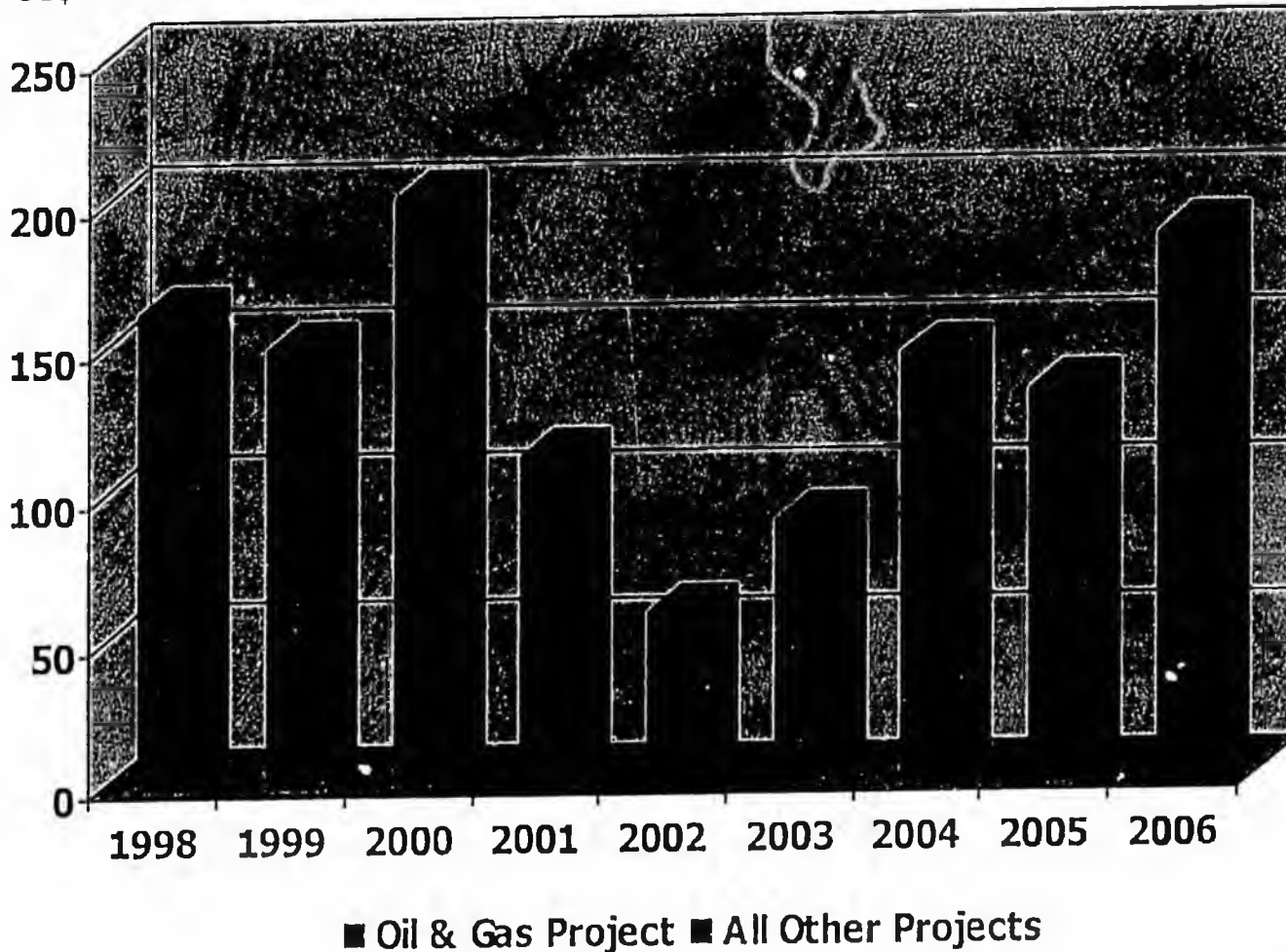


Source: Dealogic

# Total Project Finance Debt Market



US\$ Billions

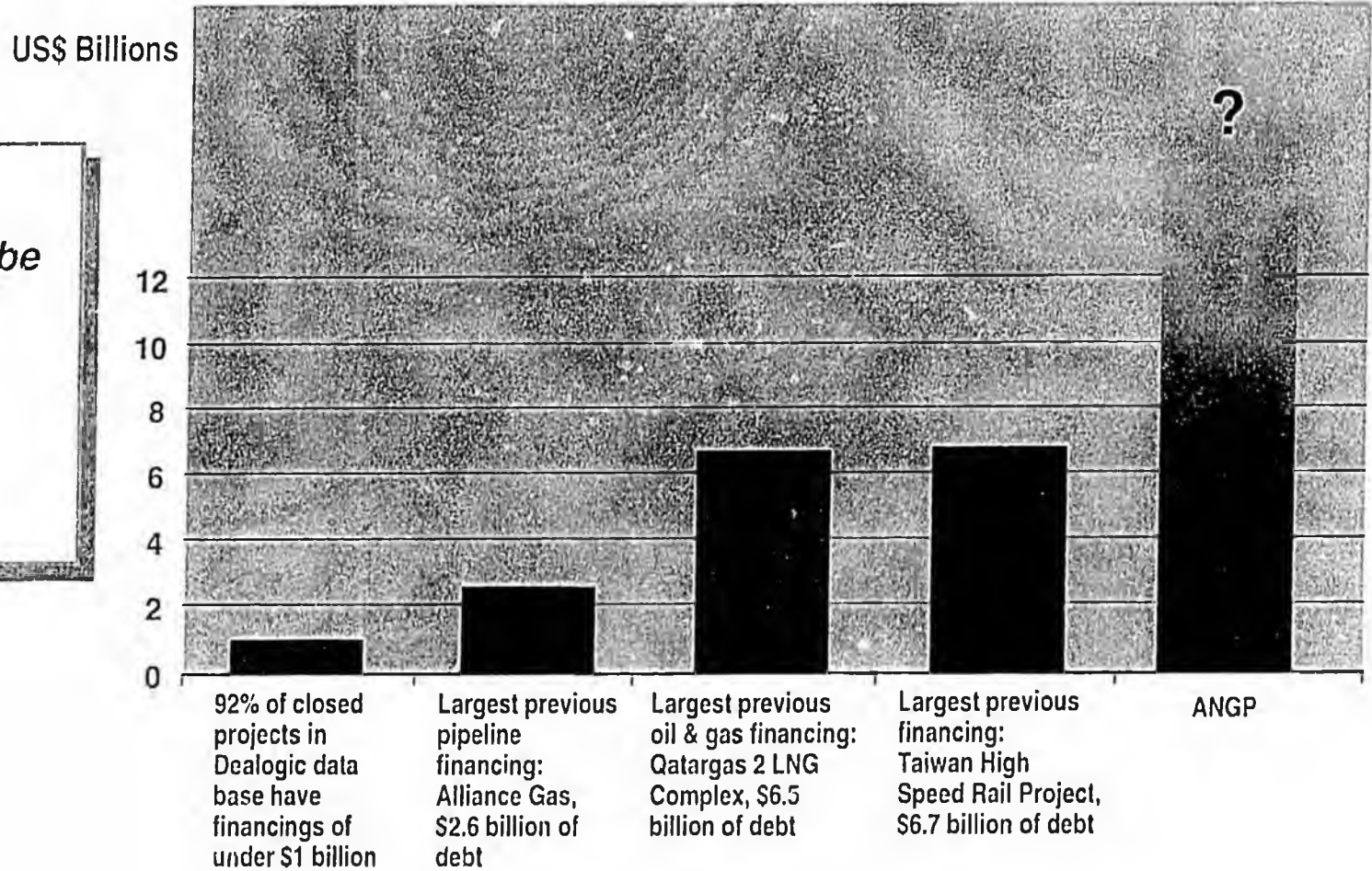


Source: Dealogic

# 3. The Current Project Finance Market



*If project financed, ANGP could be substantially larger than the largest project financing completed to date.*



# 3. The Current Project Finance Market

- **Bond market well-suited source for large borrowing program, currently favorable for oil & gas project bonds**
  - Capital markets deep, large liquid bonds attractive
  - Better pricing transparency
  - Longer tenor (term) than banks
  - Particularly well suited for pipelines given the regularity and predictability of cash flows, and the long life and large size of required investment
- **Voracious appetite by banks**
  - High degree of liquidity
  - Bullish view of risks

**But market conditions can change rapidly**



**Therefore, multi-track finance plans are common**

## 3. The Current Project Finance Market

- S&P credit study – across all industry sectors and including many emerging market projects:
  - Probability of Default (PD) — BBB+ (investment grade)
  - Loss Given Default (LGD) — Best of all the asset classes in S&P database

*“The majority of the defaulted project finance loans in this study resulted in a restructuring with 100% of loan value maintained”*

*These results include all industry sectors and emerging markets — U.S. energy projects would doubtless have more favorable PD and LGD*

## Summary of Main Points

- Project finance market has evolved, heavily influenced by capital markets and rating agencies
- Result is emphasis on underlying commercial drivers of credit
- Oil and gas pipelines a small part of the market
- Market very liquid now, but volatile, so sponsors must plan for both banks and bonds

*Section* **4**

**Building Blocks of a  
Typical Project Financing**

# 4. Building Blocks of a Typical Project Financing



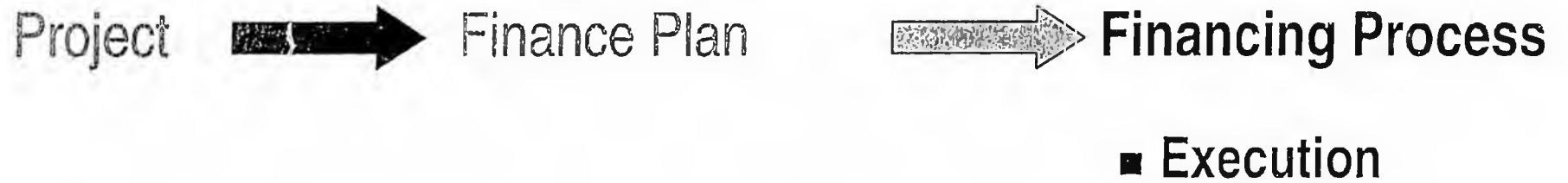
- Project Structure
- Project Agreements
- Commercial Contracts

# 4. Building Blocks of a Typical Project Financing



- Borrowing Structure
- Security and Accounts
- Completion Support

# 4. Building Blocks of a Typical Project Financing



# Project Structure



Project 

- Entity choice
  - Tax efficiency and regulatory considerations are key
  - “Pass-through” structures are common
    - Limited partnerships
    - Limited liability companies (LLCs)
    - Unincorporated joint ventures

# Project Agreements and Commercial Contracts

Project 

- **Agreements with Governments**
  - For resource projects, lease, concession, etc.
  - Investment incentive, fiscal stability and other agreements
  - Key licenses and permits
- **Agreements among Participants**
  - JV agreements
  - Management or operating arrangements
- **Commercial Agreements**
  - Key construction contracts
  - Key supply agreements
  - Offtake agreements (transportation commitments for pipeline)
  - Insurance

# Borrowing Structure

Project  Finance Plan

- **Leverage – How much debt?**
  - Concept of project “debt capacity” – driven by debt model and Debt Service Cover Ratios, viewed
    - periodically,
    - over the life of loan
  - Variations in leverage

# Security and Accounts

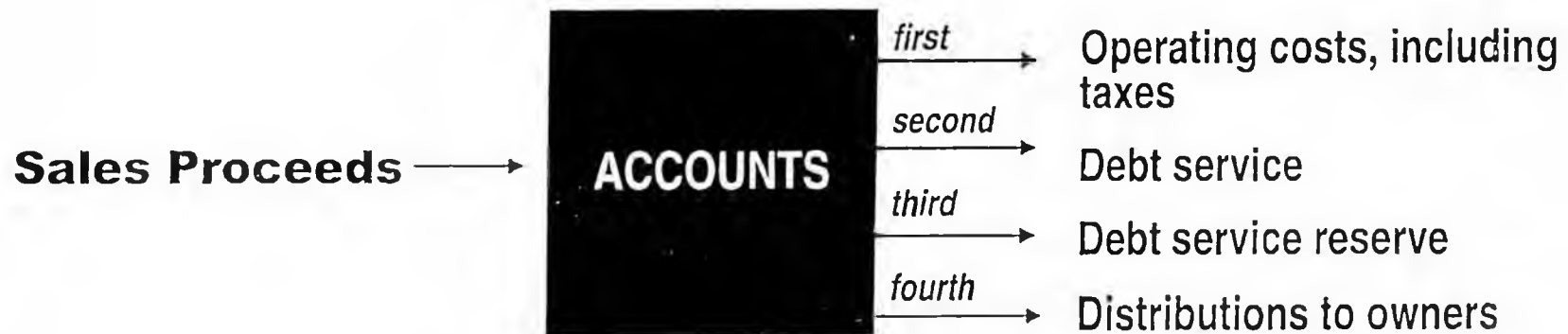
Project  Finance Plan

- Traditional security package: assets, project agreements (including offtake contracts), ownership interest, accounts, insurance
- Modern trend towards omission of asset security on a cost/benefit analysis, especially for strategic projects with strong sponsors
- Key for lenders is to capture cash flows in secured accounts

# Security and Accounts: The Waterfall

Project → Finance Plan

- Priority for continuing operations as only way to continue to service and repay debt



- Accounts create transparency, protection from other creditors (and, in emerging markets, some protection from exchange controls)

# Covenants



Project  Finance Plan

- Operational and legal covenants
  - Additional debt: norm is lender consent, sometimes objective tests based on *pro forma* debt-cover and leverage tests
  - Expansions, discretionary capital expenditure and certain other changes: norm is lender consent, sometimes more objective tests (more latitude if funded with equity)

# Completion Support



**Project**  **Finance Plan**

- **Need to define completion:  
physical and financial**
- **Sponsor support usually in form of  
additional equity commitments or debt  
guarantees**
  - **Equity commitments are common in  
pipelines and are limited in amount**
  - **Debt guarantees are in place through  
completion, requiring sponsors to repay  
the debt if the project is not completed**
- **All support falls away after completion  
tests are met**

# Lender Environmental Considerations

Project  Finance Plan

- In emerging markets, finance requirements can be greater than local law requirements
- In U.S. and Canada, not an issue, as local law requirements are robust
  - Lenders will only require compliance with law

# 4. Building Blocks of a Typical Project Financing



*Key objective is to complete financing in timely fashion so that start of construction is not delayed*

- Financing process requires extensive management and strong leadership
- Can be time-consuming and expensive
- Experienced sponsors and advisors are key
- Close collaboration among all parties is critical for success

## Summary of Main Points

- Project structure and commercial arrangements precede development of borrowing structure and finance plan
- Many large and strategic oil, gas and pipeline projects do not have full asset security package – instead focus is on accounts and waterfall
- Once finance execution starts, requires strong leadership and management, and experienced advisors, to complete financing in time and avoid any delay in start of project construction

*Section* **5**

**Project Finance for Oil, Gas and Pipelines**

# Why do lenders like oil, gas & pipeline projects?

- Past experience has been good
- Resource based lending for upstream projects; contractual based lending for pipeline projects
- Technologies are usually well-proven
- Particularly suited to cash-based credit analysis – cash flows clear
- Either commodity products without market risk (oil), or highly credit-worthy off-take/transportation commitments
- One of the main post-completion risks is usually price risk – which, traditionally, banks understand and can price
- Sponsors can be
  - highly creditworthy
  - experienced with large projects, conservative culture
  - judged by lenders unlikely to abandon strategically significant projects

# Upstream vs. midstream (pipelines)

## ■ Upstream

- Oil projects involve commodity products with little to no market risk; transportation may not be an issue
- Gas projects depend on available transportation and market, and strength of off-take commitments

# Upstream vs. midstream

## ■ Midstream

- Pipeline credits vary widely – depending on
  - Degree of project integration with upstream/downstream
    - Upstream and midstream as integrated project
    - Separate but with upstream producers as owners of midstream
    - Separate with upstream producers' role limited to customer
  - Contractual and credit links into upstream
    - Producer transportation commitment vs. buyer as shipper
    - Nature of transportation commitment
  - Tariff structure
    - Unregulated -- negotiated tariff
    - Common carrier
    - FERC/NEB
  - Emerging market vs. developed

# Main Pipeline Financing Approaches

- **Degree of Integration with Upstream/Downstream**
  - Especially for large strategic projects which rely on single transportation system, producers want (i) timely development of transportation, (ii) control over construction and operating costs, and (iii) reliability – usually leads to integration with upstream or producer participation if midstream is separate
  - Even if pipeline is organized as a separate project, development of upstream resources, transportation commitments and downstream markets are foundations of the pipeline credit

# Main Pipeline Financing Approaches

## ■ “Dual Project Risk”

- Dual completion risk if separate upstream project is also green-field
- Crux of issue: midstream lenders exposed to upstream risks without normal covenants with and remedies against upstream project
- Creates tremendous pressure (i) for common ownership or (ii) on terms and conditions of transportation agreements as only “link” into upstream
- Financing complexity, time and costs also can increase

# Transportation Agreements

- **Transportation Agreement defines cash flows for pipeline borrower**
  - producer or buyer as shipper
  - nature of shipping commitment
    - ship-or-pay (most common)
    - ship-and-pay
- **For ANGP, as FERC/NEB regulated project, open season bids would be on the basis of firm transportation commitments**

# Transportation Agreements

- Firm Transportation Commitment (ship or pay)
  - Key midstream financing issues are tenor, volume, tariff, shipper credit and force majeure
    - If Federal guarantees are available and used, these are issues for Federal government as guarantor, and for lenders as to any uncovered portion of debt . . . but force majeure exceptions to “ship or pay” obligations are key
  - Starting point for midstream post-completion credit is blended credit behind shipping commitments
  - Shipper credit analyzed based on (i) financial strength, (ii) upstream development and operating costs and break-even net-back, (iii) end-user markets, and (iv) sufficient volumes to fulfill firm commitment
  - In FERC regulated transaction, tariff adjusts — generally protects lenders because costs passed on to shippers
  - Producers may be reluctant to enter into firm “ship-or-pay” commitments if they do not own the pipeline

# Transportation Agreements

## ■ Force Majeure

- In “ship-or-pay”, force majeure provisions define circumstances where shippers do not have to pay
- Of key importance to lenders, since force majeure events result in interruption in cash flow available to service debt
- Main force majeure provisions cover operational/availability risk in midstream — if midstream cannot accept gas, shippers not obligated to pay
- Result is keen lender interest in (i) quality of original design and construction, (ii) operational expertise and track record of midstream operator, and (iii) technical and financial capacity of midstream project company and its owners to address operational issues
- Project size and complexity, together with long tenor and large size of midstream financing, likely to increase these concerns in ANGP

# Structural issues for cross-border pipelines



- Separate entities in each country most common
- Can be separately tranching loans to each entity, but
  - cross-completion risk
  - sometimes structured to create unified credit
- Two loans can equal more complexity and cost and longer time to develop

# 10 Largest Oil and Gas Pipeline Project Financings

(greenfield and expansion only – excludes acquisition financing and refinancings)<sup>1</sup>

	<b>Project Name, Location</b>	<b>Total Capital Cost (Senior Debt Portion)</b>	<b>Sponsors</b>	<b>Financial Advisers to the Consortium</b>
1.	Alliance Pipeline Project (Gas), Canada/US (3,000 km)	US\$3.73 billion (\$2.59 billion debt)	Coastal, IPL, Williams, Fort Chicago Energy, Westcoast Energy	Goldman Sachs, Scotia, Paribas.
2.	BTC Pipeline (Oil), Azerbaijan/Georgia/ Turkey (1,730 km)	US\$3.6 billion (\$2.59 billion debt)	Amerada Hess, ConocoPhillips, INPEX, SOCAR, Unocal, BP, Eni, Itochu, Statoil, TPAO	Lazard
3.	Bolivia-Brazil Pipeline Project (Gas), Bolivia/Brazil (3,075 km)	US\$2.23 billion (\$1.4 billion debt)	PETROBRAS, BG, El Paso, YPFB, BHP, Enron Corp., Shell	Credit Suisse First Boston, Kleinwort Benson
4.	Cupiagua-Cusiana Pipeline (Oil), Colombia (800 km)	US\$2.2 billion (\$1.54 billion debt)	Ecopetrol, BP, Total, Triton, TransCanada, IPL	Goldman Sachs, Credit Lyonnais
5.	Chad-Cameroon Pipeline (Oil), Chad (1,070 km)	US\$2.0 billion (pipeline only) (\$700 million debt)	Exxon Mobil, Petronas, Chevron	Citibank

<sup>1</sup> 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)<sup>1</sup>

	Project Name, Location	Total Capital Cost (Senior Debt Portion)	Sponsors	Financial Advisers to the Consortium
6.	OCP Heavy Crude Pipeline (Oil), Ecuador (503 km)	US\$1.2 billion (\$900 million debt)	Alberta Energy, Repsol YPF, Occidental, Agip, Pecom Energia, Techint, Kerr-McGee	Chase Manhattan Bank
7.	Mozambique-South Africa Pipeline Project (Gas), Mozambique (865 km)	US\$1.2 billion (\$543 million debt)	Republic of South Africa, Republic of Mozambique, Sasol Polymers	Dresdner Kleinwort Wasserstein
8.	Malhas Project (Gas), Brazil (expansion)	US\$1.0 billion (\$900 million debt)	PETROBRAS, Mitsui, Itochu, Mitsubishi	
9.	Kern River Expansion II (Gas), United States (part refinancing)	US\$875.0 million loan	Williams, Tenneco	
10.	Camisea (Gas), Peru	US\$865.0 million (\$480 debt)	Techint, Sonatrach, PlusPetrol, SK, Hunt Oil, Tractebel	Citi

<sup>1</sup> Also excludes primarily upstream projects with an integrated pipeline component. Based on Dealogic database.

## Summary of Main Points

- Even in oil and gas sector, project financings vary considerably
- Major distinction is between developer- and producer-driven projects
- Many structural variations for upstream, midstream and integrated projects
- For pipelines, credit defined by Transportation Agreement (parties, nature of commitments and pricing), completion support and operating track record
- Universe of greenfield large developer-driven pipeline financings is very limited

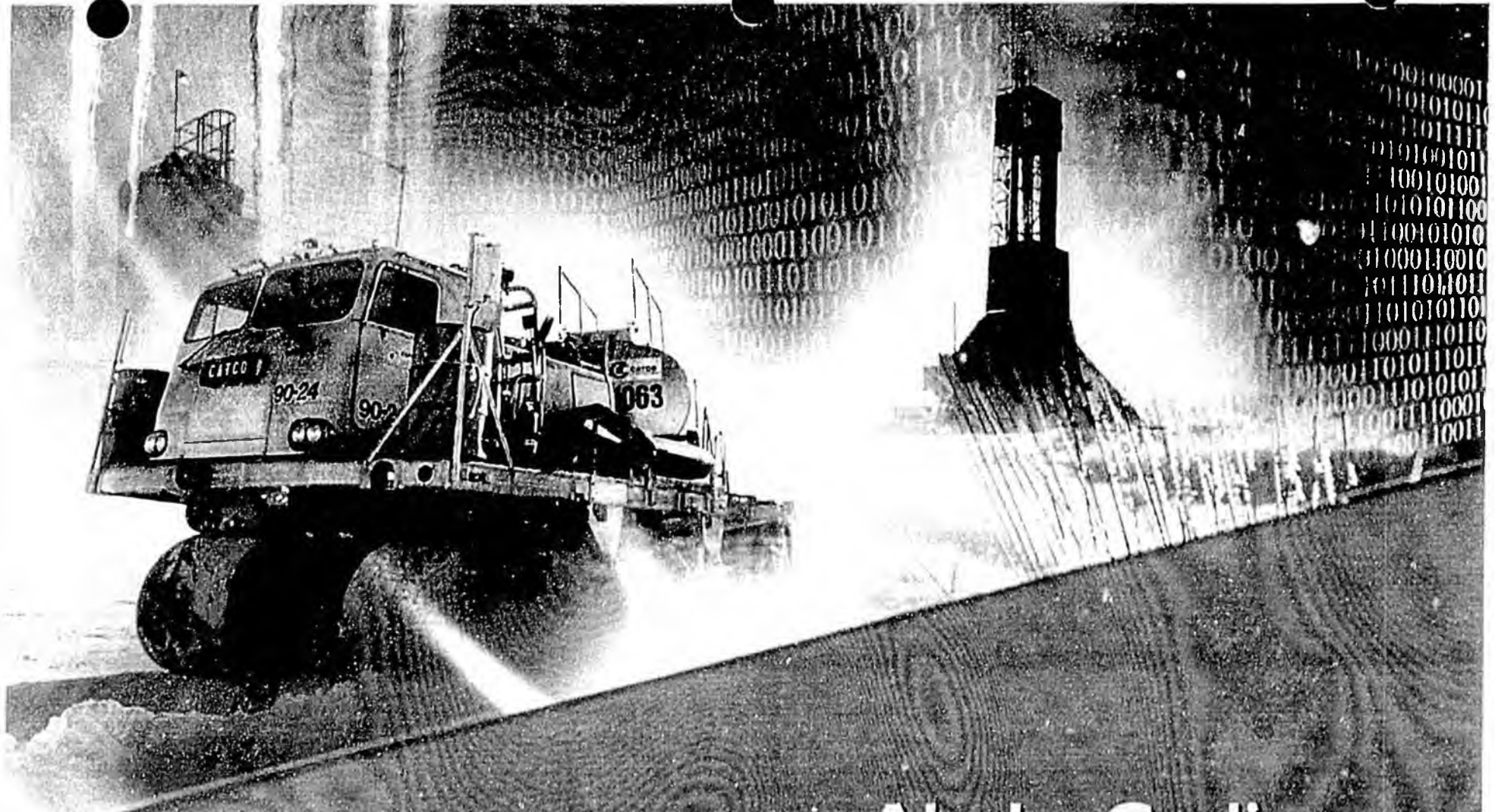
# CONCLUSION: KEY POINTS



- Every project is different and this one will likely set its own financing precedents
- Parties use project financing for different reasons
- Commercial fundamentals, together with contractual commitments, completion support and sponsor strength, are the foundation of a project credit
- With the right underlying economics and if properly structured, oil and gas projects can be strong credits
- Project finance execution is a complex enterprise requiring collaboration among many parties; flexibility is required to respond to moving markets

SULLIVAN & CROMWELL LLP

ANADARKO



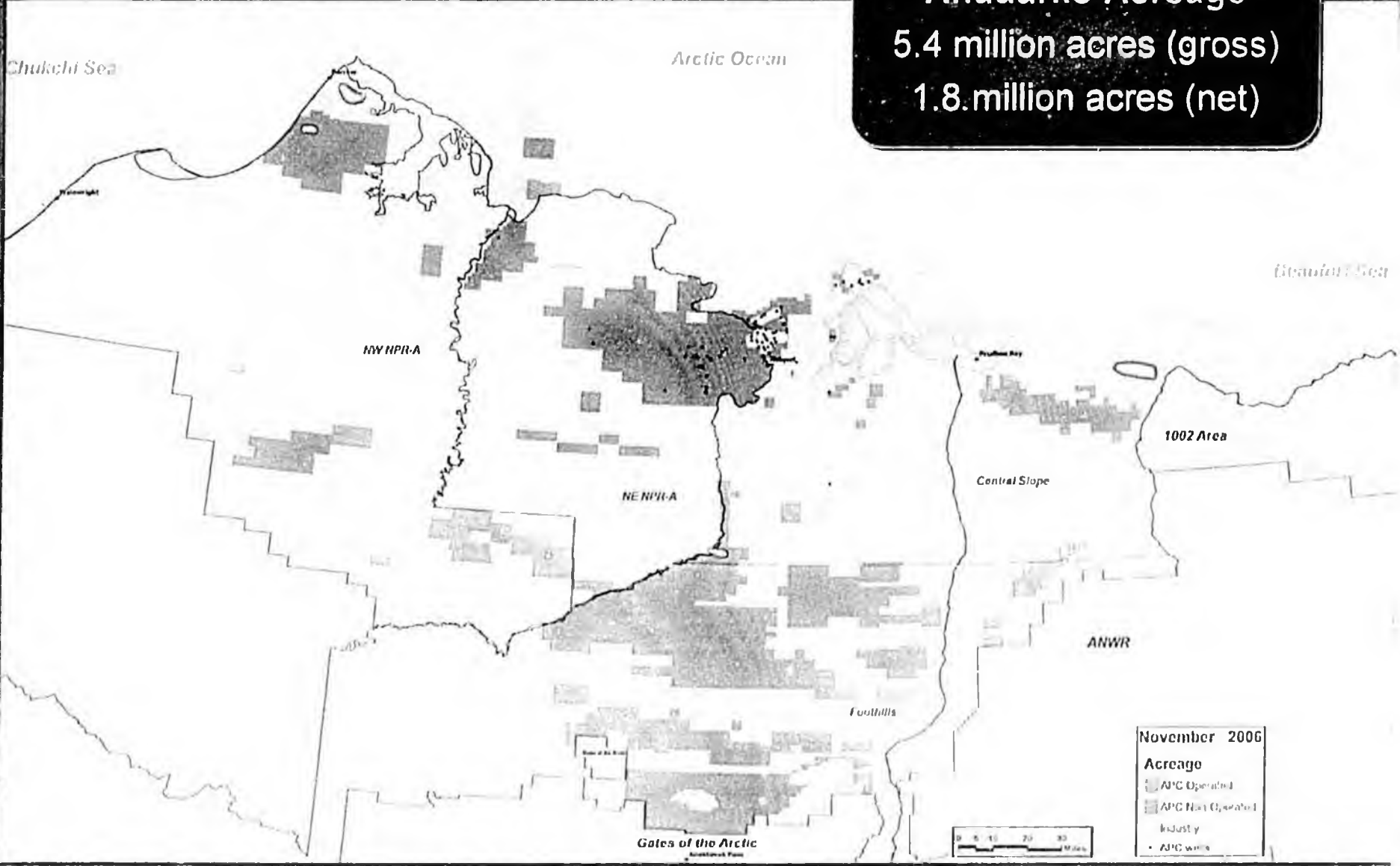
# Alaska Gasline Inducement Act

**Anadarko**<sup>®</sup>  
Petroleum Corporation

Senate Finance  
April 27, 2007

# Anadarko's Investment in Alaska-Land

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



# Support AGIA

## Support Alaska Gasline Inducement Act

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

A N A D A R K O

# Support AGIA Process

## ▶ We like the process

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

# Support Specifics in AGIA

## ▲ We support mandatory provisions on access and rates

### – Pipeline (licensee) must:

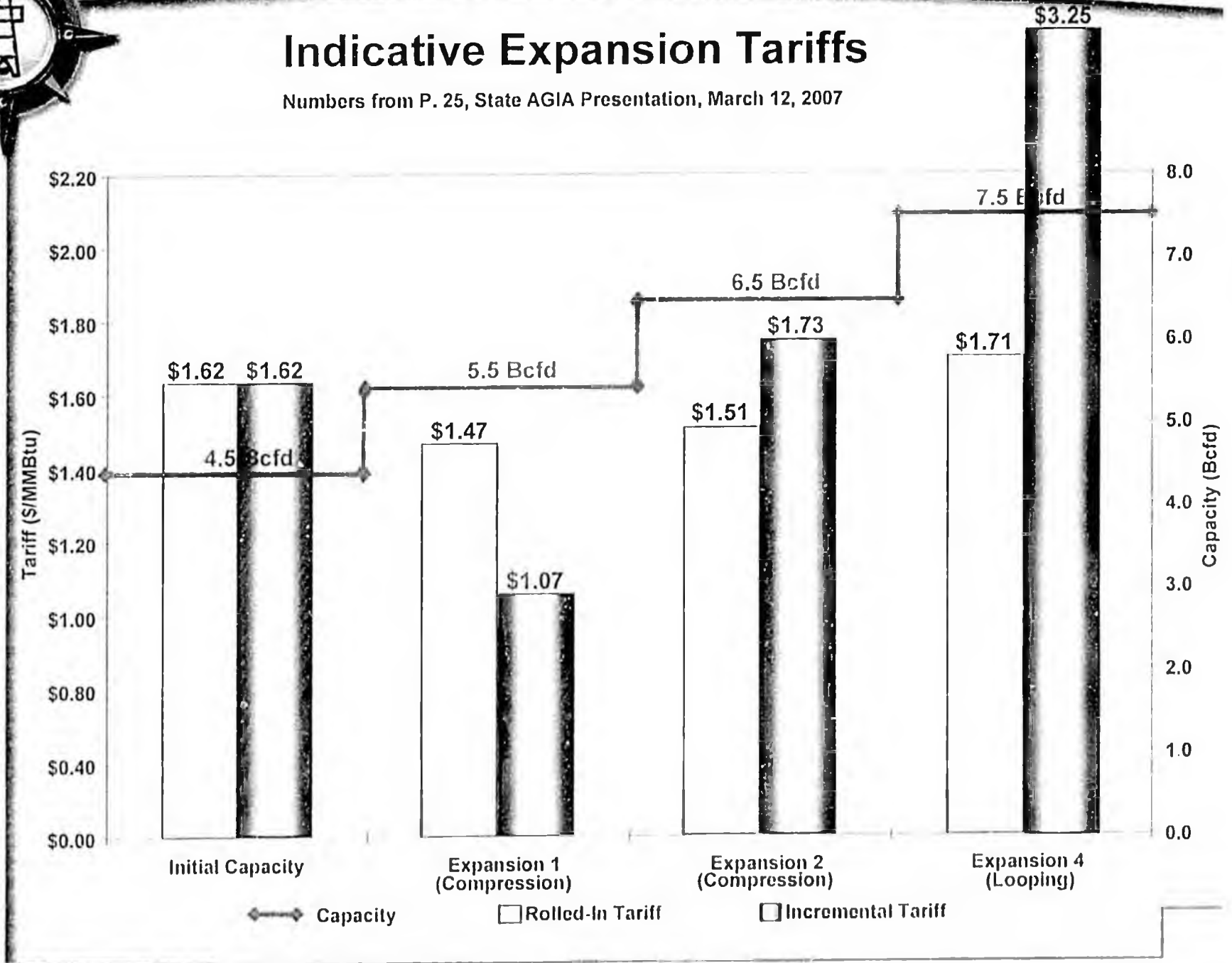
- Assess market demand for expansions every 2 years
- Commit to expand in reasonable increments on reasonable terms
- Propose and support rolled in rates up to 15% above initial rate and agree not to enter into negotiated rate agreements that would preclude the rolled in rates

A N A D A R K O



# Indicative Expansion Tariffs

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



# AGIA helps mitigate challenge of FERC rules

A  
N  
A  
D  
A  
R  
K  
O

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

# Support AGIA

## Support Alaska Gasline Inducement Act

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

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# CORRECTION

THE FOLLOWING DOCUMENT(S)  
HAVE BEEN REFILMED TO  
ASSURE LEGIBILITY OR PAGINATION



Rev. 6/98

Central Microfilm Services  
Department of Education & Early Development  
State of Alaska

UNITED STATES COURT OF APPEALS  
FOR DISTRICT OF COLUMBIA CIRCUIT  
JUN - 5 2006  
RECEIVED

UNITED STATES COURT OF APPEALS  
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Case No. 05-1299  
(and consolidated cases 05-1300 and 05-1301)

EXXON MOBIL CORPORATION,

Petitioner,

- v -

FEDERAL ENERGY REGULATORY COMMISSION,

Respondent.

Petitions for Review  
of Orders from the  
Federal Energy Regulatory Commission  
Order No. 2005 (Docket No. RM05-1-000) and Order No. 2005-A (Docket No. RM05-1-001)

JOINT BRIEF OF PETITIONERS  
BP EXPLORATION (ALASKA) INC., CONOCOPHILLIPS COMPANY,  
AND EXXON MOBIL CORPORATION

Donald B. Craven  
C. Fairley Spillman  
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*Counsel for BP Exploration (Alaska) Inc.,  
ConocoPhillips Company, and  
Exxon Mobil Corporation*

risk.<sup>50</sup> Second, as holders of leases for substantial discovered North Slope natural gas resources, the Companies are adversely affected because the regulations lower the value of such resources by increasing the risk that construction of a pipeline to bring the natural gas to market might not occur or might be delayed.

### SUMMARY OF ARGUMENT

The Commission unlawfully has asserted authority to condition a certificate of public convenience and necessity on the project sponsor's willingness to allow FERC to increase the capacity or expandability of the project. FERC's promulgation of the challenged regulations is contrary to the NGA and ANGPA. Therefore, the Court should find that §§ 157.36 and 157.37 \*  
are invalid.

The NGA does not empower FERC to order increases in pipeline capacity. Indeed, Section 7(a) of the NGA makes clear that FERC lacks the power to do so. In ANGPA, Congress, after careful consideration of competing interests, adopted a limited exception to this prohibition. However, that exception—set forth in ANGPA § 105—protects initial shippers, the pipeline, and the public interest by imposing prerequisites that must be satisfied before FERC may order a mandatory pipeline expansion. The challenged regulations would work an end-run around the checks and balances Congress saw fit to adopt. Therefore, the regulations are contrary to law.

The Commission suggests that the challenged regulations are permissible because, under them, the Commission would require increased capacity via certificate conditions, rather than by direct order. However, FERC may not do indirectly through its conditioning authority what it is precluded from doing directly. Nor is there any support for FERC's suggestions that the prohibition on ordering increased capacity can be ignored at the initial application stage or that

---

<sup>50</sup> Petitioner Comments (Rec. 32) at 8-9; Brattle Comments (Rec. 39) at 6-7.

§ 157.36 Open seasons for expansions.

Any open season for capacity exceeding the initial capacity of an Alaska natural gas transportation project must provide the opportunity for the transportation of gas other than Prudhoe Bay or Point Thomson production. In considering a proposed voluntary expansion of an Alaska natural gas pipeline project, the Commission will consider the extent to which the expansion will be utilized by shippers other than those who are the initial shippers on the project and, in order to promote competition and open access to the project, may require design changes to ensure that some portion of the expansion capacity be allocated to new shippers willing to sign long-term firm transportation contracts, including shippers seeking to transport natural gas from areas other than Prudhoe Bay and Point Thomson.

§ 157.37 Project design.

In reviewing any application for an Alaska natural gas pipeline project, the Commission will consider the extent to which a proposed project has been designed to accommodate the needs of shippers who have made conforming bids during an open season, as well as the extent to which the project can accommodate low-cost expansion, and may require changes in project design necessity to promote competition and offer a reasonable opportunity for access to the project.

§ 157.38 Pre-approval procedures.

No later than 90 days prior to providing the notice of open season required by § 157.34(a), a prospective applicant must file, for Commission approval, a detailed plan for conducting an open season in conformance with this subpart. The prospective applicant's plan shall include the proposed notice of open season. Upon receipt of a request for such a determination, the Secretary of the Commission shall issue a notice of the request, which will then be published in the Federal Register. The notice shall establish a date on which comments from interested persons are due and a date, which shall be within 60 days of receipt of the prospective applicant's request unless otherwise directed by the Commission, by which the Commission will act on the proposed plan.

§ 157.39 Rate treatment of pipeline expansions.

There shall be a rebuttable presumption that rates for any expansion of an Alaska natural gas transportation project shall be determined on a rolled-in basis.

Law Seminars International  
Energy in Alaska: Opportunities and Challenges in Developing New Energy Sources

November 18, 2005

**THE LIKELY IMPACT OF  
THE FEDERAL ENERGY REGULATORY COMMISSION'S  
ALASKA NATURAL GAS PIPELINE OPEN SEASONS REGULATIONS  
ON THE DEVELOPMENT OF OIL AND GAS RESOURCES IN ALASKA**

Presented by

**J. Curtis Moffatt, Member  
Van Ness Feldman, P.C.  
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**INTRODUCTION**

Good morning. My name is Curt Moffatt. I am a partner with the law firm Van Ness Feldman, in Washington, DC, specializing in the regulation of interstate natural gas pipelines.

In the interests of full disclosure, our firm, and I personally, serve as counsel to TransCanada Corporation with respect to its efforts to promote and support the development of the Alaska Natural Gas Transportation System ("ANGTS") to transport stranded Alaskan natural gas by pipeline to the lower-48 states. I provide these remarks and opinions, however, not in that capacity, but rather as a practitioner with over 25 years experience representing independent natural gas pipelines subject to the plenary jurisdiction of the Federal Energy Regulatory Commission ("FERC" or "Commission") under the Natural Gas Act ("NGA"); particularly, section 4 relating to tariffs, rates, charges and terms and conditions of service, and section 7 relating to the securing of certificates of public convenience and necessity to authorize the ownership, construction, and operation of transmission facilities in interstate commerce and the authority to transport or sell natural gas in interstate commerce at wholesale.

One of the reasons I suppose I was asked to speak today is that I also have a long history with the development of an Alaska natural gas pipeline project, having been involved with the project since serving as an assistant to a member of the Federal Power Commission ("FPC") and later to the FERC Chairman in the late 1970s, at the time that the agency was making its recommendations to the President with respect to the development of the project.

From these perspectives, I offer these personal comments on the interplay between the Commission's open season regulations, the NGA, the Alaska Natural Gas Transportation Act of 1976 ("ANGTA"), and the Alaska Natural Gas Pipeline Act ("ANGPA") enacted in 2004 and its impact on the specific question of whether the Commission's open season regulations provide the necessary framework to ensure the development of Alaska's resource base.

For initial capacity on the transportation system, the Commission's rules implementing the ANGPA requirement do no harm and provide some additional guidance on how to proceed with an open season to allocate initial capacity on the pipeline. But, let's be realistic, and recognize that initial capacity is going to be subscribed by shippers who are shipping current proven reserves from Prudhoe Bay or Point Thomson. The initial open season will not have much impact on the development of Alaska's presumed-to-be vast *potential* resources of natural gas. Those development decisions will depend on expansion of the initial capacity.

Regarding expansion of the pipeline beyond initial capacity, the Commission did make an important decision to establish a presumption in favor of rolled-in, as opposed to incremental, pricing of expansion facilities, albeit limited to voluntary expansions.<sup>1</sup> This decision is critical to providing economic transportation when expanding the initial capacity to meet the shipping needs of independent explorers developing other natural gas reserves.

This decision, however, will be a hollow victory for future explorers if the owners of the transportation system are unwilling to expand the transportation facilities voluntarily. The Commission's presumption in favor of rolled-in pricing is only available if the expansion is undertaken voluntarily by the owner of the pipeline. The presumption will not be applicable in the case of a forced expansion after a complaint pursuant to Section 105 of ANGPA.

Therefore, if one is interested in creating the right investment climate for the development of Alaska's natural gas resources beyond the currently proven reserves at Prudhoe Bay and Point Thomson, then I submit that the focus should not be on the Commission's regulations governing open seasons or even open access or affiliated transactions. Rather, the development of Alaska's yet-to-be-discovered natural gas resources will depend on who owns the pipeline and whether that owner will be willing to expand the pipeline voluntarily and implement rolled-in versus incremental pricing.

If assuring access and voluntary, economic expansions to promote additional, diverse exploration and development capital were the only policy objectives facing the Federal and State governments as well as the North American energy markets, then there would be no question that the pipeline system should be controlled and operated as an independent pipeline. Such a corporate structure would then mirror the overwhelming majority of large diameter natural gas transportation systems throughout North America. But, at the moment, the larger public policy question is "how do we get the North Slope

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<sup>1</sup> 18 C.F.R. § 157.39.

producers to commit to produce and market the proven reserves?" Will the open season regulations assist in that endeavor? In my personal opinion: the regulations do no harm, but they also do not provide any answers.

THE CONCEPT OF OPEN ACCESS PIPELINES AND THE ROLE OF OPEN SEASONS AS APPLIED TO AN ALASKA NORTH SLOPE NATURAL GAS PIPELINE

For almost thirty years now, the development of an Alaska natural gas pipeline has presented profound policy questions that have been committed to deliberative processes at the Federal and State levels. The project is as large and complex as they come. It has been the subject of two special acts of Congress, a Presidential decision, an international agreement, and multiple FPC / FERC proceedings. And it is currently the subject of a major State statute, the Alaska Stranded Gas Development Act, involving significant deliberative processes in the State's executive and legislative branches. It is safe to say that no other project has had such a distinguished history.

The project presents several unique issues: (1) the considerable technical challenges involved in developing a project of this magnitude in an Arctic environment; (2) the sheer amount of capital required to develop and construct the project; and (3) given that there are not likely to be competitive pipeline alternatives to the initial pipeline transportation infrastructure, concern with the potential for exercise of market power by any owner of the project. I will not discuss the technical challenges or the capital requirements here. However, I will share some observations regarding what is in my view the fundamental public policy question: how independent of the Prudhoe Bay producers should the ownership of the pipeline be if Alaska and the United States are serious about developing Alaska's other natural gas resources?

All interstate natural gas pipelines in the United States, like electric transmission lines operating in interstate commerce, are subject to federal economic regulation because of the Congressional determination that they are natural monopolies. Since 1938, the NGA has provided the primary statutory scheme to assure that rates and charges are just and reasonable, and that the services are provided on a not unduly discriminatory basis.<sup>2</sup> Congress continues to believe that appropriate regulation is necessary to address market power concerns.

Implementing Congress's intent, the Commission has gone to great lengths to limit market power and to prevent undue discrimination. Moreover, the Commission has noted repeatedly that concerns regarding market power and undue discrimination are

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<sup>2</sup> Under section 4(a) of the NGA, all rates and charges for or in connection with the transportation or sale of natural gas subject to the jurisdiction of the Commission must be "just and reasonable," and any rates or charges that are not just and reasonable are declared to be unlawful. 15 U.S.C. § 717c(a). Under section 4(b), natural gas companies are prohibited from granting any undue preferences or advantages to, or unduly discriminating against, any person, with respect to any transportation or sale of natural gas subject to the jurisdiction of the Commission. 15 U.S.C. § 717c(b).

heightened when a pipeline is owned by an entity or entities that are also affiliated with the shippers that will use the pipeline.<sup>3</sup>

There is significant precedent regarding ensuring competition and protecting against undue discrimination in the natural gas transportation industry. Indeed, such concerns were at the very foundation of the Commission's efforts to restructure the industry in the mid-1980s and early 1990s. Order 436,<sup>4</sup> issued in 1985, encouraged interstate pipeline companies to provide open access service, providing incentives for them to offer transportation service to producers and end users, as well as their regular local distribution company ("LDC") customers, on a first come, first served basis. It also prohibited pipeline companies from discriminating against transportation requests in order to protect their own merchant services.

Order 636,<sup>5</sup> issued in 1992, went a step further, actually requiring interstate pipeline companies to unbundle their transportation, sales, and storage services, in an effort to ensure that third-party suppliers would receive the same quality of transportation services that were previously provided to a pipeline company's own gas sales. Order 636 meant that interstate natural gas pipeline companies could no longer engage in merchant gas sales, and required that their production and marketing arms be restructured as arms-length affiliates. Under the Order, pipeline companies were prohibited from providing their affiliates with any advantage (such as in price, volume, or timing of gas transportation) over any other potential shippers.

Such concerns also are at the base of the Commission's Order 2004<sup>6</sup> standards of conduct governing interactions between transmission providers (including interstate natural gas pipelines) and their energy affiliates.<sup>7</sup> Order 2004 recognized that "Transmission Providers continue to have economic incentives to show undue preferences toward their Energy Affiliates."<sup>8</sup> Thus, the standards of conduct are designed to ensure that transmission providers cannot extend their market power over transmission to wholesale energy markets by giving their energy affiliates unduly preferential treatment. As FERC explained in the Order:

Producers that are selling energy are competing with other  
non-affiliated shippers for access to the pipelines'

<sup>3</sup> See, e.g., Standards of Conduct for Transmission Providers, Order No. 2004, 68 Fed. Reg. 69,134 (Nov. 25, 2003), *order on reh'g*, Order No. 2004-A, 69 Fed. Reg. 23,562 (Apr. 29, 2004), *order on reh'g*, Order No. 2004-B, 69 Fed. Reg. 48,371 (Aug. 10, 2004).

<sup>4</sup> Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, 50 Fed. Reg. 42,408 (Oct. 18, 1985).

<sup>5</sup> Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636, 57 Fed. Reg. 13,267 (Apr. 16, 1992).

<sup>6</sup> Standards of Conduct for Transmission Providers, Order No. 2004, 68 Fed. Reg. 69,134 (Nov. 25, 2003). In Order No. 2004-A, 69 Fed. Reg. 23,561 (Apr. 29, 2004), and in Order No. 2004-B, 69 Fed. Reg. 48,371 (Aug. 10, 2004), the Commission made a number of clarifications and revisions to, but largely reaffirmed, Order No. 2004.

<sup>7</sup> 18 C.F.R. § 358.3.

<sup>8</sup> 68 Fed. Reg. at 69,137.

transmission systems. Whether a producer is selling gas from its own production or from the production of another, it is competing with non-affiliates for access to the pipeline's transportation system. We conclude that providing a producer, gatherer or processor with preferential access to the pipeline's transmission system or information concerning the pipeline's system is inconsistent with NGA Section 4's prohibition against undue preferences or discrimination in the provision of interstate transportation services; accordingly, this Final Rule will prevent such conduct.<sup>9</sup>

In order to address this concern, the standards establish two general principles applicable to all interstate natural gas pipeline companies that have energy affiliates: (1) employees of the pipeline company who are engaged in transmission system operations must function independently from employees of the company's energy affiliates; and (2) the pipeline company must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and must not operate its transmission system to benefit preferentially an energy affiliate.<sup>10</sup>

All of these Commission orders and regulations, however, relate to non-discriminatory service on *only* the operating facilities—*i.e.*, once the pipeline is built and operating. They have nothing to do with whether a pipeline company will agree to expand its system.

Indeed, nowhere in any of these orders is there any discussion of the Commission ordering a pipeline to expand its system to serve new customers. That is because, prior to the enactment of ANGA and its section 105 complaint procedure, the Commission has had virtually no authority to order an expansion of a pipeline's system to serve new load—*i.e.*, in the case of Alaska, beyond proven reserves in Prudhoe Bay and Point Thomson.<sup>11</sup> This is the precise reason that concerns regarding access to the pipeline and

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<sup>9</sup> *Id.* at 69,143-44.

<sup>10</sup> 18 C.F.R. § 358.2.

<sup>11</sup> Section 7(a) of the NGA authorizes the Commission to order natural gas companies to "extend or improve" their transportation facilities, but expressly provides that "Commission shall have no authority to compel the enlargement of transportation facilities . . ." 15 U.S.C. § 717f. See *El Paso Natural Gas Co.*, 104 FERC 61,045, at P 104, n. 104 ("The Commission does not have the authority under the NGA to order a pipeline to construct additional capacity."); see also, e.g., 18 C.F.R. § 284.7(f) (providing that open access pipelines are "not required to provide any requested transportation service for which capacity is not available or that would require the construction or acquisition of any new facilities"); *Panhandle Eastern Pipe Line Co. v. FERC*, 204 F.2d 675 (3rd Cir. 1953) (opining that "the provisions of section 5(a), which confer upon the Commission power to direct the elimination of unduly discriminatory and preferential practices, must be read in the light of and construed as subject to the proviso in section 7(a) that the Commission may not compel the enlargement of the transportation facilities of a natural gas company."); *Regulation of Short-Term Natural Gas Transportation Services, Regulation of Interstate Natural Gas Transportation Services*, 106 FERC 61,088 at P 30 (2004) (recognizing "concerns about the Commission's ability, under Section 7 of the NGA, to require a pipeline to construct capacity"); *Calpine Energy Services, L.P.*, 103 FERC 61,273, at P 30 (2003) ("It is well established that Section 7 of the Natural Gas Act does

attempts to exercise market power have pervaded the more than three decades of attempts to develop an Alaska North Slope natural gas line.

With respect to the Alaska natural gas pipeline, participation by the Alaska North Slope natural gas producers in the ANGTS was originally prohibited by the President's Decision on an Alaska Natural Gas Transportation System, with the exception of providing guarantees for project debt. This prohibition reflected concerns expressed by the Attorney General to the President and Congress relating to the impact of producer participation in the Project on competition in the natural gas industry. Pursuant to sections 6 and 19 of the Alaska Natural Gas Transportation Act ("ANGTA"),<sup>12</sup> the U.S. Department of Justice thoroughly analyzed the antitrust and competitive impact effects of an Alaska natural gas transportation system.<sup>13</sup> The Department concluded that producers of significant amounts of natural gas should not be permitted to own any portion of, or otherwise participate in, the selected Alaska natural gas transportation system, and recommended that the license to be issued to the selected system should contain a condition that prevents participation in any manner by such gas producers.<sup>14</sup> The Department's conclusion and recommendation were based on the premise that "such ownership or participation under a regime of deregulated or relaxed wellhead price regulation could lead to the evasion of effective pipeline regulation and create the opportunity for the earning of monopoly profits through anticompetitive activity."<sup>15</sup>

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not obligate pipelines to build new facilities for shippers."), citing *Panhandle Eastern Pipe Line Co. v. FERC*, 204 F.2d 675, and *Panhandle Eastern Pipe Line Co.*, 91 FERC 61,037, at 61,141-42 (2000) (emphasizing that the Commission's interconnection policy, relating to the construction of new interconnections, "does not require a pipeline to expand its facilities, to construct any facilities leading up to an interconnection, or even to construct the interconnection itself"). Notably, the North Slope producers cited these principles and this and other precedent in their request for rehearing of the Commission's open season regulations, in support of their argument that the Commission lacks authority under the NGA to order design changes with respect to the initial facilities and voluntary expansions pursuant to new 18 C.F.R. §§ 157.36 and 157.37. *Request of BP Exploration (Alaska) Inc., ConocoPhillips Company and Exxon Mobil Corporation for Rehearing and Clarification of Order 2005*, Docket No. RM05-1-000, et al., FERC (Mar. 11, 2005); see 70 Fed. Reg. at 35,013.

<sup>12</sup> Section 6 of ANGTA authorized Federal officers or agencies to submit written comments to the President with respect to the recommendation and report of the FPC, including with respect to impacts upon competition. 15 U.S.C. 719d. Section 19 authorized and directed the Attorney General to "conduct a thorough study of the antitrust issues and problems relating to the production and transportation of Alaska natural gas and . . . to submit to Congress a report containing his findings and recommendations with respect thereto." 15 U.S.C. § 719 note.

<sup>13</sup> Under Section 19, the Attorney General prepared and submitted to Congress, on July 14, 1977, a detailed analysis of potential antitrust issues and problems. Under Section 6, the Attorney General submitted that same report to the Alaskan Natural Gas Task Force, along with a commentary on the FPC's findings with respect to competitive impact. In addition, the Justice Department submitted a letter to the White House on August 9, 1977, which elaborated its views concerning possible participation by the gas producers in financing the transportation system. Letter from H. Morrison, Jr., Acting Assistant Attorney General, Antitrust Division, U.S. Dep't of Justice, to L. Goldman, Assistant Administrator, Energy Resources Development, The White House (Aug. 9, 1977). See Report Accompanying a Decision on an Alaska Natural Gas Transportation System, Ch. VII, at 208.

<sup>14</sup> See Letter from H. Morrison, Jr., Acting Assistant Attorney General, Antitrust Division, U.S. Dep't of Justice, to L. Goldman, Assistant Administrator, Energy Resources Development, The White House (Aug. 9, 1977).

<sup>15</sup> *Id.*

Concern that private financing could not be accomplished without greater participation by the producers, however, ultimately led President Reagan to request and obtain from Congress a waiver overturning the prohibition against producer participation through the ANGTA section 8 waiver process. Importantly, however, the waiver was subject to the proviso, "that any agreement on producer participation may be approved by the Federal Energy Regulatory Commission only after consideration of advice from the Attorney General and upon a finding of the Federal Energy Regulatory Commission that the agreement will not (a) create or maintain a situation inconsistent with the antitrust laws, or (b) in and of itself create restrictions on *access* to the Alaska segment of the approved transportation system for *nonowner shippers* or restrictions on *capacity expansion* . . . ."<sup>16</sup> The President submitted the proposed waiver of law to Congress on October 15, 1981, and the waiver was approved as part of Public Law No. 97-93 in December 1981.<sup>17</sup>

Thus, while the waiver package allowed the producers to participate in the ownership of the project, it also included a proviso to address antitrust and anticompetitive concerns. It was generally believed that the safeguards in this proviso provided sufficient Federal review to eliminate any possible antitrust violations. As explained in the Administration's Synopsis of Waiver:

The prohibition was based upon antitrust concerns, as expressed by the Department of Justice. A more thorough analysis of the antitrust concerns reveals that the producers' ability to exert monopoly control over the project, or to inhibit further development of North Slope reserves by controlling the sole transportation available to natural gas markets, would most likely stem from their ability to limit access to the system or restrict its expansion. By requiring the Commission, in consultation with the Attorney General, to address the access and expansion issues at the time of the final ANGTS certificate issuance, the proposed waiver provides sufficient antitrust protection to meet the express concerns.<sup>18</sup>

Thus, a review of the history of the prohibition against producer participation and the subsequent waiver of that prohibition by Congress illustrates that there were two primary competition and antitrust concerns raised by potential producer ownership of an Alaska North Slope natural gas pipeline: (1) the producers could use their ownership of the pipeline and their control over natural gas supplies to manipulate gas commodity markets; and (2) the producers could prevent access to the pipeline by other producers and limit expansions of the original facility.

<sup>16</sup> See H. R. REP. NO. 97-350, pt. 2, at 13-14 (Nov. 20, 1981) (emphasis added).

<sup>17</sup> 95 Stat. 1204 (Dec. 15, 1981).

<sup>18</sup> Administration Synopsis of Waiver, reprinted at S. REP. NO. 97-272, at 46-47 (1981). See H. R. REP. NO. 97-350, pt. 2, at 13-15 (1981).

Although we are working in a different world than we had in the 1970s and early 1980s, concerns arising from the mere fact of affiliations between pipeline shippers and pipeline owners still exist today. This is evident from all of the Commission's continuing efforts to regulate affiliated transactions. In fact, it is these very concerns that gave rise to Congress, in ANPGA, directing the Commission to issue rules governing open seasons for an Alaska natural gas pipeline. It is also these concerns that were articulated by independent, explorer companies that led to the complaint procedures in ANPGA under which FERC may order expansions of the pipeline.

#### BACKGROUND ON FERC OPEN SEASON REGULATIONS

On February 9, 2005, FERC issued a Final Rule establishing requirements to govern the conduct of open seasons for proposals to construct "Alaska natural gas transportation projects."<sup>19</sup> This Rule fulfilled the Commission's responsibilities to issue open seasons regulations under section 103 of ANPGA, enacted on October 13, 2004. Section 103(e) of the ANPGA directed the Commission, within 120 days after enactment of the Act, to issue regulations governing the conduct of open seasons for Alaska natural gas transportation projects, including procedures for allocation of capacity. It further required that the regulations: (A) include the criteria for and timing of any open seasons; (B) promote competition in the exploration, development, and production of Alaska natural gas; and (C) for any open season for capacity exceeding the initial capacity, provide the opportunity for the transportation of natural gas other than from the Prudhoe Bay and Point Thomson units. It defined an "Alaska natural gas transportation project" as "any natural gas pipeline system that carries Alaska natural gas to the border between Alaska and Canada (including related facilities subject to the jurisdiction of the Commission that is authorized" under ANGTA or under section 103 of ANPGA.

The regulations are applicable to the allocation of both initial capacity and *voluntary* expansion capacity.<sup>20</sup> The regulations do not apply to expansions ordered by the Commission under section 105 of ANPGA.<sup>21</sup> Section 105 of ANPGA authorizes FERC to order an expansion of the capacity of any Alaska natural gas transportation project (whether authorized under the ANPGA or ANGTA), upon request and after giving notice and an opportunity for hearing, if it determines that such expansion is required by the present or future public convenience and necessity.<sup>22</sup> In addition, before it can order an expansion under section 105, FERC is required to make the following findings:

- that a proposed shipper will comply with, and the proposed expansion and the expansion of service will be undertaken and implemented based on,

<sup>19</sup> Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects, Order No. 2005, 70 Fed. Reg. 8,269 (Feb. 18, 2005).

<sup>20</sup> 18 C.F.R. § 157.32.

<sup>21</sup> *Id.* (stating that, "[a]bsent a Commission order to the contrary," the open season regulations "are not applicable in the case of an expansion ordered by the Commission pursuant to section 105 of the Alaska Natural Gas Pipeline Act").

<sup>22</sup> 15 U.S.C. § 720c(a).

- terms and conditions consistent with the tariff of the Alaska natural gas transportation project in effect as of the date of the expansion;
- that the proposed facilities will not adversely affect the financial or economic viability of the Alaska natural gas transportation project;
- that the proposed facilities will not adversely affect the overall operations of the Alaska natural gas transportation project;
- that the proposed facilities will not diminish the contract rights of existing shippers to previously subscribed certificated capacity;
- that all necessary environmental reviews have been completed; and
- that adequate downstream facilities exist or are expected to exist to deliver incremental Alaska natural gas to market.<sup>23</sup>

Provided that it makes the required determinations and findings, and orders the requested expansion, the Commission must then approve or establish rates for the expansion service that are designed to ensure the recovery, on an incremental or rolled-in basis, of the cost associated with the expansion (including a reasonable rate of return on investment).<sup>24</sup> Importantly, the Commission also must ensure that the rates "do not require existing shippers on the Alaska natural gas transportation project to subsidize expansion shippers."<sup>25</sup> Thus, although the statute does not prohibit the Commission from ordering rolled-in rates in connection with such "forced" expansions, it does significantly limit its ability to do so through the prohibition on subsidization. This limitation has the potential to act as a substantial impediment to new exploration and the development of Alaska's resource base.

Congress's direction to FERC to issue regulations governing the conduct of open seasons for Alaska natural gas transportation projects was a direct response to concerns raised by independent explorers that, in order for them to invest in the exploration and development of the State's gas resources, they would need to be assured fair and reasonable access to a pipeline to bring any discoveries to market. Thus, in directing FERC to issue the open seasons regulations, it required that the regulations "promote competition in the exploration, development, and production of Alaska natural gas," and "for any open season for capacity exceeding the initial capacity, provide the opportunity for the transportation of natural gas other than from the Prudhoe Bay and Point Thomson units."<sup>26</sup>

Similar concerns led the Commission to include in the open season regulations a rebuttable presumption that rates for any *voluntary* expansion of an Alaska natural gas transportation project are to be determined on a rolled-in basis.<sup>27</sup> As the Commission explained:

<sup>23</sup> 15 U.S.C. § 720c(b).

<sup>24</sup> 15 U.S.C. § 720c(b)(1).

<sup>25</sup> 15 U.S.C. § 720c(b)(2).

<sup>26</sup> 15 U.S.C. § 720a(e).

<sup>27</sup> 18 C.F.R. § 157.39. As FERC recognized in its final rulemaking, Alaska legislators and a number of independent explorers all commented that rolled-in pricing should be required for pipeline expansions. According to FERC, the State legislators contended "that incremental treatment for expansions would

Incremental pricing of expansion could put expansion shippers at a significant rate disadvantage compared with initial shippers, and accordingly could discourage exploration, development and production of Alaska natural gas. Having markedly different rates for similar service could be in conflict with one of the chief objectives of the statute, which is to encourage further exploration and development of Alaska natural gas. On the other hand, consistent with the arguments of a number of commenters, a presumption in favor of rolled-in pricing may spur investment in and development of Alaska reserves, and the ultimate delivery of that gas to the lower 48 states.<sup>28</sup>

FERC's open seasons regulations certainly do some things that, all other things being equal, could be helpful to the overall development of the project. For instance, they provide project sponsors with important flexibility to design open seasons that could help yield firm transportation contracts needed to secure the capital to develop and construct the project. In addition, they allow pre-subscriptions of reserved capacity, which may prove necessary to secure the significant capital required to develop and construct the project. And they establish the rebuttable presumption of rolled-in rate treatment for voluntary expansions. However, they are unlikely to address the concerns raised by the independent explorers and encourage the development of the State's remaining, undiscovered oil and gas resources.

#### WHY ARE FUTURE EXPANSIONS SO IMPORTANT? ISN'T 35 TRILLION CUBIC FEET ENOUGH?

Much is made of the 35 trillion cubic feet (tcf) of known reserves on the North Slope in Prudhoe Bay and Point Thomson—to which the three major Alaska North Slope producers hold most of the rights—that an Alaska natural gas pipeline project would bring to market. However, this 35 tcf is just the tip of the iceberg compared to the overall gas resource potential that ultimately could—and should—be served by the project. Federal and State geologists estimate that there are undiscovered, but technically recoverable, deposits of more than 200 additional tcf of natural gas in the North Slope basin. The development of this additional resource base is critical to the State's long-term fiscal and development interests. Because the current proved reserves will sustain the project's current design capacity for only 16 or 17 years, development of these additional resources is also important to the economics of the project.

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discriminate against expansion shippers who, merely because of the timing of their capacity needs, may pay higher rates than initial shippers." Moreover, "[i]n addition to arguing that incremental rates operate to discriminate against expansion shippers, Alaska Legislators argue that the prospect of incremental rates will also act to reduce competition and impede the development of Alaska natural gas," with the result that "the explorers and developers may be deterred from investing the large sums required to drill for Alaska natural gas . . ." 70 Fed. Reg. at 8,283.

<sup>28</sup> 70 Fed. Reg. at 8,284. See also 70 Fed. Reg. at 35,017-18.

Such development of the State's resource base requires that explorers have the confidence that they will be able to obtain fair and reasonable access to the project, through expansions of the project on fair and reasonable terms. If explorers do not have solid assurances that they will have ready access to pipeline capacity on reasonable terms and at a reasonable price, they will not invest the tens of millions of dollars needed for exploration and development, and the State's potentially vast natural gas resources will remain undiscovered and undeveloped.

The answer to the question whether the Commission's open seasons regulations provide the necessary framework to ensure the development of Alaska's resource base is that they may, depending upon whether the project is owned, constructed, and operated by an independent pipeline company, or by the major oil and gas producers on the North Slope. It is not clear that the open season regulations themselves provide the owners of the project with adequate incentives to develop and expand the project.

It is a simple matter of fact that independent pipeline companies and integrated producer-pipeline companies act according to different sets of economic considerations. This has nothing to do with either category of companies pursuing improper motives. Rather, it derives from the profit-maximizing objectives of any corporation that is responsible to the interests of its shareholders.

Who is more likely to be motivated to provide expansions of the project as needed to accommodate new discoveries? This is something that the independent exploration companies will seriously consider when putting together their plans for development and determining whether to invest their resources in the exploration and development of unknown natural gas deposits in Alaska.

**INDEPENDENTLY-OWNED PIPELINE COMPANIES HAVE A CLEAR INCENTIVE TO MAXIMIZE THROUGHPUT THROUGH INITIAL CAPACITY DESIGN AND EXPANSIONS**

Independent, transportation-only pipeline companies are in the sole business of making money by transporting gas to market. As such, independent pipeline companies have a clear incentive to maximize throughput on their facilities by constructing pipelines large enough to accommodate all interested initial shippers and by expanding their facilities when new reserves and shipping commitments become available. For an independent pipeline company, expansions can be critically important to a project's bottom line. Thus, as a prudent project owner, an independent pipeline company generally will expand an existing project to accommodate new reserves and/or shippers, provided that, based solely upon revenues from transportation services, the expansion ensures the company a profitable rate of return. Therefore, based solely upon corporate, profit-maximizing motives, ownership of the project by an independent pipeline company will support the interests of both initial and future shippers on the pipeline, and help encourage the development of the State's resource base.

A PRODUCER-OWNED PROJECT WOULD HAVE CONFLICTING INCENTIVES, WHICH  
COULD DISFAVOR EXPANDING CAPACITY FOR COMPETING INDEPENDENT  
EXPLORERS/PRODUCERS

Integrated producer-owners, on the other hand, again based purely upon corporate, profit-maximizing motives, can be expected to operate according to a different set of economic incentives and make very different decisions. A producer that is also the owner/developer of the pipeline would be in the position of deciding whether, and if so, to what extent, it will allow other, non-affiliated explorers to gain access to its facilities to transport natural gas that will compete with its own gas for sale in the commodity markets. Allowing competing supplies into the commodity markets could affect the price that the producer can obtain for its own gas. Therefore, economic factors wholly unrelated to the economics of setting the initial pipeline capacity and providing expansions may provide a disincentive for producer-owners to maximize initial and future capacity. This is particularly the case where the rate of return on a regulated asset like the pipeline would be expected to be considerably lower than the rate of return to be obtained from the sale of the commodity.

Another reality is that producer-owners are not in the business of building transportation capacity for others. Internal corporate competition for personnel and development capital will be harder to secure in an entity more focused on exploration and production, refining, and marketing, than on expanding regulated natural gas pipelines.

To ensure development of the State's resource base, explorers must have some reasonable expectation and confidence that the pipeline will be expanded, if necessary, in order to afford them fair and reasonable access to capacity to transport any gas they might discover. With the transportation system controlled by an entity that is independent of the incumbent producers and whose primary focus is building and operating pipelines, explorers may draw some comfort from this familiar structure. If, however, the pipeline system is owned and controlled by the incumbent producers, who will not have the singularity of purpose that an independent pipeline would have, logical<sup>29</sup> such confidence must come from other sources. But where?

Absent a long, drawn out complaint process at FERC under Section 105 of ANGPA,<sup>29</sup> FERC has no independent authority under the NGA—of which I am aware—to order an expansion of the original mainline facilities.<sup>30</sup> Further, even though the 1981

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<sup>29</sup> I fully concur with the statement of counsel to the Alaska Department of Law, Robert Loeffler, that, "Based on everything else connected with this project, I would not expect an expansion proceeding at the FERC to be short, uncomplicated, and uncostly." Stranded Gas Hearings before the Alaska Legislative Budget and Audit Committee (July 28, 2004) (prepared statement of Robert H. Loeffler, Morrison & Foerster LLP, for the Alaska Department of Law, "Access Under Current Law vs. Access Under Proposed Changes to Federal Law," at 11-12).

<sup>30</sup> As counsel for the Alaska Department of Law, Robert Loeffler, testified in July 2004 before the Alaska State legislature, prior to enactment of ANGPA: "The question is whether the Alaska Gas Pipeline owners can be forced to expand the pipeline in the event they do not voluntarily agree to do so. Under current law, the short answer is no. . . . [W]hat you're dealing with is really the belief that private people are building a project and you cannot force them to put more money into a project if they don't want to."

waiver of ANGTA referenced above seemed to provide a mechanism for the Commission to condition any ownership by the incumbent producers on assuring access and expansion, this mechanism—whatever its scope—is only available if the project proceeds under ANGTA. Thus, at the Federal level, there is no obvious means to provide the degree of certainty explorers will require prior to making capital investments if an expansion is likely needed to move the production. It just does not appear satisfactory to simply say that FERC will take care of it.

Turning then to the State, and to the Stranded Gas Development Act negotiations, it is not clear whether the State's minority ownership interest in the pipeline would provide adequate assurance to explorers unless the State has negotiated governance or other super-voting rights on expansion issues. But little information has been made available on the terms of the proposed Stranded Gas Development Act deal between the State and the producers. According to public reports, however, the State seems to believe that it has adequately ensured that any required expansions of the initial capacity will occur; in part, I suppose, because of the place at the table its minority ownership of the project will provide it. Of course, whether this actually would be the case depends on the terms of the project agreements negotiated between the State and the producers.

There is a significant question, however, whether the FERC's authority to order an expansion under section 105 of ANGPA will provide adequate assurances to explorers. It is not readily apparent that a company weighing a major exploration and development budget that could take many years to yield commercially viable quantities of gas will be satisfied with the FERC complaint process. After all, that process will be lengthy, costly, and then subject to judicial review. With that uncertainty and the extensive list of findings that must be made, it is hard to imagine that large amounts of additional capital will be readily deployed in reliance upon that mechanism. And even if the explorers do meet their burden of proof for ordering expansion of the pipeline, FERC is substantially limited in its ability to order rolled-in tolls, meaning that explorers will likely have to bear the full cost of any compulsory expansion. These are significant disincentives for explorers to pursue the exploration and development of the State's natural gas resources, which simply are not as likely to come into play with an independently-owned pipeline where the predominant economic incentives favor voluntary expansion; and that is when the Commission's open season regulations for rolled-in pricing of voluntary expansions would provide a definite positive incentive for long-term, basin-wide development.

#### CONCLUSION

FERC's open access regulations can help ensure that all interested shippers are afforded not unduly discriminatory access to any available capacity. But I submit that FERC cannot, and will not, ensure that the owner or owners of the pipeline have the needed incentives to expand the pipeline in order to make additional capacity available to

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And that really is the standard under existing law." Stranded Gas Hearings before the Alaska Legislative Budget and Audit Committee (July 28, 2004) (testimony of Robert H. Loeffler, Morrison & Foerster LLP, for the Alaska Department of Law).

accommodate new supplies and thus encourage the exploration for, and development of, Alaska's potential natural gas resources. FERC's open access regulations issued pursuant to ANGPA will not significantly affect whether the original capacity will be expanded. FERC currently does not possess any statutory authority to order expansions outside of the time-consuming, expensive expansion provisions of Section 105 of ANGPA. Thus, the issue of whether the owners of the pipeline are affiliated or independent will probably have a greater impact on the extent to which the project will lead to the development of Alaska's potential natural gas reserves than will FERC's open season regulations.

UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

Notice of Proposed Rulemaking on Standards of  
Conduct

Docket No. RM07-1-000

COMMENTS OF THE STATE OF ALASKA ON PROPOSED RULEMAKING

The State of Alaska ("State") offers the following comments pursuant to the Commission's Notice of Proposed Rulemaking ("NOPR")<sup>1</sup> in the above-referenced docket, which concerns revisions to the Standards of Conduct for Transmission Providers.<sup>2</sup>

In *National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (D.C. Cir. 2006) ("*National Fuel*"), the court vacated and remanded Order No. 2004 insofar as it pertains to interstate natural gas pipelines. On January 9, 2007, the Commission issued an interim rule to repromulgate temporarily the standards of conduct not challenged before the court.<sup>3</sup> On January 18, 2007, the Commission issued this NOPR, which proposes permanent regulations regarding the standards of conduct.

For the reasons set forth below, the State asks the Commission in its final rule to (i) make the standards of conduct for an interstate Alaska North Slope gas pipeline or pipelines applicable

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<sup>1</sup> *Notice of Proposed Rulemaking*, 118 FERC ¶ 61,031 (2007).

<sup>2</sup> *Standards of Conduct for Transmission Providers*, Order No. 2004, III FERC Stats. & Regs., Regulations Preambles ¶ 31,155 (2003), *order on reh'g*, Order No. 2004-A, III FERC Stats. & Regs. ¶ 31,161 (2004), 107 FERC ¶ 61,032 (2004), *order on reh'g*, Order No. 2004-B, III FERC Stats. & Regs. ¶ 31,166 (2004), 108 FERC ¶ 61,118 (2004), *order on reh'g*, Order No. 2004-C, 109 FERC ¶ 61,325 (2004) ("Order No. 2004").

<sup>3</sup> Order No. 690, Docket No. RM07-6-000, January 9, 2007.

to that pipeline's relationship with both Marketing Affiliates and Energy Affiliates, and (ii) confirm that Order Nos. 2005 and 2005-A<sup>4</sup> are unaffected by the decision in *National Fuel* to the extent they incorporate elements of Order No. 2004.

#### The Promise of Alaska Natural Gas

Before discussing some of the specifics of the NOPR, the State wants to emphasize, as it has done in other proceedings before the Commission, the vast potential of Alaska natural gas resources to help meet this nation's energy needs. The Prudhoe Bay and Point Thomson fields on the Alaska North Slope, for example, contain 35 Tcf of confirmed gas reserves.<sup>5</sup> With reasonable deliverability assumptions, these fields alone could sustain approximately 4.3 Bcf/day of pipeline throughput for approximately 15-20 years. These resources, however, are only the tip of the iceberg with respect to future gas development in Alaska. Geological information available to the State suggests a mean estimate of conventional, technically recoverable North Slope and offshore arctic gas that exceeds 225 Tcf. The National Petroleum Reserve, the Foothills of the Brooks Range, the central North Slope, and ANWR all have promising natural gas futures. In short, Alaska natural gas is poised to make a huge contribution to help reduce the nation's dependence on foreign sources of oil and gas.

A pipeline, however, must be built to realize the promise of these gas resources. Despite private, federal, and state activity for nearly four decades beginning in 1973, and intense activity during the past three years, there is no pipeline but only a set of proposals to build one. Over the

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<sup>4</sup> *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects*, Order No. 2005, 110 FERC ¶ 61,095 (2005), *order on reh'g*, Order No. 2005-A, 111 FERC ¶ 61,332 (2005).

<sup>5</sup> U.S. Energy Information Administration, Oil and Gas Supply Module, Assumption to the Annual Energy Outlook, *available at* [http://www.eia.doe.gov/oiaf/aeo/assumption/oil\\_gas.html](http://www.eia.doe.gov/oiaf/aeo/assumption/oil_gas.html).

same time period, as lower 48 fields have matured and become less productive, industry has turned to alternative sources of supply, particularly LNG imports from outside the United States. Alaska gas is available in the nation's own backyard and its development should be the first priority of the nation's energy policy.

In addition to its potential to lessen our nation's dependence on foreign hydrocarbons, Alaska's natural gas is fundamental to the State's future well being. The State owns the lands at Prudhoe Bay and Point Thomson that are leased to the developers of those gas fields. The State holds a royalty interest in production from those fields and also levies a gas production tax on production from those fields. A gas pipeline would create a new source of revenue for Alaska as oil revenues taper down. Sarah Palin, Alaska's new Governor, has set efforts to spur development of the gas line as a high priority of her administration.

#### Longstanding Concerns Over North Slope Hydrocarbon Competition

Concerns over competitive conditions on the North Slope for gas (and oil) go back to the early 1970s, shortly after oil was first discovered at Prudhoe Bay in 1968. In 1975, the Federal Power Commission ("FPC") ordered a comparative hearing to select among three potential gas projects originating on the North Slope. In 1976, as the hearing was underway, Congress passed the Alaska Natural Gas Transportation Act ("ANGTA") to expedite and elevate the normal FPC administrative and federal court appellate procedures required for the necessary government authorizations of an Alaska gas transportation system. *Alaska Natural Gas Transportation Act of 1976*, Pub. L. No. 94-586, 90 Stat. 2903 (1976). The ANGTA established a framework for presidential selection of the best delivery system after the comparative hearings before the FPC.

In September 1977, President Carter, in his Decision and Report to Congress on the Alaska Natural Gas Transportation System ("ANGTS"), selected what is now known as the

Alaska Highway route and Alcan Pipeline Company, a subsidiary of Northwest Alaskan Pipeline Company, to build the Alaskan segment of the project. Foothills Pipe Lines, Ltd. was to build the Canadian portion of the ANGTS, and the Northern Border Pipeline Company and Pacific Gas Transmission were to construct the lower 48 portions.<sup>6</sup>

As required by the ANGTA, President Carter explained the rationale of his decision and imposed multiple conditions on the project. Among those conditions was a prohibition barring ANS producers and their affiliates from owning any interest in the pipeline, although they were permitted to guarantee project debt:

“The aforesaid producers of Alaska gas may not be equity members of the sponsoring consortium, having any voting power in the project, have any role in the management or operations of the project, have any continuing financial obligation in relation to debt guarantees associated with initial project financing after the project is completed and the tariff is put in effect, or impose conditions on the guarantees of project debt permitted above which may give rise to competitive abuse, including power to veto pro-competitive policies.” (Executive Office of the President – Energy Policy and Planning, 1977).

As the project sponsors and government agencies worked on the project during the ensuing five-year period, they found that several conditions imposed by the 1977 Decision required revision. As authorized by the ANGTA, President Reagan submitted eight “Waivers of Law” to Congress, and Congress enacted these by Joint Resolution in December 1981. One of these waived the prohibition of producer participation and substituted a requirement that FERC, after advice from the Attorney General, make a determination that there would be no antitrust problems from producer participation. S. Rep. No. 97-272, at 31 (1981). As the administration

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<sup>6</sup> Today, TransCanada is the successor in interest to Alcan Pipeline Company (later renamed Northwest Alaskan Pipeline Company) and Foothills Pipe Lines, Ltd. Foothills is a wholly-owned subsidiary of TransCanada.

explained at the time, a “more thorough analysis of the antitrust issues” revealed that “sufficient antitrust protection” could be achieved by addressing “access and expansion” issues at the time of issuance of the final FERC certificate. All of this effort proved academic because the proposed pipeline was not economically viable. Realistic hopes for a gas pipeline then lay dormant for some two decades.

Fast forward to 2004. In order to encourage the development of an Alaska gas pipeline once again, Congress passed the Alaska Natural Gas Pipeline Act.<sup>7</sup> It directed that in any pipeline certification proceeding, FERC should presume that “a public need exists to construct and operate the proposed Alaska natural gas transportation project.”<sup>8</sup> Addressing competitive concerns again, Congress further directed FERC to issue Alaska-specific open season regulations that, among other things, would “promote competition in the exploration, development, and production of Alaska natural gas.”<sup>9</sup>

The proposed open season regulations were subject to commentary that focused largely on competitive, level playing field issues. For example, the Department of Interior filed comments reflecting its view that North Slope competitive access abuses had in fact occurred. “Clearly, past abuses related to access to facilities have occurred for oil production on the North Slope. Companies interested in pursuing new development in northern Alaska are aware, directly or indirectly, of the past abuses by facility and pipeline owners.”<sup>10</sup> Anadarko, on its part,

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<sup>7</sup> *Alaska Natural Gas Pipeline Act*, Pub. L. No. 108-324, div. C, §§ 101-116, 118 Stat. 1220 (2004). (“ANGPA”).

<sup>8</sup> ANGPA §§ 103(b)(2)(A).

<sup>9</sup> ANGPA §§ 103(e)(2)(B). Congress also approved an unprecedented pipeline expansion provision largely, if not entirely, in response to competitive concerns. *See id.* at § 105.

<sup>10</sup> *Comments of Department of the Interior*, Docket No. RM05-1-000, December 17, 2004, at 7.

emphasized the unique circumstances in Alaska where three companies control the vast majority of the gas reserves currently available for transportation, while others are hoping to successfully explore but are concerned about gas pipeline access issues.<sup>11</sup>

Even a company as large as ChevronTexaco was quite clear that Order No. 2004 requirements were needed in the open season:

ChevronTexaco believes that since any Alaska Gas Pipeline is expected to be operated on an open access basis, the Commission should assess Standards of Conduct-like requirements. That is, before any project sponsor conducts an open season, it must meet the type of guidelines established by the Commission for interstate transporters in Order No. 2004. It is inevitable that project sponsors will need to engage in detailed discussions with potential shippers. The tension presented is the mixed role that many project sponsors may have-in that their affiliates or marketing divisions also might be potential shippers. ChevronTexaco submits that project sponsors should not be permitted to transmit non-affiliate information to affiliates or marketing divisions; rather, they should be required to keep such information confidential.<sup>12</sup>

In its final open season regulations, FERC acknowledged Congress' competitive concerns: "Indeed, the tremendous size, scope, and cost of an Alaskan pipeline, the long lead-time needed for such a project, environmental sensitivities, *and the competitive conditions that are unique to such a project warrant special consideration and oversight.*" Order No. 2005 at ¶ 9 (emphasis added). FERC further found that "there are complex, competitive conditions surrounding an Alaska natural gas transportation project, which are intensified by the generally agreed upon fact that there will be only one such pipeline for the foreseeable future." *Id.* at ¶ 10.

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<sup>11</sup> *Comments of Anadarko Petroleum Corporation*, Docket RM05-1-000, December 17, 2004 at 2.

<sup>12</sup> *Comments of ChevronTexaco Natural Gas*, Docket No. RM05-1-000, December 17, 2004, at 8.

FERC added that “we are well aware of the risks to competition imposed by a project that is owned or primarily sponsored by a small group.”<sup>13</sup> It shaped its open season regulations accordingly, and fashioned detailed provisions to mitigate competitive concerns (e.g., the open season notice provisions of § 157.34).

A few days before Order No. 2005 was issued, Chairman Wood, in a letter to the Alaska House of Representatives Minority Leader Berkowitz, addressed some of the competitive concerns Mr. Berkowitz had raised in an earlier letter about a pipeline owned by the three major North Slope producers. He wrote “it would be prudent to conclude that the antitrust issues which concerned Congress and the President over twenty years ago are still valid and will be addressed by our Commission in our proceedings.”<sup>14</sup> He then added that “the Commission will do everything it can to preclude antitrust abuse and promote competition in the authorization, construction, *and operation* of a future Alaskan natural gas pipeline.” *Id.* (emphasis added).

To ensure that the unique and complex competitive conditions surrounding the Alaska gas project were recognized even at the pre-application open season stage, Order No. 2005 incorporated, for example, relevant portions of the Commission’s previously enacted Order No. 2004 standards of conduct.<sup>15</sup> Order No. 2005 went a step further and required that a separate

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<sup>13</sup> *Id.* at 12. The Commission made similar statements in Order No. 2005-A: “a successful Alaska natural gas transportation project will have to overcome a variety of significant obstacles, including unique and complex competitive conditions ... [and] including the need in certain instances to accommodate existing Commission policy to the unique circumstances surrounding the exploration, production, development, and transportation to market of Alaska natural gas.” Order No. 2005-A at ¶ 36.

<sup>14</sup> Letter from Pat Wood to Ethan Berkowitz, January 28, 2005, at 2, *available at* <http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10402511>.

<sup>15</sup> Order No. 2005 at ¶ 74. Under Order 2004, the standards of conduct do not apply until 30 days after FERC issues a certificate allowing the gas pipeline to begin construction. *See* Order (Footnote continues on next page.)

unit or division be created to conduct the open season and that such unit/division "will be required to function independent of the other non-regulated divisions of the project applicant as well as the project applicant's Marketing and Energy Affiliates and subject to certain provisions of the Standards of Conduct." Order No. 2005 at ¶ 74. While rehearing and/or clarification of various aspects of Order No. 2005 were sought, no commenter took issue with the applicability of the standards of conduct to the open season process.<sup>16</sup>

#### The Court's Remand

In *National Fuel*, the court found Order No. 2004 to be arbitrary and capricious because it extended, without record support, the previous standards of conduct contained in Order No. 497 (which applied only to marketing affiliates) to non-marketing affiliates, *i.e.*, "Energy Affiliates" as defined in Order No. 2005. The court agreed with two dissenting FERC commissioners that "the factual record on which FERC relied was barren and did not contain a single example of abuse involving non-marketing affiliates, much less evidence of an industry-wide problem."<sup>17</sup> The court found that Order No. 2004 had made two fundamental changes from Order No. 497: (i) it extended the standards beyond pipelines' relationship with marketing affiliates to include non-marketing affiliates (Energy Affiliates) – processors, gatherers,

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(Footnote continued from previous page.)

No. 2005 at ¶ 74, n.24. By moving up the applicability date of those standards, FERC was implicitly recognizing Alaska's unique competitive conditions.

<sup>16</sup> The dominant North Slope Producers (ExxonMobil, BP and ConocoPhillips) sought clarification that if a separate entity is created to be the project sponsor, then they need not create still another unit/division to conduct the open season. The Commission concurred that if that project sponsor functioned and operated independently from Marketing and Energy Affiliates, as well as the other divisions of the project applicant, then the creation of a further subdivision would not be necessary. Order No. 2005-A at ¶ 107-108.

<sup>17</sup> *National Fuel*, 468 F.3d at 834. *See also id.* at 841: "Indeed, Order 2004 does not include a single example of abuse by non-marketing affiliates."

producers, local distribution companies, and traders; and (ii) it broadened the standards to cover a pipeline's relationships with an Energy Affiliate even if that Energy Affiliate did not control or hold capacity on that particular pipeline. *Id.* at 838.

The court said that FERC on remand could choose a path of developing a factual record of abuse that justified the reach of Order No. 2004, *id.* at 844, or in the absence of such factual evidence, "FERC may try to support the Standards by setting out its best case for relying *solely* on a theoretical threat of abuse." *Id.* (emphasis in original). The court expressed no view on whether a case could be made that such a theoretical threat alone would justify the reach of Order No. 2004, but cautioned FERC that its analysis of a theoretical threat would have to be thorough and careful. *Id.* at 844-45.

#### The Need for an Alaska North Slope Exception to the Expected Final Rule

Under the NOPR, the standards of conduct do not apply to any relationship between natural gas transmission providers and Energy Affiliates; they only apply to dealings with Market Affiliates. NOPR at ¶ 19. In response to *National Fuel*, FERC has chosen to take neither a path of developing a factual record of energy affiliate/pipeline abuses nor a path of developing a theoretical threat of abuse case. Nor has the Commission expressly asked the public for comments on either of those two paths. It therefore appears highly likely that the final rule will be the same as the proposed rule and encompass only Marketing Affiliates, at least insofar as gas pipelines are concerned.

What this means in a practical sense is that under the NOPR a North Slope producer selling its own gas will not be considered a Marketing Affiliate.<sup>18</sup> Hence an Alaska gas pipeline

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<sup>18</sup> See proposed § 358.3(e)(3)(i): "*Marketing* means a sale of natural gas to any person or entity by a seller that is not an interstate pipeline, except where: (i) The seller is selling gas solely from its own production....." See also proposed § 358.3(k): "Marketing Affiliate means an Affiliate  
(Footnote continues on next page.)

owned in whole or in part by the three major North Slope producers would not be prohibited under the proposed regulations from disclosing commercially valuable information to those producers. For example, the pipeline could selectively disclose pipeline constraint, curtailment, or other critical operational information to affiliates without violating the NOPR. The Commission is correct in pointing out that it has statutory powers under Sections 4 and 5 of the Natural Gas Act to prevent undue preference or undue discrimination. See NOPR at ¶ 17. However, the Commission appears to concede that statutory relief under those sections would be less readily available than would relief under Order No. 2004: "If a transmission Provider provides an undue preference or advantage in favor of an affiliate that is not covered by the standards of conduct, that undue preference *may* still be prohibited by the Natural Gas Act or Federal Power Act." NOPR at ¶ 17 (emphasis added). It stands to reason that an outright prohibition under the standards of conduct against certain dealings with an Energy Affiliate avoids the requirement, as would be necessary under Section 4 or 5, to show that those dealings rose to the level of becoming *unduly* preferential or *unduly* discriminatory.

The Commission is certainly aware that a producer-owned pipeline originating on the North Slope is a very real possibility. Three North Slope producers now own more than 90% of the 35 tcf of confirmed gas reserves, and the potential for a like percentage ownership of a pipeline for those companies must be acknowledged. Whether those three producers own all of the pipeline, a portion of the pipeline, or none of the pipeline, their control over the gas reserves that will provide the initial throughput of the pipeline will give those producers much influence over the rates, and the terms and conditions of service under which the pipeline will transport

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(Footnote continued from previous page.)

as that term is defined in § 358.3(b) or a unit that engages in marketing, sales or brokering activities as those terms are defined § 358.3(c)."

natural gas. The three producers will also influence the criteria used to award and allocate capacity in any open season as well as the timing of any open season. These facts make the situation far different than in the lower 48, where producers and pipeline owners for a project are typically or largely unaffiliated. Also, while in the lower 48 there are often competing pipelines, it is generally accepted that the North Slope most likely will be served by only one large diameter gas pipeline.

The State takes no position on the propriety of the NOPR's proposed approach with regard to lower 48 gas pipelines. Nor does the State object to that proposed approach being applied to Alaska gas pipelines not originating on the North Slope, *e.g.*, those in Cook Inlet. However, the State submits that the Commission-found unique competitive conditions surrounding the North Slope gas project do indeed "warrant special consideration and oversight." *See* Order No. 2005 at ¶ 9. The past concerns over various aspects of North Slope gas competition, discussed *supra*, and the continuing concentration of reserves ownership in three companies sets Alaska apart from the lower 48 and justifies the continued application of the more sweeping standards of conduct contained in Order No. 2004. The State submits that it is better to put safeguards in place now in the form of the Order No. 2004 requirements than to try later to unscramble abuses after the fact.

The State does recognize that *National Fuel* evidenced skepticism in the Commission's being able to justify Order No. 2004 solely on a theoretical abuse basis. While that skepticism may be well founded for the lower 48, where there are many existing pipelines and thus plenty of opportunity to show actual (as opposed to theoretical) abuse, that is not the situation in Alaska. Order No. 2004 had no reason to, and did not, discuss Alaska separately, and thus the court was unlikely to have considered or even been aware of the unique situation on the North Slope. If

there is any situation where the theoretical threat alone would be sufficient to justify an order extending the standards of conduct to Energy Affiliates, it is for this yet-to-be-built North Slope project. Because the North Slope project has yet to be certificated much less built, there literally can be no factual evidence of abuse between unknown marketing/non-marketing affiliates and an unknown pipeline company. However, Congress and the Executive Branch have repeatedly voiced their concerns about competition in the exploration, development, and production of Alaska natural gas and the potential for abuse. This justifies the Commission taking the action the State requests.

To accomplish this exception, the State recommends that the following italicized words be added to § 358.1(e):

*“The Standards of Conduct in this part do not govern the relationship between a natural gas Transmission Provider as defined in § 358.3(a)(2) and its Energy Affiliates, except for a Transmission Provider carrying natural gas from Alaska’s North Slope to destinations in the lower 48 states, and its Energy Affiliates.*

The Commission Should Confirm that Order Nos. 2005 and 2005-A Remain Intact

As noted above, Order No. 2005 incorporated relevant portions of the Order No. 2004 standards of conduct and made them applicable to the open season process. See Order No. 2005 at ¶ 74. The incorporation included prohibited dealings between a North Slope gas pipeline and its Energy Affiliates. Also as noted, no challenge was made to the Commission’s holding on the applicability of Order No. 2004. However, in light of the D.C. Circuit’s action in *National Fuel*, an argument could be fashioned that the vacated portions of the standards of conduct incorporated into Order No. 2005 are no longer binding unless the Commission addresses Order No. 2005 in its final rule in this proceeding.

This argument fails for at least two reasons. First, the Order No. 2004 standards of conduct apply only to a certificated pipeline. See Order No. 2005 at ¶ 74 n.24. Order No. 2005 takes portions of Order No. 2004 and applies it to an entirely new and different situation -- an open season that will take place well before the certificate stage. Order No. 2005 also has an independent foundation, Section 103(e) of the ANGPA. The Commission found based on the record in the Order No. 2005 proceeding that North Slope competition concerns justified its action. No one has appealed that aspect of Order No. 2005 and it is thus final and non-appealable.

Second, even though the same standards applied to all Transmission Providers, the court vacated the standards of conduct only for natural gas Transmission Providers and thus did not treat all Transmission Providers the same. The court left the standards intact for electric Transmission Providers because no one appealed their applicability to electric services. Just as the court implicitly viewed electric Transmission Providers as performing a different service than natural gas Transmission Providers, the Commission should view the open season "service" as being different than that provided by natural gas Transmission Providers -- one unaffected by the holding in *National Fuel*.

Nonetheless, the State recommends that the Commission err on the side of caution and presume that *National Fuel* does have an impact. The Commission can negate this presumed impact by simply confirming that Order Nos. 2005 and 2005-A remain intact because those orders are necessary to address the unique competitive concerns surrounding an open season for the North Slope project.

Respectfully submitted,

/s/ Robert H. Loeffler

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Dated: March 30, 2007

CERTIFICATE OF SERVICE

I, Edward J. Twomey, hereby certify that on March 30, 2007, copies of the foregoing COMMENTS OF THE STATE OF ALASKA ON PROPOSED RULEMAKING in the above-captioned proceedings were served upon each person designated on the service list compiled by the Secretary in these proceedings.

/s/ Edward J. Twomey  
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UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

Standards of Conduct for  
Transmission Providers

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Docket No. RM07-1-000

REPLY COMMENTS OF  
ANADARKO PETROLEUM CORPORATION

INTRODUCTION

On January 18, 2007, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued a Notice of Proposed Rulemaking proposing revisions to the Standards of Conduct for transmission providers ("Standards of Conduct NOPR").<sup>1</sup> On March 30, 2007, the State of Alaska submitted timely Comments on the proposed rule, directed solely at the relationship between this rulemaking proceeding and federal regulation of an Alaska natural gas transportation project. Anadarko Petroleum Corporation ("Anadarko"), an oil and gas exploration company with significant gas-prone acreage in the State of Alaska, hereby submits Reply Comments supporting the Comments filed by the State of Alaska.

Anadarko joins the State of Alaska in its request that the Commission (1) make it clear that the Standards of Conduct for an Alaska natural gas transportation project apply to the relationship between the project sponsor's and the ultimate pipeline's relationship with *both* its "Marketing Affiliates" and "Energy Affiliates", and (2) confirm that the requirements of Order Nos. 2005 and 2005-A, relating to the conduct of open seasons for an Alaska natural gas

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<sup>1</sup> *Standards of Conduct for Transmission Providers*, Notice of Proposed Rulemaking, 118 FERC ¶ 61,031 (2007).

transportation project,<sup>2</sup> remain unaltered by this Commission's actions on remand of *National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (D. C. Cir. 2006) ("*National Fuel*").

## BACKGROUND

### 1. Competitive Concerns Affecting The Alaska Natural Gas Pipeline

In Order Nos. 2005 and 2005-A, the Commission promulgated its first rules relating specifically to an Alaska natural gas transportation project. The rules were promulgated to satisfy a Congressional directive in the Alaska Natural Gas Pipeline Act, 15 U.S.C. § 720, *et seq.* ("ANGPA") that the Commission promulgate specific rules formalizing for an Alaska pipeline the Commission's policy that all new pipeline construction be preceded by a non-discriminatory "open season." The open season is the process through which potential shippers bid on capacity on the pipeline, as designed by the project sponsor. It culminates in a final project design and the execution of precedent agreements between the project sponsor and the prospective shippers for some or all of the design capacity of the project.

In enacting the ANGPA Congress was cognizant of the fact that virtually all of the natural gas that would be available for commitment to an Alaska pipeline in the initial open season would be the Prudhoe Bay/Point Thomson reserves, identified as a result of the development of the Prudhoe Bay/Point Thomson oil and gas fields. Over 90% of these reserves are owned by three producers – ExxonMobil Corporation, ConocoPhillips Company, and BP Exploration (Alaska) Inc. ("North Slope Producers") – the self-declared Alaska pipeline project sponsors. Therefore, to ensure that potential competitors of the North Slope Producers will have access to the pipeline, and, thereby, be positioned to move forward in their exploration programs, Congress required that the Commission's open season regulations "promote competition in the

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<sup>2</sup> *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects*, Order No. 2005, 110 FERC ¶ 61,095 (2005), *order on reh'g*, Order No. 2005-A, 111 FERC ¶ 61,332 (2005).

exploration, development, and production of Alaska natural gas" and, as to open seasons for capacity exceeding the initial capacity, that the regulations provide the opportunity for gas other than that from Prudhoe Bay and Point Thomson to be transported through the pipeline.

To develop the rules, the Commission compiled a substantial record, receiving both written comments and oral testimony from many parties, including the State of Alaska, certain Alaskan elected officials, Alaskan Natives, representatives of potential project sponsors – both the North Slope Producers and independent pipeline companies, potential shippers – including the North Slope Producers and explorers, representatives of state and federal agencies, and the general public.

A primary concern expressed by the State of Alaska, explorers, independent pipeline companies, and federal and state agency representatives, was the fact that the North Slope Producers intend to own and/or control the pipeline, and, were they to succeed in doing so, would have every incentive to enhance and solidify their dominance in the Alaska natural gas production market through their control over the Alaska natural gas pipeline. This expressed concern related not only to the open season process but also to the on-going operating conditions of the pipeline. As to open seasons, the primary concern expressed by these parties is the pipeline's ability to hold open seasons for expansion capacity under conditions that could tilt the balance toward their own production – either through timing, rates, or terms and conditions of service. If the North Slope Producers controlled the pipeline, the Commission was told, the risk would be significant that the North Slope Producers would give themselves preferential access to the pipeline and preferential terms and conditions of service in order to enhance their already dominant market position in Alaska.

These competitive concerns are not new, as noted in the Comments filed by the State of Alaska. Rather, they date back to the Alaska Natural Gas Transportation Act of 1976 (“ANGTA”),<sup>3</sup> in the very early stages of the effort to develop a natural gas pipeline to transport Alaska’s North Slope gas to markets in the lower 48 states. That the concerns remain today is clear from the record in Docket No. RM05-1, and ANGPA itself, where Congress directed the Commission to ensure that the rules governing access to the pipeline will “promote competition in the exploration, development, and production of Alaska natural gas.”<sup>4</sup>

The need to establish a level playing field for explorers, both in terms of obtaining capacity and in terms of receiving service, was a fundamental objective of the Commission’s rulemaking proceeding in Docket No. RM05-1. To address the competitive concerns, the Commission found it necessary to impose “strict requirements on all proposals, and *particularly on affiliate-owned projects*, with respect to the public disclosure of information.”<sup>5</sup> Concerned that even with the informational disclosure requirements there would still be an unacceptable risk that the producer and/or marketing affiliates of a project applicant would have an advantage over non-affiliates, the Commission specifically incorporated into its Order No. 2005 rules certain of the Standards of Conduct promulgated in Order Nos. 2004 *et seq.* to govern the relationship between the project sponsor and any of its marketing or energy affiliates. Moreover, faced with the prospect that the North Slope Producers, themselves, will be the project sponsors conducting the open seasons for capacity on the Alaska pipeline, the Commission required that any project applicant create a unit or division to conduct the open season, which unit or division “will be required to function independent of the *other non-regulated divisions* of the project applicant as

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<sup>3</sup> Pub. L. No. 94-586, 90 Stat. 2903 (1976).

<sup>4</sup> ANGPA § 103(e)(2)(B).

<sup>5</sup> *Id.*

well as the project applicant's Marketing and Energy Affiliates."<sup>6</sup> Through this rule, the Commission independently adopted and made applicable to project applicants conducting an open season for an Alaska natural gas transportation project the following regulations, initially promulgated in Order Nos. 2004 *et seq.*: separation of functions (18 C.F.R. §§ 358.4(a)(1), (3), (4), (5) and (6) and (b)(e)(3), (5) and (6) (2004)); information access (18 C.F.R. § 358.5(b) (2004)); prohibitions against discrimination (18 C.F.R. § 358.5(c)(5) (2004)) and discounts (18 C.F.R. § 358.4(d) (2004)).<sup>7</sup> The Commission's application of these regulations to an Alaska natural gas transportation project was not the subject of a rehearing request in Docket No. RM05-1 and was not the subject of the court appeal filed in that rulemaking docket.

## 2. The Standards of Conduct As They Relate To An Alaska Natural Gas Pipeline

The Commission's rulemaking adopting Standards of Conduct for transmission providers in Order Nos. 2004 *et seq.*, as it relates to interstate pipelines, had its genesis in the Standards of Conduct developed in Order No. 497, *et seq.*<sup>8</sup> These rules were intended to address the propensity of interstate natural gas pipelines to grant special preferences to their marketing or brokering affiliates over non-affiliate<sup>9</sup> The Alaska pipeline was not a focus of the rule. The Commission subsequently promulgated similar Standards of Conduct for electric transmission providers.<sup>10</sup> In an effort to develop one rule applicable to all transmission providers, gas or electric, the Commission synthesized and expanded the application of its Standards of Conduct

<sup>6</sup> Order No. 2005 at P 74.

<sup>7</sup> See Order No. 2005 at P 74.

<sup>8</sup> *Inquiry Into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines*, Order No. 497, FERC Stats. & Regs. Regulations Preambles 1986-1990 ¶ 30,820 (1988); *order on reh'g*, Order No. 497-A, FERC Stats. & Regs. Regulations Preambles 1986-1990 ¶ 30,868 (1989); *order extending sunset date*, Order No. 497-B, FERC Stats. & Regs. Regulations Preambles 1986-1990 ¶ 30,908 (1990); *order extending sunset date*, Order No. 487-C, FERC Stats. & Regs. Regulations Preambles 1991-1996 ¶ 30,934 (1991), *reh'g denied*, 58 FERC ¶ 61,139 (1992); *aff'd in part and remanded in part sub nom. Tenneco Gas v. FERC*, 969 F.2d 1187 (D.C. Cir. 1992).

<sup>9</sup> See Order No. 497 at ¶ 31,127; *Tenneco Gas*, 969 F.2d at 1194 (D.C. Cir. 1992)

<sup>10</sup> See *Open Access Same-Time Information System and Standards of Conduct*, Order 889, FERC Stats. & Regs. Regulations Preambles Jan. 1991- Jan. 1996 ¶ 31,035 (1996).

rules in Order Nos. 2004, *et seq.* to govern not only the relationship between transmission providers and their “Marketing Affiliates,” but also the relationship between transmission providers and their “Energy Affiliates.”<sup>11</sup> As relevant here, a “Marketing Affiliate” excludes sellers that sell gas solely from their own production or solely from their own gathering or processing facilities.<sup>12</sup> Therefore, with respect to an Alaska pipeline, the Standards of Conduct would not apply to the relationship between the pipeline and its producer affiliates if the rule were restricted to “Marketing” rather than “Energy” affiliates of the pipeline.

In *National Fuel*, the United States Court of Appeals District of Columbia Circuit vacated Order Nos. 2004, *et seq.* as applied to interstate pipelines, noting that while the court had affirmed the rules developed in Order Nos. 497, *et seq.* governing the relationship between interstate pipelines and their “Marketing Affiliates”<sup>13</sup> there was no record evidence in the Order No. 2004 proceeding supporting the extension of the restrictions to the pipeline’s “Energy Affiliates.”

As a result of the court’s decision in *National Fuel*, the Commission is proposing in this rulemaking to eliminate the restrictions that Order Nos. 2004 *et seq.* placed on the relationships between an interstate pipeline and its “Energy Affiliates” and to reinstate the Order Nos. 497, *et seq.* “Marketing Affiliate” rules. The proposed rule in this proceeding makes no distinction between the application of the “Marketing Affiliate” rules to interstate pipelines, in general, and the application of those rules to an Alaska natural gas transportation project, despite the Commission’s action in Order Nos. 2005 and 2005-A. As explained in greater detail below, it is

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<sup>11</sup> See *Standards of Conduct for Transmission Providers*, Order No. 2004, FERC Stats. & Regs., Regulations Preambles, 2001-2005 ¶ 31,155 (2003); *order on reh’g*, Order No. 2004-A, FERC Stats. & Regs., Regulations Preambles, 2001-2005 ¶ 31,161 (2004); *order on reh’g*, Order No. 2004-B, FERC Stats. & Regs., Regulations Preambles, 2001-2005 ¶ 31,166 (2003); *order on reh’g*, Order No. 2004-C, FERC Stats. & Regs., Regulations Preambles, 2001-2005 ¶ 31,172 (2004); *order on reh’g*, Order No. 2004-D, 110 FERC ¶ 61,320 (2005).

<sup>12</sup> See, proposed §§ 358.3(e)(3)(i) and (ii).

<sup>13</sup> *Tenneco Gas v. FERC*, 969 F.2d 1187 (D.C. Cir. 1992).

important that the Commission clarify that its proposed rulemaking in this docket does not impact the adoption of the specific regulations implementing the Standards of Conduct governing the relationship between an Alaska natural gas transportation project, its sponsors, and their Marketing and Energy Affiliates under Order Nos. 2005 and 2005-A.

### DISCUSSION

Anadarko fully agrees with and supports the State of Alaska's request that the Commission confirm that the regulations promulgated by Order Nos. 2005 and 2005-A remain intact, including the application of § 157.34(c)(18)-(21), §157.35(c) – (d) to an Alaska natural gas transportation project and its sponsors. Further, Anadarko supports the request by the State of Alaska that the Commission modify its regulations at § 158.1(e) to confirm that the Standards of Conduct govern the not only the relationship between an Alaska natural gas transportation project, its sponsors, and their Marketing Affiliates, but also the relationship between an Alaska natural gas transportation project, its sponsors, and their Energy Affiliates. It is also important that the Commission confirm that as to an Alaska natural gas pipeline, the Standards of Conduct apply in the pre-certification open season process, as provided in Order Nos. 2005 and 2005-A. In this regard, Anadarko respectfully submits that the *National Fuel* decision does not affect the Commission's regulations promulgated in Order Nos. 2005 and 2005-A.

At the heart of the court's decision in *National Fuel* is the proposition that vertical integration creates efficiencies and benefits for consumers, and, therefore, the Commission "cannot impede vertical integration between a pipeline and its affiliates without adequate justification."<sup>14</sup> This proposition derives from the D.C. Circuit's earlier analysis in *Tenneco*, where it found that "in a competitive market, the efficiencies of the pipeline-affiliate relationship

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<sup>14</sup> See *National Fuel Gas Supply Corp.*, 468 F.3d at 840 (citing *Tenneco Gas v. FERC*, 969 F.2d 1187, 1199 (D.C. Cir. 1992)).

should produce benefits for consumers.” The *National Fuel* court further commented that “advantages a pipeline gives its affiliate are improper only to the extent that they flow from the pipeline’s anti-competitive market power; otherwise, vertical integration produces permissible efficiencies that cannot by themselves be considered uses of monopoly power.”<sup>15</sup> Because the Commission did not have specific findings of affiliate abuse between a pipeline and its Energy Affiliates, the *National Fuel* court vacated Order No. 2004’s application of the Standards of Conduct to the relationship between a pipeline and its Energy Affiliates.

But, the rationale of *National Fuel* does not apply to an Alaska natural gas transportation project. Firstly, an Alaska natural gas transportation project will be a monopoly. Secondly, the North Slope Producers own over 90% of the natural gas reserves initially available for transportation through the pipeline. Thirdly, the North Slope Producers may well own or control, either themselves or through affiliates, the Alaska natural gas transportation project. Finally, Congress has recognized the unique competitive issues applicable to the development of Alaska natural gas and access to the pipeline by directing the Commission to promulgate regulations governing access to that pipeline that promote competition in the exploration, development and production of Alaska natural gas.

It can safely be said that the market for interstate pipeline capacity in Alaska is *not competitive*. It can also safely be said that the North Slope Producers’ control over the gas reserves that will anchor the project, and their resultant ability to influence the terms and conditions of access to the pipeline, create serious competitive concerns for explorers. These concerns take on added significance in the likely circumstance that the North Slope Producers will own or control the pipeline, either directly or through affiliates. The Commission

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<sup>15</sup> See *National Fuel Gas*, 468 F.3d at 840 (citing *Tenneco*, 969 F.2d at 1205)

recognized as much in Order No. 2005 when it stated: “the competitive conditions that are unique to such a project warrant special consideration and oversight.”<sup>16</sup>

This is not the natural gas market addressed by the D.C. Circuit in *National Fuel*. This is the Alaska natural gas market – a market with respect to which the Commission received considerable evidence during the rulemaking proceeding in Docket No. RM05-1, and which has been the subject of substantial competitive analyses since the 1970’s, during which time the United States Department of Justice (“DOJ”) conducted an extensive study into the anticompetitive issues related to an Alaska natural gas pipeline.<sup>17</sup> Even then, DOJ identified serious anticompetitive concerns associated with a producer-sponsored Alaska natural gas pipeline, concluding that “an ownership interest, or participation in any form in the transportation system, by producers of significant amounts of natural gas, or their subsidiaries or affiliates, should be prohibited.”<sup>18</sup> The DOJ Report discusses not only competition concerns at the very outset of the pipeline planning process, but also competition concerns after the initial construction, noting: “[W]e cannot say that the problem has been solved just because initial pipeline capacity seems adequate (indeed, even if initial capacity strains technical construction and operating capabilities). For the case we are concerned with includes future efforts by other producers to enter the Alaskan field and consequential needs for expanded pipeline capacity . . . . Producer-ownership of the pipeline creates incentives to deny or impede such future capacity expansion.”<sup>19</sup>

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<sup>16</sup> See Order No. 2005 at P 3.

<sup>17</sup> See Report of the Attorney General Pursuant to the Alaska Natural Gas Transportation Act of 1976 (July 1977) (“Attorney General Report”).

<sup>18</sup> *Id.* at p. 80; see also *id.* at pp. v, 29, 30.

<sup>19</sup> *Id.* at p. 39.

The competitive environment in Alaska has not improved since the time of the DOJ Report. In fact, if anything, it has worsened, with the North Slope Producers now owning or controlling over 90% of the discovered natural gas reserves on the North Slope. Faced with these competition concerns and Congressional directives, as well as the extensive record in the RM05-1 rulemaking proceeding, the Commission's decision to apply the Standards of Conduct to the Energy Affiliates, as well as the Marketing Affiliates, of an Alaska natural gas transportation project, and to do so from the outset, is fully justified. Thus, even if the Commission were to have to justify its application of those rules to an Alaska natural gas pipeline project, it could clearly do so.

But, *National Fuel* is simply inapposite. The risk of anti-competitive conduct relating to access to an Alaska natural gas pipeline controlled by the North Slope Producers has been fully recognized by Congress and by the Commission. Here, the threat of a producer-owned or controlled pipeline enabling its producer affiliates to secure capacity under terms and conditions not generally available to their non-affiliated competitors or otherwise to benefit from non-public information or knowledge about the operations and plans of the transmission system is readily apparent. The threat, here, like in *Tennaco*, stems directly from the pipeline's monopoly position and the North Slope Producers' control over Alaska's immediately available reserves. The facts are clearly different from those in *National Fuel*.

Finally, as explained by the State of Alaska, and as noted above, the Commission's regulations applying the Energy Affiliate rules to an Alaska natural gas transportation project were not challenged by any party to the proceeding and, therefore, are final and non-appealable. Accordingly, the Commission should confirm that these regulations remain in full force and effect, notwithstanding *National Fuel*.

CONCLUSION

For the reasons set forth above, Anadarko supports the Comments filed by the State of Alaska and urges the Commission to clarify that its open season regulations promulgated in Order Nos. 2005 and 2005-A remain in full force and effect and are not in any way affected by the Commission's actions in this rulemaking proceeding. In addition, Anadarko supports Commission adoption of the suggested clarification to its regulations, as requested by the State of Alaska.

Respectfully submitted,

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Dated: April \_\_\_\_, 2007

Anadarko Petroleum Corporation

Paper on Alaska Gas Line Issues

Relative To the Alaska Natural Gas Pipeline Act of 2001

August 2001

Note: This paper was prepared before Congress enacted legislation relative to the Alaska Gas Line and before FERC adopted its open season regulations. Some issues raised in this paper have been addressed. It is being distributed because much of the background is still relevant in June of 2006.

Rationale for Modifications to  
Alaska Natural Gas Pipeline Act of 2001

**BACKGROUND**

The natural gas pipeline required to deliver Alaskan North Slope ("ANS") natural gas reserves to Western Canada and the U.S. Lower 48 States is a massive undertaking. It is anticipated that an 1,800 mile-large diameter pipeline will need to be constructed to Alberta, Canada. This ANS gas pipeline is expected to have an initial capacity of about 4 Bcfd.

In addition, it is assumed that the existing pipelines emanating out of Western Canada to market centers in Eastern Canada, the U.S. Midwest, and U.S. Pacific Coast will not have sufficient excess capacity to transport all of this new Arctic gas supply to market centers. Therefore, it is anticipated that another 1,800 miles of new pipeline, of somewhat smaller diameter will have to be installed to transport ANS gas to markets. Including the cost of a gas conditioning plant and the anticipated need for new pipeline facilities all the way to U.S. market centers (e.g. Chicago), the project sponsors (Exxon, BP, and Phillips) have been quoting total costs for this ANS gas pipeline project in the \$15 - \$20 billion range.

The 1,800-mile ANS to Alberta portion of the pipeline alone will be the largest, most expensive pipeline project ever undertaken. Cost estimates for this portion of the project, excluding ancillary services such as gas conditioning, run in the \$7 - \$10 billion range.

The ANS reserves anchoring the proposed pipeline are predominately held by three multinational oil companies, BP, Exxon-Mobil, and Phillips. These three majors, own more than 98% of the gas reserves in the giant Prudhoe Bay Unit and nearly 80% of the gas reserves in the second largest North Slope gas accumulation, Point Thomson Unit. Together, these two fields represent more than 30 Tcf of the 35 Tcf of proved ANS gas reserves. In addition, BP, Exxon-Mobil, and Phillips own the overwhelming majority of the remaining ~ 5 Tcf of proven gas reserves attributable to the other North Slope oil and gas fields. On a volume-weighted basis, these three companies control more than 90% of the proven North Slope gas reserves.

This dominant market position and power held BP, Exxon-Mobil, and Phillips is a competitive concern and threat to other natural gas explorers in northern Alaska. By holding practically all of the ANS gas reserves, these three companies also control all of the critical facets of the pipeline required to monetize the vast North Slope natural gas reserves and even far greater gas resources. The proven natural gas reserves on the North Slope are equivalent to nearly 25% of the proven natural gas reserves in the U.S. Lower 48 states.

Exxon-Mobil, BP, and Phillips have undertaken a detailed, \$100 million feasibility study to determine the economic feasibility and routing for the required ANS gas pipeline. The feasibility study is scheduled to be completed by years' end.

## CONCERNS

### Anti-Competitive / Market Concentration Issues

With more than 90% of the natural gas reserves concentrated among three companies, these companies wield unnatural and de facto monopolistic market powers. These three companies will control all of the commercial issues surrounding an ANS gas pipeline and are poised to exercise their market powers to the detriment of all competing ANS gas explorers.

Access to the ANS gas pipeline is of paramount importance. Without access to the pipeline, natural gas explorers' gas discoveries will be of no value. There is a very real fear that Exxon-Mobil, BP, and Phillips will secure all of the pipeline capacity. Those shut-out of the pipeline initially will have to either (1) await spare capacity after initial fields have declined; (2) seek release capacity from the shippers that secured the initial capacity; or (3) sell their discoveries at distressed prices to the holders of the pipeline capacity.

Each of these options is either unrealistic or extremely onerous to the explorers. In the first case, gas reserves and expected production rates from the Prudhoe Bay and Point Thomson Units will likely keep a 4 Bcf/d pipeline at capacity for nearly twenty (20) years. In addition, BP and Phillips each hold huge acreage positions from which they are expected to be able to replace Prudhoe Bay and Point Thomson production declines. Therefore, if the three dominate gas reserve holders secure all of the initial pipeline capacity, it is likely that they will be able to keep the pipeline full with their own equity production for decades.

Relying upon released capacity from the shippers securing capacity on the pipeline is also an onerous option due to the provisions of FERC Order 637. Under Order 637, the shippers releasing capacity to other are not bound by the maximum tariff imposed by the FERC at the outset of the pipeline capacity contractual process. Therefore, holders of the capacity can either release capacity to the explorers at whatever tariffs the market will bear, or similarly offer to buy the explorers' gas at distressed prices.

Explorers need look no further than the recent past in Western Canada for an example of how holders of transportation capacity can drive wellhead prices to severely low levels during periods that transportation capacity is in short supply. During the year 1996, Western Canadian gas prices averaged \$1.03 per MMBtu, while U.S. gas prices averaged \$2.51 per MMBtu (Henry Hub, Louisiana). The Western Canada prices should have averaged more like \$1.80 per MMBtu, based solely upon transportation cost differentials. However, pipeline capacity out of Western Canada was constrained and as a result,

Western Canadian gas prices were more than 40% lower than they should have been. Parties holding the scarce pipeline capacity were the segment of the industry that reaped the nearly \$0.75 per MMBtu windfall. This windfall represents 70 – 75% of the wellhead prices realized to find, develop, and produce the natural gas.

Lastly, if Exxon-Mobil, Phillips, and BP hold all or nearly all of the capacity on the pipeline, other petroleum companies will be at their mercy in order to secure transportation of all new natural gas discoveries. The big three producers could deny the purchase or transport of their competitors' natural gas with the intention of driving them out of business and/or forcing the distressed sale of their properties.

Manipulation of the pipeline access and tariffs in Alaska by the major players to the detriment of the second tier companies has a storied history in Alaska. Companies that exited Alaskan North Slope exploration and production in the 1980's and 1990's, such as Conoco, have been very open and vocal that they were squeezed out of their North Slope properties due to unfair manipulation of the Trans-Alaskan Oil Pipeline (TAPS).

Just last week (August 9, 2001), the *Calgary Herald* carried a story about the Arctic gas pipeline situation in which Conoco's CEO Archie Dunham cited anti-competitive operation of TAPS for his vehement insistence that Conoco have an ownership in any Arctic gas pipeline serving the Canadian Mackenzie Delta region. The article stated in part, "Dunham defended his hard-line position by citing Conoco's woes in Alaska in the early 1990's when it felt it couldn't get full value for its resources because it did not own a stake in the Trans-Alaska pipeline. 'The owners of the pipeline, by adjusting tariffs on the pipeline, could really diminish the value of producing properties and that's not going to happen again,' pledged the CEO of the Houston-based company."

The remote location of the Alaskan North Slope, for all intents and purposes, creates a natural monopoly for the pipeline owners and capacity holders. The 1,800 miles of pipeline and \$7 - \$10 billion of capital outlays to build the pipeline's initial pipeline leg to Alberta, Canada represent very real barriers to entry. In all likelihood, there will never be another gas pipeline built from the North Slope to Western Canada and the Lower 48 states. In order to build another pipeline, another 30 Tcf of natural gas reserves will have to be discovered and shut-in awaiting pipeline outlet. It is extremely unlikely that petroleum companies will spend the money to prove-up another 30 Tcf to justify a second, competing pipeline. It has taken more than 20 years for there to be sufficient economic inertia to drive the probable construction of the first such pipeline.

In all probability, the ANS gas pipeline project that is currently being controlled by BP, Phillips, and Exxon-Mobil, will be the only gas pipeline built to the Lower 48 states from the ANS. Therefore, the dominant producers, BP, Exxon-Mobil, and Phillips, are poised to control construction of the pipeline, as well as the throughput capacity. BP, Exxon-Mobil, and Phillips will enjoy monopolistic power over the North Slope gas pipeline and by extension hold a monopoly over the exploration and production of Alaskan North Slope natural gas.

### Non-Discriminatory, Open-Access Is a Misnomer

There is a common misconception that, as an interstate natural gas pipeline that falls under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), access to the pipeline by all comers will not be an issue. The FERC regulates interstate pipelines under a non-discriminatory, open-access mandate. However, under the circumstances of this pipeline, non-discriminatory, open-access statutes are of dubious value and comfort to the exploration and production companies other than Phillips, Exxon-Mobil, and BP.

FERC regulated natural gas pipelines are generally known as "contract carriage" pipelines. Under such a regime, the parties desiring transportation service ("shippers") contract for capacity to the pipeline. In areas with little or no direct competition, most, if not all of the capacity is contracted for on a firm basis for extended periods, such as 10 or 20 years. Once the capacity has been fully subscribed, only interruptible or capacity released, or sublet, by such firm shippers is available to parties unable to secure firm transportation services at the outset. As discussed above, if the holders of the firm capacity are direct competitors of the parties desiring new pipeline capacity, the firm capacity holders are likely to take economic advantage by charging excessive tariffs for its released capacity. In other words, potential shippers that fail to secure capacity on the pipeline under firm contracts at the outset, face having no access to capacity, or access at unattractive and even detrimental tariffs.

This "contract carriage" system of capacity allocation differs greatly from the standard for allocation of capacity on oil pipelines. Oil pipelines are generally structured as "common carriers". Capacity on a common carrier pipeline is always allocated on a pro rata basis. If shippers, both existing and new, tender more oil to the pipeline than there is capacity, then all shippers, both existing and new, are prorated such that each shipper is allocated a proportionate share of the pipeline capacity. Therefore, failure to secure transportation capacity at the outset of an oil pipeline's operation is not nearly as onerous as the situation related to securing capacity on a natural gas pipeline. New comers are afforded a pro rata share of the pipeline capacity regardless whether they had achieved capacity at any prior point.

With respect to the allocation of capacity on a "contract carriage" natural gas pipeline, the capacity is generally bid for during an "open season" process. The open season is a relatively short, typically 30-day, period for which bids are taken. If all of the capacity is subscribed for on a firm basis during the open season, no capacity may be available on the pipeline for a very long period, up to 20 years or more.

Therefore, the "non-discriminatory, open access" process is not synonymous with free access to the pipeline at any point in time. In fact, in a pipeline such as the Alaskan natural gas pipeline, access to the pipeline will likely be limited to those companies that successfully bid for capacity during the 30-day open season. Thereafter, for up to 20 years or longer, all other interested shippers will be either at the mercy of those securing capacity in the open season, or potentially completely shutout.

### Open Season Process and Oversight

Generally, the open season process is either lightly regulated or not regulated at all. One of our concerns is that the pipeline sponsors will keep all potential shippers and other stakeholders in the dark as to the operational and commercial characteristics for the pipeline until announcing the open season. By controlling the information disclosed and the timing thereof, the project sponsors can limit the number and effectiveness of those shippers interested in bidding for pipeline capacity in the open season. This concern is exacerbated by the fact that the project sponsors are the major reserves holders on the Alaskan North Slope and can use this "control" of information to their competitive advantage over competing exploration and production companies.

Our proposed resolution of this potential anti-competitive situation is to require at least a 90-day notice period prior to the start of the open season and further require disclosure of critical information needed to make an informed and competitive bid for capacity. The type of information that we seek in our "pre-open season disclosure" includes: specifications of the proposed pipeline such as route, diameter of pipe, operating pressures, pipeline capacity and the amount available for transportation, gas quality specifications, anticipated tariff rates, delivery and receipt points, tariff structure, bidding procedures in the open season, methodology utilized in determining capacity awards, allocation procedures for capacity in the event of receiving bids of equal value and the inclusion of the precedent agreement. This detailed document should provide sufficient information to allow an interested party to make an informed, competitive bid for capacity on the proposed pipeline.

Another major concern regarding the securing of pipeline capacity is the potential for the project sponsors to "hold-back" capacity from the open season process. A number of recent FERC regulated natural gas pipelines have been implemented allowing sponsor holdbacks of up to 50% of the ultimate capacity. Under such a scenario, not only will non-owners desiring capacity be at a major knowledge disadvantage in competing for capacity at the open season, as much as one-half of the pipeline capacity may be withheld for the project sponsors prior to the advent of the open season. Again, given the fact that this pipeline is likely to be the only gas pipeline constructed from the Alaskan North Slope to the Lower 48 states, none of the capacity should be permitted to be withheld from the open season.

Lastly, the determination process for awarding of winning bids during the open season should be set out in the pre-open season announcement. Potential shippers that are not pipeline owners must be afforded an even playing field in the competition for finite transportation capacity. All bids submitted for the maximum allowable tariff and for the full contract term should be allocated a full pro rata share of the pipeline capacity, up to the capacity bid for by such shippers. For this purpose, the maximum contract term used in assessing the bids should be capped at some reasonable term, such as 10 or 20 years. Again, producer owners of the pipeline will have an unfair economic advantage in bidding longer terms, if a reasonable truncation is not imposed.

## Tariff Issues

There are a number of components within the tariff structure that could be crafted by the pipeline sponsors that we would favor themselves at the expense of their competitors. One of the major concerns is the amortization period used in the tariff calculation for the recovery and return on capital investments. If a relatively short amortization period were permitted, the resultant tariff would be excessively high. If high pipeline tariff would reduce the netback gas price received by the gas producers. Given the remote location and seasonal drilling limitations associated with the Alaskan North Slope, it is expected that new natural gas developments will be quite expensive. If the pipeline tariff is too high, the wellhead price could be driven to unattractive or even uneconomic levels.

If the major North Slope producers are also major equity owners in the pipeline, they will be insulated from the adverse impact of such high tariffs and will have preferentially better project economics than non-pipeline owner petroleum companies. This is precisely the anti-competitive situation that Conoco's Mr. Dunham referred to with respect to the operation of the TAPS oil pipeline and what he stridently intends to avoid in the Canadian Mckenzie Delta region.

Another major issue is to ensure that the pipeline tariff is "unbundled" as to ancillary services. Such unbundling has been FERC policy for the past decade. However, there is concern that the producer sponsors intend to include the costs of a gas conditioning plant in the pipeline tariff. The subject treating plant would be used to extract CO<sub>2</sub> from the Prudhoe Bay Unit gas prior to injection into the pipeline. CO<sub>2</sub> is a corrosive gas that must be reduced to minimal levels prior to delivery into the pipeline. Cost estimates for the CO<sub>2</sub> plant have been estimated at \$1 billion or more. On a per unit basis, the cost of CO<sub>2</sub> conditioning can exceed \$0.50 per MMBtu.

It would be inequitable and anti-competitive to include the CO<sub>2</sub> conditioning plant, or any other ancillary services in the pipeline tariff. By including such costs in the tariff, the producer pipeline sponsors would effectively have the largest natural gas field in North America be subsidized by the producers of other smaller, less profitable gas fields. Many new ANS gas fields are expected to be of pipeline quality as produced and therefore not require CO<sub>2</sub> conditioning.

While others, such as those expected to be found south of Prudhoe Bay in the Brooks Range, will likely interconnect with the pipeline downstream of the Prudhoe Bay area CO<sub>2</sub> conditioning plant and will not derive any benefit from such a Prudhoe Bay sited plant. To exacerbate the situation, fields connected downstream may have to install their own CO<sub>2</sub> conditioning plants at their sole cost and expense, while subsidizing the Prudhoe Bay CO<sub>2</sub> conditioning plant.

There are a number of other aspects, of the tariff process that could be structured to the benefit of the producer pipeline owners. Even fairly innocuous provisions such as quality specifications could be structured in an anti-competitive manner in an attempt to manipulate and monopolize the limited pipeline capacity.

For instance, the sponsors could set the minimum Btu content at higher than normal levels in order to deny capacity to leaner natural gas sources.

Another concern along the same vein is the potential for the sponsors to require shippers to forfeit their rights to natural gas liquids (NGLs) entrained in their gas stream. This is purported to be the case on the recently completed Alliance Pipeline. Under such a scenario, the pipeline sponsors would reap a windfall processing the shippers gas for the profitable extraction of NGLs.

In addition, there is concern that the sponsors may compute the tariff rates on a volumetric (Mcf) basis rather than on a heating value (MMBtu) basis. Natural gas is now bought and sold on an MMBtu basis, computing the tariff on an Mcf basis would result in leaner gas subsidizing richer gas streams.

One final concern is to ensure that new receipt and delivery points are afforded unfettered connection to the pipeline. If new natural gas fields are discovered along the pipeline route, they should be afforded interconnection to the pipeline so long as capacity on the pipeline exists. Conversely, if new markets develop along the pipeline route, parties should be afforded new delivery points to serve these markets. Again, under the assumption of a single Alaskan gas pipeline to the Lower 48 states, this pipeline will enjoy a natural monopoly and as such should be required to accommodate all new receipt and delivery point requests.

Along these same lines, the tariffs assessed these intermediate receipt and delivery points should be computed on a mileage based manner taking into consideration the fact that these new points do not require use of the full pipeline distance and should therefore pay commensurately lower tariff rates.

### Pipeline Expansions

The FERC does not currently hold the regulatory authority to order pipeline expansions. The modifications we have made to the proposed Senate Bill provide that the FERC be afforded the authority to require expansion of the pipeline when credible shippers are willing to enter into long-term transportation arrangements needed to underpin such an expansion.

We are concerned that the producer pipeline sponsors could deny or delay pipeline expansions to serve their competitive aspirations rather than operating the pipeline as a prudent pipeline owner. That is, a prudent pipeline owner would expand its pipeline if viable economic opportunity presented its self. However, the pipeline sponsors in this case may intentionally delay or withhold expansion in order to be better postured to secure the expansion capacity for its own use.

A case in point, would be a scenario where a third-party exploration company makes a major discovery and petitions the pipeline for an expansion and is willing to commit to long-term transportation contracts to justify the expansion costs. If this situation were to occur a few years before the Prudhoe Bay Unit owners, BP, Exxon-Mobil, and Phillips, intended to maximize gas production from their field, they may delay the requested expansion so that they could be better positioned to secure the pipeline capacity for themselves at expansion.

This access to and timing of pipeline expansions is a critical issue inasmuch as there are physical limitations to how much the pipeline can be expanded. Current thinking is that the maximum the pipeline can be expanded beyond the expected initial capacity is only an incremental 50%.

**Conoco dismisses native demands: CEO insists on pipeline ownership**

Calgary Herald  
Thursday, August 9, 2001  
Page: D1 / FRONT  
Section: Business  
Byline: Stephen Ewart  
Column: The Politics of Energy  
Source: Calgary Herald

Archie Dunham, the chief executive of Conoco Inc., has a message for aboriginal groups demanding 100 per cent ownership of a proposed Mackenzie Valley natural gas pipeline: No.

Dunham, who gained control of 1.2 trillion cubic feet of gas in the Canadian Arctic with Conoco's blockbuster takeover of Gulf Canada Resources Ltd., said his company must have a stake in the pipeline.

"We're going to have an ownership of the pipeline . . . we have to have it," he said Wednesday.

Dunham, who was in Calgary for the first time since signing the \$9.8-billion takeover of Gulf Canada in May, spelled out the position while asserting that Conoco will be a much more active proponent of speedy development of Canadian Arctic gas than Gulf had been.

"We need to bring Mackenzie Delta gas to market a lot quicker than what we were originally thinking," he said, listing it as the top priority for new Conoco Canada Ltd. president Henry Sykes.

"If we could do it in four to six years, that would be good."

Dunham was here to welcome Gulf's 1,200 employees to Conoco with the completion of the largest takeover in Canadian oilpatch history. He was also able to report second quarter earnings had jumped 37 per cent from last year to \$119 million.

But Arctic gas was the primary topic of his meeting with the media. The Mackenzie Delta producers' group, led by Imperial Oil Ltd., proposes taking a two-thirds ownership stake in the line, but is facing twin problems -- demanding unanimous aboriginal support before proceeding with the \$3-billion project although some native groups are insisting on 100 per cent ownership.

Winter Lennie, a member of the Sahtu First Nation seeking complete native ownership for the pipeline, wasn't alarmed by the comments from the newest player in the renewed effort to develop the massive northern resource.

"It's a only a bargaining position," said Lennie, president of Western Arctic Energy Corp. in Norman Wells, N.W.T.

\* Dunham defended his hard-line position by citing Conoco's woes in Alaska in the early 1990s when it felt it couldn't get full value for its resources because it did not own a stake in the Trans-Alaska pipeline.

\* "The owners of the pipeline, by adjusting the tariffs on the pipeline, could really diminish the value of the producing properties and that's not going to happen again," pledged the CEO of the Houston-based company.

Intense demand for gas has renewed interest in developing the Mackenzie Delta after a two-decade moratorium was imposed by a federal commission amid aboriginal land claim battles in the 1970s.

Another gas megaproject has been proposed for Alaska's Prudhoe Bay and there are concerns from the likes of N.W.T. Premier Stephen Kakul that development of the larger U.S. resource could strand Mackenzie Delta gas for a decade or more.

Dunham said the companies behind the two Arctic projects -- including ExxonMobil Corp. BP PLC and the Canadian affiliate of the Royal Dutch/Shell Group -- must work together to develop the massive strategic resources.

He was also adamant the Mackenzie gas must be part of the plan.

"I can not imagine a politician in Canada agreeing to a pipeline route that did not include Mackenzie Delta gas," said Dunham, who urged Ottawa to throw its support to the Canadian development.

Alaskan producers are studying a pipeline route through the state that would cross into Canada en route to markets in the lower 48 states.

He also cited the potential conflict of interest of some resource owners in Canada who have resources in Alaska -- most notably ExxonMobil, which is the majority owner of Imperial -- to "chase in" one project over another.

Spokesman for Imperial and ExxonMobil dismissed the suggestion and noted the merits of both projects and any "synergies" are being studied.

Imperial spokesman Plus Rolinsor also warned it would be difficult to push ahead the timetable for Mackenzie Delta development noting "the political and social-economic challenges are just as complicated or more as the technical side."

SHELL

Testimony on April 27, 2007, to the Sen. Finance Committee, Alaska  
State Legislature on SB 104, AK Gas Inducement Act, 'AGIA'.

Mr. Chairman, and members of the committee, my name is Cam Toohey, Alaska Manager of Communications and Government Relations with Shell Exploration and Production Company.

I appreciate the opportunity to provide Shell comments in support of SB 104, Governor Palin's Alaska Gas Inducement Act "AGIA" legislation.

Last year, Shell submitted formal comments on the North Slope gas pipeline proposal developed by the Murkowski Administration. That letter has been provided to the committee. I am going to highlight a couple of points discussed in that letter that I believe are relevant as you consider this legislation.

Shell supports development of a North Slope gas pipeline and believes it is important to the continued economic health of the State of Alaska and the Nation.

While Shell currently does not have material proven gas reserves to commit to a North Slope pipeline Project, Shell has made a significant investment in the State with the specific objective of aggressively exploring for and, where economically feasible, developing oil and gas reserves.

The certainty of construction of a North Slope gas pipeline is an important factor in Shell's planning and future investment decisions in the State.

Of importance to Shell is capacity access and expansion and as we stated last year,.....

### Capacity Access and Expansion

Any North Slope gas pipeline Project should be structured to ensure reasonable access to pipeline capacity by new explorers and non-owner shippers.

In addition, it would be prudent to design and permit the Project in anticipation of the future expansion of the pipeline, especially with respect to establishing adequate right-of-way width and environmental assessment that paves the way for future incremental compression facilities, pipeline looping, and/or a second parallel pipeline.

The Project structure should provide reasonable terms for accomplishing future expansion of the line, including a presumption for rolled-in rates and mechanisms for requiring and advancing the timely completion of expansions.

Given the vast reserve potential within the State, the pipeline should be designed to provide a minimum expansion capacity of 6 bcf/d.

*Shell believes AGIA addresses these aspects very well.*

Another important element of a North Slope pipeline identified in 2006 was that .....

### Terms of Service

The Project should provide fair and reasonable terms of service for new explorers and non-owner shippers.

The terms of service, particularly transportation rates, have a critical bearing on whether North Slope development Projects are economic and competitive with other global opportunities.

Project construction costs will be the principal driver of the future rate for shipping gas on the pipeline system, and it is important that the State take steps to ensure that construction is completed in the most cost-effective and timely manner to ensure the lowest possible rate.

These concerns are not simply a matter of Shell's economic interest. For the State, as the royalty owner, the terms of service are vitally important because increases in pipeline project costs will be passed on to shippers in the form of higher transportation rates, and higher transportation rates will be detrimental to the development of new reserves and will decrease the netback value of the State's royalty gas.

*Shell believes that these issues are well incorporated in AGIA.*

#### FERC Regulation

*Shell also believes it is important that* All sections of the pipeline traversing the United States should be subject to the regulatory oversight of the Federal Energy Regulatory Commission ("FERC").

FERC oversight is necessary to ensure open access, fair and reasonable terms of service, and non-discriminatory behavior.

FERC oversight will also provide all parties an impartial forum to seek redress of grievances.

Should FERC decline regulatory oversight of certain components of the Project, then those facilities should be regulated under the jurisdiction of the Regulatory Commission of Alaska.

In closing;

- Shell applauds the effort of the Palin Administration to advance the gas line project.
- Shell fully supports the Administration in their efforts to include all interested parties in the gas line discussions as this will impact the future of all involved for generations to come.
- Shell believes development of a North Slope gas pipeline is critical to the continued economic health of the State of Alaska and the Nation.
- The certainty of construction of a North Slope gas pipeline is an important factor in Shell's planning for its current holdings in the State, as well as its decision-making regarding Shell's future investment.
- Shell believes it is critically important to future explorers that they have access to the gas pipeline and the line must be expandable.
- The project should provide fair and reasonable terms of service for new explorers and non-owner shippers, which will benefit the State of Alaska.

Thank you for the opportunity to present this morning in support of AGIA.

I would be happy to take any questions from the committee and provide written responses.



# Shell Exploration & Production

## Shell Energy Resources Company

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July 24, 2006

The Honorable William Corbus  
Commissioner, Alaska Department of Revenue  
P.O. Box 110430  
Juneau, Alaska 99811-0430

RE: Alaska Stranded Gas Fiscal Contract Between the State of Alaska and BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc., and ExxonMobil Alaska Production Inc. ("Fiscal Contract") / Preliminary Findings and Determination ("Preliminary Findings")

Dear Commissioner Corbus:

Shell supports development of a North Slope gas pipeline as important to the continued economic health of the State of Alaska and the Nation. While Shell currently does not have material proven gas reserves to commit to a North Slope pipeline Project, Shell has made a significant investment in the State with the specific objective of aggressively exploring for and, where economically feasible, developing oil and gas reserves. The certainty of construction of a North Slope gas pipeline is an important factor in Shell's planning and decisions regarding future investment in the State, and Shell applauds the effort of the Administration to advance this important Project.

Several months ago, the Governor outlined six principles guiding the Administration's negotiation of an agreement for the construction of a North Slope gas pipeline with the current North Slope producers. Shell's comments with respect to the proposed Fiscal Contract and Preliminary Findings are primarily focused on two of those six principles: Principle No. 3, "Future explorers must have access to the gas pipeline"; and Principle No. 4, "The gas pipeline must be expandable."

Given the monopoly nature of the proposed North Slope pipeline system, certain modifications to the proposed Fiscal Contract and Preliminary Findings are needed to bolster the principles articulated by the Administration, particularly with respect to access and expansion. Below are Shell's preliminary comments on these and several other important aspects of this Project. At this time, Shell's comments are necessarily general in nature as critical components of the Project are, as yet, not available for public review, including, for example, the LLC agreement, the construction management agreement, the pipeline operating agreement and, most importantly, the pipeline Tariff General Terms & Conditions of Service. We assume that these documents are currently being negotiated and may not be available for public review for some time.

### Capacity Access and Expansion

Any North Slope gas pipeline Project should be structured to ensure reasonable access to pipeline capacity by new explorers and non-owner shippers. In addition, it would be prudent to design and permit the Project in anticipation of the future expansion of the pipeline, especially with respect to establishing adequate right-of-way width and environmental assessment that paves the way for future incremental compression facilities, pipeline looping, and/or a second parallel pipeline. The Project structure should provide reasonable terms for accomplishing future expansion of the line, including a presumption for rolled-in rates and mechanisms for requiring and advancing the timely completion of expansions. Given the vast reserve potential within the State, the pipeline should be designed to provide a minimum expansion capacity of 6 bcf/d.

### FERC Regulation

All sections of the pipeline traversing the territory of the United States should be subject to the regulatory oversight of the Federal Energy Regulatory Commission ("FERC"), including the Point Thomson transmission line. FERC oversight is necessary to ensure open access, fair and reasonable terms of service, and non-discriminatory behavior. FERC oversight will also provide all parties an impartial forum to seek redress of grievances. FERC regulation should not be prospectively limited or conditioned in any contract or other agreement with the State of Alaska. Should FERC decline regulatory oversight of certain components of the Project, then those facilities should be regulated under the jurisdiction of the Regulatory Commission of Alaska ("RCA").

### Terms of Service

The Project should provide fair and reasonable terms of service for new explorers and non-owner shippers. The terms of service, particularly transportation rates, have a critical bearing on whether North Slope development Projects are economic and competitive with other global opportunities. Project construction costs will be the principal driver of the future rate for shipping gas on the pipeline system, and it is important that the State take steps to ensure that construction is completed in the most cost-effective and timely manner to ensure the lowest possible rate. This will require prudent construction management by an entity that has the capabilities and resources to manage a project of this magnitude and an incentive to manage costs.

These concerns are not simply a matter of Shell's economic interest. For the State, as the royalty owner, the terms of service are vitally important because increases in pipeline project costs will be passed on to shippers in the form of higher transportation rates, and higher transportation rates will be detrimental to the development of new reserves and will decrease the netback value of the State's royalty gas.

### Upstream Facilities

For the Project to succeed in stimulating new investment, new explorers need access to existing and newly constructed upstream facilities that serve to deliver gas to the Project. Mechanisms must exist for new explorers to access these facilities on reasonable and fair terms preventing duplication of facilities to minimize the impact on the environment, local communities and future development costs.

In addition, the Project description should clearly include the transmission line from Point Thomson to the gas treatment plant. Similarly, future upstream transmission lines that might be developed, such as any NPRA feeder lines, should be deemed part of the Project and subject to FERC regulation.

State Capacity

If the State assumes an ownership interest in the Project, the State should have the power and discretion to broker its capacity to third-party shippers. Such authority should extend to both the gas treatment plant and pipeline capacity. Brokering of capacity is a very successful and active program on US pipelines ever since FERC established capacity release rules as part of Order 436 in 1992.

Shell applauds the Administration's efforts to date to advance a North Slope gas pipeline Project. However, Shell believes that the proposed Fiscal Contract can be improved to protect the interests of new explorers and, at the same time, better promote the interests of the State of Alaska in encouraging new development. Shell looks forward to working with the State of Alaska as this Project becomes more fully developed and as remaining Project components are introduced. Shell representatives are available to discuss Shell's views with you, or others in the Administration or Legislature, upon request.

If you have any questions or followup, please contact Cam Toohey with our Alaska office at 907-770-3700.

Sincerely,

A handwritten signature in black ink, appearing to be 'C. Toohey', written over a horizontal line. The signature is fluid and cursive.

BP

4/28/07

bp



David Van Tuyl

Gas Commercialization Team Lead  
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# **Alaska Natural Gas Pipeline Project**

## **Testimony on AGIA**

### **Senate Finance Committee**

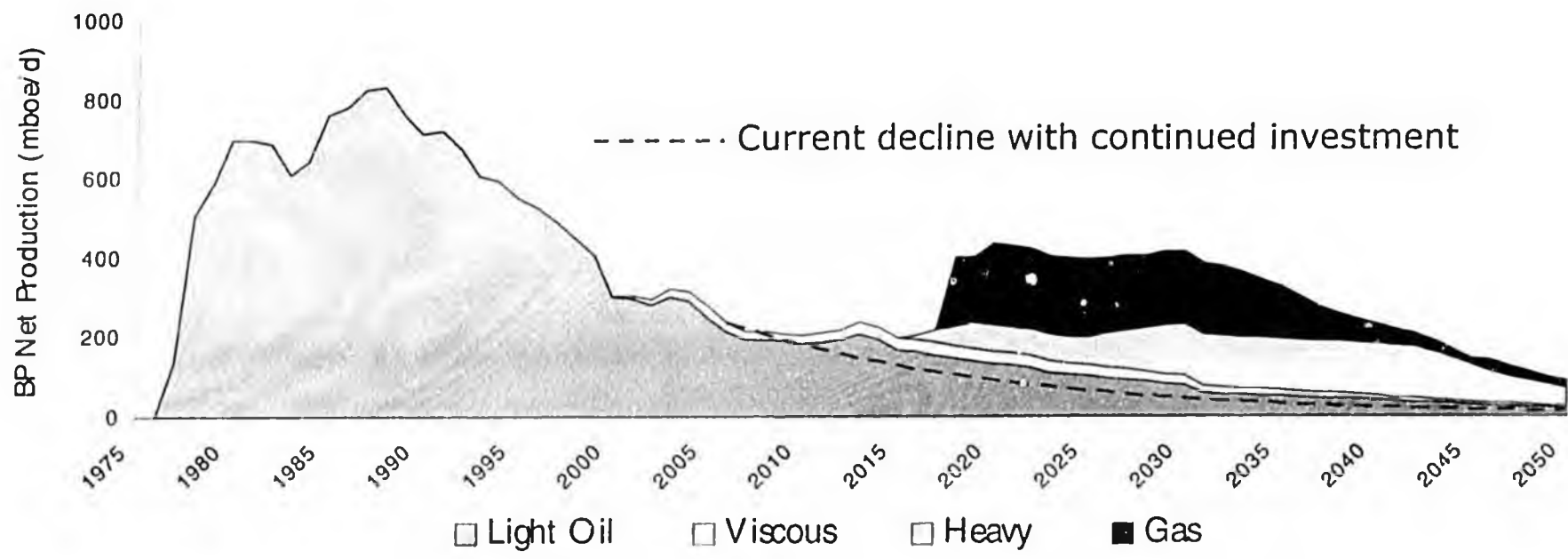
April 28, 2007





# An Opportunity...and a Challenge

- BP wants and needs a successful gas pipeline



- Project remains commercially challenged

# BP Disagrees with Administration's Economics



- Project is not "wildly profitable"
  - Can't separate upstream economics from midstream commitments
  - Economics must be based on the complete project
  
- Firm transportation commitments must be accounted for in project economics
  - Upstream pays for the midstream
  - Without FT there is no project
  
- Long-term cash generation is highly important
  - Cash flow well beyond 10 years remains vital
  
- Need common understanding of project to determine best way forward

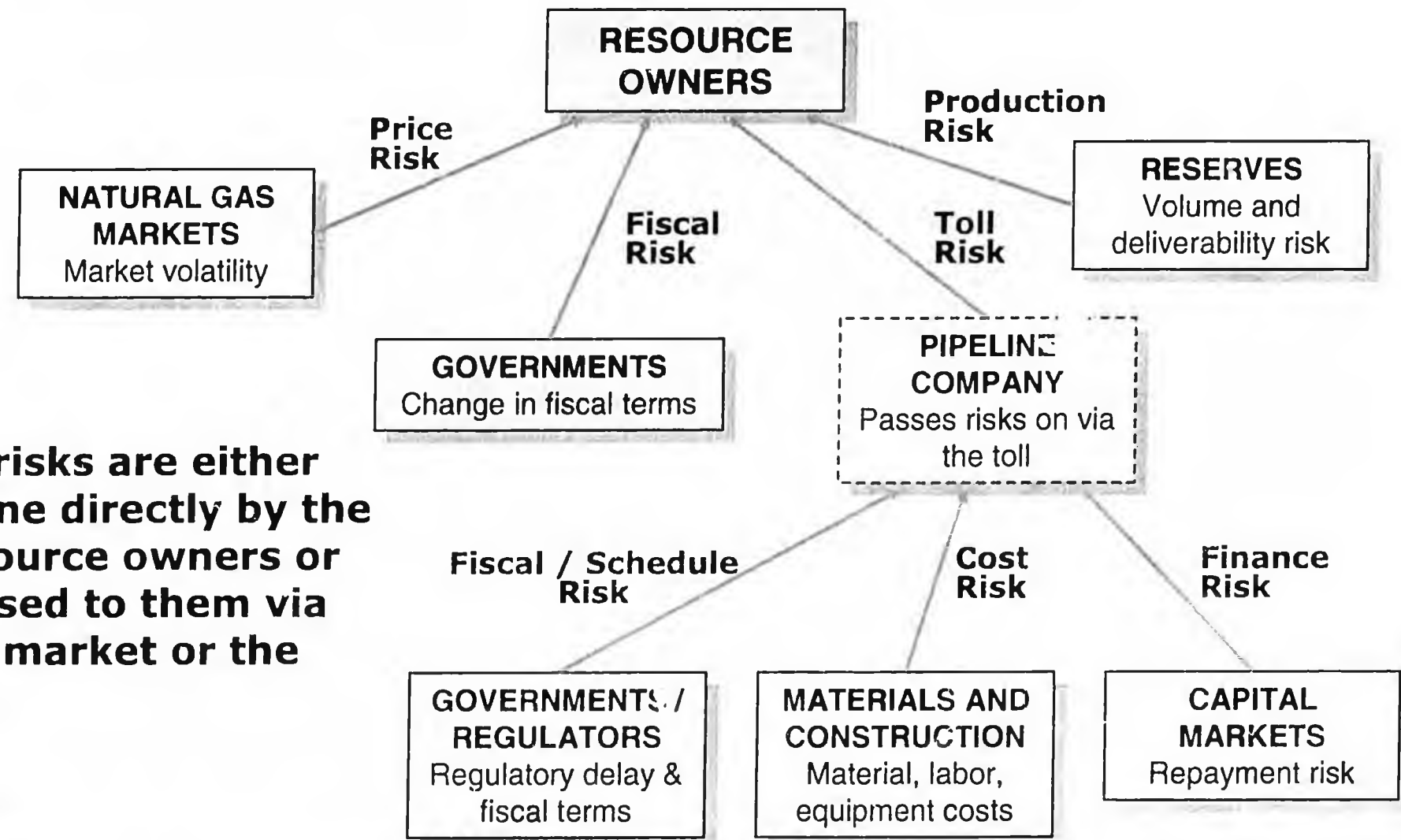
## What is so important about FT?



- Firm Transportation commitments (FT) by the resource owners are needed for a gas pipeline company to get financing
  - "No customers, no credit, no pipeline" (TransCanada)
  - "No producers, no pipeline" (Enbridge)
- FT is a binding financial obligation
  - not simply "committing gas to a pipeline"
- Requires multi-billion dollar commitments by resource owners
  - Assuming 4.5 bcfd, \$3.50/mcf, 25 year term.....**\$144 billion**
- Long term commitments represent real risk
  - Two risks:
    - Price risk (over time, market price will not cover FT cost *and* produce an acceptable return on the investment)
    - Supply risk (will not have sufficient gas to use the FT commitment over time)
  - Risk is borne by those making the commitments



# 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**

## BP Messages on AGIA



- AGIA needs significant modification to result in a successful project
- As drafted, BP will not be able to submit a bid under AGIA
- As drafted, it is difficult to envision circumstances that would allow BP to make a firm transportation commitment to a licensed project under AGIA

Why?...

- Negotiated rate protection unavailable upon expansion
  - Subsidization of competitors is commercially unreasonable
  - Resource terms insufficient to justify FT commitment
- BP intends to bid if AGIA is appropriately modified

## Key Concerns Preventing BP Bid Under AGIA

In the order they appear in SB-104



- .130(2)(B) / .210 – “Detailed” description of design requires substantial customer consultation, engineering
  - FERC Order 2005 requires “good faith estimate”
- .130(2)(C-D) – Can’t “demonstrate” economic viability
  - “nobody can say today whether this project is economic or not” (Mid-American Energy); need bottoms-up cost and revenue estimate
- .130(7) - Requires subsidization of competitors & eliminates negotiated rate protections
  - contrary to ANGPA & FERC rules
  - imposes unreasonable commercial risk
- .130(13) - Commitment to reserve capacity for in-state delivery points, regardless of open season outcome
  - imposes unreasonable commercial risk
  - not consistent with FERC Order 2005 [157.34(c)(8)]
- .150(a) - Release of proprietary information to competitors after license award creates huge exposure

## Key Concerns Preventing BP Bid Under AGIA

In the order they appear in SB-104



- .200(a) - Must accept FERC certificate despite conditions
  - could add significantly to project cost
- .200(b) - Must sanction project within one year of FERC certification, regardless of cost
  - failure to sanction results in loss of all data to state (engineering, design, contracts, permits, etc.)
- .230(a)(2) / .210 - In breach if substantial deviation from plan set out in application
  - Unless it increases NPV, is ordered by AOGCC or isn't foreseeable
  - FERC, BLM, municipal agencies, Canada, etc. could require changes to project specs outside state control
- .240(c) - Effectively no way to abandon an uneconomic project; licensee subject to damages
- .310 - .320 - Fiscal terms insufficient; risk of no FT customers
  - "no customers, no credit, no pipeline" (TransCanada)

# How AGIA can help deliver a successful project

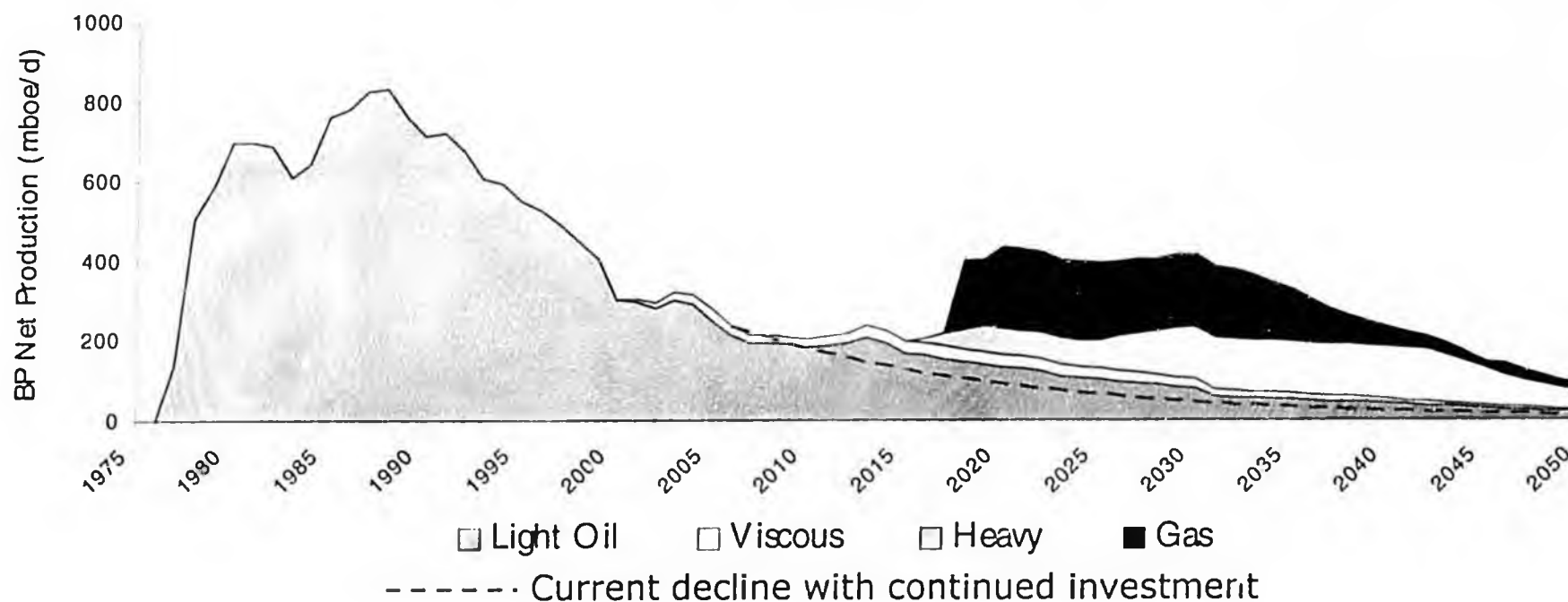


- Address areas of key concern listed on prior slides
- Allow applicants to respond to State's objectives
  - Prescribing solutions up front will not result in the best project
- Avoid exclusivity to ensure a pipeline gets built
  - Even as amended, AGIA creates exclusivity
  - Federal model encourages competition in the marketplace
- Address fiscal terms to encourage FT commitments needed for a successful project
  - Allow resource owners to make offer in bid
- Allow due process of appeal, remove potential Order 2004 conflict, other clarifying edits



# BP's Vision for Alaska

- BP has a long history in Alaska....
- .....and we look forward to a 50-year future
- That future is only possible with a gas pipeline
- BP wants to bid under AGIA and hopes it will be modified appropriately

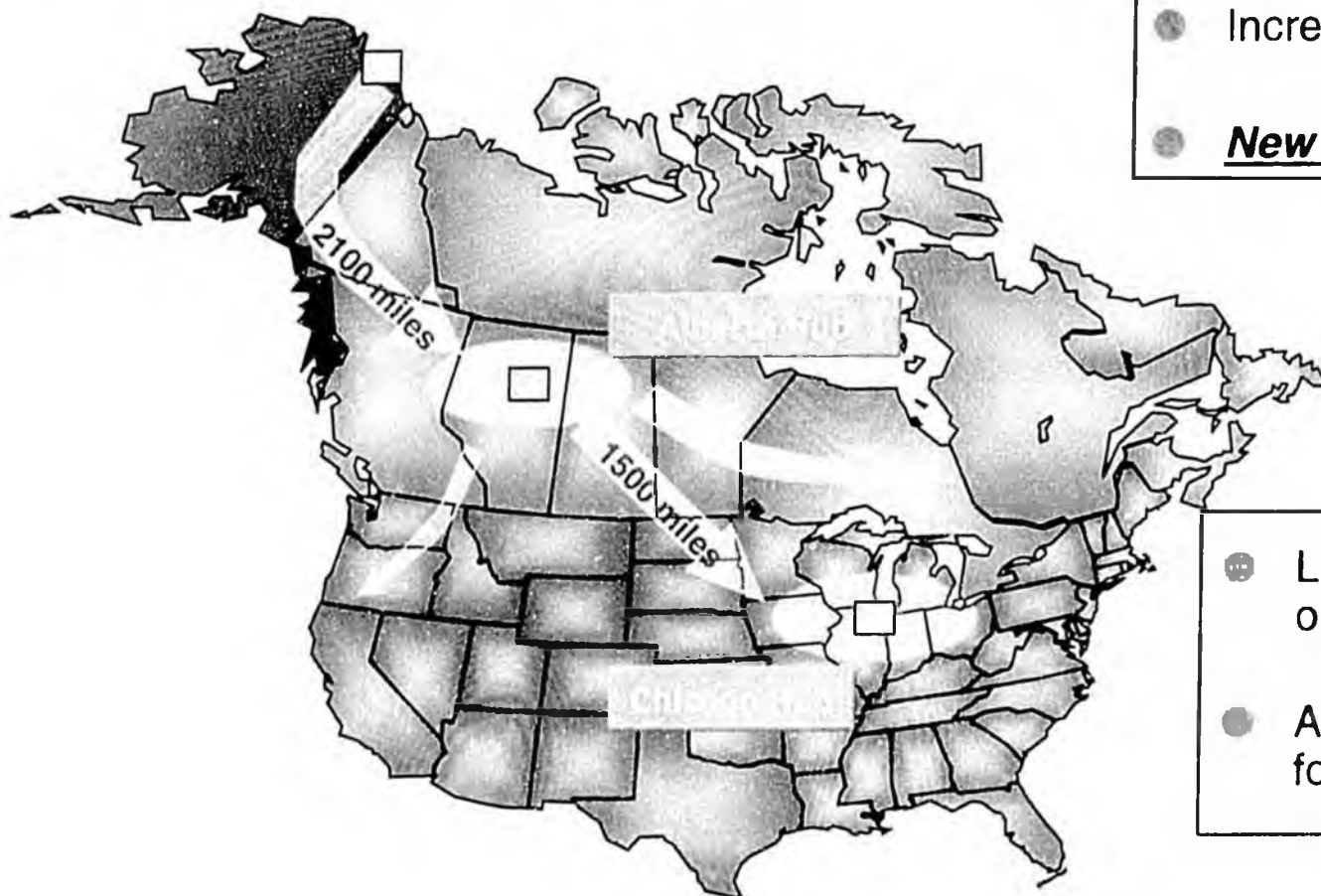




# What A Successful Gasline Means

- Jobs for Alaskans
- Additional revenue for future generations

- Increased economic activity
- New businesses created



- Long term gas supply opportunity for Alaskans
- A more diversified economy for decades

**BP Testimony on AGIA (SB104)**  
**Senate Finance Committee**  
**April 28, 2007**

- Mr. Chairman, members of the committee, for the record my name is Dave Van Tuyl. I am the Gas Commercialization Manager for BP Alaska. Thank you for the opportunity to testify before you this morning.
- My testimony will start with a reminder of the opportunity and challenge before us, and a brief discussion of the project economics and risk. Then I'll provide our specific concerns on AGIA, and end with a vision of a successful outcome which I think we are all trying to achieve.

**An Opportunity...and a Challenge**

- **BP wants and needs a gas pipeline.** And we need that pipeline to be built for a low capital cost and then operated cost efficiently. We believe that is what is required to make the project happen and be successful. Low costs are good for both BP and the State because it results in lower tariffs, higher netbacks and more revenues for the State and BP.
- Also, a low cost project will provide incentive to explore for more gas to keep the pipeline full into the future. That is also good for the State and for BP
- The best way to ensure there is gas exploration in the future is to get a gas pipeline built in the first place, and to get it built for a low cost.
- **This is a hugely important project to BP, to Alaska and to the nation.** It represents the largest, known, undeveloped gas resource in the United States, and in BP's global portfolio. The gas project is important in its own right – but it also extends the economic life of Alaska's oil production for decades. Extending oil production is good for the State, the nation and for BP.

- We share the governor's and the legislature's desire to get a successful gas project moving.
- But the project remains commercially challenged. It requires massive capital investment. It requires even larger financial commitments to get the necessary financing to allow the project to advance.
- If it was easy, it would be advancing today. But it's not easy. It's incredibly challenging. The size of this project alone makes it incredibly challenging and risky.

#### **BP Disagrees with the Administration's Economics**

An important point I want to leave with you is that we fundamentally disagree with the characterization of the Alaska Gas project economics as recently presented by the Administration.

We have concerns over many different statements made by the Administration, but I'll limit my comments to addressing three key concerns.

1. Underlying economic methodology – Decoupling the Upstream from the Midstream
2. Nature of firm shipping commitments
3. The importance of long term cash flow in investment decision making

We are very concerned that the economic analysis presented by the Administration to the legislature is very misleading.

### Economics

- Without the commitment of capital to the pipeline or the huge financial obligation required for Firm Transportation (FT) for the midstream facilities, there is no way to realize value from the sale of gas. Thus, any analysis of the project that excludes midstream capital and FT is incomplete.
- And because these commitments are just that, legally binding commitments, they need to be accounted for when evaluating project economics. These commitments were ignored in the Administration's analysis of the economics.
- Because that method ignores the FT obligation, the resulting assertion that our upstream economics are so robust is patently incorrect. In fact, the upstream pays for the midstream. It does this through firm transportation commitments. These commitments cannot be ignored.

The second point we want to emphasize is to ensure we have a common understanding of the nature of these firm transportation commitments we've just talked about.

### Nature of Firm Transportation Commitments

- FT is a binding commitment made by a shipper to a pipeline company in an open season to secure capacity on the pipeline for a specified duration at a specified cost. We heard Fred Rich talk about this the other day.
- There are a few important facts to be clear on about FT
- FT is binding legal obligation. It becomes binding once the necessary conditions are met, including the pipeline coming into operation.
- The Administration has claimed that the Producers say that FT is "exactly like debt". I'm not aware of any of us having said that in testimony. Long

term commercial commitments like FT are often characterized as "debt-like", and must be reported to the SEC.

- The core issue is whether the FT commitments require the producers to absorb the substantial majority of the risk associated with the project.
- FT is a financial obligation, and it is certain that the lenders would have recourse to the financial security provided by the producers' FT, should the pipeline company fail to meet its obligations.
- Therefore, FT cannot be ignored if a project is to be evaluated properly.
- And generic statements about treatment of long term commercial commitments is dangerous. Commitments of the magnitude required to underpin this project are massive in both the dollar amount and the likely duration.
- These commitments will create their own weather in the financial markets – they must be considered.

The third and final point I wanted to emphasize is that confidence in future cash flows is very important in evaluating the commercial viability of any investment decision. That is particularly true for a commitment as large as the Alaska gas pipeline project.

#### Importance of Long Term Cash Flow

- The Administration suggested that cash flows beyond 10 years are relatively unimportant in financial decision making on this project
- That's not true.

- Cash flows further out in time tend to have less effect on NPV – this is true
  - But cash impact years into the future will indeed be real
  - In evaluating the economics of projects, we look at many different measures. NPV, IRR and PI are just some of the measures which are considered.
  - The ability of a project to generate long-term cash flow is also an important consideration to investors.
  - It's important to bear in mind that we expect the FT commitments we just talked about will be in effect well beyond 10 years.
  - So those making long terms commitments want to know that they'll be able to make good on them. Lenders will want to know this, too.

Getting this project right has enough challenges of its own, let alone when we have such fundamental disagreement with how the project is characterized.

#### **What Is So Important about FT?**

- FT commitments, typically obligations to "ship or pay" made by the resource owners or "shippers", are needed by the pipeline company to get financing
  - validating just how important they are, we've heard some very simple and straightforward comments from pipeline companies who have testified in the past couple of weeks
  - TransCanada has said "No customers, no credit, no pipeline" (and in this context customers means shippers)
  - Enbridge put it even more simply by saying "No producers, no pipeline"
- Those aren't "political" statements. They are statements about the simple financial truths of gas pipeline projects
- FT is a binding FINANCIAL obligation. I've sometimes heard FT described as "committing gas to a pipeline". I've heard that quote from industry as well as

others, so I'm not pointing any fingers here. But I just wanted to make it clear that FT is an actual financial obligation

- Typically, FT is known as a "ship or pay" obligation
  - That means that a shipper commits to pay the pipeline company for use of its service whether or not the shipper actually delivers gas to the line
  - And it's also important to note that a company does not need to have ANY gas resources to enter into a firm transportation commitment. Any company who meets the creditworthiness standards set by the pipeline company is free to bid for capacity. Gas pipelines are "open access". Anyone is free to obtain capacity if they make the requisite commitments.
- The scale of these commitments is often oversimplified. It's not "just" the capital cost of the project, if that weren't in itself a large enough commitment.
    - the commitment is for what is known as the "demand charge" which is the cost of service the pipeline will charge through time
    - Capital is one major component
    - But for illustration, I've provided some broad assumptions to put the scale of these commitments in perspective.
      - assuming a 4.5 bcf/d project, at a unit cost of \$3.50/mcf for 25 years results in a total FT commitment of \$144 billion
      - That's a huge sum, even for a company the size of BP
  - These long term commitments are just that – commitments. Therefore, they represent real risk. The risk can manifest itself in two key ways:
    - the PRICE can drop such that the costs of these commitments isn't covered; and
    - the GAS SUPPLY may be insufficient to use the capacity that has been committed over time.

- And the size of these commitments magnifies the risk. And that risk is borne by those making the commitments,

### Project Risk Resides with the Resource Owners

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

- Material, labor and equipment costs → cost risk, which includes project management and execution
- Need for finances from the capital markets → finance risk (Again, Fred Rich talked at some length about this risk at his project finance workshop earlier this week)
- **What is critical to appreciate** is that all these project-related risks that are taken by the pipeline company are ultimately passed through to the resource owners through the toll
  - The Pipeline company receives a regulated rate of return
  - Gets a reasonable return on investment commensurate with the risks
  - That's the pipeline's reward
  - In exchange for this regulated rate of return, the regulators ensure that the pipeline does not take on certain risks
  - These instead are passed through to the resource owners, provided that the pipeline owner delivers the project on time and operated efficiently
  - That's how the risk / reward balance is struck by the pipeline regulators
- So ultimately, virtually **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

#### **BP Messages on AGIA**

- I'd like to turn to our specific comments on the current version of SB-104.

- To put it clearly and succinctly, AGIA needs substantial modification to result in a successful project. And I'll go into some detail as to the modifications we see as necessary.
- As we've said in previous testimony, we agree with the Governor's intent on using AGIA to advance a successful project. But the current version of AGIA won't get us there. I'll explain why in a moment.
- I want to be very clear with BP's evaluation of AGIA as it's currently drafted. Simply put, BP won't be able to submit a bid that conforms to the requirements of AGIA.
- It's not easy for me to say that. BP really does want to be able to compete in the AGIA process. BP wants to help deliver a successful Alaska gas pipeline project. We think we can add significantly to the success of the project.
- If AGIA is fixed, we intend to bid. We're happy to have our bid openly evaluated along with others. But the current terms of AGIA won't allow that to happen.
- I also want to be very clear about the implications the current version of AGIA holds for BP participating in an open season. As currently drafted, it's difficult to envision the circumstances that would allow BP to make a firm transportation commitment to the licensed project under AGIA in an initial open season.
- And that's true even if a BP affiliate was the licensee.
- That's because BP believes the terms of AGIA put unreasonable commercial risk on initial shippers.

- AGIA removes negotiated rate protection (protections from potential cost overruns, protections from subsidization of expansion shippers, and the ability to gain long term certainty of future rates).
  - There is language in the bill that now references negotiated rates, but it doesn't actually provide rate protection for initial shippers
- AGIA doesn't provide the fiscal certainty needed to justify the massive, long term firm transportation commitments necessary for a successful project.
- I'm not trying to be dramatic, or issue any sort of a "threat". I'm trying to be very open, and transparent. We owe that to you because there is so much at stake.
- Next I'll explain what provisions prevent us from making a bid under AGIA as it's currently drafted.

#### **Key Concerns Preventing BP Bid Under AGIA**

- While we have several concerns with AGIA as drafted, we've tried to hone this list only to the most significant concerns we have that would prevent us from submitting a conforming bid.
- I'm not planning to walk through each of these in detail, but I'll explain a few of them to give you a sense of our concern. They are arranged in the order they appear in the bill and not in any sort of ranking.
- 130(2)(B) / .210 – currently requires a "detailed" description of size and offtake, and the way we understand section .210, we wouldn't be able to change our plan as better information becomes available

- 130(2)(C-D) – We think it's impossible to "demonstrate" economic viability of the project within the AGIA timeframe.
- 130(7) – We've already testified in some detail regarding our concerns with this section.
  - these provisions are in conflict with FERC policy and the ANGPA
  - it ignores one key objective of FERC Order 2005 – rate predictability for initial shippers!
- 130(13) – Implies a commitment to reserve capacity for in-state delivery points, whether or not that service is committed in an open season
- 150(a) – requires release of the successful licensee's proprietary information.

#### Key Concerns Preventing BP Bid Under AGIA (cont.)

- 200(a) – requires the licensee to accept a FERC certificate despite of potential conditions FERC may impose.
- 200(b) – the licensee effectively turns over sanction authority to the State
- 230(a)(2) – This provision says that the licensee is in breach if there is a substantial deviation from the terms set out in the application
- 240(c) – The way we understand this section, there is effectively no way to prove the project uneconomic, therefore there is no "off-ramp"
- 310 – 320 – Finally, as we've consistently testified, the resource terms under AGIA are inadequate.

#### How Can AGIA Help to Deliver a Successful Project?

- For BP to be able to submit a bid under AGIA, a number of modifications need to be made
- The 10 areas of concern I just walked through need to be fixed
- As we've discussed in every testimony on AGIA we've offered, there are three other key areas that need to be fixed
- First, the State should provide its list of objectives that prospective applicants must address
  - BP, and other applicants, should be allowed to tell the State how we would address the State's objectives
  - that's how the best solutions are developed – through creative thought, not by presupposed outcomes
- Second, AGIA should remove elements of exclusivity.
  - An amendment was made in a prior committee to try and address this concern [in .100(b)], but even with this amendment, AGIA creates exclusivity
  - Exclusivity prevents competition in the marketplace.
  - The Federal model works well, and encourages open competition in the marketplace. It works everywhere else in America. It will work for Alaska as well.
- Third, fiscal terms have to get solved in a way that will encourage firm transportation commitments from shippers
  - we would like the opportunity to include fiscal terms in an bid under AGIA that the State can consider (and reject if it likes)
  - BP wants to be able to submit a bid under AGIA

- Finally, there are other edits, less fundamental than the ones I just mentioned that we think also should be addressed.

### BP's Vision for Alaska

- To close, I'd like to spend a moment to look into the future and consider again the opportunities we have before us.
- BP has a long history in Alaska. BP has been actively involved in the exploration, development and production of Alaska's North Slope energy resources for decades.
- And we see the opportunity for a bright future ahead. In fact, we envision our 50-year future in Alaska. It's not just a slogan.
- I'd like to turn your attention to the graph at the bottom the slide, which shows the possibility of the future that BP sees in Alaska, depicting BP's share of production through time.
- There are a few key points to draw from the graph.
- The days of high plateau production are behind us.
- We still have a significant level of production today, but that production will continue to decline with time. That's what the dotted red line depicts.
- That shows production declining at historic levels, which already would require significant investment.
- We can make up that decline in production with new investment that would result in new production from heavy oil resources and from gas.

- But it's not a given. It's a view of what's **POSSIBLE**.
- That future is only made possible with an Alaska gas pipeline project.

#### **What A Successful Gasline Means**

- Finally, it's worth a reminder of the importance of a successful project. And I'd like to emphasize that what we need is a **SUCCESSFUL** gas pipeline, not just ANY gasline.
- As we've said, this is a project of tremendous scope and scale and that's what the picture reminds us of. Because of this it presents tremendous risk. But if it's done right, it presents a wonderful opportunity for the State, Industry and the people of Alaska.
- Because there is much at stake, we need to get it right.
- The project creates the opportunity for jobs for Alaskans, and if we deliver a successful, low cost project, for revenues to the State and to Industry well into the future.
- We can create a whole new industry of gas exploration with a successful, low cost project. Gas exploration and expansion are only possible if the pipeline gets built in the first place, and if it's built for a low capital and operating cost. That will make it attractive for bringing new volumes into the project, which benefits the State, gas explorers, and initial shippers as well.
- A successful gas pipeline project will provide the opportunity to bring a long term gas supply source for use by Alaskans.

- And finally, gas sales will diversify Alaska's economy for decades into the future.
  
- As I said, there's a lot at stake, so we need to get it right.
  
- BP wants to get it right. That's why we've tried to be very forthright and specific with our comments. We owe that to you as you finish your deliberations on AGIA.
  
- Thank you for the opportunity to testify today. I'd be happy to answer any questions you might have.

TRANS CANADA

4/28/07 PM



## Tony Palmer

Vice-President, Alaska Business Development

As Vice-President, Alaska Business Development, Tony Palmer leads TransCanada Corporation's efforts on the Alaska Highway pipeline project. Tony is also CEO of Foothills Pipe Lines Limited, a subsidiary of TransCanada. Foothills owns the Canadian section of the Alaska Natural Gas Transportation System. TransCanada and Foothills own the Alaskan segment.

Tony joined Foothills Pipe Lines Ltd. in 1985 and worked in NOVA Gas International Ltd. from 1994 to 1998. Since then, Tony has held several senior positions in Business Development, Strategy and Transmission Planning at TransCanada. Tony has 24 years experience in the pipeline business.

Tony earned a Bachelor of Arts from Concordia University in Montreal in 1979 and is a graduate of the Executive Development program at the University of Calgary in 1988.

TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure. TransCanada's network of approximately 42,000 kilometres (26,000 miles) of pipeline transports the majority of Western Canada's natural gas production to key Canadian and U.S. markets. A growing independent power producer, TransCanada owns, or has interests in, approximately 7,700 megawatts of power generation in Canada and the United States. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP.

TransCanada (December 5, 2006)



ENBRIDGE

The background of the slide is a black and white photograph of a natural gas flare. A large, bright plume of fire and smoke rises from the ground, illuminating the surrounding landscape. The foreground shows a flat, open field with some tracks or paths.

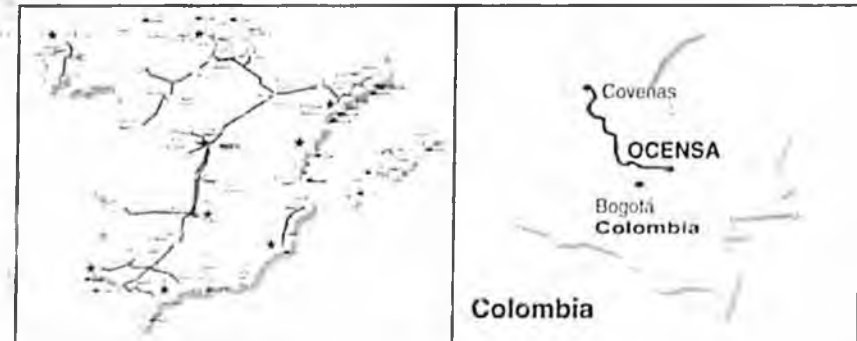
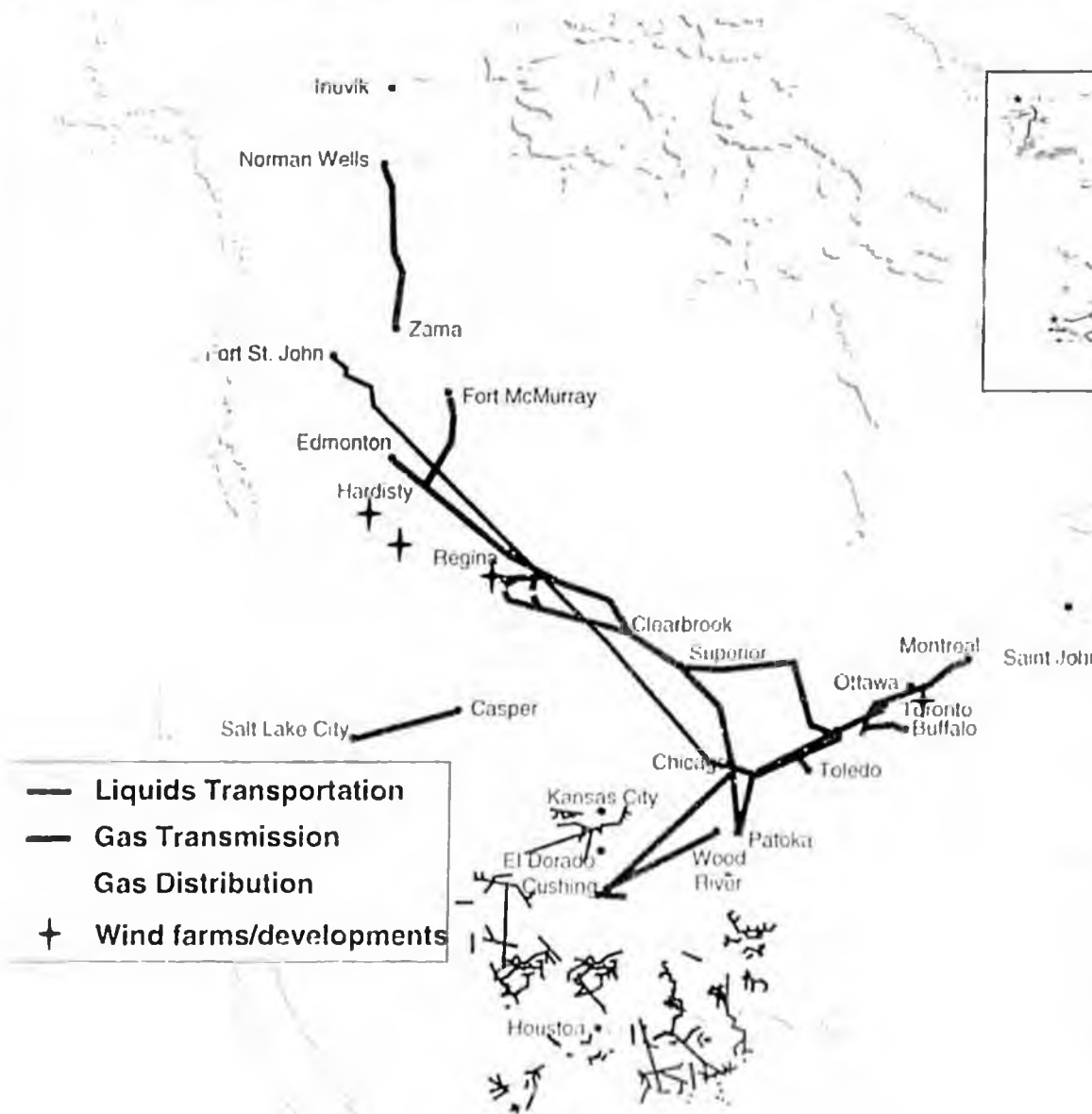
# Alaska Natural Gas Pipeline Senate Finance Committee

April 30, 2007

**Ron Brintnell**

**Director, Gas Development**

# Enbridge Overview

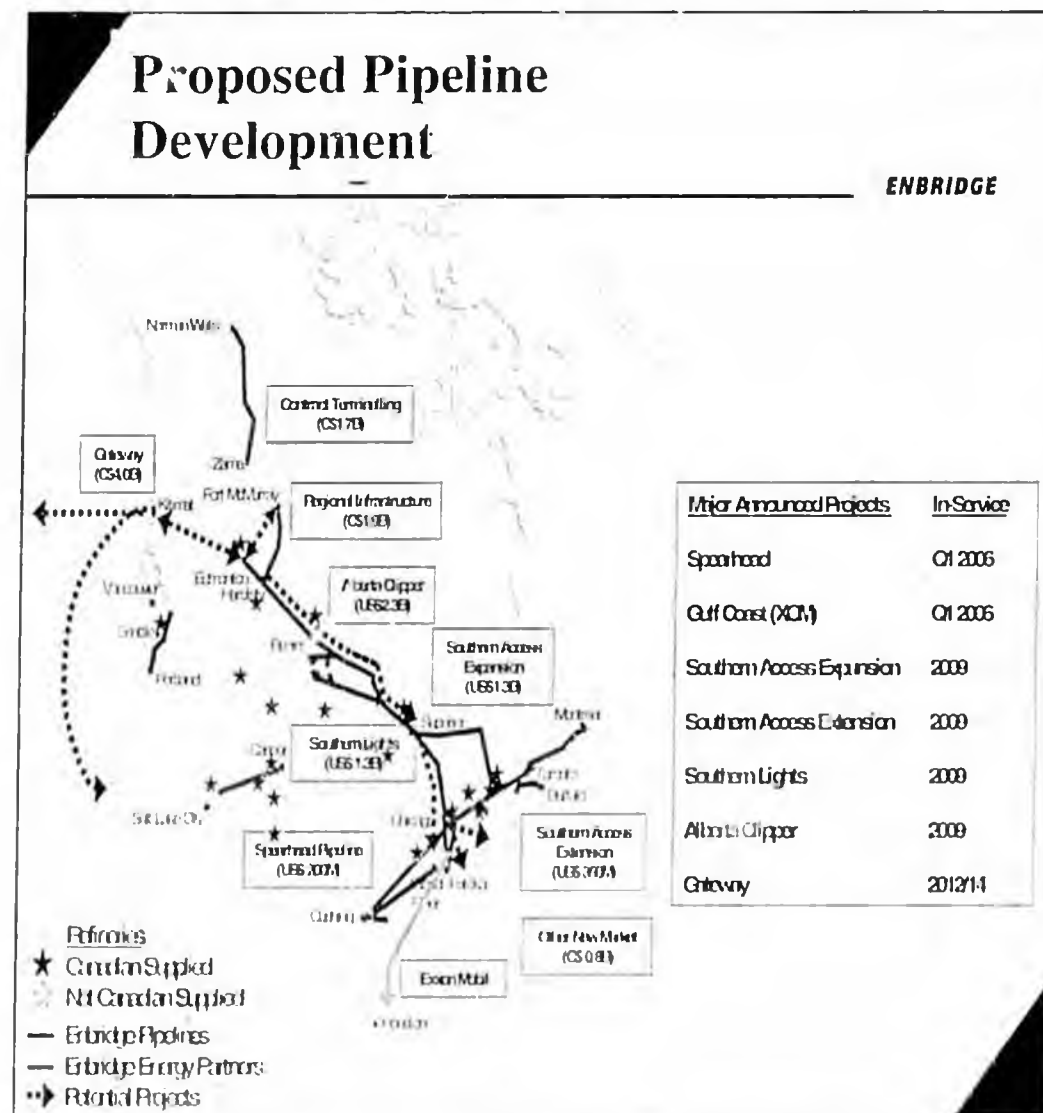


- Interest in 50,000 miles of pipelines
- Own and operate world's longest liquid petroleum pipeline
- Deliver 70% of WCSB crude oil production
- Deliver half of deep water Gulf of Mexico natural gas production
- Canada's largest natural gas local distribution company
- Employ 4,900 people
- One of the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

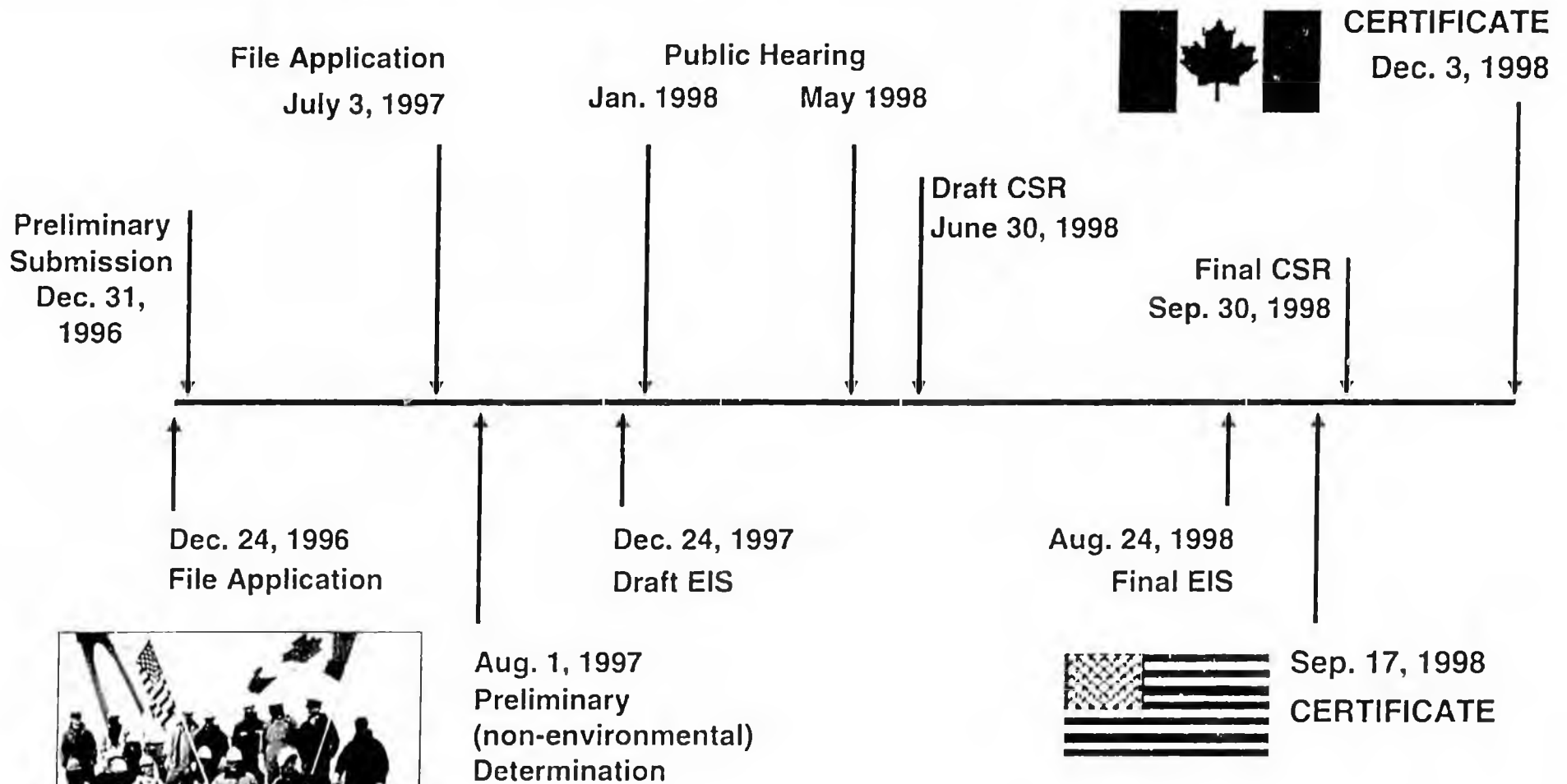
# Unparalleled Experience in Recent Pipeline Development



- \$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



# Alliance Pipeline



# Moving the Project Forward Requires Producer Alignment



- **No producers No pipeline !**
- **Project is too risky - too big, too complex, too expensive - to move forward without producers**
- **Potential gas buyers see *no producers as no progress***
  - Buyers' dilemma, switch to coal, go off-shore or wait for Alaska?

# Moving the Project Forward Don't Just Focus On The Pipeline



- As drafted, AGIA is unlikely to produce significant commercial results.
- AGIA introduced as a catalyst to expedite the construction of a natural gas pipeline
- AGIA focus is on the pipeline and not entire project which requires Producer alignment
- AGIA adds unnecessary regulatory complexity
  - FERC process well defined and effective

# Moving the Project Forward Promote, Don't Stymie Innovation



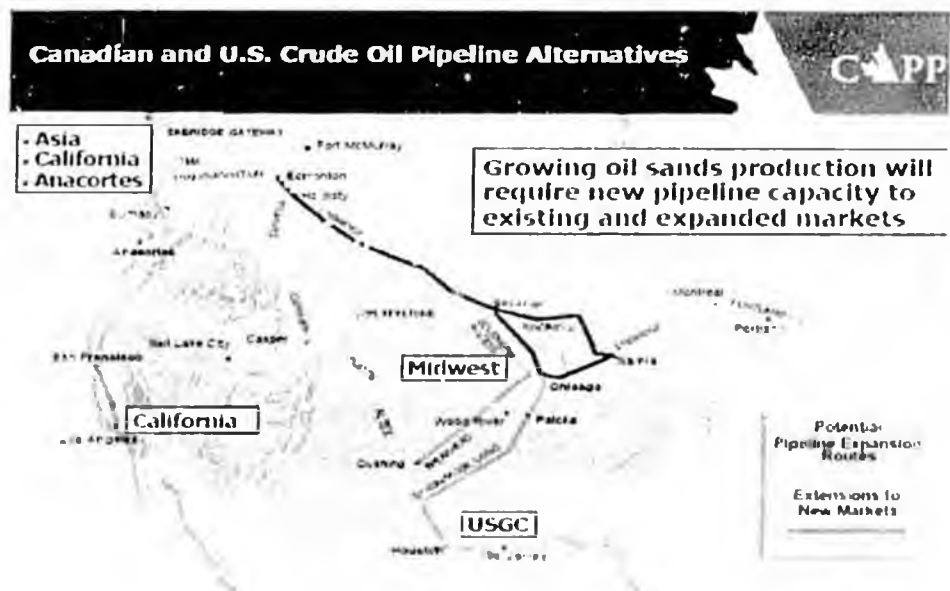
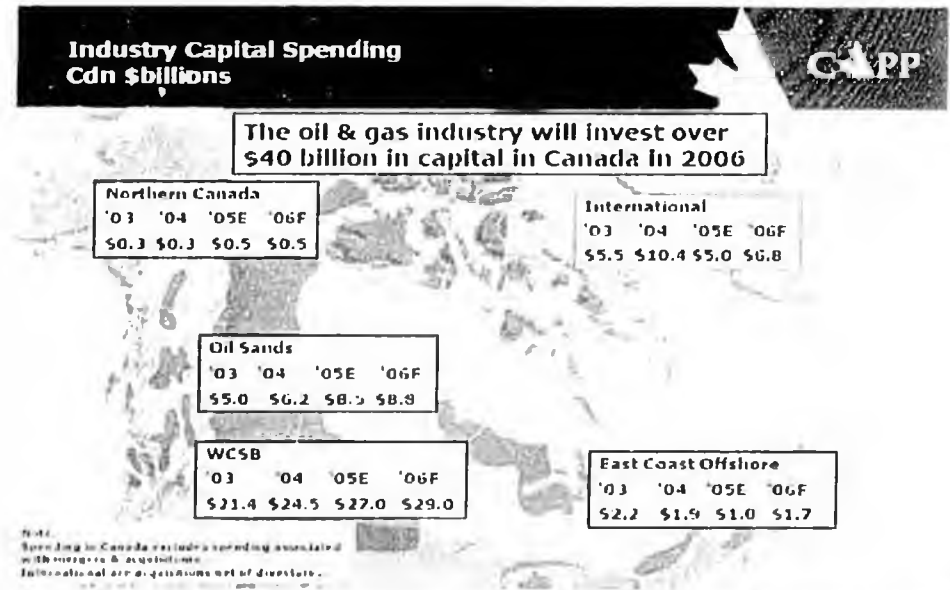
- Absolute requirements may result in not having the opportunity to evaluate creative solutions that add value in different ways
- This is not a standard RFP project



# Canadian Oil Sands Development Valuable Lessons



- Investment of \$125 billion
  - Significant new employment, tax revenue, long term growth
  - Extensive new pipeline development
  
- Resulted from proactive progressive political vision that facilitated development
  - Worked cooperatively with industry
  - Generating greater returns for all



# Moving the Project Forward Understand What Is Achievable



- 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

# Moving the Project Forward Understand Canada



## No company has the exclusive right to build a pipeline to ship Alaskan gas in Canada

- 2 Options to Permit the Project Through Canada

### **NPA**

Northern Pipeline Act passed in 1977

Socio-economic baseline impact developed late 1970s

Certificates of Public Convenience and Necessity issued to Foothills Pipeline to build the Cdn portion of the Alaska Natural Gas Transportation System proposal.

Enshrines a 30-year old project never undertaken that has now significantly changed

### **NEB – CEAA**

Modern, efficient and transparent regulatory process

Dove-tails with FERC

Consistent with NAFTA

Contemporary, well understood processes:

First Nations participation

Environmental assessments and practices

Economic benefits through open competition

# Moving the Project Forward Understand Canada



“As we move forward, I am guided by **five principles** that I believe can be **applied to all pipeline decisions:**

- First, they **must not interfere with market forces.** We will **let the market decide.**
- Second, our decisions must be **supportive of a modern regulatory regime**
- Third there must be a **project management approach**
- Fourth, the **pipelines must support Aboriginal economic development**
- Finally, decisions **must ensure that Canadian benefits are realized**”

Honourable Jim Prentice

Minister of Indian Affairs and Northern Development

Presentation to Canadian Energy Pipeline Association Annual Dinner

May 2006

# Moving the Project Forward Final Thoughts



## Enbridge believes:

- Outstanding fiscal issues are the project's "elephant in the living room."
- An unconditional commitment to advance the project is not achievable
- AGIA will best serve Alaskans if it allows for the creativity and innovation that drives the market place.
- Government financial assistance is not essential
- Government can achieve key goals without adding to regulatory process
- Canada will be ready for this project, but claims of exclusivity will be denied
- Alaska should ensure that it does not create a process that is all about process