

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2928 SCOMM 128: HOUSE SPEC.COMM. ON OIL AND GAS, 2001-02

Alaska Royalty-In-Kind Gas Sale

Division of Oil and Gas
January 2002



Alaska Department of
**Natural
Resources**

THE STATE'S ROYALTY SHARE

- **Is a percentage of production**
- **Usually is 12.5% of production, but may be 16 2/3% or 20% of production**
- **May be taken “in-value” or “in-kind”**
 - **When taken “in-value” the gas is left with the producer, who sells 100% of the gas, then pays the state 12.5% of the net proceeds from the sale of 100% of the gas, or the market value of the gas, whichever is higher**
 - **When taken “in-kind” the state physically takes 12.5% of the gas in the field and sells it itself**

**THE STATE MAY TAKE IT'S ROYALTY SHARE OF GAS
EITHER IN-KIND OR IN-VALUE**

The State's right to take gas either in-kind or in value:

- **Is a term of the lease agreement**
- **Allows switching between in-kind and in-value on six month's notice**
- **Is the same for oil and gas**
- **Has been part of the State's lease form for more than 40 years**

**THE STATE'S RIGHT TO TAKE IN-KIND, AND TO SWITCH
BETWEEN IN-KIND AND IN-VALUE, IS VALUABLE**

- **If the reported proceeds on royalty in-value appear low, the state can test the market by offering gas for sale in-kind**
- **If in-state producers are unwilling to sell to in-state purchasers (who may also be competitors of the producers), the state can supply in-state purchasers**
- **The state may be able to command a premium for its gas if it is willing to sell on terms different from the industry standard**

WHY CONSIDER A ROYALTY-IN-KIND SALE NOW?

- **2001 Legislative resolution**
- **Open season requires long-term commitments for pipeline capacity**
- **Governor's policy council**
- **Expressions of interest**

PROCEDURES FOR ROYALTY-IN-KIND SALE

To Date:

First DNR Finding	October 2001
First Royalty Board Hearing	November 2001
First Public Comment Period	Oct – Nov 2001
Second DNR Finding*	December 2001
Request for Proposals*	December 2001

Remaining:

Submission of Proposals	January 31, 2002
Public Opening of Proposals	February 1, 2002
Negotiations Based on Proposals	February 2002
Second Public Comment Period	March 2002
Second Royalty Board Hearing	March 2002
Third DNR Finding	March 2002
Submission of Proposed Contract(s) to Legislature for Approval/Disapproval	April 1, 2002
2002 Legislative Session Adjourns	May 14, 2002

* Available on the web at dog.dnr.state.ak.us

** Remaining dates are subject to change, except date 2002 legislature adjourns

IMPACT OF ROYALTY-IN-KIND SALE ON GASLINE

Three Scenarios:

Case #1: No RIK Sale

***Example:* 15 year nominations required in initial open season
No RIK gas sales during first 15 years of gasline's operation**

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

***Example:* 15 year nominations required in initial open season
15 year RIK gas sales contract, no early cancellation rights**

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

***Example:* 15 year nominations required in initial open season
5 year RIK gas sales contract, commencing at gasline start-up**

IMPACT ON INITIAL PIPELINE SIZING

RIK Sale May Result In Bigger Pipeline

Case #1: No RIK Sale

Example:

PBU + PTU Equity Gas	3.50 bcf/d
PBU + PTU Royalty Share (nominated by PBU + PTU lessees)	<u>.50 bcf/d</u>
Total Pipeline Capacity	4.00 bcf/d

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

Example:

PBU + PTU Equity Gas	3.50 bcf/d
PBU + PTU Royalty Share (nominated by RIK buyer)	.35 bcf/d
PBU + PTU Royalty Share (nominated by PBU + PTU lessees)	<u>.15 bcf/d</u>
Total Pipeline Capacity	4.00 bcf/d

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

Example:

PBU + PTU Equity Gas	3.50 bcf/d
PBU + PTU Royalty Share (nominated by RIK buyer)	.35 bcf/d
PBU + PTU Royalty Share (nominated by PBU + PTU lessees)	<u>.50 bcf/d</u>
Total Pipeline Capacity	4.35 bcf/d

IMPACT ON GAS PIPELINE COMPANY

Full Pipeline Capacity Paid For At All Times

Case #1: No RIK Sale

4.00 bcf/d Pipeline Capacity Nominated

4.00 bcf/d Pipeline Capacity Paid For

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

4.00 bcf/d Pipeline Capacity Nominated

4.00 bcf/d Pipeline Capacity Paid For

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

4.35 bcf/d Pipeline Capacity Nominated

4.35 bcf/d Pipeline Capacity Paid For

IMPACT ON PBU + PTU OIL & GAS PRODUCERS

May Affect, Positively or Negatively:

- **Pipeline Tariff,**
- **Date of Monetization of Stranded Gas Reserves, and**
- **Level of Usage of Gas Treatment Plant (GTP)**

Case #1: No RIK Sale

Gains: Fixed usage level of Gas Treatment Plant

Losses: Smaller pipeline may mean higher per unit tariff
No acceleration of monetization of stranded gas reserves

Case #2: RIK Sale For Same Duration As Nominations In Initial Open Season

Gains: Fixed usage level of Gas Treatment Plant

Losses: Smaller pipeline may mean higher per unit tariff
No acceleration of monetization of stranded gas reserves

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

Gains: Larger pipeline may mean lower per unit tariff
Acceleration of monetization of stranded gas reserves

Losses: Usage of Gas Treatment Plant may vary between 4.00 and 4.35 bcfd

IMPACT ON PBU + PTU PRODUCERS

(Continued)

Producers Can Mitigate Impact on Level of Usage of Gas Treatment Plant

Case #3: RIK Sale For Shorter Duration Than Nominations In Initial Open Season

Gains: Larger pipeline may mean lower per unit tariff
Acceleration of monetization of stranded gas reserves

Losses: Usage of Gas Treatment Plant may vary between 4.00 and 4.35 bcfd

Solutions: Leave .35 bcfd (8%) of GTP capacity idle after 5 years

Sell .35 bcfd GTP capacity to RIK purchaser

Expand pipeline capacity .35 bcfd (or more)

Negotiate for better solution

IMPACT ON PBU + PTU PRODUCERS

(Continued)

Are PBU + PTU Producers Unfairly Disadvantaged?

- **State's right to take in-kind or in-value exists under all leases**
- **State's right to switch between in-kind and in-value exists under all leases**
- **A decision to sell royalty gas from PBU + PTU now does not preclude future RIK sales from the same units or other leases or units**
- **Future sources of royalty gas may be equally "disadvantaged"**

PIPELINE CAPACITY

Initial:	4.5 bcfd	
Optimization:	4.6 – 4.7 bcfd	(+.1 - .2 bcfd)
Expansion through Compression:	5.6 bcfd	(+1.0 bcfd)
Further Expansions:	full length looping future technology	

OBSTACLES TO FUTURE EXPANSIONS

- **Arguably, FERC cannot compel expansion, even where economic**
- **Party or parties must have additional 1+ bcfd gas for expansion**
 - **Party with less than 1 bcfd gas powerless on timing of expansion**
 - **Currently appears PBU/PTU Producers will control timing of expansion**

Current Hydrocarbon Flow

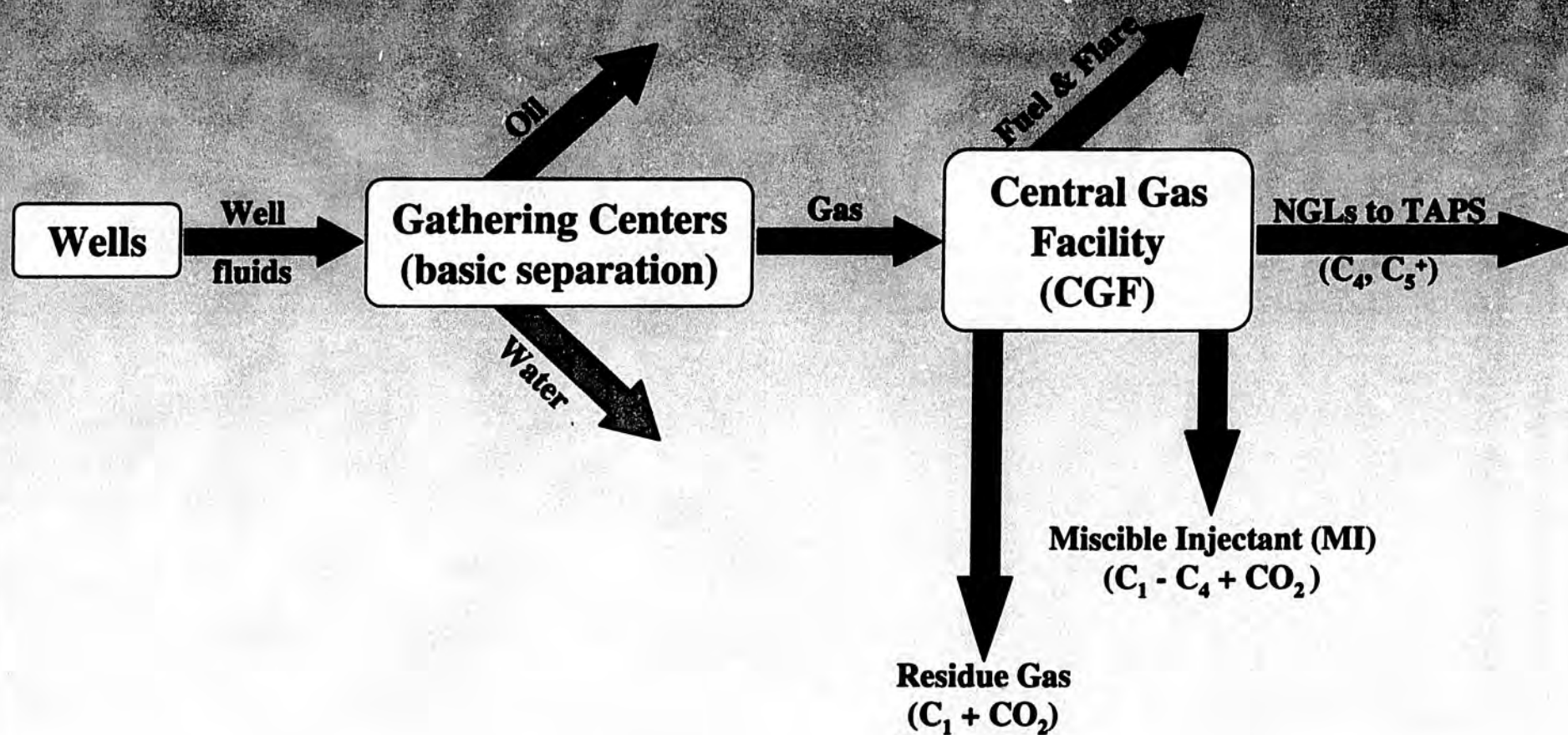


Figure 1

Current Hydrocarbon Flow - Volumes

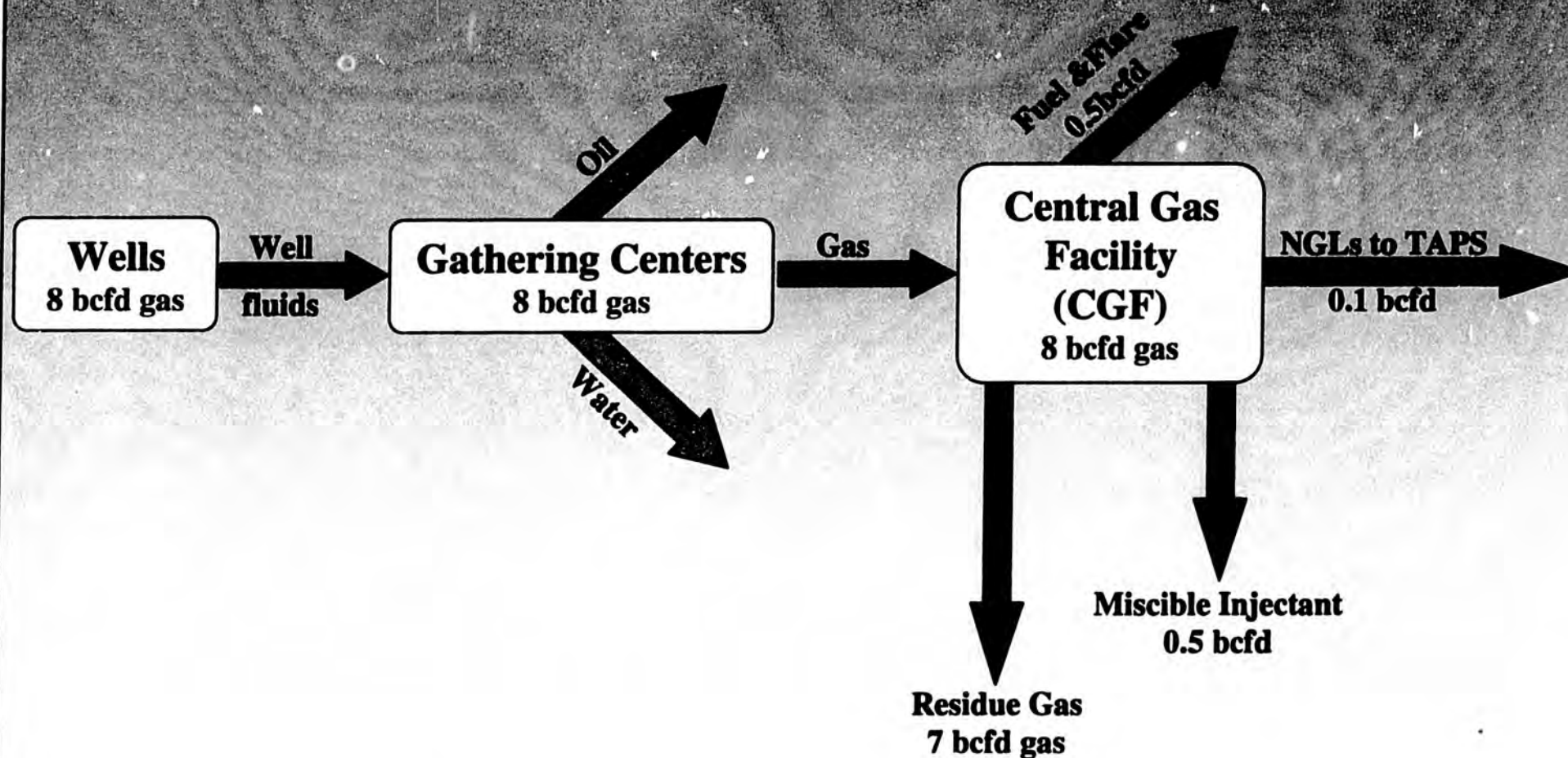


Figure 2

Future Hydrocarbon Flow

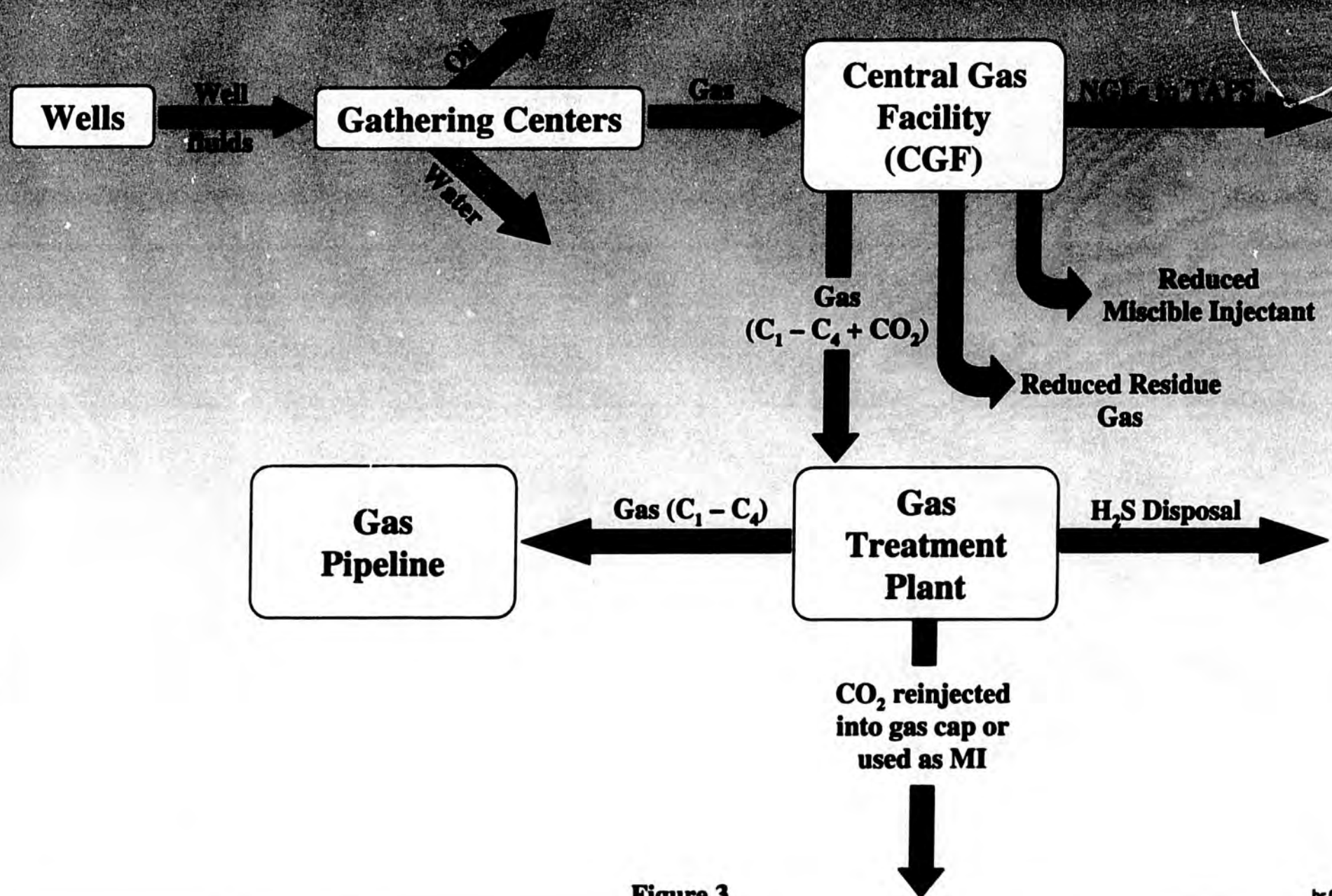
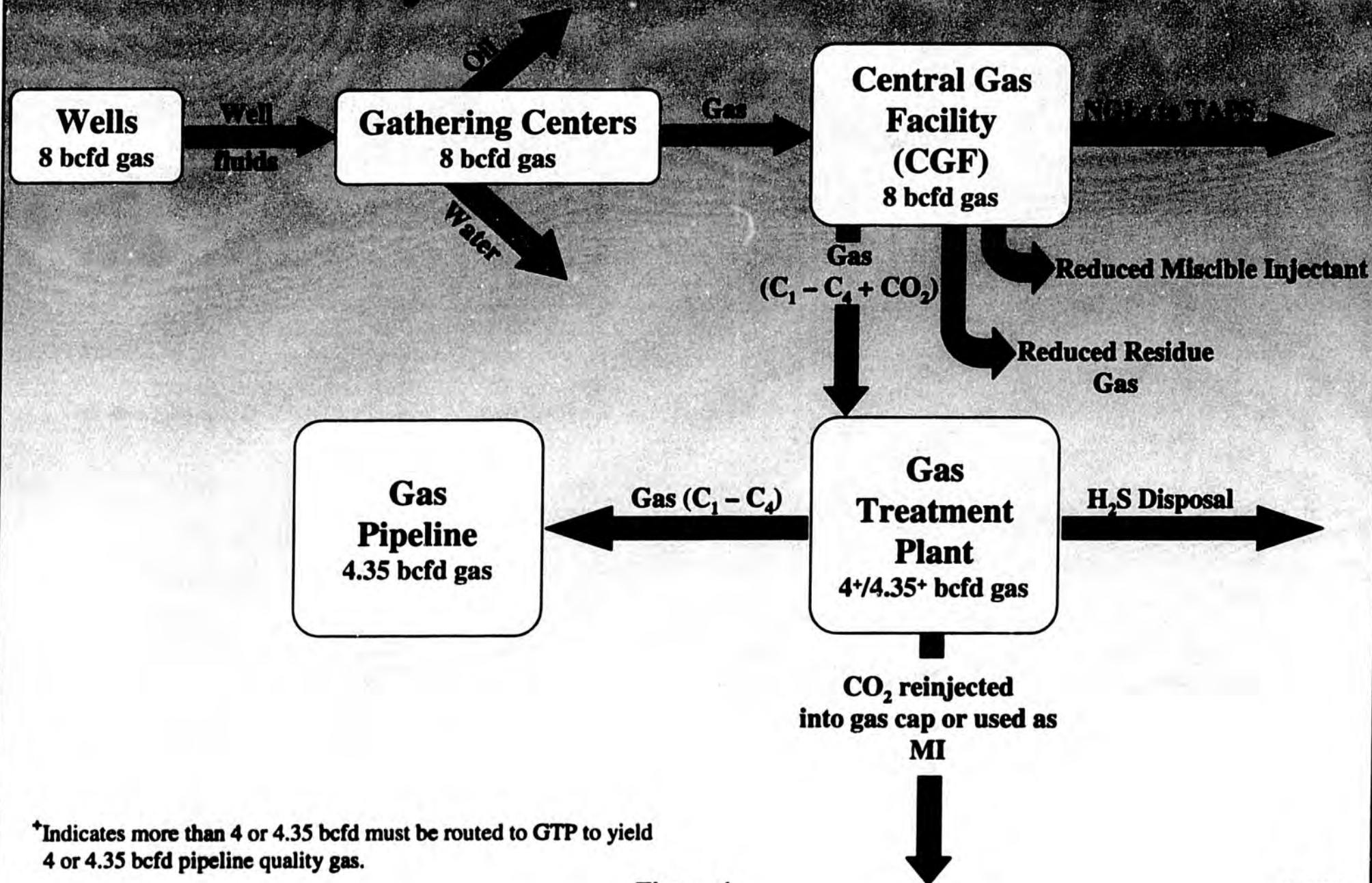


Figure 3

Future Hydrocarbon Flow - Volumes



*Indicates more than 4 or 4.35 bcfd must be routed to GTP to yield 4 or 4.35 bcfd pipeline quality gas.

Figure 4



Alaska Gas Producers Pipeline Team
601 W. 5th Ave. Suite 500
Anchorage, Alaska 99501
1 (907) 770-8000

January 15, 2002

Mr. Pat Pourchot
Commissioner
Alaska Department of Natural Resources
400 Willoughby Avenue, 5th Floor
Juneau, AK 99801

Re: North Slope Royalty Gas Sale Solicitation
Request for Reconsideration of Best Interest Finding

Dear Commissioner Pourchot:

The undersigned represent BP Exploration (Alaska) Inc., ExxonMobil Production Company, a division of Exxon Mobil Corporation, and Phillips Alaska, Inc. Please consider this letter as our request for your reconsideration of the Final Finding and Determination for a Solicitation for Offers to Purchase Alaska North Slope Royalty Gas, dated December 26, 2001 (the "BIF").

As you know, our three companies, and our affiliates, have expended in excess of \$100 million evaluating the feasibility of commercializing the ANS gas resources through the construction of a gas pipeline from the Alaska North Slope to markets in Canada and the "lower 48" states of the United States. To date, we have been unable to identify an economic project. We welcome State of Alaska actions that increase the prospects for project sanction. In that regard, we note that the BIF acknowledges that a gas pipeline project is "by no means certain."¹ We agree, and thus urge the State to focus its efforts on supporting the federal enabling legislation proposed by our companies, advancing discussion of terms and conditions that would enhance certainty in the state's fiscal regime, and other actions that would increase the prospects for an economic project. In contrast, we believe the Department of Natural Resources' solicitation for offers to purchase royalty in kind gas as currently structured is both premature and damaging to the prospects for project sanction.

The BIF states that the RIK solicitation schedule is driven by a desire to accommodate potential buyers who "are motivated to purchase RIK gas at this time in order to be able to nominate capacity on the gas pipeline during an 'open season,' which is currently expected to occur in 2002."² Contrary to this assertion, we do not foresee that we will

bp



ExxonMobil



conduct an open season in 2002. Moreover, we have consistently said that we would not proceed with a project that is not supported by the State of Alaska.

The BIF is based on the premise that the proposed sale of royalty gas would "possibly stimulate an earlier commercialization of ANS gas."³ We disagree. To the contrary, the proposed sale increases the risks for the parties with proven resources, who will ultimately underpin the costs of the pipeline construction. This increase in risk further burdens a project that has yet to be shown to be economic. Moreover, it is unreasonable to assume, as the BIF does, that the pipeline will be overbuilt on the basis of nominations backstopped by RIK gas. The project is being designed to optimize pipeline construction and field development (albeit with expansion potential in mind). Any overbuilding for RIK volumes would be inherently suboptimal.

Finally, the BIF asserts that "[t]he producers acknowledge that the FERC cannot compel a pipeline owner to expand capacity. It is presumed that competitive market forces will provide the necessary incentives."⁴ No precedent is cited in support of this assertion.

In fact, the Federal Energy Regulatory Commission (FERC) asserts that it can compel pipeline expansions in appropriate circumstances.⁵ FERC has implied they would apply the same principles they have applied in interconnection situations, and that would suggest expansion if

1. The party seeking the expansion is willing to bear the costs of construction,
2. The expansion can be accomplished in compliance with the pipeline's technical requirements,
3. The expansion and resulting transportation does not diminish service to the pipeline's existing customers,
4. The expansion does not cause the pipeline to be in violation of any applicable environmental or safety laws or requirements, and
5. The expansion does not cause the pipeline to be in violation of its right of way agreements or any other contractual obligations.⁶

We would be happy to meet with the State and the FERC to discuss these issues to assure a common understanding of these issues.

In conclusion, we believe that FERC regulatory authority will insure that future expansions of transportation capacity for North Slope gas are based solely on market forces. By contrast, the RIK "backstop" mechanism under consideration by the Department of Natural Resources is contrary to the modern FERC market-based principles, since it would burden the initial project with a reservation of capacity for as-yet unproven, and thus currently uneconomic, gas resources.

Mr. Pat Pourchot
January 15, 2002
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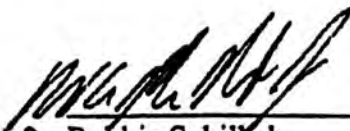
We request that you exercise your authority to cancel the solicitation. Alternatively, we request that you delay the solicitation until at least December 2002.

Please mail any notice or decision concerning the appeal to:

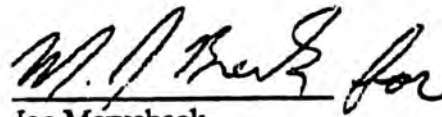
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We appreciate your reconsideration of this important matter. While we do not request a formal hearing, we would be pleased to meet with you to address our conviction that the state's proposed sale will have a negative impact on the prospects for the construction of a gas pipeline and our belief that there is, in any event, no need to rush the timing of the solicitation.

Sincerely,


for Robbie Schilhab

Ken Konrad


Joe Marushack

cc: Mark Myers

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January 15, 2002
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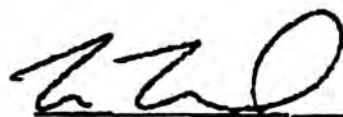
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¹ BIF at Section I.B.

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³ BIF at Section IV.A.

⁴ BIF at Appendix B-8.

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

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⁶ Panhandle Eastern Pipeline Co., 79 FERC P61,016 (1997), ANR Pipeline Company v. Transcontinental Gas Pipe Line Corp., 91 FERC P61,066, 2000 FERC LEXIS 823 (2000)



Remember what happened...



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Anchorage Daily News

North Slope gas opened to bidders

ROYALTY: State hopes to spark interest and test the market.

By Paula Dobbyn

Anchorage Daily News

(Published: December 27, 2001)

In a bid to stimulate exploration and test the market, the state is offering to sell North Slope natural gas directly to buyers for the first time. Bids can be made through the end of next month through the Alaska Department of Natural Resources.

As owner of the land, the state collects a percentage of oil and gas produced from state leases. Typically the state collects cash from the producers instead of actually finding buyers for the gas. State officials also sometimes take this "royalty" oil or gas and sell it directly to the highest bidder.

On the North Slope, the state has never taken that step before with its gas. But a natural gas policy advisory group appointed by the governor recommended such a move in November.

The state's option to sell its royalty gas directly must be retained, the advisory group said. Sales of royalty gas to companies other than producers will foster competition, leading to greater values and more benefits to residents, it said.

Although the state will be taking bids, it might not go through with the sales. Much will depend on the prices offered and to what extent the bidders' plans for the gas would benefit Alaska residents, said Mark Myers, director of the state Division of Oil and Gas.

Huge amounts of North Slope natural gas are produced now, but most is injected back underground to help produce more oil and because there's no way to get it to market; a little is used to power the oil fields or becomes liquid during production and then is put in the trans-Alaska oil pipeline.

The main North Slope companies are considering whether to pursue a multibillion-dollar gas pipeline project. If that happens, the state as landowner would get the fourth largest share of production, behind Exxon, Phillips and BP.

The state has received numerous inquiries about royalty gas from exploration and gas trading companies that want to see the pipeline built, said Kevin Banks, state petroleum market analyst.

To get the financing needed to make the pipeline a reality, the companies must show lenders signed contracts with gas suppliers to demonstrate that enough gas will flow through the line. Giving exploration companies the option of purchasing royalty gas puts them on more solid financial ground because if they don't find enough gas on their own, they have the option of buying it from the state, said Banks and other industry watchers.

"It removes some of the risk about getting gas into the pipeline," Myers said.

Spokesmen for BP Exploration (Alaska) Inc. and Phillips Alaska Inc. declined to comment.

"It's just good business sense," said Frank Brown, an oil and gas consultant and former senior vice president at Arco Alaska Inc.

"What the state needs to do is to preserve its option. Rather than depending on the big oil companies to market their gas for them, they need to preserve their options," said Brown, who co-chaired the governor's natural gas advisory group.

Reporter Paula Dobbyn can be reached at pdobbyn@adn.com or 907 257-4317.

Close Window

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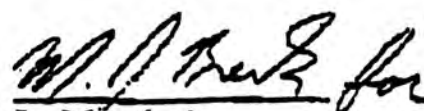
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Subject: Re: House Oil & Gas

Date: Mon, 14 Jan 2002 16:06:09 -0900

From: "Ken Thompson" <ken@pacrimldr.com>

To: "Linda Hay" <Linda_Hay@Legis.state.ak.us>

Linda, I strongly support the State selling part - not all - of its royalty gas "in kind" versus "in value". This was a key recommendation from my "In-state Gas Use Committee" of the Natural Gas Policy Council. Selling part of the royalty gas to a high bidder creates more natural gas marketing competition. There are other pluses also. Importantly, the State would only sell to a third party if the netback natural gas price exceeded at least the average of the netback prices being received by the producers, so value of the RIK gas would be maximized.

Linda, I have attached excerpts from my committee's recommendations and conclusions from the Natural Gas Policy Council that highlights my and our committee's views. As Representative Ogan reviews what the State considers, any deal should meet the recommendations in the attachments.

Linda, importantly, I did review the DNR-DOG final "solicitation for RIK gas bid" letter that went out to potential bidders. I agreed with that overall and believe it is the best course of action. I did, however, have one major difference of opinion: the DNR is putting up for bid 70% of the State's RIK gas share. At this time, I personally would put up for bid only 50% of the State's RIK gas share to ensure we have enough gas for in-state markets and in-state use in the event the Cook Inlet deliverability falls more quickly than we forecast. If Cook Inlet gas deliverability forecasts are accurate, additional RIK gas could be sold to a third party at that time.

Additionally, I don't think we should sell all the RIK to one bidder, but perhaps to the top two bidders...to create competition even among those third parties and to keep good companies other than the producers interested in marketing Alaska's natural gas.

This note and the attachment really summarizes my views. If you or Representative Ogan have questions, please e-mail me or give me a call at 907-770-1600. I also can testify to the House Oil and Gas Resources Committee if needed. Ken

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

From: "Linda Hay" <Linda_Hay@Legis.state.ak.us>

To: <ken@pacrimldr.com>

Sent: Monday, January 14, 2002 2:00 PM

Subject: House Oil & Gas

> Ken. Rep. Ogan has asked me to contact you and get your thoughts on the
> administration's decision to sell "royalty gas". We have scheduled a
> hearing for Thursday, January 17th, from 10 - noon. We will begin with
> an overview by the the Division of Oil & Gas on what has transpired
> since adjournment and then begin a discussion regarding the royalty gas
> sale issue. We are interested in your thoughts on this decision. Look
> forward to talking to you and perhaps seeing you here in Juneau in the
> near future.

> Linda Hay
> O & G Committee Aide
> 465-2283 (direct line)
>
>

EXCERPTS FROM NATURAL GAS POLICY COUNCIL REPORT
KEN THOMPSON'S "IN-STATE GAS USE COMMITTEE"
RECOMMENDATIONS, CONCLUSIONS REGARDING RIK GAS SHARE

Goal: Assess the costs or benefits of the state taking its royalty share "in kind" for facilitation of in-state access and use.

Recommendation:

The State should retain its right to take its royalty share of gas on the North Slope "in kind" or "in value". This flexibility creates competition to maximize wellhead value for the State by either the producers or other firms such as energy trading companies interested in marketing the State's share of gas. The producers have requested a long-term commitment by the state and are asking the State to decide up front to take either "in-kind" or "in-value". The council feels the flexibility to switch on six months notice is very important, creates marketing competition, and will ultimately maximize resource value. The State should not negotiate away its right to take its royalty share of gas "in-value" or "in-kind".

Recommendation:

The state could maximize the value of its natural gas royalty resource with a mixed portfolio of "in-value" and "in-kind" sales, with in-kind royalty marketed by energy trading companies such as Duke Energy, Enron, Williams Energy or major companies like them. The state should put its royalty "in-kind" gas out for bid and seek bids from multiple parties for contract terms and price. Such contracts should ask for a "floor price" equal to or exceeding the average netback wellhead price achieved by the three major producers or from "in value" sales as "insurance" that the energy trading companies are working in their marketing to beat the producers gas sales realization.

Recommendation:

When there are out-of-state sales using an energy trading company, the energy trading company will reserve the capacity and the liability associated with that capacity, and that liability will not fall back on the state.

Recommendation:

The State may choose to direct market some portion of its gas to in-state consumers using State staff, but it is recommended that sales to customers in outside markets be handled by professional energy trading firms, considering the complexity of and rapid change in those markets. This would also allow those firms to absorb the risk of nominating pipeline capacity and buying hedging instruments to lessen risk on pricing of contracts.

Recommendation:

By keeping some portion of its royalty share of natural gas "in-kind", the State may be able to make some contract deals with consumers in-state at more favorable terms than the producers, as the State might realize added dollar benefits through jobs and corporate taxation of value-added processing such as natural gas liquids processing, petrochemical manufacturing, power generation, etc. that may not otherwise be economically viable to entrepreneurs within the State. However, there should not be a subsidy in sales of royalty-in-kind gas. The state should receive a netback price for royalty gas equal to or greater than the market-based "netback value" of gas on the North Slope.

Recommendation:

To the extent practical, the State of Alaska should enforce its "higher of" clauses on natural gas royalty as this could add value and ensure producers work hard in their marketing to obtain the best value in their sales of natural gas. When the State elects to take any share of its royalty gas "in value", existing lease terms and statutes allow the State to receive royalty payments and production taxes on the "higher of" actual proceeds or market value. Other states, as well as the U.S. Minerals Management Service, are aggressive in ensuring all producers pay this "higher of" price for royalty and relevant taxes and receives such payments from the same producers that produce on the North Slope.

Recommendation:

Because of the complexities of the natural gas industry and the differences with the oil industry, the State should form a Natural Gas Services Group with people experienced in the natural gas industry, shipping, marketing, and trading so that the State becomes even more sophisticated in understanding deals and transactions that are often involved in the natural gas business. The group would provide an oversight function on sales of royalty gas out-of-state, but could also negotiate and manage in-state sales much like the Division of Oil and Gas now manages sales of royalty oil.

Recommendation:

For more cost effective development of in-state gas infrastructure resulting in more economical transportation of state royalty gas within the State, the State should encourage entities to examine the port authority concept of tax advantaged financing for a gas "hub", spur lines, and other distribution facilities.

Conclusions:

* Current North Slope oil and gas leases, and state statutes, allow state royalty production share to be taken "in kind", i.e. physically take the oil or gas and market the products itself or arrange for other parties to purchase the gas at market

value contracts; or to take "in value", i.e. allow the producers to sell the products and pay the State their realized value of wellhead price after deduction of certain transportation costs. The state has the option to switch between taking its royalty share "in-kind" and "in-value" every six months. Current state law requires any "in-kind" sales, however, to obtain values equal to or higher than "in-value" sales.

* The current North Slope producers have complied with the "in kind" or "in value" lease terms and statutes in other states and on federal offshore leases for decades and have instituted internal procedures that allow them to process the selection of "in kind" or "in value" promptly. Other states and the federal government also have internal processes for administering the switch between "in kind" or "in value" as does the State of Alaska for its royalty share of oil. The producers' arguments that Alaska must decide up front on "in kind" or "in value" to ease marketing and sales administration or to bring more certainty to gas transportation or marketing are not valid considering the same producers' decades of experience administering such programs for transportation and marketing elsewhere successfully.

* The natural gas industry in the U.S. is very sophisticated in gas trading and marketing. There are energy trading companies which may be able to market the state's royalty gas for a higher netback price than would be paid by the producers if the gas were taken in-value. If so, the state's leases include a "higher of" clause which means producers would have to pay royalties and taxes on the higher of their actual netback wellhead price or the actual netback wellhead price of an energy trader. This, in a way, creates competition and options to achieve the best possible wellhead netback value.

* In testimony from the General Land Office of Texas, the committee learned that Texas has similar "higher-of" clauses in their state leases that they enforce. In 2000, enforcement of the "higher-of" clauses, with producers paying royalties and taxes on the highest actual netback wellhead price achieved on various leases, resulted in additional revenues of \$17 million. Alaska's royalty gas sales will be ten times higher than Texas' volume of royalty gas sales.

* Alaska may achieve higher prices on some of its royalty gas by allowing energy trading companies to market the State's "in kind" share. The State of Texas takes 53 percent of its royalty gas in-kind and 47 percent in value, and claims to achieve higher prices on much of its royalty-in-kind sales by achieving better negotiated pipeline tariffs, higher customer prices, or integration for power generation.

* However, the flexibility in taking royalty-in-kind is important for other reasons as well as price. First, royalty sales will allow the state to periodically test the market, to assess whether it is getting fair market prices from producers. Second,

allowing energy trading companies to market royalty gas will create more competition by their accessing different customers than the producers and broadening the market exposure of Alaska's natural gas.

* While Texas is able to market its royalty gas with a small staff of state employees, Alaska should "outsource" its sales of royalty gas to the Lower 48 or other outside markets through an experienced gas trading firm. Because large volumes of Alaska royalty gas may be marketed in several of the Lower 48 gas markets or outside markets initially, a thorough understanding of and experience in those markets will be required.

* On the other hand, it may be more appropriate that the state negotiate directly for sales within Alaska of in-kind royalty gas as is now done with royalty oil, because of the better understanding of local conditions. A section within a new Natural Gas Services Group could perform this function.

* The concept of a public authority owning a segment of a natural gas pipeline within Alaska may present significant benefits for transportation of state royalty gas to in-state users. The tax advantage of a public authority, for example, would allow a lower tariff for transporting gas within the State, and resulting savings could help generate more business activity by providing natural gas at lower prices to consumers. The netback price, however, should remain at market values.

**Williams [NYSE: WMB]
Alaska North Slope Royalty Gas
January 31, 2002**

Alaska North Slope Royalty Gas Offer

Williams is pleased to participate in the State of Alaska's Solicitation for Offers issued Dec. 26, 2001, for the Alaska North Slope Royalty Gas. It is Williams' standard practice to submit all such responses under confidential terms and conditions. Therefore, the specific terms and conditions included in Williams' response submitted to the State of Alaska on Jan. 31 will not be able to disclose at this time.

Williams has a long history of working with the State of Alaska through contractual agreements to purchase the state's Royalty Crude.

Williams in Alaska

Williams operates the state's largest refinery at North Pole, processing 215,000 barrels per day of Alaska North Slope crude into 70,000 barrels of products (primarily jet fuel) per day. Williams also operates terminal facilities in Anchorage and Fairbanks and 29 convenience stores in the State.

Williams spent nearly \$1 billion for goods and services in Alaska during 2001, primarily for crude oil supply. Williams has more than 500 employees in Alaska with an annual payroll in excess of \$20 million. Williams is a large customer of the state-owned Alaska Railroad. And, Williams is a major contributor with dollars and manpower for a wide range of charitable groups.

About Williams

Williams, through its subsidiaries, connects businesses to energy, delivering innovative, reliable products and services. Williams information is available at www.williams.com.

Offer

To Purchase Alaska North Slope Royalty Gas

By

Alaska Power & Telephone Company

January 25, 2002

1. Qualification to Offer was submitted to Department of Natural Resources, Division of Oil and Gas on January 7, 2002. A copy of that submission is attached.
2. We hereby commit to a cash bonus of \$1.00 per Mcf per day.
3. We hereby agree to a Maximum Quantity of 1600 Mcf per day.
4. We hereby agree to pay at a "minimum" the base price as established in Article 3.3.1 of the sample contract.
5. Attached is a white paper that discusses the economic benefits of converting the power plant to use natural gas as its primary fuel and also building a small natural gas distribution system. Both the power system and the natural gas system would be located in Tok, Alaska. This paper indicates significant economic benefit to our existing electric customers as well as our proposed future natural gas customers.

Alaska Power & Telephone Company

By 

Its President

ANADARKO/AEC
OFFER FOR ROYALTY GAS SUMMARY
January 31, 2002

1. Cash Payment: \$350,000.
2. Option Payment: \$2 million up-front and an additional \$2 million at each 5 year term renewal.
3. Price Premium: \$0.02 per MMBtu first 5 years, with \$0.02 per MMBtu increases at each 5-year term renewal.
4. Reservation Fee: Equal to one percent (1.0%) of the sum of the Base Price and the then applicable Price Premium, subject to a cap equal to the then effective Price Premium.
5. Exploration Work Commitment: A minimum \$50 million expenditure for exploration and development in the gas-prone Brooks Range foothills ("Foothills") for 2002-2007.
6. Preference for Local Hire: The Purchasers agree to a local hire preference.
7. Training Obligation: In the even of a commercial Foothills gas discovery, the Purchasers agree to an annual training obligation of not less than \$25,000 per annum commencing the year of commercial discovery declaration and for a period of not less than ten (10) years.
8. Preference for In-State Gas Processing: The Purchasers agree to give preference to in-State processing of both the purchased State ANS Royalty Gas and any gas discovered in the Purchasers' Foothills exploration efforts. Such in-State processing must afford the Purchasers equivalent terms and conditions that they could otherwise receive for out-of-state processing.
9. In-State Usage Reservation: The State is afforded an in-State gas use preference to the extent the Purchasers' 70% call would exceed 350 MMcfd.
10. Call Option: APC and AEC granted right to call for all or a portion of State's royalty gas up to 70% of State's ANS royalty gas (Estimated at 350 MMcfd).
11. Quantity: Up to 70% of State's ANS royalty gas at APC's/AEC's election (Estimated at 350 MMcfd).
12. Employment & Economic Impact Related to the Exploration Work Commitment: Anchorage based Northern Economics has prepared a study quantifying these two benefits with respect to our Exploration Work Commitments under both an "Exploration Only Scenario" and a "Successful Development Scenario". The Exploration Only Scenario yields total in-State economic value of \$40 million and creates an annual average of 180 new jobs. The Successful Development Scenario yields total in-State economic benefits of \$6.4 billion and creates an annual average 560 - 3,300 new jobs, depending upon the operations mode (exploration, development, or production).
13. Offer Value Per Mcf: The Purchasers' Offer yields a value of \$0.09 per Mcf and \$10.06 per Mcf, in the Exploration Only and the Successful Development Scenarios, respectively. These values were computed based upon a purchase quantity of 639 Bcf during the Primary Term of five (5) years.

14. Term: Call option for primary term of 5 years ending at 5th anniversary of Pipeline being placed in full, normal service. APC and AEC have the option to extend the term for additional 5-year intervals with additional Option Payments and escalations in the Price Premium. Term cannot be extended beyond the term of the transportation contracts secured for such gas.
15. Early Termination Provision: Either Party may terminate early if (i) the Royalty Board and Legislature have not approved the definitive Agreement by August 31, 2002; (ii) no Pipeline open season has occurred by March 31, 2005; or (iii) the Pipeline is not in service or State Royalty Gas has not been delivered by July 31, 2012.
16. Point of Delivery: To be negotiated between the State and the Purchasers.
17. Firm Transportation Service Release: If APC/AEC are unsuccessful in securing firm transportation on the Pipeline in quantities equal to or greater than the volume necessary to achieve an economic gas development, APC/AEC may terminate the Agreement without further obligation.
18. Separate Agreements: Anadarko and AEC will enter into separate Agreements with the State for one-half of the option volume rights and one-half the obligations. Initial Agreements shall be equivalent, but administration and application shall be separate and independent.

**Testimony of Ken Konrad, Sr Vice President BP Exploration (Alaska) Inc.
to**

**House Oil and Gas Committee Hearing on
State Royalty In Kind Gas Sale Proposal**

February 5, 2002

Good Morning. My name is Ken Konrad. I am Vice President for BP's Alaska Gas business. Thanks for inviting me to speak here today regarding the State's proposed Royalty in Kind gas sale.

I'd like to begin by saying that BP supports the State's right to take gas in kind. We also fully support exploring for new sources of gas that could be produced into a gas pipeline. Furthermore, we support gas pipeline capacity expansion on open, fair and reasonable terms.

BP, and our major partners, are in the process of completing a major feasibility and engineering study on a possible gas pipeline. A central premise in that study is designing a pipeline system that can be easily expanded - and we have been successful in achieving a design that has higher expansion capability at lower cost than any other proposal we have seen. Efficient pipeline expansion can benefit both existing producers and explorers.

We understand the State's desire to see development of additional gas beyond the existing known resource. Indeed, the feasibility study we have undertaken this year assumes that additional gas will be found beyond the 35 TCF of currently identified gas. We currently assume at least 50 TCF of total gas will be needed during the life of a project.

Separately, BP is working on a major study with the DOE and the University of Alaska - Fairbanks to study possible ways to produce the enormous gas hydrate resource known to exist in and around existing north slope fields - this resource alone has been estimated at nearly 50 TCF. This is long term possibility with many technical challenges but is indicative of our active support for new sources of gas supply.

We support the States right to take gas in kind. This is clearly a choice the State should make on its own. Our sole request is that the State do so in a predictable manner that is consistent with how a contract carry gas pipeline will operate.

So we fully support the State's ability to take in kind, we fully support pipeline expansion on fair and reasonable terms and we fully support finding new sources of gas supply.

We do however have concerns over the proposed State sale of RIK gas as currently structured and also with respect to timing. We have openly discussed our concerns with the DNR over the past several months.

The State has frequently indicated that this proposed RIK sale is being driven by the perception that the Alaska Gas Producers Pipeline Team may hold an "open season" for

pipeline capacity in early 2002. We do not foresee any possibility of holding an open season during 2002.

As we have stated previously, for a gas pipeline to attract investment, there must first be an economic project. To reduce project risks, there must also be a predictable and viable government framework in place to support investment. Both federal regulatory legislation and clarity around State tax and royalty are important pieces of this government framework. Neither of these vital ingredients are currently in place.

According to DNR, the State's proposed RIK gas sale is being pursued to provide a free capacity access option to explorers without currently proven gas resources. The idea being that explorers could use the state's RIK gas to backstop their own bids for firm transport capacity on a new build line and then release the RIK gas back to the state should they find their own reserves.

The ability of RIK purchasers to return gas to the state on relatively short notice places a significant additional burden on our overall project economics by increasing the uncertainty on the amount of equity gas the major producers would be able to ship - i.e. uncertain cash flow. This burden on a sub-economic project is a clear step in the wrong direction.

For example, if a pipeline is designed to transport 4bcfd (just an example) and the State took 1/8th of this gas in kind - 500 mmcf/d - an RIK purchaser could use its purchased gas as a backstop for making a long term firm transportation commitment on a gas line. The balance of the FT commitments to get the line built would be made by the known resource owners. Should an RIK purchaser discover its own gas resources, it could cancel its purchase contract with the state and substitute its own gas into its Firm Transportation commitment. The State's gas would then revert back to the known resource owners in the form of RIV gas thus reducing by 500mmcf/d the amount of their own gas that the resource owners could export via their own fixed-volume of FT commitment. This reduction in cash flow is against firm financial commitments that have already been made.

The State's RIK proposal clearly seeks to transfer benefits from long term investors to new participants without transferring the risk associated with the massive investment that will be required to make any gas pipeline a reality. Such subsidies at the expense of those who will ultimately underwrite any new build pipeline are both unfair and, more importantly, reduce the chances of developing an economically viable project.

There is no access to a pipeline that never gets built.

BP supports the State's right to take gas in kind. We support pipeline expansion on fair and reasonable terms. We support vibrant exploration for gas. We believe FERC will ensure fair and open access to any gas pipeline.

However, we cannot support the State's proposed RIK sale as it is currently structured. We are deeply concerned that efforts to fix a problem that doesn't exist with economically

burdensome solutions cannot be in the best interest of the State, especially if those solutions could cause a gas pipeline project not to proceed at all.

Thank you

**Phillips Petroleum Company Testimony
House Oil and Gas Committee Hearing
Tuesday, February 5, 2002**

Good Morning, Mr. Chairman, members of the committee. My name is Michael Hurley and I represent Phillips Alaska. Simply stated, we believe the department's proposed royalty in kind sale of North Slope gas, as currently envisioned, further burdens an already economically challenged project.

Let me begin by saying that we understand the State's goal to ensure third party access to a gas pipeline. We understand that goal, and the State's desire to increase the value of their unleased acreage. As the state's most active explorer, Phillips has a keen interest in ensuring expandability and access in a new gas pipeline. We do not, however, believe that the department's RIK backstop proposal is the most appropriate way to address these goals.

Let me walk you through a simple example of the potential impacts of the department's proposal.

[example on next page]

This example demonstrates the department's RIK backstop sale proposal results in decreased revenues to us, and increases the level of uncertainty in the project. We have a hard time envisioning how to move forward on the project with this situation unchallenged.

In closing, we share the state's desire for equitable pipeline access. We are committed to fair and open access to any gas pipeline in which we participate, consistent with the regulatory requirements and direction of the Federal Energy Regulatory Commission. They have a regulatory structure in place which requires open, non-discriminatory access for both initial and expansion volumes. And we believe their regulatory oversight will ensure, as it does throughout the US, that all potential shippers are treated fairly and that economic burdens are distributed equitably.

We encourage you to look carefully, as you consider this proposal, at the impacts it has on the economics of the other potential shippers, who's long term shipping commitments will underpin the financing of the project.

Mr. Chairman, thank you for this opportunity to explain our position on this proposal. I'd be happy to try to answer any questions you might have.

Royalty in Kind Backstop Sale Example

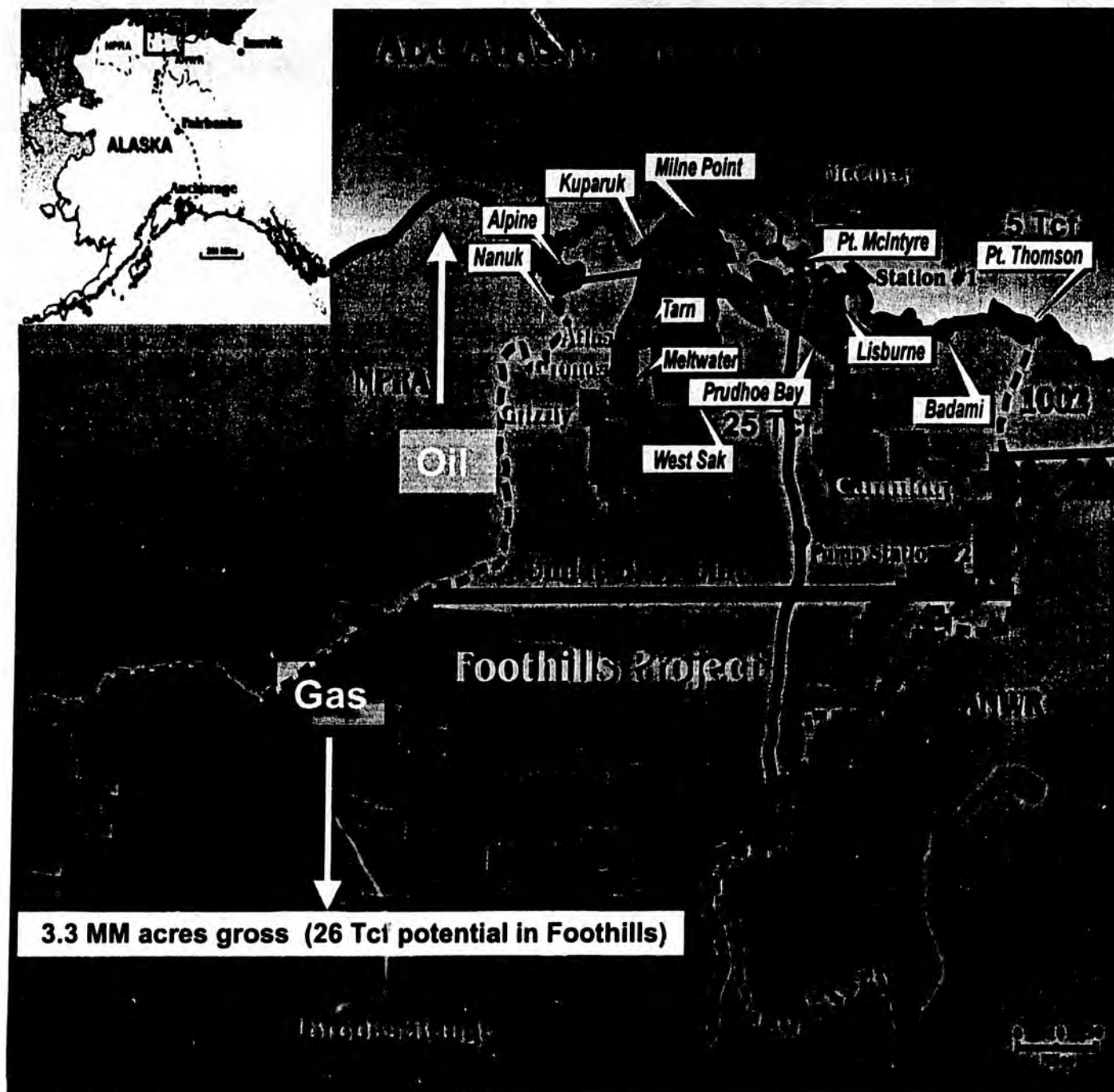
Total System in MMCFD	4,000
Royalty at 12.5 %	500
RIK Sale at 70%	350

<u>During RIK Sale</u>		<u>After Termination</u>
3,500	Producer Equity Gas	3,194
150	Royalty in Value	456
3,650	Producer Shipped Gas	3,650
350	Others Shipped Gas	350
4,000	Prudhoe Bay Gas	3,650
0	Other Non-Prudhoe Gas	350

Royalty In Kind (RIK) Sale

House Special Committee on Oil & Gas

Alan Sharp
AEC Marketing (USA) Inc.
February 5, 2002



Alaska* Players

Proven Reserves (Tcf)

• BP	9
• Exxon	10
• Phillips	9
• Chevron	2
• Other	< 1
	30

Other

- AEC
- Anadarko
- "others"

* North Slope Players; volumes include State royalty volumes

Why RIK in 'best interest' for State

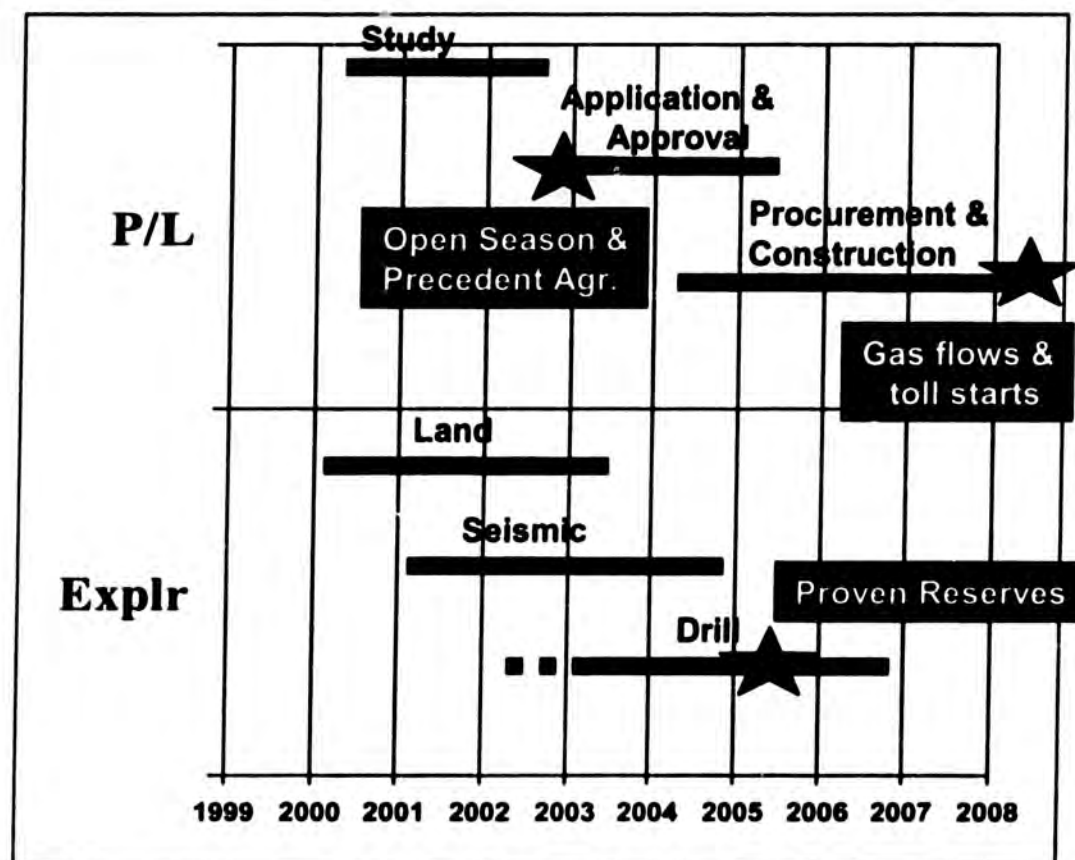
- No risk - leveraging gas volumes of tomorrow to support exploration projects of today
- Maximizes State's royalty value
- More players => more competition => more jobs => more revenue
- Elevates State to significant stakeholder in Pipeline and inclusion on the Pipeline negotiations
- Exploration dollars & jobs today (otherwise in 20 years)

Why do we need RIK now

- RIK sale requires at least 5 months
- Legislative approval required (Jan-May)
- No AGPPT open season commitments
- Explorer Open Season recommendations
 - on or later than June 2003
 - 6 months advance notice
 - disclosure of tariff (terms & conditions)
 - access, expansion, & tolls
 - reasonable expansion capacity increments

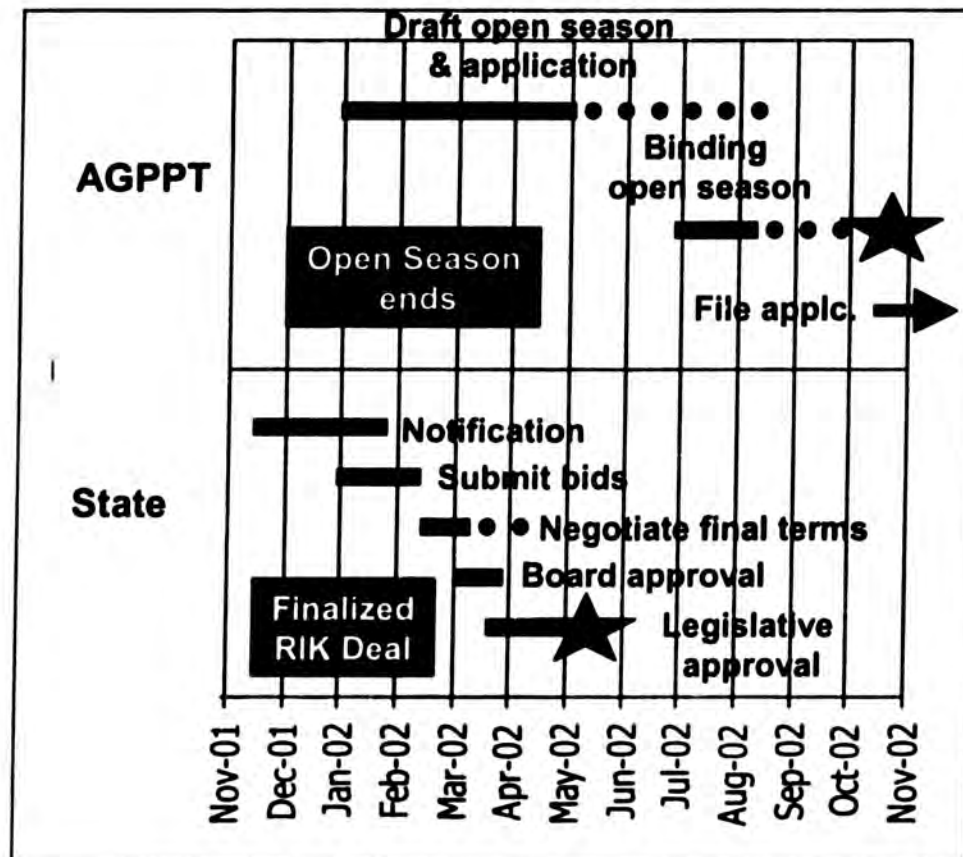
*may not be in
producer's power*

Explorers' Pipeline Decision Timeline



- 2002 Binding Open-season
- 2005 Earliest proven reserves
- 2008 Earliest pipeline ready
- Explorers' will not have proven gas reserves prior to the open-season (2002?)

State's RIK Decision Timeline



- Example timelines
- RIK sale requires ~5 months
- Legislative approval sets timeframe for sale (Jan-May)
- Open Season originally Q1 2002
- AGPPT does not 'foresee' an open season in 2002
- **Must execute the RIK agreement before a binding open-season occurs**

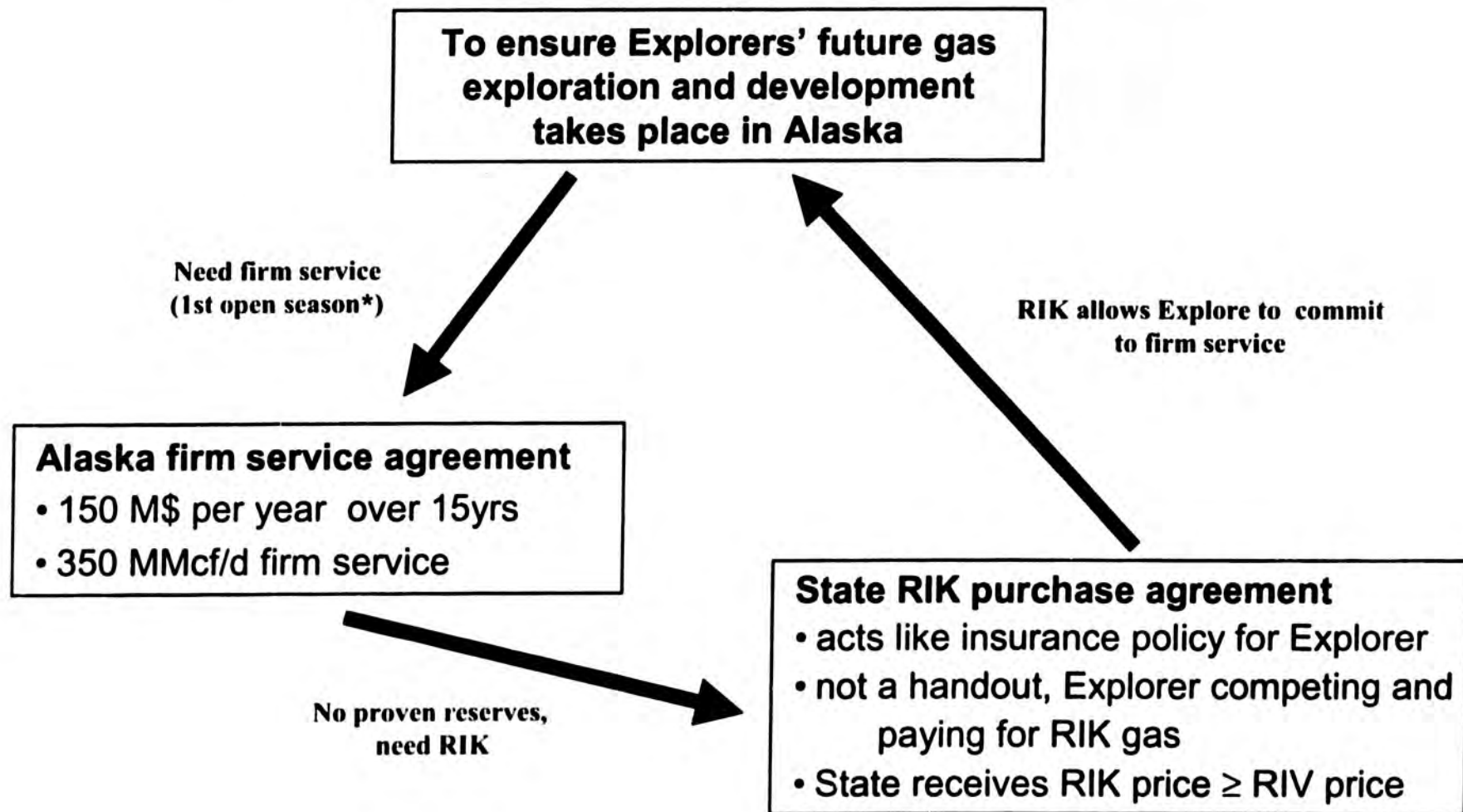
How can FERC* help

- Can not force a pipeline expansion**
- Open seasons are encouraged but not required
- Open seasons are not regulated (complaints basis)
- Open seasons held significantly before the application
 - helps determine design and size of pipeline required for application
- We do not agree with AGPPT, that FERC has the power to enforce pipeline access and expansion
 - why not write the access and expansion terms and conditions in to the proposed Federal Enabling Legislation ✱

* FERC points from July 17, 2001 Joint Pipeline Committee testimony by Robert Cupina - FERC Director of Energy Projects

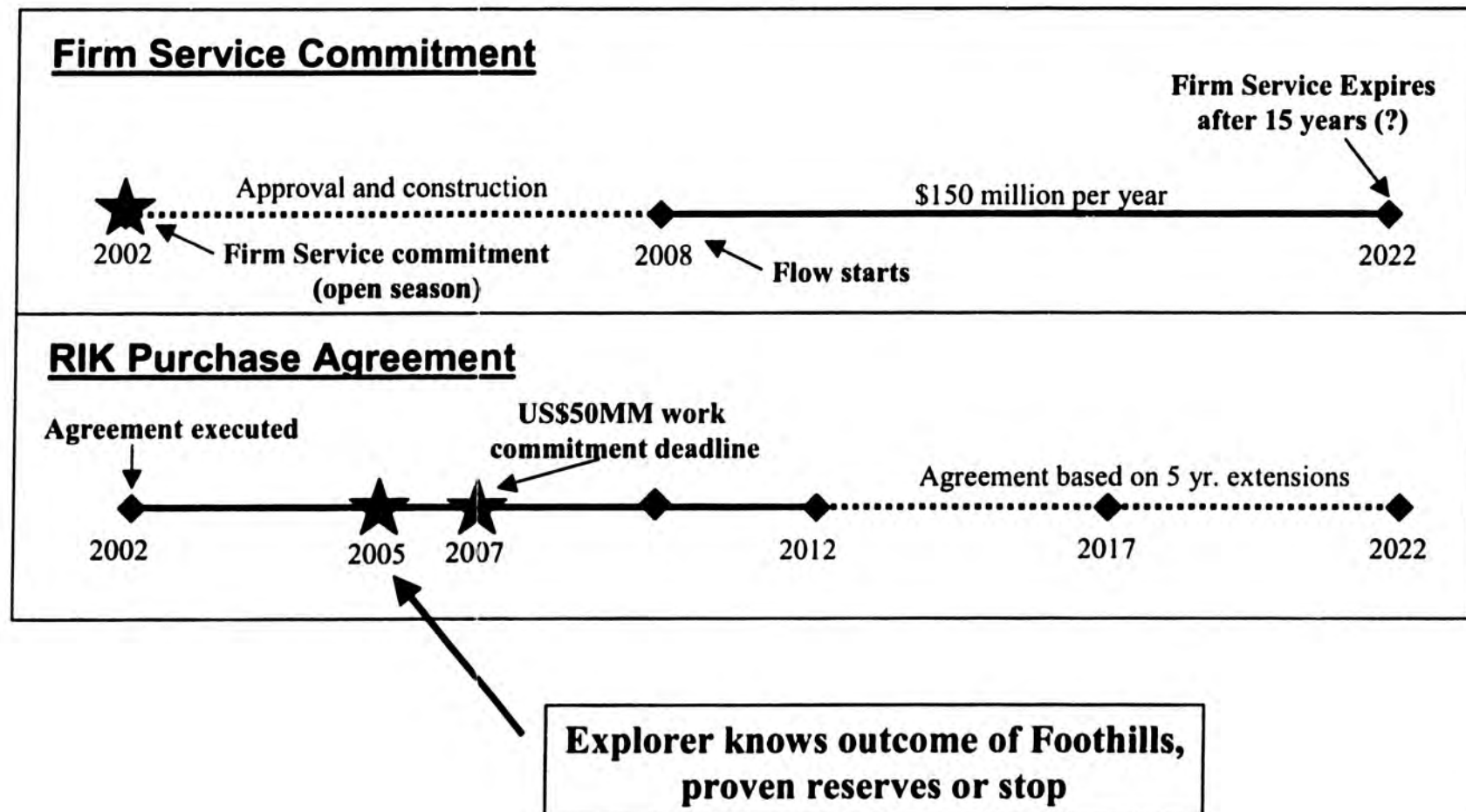
** Section 7 of the Natural Gas Act, Panhandle Eastern Pipe Line Co. v. FERC, 204 F.2d 675 (3rd Cir. 1953)

Why does the Explorer need RIK

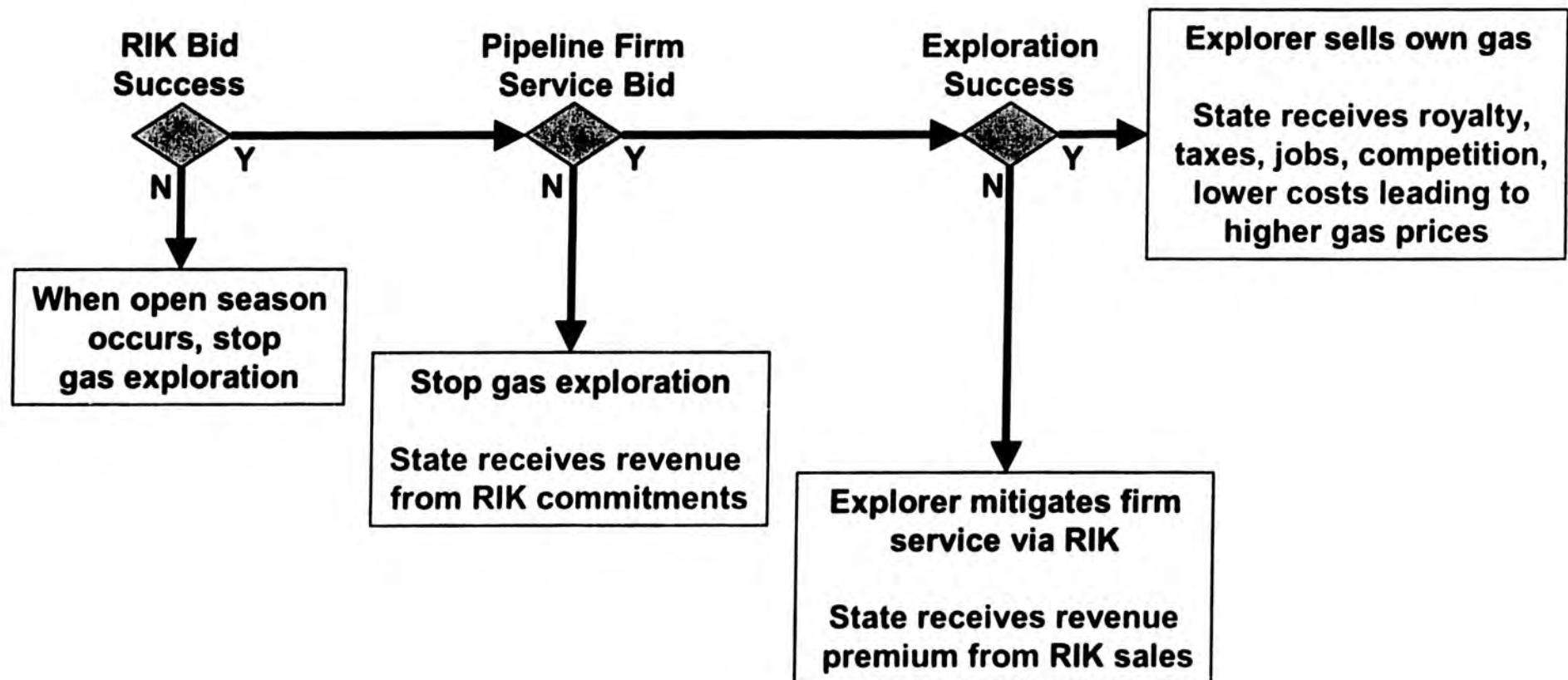


* Pipeline full for over 20 years; expansion can not be relied upon to make investment

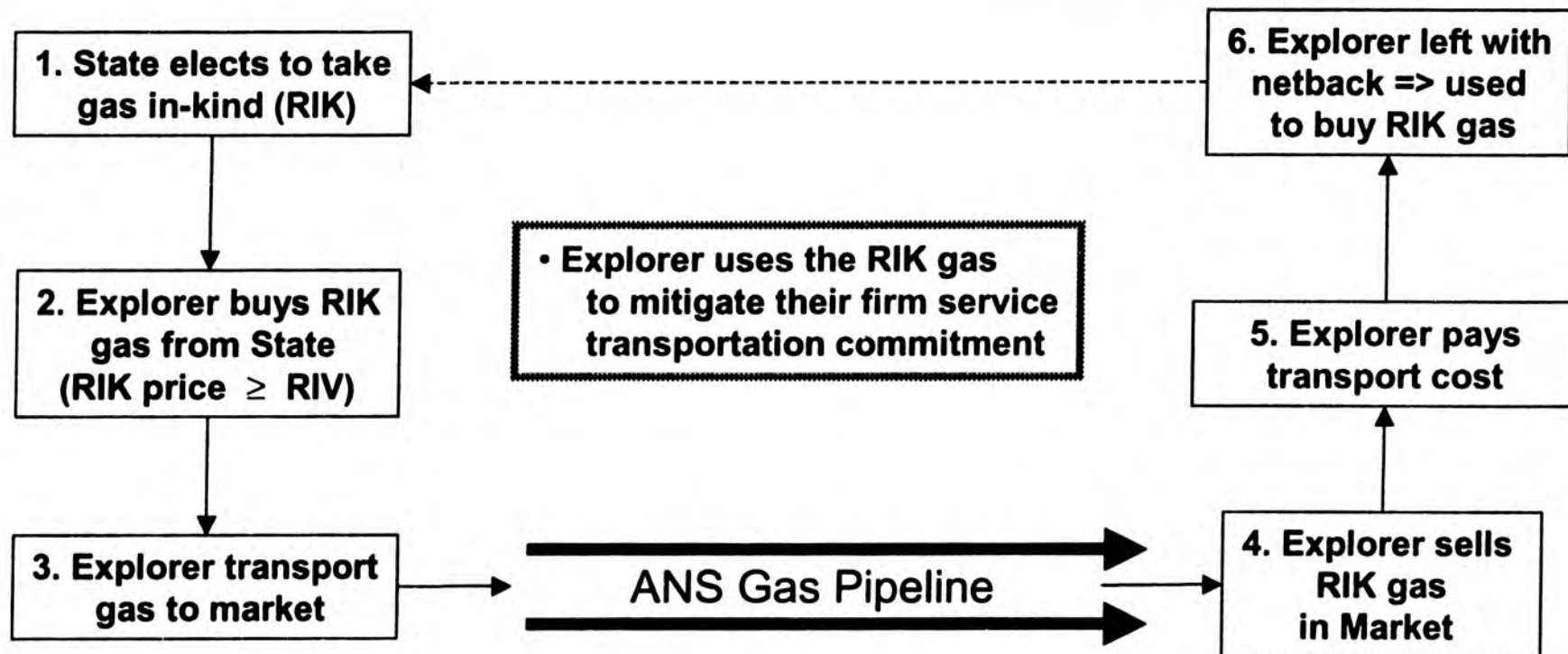
Firm Service & RIK Sale Timeline



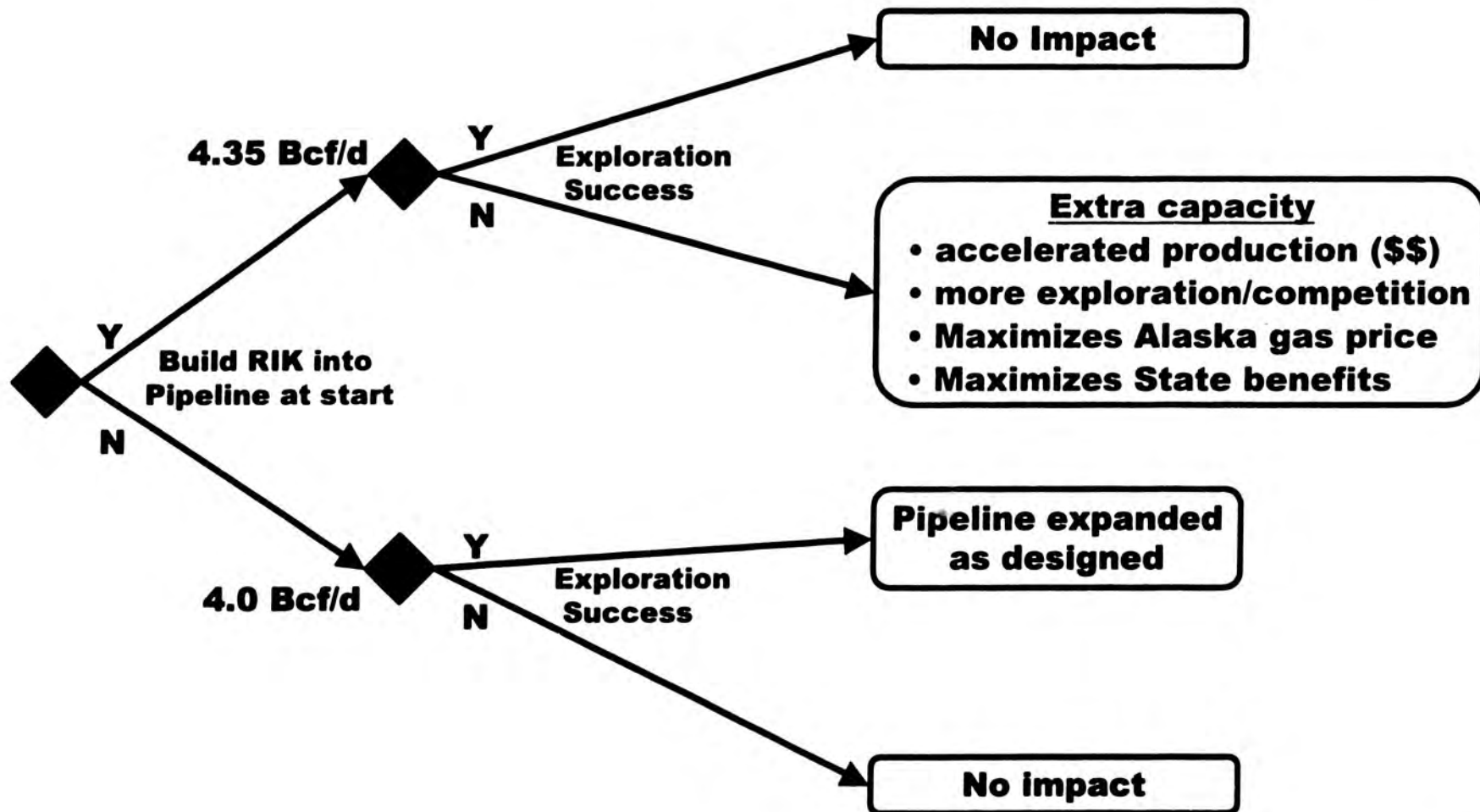
Explorers' Foothills Gas Decision Tree



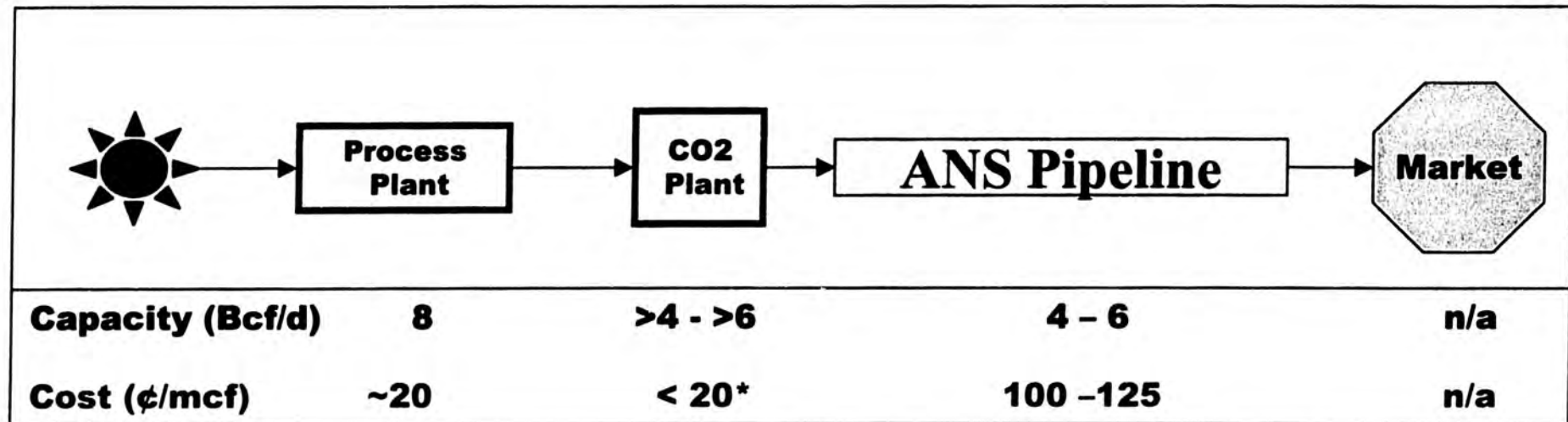
How does Explorer use RIK



Does RIK Impact AGPPT or Pipeline (Decision Tree)



Does RIK Impact AGPPT or Pipeline (Producer Gas Supply Cost Chain)



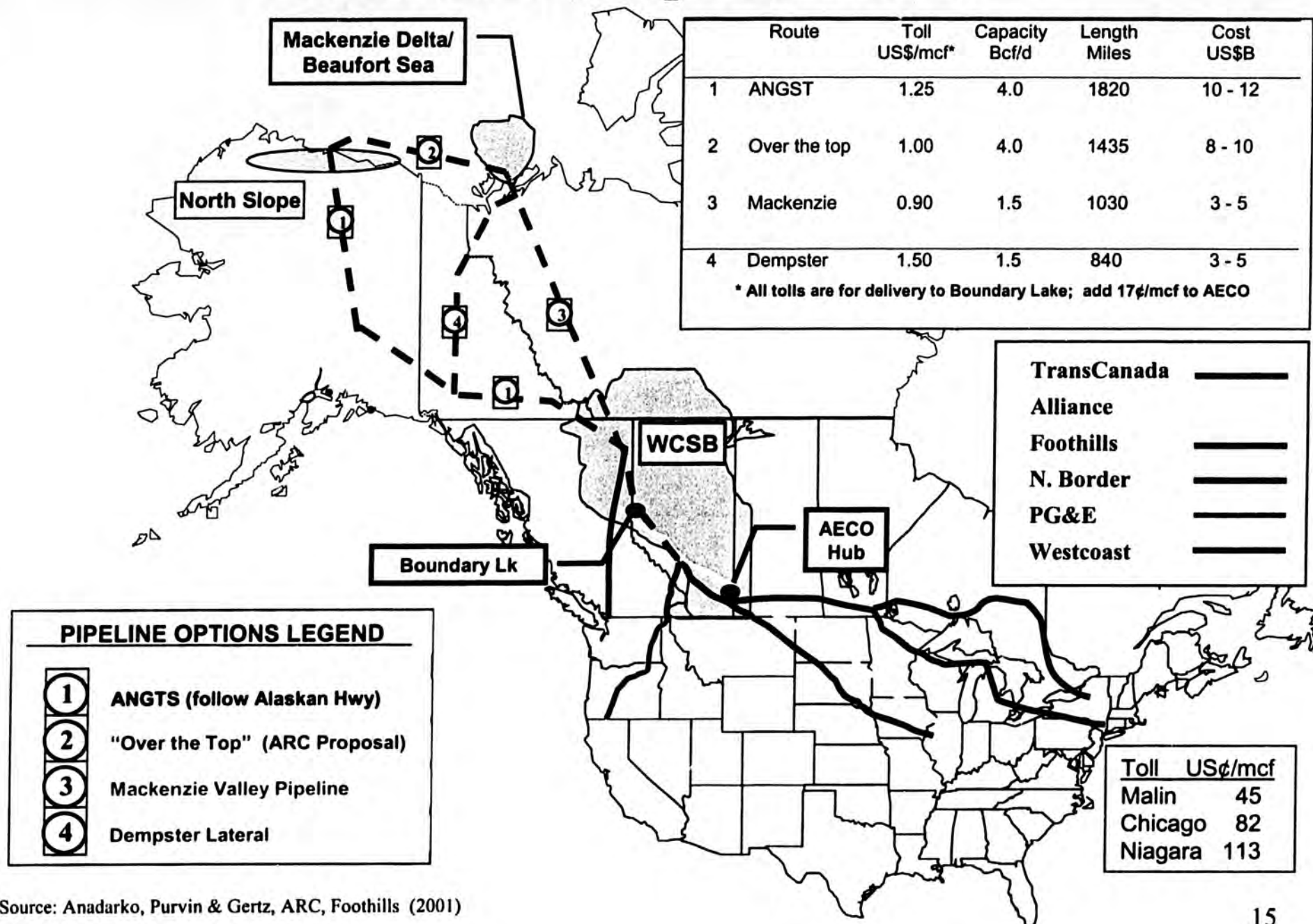
- **AGPPT would over design the CO2 plant (pipeline 5 – 6 times the cost)**
- **Annual down time for field and pipelines ~5% (non-coincidental)**
- **RIK volume 8% of pipeline capacity => net impact 3%**
- **Cost impact of 3% is less than 5 ¢/mcf**
- **Can AGPPT forecast their costs and prices this accurately ?**

* Cost assumed ≤ full process plant cost

Conclusion

- RIK is in the 'best interest' for the State and the Explorer
- RIK provides no risk to the State (guaranteed price $\geq$ RIV)
- RIK allows the State to influence the pipeline project
- RIK creates competition and higher gas prices for ANS gas
- RIK creates jobs for Alaskans
- RIK ensures exploration continues today

Northern Gas Pipeline Routes



Source: Anadarko, Purvin & Gertz, ARC, Foothills (2001)

Royalty In Kind (RIK) Sale

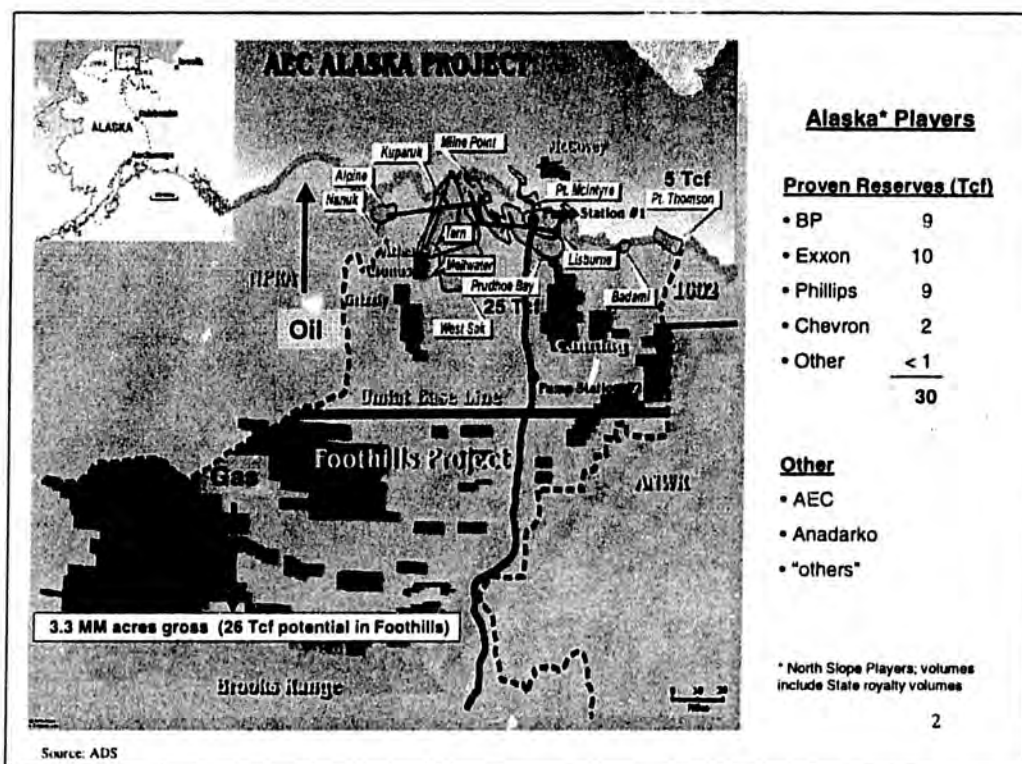
House Special Committee on Oil & Gas

Alan Sharp

AEC Marketing (USA) Inc.

February 5, 2002

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1. Majority of proven gas reserves controlled by three companies, who form the AGPPT
2. Only small area has been explored (for oil – barrow arch); Exploring in area that would not otherwise be explored for over 20yrs (100Tcf potential of gas on ANS)

Others – PetroCanda, Unocal, Chevron, Burlington

- **30 Tcf at 4Bcf/d => 20yrs** AEC locked out of Alaska if not in 1st open season
- **ASRC** - Arctic Slope Regional Corporation is who some of our lands are leased from (right to earn)
- **NPRA** - National Petroleum Reserve of Alaska - held for future energy use for US
- **#1002** small area of ANWR that may be opened by Bush, no infrastructure, on coastal plain
- **ANWR** - Arctic National Wildlife Refuge - protected wildlife park area
- **TAPS** - TransAlaska Pipeline System - existing oil line to Valdez
- above Umiat Base Line Oil (coastal plain), below Gas (foothills)
 - ~30 Tcf onshore proven, (94 Tcf potential, mainly onshore, economic)
- **McCovey, Canning, & Grizzly** world class oil plays; could all have significant solution gas and potentially gas caps

Why RIK in 'best interest' for State

- No risk - leveraging gas volumes of tomorrow to support exploration projects of today
- Maximizes State's royalty value
- More players => more competition => more jobs => more revenue
- Elevates State to significant stakeholder in Pipeline and inclusion on the Pipeline negotiations
- Exploration dollars & jobs today (otherwise in 20 years)

3

1. Yes, RIK is in States best interest
2. Maximizes the State's gas value at no risk (royalty, tax, jobs, lease sales, EOR)

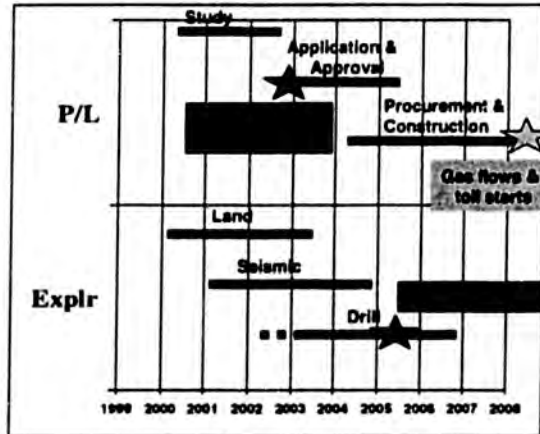
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 - on or later than June 2003
 - 6 months advance notice
 - disclosure of tariff (terms & conditions)
 - access, expansion, & tolls
 - reasonable expansion capacity increments

4

1. Timing is critical for RIK to work – must do now or lose opportunity
2. Open season can be used to exclude other parties (explorers)
3. Require written agreement with AGPPT & pipelines to delay RIK (not likely)

Explorers' Pipeline Decision Timeline

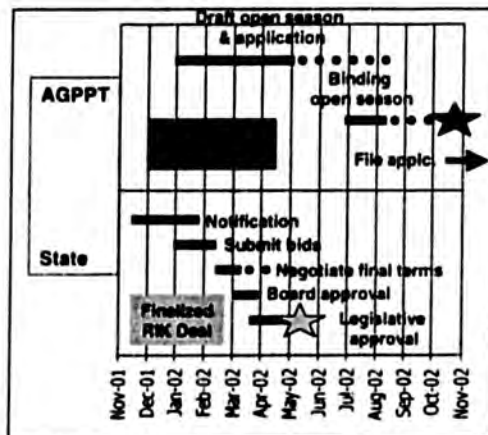


- 2002 Binding Open-season
- 2005 Earliest proven reserves
- 2008 Earliest pipeline ready
- Explorers' will not have proven gas reserves prior to the open-season (2002?)

5

1. Explorers will not have proven reserves prior to an open season
 2. Explorers need your assistance (RIK, legislative protection) – AEC/Anadarko furthest along paying for and competing for your support – not asking for a handout
- Gas pipeline support and timeline are likely to accelerate due to the terrorist attacks - national security. House has already passed the energy bill.
 - OTT from Alaska will only have 4 Bcf/d capacity; Mackenzie down will be 5 Bcf/d. No room for Explorers' (AEC) gas on either side.
 - Exploration issues for the Foothills gas
 - extended flaring
 - successfully obtaining firm service (at min economic rate)
 - lease access (gravel pads and roads)

State's RIK Decision Timeline



- Example timelines
- RIK sale requires ~5 months
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- AGPPT does not 'foresee' an open season in 2002
- **Must execute the RIK agreement before a binding open-season occurs**

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1. **MUST** do RIK now or lose opportunity
 2. AGPPT has made no firm commitment; could be P/L company or other initiating open season
- We are on the critical path. If the State realizes this, we hope they will help expedite the process.
 - The binding open season could be later in Q1 2002. When we are in Alaska, we hear Jan/02 is what AGPPT has told the State. AGPPT is telling explorers late Q1. If it is later, we can make the RIK deadline.
 - Note the RIK purchase is a competitive bid process.

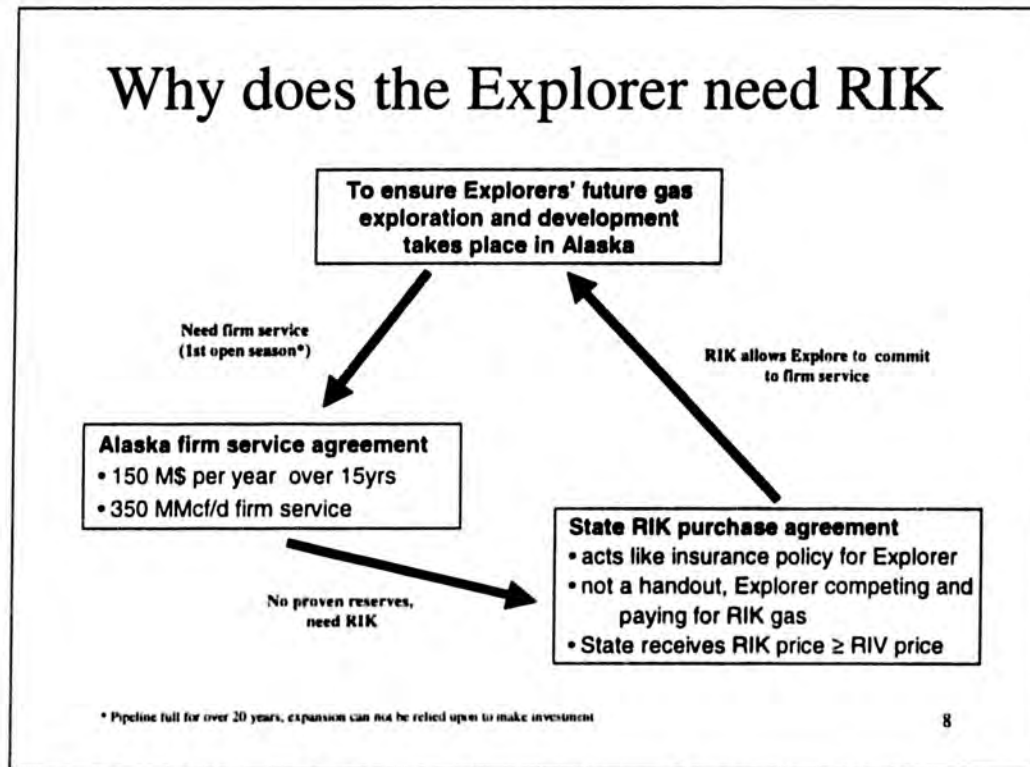
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* FERC points from July 17, 2001 Joint Pipeline Committee testimony by Robert Cupina - FERC Director of Energy Projects
** Section 7 of the Natural Gas Act, *Panhandle Eastern Pipe Line Co. v. FERC*, 204 F.2d 675 (3rd Cir. 1953)

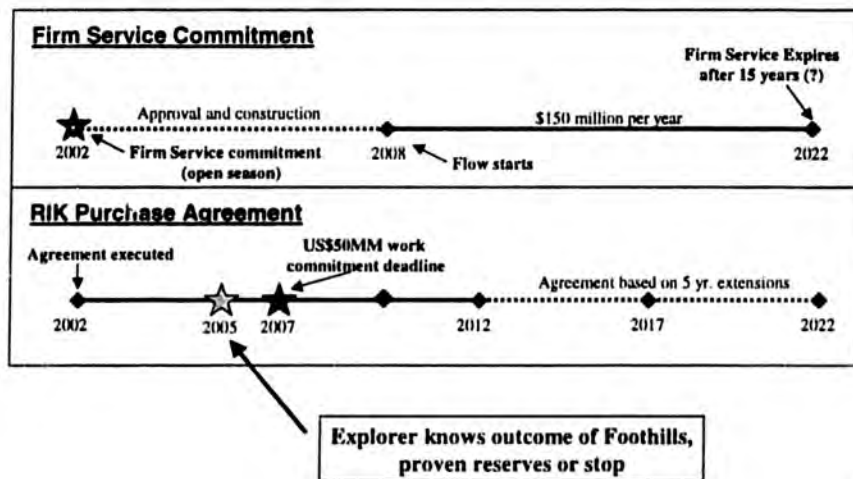
1. No, FERC can not force an expansion – legal precedent
2. If AGPPT believes it already exists, let's write it in to their Federal Enabling Legislation

Why does the Explorer need RIK



1. Explorer can not take risk on firm service without proven reserves – AGPPT think economics tight without exploration risk and cost
2. RIK acts like an insurance policy for the Explorer (firm service risk)
 - 2.0 B\$ over 15yrs, ~150 M\$/yr
 - 3.2 B\$ over 25yrs, ~150 M\$/yr

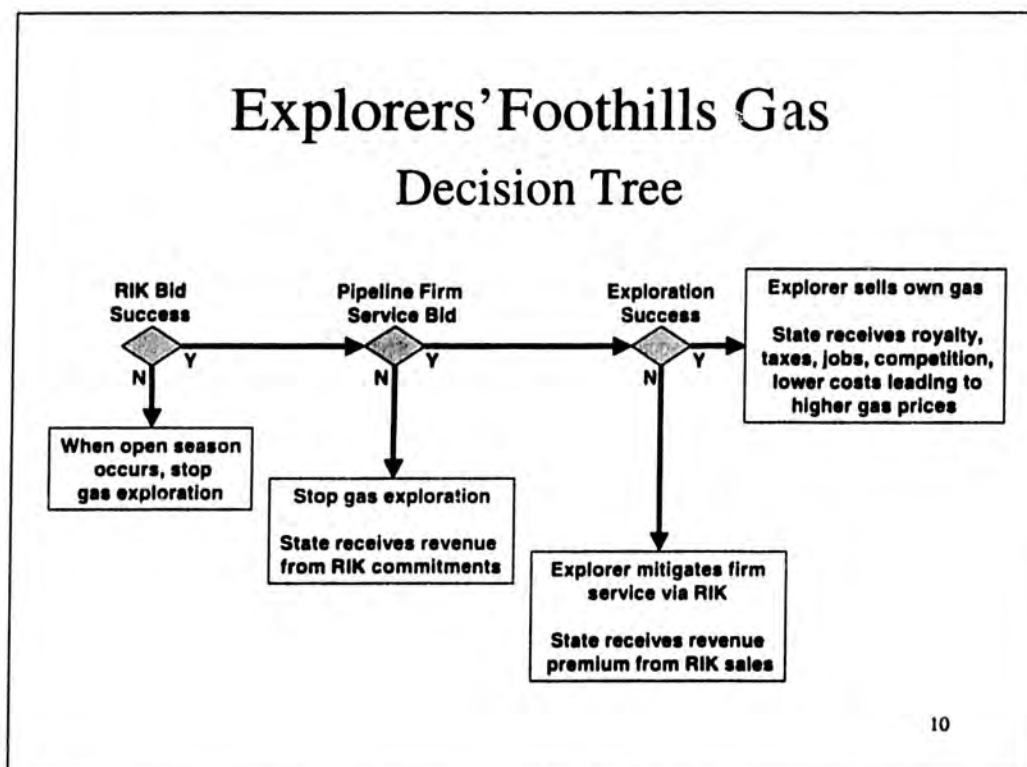
Firm Service & RIK Sale Timeline



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1. Explorers will know by 2005 (before the P/L flows) if Foothills exploration successful
 2. Need RIK to participate in open season
- Top of the chart shows the firm service timeline. We estimated the term to be 15yrs. It could be longer (e.g., 25yrs) to create barriers to entry.
 - Notice the pipeline's earliest start date is 2008. The firm service term starts from this start date.
 - Also note that we will have proven gas or made the exit decision prior to the actual pipeline start-up date.
 - The option agreement will commence right away and terminate 5yrs after gas starts to flow on the pipeline, if the purchase has not been extended.

Explorers' Foothills Gas Decision Tree

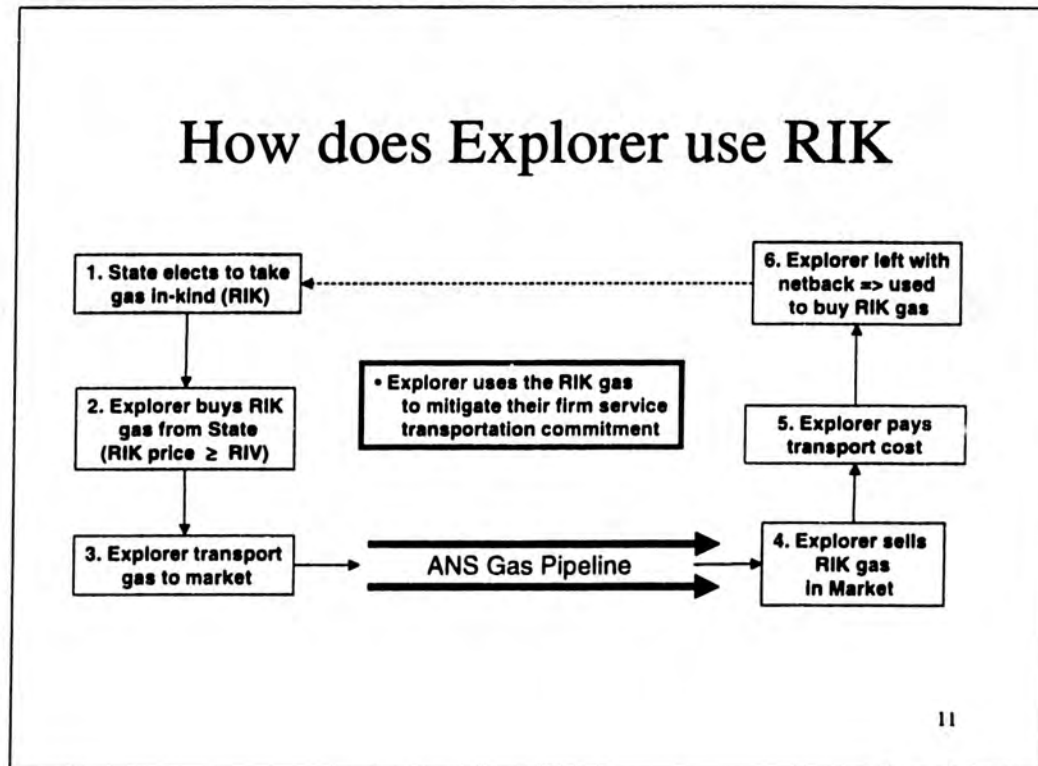


1. State receives benefit in all cases - no risk to State (win/win for all)
2. Foothills gas exploration will otherwise not occur for over 20yrs

Firm Service

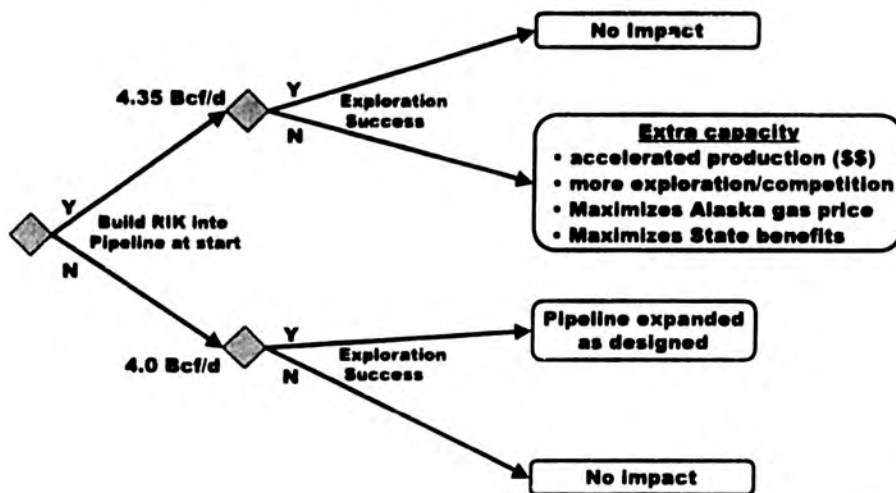
200MMcf/d @ 1\$US/Mcf	73M\$/yr	1.8B\$US over 25yrs
175MMcf/d @ 1\$US/Mcf	64M\$/yr	1.6B\$US over 25yrs

How does Explorer use RIK



1. Explorer uses the RIK to mitigate the firm service risk (get firm service in 1st open season)
2. Chart shows how Explorer uses RIK as an 'insurance policy'

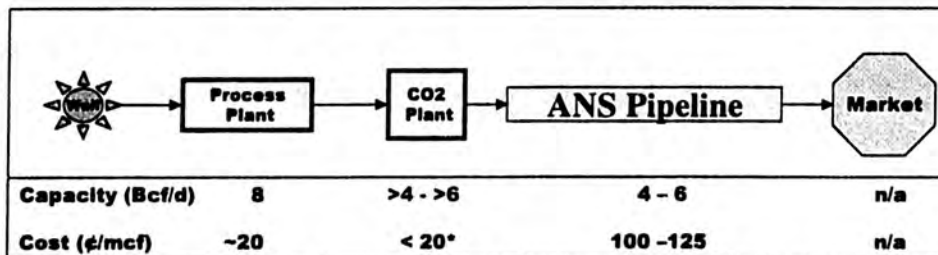
Does RIK Impact AGPPT or Pipeline (Decision Tree)



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1. Shows AGPPT not impacted (creates competition, limits control)
2. State gets huge benefit building RIK in to pipeline at very start

Does RIK Impact AGPPT or Pipeline (Producer Gas Supply Cost Chain)



- AGPPT would over design the CO2 plant (pipeline 5 - 6 times the cost)
- Annual down time for field and pipelines ~5% (non-coincidental)
- RIK volume 8% of pipeline capacity => net impact 3%
- Cost impact of 3% is less than 5 \$/mcf
- Can AGPPT forecast their costs and prices this accurately ?

* Cost assumed ≤ full process plant cost

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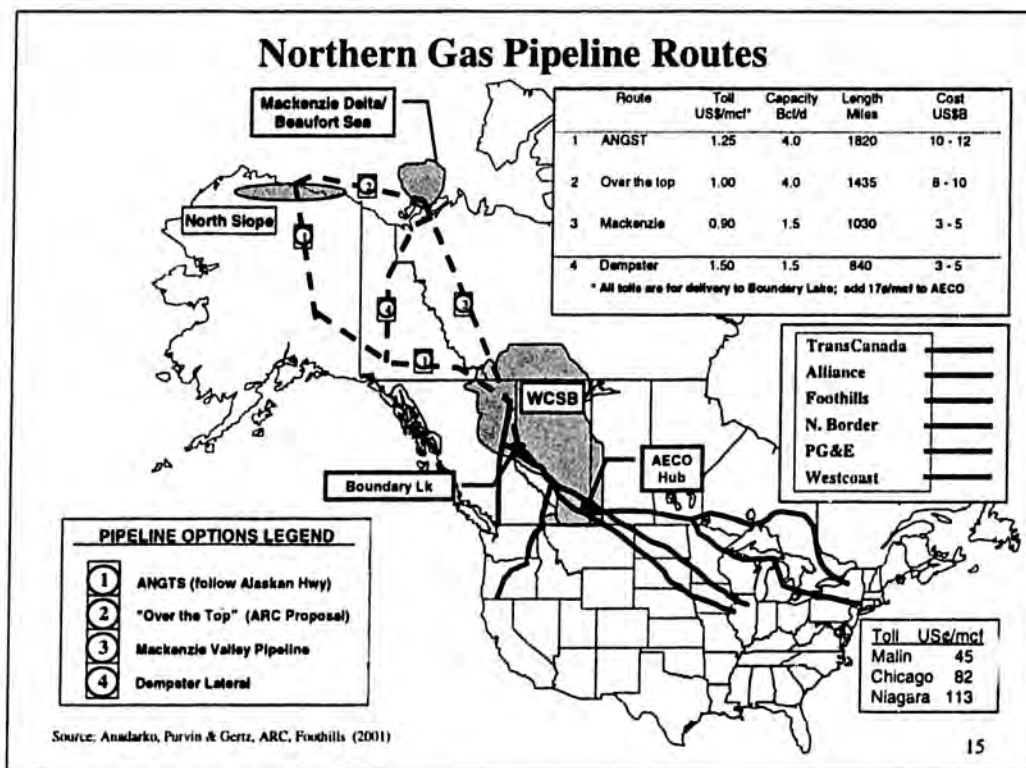
1. Shows that AGPPT impact insignificant relative to the other pipeline project risks/costs
2. Have AGPPT show us their economics (accuracy ??)

Conclusion

- RIK is in the 'best interest' for the State and the Explorer
- RIK provides no risk to the State (guaranteed price $\geq$ RIV)
- RIK allows the State to influence the pipeline project
- RIK creates competition and higher gas prices for ANS gas
- RIK creates jobs for Alaskans
- RIK ensures exploration continues today

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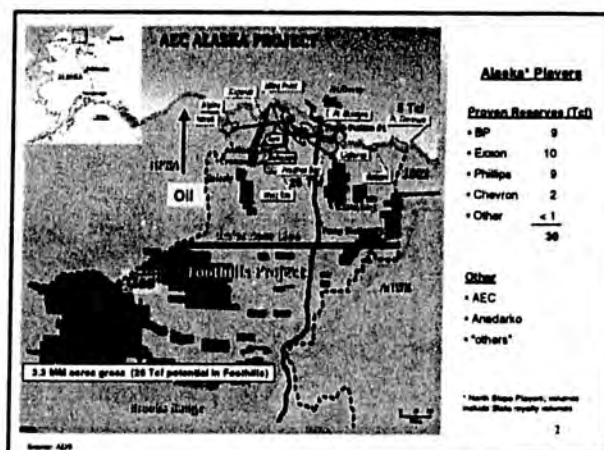
1. RIK is in the best interest of the State, State has no risk
2. AGPPT is not impacted – RIK insignificant relative to their other risks/costs
3. We are offering the State more than a bid, we are offering the State to share in our vision – to create a competitive, multi-player natural gas industry in Alaska – RIK is the first step towards this vision.



- Mackenzie < 6 Tcf proven onshore; most of the reserves are offshore in the Beaufort Sea; total potential 64 Tcf, 20 onshore, 44 offshore (mostly uneconomic)
 - Alaska is mostly onshore 30 Tcf proven, potential 94 Tcf (economic)
 - 26 Tcf in the Foothills; of which more than half is considered to be on AEC & adjacent open State lands
 - Alta 270 Tcf - 86 Tcf produced, 49 Tcf proven, 135 Potential
 - BC 50 Tcf - 13 Tcf produced, 10 Tcf proven, 27 Potential
 - Players
 - Governments (Municipal, State, Provincial, & Federal)
 - Producers (mainly super independents)
 - Pipeline companies
 - Marketers
 - Environmental groups
 - First Nation bands
 - Service industries (direct, indirect)
 - Others (e.g., GTL, LNG)
1. **ANGTS** (Alaska Northern Gas Transportation System) which follows the Alaska Highway.
 2. **Over the top** - from Prudhoe Bay to Mackenzie via the Beaufort Sea, then approximately follows the Mackenzie Valley Pipeline
 3. **Mackenzie Valley** - standalone pipeline for the Delta; small capacity proposed
 4. **Dempster lateral** is a hold over from the Berger Commission - this pipeline would only be built if ANGTS is built first, stranding the Mackenzie reserves until 2010-2012 (assumes Market can not handle more gas and reserves are still small <6 Tcf).

Will the WCSB 'potential' reserves be economic (i.e., small pools) vs the North?

House Special Committee on Oil & Gas

[illegible]

- No risk - leveraging gas volumes of tomorrow to support exploration projects of today
- Maximizes State's royalty value
- More players => more competition => more jobs => more revenue
- Elevates State to significant stakeholder in Pipeline and inclusion on the Pipeline negotiations
- Exploration dollars & jobs today (otherwise in 20 years)

- RIK sale requires at least 5 months
- Legislative approval required (Jan-May)
- No AGPPT open season commitments
- Explorer Open Season recommendations
 - on or later than June 2003
 - 6 months advance notice
 - disclosure of tariff (terms & conditions)
 - access, expansion, & tolls
 - reasonable expansion capacity increments

Figure 1 is a Gantt chart illustrating the project schedule from 1990 to 2005. The chart is divided into two main sections: 'P/L' (Profit/Loss) and 'Expr' (Expense). The 'P/L' section shows a large black bar from 1990 to 1995, followed by a smaller black bar from 1995 to 2000. The 'Expr' section shows a black bar from 1990 to 1995, followed by a smaller black bar from 1995 to 2000. The chart also includes labels for 'Study', 'Application & Software', 'Preparation & Construction', and 'Start (new & old plants)'. A star is placed at the end of the 'Preparation & Construction' bar in 2000.

- 2002 Binding Open-season
- 2005 Earliest proven reserves
- 2008 Earliest pipeline ready
- Explorers' will not have proven gas reserves prior to the open-season (20027)

AGPPT

State

Federal

Legend:

- AGPPT
- State

Timeline:

1982 1983 1984 1985 1986 1987 1988 1989 1990 1991 1992

AGPPT Progress:

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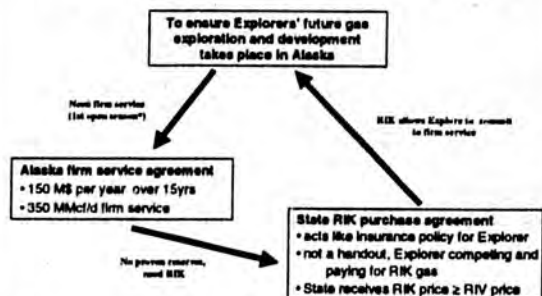
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* FERC process from July 17, 2001 Joint Pipeline Commission testimony by Robert Chappin - FERC Director of Energy Projects
** Section 7 of the Natural Gas Act, Public Law 86-417, 49 USC, 3017.34 (19) (1952)

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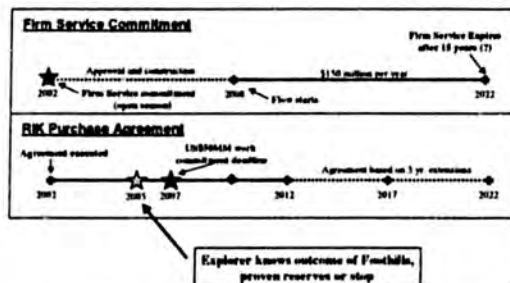
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* Pipeline bid not over 20 years, exploration cost can be added upon an early termination

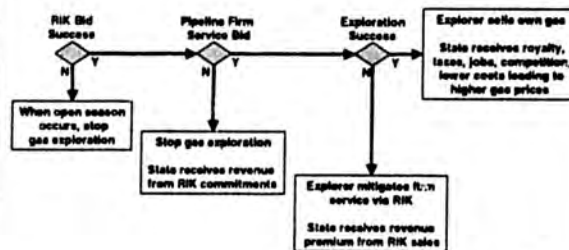
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Firm Service & RIK Sale Timeline



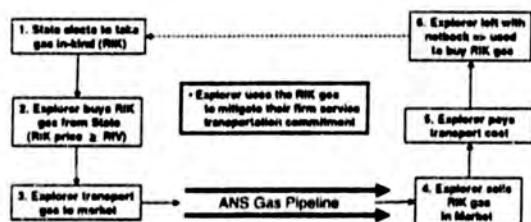
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Explorers' Foothills Gas Decision Tree



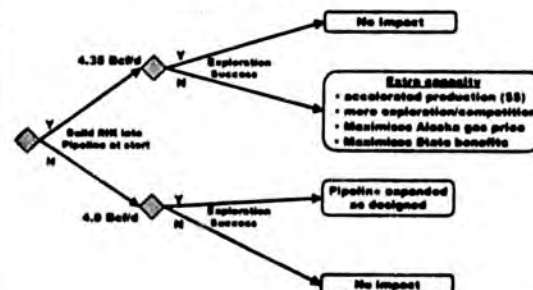
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How does Explorer use RIK



11

Does RIK Impact AGPPT or Pipeline (Decision Tree)



12

CORRECTION

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



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

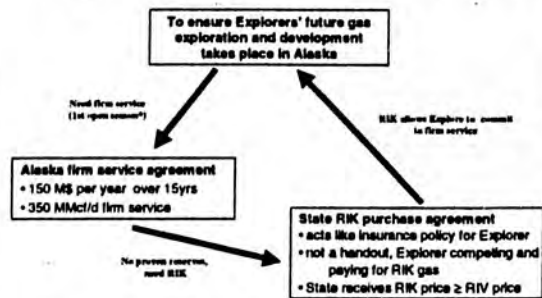
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* FERC's power comes from July 17, 2001 Joint Pipeline Committee testimony by Robert Capen - FERC's Director of Energy Projects
 ** Section 7 of the Natural Gas Act, Pipeline Access Rule Case No. 1 FERC, 204 P.2d 415 (2nd Cir. 1952)

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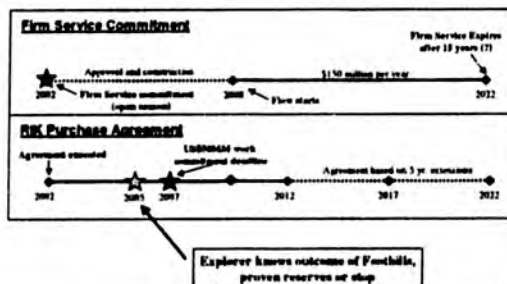
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* Pipeline built but over 20 years, explorers can not be relied upon to make investment

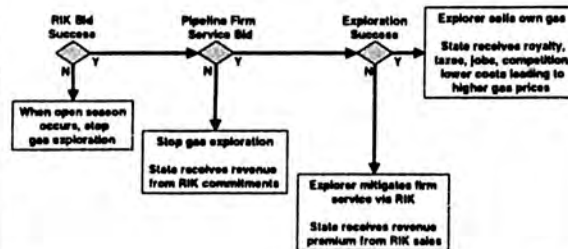
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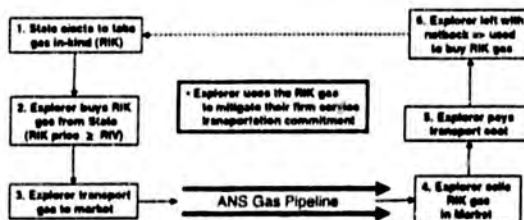
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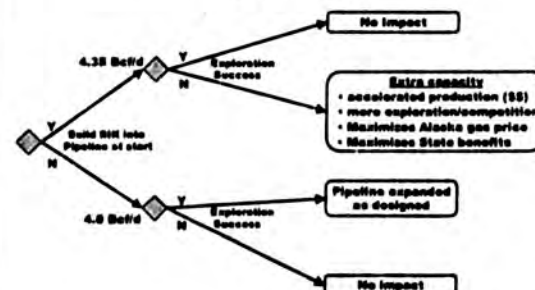
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