

SCOMM

128:24

FISCAL NOTE

STATE OF ALASKA
2001 LEGISLATIVE SESSION

Fiscal Note Number: _____

Bill Version: _____

SS HB 190

() Publish Date: _____

Revision Date/Time (Note if correction): _____

Dept. Affected: _____

Natural Resources

Title: Natural Gas Pipeline Incentive/Gas Tax

BRU: _____

Oil & Gas Development

Component: _____

Oil & Gas Development

Sponsor: Representative Whitaker

Requester: (H) O&G

Component Number: _____

439

Expenditures/Revenues

(Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	FY 2007
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	*	*	*	*	*	*

CAPITAL EXPENDITURES						
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CHANGE IN REVENUES ()	**	**	**	**	**	**
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FUND SOURCE

(Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type)						
TOTAL	*	*	*	*	*	*

Estimate of any current year (FY2001) cost: _____

none

Check this box (X) if funding for this bill is included in the Governor's FY2002 budget proposal: ☐

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

* It is not possible at this time to calculate operating expenditures associated with implementation of this legislation for the following reason. It is unclear which agency will be responsible for evaluating industry data to determine if a situation of "proven gas reserves" exists as defined by proposed AS 43.58.395(5), or if the lessee's estimate of volume is correct.

** A property tax on gas reserves could have a chilling effect on industry's efforts to explore for new gas deposits. It could also discourage the bidding for leases on state land, and exploration for oil if gas was likely to be found.

Prepared by: Mark D. Myers

Division: Oil and Gas

Phone 269-8800

Date/Time 26-Apr-01

Approved by: Pat Pourchot

Agency: Natural Resources

Date 26-Apr-01

For distribution information, call the Governor's Legislative Office

FISCAL NOTE

STATE OF ALASKA
2001 LEGISLATIVE SESSION

Fiscal Note Number: _____
Bill Version: SS HB 190
() Publish Date: _____

Revision Date/Time (Note if correction): _____ Dept. Affected: Revenue
Title: Natural Gas Pipeline Incentive / Gas Tax BRU: Operations
Sponsor: Representative Whitaker Component: Tax Division
Requester: House Oil & Gas Committee Component Number: 2476

Expenditures/Revenues

(Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	FY 2007
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES						
-----------------------------	--	--	--	--	--	--

CHANGE IN REVENUES ()	**	**	**	**	**	**
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FUND SOURCE

(Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type)						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2001) cost: 0.0

Check this box (X) if funding for this bill is included in the Governor's FY 2002 budget proposal: ☐

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

** It is not possible at this time to determine property tax revenue to the state under this legislation.

(See attached sheet for more information.)

Prepared by: Dan Dickinson, Director Phone 269-1033
Division: Tax Division Date/Time April 24, 2001, 9 a.m.
Approved by: Larry Persily, Deputy Commissioner Date 04/24/2001
Agency: Department of Revenue

For distribution information, call the Governor's Legislative Office

Department of Revenue fiscal note and bill analysis

SS HB 190 – April 24, 2001

This legislation would require North Slope oil and gas producers to pay a property tax on natural gas reserves unless the producers contract by Dec. 31, 2003 to deliver natural gas to a "qualified bona fide purchaser" for delivery under a contract of at least 20 years starting no later than Dec. 31, 2007.

Before discussing the revenue potential of the legislation, the department sees a conflict between AS 43.58.210(b) of this legislation that sets the tax rate at 2 cents per 1,000 cubic feet of gas and AS 43.58.230 of this legislation, which directs the department to assess the gas at "its full and true value." The legislation defines "full and true value" as the "estimated price that the taxable property would bring in an open market and under the then prevailing market conditions in a sale between a willing seller and a willing buyer." For the purposes of this bill analysis, the department assumes it would assess the natural gas reserves at 2 cents per 1,000 cubic feet instead of following the statutory definition of "full and true value."

Using the Department of Natural Resources' estimate of approximately 31 trillion cubic feet of gas reserves on state leases, the annual property tax bill to North Slope lease holders would be \$620 million at 2 cents per 1,000 cubic feet. The legislation, however, exempts from taxation that volume of gas needed for reinjection for enhanced recovery of oil (as determined by the Alaska Oil and Gas Conservation Commission) and that volume of gas consumed in North Slope production operations.

If, for example, one-third of the gas reserves were needed for reinjection and operations, the property tax bill would be \$415 million a year. If that were the case, the revenue likely would exceed what the state could expect to receive in property tax, severance tax and corporate income tax and royalties from a natural gas project, forcing the state to question whether it would be money ahead with the property tax revenue on stranded gas reserves instead of promoting a natural gas development project.

It also is possible that the gas reserves property tax could act as a disincentive to oil and gas exploration if producers viewed any new gas discoveries as a potential tax liability.

Alaska State Legislature

**Representative Jim Whitaker
House of Representatives
District 31**



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Statement Before House Special Committee on Oil and Gas Lori Backes, Chief of Staff Office of Representative Jim Whitaker

HB 190 - Alaska Natural Gas Pipeline Incentive Act

"Mr. Chairman, Members of the Committee, my name is Lori Backes, I am Legislative Aide to Representative Jim Whitaker, who asked me to make a brief statement before you today.

The sponsor of HB 190 requested at the time this bill was introduced, and has maintained since then, that it not be heard unless, after appropriate testimony, a vote be taken by the committee for passage or against passage.

The sponsor's position has not changed. However, Representative Whitaker recognizes the Chairman's prerogative and therefore does not object to HB 190 being heard.

That concludes my statement. I have not been authorized by the sponsor to answer questions from the committee."

Alaska State Legislature

Representative Jim Whitaker
House of Representatives
District 31



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SPONSOR STATEMENT

HB 190

ALASKA NATURAL GAS PIPELINE INCENTIVE ACT

For many years, the State of Alaska has relied heavily on the production of oil to foster its livelihood, provide opportunities for its people, and generate revenues to ensure continued prosperity. We have all seen and enjoyed the positive effects of oil development. However, low oil prices, reduced production, and potential field depletion adversely affect the state's ability to provide a secure future for its people.

As of the end of the last century, December 31st, 1999, through political subdivisions of state and local governments, the people of Alaska accrued roughly \$55 Billion dollars in taxes, royalties and settlements from the oil industry. In addition, the industry has provided enormous employment opportunities, infrastructure growth opportunities, and a host of other positive benefits to the state.

While Alaska has enjoyed many positive benefits from production of its oil resources, the industry has profited greatly as well, earning approximately \$65 Billion dollars in pre-federal tax revenues from Alaskan operations. The industry's Alaskan operations also have provided for their West Coast refinery and petro-chemical feed stocks.

As we face an enormous budget deficit, we must look beyond our reliance on oil production, budget cutting, and taxation as the only means of ensuring a long-term fiscal solution. It is incumbent upon the leaders of this state to recognize that further resource development is critical in order to secure an additional and substantial revenue stream to the State of Alaska.

Conservatively, 35 trillion cubic feet of natural gas reserves have been identified on the North Slope, and estimates of 100 tcf of reserves yet to be proven are realistic. The failure of the Legislature to insist upon commercialization of this vital resource as a valuable commodity is in direct conflict with the provisions of the Constitution of the State of Alaska.

Article VIII, sec. 1, Constitution of the State of Alaska, provides that it is the policy of the state to encourage the settlement of its land and the development of its resources by making them available for maximum use consistent with the public interest.

Article VIII, sec. 2, Constitution of the State of Alaska, requires the legislature to provide for the utilization, development, and conservation of all natural resources belonging to the state, including land and waters, for the maximum benefit of its people.

The resource of greatest value associated with economic growth now available to Alaska is North Slope natural gas.

The past months have shown a critical need for new supply to the "Lower 48", and recently, representatives of the Asian gas markets have expressed immediate interest in contracting for the purchase of North Slope natural gas.

Despite repeated efforts on the part of Alaska's Legislature, Administration, and Municipalities to encourage an Alaskan gas pipeline, the producers continue to favor their competing projects around the world. The latest news of the involvement of Phillips Petroleum and Chevron in projects to bring LNG from Australia to the U.S., and the possibility that BP will be in a position to bring LNG to the U.S. market from Egypt, further exemplifies the propensity of major leaseholders on the North Slope to subordinate an Alaskan project to their holdings elsewhere for reasons of internal best interest economics.

The time has come for Alaska's legislature to send a clear and compelling message to the producers: we will meet our constitutional obligation and insist that Alaska's resources be developed in a manner that is in the maximum best interest of the people of the State of Alaska.

To that end, HB 190 will levy a tax on North Slope natural gas in an amount that will provide an economic incentive to the producers to expedite an Alaskan project.

Firstly, HB 190 encourages development of our resources by applying a tax rate of \$.02 per mcf to the natural gas resource under lease on the North Slope if certain performance benchmarks are not met.

The gas reserves tax does not take effect if the leaseholders secure specific benchmark requirements. By December 31, 2003, the leaseholders must have signed agreements to sell a minimum of 500,000,000 mcf per year for at least a 20 year period. If the 2003 benchmark is met, the gas reserves tax does not take effect until December 31, 2007. On this date, if North Slope natural gas is delivered to market, the gas reserves tax is permanently removed from the statutes. These benchmarks are reasonable and achievable.

Secondly, HB 190 inserts specific language into leases upon initial contract, renewal or transfer of leases, which requires the sale of natural gas when certain conditions are met. The current lease language requires only general efforts for development. We must be more specific regarding reasonable expectations for natural gas development.

Finally, HB 190 provides for an option under which North Slope leaseholders may surrender rights held in land under lease in order to avoid liability under the act.

Office of Rep. Whitaker
L. Backes
03/20/01

Alaska State Legislature

Representative Jim Whitaker
House of Representatives
District 31



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SSHB 190 Sectional Analysis

The bill (1) provides for levy and collection of a tax on certain North Slope natural gas in place under circumstances in which the gas is not timely developed, and (2) sets limits on the authority of the commissioner of natural resources to issue or extend an oil and gas lease unless the lessee complies with requirements relating to the development and sale of North Slope natural gas.

Bill Section 1: An uncodified provision, gives the measure a short title.

Bill Section 2: Also uncodified, sets out legislative findings and a statement of legislative intent for the measure.

Bill Section 3: AS38.05.180 (m) sets out the terms and conditions relating to the duration of an oil and gas lease both upon initial issuance of the lease and for the extension of the lease when oil or gas is produced in paying quantities. The insertions at page 3, lines 9-13 (for lease extensions) and at page 3, lines 16-19 (for leases initially issued) add an additional requirement prohibiting issuance or extension, as appropriate, of a lease without a commitment by the lessee or prospective lessee "to contract to sell the gas [produced from the lease]...to a qualified bona fide purchaser." The section also, at the top of page 4, supplies a definition for the term "qualified bona fide purchaser."

Bill Section 4: The bill section provides for levy and collection of the gas reserves tax --

--AS 43.58.210 imposes the levy as an annual tax and sets the tax rate (\$0.02 per mcf);

--AS 43.58.220 defines the property subject to the tax as North Slope leases with proven gas reserves;

--AS43.58.230 sets the standard for assessment of the value of the gas reserves;

--AS43.58.240 - 43.58.300 are "boilerplate" provisions that spell out how the gas reserves property assessment roll shall be prepared and prescribes the procedures that attend preparation and submission of the tax return and payment of the tax;

--AS43.58.310 applies the general remedy of distraint on property as an enforcement remedy;

--AS43.58.320 authorizes adoption of implementing regulations for the tax; and

--AS 43.58.395 sets out necessary definitions for terms used in the chapter.

Bill Section 5: The section allows for the surrender of the land held under lease to avoid tax liability, if the surrender takes place no later than December 31, 2003.

Bill Section 6: The section sets a first condition on the taking effect of the gas reserves tax: the tax is to take effect *unless* the terms of the condition are met--

...no later than December 31, 2003, not less than 500,000,000,000 cubic feet of North Slope natural gas, that is undeveloped on the effective date of this section, is annually committed by contract for sale and timely delivery as commercially marketable gas to a qualified bona fide purchaser, not for enhanced recovery operations, for a contract term of at least 20 years, with delivery scheduled to begin no later than December 31, 2007.

If the condition is met, the tax does not take effect.

Bill Section 7: The section sets an alternate condition on the taking effect of the gas reserves tax: the tax is to take effect if the provisions of the tax have not taken effect at an earlier time and *unless* the terms of the following condition are met--

...no later than December 31, 2007, the cubic feet of North Slope natural gas...that is undeveloped on the effective date of this section, that has been committed by contract for sale and timely delivery as commercially marketable gas as required by sec. 6 of this Act is deliverable as provided by the appropriate terms of the contract.

If this condition is met, the tax does not take effect.

Bill Section 8: In the event a question arises as to compliance with either of the appropriate conditions that keeps the reserves tax from taking effect, this provision gives "any qualified voter" standing to challenge a decision by the commissioner of revenue not to give effect to the tax. The language draws upon the text of similar authority set out in article VI, section 11, Constitution of the State of Alaska, the basis for enforcement of legislative redistricting.

Bill Section 9: Under this section, if, because the appropriate conditions are complied with, the reserves tax does not take effect, the revisor of statutes is directed to repeal the provisions of the tax.

Office of Rep. Whitaker
L. Backes
03/20/01

Bill Section 10: gives the first condition giving effect to the gas reserves tax a January 2004, effective date.

Bill Section 11: gives the alternate condition giving effect to the gas reserves tax a January 1, 2008, effective date.

Except for the bill section setting out conditional provisions that would cause the tax to take effect in 2004 or 2008, other sections of the measure take effect 90 days after becoming law.

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House Special Committee on Oil & Gas

MEMORANDUM

DATE: April 25, 2001
TO: All Oil & Gas Committee Members
FROM: Representative Scott Ogan, Chairman
RE: Question given to Jack Chenoweth, Legal Services

Question posed to Jack Chenoweth, Legislative Legal Services:

Under what circumstances can the state take a lease back?

Have we ever taken a lease back?

Is Point Thompson a good example?

Please see attached answer.

Subject: Oil/gas lease termination

Date: Tue, 24 Apr 2001 16:58:54 -0800

From: Jack Chenoweth <Jack_Chenoweth@legis.state.ak.us>

Organization: Alaska State Legislature

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

There is one statute, AS 38.05.180(m), that makes reference to termination "by reason of cessation of production"; I take that to be the downside reference to mention made earlier in subsection (m) as to providing for "automatic [extension] if and for so long thereafter as oil or gas is produced in paying quantities . . .". In other words, under the statute, so long as you're producing "oil or gas" in paying quantities, the initial lease is to be extended; if production ceases--or, I would guess--if production never initiated, the lease is subject to termination.

That looks to me to be the only statutory reference to "terminate" or "termination" in the language of existing AS 38.05.180, the section generally governing oil and gas leasing. (The matter of lease termination is more extensively addressed in AS 38.05.177, the 1996 addition addressing shallow natural gas leases.)

There are references in several departmental administrative regulations, most notably under 11 AAC 83.700, relating to termination *for failure to adhere to a work commitment under the lease*, but the citation of authority is to AS 38.05.020, the section generally setting out the authority and duties of the commissioner, and to AS 38.05.180 without specifying any subsection within the section.

Again, because former Governor Hickel disclosed that he had seriously contemplated taking action to terminate (but ultimately did not), it would be interesting to know (1) what the basis of the action that he contemplated actually was and (2) whether he was advised that there were legal barriers to pursuing that action. I am not at all familiar with the details of his considering this issue, but I'll bet it would be an interesting story.

Jack Chenoweth

LEGAL SERVICES

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MEMORANDUM

February 16, 2001

SUBJECT: Transmittal of copy of April 4, 2000, letter of former Governor
Walter J. Hickel endorsing consideration of gas reserves tax

TO: Representative Scott Ogan

FROM: Jack Chenoweth
Assistant Revisor of Statutes 

Enclosed is a copy of the letter of last year from former Governor Hickel endorsing House Special Oil and Gas Committee deliberations on a gas reserves tax (HB 399, 21st Legislature, Second Session). The letter also mentions actions contemplated, but not taken, with respect to termination of the Point Thompson leases.

JBC:glc
01-159.glc

Enclosure

Walter J. Hickel

Box 101700
Anchorage, Alaska 99510-1700
907-278-7400

April 4, 2000

Representative Jim Whittaker, Chairman
House Special Committee on Oil and Gas
Alaska State Capitol
Juneau, AK

BY FAX (907) 465-2070

Dear Jim,

I would like to congratulate you and the Committee for giving serious consideration to additional incentives the State of Alaska can offer its leaseholders to commercialize Alaska North Slope Natural Gas.

As I see it, the state has three major options as an owner:

- It can work with the producers and pipeline companies to promote gas sales. It should do this by continuing the state offices abroad, supporting the property tax exemption option proposed by the Mayor's group, and otherwise working to improve project economics and market interest.
- It can take back the gas interest if it determines the gas producers are not fulfilling their leasehold commitment. I considered this option as Governor with the Point Thompson leases, but as far as I know, the option has not been used with any of our major untapped gas fields at present.
- It can charge a tax on gas reserves that are not produced, reflecting the argument that the gas is more valuable "in the ground" than "in the market" in competition with supplies leaseholders sell from other areas.

Your bill, HB 399, puts the third option in place and strengthens the second option. I hope a reserve tax never needs to be used, but it is high time – given the fact gas was discovered over 30 years ago – that the option is there. Other nations have much stronger "disincentives" to a lack of production, and I believe that is part of the reason producers put us off as an option for the Asia marketplace.

With best regards,


Walter J. Hickel

Walter J. Hickel

Box 101700
Anchorage, Alaska 99510-1700
907-276-7400

Distributed By
Representative Scott Ogan
District 27

March 23, 2001

The Honorable Scott Ogan
Alaska State House of Representatives
State Capitol (MS 3100)
Juneau, AK 99801-1182

FAX 907-465-3265

Dear Representative Ogan,

While I had hoped to visit you and the House Special Committee on Oil and Gas before the end of March, I'm not able to do so because I'm traveling to Moscow for a meeting of Northern Forum leaders. Nevertheless, I want to compliment you and the Committee on its efforts to understand where Alaska stands in world markets for natural gas.

Any successful gas project requires willing buyers, willing sellers, willing transporters, and financing. My work in this area has been to try to bring those elements together, and I hope your committee can do the same.

If I were there, I would make three points.

First, Alaska has to look out for its own interests. In the late 1970s, an overland project failed – but not before Alaska's efforts helped Canadian reserves get to market. If overland was the best way to go, we would have an oil pipeline to Bellingham today. We don't. Tidewater gives us the most options, and while we can pursue an overland route, we can't allow the tidewater option to be ignored by the state or the producers. We must aggressively pursue Asian markets, and that means ensuring that a gas supply is independently offered for sale. So far, that has not been done. Instead, we're telling the Asian market we're not ready to sell.

Second, I've attached an excerpt from a talk the late Senator Bob Bartlett gave to Alaska's Constitutional Convention. He warned about companies with assets Outside Alaska warehousing assets they acquire in Alaska. Of course, no oil company would admit that they are warehousing gas, or keeping it out of the market because it has other supplies available. But a state owner of such a large resource has to protect itself, because it could happen. It is clear to me we haven't protected ourselves.

What do we do? We must be tough. Our options range from a reserve tax to taking back the resource for non-performance. Neither of these options would

be necessary if a sufficient gas supply to serve the LNG route were committed to an independent marketing effort.

Third, we must learn our lessons from the oil line: Unless structured correctly, a pipeline owned by producers is likely to result in tariff, royalty, and tax disputes because of a conflict in incentives between profits from transportation and profits from wellhead production. Since TAPS began, the state has had to collect close to \$10 billion in dispute because of the way the Trans-Alaska Pipeline was structured. Two options could help head off similar disputes on gas. First may be requiring an independent transportation company to carry the gas. Second may be having the state take an ownership interest in the pipeline at least equal to its royalty interest in the gas. Ken Thompson's trading hub idea also has merit in heading off this kind of conflict.

At least two transport companies have invested millions of dollars designing and permitting systems to deliver North Slope gas. The state is doing nothing I'm aware of to help bring these investors together with the producers.

I look forward to further discussion with you on my return. I'm doing what I can, as an individual, to urge producers, transporters, buyers, and financiers to get together. The state must help to do the same.

If this letter is presented to your Committee in my absence, Mead Treadwell – who works with me – can attempt to answer any questions you have.

With best regards.

Sincerely,


Walter J. Hickel

Enc.

Excerpt from

MEETING THE CHALLENGE

By

Delegate E. L. Bartlett

Alaska Constitutional Convention

University of Alaska

November 8, 1955

...

The various bills for statehood enabling legislation which have been introduced in the Congress in recent years have uniformly called for large grants of land from the United States public domain to be made to the State of Alaska. The figure mentioned has been in excess of 100 million acres, an area roughly equal to the total land area of the State of California. The 100 million acre figure would appear to be approximately the figure which will finally be adopted.

The State of Alaska would choose almost all this acreage from the lands not included in present federal reservations and withdrawals, or which is otherwise unappropriated. The 100 million plus acres represent a veritable empire, a wealth of land and resources never before conferred on any state, saving only Texas which, upon its entry into the Union, was allowed to retain all its public lands. Alaska will receive also, in addition to the 100 million acre plus grant, an uncounted but tremendous acreage of submerged lands, land which under decisions of the Supreme Court of the United States have been held in trust for the future state. These submerged lands include lands under the beds of navigable rivers, lakes, and streams; the tidelands proper; and the submerged soils of the marginal sea out to the three-mile limit.

...

Two very real dangers are present. The first, and most obvious, danger is that of exploitation under the thin disguise of development. The taking of Alaska's mineral resources without leaving some reasonable return for the support of Alaska governmental services and the use of all the people of Alaska will mean a betrayal in the administration of the people's wealth. The second danger is that outside interests, determined to stifle any development in Alaska which might compete with their activities elsewhere, will attempt to acquire great areas of Alaska's public lands in order NOT to develop them until such time as, in their omnipotence and the pursuance of their own interests, they see fit. If large areas of Alaska's patrimony are turned over to such corporations the people of Alaska may be even more the losers than if the lands had been exploited.

www.nytimes.com

The New York Times
ON THE WEB

April 23, 2001

Australia Blocks Shell-Woodside Deal

By THE ASSOCIATED PRESS

Filed at 8:04 a.m. ET

CANBERRA, Australia (AP) -- Bowing to political pressure, the government Monday rejected oil giant Royal Dutch/Shell Group's \$5.1 billion hostile takeover of Woodside Petroleum, Australia's largest oil and natural gas producer, saying it was against the country's interests.

The move stunned the business sector, which had widely expected the conservative government to approve the takeover. Some Australian businesses denounced the decision, saying it would discourage foreign investment, and the Australian dollar fell in reaction.

"I have decided the Shell proposal is contrary to the national interest," Treasurer Peter Costello said in a statement.

The government is under intense pressure to limit foreign purchases of Australian companies. Many Australians fear the country's economy is being taken over by foreign multinationals that are not concerned about protecting local workers and assets.

The government's economic reforms to spur competition and attract foreign investment are unpopular, especially among key supporters such as small businesses and farmers. Facing likely defeat in elections later this year, the government's decision Monday appeared aimed at trying to maintain its political support. The decision was warmly welcomed by its own lawmakers.

Shell reacted with disappointment, insisting the takeover would have been in Australia's interests.

"It is disturbing that the intensive campaign to position the merger as against the national interest has succeeded in depriving Woodside shareholders of the benefits of the merger proposal," Shell Australia chairman Peter Duncan told reporters.

Costello said the government would consider any new bid from Shell, which already owns 34 percent of Woodside shares.

At the heart of Shell's bid was control of the multibillion-dollar North West Shelf liquefied natural gas project in Western Australia, one of the nation's largest fuel resources.

"Woodside is the operator of the project and it is in the national interest of Australia that the project be developed to its full capacity and that Australia's export sales from the North West Shelf are maximized," Costello said.

The government has the power to prohibit a foreign takeover if the move is deemed to be against the national interest.

"I've determined that this is one of those rare occasions on which that power should be operated," Costello said. "I believe it is in the national interest of Australia that that resource be developed to its full," he said.

The Woodside board had urged shareholders to reject the offer, arguing it undervalued the company.

In a statement, Woodside called the government's decision "informed and clear" and said that it planned to meet with Shell "to discuss ways to take the company forward for the benefit of all shareholders."

The long-awaited decision was seen as unfriendly to foreign investment by money markets, which dumped almost 1.5 U.S. cents from the value of the Australian dollar to 50.42 cents. Further losses were expected with currency traders saying the decision sent a negative signal to foreign investors.

Shares of Woodside fell 1.47 Australian dollars, or 10.5 percent, to 12.49 Australian dollars (\$6.30) on the news.

Shell said the decision would not effect its commitment to Australia or Woodside.

The Australian Gold Council, which represents the country's producers, said the decision was a blow for Australian industries that rely on international investment.

"It will send a negative message to international capital markets that don't fully appreciate Australia's domestic political environment," AGC chief executive Greg Barns said.

6) Foreign laws and concessions (Phillips Timor Sea activities)

What is Phillips' general approach to developing multiple, potentially competing projects around the world?

Phillips is in the business of exploring for, developing, producing and marketing hydrocarbon resources. The development strategies and tactics in this endeavor are as numerous and varied as are the resources and their locales. However, there are two aspects common to all. First, our efforts involve high front end risk because discoveries are relatively unlikely and require large capital outlays. Second, there is an ongoing need to use innovative approaches to shorten the time between first discovery and the realization of revenues. Phillips' activities on both the Alaska and Timor Sea legacy assets exemplify this.

Over 30 years ago, Phillips pursued and developed a new option for its Cook Inlet gas and created what is now known as the East Asian LNG market. Unlike many later LNG projects, the Kenai project did not have condensate available to it for early revenues. In addition, buyers had to develop the facilities to receive and utilize LNG. While the project required pioneering innovation to develop, Phillips has also demonstrated an impressive record of safety and reliability over the past 30+ years.

Today, Phillips has many gas developments ongoing around the world. Simply stated, a diverse portfolio of projects is essential to the success of our company. We've taken significant risks and invested significant capital in each one and we need to commercialize each opportunity as quickly as possible. At times, multiple Phillips projects may be entering the same markets. We believe that this is healthy, because the competitive spirit just makes our projects stronger in the long term. Phillips works hard to ensure that each of its projects succeeds. Phillips does not have a strategy to "warehouse" gas.

Following its discovery in 1995, Phillips has aggressively pursued development of its Timor Sea resources. Plans for field development yielding liquid condensate reserves are being executed. Phillips has also actively pursued gas development, both by increasing its equity interest and by pursuing diverse markets. Because of its need for additional gas resources, the L-48 market is now a primary target as indicated by the recent Phillips/El Paso announcement, discussed below.

Following the acquisition of ARCO Alaska in 2000, Phillips immediately stepped up an already aggressive gas commercialization program by proactively pursuing the L-48 market option via its participation in the North American Natural Gas Pipeline Group. We believe strongly that there is sufficient demand in this market to accommodate both ANS gas as well as Timor Sea gas and gas from many other sources. Further, our development of LNG receiving facilities on the West Coast may further provide opportunities for Alaskan LNG if and when that option becomes cost competitive. We

believe that it is strategic for an Alaskan gas owner to have ownership in West Coast receiving facilities.

What are the characteristics of the Timor Sea development including the latest Baja announcement?

Attachments 4, 5 and 6 show the location of the Timor fields off of the Northwest Coast of Australia, west of the city of Darwin. As another point of reference, the fields are southeast of East Timor, Indonesia.

In 1995, Phillips discovered the Bayu-Undan condensate/gas field. This field is located in the Zone of Cooperation between Australia and Indonesia. Nine appraisal wells have been drilled, confirming the presence of a world-class gas and gas condensate field. The field is located some 300 miles Northwest of Darwin in 240 feet of water. Phillips is the operator. Additional information can be accessed at: <http://phillips66.com/newsroom/>.

The Bayu-Undan field is being developed in two phases which will involve a total of about 26 wells. The first phase is a gas-recycle project to recover condensate, with an expected startup date of 2003 and full commercial production to begin in 2004. A schematic of the platforms and ship for this development is shown in Attachments 6 and 8 (more detail on this can be accessed at <http://bayuundan.phillips66.com/>).

This first phase will allow Phillips to realize revenues as soon as practicable. The second phase will be a gas project and will proceed as gas markets are developed. This phase will involve a subsea pipeline to Darwin, also shown in that schematic. All potential gas markets, including LNG and domestic Australian markets are being pursued.

What has been the chronology of the Phillips' announcements concerning Timor Sea?

On April 13, 1999, Phillips announced the acquisition of Broken Hill Proprietary Co.'s interest in the Bayu-Undan field. This resulted in a booking of about 98 million boe of reserves. This raised Phillips interest to 50.3%. The sale package also included permits for other static gas resources in the Timor Sea area.

On October 26, 1999, Phillips announced that the condensate development at Bayu-Undan will proceed, with first production expected by late 2003 or early 2004. The project is estimated to cost about \$1.4 billion. Phillips also announced continuing progress towards the establishment of gas markets for Bayu-Undan gas resources.

On November 23, 1999, Phillips announced that it and Epic Energy had entered into an alliance to conduct market development activities to commercialize Timor Sea gas throughout Australia. This domestic market focus is in the Northern Territory, Queensland and the southeastern states. Phillips also indicated that it had made significant progress in identifying near-term gas markets in the Northern Territory. Epic Energy is Australia's largest natural gas transmission company.

On June 26, 2000, Phillips Chairman, Jim Mulva, delivered a speech to the South East Asia Australia Offshore Conference 2000 summarizing Phillips activities relative to Timor Sea resources and demonstrating Phillips proactive approach to developing its legacy assets. See Attachment 7.

On November 11, 2000, Phillips and Woodside announced that they had reached in-principle an agreement to pursue cooperative development of their Timor Sea gas resources. Woodside has an equity interest and is operator of the Greater Sunrise venture, the location of which is shown in Attachment 5. This announcement reinforced the emphasis on domestic Australian markets as well as methanol and LNG. Phillips also said that it would buy additional equity from Woodside to achieve a 30% interest in the Greater Sunrise project.

On February 22, 2001, Phillips announced an agreement with Woodside and Shell for Timor Sea Cooperation. Phillips agreed to bring its interest to 30% in the Greater Sunrise field. Phillips also agreed with Shell to purchase 25% interest in the Evans Shoal field. The three parties also announced that they had finalized principles for cooperative development of Timor Sea gas resources, including Bayu-Undan and Greater Sunrise.

The principles cover supply of gas and marketing of LNG, pipeline infrastructure and field optimization. Gas production is to begin from Bayu-Undan in 2004 for domestic Australia markets (and possibly to fulfill early Sunrise commitments) and from Greater Sunrise in 2006 for a diverse customer base, including an LNG plant at Darwin and a Methanex-owned methanol venture.

The following table summarizes the key items relating to Phillips interest in the Timor Sea resources. In total, Phillips currently owns about 6.5 TCF of known Timor Sea Gas resources.

	Bayu-Undan	Greater Sunrise	Evans Shoal
Operator	Phillips	Woodside	Shell
Phillips Equity, %	58.5%	30%	25%(pend)
Total Liq., MMBOE	400	321	nil
Total Gas, TCF	3.4	9.6	6.6
Phillips Gas, TCF	2.0	2.8	1.7
First gas	2004	2006	?

The current ownership of the Bayu-Undan field is:

Phillips	58.5%
Santos	11.8%
Inpex	11.7%
Kerr-McGee	11.2%
British Borneo	6.7%

The current ownership of the Greater Sunrise field is:

Woodside	33.44%
Phillips	30.00%
Shell	26.56%
Osaka Gas	10.00%

The Evans Shoal field is located to the east of the Sunrise and Bayu-Undan fields and development plans are more prospective.

What about the recent announcement for Timor LNG to the West Coast of North American in 2005?

On March 8, 2001, Phillips and El Paso announced a letter of intent which contemplates development of a project to deliver LNG to growing gas markets in California and Mexico's Baja California peninsula. The Phillips press release is given in Attachments 9. Additional information concerning the Woodside estimates referenced below can be accessed from Reuter News Service (Friday, March 9 - "Woodside Timor Sea fields poised for LNG) and Dow Jones Newswires (Friday March 9, - "Interview: Woodside Eyes Early Share of a A2\$B/yr LNG sales).

Aren't the costs of Timor LNG roughly equivalent to ANS LNG?

Attachment 10 summarizes unit capital costs on several projects, which is a key indicator of competitiveness. ANS LNG costs are not roughly or otherwise equivalent to E. Timor capital costs for LNG. At \$6.8 Billion (\$4.9 Billion without ships) for 8 MTPA, the Alaska North Slope LNG Project unit capital cost is currently over \$600 million per MTPA. Thus, by this one measure alone, an Alaskan LNG project needs more improvement to be cost competitive with other new, grass roots projects that are being developed in the \$200 - \$300 million per MTPA range.

Proprietary cost estimates have not yet been publicly disclosed and will ultimately require partner concurrence to be released. The Timor Sea to Baja or the U.S. west coast LNG Project can be expected to be significantly more competitive than the ANS LNG Project on this unit cost basis, since an 800 mile pipeline adds about \$300 million per MTPA to the Alaska LNG project.

Field development costs for E. Timor are primarily for the benefit of condensate recovery and anticipated domestic natural gas delivery to Australia, but some comparison scenarios from published data can be developed. The *March 9, 2001, Dow Jones Newswire* article cites a Woodside estimate for an E. Timor LNG Plant at roughly U.S. \$1.25 billion. Using 4.8 MTPA, that computes to a unit capital cost of around \$260 million per MTPA versus ANS LNG's \$610 million per MTPA. (($\$1.25 \text{ B} / 4.8 \text{ MTPA} = \$260.4 \text{ million}$)

It could be argued that there are also more ships involved in shipping E. Timor gas to Baja than from Alaska. The cost of ships is not included in unit capital costs given in Attachment 10. However, if we add an incremental 4 ships for Timor LNG (compared to Alaskan LNG) at an estimated cost of \$175 million per ship, for illustrative purposes, the unit capital cost is \$405 per MTPA, still well below the \$600 million per MTPA ANS number. Again, these shipping assumptions are hypotheticals, in addition to the Woodside LNG cost projection. (($\$175 \text{ million} \times 4 + \$1.25 \text{ B} = \$1.95 \text{ B} / 4.8 \text{ MTPA} = \$406.3 \text{ million}$)

Finally, previously published reports indicate that the offshore pipeline is anticipated to be built to supply domestic gas to Australia with or without an LNG project. However, we can take the extreme position and allocate, say, half of the Woodside estimated ~US\$500 million of that offshore pipeline to the LNG plant. With the LNG plant and additional ship cost above, E. Timor cost per MTPA at about \$460 million would still be less than the \$600 million per MTPA of the ANS LNG project when burdening the calculation with this pipeline cost. ($\$1.95 \text{ Billion} + \$0.25 \text{ Billion} = \$2.2 \text{ Billion} / 4.8 \text{ MTPA} = \$458.3 \text{ million}$)

Is there some penalty clause in the Timor agreement that has motivated Phillips to commercialize Timor gas ahead of AK gas?

No, as indicated above, Phillips' motivation for developing its Timor Sea resources is driven by economics, not by punitive provisions or economic disincentives. To summarize, Phillips realizes its interest in Bayu-Undan through a Production Sharing Contract (PSC) with the Timor Gas Joint Authority. The Timor Gap (being that offshore area between Australia and the island of East Timor, Indonesia where they could not agree on the international boundaries) was developed as a 'Zone of Cooperation' through the Joint Authority. As such, the two contracting countries (Australia and Indonesia) adopted a hybrid of their two petroleum regimes. This hybrid is a completely different system from Alaska's bonus-bid leasing system. Phillips, similar to its partners, is essentially a contractor to the Authority. Among the partners, Phillips is also designated as the operator. The PSC forms the basis for a mutually agreed to work program which the contractors are then obliged to perform. The PSC entitles Phillips to a share of the production. The following expands on these summary points. Further general information can be accessed at bayuundan.phillips66.com.

PSC's entered into within the Zone of Cooperation are substantially on similar terms and follow a basic model form attached to the Treaty. As with most contracts that can be terminated for breach, Section 13 of the PSC refers to article 48 of the Petroleum Mining Code. Article 48 generally provides that where the Contractor has not complied with any provision of the Treaty, the Joint Authority must give 30 days notice of its intention to

recommend termination. The Ministerial Council (comprised of a minister from each country – effectively the head of the Joint Authority) cannot agree to termination until the contractor has had an opportunity to respond. Thus, even where there may have been an event that may potentially justify termination, rather than being punitive, steps are in place to allow a response and corrective action prior to any contract termination.

The PSC sets forth the mechanism for allocating production and its provisions for liquids and gas are different. To some extent this reflects the reality that field development is primarily underpinned by liquids recovery. The PSC requires that a first tranche of liquids to be split between the Authority and the contractors. Then, liquids are next allocated to the contractors to cover 125% of field development costs and operating costs. Liquids beyond that level, as well as gas, are shared 50/50 between the Authority and the contractors. Phillips is subject to the normal taxes of the relevant country, but there are no additional royalties, rent or the like which are levied on the recovered liquids and gas. There are no incentive taxes.

However, the Timor Sea Treaty's absence of disincentives notwithstanding, punitive provisions in agreements or treaties rarely motivate us to develop resources under concessions or agreements. Strong resource bases and robust economics encourage us to develop while marginal, high-risk, economics, which can be caused in part by onerous tax or other fiscal disincentives or instabilities, inhibit development.

Shouldn't AK gas be better positioned for Baja than Timor?

Though developed independently and begun prior to Phillips ownership of substantial Alaska North Slope reserves, the Timor project would have been considered by the marketplace before the ANS LNG Project regardless of development timing and regardless of ownership. As indicated earlier, this is because of Timor's economic viability and competitiveness relative to other world-class LNG projects versus ANS LNG's cost of development, primarily due to the requirement for an 800 mile, buried Arctic pipeline to ice-free, tide water.

What does this say about Alaska's ability to compete in the E. Asian marketplace?

The Alaska North Slope LNG Project sponsor group determined in its early analysis that 1) the E. Asian market is fiercely competitive and, 2) that market entry before the end of the decade for any new green field project would be very difficult. The projects with current inroads into the E. Asian marketplace are existing, incremental LNG project expansions such as Australia's NW Shelf with relatively low, incremental unit capital costs.

For various reasons, the Phillips Timor Sea LNG project team determined that its best near term opportunity to enter the market would be in the Western U.S. and/or Mexico over East Asia. Clearly, the near term E. Asian market does not sufficiently support an E. Timor project in the near term. Rather, the investors were economically and market

driven to engage a lower 48 market that is 6,900 nautical miles away from E. Timor rather than E. Asia at only 3,000 nautical miles away.

If and when ANS LNG becomes economically viable and cost competitive with other new, green field projects or other alternatives for North Slope gas, Phillips would expect to expeditiously advance it within the gas/LNG market dynamics. The best possibility for an ANS LNG project may be in synergy with a L-48 pipeline to maximize cost sharing potential.

Phillips ownership and strategy for Timor Sea LNG (Bayu-Undan and Sunrise) was developed over the last 6+ years (since about 1995). This development strategy pre-dates Phillips acquisition of ARCO Alaska, Inc. and subsequent ownership of substantial Alaska North Slope gas reserves that were purchased this last year (April, 2000).

Even before its acquisition of these significant volumes of North Slope gas, Phillips joined (as a charter member) and actively participated in the Alaska North Slope LNG Project Sponsor Group. This \$12-15 million LNG development project began in October of 1998 and is ongoing today as a concerted effort to commercialize North Slope gas. The Sponsor Group continues to try to develop an economic or cost competitive LNG project.

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1989 the State has kept its fiscal regime stable, although there are occasional proposals to change the taxes or enact new ones.

21. *State whether BP's concessions or interests in Indonesian natural gas projects are subject to any provisions of Indonesian law that penalize or jeopardize the concessionaire or interest holder for delays in bringing natural gas reserves into production.*

The concessions in Indonesia call for the companies, who are contractors to the state oil company Pertamina, to pursue specific programs of exploration for oil and gas, and often it is the diligence with which a company promises to explore for oil and gas that determines who is awarded a particular concession. Once oil or gas is found, the concessions contemplate that it will be brought into production within a reasonable time. From the time of discovery to the time in which a Plan of Development is sanctioned, certain provisions are imposed that include acreage relinquishments and spending commitments. There is no requirement to develop a discovery while it is uneconomic to do so. Typically, the concession-holder is required to pay a fixed sum of money to the government each year, similar to lease rentals in Alaska, as the price to continue holding a concession with sub-economic discoveries until they become economic and go into production. Once a development is on production and delivery contracts are in place, the contractors act on a best endeavours basis with no penalty clauses for failing to meet contract rates.

22. *Please set forth information obtained and/or developed by BP pertaining to Indonesian rebel, separatist and terrorists groups and organizations.*

It would be inappropriate to respond to this question.

23. *Please set forth the three highest non-spot LNG prices, which have come to BP's attention directly or indirectly in the last three years, and which may have been obtained from customers located in Taiwan, South Korea and/or Japan. If BP contends its LNG pricing is confidential and/or proprietary, then provide any price data BP has obtained or developed from third party sources or indices that are not subject to contractual confidentiality provisions.*

Two potential sources of LNG prices are *LNG in World Markets* and *World Gas Intelligence*.

The highest LNG prices, from the last three years, BP found by referencing *LNG in World Markets* were all from LNG supplied by Indonesia during October 2000. The three highest LNG prices and the countries of delivery are as follows:

Korea \$6.06/mmbtu
Taiwan \$6.04/mmbtu
Japan \$5.89/mmbtu

For comparison, the average Brent crude oil price during the same month was \$30.91/bbl.

24. *Please describe in detail all efforts, initiatives and undertakings by or on behalf of BP to offer ANS natural gas for sale to unrelated third parties from the inception of Prudhoe Bay production to the present.*

BP has been selling natural gas from the Prudhoe Bay field to third parties for over fifteen years. It has been, and will continue to be, in BP's best interest to give full consideration to any commercially viable opportunity to sell gas from the North Slope of Alaska as well as to work with all third parties who demonstrate the ability to add value to any ANS gas commercialization scheme. As mentioned in the

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Gas Transportation System, or equivalent pipeline system along the Alcan Highway route.

The viability of a project depends on a number of factors, including the overall economics and risks associated with a project. Market conditions are a key determinant in whether a project is viable and when it could be built. Specific pricing terms would be negotiated by individual companies through private and confidential negotiations.

17. EM has made substantial capital commitments to LNG projects in Yemen, Qatar, Natuna, and Sakhalin, apparently targeting sales to Asian markets. Please set forth in detail EM's rationale and analysis supporting capital expenditures to commercialize natural gas reserves in foreign countries rather than ANS natural gas reserves.

ExxonMobil continues to pursue commercialization of all of its worldwide gas resources by progressing all potentially viable projects. Each project has its own characteristics that impact its feasibility. ExxonMobil has spent over \$110M on specific efforts seeking a means of commercializing Alaska North Slope gas.

18. Please describe and compare the political and business conditions in Yemen, Qatar, Natuna, and Sakhalin with the political and business conditions in Alaska, particularly focussing on the political stability of the differing regimes.

It is inappropriate for ExxonMobil to comment on the political regimes and conditions in these countries.

19. State whether EM's concessions or interests in Yemen, Qatar, Natuna, and Sakhalin natural gas projects are subject to any provisions of law that penalize or jeopardize the concessionaire or interest holder for delays in bringing natural gas reserves into production.

The terms of our agreements with other governments contain confidentiality provisions that limit our ability to discuss them.

20. Please set forth information obtained and/or developed by EM pertaining to rebel, separatist and terrorist groups and organizations operating in the vicinity of the Yemen, Qatar, Natuna, and Sakhalin natural gas fields and developments.

It is inappropriate for ExxonMobil to comment on rebel, separatist, or terrorist activities in other countries. Each potential project has many different characteristics that impact the overall risks and commercial viability of the project. Ultimately for a project to be built the project investors, those that finance the project, and those buying the product from the project must be convinced that the risks are acceptable, the project is competitive with other sources of supply and provides a reasonable return to investors.

21. Please set forth the three highest non-spot LNG prices, which have come to EM's attention directly or indirectly in the last three years, and which may have been

appropriate recommendations for the valuation of the state's royalty gas. The Lower 48 market is complex and rapidly changing. Customers (local distribution companies, power utilities, and industrial end-users) meet gas producers and merchant marketers of gas throughout the U.S. in an active marketplace. Prices are relatively transparent. New gas supplies, whether shipped by pipeline into California and the Midwest or delivered as LNG to the West Coast, have access to the entire Lower 48 market, either physically, through the existing pipeline network, or virtually, through exchanges or swaps.

5. Please identify potential customers for sales of ANS natural gas in Mexico.

See 2 above.

6. Please identify potential customers for sales of ANS natural gas in the Midwest region of the United States.

See 4 above.

7. Please identify potential customers for sales of ANS natural gas in Canada.

See 1 above.

8. Please set forth the minimum sales price per million BTU or thousand cubic feet at a specified delivery point which must be sustainable, specifying the relevant period of time and the required volumes, to support capital construction of the Alaska Natural Gas Transportation System or equivalent pipeline systems along the Alcan Highway route.

See 4 above.

9. Are you aware of any provisions or law that penalize or jeopardize the concessionaire or interest holder for delays in bringing natural gas reserves into production? In the United States? In the world?

Our own leases provide for a term—usually seven to ten years—when the lease expires if the lessee has not found oil or gas, or included the lease in a unit. Holders of state leases with shut-in oil and gas wells can be ordered to develop and produce the lease. The Charter for Development, section I.J., compels BP and ARCO (Phillips Alaska) to provide ANS gas reserves in sufficient quantities to any qualified "treatment and transmission project" that is willing to pay a fair market price for the gas. BP and Phillips have an obligation to negotiate in good faith with the sponsors of any such project through December 31, 2003. We are not aware of any specific laws noted in this question.

10. Please set forth the three highest non-spot LNG prices, which have come to your attention, directly or indirectly in the last three years, and which may have been obtained from customers located in Taiwan, South Korea and/or Japan.

Answer:

Please see answer to question #1.

7. Please identify potential customers for sales of ANS natural gas in Canada.

Answer:

Please see answer to question #1.

8. Please set forth the minimum sales price per million BTU or thousand cubic feet at a specified delivery point which must be sustainable, specifying the relevant period of time and the required volumes, to support capital construction of the Alaska Natural Gas Transportation System or equivalent pipeline system along the Alcan Highway route.

Answer:

Pipeline economics are not part of the AOGCC's regulatory jurisdiction and information related to this issue is not regularly provided to us.

9. Are you aware of any provisions or law that penalize or jeopardize the concessionaire or interest holder for delays in bringing natural gas reserves into production? In the United States? In the world?

Answer:

This question involves lease obligations and relations between lessor and lessee. These subjects are not regulated by the AOGCC.

10. Please set forth the three highest non-spot LNG prices, which have come to your attention, directly or indirectly in the last three years, and which may have been obtained from customers located in Taiwan, South Korea and/or Japan.

Answer:

Please see answer to #1

NATURAL GAS UTILIZATION STUDY: OFFSHORE NEWFOUNDLAND

1998

Prepared for:

Atlantic Canada Opportunities Agency
and
Newfoundland Ocean Industries Association

Prepared by:

Imperial Venture Corp
St. John's, Newfoundland
Canada

2. BACKGROUND

2.1 Purpose and Scope

The purpose of the study is to quantify the gas resources of Newfoundland, identify production and transportation options and lay out the Terms of Reference for a follow-up study. The present study (Phase I) is characterized as a scoping study while Phase II will be comprehensive examination of critical issues. The ultimate objective is to create a development strategy for Newfoundland industry.

This report was commissioned by the Newfoundland Ocean Industries Association (NOIA) and the Atlantic Canada Opportunities Agency (ACOA). The Terms of Reference were developed by NOIA and ACOA who also provided supervision of the study through a Steering Committee. The Departments of Industry, Trade and Technology and Mines and Energy of the Newfoundland and Labrador Government were also represented on the Steering Committee.

The study was carried out by an alliance of independent consultants under the lead of the principal contractor, Imperial Venture Corp of St. John's, Newfoundland. The study team and their principal areas of expertise are as follows:

Steven M. Millan, P.Geol. - *Project Leader, Resource Assessments*

Gus Cammaert, Ph.D, P.Eng. - *Development and Transportation Options*

Lorne Spracklin, M.A. - *Project Economics*

Pedro van Meurs, Ph.D - *Global Economics, Fiscal Regimes*

The level of effort for the study was approximately \$25,000 and it was conducted over a period of approximately eight weeks in May and June 1998.

Information for the study was derived mainly from public domain sources augmented, where appropriate, from the consultants' databases. Proprietary cash-flow (van Meurs) and cost models (Cammaert) were used for analysis.

The report is organized into the following main sections:

- **Summary and Conclusion**
- **Background**
- **Resource Endowment**
- **Production Systems**
- **Transportation Systems**
- **Preliminary Project Economics**
- **Phase II - Terms of Reference**

As a result, some governments have started to respond to the fact that gas is an energy source with very different characteristics from oil. Accordingly, fiscal systems are now being developed for gas which are different from oil. Most gas terms involve a lower governmental take than for oil.

The strongest case of a country adopting a concerted policy of offering substantially more favorable terms for gas than for oil is Indonesia. Indonesia accepts a government take which ranges from 30% to 17% lower than for oil. Given that gas development in Indonesia has a low netback to the producer, the policy appears entirely rational. Indonesia also has an aggressive policy of promoting the export of LNG.

Within Canada, Manitoba is the only province which offers a substantial incentive for natural gas by fixing the royalty level at 12.5% as compared to the marginal oil royalty rate of 24.75%. This results in a drop of 15% in government take.

Next in line is Australia whose onshore State regimes exhibit a government take which is roughly 14% lower for gas than for oil. This is because the commonwealth excise tax which applies to cumulative oil production above 30 MMbbl does not apply to natural gas, LNG or LPG.

The same fiscal regime which applies to both France and St. Pierre and Miquelon offers a government take which is also just under 14% lower for gas than for oil. This is partially accomplished by a royalty free gas production of up to 29 MMcf/d with a royalty of only 5% in excess of this amount, as opposed to a sliding scale oil royalty whose marginal rate is 12%.

Trinidad & Tobago is another country which has adopted a clear policy and implementation plan of encouraging natural gas development over the past decade. As the Supplemental Petroleum Tax and the Petroleum Levy do not apply to natural gas, the government take in the case of a natural gas development is almost 14% lower than for oil. ***The success of this strategy was recently witnessed by a Newfoundland trade mission to that country in April of this year.***

This trend is increasing and recently a number of other potential LNG exporting countries have taken steps to introduce significant incentives for gas development. These countries include Qatar, Yemen, and Papua-New Guinea. In addition, Iran has recently concluded a contract with the oil company Total under terms that greatly stimulate gas development.

The fact that both Qatar (with 300 Tcf of gas reserves) and Iran (with 812 Tcf of gas reserves) are taking aggressive steps to make their gas resources economically attractive, indicates that even the huge gas reserves in the Middle East may become increasingly part of a new worldwide pattern of gas-gas competition.

An interesting case for Newfoundland is that Alaska recently passed a new law which dramatically changes the fiscal terms applicable to gas for LNG exports. This now may become the basis for an Arco-led consortium for the production of Prudhoe Bay gas for exports.

It is important to realize, therefore, that it is unlikely that gas development will come about in Newfoundland unless the Province joins the worldwide trend of offering fiscal terms for gas which are substantially more attractive than for oil. The assessment of the Province's competitive position will require the analysis of a variety of factors affecting the value of the resource to prospective developers and resource owners. A key factor is the fiscal regime.

2.3 Regulatory Setting

Management of the offshore hydrocarbon reserves rests with the Canada Newfoundland Offshore Petroleum Board (CNOPB) which administers mirror legislation of the Governments of Canada and the Government of Newfoundland and Labrador. Onshore resources fall under Provincial jurisdiction. In both cases, Legislation covering such major aspects as land tenure, fiscal take, exploration and production operations, are in place. In general, oil developments were contemplated in the drafting of the various pieces of Legislation and usually natural gas is included under the definition of petroleum. Generic royalty regimes have been announced for both the onshore and offshore areas. These regimes have not yet been put into regulations. Whether these systems will apply to oil only or extend to gas is unclear.

As discussed elsewhere, gas specific legislation is advisable where there are clear differences in the development characteristics of oil and gas. Within a competitive investment setting, having an explicit competitive regime for natural gas would be expected to encourage exploration and development by improving potential rewards and providing a firm foundation of established legislation in the assessment of risk factors by the private sector.

Northern Territory, Australia: Petroleum Act

Licenses for Petroleum Retrieval:

- 1) **Exploration License:** A license for exploration is issued for a period of 1½ years (Sec.22).
- 2) **Retention License:** After the exploration license has expired, if significant quantities of petroleum have not been found, a retention license may be issued for anywhere from 2-5 years (Sec. 34). However, if at any time, the minister finds that production of the petroleum held within the exploration blocks is economically viable, both in size and marketability, he may order that production begin (Sec. 43, 44).
- 3) **Production License:** An initial production license is issued for a period of five years, that initial license, however, may be extended for up to 25 years, subject to the will of the minister. If, at any time, the minister does not feel that the petroleum resource is being properly produced (according to the Petroleum Act), he may withdraw the license* (Sec. 50 and conversation with Dept of Mining and Petroleum Production, Northern Territory, Australia).

Additional notes:

Any survey or core sample may not be disposed of, held, or kept confidential by the producer (Sec. 60).

Core Samples: Any core sample taken must be presented to the minister within 28 days of the time that it is taken. The sample will then be made public with an announcement in the *Gazette*.

Surveys: Any survey taken must be presented to the minister and his staff within one calendar year of its completion. The minister may then decide to make the survey public based upon information provided by the producer of the survey and the requestor of the survey. If it is decided that the survey need remain confidential, then it shall only be made available to the members of the territorial and parliamentary government and no to the general public.

- There has never been an instance, in the Northern Territories, when a petroleum producer failed or refused to produce an economically viable field.

(1) Subject to section 18(3), a person may object to the granting of a permit by lodging with the Minister, within the time referred to in section 18(1)(e), a written notice of his objection setting out the grounds on which the objection is made.

(2) The Minister shall give an applicant notice of the content of objections received under this section and specify a date, not being earlier than 28 days after the date of the notice, by which the applicant may lodge a reply or other comment in relation to the objections.

20. GRANT OF PERMIT

(1) After the date specified in a notice under section 19(2), the Minister shall consider -

(a) the application;

(b) the objections, if any;

(c) the replies or other comments of the applicant, if any; and

(d) any other information supplied to him under a request made under section 16(2) or other matter which, in the opinion of the Minister, is relevant to the application,

and shall determine to grant the permit in respect of some or all of the blocks to which the application relates or refuse to grant it.

(2) Where the Minister determines under subsection (1) to grant a permit, he shall give notice to the applicant of -

(a) the conditions subject to which he is prepared to grant it; and

(b) the date, not being earlier than 28 days after the date of the notice, after which the application shall lapse unless the Minister has received from the applicant an acceptance of the conditions specified in the notice.

(3) Subject to subsection (4), where the Minister receives from an applicant within the time specified a written acceptance of the conditions specified in a notice under subsection (2), he shall grant to the applicant a permit subject to those conditions.

(4) The Minister may not grant a permit in relation to an area which is the subject of another permit or a licence.

21. REFUSAL OF PERMIT

Where the Minister determines not to grant a permit, he shall, as soon as practicable after he has so determined, serve notice of his determination on the applicant.

22. TERM OF PERMIT

(1) Subject to sections 28(3), 30(3), 73 and 74, a permit remains in force for the period specified in the application, being a period of not less than 2 years or more than 5 years, commencing on the day on which

it was granted or last renewed.

(2) The Minister may not renew a permit more than twice.

23. APPLICATION FOR RENEWAL OF PERMIT

(1) Subject to section 24, a permittee may apply to the Minister to renew his permit in relation to the blocks specified in the application.

(2) For the purposes of subsection (1), an application for the renewal of a permit shall be -

- (a) in an approved form;
- (b) made in an approved manner; and
- (c) accompanied by the prescribed fee.

(3) In relation to an application for a renewal of a permit, the Minister -

- (a) shall, where the application is received not earlier than 6 months before, but not later than 3 months before, the expiration of the permit;
- (b) may, where the application is received later than 3 months before the expiration of the permit; and
- (c) shall not, where the application is received after the expiration of the permit, accept the application.

24. APPLICATION FOR RENEWAL OF PERMIT TO BE IN RELATION TO REDUCED AREA

(1) Subject to subsection (3), the number of blocks in relation to which an application for the renewal of a permit may be made shall not exceed -

- (a) where the number of blocks in respect of which the permit is in force is a number that is divisible by 2 without remainder - one-half of that number; or
- (b) where the number of blocks in respect of which the permit is in force is a number that is not divisible by 2 without remainder - one-half of the number arrived at by increasing the number of blocks by one.

(2) In an application for the renewal of a permit -

- (a) the blocks specified in the application shall constitute a single area, or a number of discrete areas each comprised of 2 or more blocks; and
- (b) each block, in a discrete area referred to in paragraph (a), shall have a side in common with at least one other block in the area.

(3) Subject to subsection (4), where the number of blocks in respect of which an application for the renewal of a permit may be made is 12 or more, each area constituted by blocks in respect of which the application is made shall be constituted by not less than 12 blocks.

- ### 34. GRANT OF RETENTION LICENCE

- ### 35. PERMIT NOT AFFECTED

(a) an application for a retention licence; or

(b) the determination of the Minister not to grant a retention licence.

Subject to sections 43(3), 73 and 74, a retention licence remains in force for a period of 5 years commencing on the date on which it was granted or last renewed.

43. NOTICE TO APPLY FOR PRODUCTION LICENCE

(1) Subject to subsection (5), where the Minister is satisfied that commercial production of **petroleum** should commence in a retention licence area, he may, by notice served on the retention licensee, require him to show cause why he should not apply for a production licence in relation to the blocks where the commercially exploitable accumulation of **petroleum** occurs and specify a date, being not earlier than 6 months after the date of the notice, by which the licensee should show cause.

(2) Where a retention licensee has been served with a notice under subsection (1) and he fails to show cause to the satisfaction of the Minister, within the time specified in the notice, the Minister may, by notice served on the retention licensee, direct him to apply for a production licence and specify a date, being not earlier than 3 months after the date of the notice, by which the licensee should apply for the production licence.

(3) Where, under subsection (2), a retention licensee has been directed to apply for a production licence before a date specified in the direction and the licensee has failed to so apply, the Minister may, by notice served on the licensee, cancel his licence.

(4) The Minister may, by notice served on a retention licensee, vary the date in a notice under subsection (1) or (2) so as to allow a longer period for the retention licensee to show cause or apply for a production licence.

(5) The Minister may not exercise his powers under this section if the blocks where the commercially exploitable accumulation of **petroleum** occurs are, in whole or part, Aboriginal land and no agreement in relation to the production of **petroleum in that area has been reached under the Land Rights Act** between the retention licensee and the Land Council or as otherwise permitted under that **Act**.

Division 4 - Production Licences

44. APPLICANT

A person who is -

- (a) a permittee; or
- (b) a retention licensee,

may apply for a production licence in relation to the whole or part of his permit or licence area.

45. APPLICATION FOR PRODUCTION LICENCE

(1) Subject to this **Act**, a permittee or licensee may apply for a production licence by lodging with the Minister -

- (a) a statement containing the name and address of the applicant and an address for service within the Territory;
- (b) a statement containing the designated number of each block the subject of the application;

- (c) a map clearly delineating the application area and the boundaries of the existing permit or retention licence area in which the application is comprised;
- (d) a proposed technical works programme specifying the proposals for exploration, appraisal and production of ~~petroleum~~ from within the proposed licence area;
- (e) evidence of the technical and financial capacity of the applicant to carry out the proposed technical works programme and to comply with this ~~Act~~;
- (f) proposals for the protection of the environment, including proposed measures to be undertaken by the applicant for the rehabilitation of the licence area or other affected areas;
- (g) where the application is made by 2 or more persons, the proposed sharing arrangements between the applicants;
- (h) a statutory declaration stating the applicant's interest, if any, in or in relation to each permit or licence applied for or granted under, or in force by virtue of, this ~~Act or the repealed Act~~;
- (j) the prescribed application fee; and
- (k) such other information in support of his application as the applicant thinks fit.

(2) Where the Minister has received an application for a production licence, he may, by notice served on the applicant, request further information in relation to the applicant or his application.

(3) A permittee or licensee may apply for one or more production licences.

46. SIZE OF PRODUCTION LICENCE

(1) A person shall not apply for a production licence in respect of an area which is constituted by more than 12 blocks.

(2) A person shall not apply for a production licence in respect of an area which is constituted by more than one block unless the blocks form a discrete area which conforms to an approved shape.

(3) The Minister may grant a production licence in respect of -

- (a) an area of less than one block; or
- (b) blocks which form more than one discrete area,

where he is of the opinion that circumstances justify his doing so or it is in the public interest to do so.

47. GRANT OF PRODUCTION LICENCE

(1) Where the Minister -

- (a) has received an application under section 45;
- (b) is satisfied that the applicant has complied with the requirements of this ~~Act~~ relating to an

(b) by notice served on the licensee, inform him as to the conditions to which the licence on its being granted, is to be subject and the amount of security to be lodged.

(8) An applicant who has been served with a notice under subsection (7)(b) may, within 28 days after the date of service of the notice on him, by notice served on the Minister, request the Minister to grant to him the licence subject to the conditions specified in the notice under subsection (7)(b).

(9) Where an applicant has served a notice under subsection (8), within the period referred to in that subsection, the Minister shall grant to him the licence subject to the conditions specified in the notice under subsection (7)(b).

(10) Where an applicant who may request, under subsection (5) or (8), that the Minister grant a licence to him, fails to make the request, his application for a licence lapses at the expiration of the period during which the request may be made.

48. REFUSAL OF PRODUCTION LICENCE

(1) Where the Minister determines to refuse to grant a production licence he shall, as soon as practicable after he has so determined, serve notice of his determination on the applicant, setting out the reasons for his determination.

(2) The Minister may not determine to refuse to grant a licence, unless he has -

(a) by notice served on the applicant, given not less than 28 days notice of his intention to refuse to grant the licence;

(b) in the notice, specified -

(i) the reasons for his intended refusal; and

(ii) a date on or before which the applicant may, by notice served on the Minister, submit any matters he wishes the Minister to consider; and

(c) taken into account any matters so submitted to him on or before the specified date by the applicant.

49. PERMIT OR LICENCE NOT AFFECTED

The term and area of a permit or retention licence are not affected by -

(a) an application for a production licence; or

(b) the determination of the Minister not to grant a production licence.

50. TERM OF PRODUCTION LICENCE

Subject to sections 73 and 74, a production licence remains in force for a period of 25 years commencing on the date on which it was granted or, in respect of the renewal of a production licence, the date on which it was last renewed, notwithstanding that it is renewed before the date on which it would otherwise have expired.



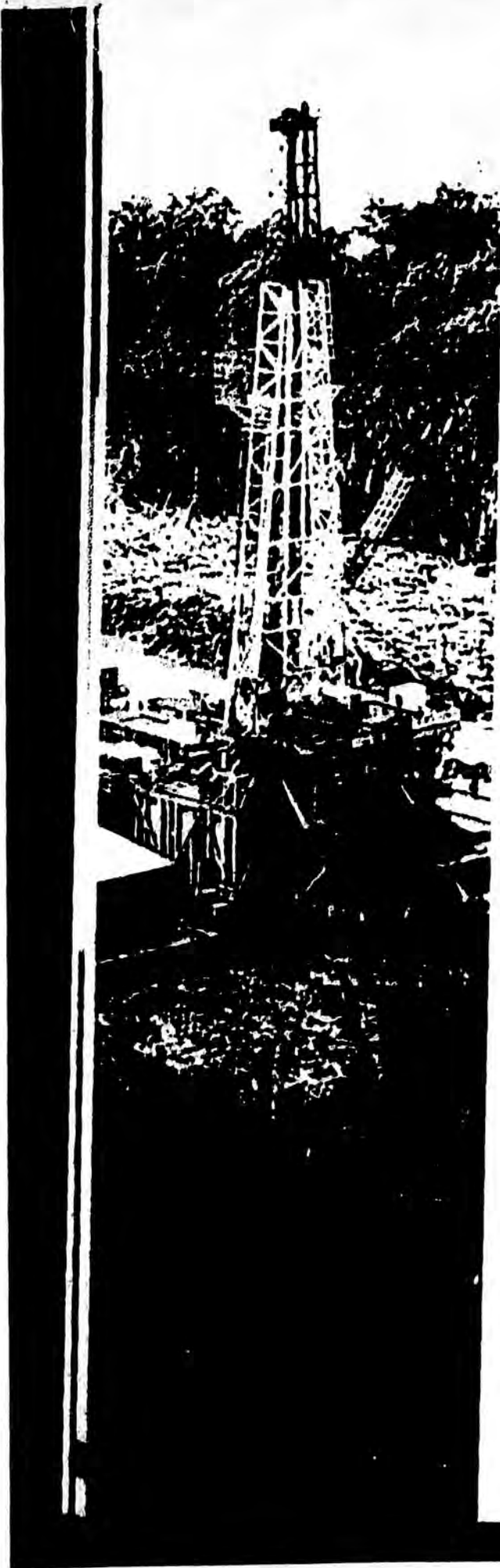
The Indonesia

Production Sharing Contract



Production Sharing Contract

Basic Term



- PERTAMINA is responsible for the management of the operations, but the contractor bears all risks and is responsible for the preparation and execution of work program.
- The term of the contract is 30 years, including 6 to 10 years exploration period. If a commercial petroleum discovery is not made by the end of the exploration period, the contract shall be automatically terminated.
- * The contractor is free to export its entitlement under the cost recovery and production split subject to fulfill its domestic supply obligation.
- Allowable costs, as defined on the basis of an accounting procedure, are recoverable from available production without volume restrictions.
- The sharing is made on production, not on profit. Government / PERTAMINA and Contractor share will be split after deduction of cost recovery and tax.
- Contractor and PERTAMINA shall be entitled to first take (First Tranche Petroleum - FTP) and receive each year a quantity of petroleum from the annual production before deduction of cost through the cost recovery mechanism. The FTP is further shared between PERTAMINA and Contractor in accordance with the applied sharing split.
- PERTAMINA shall have the right to demand from Contractor that a ten percent (10%) undivided interest in the total rights and obligations to itself or a limited liability company to be designated by PERTAMINA.

745-3300

**COMPARATIVE STUDY
OF FISCAL REGIMES
FOR LNG PROJECTS**

by
**Dr. Pedro van Meurs
&
Andrew Seck**

DRAFT ONLY
20 November 1996

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7.2.2 Land and System

Article 33 of the 1945 Constitution stipulates that land and water and all natural richness contained therein shall be controlled by the State to be utilized for the maximum benefit of the people.

7.2.2.1 Land Allocation Procedures

Acreeage is awarded under direct negotiations.

7.2.2.2 Block Size

304 sq. km (1993 ARCO PSC).

7.2.3 Exploration and Production Periods and Phases

30 year duration with an initial exploration period of 6 years which may be extended for another 4 years (1993 ARCO PSC).

7.2.4 Relinquishments

*

In the case of the 1993 ARCO PSC for the Wiriagar Block which only covered 304 sq. km, the Contractor is relieved of the relinquishment obligation.

7.2.5 Work Obligation

7.2.5.1 Work Program and Financial Obligations

Contractor to spend US \$3.5 million in year 1, US \$1.5 million in year 2, US \$1.5 million in year 3, US \$3.5 million in year 4, US \$1.5 million in year 5, US \$3.5 million in year 6, US \$1.5 million in year 7, US \$1.5 million in year 8, US \$1.5 million in year 9 and US \$1.5 million in year 10 for an aggregate total of US \$21 million (1993 ARCO PSC).

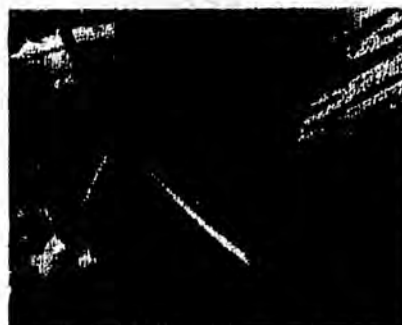
7.2.5.2 Guarantees and Non-Performance Provisions

Contract shall be terminated in its entirety by a 90 days notice if a major breach of the Contract is committed by the other Party

7.2.6 Fiscal Framework

7.2.6.1 Negotiation of Terms

Terms more or less fixed, details negotiable.

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Four types of contract in the exploration and production of oil and natural gas in Indonesia are: PSC, JOA/JOB, EOR, and TAC.

In Indonesia, nearly all of the oil and gas operations are operated by foreign companies

under Production Sharing Contract (PSC), which allow the Contractor's profit after tax and cost recovery about 15-35% on oil and 30-40% on gas. The production sharing contract now covers about 90% of the contracted petroleum acreage, thereby representing the dominant share of all the petroleum activities in the country.

In Indonesia, the cooperation between PERTAMINA and foreign contractors in the petroleum sector through the form of the PSC has proven to be highly successful.

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Flow of Contract Arrangement

● Production Sharing Contract (PSC)

Cooperative agreement in the sector of oil and natural gas between PERTAMINA and foreign capital investors, in which:

- PERTAMINA is responsible for the management.
- Related foreign oil company is a Contractor who is responsible to PERTAMINA.
- The sharing is made on production, not on profit.
- Title to the Contractor's portion of crude oil and gas (cost entitlement oil/gas) shall passed to the Contractor at the point of export or point of delivery.
- The contract application is under the laws, decrees, regulations, decisions, etc. of the Republic of Indonesia.

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● Joint Operating Agreement (JOA), Joint Operating Body (JOB)

- o PERTAMINA holds 50% participating interest.
- o The participating interest of the Contractors is subject to the same terms and split as used in the current PSCs.
- o PERTAMINA is the operator assisted by the Contractor in the form of a Joint Operating Body (JOB).
- o JOB is responsible to, and is supervised by a Joint Operating Committee (JOC).
- o PERTAMINA and the Contractors form the members of the JOC.
- o JOC approves Work Program and Budget and holds the policies.
- o Contractors carry PERTAMINA in financing exploration ventures and advanced development project.
- o The Sunk Cost of PERTAMINA is recoverable and an uplift of 50% is applicable.

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● Enhanced Oil Recovery (EOR)

- o The scope of project: pilot phase in water injection, fluid handling and facilities treating, drilling/workover of injection and production wells, injection system, flowlines to the connecting flange of the manifold inlet at gathering stations of PERTAMINA.
- o Primary production is determined for each production zone and is agreed prior to contract signing.
- o EOR cost and incremental oil produced are governed by the same terms as in JOA, except that a 65% cost recovery ceiling is applied.
- o Cost incurred by PERTAMINA down stream activities is chargeable to the EOR operation on pro-rata basis.
- o The initial two-year contract is allowed for the pilot phase, after which, the full EOR project will commence.

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● Technical Assistance Contract (TAC)

- o Shareable crude is crude other than the primary crude.
- o Cost of equipment and services for the primary crude

- will be defined part of operating cost.
- o Maximum operating cost is 65% of total shareable lifting cost.
- o An obligation of DMO contribution at 15% of the export price is taken from the share of the Contractor.
- o After Cost Recovery, the share of PERTAMINA will be 85% and the share of the Contractor will be 15%.

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The policy is summarised as follows:

To assure availability of energy for domestic use at affordable prices
 To make energy available for export
 To conserve oil consumption
 To develop new and renewable energy resources
 To protect the environment

In essence, the energy policy is aimed at balancing the

required energy resources to fulfill domestic demand and to obtain foreign exchange through export. Further, development of the nation's energy reserves, in order of priority, should start from renewable and non-tradeable energies such as hydropower and geothermal, followed by coal with its relatively low export value. Consideration then goes to energy resources which can be exported with a high value, such as natural gas.

According to the energy policy, oil should be utilised only if there is no alternative energy for the end user.

Implementation of the energy policy can be summarised into three measures:

- Intensification: increasing and expanding surveys for the exploration of energy resources
- Diversification: developing and using non-oil energy resources as far as possible
- Conservation: economizing energy use by using it efficiently

For economic and technological reasons however, fossil fuels (oil, gas, coal) still maintain the majority share in global energy consumption. Oil is the fuel of today and natural gas is described as the 'fuel of the future'.

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☒ Petroleum Incentive Package**Second Incentive Package, February 1989**

Element	Description
Split for Marginal Fields and for Tertiary EOR	Conventional areas 80% : 20% Frontier areas 75% : 25%
Split for Pre-Tertiary and Deep Sea Production	Incremental split as for frontier production (see First Incentive Package)
Investment Credit for Deep Sea Areas	For oil = 110% For Gas = 55%
Extension to the 6 years Exploration Period	1 x 4 years
Gas Pricing	Oriented towards field development economics
Access to Data	Not restricted to areas open for bidding
Field Data Acquisition	Will be conducted by PERTAMINA and will be available to contractors



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Fourth Incentive Package, 1993

Element	Description
After Tax Split for Oil	65% : 35%
After Tax Split for Gas	60% : 40%
DMO Oil Fee	25% of export price (after first five years)
FTP for Oil and Gas	15%

Explanation of the 1993 Petroleum Incentive Package

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1993 Incentive Package Table and Explanation

Table

Element	Precious Incentive Packages (1988, 1989, 1992)	1993 Incentive Package
After tax split for oil	Frontier : 80% / 20% Water depth of more than 1500 meters: 75% / 25%	65 % : 35%
After tax split for gas	Frontier: 60% / 40% Water depth of more than 1500 meters: 55% / 45%	60% : 40%
DMO oil fee	Petroleum: 15% of export price (after first five years)	25% of export price (after first five years)
FTP for oil & gas	20%	15%

Explanation

1. Objective

The purpose of the 1993 Petroleum Incentive Package is to encourage the petroleum exploration & production in the eastern and western parts of Indonesia that have similar geological and geographic conditions.

2. Applied Areas the Package

a. Eastern Indonesia areas are:

- east of 200 meters isobath starting from the offshore Kalimantan in Makassar Strait to the offshore Bali in Lombok Strait and an Area in the South east of Bali to the east of 155°30'00" longitude
- all Tertiary and Pre-Tertiary basins, except producing fields of Tertiary reservoir in the Bintuni, Salawati and Seram Basins

b. Western Indonesia areas are:

- west of Sumatra and south of Java offshore areas
- any other offshore areas in excess of 200 meters water depth
- Intramontane areas of Sumatra that are geologically located outside of the known existing basins (i.e.: North Sumatra, Central Sumatra and South Sumatra basins) and physiographically located in hilly areas of the volcanic back bone of Sumatra
- Basins in Melawi and Ketungau in West Kalimantan

3. Application

- a. the 1993 Incentive Package is an integrated package, that is, the package should be applied as a whole.
- b. Contractors who signed the working contract before January the 1st, 1994 have the option to apply either the 1993 Incentive Package relevant to the frontier terms.
- c. The application of two different fiscal terms is considered in the case where the new field development is located on two different areas that have different concepts.

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- **General Conditions**
- **Fiscal Conditions**
- **Tax Regime**

● General Conditions

Oil and gas in Indonesia are considered as a very vital commodity; all oil and gas minerals existing within the territory are national riches and controlled by the State. The authority to mine is delegated to PERTAMINA.

The general conditions of the Indonesian PSC is as follow:

1. PERTAMINA is responsible for the management of the operations.
2. Government must have a guarantee of the minimum income for each field development.
 - a. Oil field development - 85% (including Contractor Income tax) of First Tranche Petroleum 20% and 15% (for frontier area)
 - b. Gas field development - 70% for (including Contractor Income tax) of First Tranche Petroleum 20% and 15% (for frontier area)
3. In order to accelerate the exploration and development of the potential oil and gas resources, partners or investors shall have the financial ability, technical competence and professional skills necessary to carry out the operations.

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● Fiscal Conditions

The status of acquisition cost, the principle of cost recognition and the operating cost components are important issues to oil and gas investors. Fiscal conditions of the Indonesian PSC are based on:

1. In the stage of working area acquisition, the investor have to pay signature, compensation and production bonuses, not included in operating costs, but tax deductible.
2. Yearly operating costs and working area ring fencing
3. The unrecovered excess shall be recovered in succeeding years
4. Interest expense that approved by PERTAMINA shall include Operating Cost
5. Operating Cost
 - a. Non Capital - Current Year Operating Cost
 - b. Capital - Current Year Depreciation
 - c. Non Drilling Exploration - Direct Non Capital
 - d. Drilling (Exploratory, Delineation, Development, Workover)
 - i. Success Intangible Drilling Cost - direct Non Capital & Tangible Drilling Cost - Capital
 - ii. Dryhole Intangible and Tangible Drilling Cost - direct Non Capital
6. Depreciation
 - a. Asset placed in to service
 - b. Full year depreciation
 - c. Average asset use life 5 years with depreciation factor 25%
 - d. End year of the use life direct fully recovered
7. Profit Oil or Gas Split
 - a. Standard or conventional oil field - 85% for PERTAMINA, 15% for the Contractor (after income tax)
 - b. Marginal oil field (2 years for the first

- production working areas less than 10 MBOPD) 80% for PERTAMINA, 20% for the Contractor (after Income tax)
- c. Gas field - 70% for PERTAMINA, 30% for the Contractor (after Income tax)

8. Domestic Market Obligation (DMO)

After commercial production commences, Contractor agrees to sell and deliver a portion of the share of crude oil to fulfill towards the supply of the domestic market in Indonesia. Fee DMO oil for 5 calendar year production is market price and after 25% from market price.

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● **Tax Regimes**

1. Production Sharing Contractor has an economic interest in the development of oil and gas reserves.
2. Working area ring fencing consolidation.
3. Contractor subjected the Indonesian income tax with tax rate of 44%.
4. Contractor assumes and discharges all Indonesian taxes including transfer tax, value added tax, import and export duties, exaction's in respect of property, capital, net worth, operations, remittances or transactions including any tax or levy on/or in connection with operations.
5. Value added tax to be reimbursed by PERTAMINA after production commence.

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LEGISLATIVE RESEARCH REPORT

MARCH 14, 2001



REPORT NUMBER 01.147

TAXES ON NATURAL GAS RESERVES

PREPARED FOR REPRESENTATIVE SCOTT OGAN

BY CHERIE NIENHUIS, LEGISLATIVE ANALYST

You asked us to determine which other states or countries, if any, tax natural gas reserves. You also requested that we identify natural gas development *disincentives* you believe were instrumental in encouraging development of Australia's natural gas reserves.

We made extensive contacts with national and international experts in the fields of energy, natural gas and oil, and in taxation. We could not locate a state or country that levies a tax on undeveloped natural gas reserves.¹ Most individuals with whom we spoke indicated that tax *incentives* are the norm around the world for encouraging development of natural gas reserves—and that a tax on nonproducing reserve leaseholds would only exacerbate the economic feasibility problem that keeps producers from developing them. Following a short discussion on the fiscal regimes used by various countries, we summarize Australia's current gas development policy, and then lastly, we look at laws in other states regarding undeveloped mineral reserve taxation.

¹ We contacted the following individuals and/or organizations: National Conference of State Legislatures; Interstate Oil and Gas Compact Commission; American Petroleum Institute; International Association of Assessing Officers; Pritchard & Abbott, Inc. (a resource valuation firm); the National Energy Information Center Tax Department; the International Monetary Fund; the International Energy Agency; Cambridge Energy Research Associates; Robin Boadway, a much published Professor of Economic Theory at Queen's University at Kingston, Ontario; Commissioner Wilson Condon, Alaska Department of Revenue (DOR); Deputy Commissioner Larry Persily, DOR; Tom Williams, former Commissioner, DOR, who now works for British Petroleum; Bill Van Dyke, Petroleum Manager, Alaska Department of Natural Resources; Richard Brewer, State Petroleum Property Assessor, DOR; and Glen Gray, Project Analyst, Alaska Division of Governmental Coordination.

In addition, we consulted numerous Internet sites and publications. The publications include, but are not limited to the following: Pedro van Meurs, *Alaska North Slope LNG Project*, February 12, 1997; Robert L. Bradley Jr., *Oil, Gas and Government*, Vol. II, Cato Institute (1996); Georg Koopman, Klaus Matthies, and Beate Reesat, *Oil and the International Economy: Lessons from Two Price Shocks*, Transaction Publishers (1989); Robert Mabro, *Natural Gas: An International Perspective*, Oxford University Press (1986); Aaron Wildavsky and Ellen Tenenbaum, *The Politics of Mistrust: Estimating American Oil and Gas Resources*, Sage Publications (1981).

NATURAL GAS FISCAL REGIMES

As of January 1, 2000, approximately 89% of the world's known natural gas reserves were distributed among just 20 countries, with one-third of that supply attributed to the Russian Federation.² Of these 20 countries, the United States is ranked 6th, holding approximately 164 trillion cubic feet, or 3.2% of the world's reserves. According to the Energy Information Administration, natural gas is the fastest growing component of world energy consumption. In 1999, several major international pipeline projects were completed, including lines linking Asia, Europe and South America with nearby countries.³

We spoke with Marie Fagan, Associate Director of the Cambridge Energy Research Associates (CERA). Ms. Fagan is very knowledgeable in the topic of world oil and gas fiscal regimes. She told us that there are currently two major types of fiscal regimes used in oil and gas production operations: tax/royalty regimes (common in the U.S. and Great Britain) and production sharing agreements (commonly used to develop resources in higher risk areas or areas with significant start-up costs). Production sharing agreements are contracts between governments and resource developers that usually contain terms delaying revenue sharing in the first several years of operation while the company recoups initial investment costs.

In his testimony before the U.S. Senate Committee on Energy and Natural Resources in July 1997, Dr. Pedro van Meurs, an expert in fiscal policies relating to oil and gas resource development, supported Ms. Fagan's views.⁴ He said that countries generally fall into one of two fiscal policy groups when addressing the liquefied natural gas market: countries that levy taxes on natural gas as part of an overall tax system (such as the U.S., Canada, and Australia); and countries that negotiate their fiscal policies with the developers on an individual basis (such as Southeast Asian and Middle Eastern countries). Mr. van Meurs said that Asian and Middle Eastern countries almost "foot the bill" for development-related construction and provide long-term tax breaks, which, he claims, amount to "corporate welfare."⁵ Additionally, the style differs between leases offered by the two groups of fiscal policies. Whereas U.S. leases can last indefinitely, leases in the Middle East are very limited in duration, and companies therefore have an incentive to "get in, get the gas, and get out."⁶

AUSTRALIA'S DEVELOPMENT OF NATURAL GAS RESERVES

You expressed a special interest in what incentives or disincentives Australia uses to encourage development of their natural gas reserves. We searched numerous Internet sites to learn as much as we could about the country's fiscal policies. We also e-mailed several gas and oil

² See "Table 16: World Natural Gas Reserves by Country as of January 1, 2000," reproduced from "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 97, No. 51, pp. 91-93, at <http://www.eia.doe.gov/oiaf/ieo/ta16.html>, accessed 3/1/01, included as Attachment A.

³ See Energy Information Agency's "Natural Gas" information, p. 2, included as Attachment A.

⁴ Senate Hearing on the Natural Gas Industry, July 23, 1997, before the Senate Committee on Energy and Natural Resources, available at <http://stage.eplweb.org/hearings/natga.html>, accessed 3/8/01.

⁵ Senate Hearing on the Natural Gas Industry, July 23, 1997, p. 4.

⁶ Senate Hearing on the Natural Gas Industry, July 23, 1997, p. 4.

representatives in Australia, inquiring about the use of incentives and/or disincentives to spur development of their natural resources.

The Western Australia Minerals and Energy Department website describes the following three petroleum royalty systems the country uses:

- Well-head Royalties
- Resource Rent Royalties
- Resource Rent Tax

Although all three systems basically tax the value of petroleum produced, there is a noticeable difference between the deduction limits on oil projects as opposed to gas projects. According to the government's web page, deductible costs can be as much as 90% of the gross value of production for gas projects, whereas only 50% of costs may be deducted for oil projects.⁸ According to Ms. Fagan, CERA, it is not uncommon for countries to tax natural gas projects at a lower percentage than they tax oil projects.

The recent East Timor/Australia petroleum project was initiated under a three-party production sharing agreement between the developers, Australia, and Indonesia. An important aspect of the agreement is that developers will be able to recover all exploration and operating costs.⁹

All news releases and articles we located on the development of Australia's oil and gas indicated that the government provides *incentives* for development, not *disincentives* against not developing the resources. Additionally, e-mail contacts with Australian officials were fruitless in uncovering policies applied by state or federal governments for the purpose of compelling companies to develop natural resources. We did find a document that provides a framework of joint government and industry commitments to the future of the natural gas industry in the country, called the "LNG (liquefied natural gas) Action Agenda."¹⁰ This lengthy document may be accessed at: <http://www.isr.gov.au/resources/lng/>.

TAXATION OF UNMINED MINERALS IN OTHER STATES

Even though we were unable to identify any states that specifically tax natural gas reserves, we did find that in at least two states—Kentucky and Colorado—unmined minerals that are held separately from surface real property are assessed and taxed on their value, just as are other real properties.

Kentucky Revised Statutes § 132.820 mandates that "unmined coal, oil, and gas reserves and other mineral or energy resources shall in all cases be valued and assessed by the Revenue

⁷ A copy of the web page describing Australia's petroleum royalties is included as Attachment B.

⁸ See Attachment B, p. 1.

⁹ From Barrow's Inc. *World Fiscal Systems for Oil*, pp. 234-235, included as Attachment C. Because the publication is voluminous, the Australia portion of the book was faxed to us by Ms. Fagan at CERA.

¹⁰ See "Government and Producers Boost LNG Industry" Media Release, Senator Nick Minchin, Minister for Industry, Science and Resources, dated October 10, 2000, accessed 3/9/01 at <http://www.minister.industry.gov.au/minchin/releases/2000/october/cmr516%2D00.doc>, included as Attachment D.

Cabinet" and shall be subject to taxation on that value.¹¹ Colorado law also specifies that "nonproducing severed mineral interests are to be valued at twenty-nine percent of actual value in the same manner as other real property."¹²

We discussed Kentucky's taxation of nonproducing mines with David Gabbard, Branch Manager for Minerals Service Tax, Kentucky Revenue Cabinet.¹³ He told us that although unmined mineral interests had long been subject to property tax, the properties were previously granted a special classification, and taxed at such a low rate that it created a *de facto* exemption for the properties. In a class action lawsuit brought against the state of Kentucky Revenue Cabinet in 1988, the Kentucky Supreme Court ruled the classification unconstitutional, thereby requiring the state to tax these properties as they would other real properties in the state.¹⁴

Mr. Gabbard said that in 1989, the Revenue Cabinet began assessing coal properties in order to determine a fair market value for them for taxation purposes. Coal reserves are known to exist in 32 counties in the state of Kentucky, and valuing these properties has been an arduous task for the Cabinet. Yet, Mr. Gabbard explains, coal reserves are easier to quantify than gas and oil reserves, of which the state has very little. For that reason, no effort has been made to place a value on the unproduced reserves of oil and gas in Kentucky, and even though the law requires these resources be taxed, thus far, no taxes have been levied on them. Mr. Gabbard told us it probably would not be worth the Revenue Cabinet's time to try to value these scant reserves, and his department has not received complaints from interested parties that the limited petroleum reserves have not been taxed.

Additionally, Mr. Gabbard believes the tax imposed on unmined resources has had a negligible effect on development of them. The tax is so minimal—1% of the value of the property—that it is not much of a factor, although Mr. Gabbard thinks that a higher tax on more valuable reserves could prompt a positive response. Coal mining has decreased for other demand-related reasons, Mr. Gabbard said, and Kentucky simply does not have the vast quantities of undeveloped natural gas reserves that Alaska has.

I hope you find this information useful. Please do not hesitate to contact us if you have questions or need additional information.

¹¹ KRS § 132.820 is included as Attachment E.

¹² CRS § 39-1-104 (4).

¹³ Mr. Gabbard may be reached at (502) 564-8334.

¹⁴ *Gillis v. Yount*, 748 S.W.2d 357, (1988 KY) is included as Attachment F.

LIST OF ATTACHMENTS

Attachment A

"Table 16: World Natural Gas Reserves by Country as of January 1, 2000,"
from *Oil & Gas Journal*, Vol. 97, No. 51, pp. 91-93,
http://www.eia.doe.gov/oiaf/ieo/tabl_16.html;
and Energy Information Agency's "Natural Gas,"
http://www.eia.doe.gov/oiaf/ieo/nat_gas.html

Attachment B

Western Australia Department of Minerals and Energy
"Petroleum Royalties,"
<http://www.dme.wa.gov.au/insidedme/royalty/petsys.html>

Attachment C

Barrow's Inc., *World Fiscal Systems for Oil*,
pp. 234-235, "Australia"

Attachment D

"Government and Producers Boost LNG Industry"
Media Release, Senator Nick Minchin, Minister for Industry,
Science and Resources, October 10, 2000
<http://www.minister.industry.gov.au/minchin/releases/2000/october/cmr516%2D00.doc>

Attachment E

Kentucky Revised Statutes § 132.820, relating to the
Assessment and Taxation of Unmined Minerals and Energy Resources

Attachment F

Gillis v. Yount,
748 S.W.2d 357, (1988 KY)

Attachment A

"Table 16: World Natural Gas Reserves by Country as of January 1, 2000,"
from *Oil & Gas Journal*, Vol. 97, No. 51, pp. 91-93,
http://www.eia.doe.gov/oiaf/ieo/tabl_16.html;
and Energy Information Agency's "Natural Gas,"
http://www.eia.doe.gov/oiaf/ieo/nat_gas.html

Table 16. World Natural Gas Reserves by Country as of January 1, 2000

Country	Reserves (Trillion Cubic Feet)	Percent of World Total
World	5,146	100.0
Top 20 Countries	4,571	88.8
Russian Federation	1,700	33.0
Iran	812	15.8
Qatar	300	5.8
United Arab Emirates	212	4.1
Saudi Arabia	204	4.0
United States	164	3.2
Algeria	160	3.1
Venezuela	143	2.8
Nigeria	124	2.4
Iraq	110	2.1
Turkmenistan	101	2.0
Malaysia	82	1.6
Indonesia	72	1.4
Uzbekistan	66	1.3
Kazakhstan	65	1.3
Canada	64	1.2
Netherlands	63	1.2
Kuwait	52	1.0
China	48	0.9
Mexico	30	0.6
Rest of World	575	11.0
Source: "Worldwide Look at Reserves and Production," <i>Oil & Gas Journal</i> , Vol. 97, No. 51 (December 20, 1999), pp. 91-93.		

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Natural Gas

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Natural gas is the fastest growing primary energy source in the IEO2000 forecast. The use of natural gas is projected to more than double between 1997 and 2020, providing a relatively clean fuel for efficient new gas turbine power plants.

World natural gas consumption continues to grow, increasing its market share of total primary energy consumption. In the *International Energy Outlook 2000* (IEO2000), natural gas remains the fastest growing component of world energy consumption. Over the IEO2000 forecast period from 1997 to 2020, gas use is projected to more than double in the reference case, reaching 167 trillion cubic feet in 2020 from the 1997 level of 82 trillion cubic feet (Figure 46). Over the 1997-2020 period, the role of natural gas in energy use is projected to increase in all regions except the Middle East and Africa, where its share remains relatively stable. The developing countries of Asia and of South and Central America will see the strongest growth rates in gas demand. Large incremental increases are also projected for industrialized countries, including the United States, and for the former Soviet Union (FSU).

Figure 46. World Natural Gas Consumption, 1970-2020
[Sources]

In the IEO2000 reference case, a slowly increasing share of world gas consumption is used in the electric power sector (rising from 29 percent in 1997 to 33 percent in 2020), and natural gas accounts for the largest increment in electricity generation (increasing by 33 quadrillion Btu). Not only do combined-cycle gas turbine power plants offer some of the highest commercially available plant efficiencies, but natural gas is also attractive for environmental reasons. When it is burned, natural gas releases less sulfur dioxide, less particulate matter, and less carbon dioxide than does oil or coal.

For the industrialized countries, natural gas—compared with other fuels—is expected to provide the greatest incremental increase in energy consumption among the major fuels and has the fastest average annual growth in the forecast (2.1 percent per year, compared with 1.0 percent for oil). The percentage of gas used for power generation also grows from 20 percent in 1997 to over 30 percent in 2020. In 1997, natural gas consumption in the developing countries was a smaller portion of total energy use (14 percent) than the world average (22 percent). From that starting point, gas consumption in developing countries grows at a faster rate in the reference case than any other fuel (an average of 5.6 percent per year, compared with 3.1 percent for both oil and coal). Increments in gas use in the developing countries are expected to supply both power generation and other uses, such as town gas and fuel for industry.

In Central and South America, the power sector currently

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relies heavily on hydroelectric power, which accounts for about 12 percent of primary energy use (compared with a 2.5-percent share in the global energy mix in 1997). Because dependence on hydroelectric resources in the region has led to problems in maintaining electricity supply during times of drought, fuel diversification is now being pursued. In developing Asia, gas use is also desirable for environmental reasons and to diversify the energy mix away from heavy reliance on oil imports. The problem has been complicated, however, by greater distances between gas resources and market centers, leading to a combination of liquefied natural gas (LNG) and pipeline trade in the region.

There are also new efforts to develop natural gas use in the Middle East, although the projected growth rates and incremental increases there are smaller than in Asia or the Americas. Domestic resources may supply some of the increase in gas use in the Middle East (for example, in Saudi Arabia), but trade will also be important. In addition to Turkey and Israel, both Oman and the United Arab Emirates may become gas importers, using pipeline imports from Qatar to meet domestic demand while sustaining their own LNG export commitments.

Some important gas market developments in 1999 include:

- The completion of several major international pipelines and firming of plans for other new pipelines in Europe and South America. Steady growth in pipeline infrastructure is leading to increased trade, which can facilitate a more transparent (and mature) gas market. The 1999 completion of the Europipe II from Norway to Germany will lead to an expanded role for North Sea gas in Germany. On the southern side of Europe, Italy moved forward with plans to build a new pipeline for imports of Libyan gas. In South America, pipelines from Bolivia to Brazil and from Argentina to Chile (the GasAtacama and the Norandino) were completed in 1999.
- Completion in Asia of several major international pipelines and plans for additional lines. In Asia, the new pipeline from Myanmar to Thailand began building up deliveries to contracted volumes, more than a year behind schedule. Contracts were signed for two new pipelines that would carry Indonesian gas exports to Singapore, and plans moved forward for a pipeline from Papua New Guinea to Australia, with finalization of gas sales contracts.
- The completion of several LNG facilities. Three grassroots natural gas liquefaction facilities came on stream in 1999 in Trinidad and Tobago (Atlantic LNG), Nigeria (Bonny), and Qatar (Rasgas). An expansion, Indonesia's eighth train ("Train H") at its Bontang facility is also starting operations at the end of 1999 or early in 2000. Qatar has concluded agreements with India for the sale of 7.5 million metric tons of LNG with deliveries starting in 2003.

Reserves

Global gas reserves have more than doubled over the past 20 years, outpacing the 62-percent growth in oil reserves over the same period. *Oil & Gas Journal* estimated proven world gas reserves as of January 1, 2000, at 5,146 trillion cubic feet, an increase of 1.5 trillion cubic feet over the previous year's estimate (see discussion on "Taking Stock: Reporting Reserves and Selected Natural Gas Finds of 1999").² Over the past 20 years, reserve estimates have grown rapidly in the FSU and in developing countries in the Middle East, South and Central America, and the Asia-Pacific region (Figure 47).

Figure 47. World Natural Gas Reserves by Region, 1975-2000 [Sources]

The largest incremental increases in reserves over the past year were nearly 4 trillion cubic feet for the Asia-Pacific region and more than 33 trillion cubic feet for Africa, mostly in Algeria and Egypt. Those reserve expansions were offset, however, by reported decreases in all other regions. Reserves in Mexico were reported to decline by more than 50 percent (from 63 to 30 trillion cubic feet), and reserves in the United States and Western Europe also declined by 3 and 2 trillion cubic feet, respectively. Gas reserves reported by *Oil & Gas Journal* are compiled from voluntary survey responses and do not always reflect most recent changes. Some significant gas discoveries made in 1999, for example in Asia and the Middle East, are not reflected in the most recent estimates.

In regional terms, world gas reserves are more widely distributed than oil reserves. The Middle East, which holds nearly 65 percent of global oil reserves, accounts for only 34 percent of gas reserves (Figure 48). Thus, some regions with limited oil reserves hold a greater portion of global gas

Figure 48. World Natural Gas Reserves by Region as of January 1, 2000 [Sources]

stocks. The FSU, in particular, accounts for around 6 percent of world oil reserves but nearly 40 percent of proven gas reserves, most of which (33 percent of world reserves) is located in the Russian Federation. The Russian reserves are the largest in the world, more than double the second-largest reserve volume in Iran. Gas reserves are also more widely distributed than oil reserves within the Middle East, where Qatar, Iraq, Saudi Arabia, and the United Arab Emirates all have significant gas volumes (Table 16).

Reserve-to-production (R/P) ratios exceed 100 years in the Middle East and Africa and are next highest in the FSU at 83.4 years. South and Central America also has a high ratio (71.5 years), but in North America and Europe R/P ratios are relatively low at 11.4 years and 18.3 years, respectively. The R/P average for natural gas in the world is 63.4 years, compared with 41 years for oil [1].

Table 16. World Natural Gas Reserves by Country as of January 1, 2000

Regional Activity

North America

In the *IEO2000* reference case, natural gas consumption is projected to grow by 1.6 percent per year between 1997 and 2020 in Canada and the United States and by 2.4 percent in Mexico. Fuel use for electric power generation is largely responsible for the increases in all three countries. In the United States alone, natural gas consumption for electricity generation (excluding cogenerators) is projected to grow from 3.4 trillion cubic feet in 1997 to 9.3 trillion cubic feet in 2020. In projections from EIA's *Annual Energy Outlook 2000* (*AEO2000*), nearly 90 percent of new electricity generating capacity between 1997 and 2020 is combined-cycle or combustion turbine technology fueled by natural gas or both oil and gas; and while increases are also expected in the other U.S. demand sectors, the growth in gas use in the electric utility sector is by far the most significant [2]. For Canada, the Canadian Energy Research Institute (CERI) estimates that gas demand for electricity generation could nearly triple in the next decade, assuming the continued restructuring of the electricity sector that is currently either underway or anticipated in many provinces.

In 1998, approximately 55 percent of Canada's natural gas production was exported to the United States, and Canadian gas accounted for about 14 percent of U.S. consumption. Canada's exports have been growing steadily in response to increasing demand in the United States, more than tripling since 1985. By 2005, *AEO2000* projects that Canada's share of end-use consumption in the U.S. gas market will increase to 18.4 percent.

Currently, significant pipeline construction both within Canada and between the United States and Canada is underway to accommodate U.S. import demand. By the end of 2000, five major new natural gas pipeline projects and an upgrade on a sixth (Alliance, Millennium, NOVA, Northern Border, TransCanada, and Maritimes Northeast) are expected to be complete, allowing a considerable increase in trade between the two countries [3]. Most of the construction will provide access to supplies in western Canada, and the Maritimes and Northeast project will transport supplies from Canada's offshore Atlantic Sable Island fields to markets in New England. Gas fields with more than 6 trillion cubic feet of combined reserves near Sable Island and at Terra Nova are under development, and Cambridge Energy Research Associates has indicated that natural gas reserves off Nova Scotia may be five times what has already been discovered, with approximately 53 trillion cubic feet possible [4].

Considerable pipeline construction is also under way in the United States. Several major projects will provide access to new sources of both supply and demand and increase capacity along corridors where utilization rates are high during peak periods. Recently completed projects include Interstate's Pony Express project, the Trailblazer system expansion, the Transwestern Pipeline expansion, and the El Paso Natural Gas system expansion. The first two provide access to Wyoming and Montana production regions, and the last two provide access to New Mexico's San Juan Basin. Further expansions are underway that will increase flows from these areas to markets on the east and west

coasts. U.S. pipeline capacity expansion is expected to slow after 2001, however, to less than 1 percent a year. Overall utilization of pipeline capacity is expected to increase significantly after 2001 as demand for natural gas to fuel electricity generation leads to increased flows during the summer months.

LNG imports are also becoming more economical for the United States. LNG imports are expected to increase more than fivefold between 1997 and 2020, from 0.08 trillion cubic feet per year to 0.39 trillion cubic feet per year. In the past, U.S. LNG imports have come predominantly from Algeria. New sources of supply include Australia, Trinidad and Tobago, and Qatar, and Abu Dhabi and Norway are potential sources.

Additions to U.S. LNG import capability include a 50-percent increase in offloading capacity at the Everett, Massachusetts, port facility; a projected reopening of the Southern Natural Gas Company LNG terminal at Elba Island, Georgia; and a potential reopening of Columbia LNG's Cove Point, Maryland, facility. Both Elba Island and Cove Point were closed over 15 years ago when LNG became too costly to compete with other sources of natural gas in the United States. Cove Point subsequently reopened in the early 1990s for peak-period service storage only. Preliminary approval to reopen Elba Island was granted by the Federal Energy Regulatory Commission (FERC) in December 1999, and Southern plans to begin importing up to 0.8 trillion cubic feet of LNG per year from Trinidad in 2002 [5]. Anticipating increased demand for LNG shipments, especially in the Northeast, Columbia LNG is hoping to recommission its Cove Point, Maryland, facility to provide LNG tanker unloading services. The terminal can deliver up to 1 billion cubic feet per day to Columbia's main system. If response is sufficient to a planned open season for customers to bid on capacity, as Columbia expects it to be, Cove Point will file with the FERC for authorization to recommission [6].

Although Mexico has considerable resources that could be developed, production is not expected to keep pace with rising internal demand, and Mexico is expected to remain a net importer of natural gas. As in the United States and Canada, most of the projected growth in demand is for electricity generation. A recent forecast by the Mexican government indicates that natural gas demand will grow by 9.2 percent a year between 1998 and 2007, with consumption for electricity generation increasing by 20 percent a year.

Another area of significant growth in Mexico's gas consumption is expected to be manufacturing and assembly plants located close to the U.S. border, where U.S. producers are in a much better position to satisfy the demand [7]. Although considerable investment is currently being made in the expansion of pipeline infrastructure, Mexico continues to have the problem, at least in the near term, of not being able to transport natural gas from southern producing regions to northern consuming regions in quantities sufficient to meet demand. AEO2000 projects U.S. exports to Mexico to grow from 0.05 trillion cubic feet in 1997 to 0.24 trillion cubic feet in 2020, in the wake of Mexico's

recent elimination of a 4-percent import tariff and an increase in pipeline capacity between the two countries.

Western Europe

Europe's gas reserves, which account for less than 5 percent of global resources, are located predominantly in the Netherlands, Norway, and the United Kingdom. Production in those three countries currently surpasses production in other regions with greater reserves, such as the Middle East. Nearly one-third of Europe's gas demand is met by supplies from outside the region, particularly pipeline imports from the FSU and Algeria, as well as LNG primarily from North Africa. Recent demand increases reflect rising gas use for power generation as well as in the industrial sector. Demand growth has been particularly strong in Greece, Portugal, Italy, Spain, Finland, Belgium, and Denmark. *IEO2000* projects growth in Western Europe's gas use averaging 2.9 percent per year, reaching 25.9 trillion cubic feet by 2020 (Figure 49).

Figure 49. Natural Gas Consumption in Western Europe, 1970-2020 [Sources]

European investments in infrastructure in 1998 included the completion of the Interconnector and at least four other significant pipeline projects, and 1999 saw the on-schedule completion and commissioning of the Europipe II. The 420-mile Europipe II, operated by Statoil, links Norway's west coast to Dornum in northwest Germany. With its commissioning, imports from Norway could supply up to 30 percent of Germany's natural gas use by 2010 [8]. In *IEO2000*, German gas consumption is expected to rise by an average of 2.9 percent per year, nearly doubling in 2020 from the 1997 level of 3.4 trillion cubic feet (Figure 50).

Figure 50. Natural Gas Consumption in Germany, 1970-2020 [Sources]

Elsewhere in Europe, pipeline projects such as a Swiss line scheduled for completion in October 1999 will improve and increase north-south gas flows. Future construction in Switzerland could eventually double capacity by 2003. A new leg of the Yamal-Europe pipeline was also completed in Germany in September. Financed by Wiggins and Gazprom investment, the 209-mile section stretches from Frankfurt-on-Oder to Rueckersdorf, Thuringen, and will transport up to 990 billion cubic feet of gas per year to German and West European consumers [9]. Germany's Ruhrgas started construction of a 71-mile pipeline from Mittelbrunn in Saarland to Esch in Luxembourg. With deliveries scheduled to start mid-2000, the \$45 million project will transport 20 billion cubic feet of gas annually to a gas and steam power plant under a 15-year contract signed with Soteg [10].

In addition to the announced and planned mergers of such large international corporations as BP, Amoco, and ARCO and Mobil and Exxon, Europe also saw important mergers in 1999. TotalFina and Elf Aquitaine agreed in September to a friendly merger that would rival BP Amoco (which plans to merge with ARCO) in European gas production and

marketing. In October, however, the European Union announced an investigation into the merger, citing concerns about potential dominance in the liquid petroleum gas (LPG) market [11]. In Germany, Veba and Viag will merge to create a group with electricity, natural gas, and water businesses and with the stated goal of pursuing growth abroad through targeted acquisitions [12].

Strong gas market growth continues in Italy and Spain. Italy's Eni announced that final agreements were reached with Libya's National Oil Corporation (NOC) to import gas via a new undersea pipeline. Plans call for imports of some 280 billion cubic feet per year starting as soon as 2003, with Italy now in the stage of awarding contracts [13]. Regional approval has been given to Edison-Mobil plans for a new Italian LNG receiving terminal in the northern Adriatic Po Delta (Figure 51) to be built on an artificial island; approval by the national government is still required. The terminal could be operational as early as 2003, with Egypt as the potential supplier of LNG [14].

Figure 51. Italy's Natural Gas Infrastructure [Sources]

Spain has agreed to buy more LNG from Shell-led facilities in Nigeria, enabling Shell to go forward with expansion plans there. Spanish gas demand is expected to grow rapidly after 2000, when a series of gas-fired, combined-cycle power plants are due for commissioning [15]. Competition has been increasing in the Spanish gas and power markets with the government's announcement of new operators allowed in each market. Five more companies now able to trade in gas include Enagas, Gas de Asturias, Gas de Euskadi, Iberdrola, and BP Amoco [16]. In Portugal, plans continue to develop the country's first LNG receiving terminal, to be sited on the Atlantic coast near the Sines oil terminal. Transgas Atlantico is seeking a turnkey contractor for the project and has issued an invitation to tender. Construction could begin by the end of 2000.

Eastern Europe and the Former Soviet Union

In most of Eastern Europe, natural gas consumption continued to decline in 1998, although there were increases in some countries. The Russian Federation continued to dominate world trade movements of natural gas, exporting 4.2 trillion cubic feet to Europe and to other FSU countries. The only other exports of natural gas from the FSU were 63.5 billion cubic feet delivered to Iran from Turkmenistan [17].

Nonpayment for gas supplies continues to be an issue throughout the FSU, both within and between countries, and barter continues to be an accepted form of payment. Uzbekistan threatened to stop deliveries to Kyrgyzstan on November 15, 1999, if the mounting debt was not paid. Because of problems with Kyrgyzstan's hard currency, Uzbekistan had agreed to take partial payment for gas supplies in flour, but Kyrgyzstan had fallen considerably behind even in its "flour debt." As a result, the Uzbek gas transport company Uztransgaz indicated that it had no option but to cut off supplies [18]. Deliveries were temporarily halted

but resumed in mid-December after the payment of \$3 million, partly in cash and partly in goods. The gas currently being received is roughly half the amount received during 1998, and it is going mainly to homes in the northern part of the country [19].

Belarus, in debt to the Russian gas monopoly Gazprom, has major internal problems with consumers not paying their gas bills, which in turn make it difficult for the Belarusian government to pay Gazprom. The government gave internal consumers until January 1, 2000, to pay gas debts, and the state-owned gas transport company Beltransgaz proposed that partial payment of the debt to Gazprom be made in agricultural equipment [20].

The situation is similar in Ukraine, which owes Russia more than \$1 billion for natural gas purchases. Ukraine's internal nonpayment problem is significant, with consumers owing Naftogaz Ukrainy about \$3 billion. In an effort to secure payment from domestic customers, the government has been cracking down on nonpaying customers by curtailing supplies. A total of 13,700 were disconnected in 1998, including 3,650 industrial customers. After some initial problems involving cutoffs during the cold winter months, the government pledged to forbid cutoffs during the winter. Cutoffs resumed in the spring, however, and at the beginning of April 1999, 378 debtor firms were disconnected from natural gas supplies [21].

Ukraine has resorted to barter to satisfy its external debt, agreeing to deliver to Russia 11 bombers and 500 cruise missiles, valued at \$285 million, by the end of 1999 as partial payment of the debt owed to Gazprom. The first of the bombers, all of which were inherited after the breakup of the Soviet Union, were delivered to Russia in November 1999 [22]. Ukraine is also in debt to Turkmenistan for gas supplies delivered as far back as 1993, and Turkmenistan cut off supplies in June 1999. The debt has since been restructured, with payments to be completed in December 2001. In October 1999, the debt exceeded \$300 million [23].

Russia has also threatened to take action against Ukraine for reasons other than nonpayment. Ukraine is the main transit route for Russian gas to reach European markets, and Russia has long accused Ukraine of siphoning off gas during transit. Itera, the main supplier of Russian gas to Ukraine, threatened to stop supplying gas to Ukraine by October 1, 1999, pending payment of debt. Gas exports are a major source of revenue for Russia, and over 90 percent of gas exported by Russia passes through Ukraine. According to a Gazprom spokesman, since ceasing gas flow to Ukraine would entail giving up the European market, it is unlikely that gas shipments to and through Ukraine will cease anytime soon [24].

Although Russian natural gas trade with Europe is currently dependent on Ukraine, Russia expects new export routes to be developed in the next few years. The first section of the Yamal-Europe pipeline, through Belarus and Poland, went into operation in 1999, and a second parallel section is in the planning stages. The new pipeline allows Russia to eliminate Ukraine from its route to Western Europe, which currently

Poland's natural gas needs. As a move towards diversification, however, Poland signed a 5-year gas supply contract with Norway in December 1999 for supplies beginning in 2001. Talks to determine how the gas might be transported to Poland are only at an initial stage, however [30]. Poland is anticipating large increases in natural gas demand between now and 2020 and is dependent on imports to meet most of the new demand. Natural gas industry restructuring, which will facilitate gas purchases from countries such as Norway, Holland, and Germany, is in the works, with an anticipated start date sometime in 2001. Accompanying the restructuring is a move toward privatization, which the government expects to be completed in 2005.

In spite of the uncertainties and problems currently facing the EE/FSU, *IEO2000* projects significant future growth in the region's natural gas markets. Consumption in the FSU is projected to grow at a rate of 2.1 percent a year between 1997 and 2020, with the strongest growth at the end of the forecast period from 2015 to 2020. The projected increase in Eastern Europe is steadier but considerably higher, at an overall rate of 5.6 percent per year. Total EE/FSU consumption nearly doubles, from 22.3 trillion cubic feet in 1997 to 41.2 trillion cubic feet at the end of the forecast period. The considerable effort, both internally and via foreign investment, that is going into the development of the region's natural gas infrastructure will be a significant factor in increasing future production, consumption, and export capabilities for natural gas.

Central and South America

Central and South American gas markets are small in terms of total volumes handled, but they continue to show strong growth with active upstream and downstream development. Between 1990 and 1997, the region's gas consumption grew by an average of more than 5 percent per year. Estimated reserves in the region account for less than 5 percent of global gas reserves, but much of the area has been underexplored, and discoveries are accompanying recent exploration activity. Production, consumption, and trade are also limited. Production and consumption of natural gas in the region were at about 2.9 trillion cubic feet in 1997. In 1999, natural gas trade extended outside the region with initiation of LNG exports from Trinidad and Tobago. The only international pipelines in the region before 1999 operated from Bolivia to Argentina and from Argentina to Chile. The *IEO2000* reference case projects that the region's gas use, facilitated by additional pipelines, will grow to 15.3 trillion cubic feet by 2020, at an average annual growth rate of 7.5 percent (Figure 52).

Figure 52. Natural Gas Consumption in Central and South America, 1990-2020 [Sources]

On the production side, a new LNG facility in Trinidad and Tobago came on stream in 1999, loading the first Atlantic Basin export cargoes in April [31]. Starting in 2000, the U.S. LNG company Cabot will take 1.8 million metric tons of LNG per year from the facility, some of which will be delivered to Puerto Rico. A new receiving terminal now under

construction in Puerto Rico will enable increased use of gas in power generation. BP Amoco and Repsol are promoting plans to add two more LNG trains in Trinidad and Tobago, with Spain lined up as a buyer for at least some of the increased output and Cabot also expected to take more gas [32].

Much of the gas market growth in South America involves Brazil, a large country with large projected gas demand. In the *IEO2000* reference case, gas use in Brazil grows from 0.2 trillion cubic feet in 1997 to 2.5 trillion cubic feet in 2020. A new Bolivia-Brazil pipeline began operating in July 1999 after years of negotiation. Initially, the line was expected to begin carrying about 78 million cubic feet per day to Brazil, rising to 200 million cubic feet per day by the end of 1999 and then to 318 million cubic feet per day in 2000, when a take-or-pay contract begins. By 2006, volumes could exceed 1 billion cubic feet per day, worth about \$400 million per year. Import volumes at the end of 1999 were much lower, however, ranging only around 22 to 53 million cubic feet per day due to a significant rise in Brazilian gas prices. Prices are linked via formulae to fuel oil prices (which were rising) and were also affected by a 40-percent devaluation of the Brazilian real. Pipeline operators are estimating the associated financial loss at about \$500,000 per month [33].

A second line to Brazil is now under consideration following significant gas discoveries in Bolivia, but construction is not anticipated before 2001. In addition, an Enron project involving a 390-mile pipeline from Bolivia to Cuiaba in Brazil has received approval from the U.S. Overseas Private Investment Corporation (OPIC) for a \$200 million credit, despite objections from environmentalists. Protestors opposed the pipeline route through what may be the world's largest intact dry forest (called Chiquitana). Backers of the project have emphasized planned environmental mitigation measures (including a partial rerouting to avoid the most environmentally sensitive areas and a pledge of \$20 million over 15 years for conservation efforts) as well as benefits of new gas supplies replacing diesel use and local firewood demand. A 490-megawatt Cuiaba power plant and the pipeline together amount to a \$570 million effort involving Shell and Bolivian firm Transredes (50 percent owned by Enron and Shell) [34].

In addition, a pipeline to Brazil from Argentina is under construction to enable the first imports of Argentine gas. The 272-mile Transportadora de Gas del Mercosur, SA (TGM) pipeline from Parana in Entre Rios, Argentina, to Uruguaiana, Brazil, will connect to Argentina's existing domestic line, Transportadora de Gas del Norte (TGN). CMS Energy holds equity in both pipelines. TGM's other owners include Canada's TransCanada Pipelines, Argentina's CGC and Techint, and Malaysia's Petronas. The pipeline is scheduled for completion in 2000 and will initially transport about 100 million cubic feet per day, with capacity expandable up to 425 million cubic feet per day [35].

To address higher gas prices in Brazil and encourage gas-related investment, particularly in the power sector, the government announced that it may control prices in some regions. In southern, southeastern, and central western

states as well as the Brasilia Federal District, power projects signing 20-year contracts could have a price ceiling equivalent to \$2.26 per million Btu (in 1999 dollars). In Brazil's northeast, where gas will initially be domestically supplied, there is a proposed price ceiling for the first 5 years of \$1.94 per million Btu and \$2.26 for the remainder of the 20-year period. As many as 23 power plants with a combined capacity of 7,400 megawatts could benefit from the price control policy. The move is welcome by foreign investors and will facilitate project funding, because it fixes long-term contracts in dollars rather than the more volatile Brazilian real [36].

Elsewhere in South America, the GasAtacama pipeline began operating in mid-1999, sending gas from Argentina to Chile. It is the second pipeline linking the two countries, after TransCanada's GasAndes pipeline in central Chile, which started operation in 1997. The \$400 million GasAtacama line was built by CMS Energy and Chilean generator Endesa in a project that includes a \$350 million, 370-megawatt power plant. A parallel and rival line, Norandino, backed by Belgian Tractabel and Southern Energy, began operation at the end of 1999. The 585-mile GasAtacama has a capacity of 300 million cubic feet per day but will operate significantly below that at first. Because the project's associated long-term electricity sales contract with Chilean Emel and its distribution companies (via the Nopel power plant) does not begin until 2002, it will sell power on the spot market at first. A pipeline extension is being planned to reach other power plants [37].

A pipeline has also been proposed for transporting Colombian gas into Central America. Backed by local firm Promigas (operated by Enron) and supported by state oil company Ecopetrol, such a project could supply gas to Panama, Costa Rica, and Nicaragua. Conceived to find markets for Colombia's abundant known and potential reserves, the line could face a possible competing or complementing project from Mexico [38]. Venezuela has also expressed an interest in exporting gas to Central America and/or forming a strategic alliance with Ecopetrol [39].

In Peru, the government repeatedly postponed bidding deadlines in 1999 for the sale of the \$2 billion Camisea natural gas project. Although the delays purportedly were to give interested parties more time, they followed the resignation of energy and mines minister Daniel Hokama, as well as reports of disagreement within the government's Camisea committee. Potential investors have complained that the terms of the project are not sufficiently attractive and that gas prices should be set by the market, while the government has maintained that set prices are needed as incentive to potential power producers [40].

Venezuela's election of populist president Hugo Chavez has led to turmoil and power struggles for Petroleos de Venezuela (PDVSA), one of Latin America's biggest companies. The president of PDVSA, Roberto Mandini, has resigned, to be replaced by Hector Ciavaldini, who is said to back reforms promoted by Venezuelan President Chavez including a government effort to control the oil industry. PDVSA has been described as the economic backbone of

Venezuela, the largest producer and consumer of natural gas in South and Central America [41]. Reorganization at PDVSA includes the establishment of a Natural Gas Division, reflecting a government preference to emphasize gas resource development. Although PDVSA will no longer pursue plans with Shell for an offshore Cristobal Colon LNG project because of poor economics, it is still looking for potential LNG or pipeline projects to commercialize gas reserves. Several domestic pipeline projects will also be prioritized [42].

Asia

Gas market activity in Asia during 1999 reflected ongoing recovery in the region from the Asian financial and economic crisis. Demand growth recovered, most notably in South Korea and Thailand, and new projects moved forward. In the *IEO2000* reference case, the growth rate for natural gas use through 2020 in the whole of Asia (both industrialized and developing) averages 5.6 percent per year, increasing consumption to 31.5 trillion cubic feet from 8.9 trillion cubic feet in 1997. The projected demand growth in developing Asia is much higher than in the industrialized countries of the region (Figure 53).

Figure 53. Natural Gas Consumption in Asia by Region, 1980-2020 [Sources]

Industrialized Asia

For the countries of industrialized Asia, natural gas consumption is expected to rise from 3.2 trillion cubic feet in 1997 to 5.2 trillion cubic feet in 2020. Gas use in Japan, the world's largest consumer of LNG, accounts for 70 percent of the incremental increase over the period, increasing from 2.3 to 3.7 trillion cubic feet in the *IEO2000* reference case.

Although in the short run Japanese demand growth is affected by economic recession there, LNG imports to Japan are expected in the long run to grow slowly from their large base. The September 1999 occurrence of Japan's worst nuclear accident in history could ultimately affect gas use, which is consumed primarily in the electricity sector, competing with nuclear power.

As not only the largest but also the first LNG importer in Asia, Japan has several major contracts that end over the next 5 to 10 years. Whether or not Japanese utilities seek to renew those contracts and/or secure LNG from other suppliers could have a major impact on the gas industry in the region. In September 1999, Tokyo Electric (Tepco) and Tohoku reached an initial agreement with Indonesia's Pertamina to extend their purchase of Arun LNG for another 5 years from the 2005 conclusion of their current contract. Volumes would drop from 3.5 million metric tons per year in 1999 to 1 million metric tons per year (reflecting Japan's uncertain demand outlook and desire to diversify suppliers). In view of increasing competition among suppliers, the agreement is good news for Pertamina, although a firm contract must still be finalized [43]. Tokyo Electric and Tokyo Gas also have contracts with Malaysia that will expire before 2005.

Australia is not a large gas consumer (fifth largest in the Asian region in 1997), but it is an important LNG exporter using its sizable resources located in the northwest, far from domestic demand centers. In 1999, Texaco and Chevron announced the discovery of a new field holding several trillion cubic feet of gas near the existing Gorgon reserves offshore Western Australia (Figure 54). Although the Gorgon and nearby fields contain proven, probable, and possible reserves of 21.5 trillion cubic feet—enough to more than double Australia's current LNG exports—no buyer has yet signed a final sales contract, delaying development plans [44]. Australia is promoting its LNG in China (a future importer) and Taiwan, and a number of high-level government and private-sector meetings were held in 1999.

Figure 54. Australia's Natural Gas Pipelines [Sources]

At the same time, there are also plans for Australia to become a gas importer, via a pipeline planned from Papua New Guinea (PNG) to northeastern (Queensland) Australia. In July 1999, the \$3.5 billion dollar project involving Chevron received a boost with the finalization of sales contracts between upstream producers and Australian buyers. The Australian side of the pipeline will be built and owned by a joint venture between Australian Gas Light Company and Malaysia's Petronas. On the PNG side, owners of the gas assets are expected to set up an entity for pipeline construction, funding, and ownership [45].

Developing Asia

Developing Asia includes the two most populous countries in the world, China and India—emerging giants that are geographically large, have large economies, and are expected to have a tremendous impact on gas use in the region (see discussion on "Two Giants Emerge: natural Gas in China and India"). At the same time, China and India accounted for only about 15 percent of gas use in the region in 1997, and both use a much smaller proportion of gas in their total energy mix than the region as a whole.

For now, much of the gas market growth and significant infrastructure projects are taking place elsewhere in the region, largely, in Southeast Asia. At the beginning of 1999, Singapore agreed to import gas via pipeline from Indonesia's Natuna West field. A contract involving SembCorp Industries, Ltd. (a government-linked company in Singapore) calls for deliveries of 325 million cubic feet of gas per day over a 22-year period and links the price primarily to Singapore spot prices for high-sulfur fuel oil. The project has raised controversy in Indonesia, including allegations of corruption because of linkages to Mohamad "Bob" Hasan, a businessman and close friend of former president Suharto. A pipeline construction contract worth \$335 million was awarded to McDermott, and Hasan holds about 18 percent equity in McDermott Indonesia. In October, however, two independent audits reported that the contract was awarded fairly. The pipeline is under construction, with deliveries still scheduled to start in 2001 [46].

A second deal between Singapore and Indonesia, worth about \$7 billion and leading to further pipeline trade, was

also finalized in September 1999. The 20-year contract set to begin in 2002 calls for state-owned Singapore Power to buy from Pertamina initially 150 million cubic feet per day of gas, with volumes increasing up to 350 million cubic feet per day by 2008. Gas could be used increasingly in Singapore for power generation and petrochemicals [47].

Despite its political and economic upheaval, Indonesia is completing an eighth train at its Bontang LNG plant. Train H is set to begin exporting gas to Taiwan and South Korea by the end of 1999 or early 2000. Already the world's largest LNG exporter, Indonesia would also like to proceed with construction of a grassroots LNG plant, "Tangguh," in Wiriagar, Irian Jaya, using reserves discovered by British Gas and ARCO (which will merge with BP Amoco). To do so, Pertamina must find buyers for the LNG, which it is actively marketing to China in competition with Australian producers, among others [48]. In its domestic market, the Indonesian government will reduce natural gas prices from around \$2.50 per million Btu (U.S. dollars) to about \$1.50 per million Btu, in response to a dramatic plunge in gas use over the past 2 years, during which domestic contracts were priced in dollars and the Indonesian rupiah depreciated sharply against the U.S. dollar [49].

Elsewhere in Southeast Asia, production and delivery of contracted gas from the Yadana field in Myanmar (formerly Burma) was delayed until 2000 because of the postponed completion of Thailand's Ratchaburi power plant from its originally scheduled July 1998 startup. The Petroleum Authority of Thailand (PTT), which has a take-or-pay contract with the Yadana consortium, recently reached settlement to pay for some of the gas not taken. It was at first claiming "force majeure" following paralyzing events of the Asian financial and economic crisis [50]. Early estimates from PTT are that it will transmit 10 percent more gas in 1999 than the previous year, suggesting some recovery from the Asian crisis in the gas sector [51].

Completion of the Ratchaburi plant and recovery of Thai gas demand growth will also be important, because Malaysia and Thailand have reached agreement over the development of gas resources in their joint development area (JDA), with infrastructure construction to begin as early as 2000. Initially, project equity is split with 50 percent held by Petronas and 50 percent by PTT. Thailand may offer equity to foreign investors. In September 1999, Thai cabinet ministers approved a PTT investment plan for the project, which includes a pipeline and gas separation plant [52]. Malaysia could take all of the gas during the initial years of production if Thai demand cannot at first absorb the supply [53]. The first phase of the project (with targeted completion by 2002) calls for a 220-mile off/onshore pipeline from the JDA through the southern Thai town of Songkhla to the Malaysian province of Kedah. A second phase would involve a pipeline connecting JDA gas fields to the PTT grid in the Gulf of Thailand. Thai environmentalists quickly objected to the approval of investment plans before public hearings could be convened [54].

In 1998, Petronas of Malaysia signed eight oil and gas production sharing contracts (PSCs), the highest number in

10 years, reflecting the 1997 introduction of new revenue-over-cost formulae in PSCs [55]. Petronas also reached an agreement with Metropolis (wholly owned by Enron) to supply 2.6 million metric tons of LNG to India for a 20-year period starting in 2002. If a final contract is signed, it could be the first arrangement for delivery of Asian LNG into India [56].

India moved forward in 1999 with other plans to begin importing gas, which involve a host of projects and potential LNG terminals. In May, Enron's 624-megawatt Dabhol I power plant began operating, and the 1,624-megawatt Dabhol II reached financial closure [57]. Dabhol I is initially burning naphtha but will switch to LNG, and Dabhol II should use LNG at startup. Enron is making shipping arrangements for LNG imports, which are planned to start in 2002 (from Oman) and will eventually send fuel to the Dabhol power plants. Petronet is still pursuing plans for two initial LNG import terminals, and other terminals are also planned. In July, a 25-year agreement was signed with Rasgas for the purchase of 7.5 million metric tons of LNG per year, although a final contract must still be signed. The agreement calls for delivery of 5 million metric tons per year to a terminal at Dahej in Gujarat and 2.5 million metric tons per year to Cochin in Kerala [58]. Deliveries are scheduled to begin July 2003.

Gujarat Pipavav LNG, involving British Gas and Sea King Engineers, obtained agreement from India's National Thermal Power Corporation (NTPC) to take on a 26-percent equity stake in their project. British Gas and Sea King will then jointly hold a 50-percent share and offer the balance to public-sector gas users. As part of the agreement, an international tender will be issued to select an LNG supplier, although British Gas had earlier signed a memorandum of understanding with Yemen LNG. NTPC also continues to pursue an equity stake in Petronet and will eventually seek the best LNG price possible to fuel its power plants [59].

Another Indian LNG project in strong standing involves Total and Tata Electric Companies (TEC) at Trombay near Mumbai (formerly, Bombay). Equity in the project's joint subsidiary, Indigas, will be acquired by Gas Authority of India (GAIL). TEC and GAIL have agreed to initial purchases of 3 million metric tons of LNG imports per year. TEC will use the gas to fuel its Trombay power station, and GAIL will market gas to industries around Mumbai [60]. Plans for gas imports to India reflect expectations of rising consumption. In the IEO2000 reference case, gas use in India is projected to grow at an average annual rate of nearly 8 percent per year from 1997 to 2020, increasing sixfold (Figure 55).

Figure 55. Natural Gas Consumption in India, 1990-2020
[Sources]

China, also moving toward initiating LNG imports, has undertaken a feasibility study of importing LNG in Guangdong. Australia has remained visible as the potential supplier, with visits to southern China by Australia's Foreign Minister. The Chinese import project involves a consortium led by China National Offshore Oil Corporation (CNOOC), which is likely to retain a 36-percent equity share. CNOOC is

to invite bids from foreign companies, which will be allowed to acquire a 35-percent share [61]. In addition, Shell has reached a gas and power joint venture agreement with China National Petroleum Company (CNPC) for a \$3 billion project to construct pipelines and convert power plants and industrial facilities from coal to gas supplied from the Ordos Basin (Changbei field) [62].

In LNG-importing South Korea, monopoly importer Kogas faces deregulation and privatization. Presenting a restructuring plan in October 1999, the Commerce, Industry and Energy Ministry proposed spinning off and selling importing and wholesale units of Kogas as well as selling off its stakes in storage facilities and the main pipeline network by 2001 [63]. Taiwan, another LNG importer, was hit by a major earthquake in September 1999. Damage to the power grid could cause Taipower to take less LNG from Chinese Petroleum Corporation (CPC) in 2000 for power generation.

Middle East

As a region, the Middle East has the second largest natural gas reserves after the former Soviet Union. Reserves in the Middle East were estimated at 1,750 trillion cubic feet as of January 1, 2000. Iran, Qatar, and the United Arab Emirates (UAE) have the second, third, and fourth largest reserves in the world, respectively, following Russia. Middle East reserves, which expanded rapidly in the late 1980s and early 1990s, include the super-giant gas structure involving Qatar's North Field and Iran's South Pars. With its large reserves, the Middle East is a strong producer and growing exporter of natural gas, although domestic consumption to date has generally been quite low in the region. The *IEO2000* reference case projects a doubling of Middle East gas consumption between 1997 and 2020, rising from 6.0 to 12.0 trillion cubic feet (Figure 56).

Figure 56. Natural Gas Consumption in the Middle East, 1990-2020 [Sources]

Turkey, one of the fastest growing gas markets, suffered a major earthquake in August 1999 (and another in November), taking at least 16,000 lives and causing infrastructure damage, especially to an oil refinery, but not to gas pipelines. Fierce competition continued among gas projects proposing to supply the Turkish market. Russian Gazprom's Blue Stream project (involving a pipeline from Russia directly to Turkey under the Black Sea) signed a memorandum of understanding with Italy's Eni in February 1999 and then received a series of approvals in Russia. Construction of the pipeline could begin in 2000, according to project participants. The competing Trans-Caspian Pipeline proposal (which would export Turkmen gas to Turkey via the Caspian Sea) also received a boost when commercial agreements were signed in November in Istanbul with President Clinton attending [64].

In an effort to provide gas for domestic development in the south Persian Gulf region, the UAE Offsets Group (UOG) has begun promoting the "Dolphin" gas venture. The UAE and Oman have little gas for local demand, because resources are earmarked for export. Thus, a pipeline has

been proposed from Qatar's North Field to Abu Dhabi, Dubai, and Oman—with a proposed future extension on to Pakistan. UOG has signed a memorandum of understanding with Mobil Oil Qatar, Inc., for gas volumes in the range of 300 to 500 million cubic feet per day. Developers say construction could start in 2000, with deliveries by 2003 [65]. Elsewhere in the UAE, BC Gas of Canada began connecting gas consumers to a new domestic gas grid in Sharjah [66].

In Qatar, the Mobil-led RasGas LNG venture loaded its first cargo in August 1999. Korean owned and operated LNG carriers will ship the LNG to Korea under a 25-year contract. A second LNG train under construction is on schedule and expected to start up in the first half of 2000. In addition, further trains can be expected if a RasGas agreement is finalized with India for 7.5 million metric tons per year of LNG [67]. Qatar has also announced intentions to develop a commercial-scale gas-to-liquids (GTL) conversion project that would use its substantial domestic reserves for emerging GTL technologies (see discussion on "Gas-To-Liquids Technology: The Current Picture").

Elsewhere in the Middle East, Israel has announced that natural gas will power 25 percent of its electricity needs by 2005, but it is still seeking gas supplies. British Gas has discussed exploring for gas in Israel, and Egypt is also a possible source, although talks between the two countries stalled in 1999. Israel is prequalifying bidders for an upcoming tender on development of domestic gas infrastructure, which is due to be issued in the first quarter of 2000 [68]. A pipeline is currently under construction from Egypt to Jordan and on to the Palestinian Authority areas [69], and plans are nearing finalization for a pipeline from Syria to Lebanon that would supply Lebanon with 105 million cubic feet of gas per day. The pipeline would have two sections: a 75-mile stretch from the Syrian city of Homs to Deir Ammar in northern Lebanon and a 90-mile portion continuing to the southern Lebanese town of Zahrani. Conoco and Elf already signed a deal to process gas from the Syrian Deir al-Zur field [70].

Saudi Arabia is also seeking to increase domestic gas use and has undertaken a \$4 billion program to develop gas infrastructure and the non-associated gas reserves from the Khuff reservoir. The gas will go to the new Hawiyah gas processing plant (due on stream in 2001) and to power plants in Riyadh. Saudi Arabia's 204 trillion cubic feet of gas reserves are primarily associated gas, which was flared until the early 1980s. Gas is currently produced from about 10 of more than 80 known fields and is used in fertilizer and petrochemical plants at Jubail and Yanbu [71].

Africa

Gas reserves in Africa account for nearly 8 percent of global stocks. With new additions in Egypt and Nigeria, the region's reserves amount to 394 trillion cubic feet. Roughly 70 percent of Africa's domestic gas consumption and more than 80 percent of its production occurs in Algeria and Egypt. Algeria exports 70 percent of its domestic production via pipeline and LNG tanker. Within Africa, natural gas remains

the least utilized fossil fuel. Low growth in Africa's gas consumption (Figure 57) reflects a lack of economic growth in much of the region as a result of political instability, which has been particularly severe in sub-Saharan Africa. In Ghana and the Ivory Coast (in West Africa), economic growth has led to rising demand for energy and associated interest in natural gas development, particularly for electricity generation. Domestic use of natural gas in Africa is heavily for power generation, amounting to 40 percent of the region's gas demand [72].

Figure 57. Natural Gas Consumption in Africa, 1990-2020
[Sources]

In the *IEO2000* forecast, Africa's natural gas consumption continues to grow at a relatively slow pace. The average projected growth rate of 1.8 percent annually from 1997 to 2020 is the slowest among the developing regions, including the Middle East, developing Asia, and Central and South America. In the reference case, total gas use in Africa rises from 1.8 trillion cubic feet in 1997 to 2.8 trillion cubic feet in 2020.

In 1999, Nigeria's LNG (NLNG) export facility came on stream amid continued protests by local activists demanding jobs and cash payments. Protests that closed down the Bonny plant in September, just 2 weeks after production began, and again in late September and early October, ended after negotiations with government officials. NLNG was able to repair related damage and make its first delivery to France at the end of October [73]. In early 1999, Shell awarded a construction contract for a third Nigerian LNG train to a consortium involving Technip, Snamprogetti, MW Kellogg, and JGC Corp. More than 70 percent of the LNG from the expansion has already been sold to Spain's Enagas over a 21-year period [74]. Like Qatar, Nigeria has tentative plans for a GTL project (see box on pages 59-60), with South Africa's Sasol as a partner.

Plans to supply Nigerian gas to Ghana, primarily for power generation, also made progress in 1999. The West African Gas Pipeline (WAGP) joint venture agreement was signed in August by six energy companies, including Chevron, Shell, and the oil companies of Nigeria, Ghana, Benin, and Togo. The consortium seeks to build a \$400 million pipeline by 2002 that would send initially about 120 million cubic feet per day of now flared Nigerian gas to Ghana, Togo, and Benin [75]. In addition, Ghana has started up the second of two gas-fired power plants using offshore Ivorian gas [76]. There is also development of domestic resources for power generation in the Tano Fields Development and Power Project, involving a 100- to 140-megawatt power plant fueled by offshore gas [77].

Egypt, too, is moving toward expanding its domestic gas market, in part to switch from oil to gas and save oil for export. The state-owned Egyptian General Petroleum Company (EGPC) has amended agreements with BP Amoco and Eni, allowing production to expand at offshore gas fields (in the Ras el-Barr concession) in order to supply the domestic market. Investments of up to \$200 million will be used to expand production by up to 399 million cubic feet per

day by 2002. In addition, BP Amoco together with Burlington Resources has also signed a separate gas sales agreement with EGPC for gas off the coast of northern Sinai. Requiring a \$150 million investment, production from three fields in the area, which could reach 110 million cubic feet per day by 2004, will also be used for the domestic market [78]. EGPC will also form a joint venture with UK-based British Gas and Italy's Edison International to develop Egypt's largest gas field, Sacarab/Saffron, in the Nile Delta. Production of high-quality gas from the field is expected to start in 2003 and build quickly to deliveries of about 530 million cubic feet per day for a contract period of at least 17 years. The European Investment Bank (EIB) will advance a loan to Egyptian Natural Gas Company (Gasco) for the construction and operation of a pipeline to move gas from the Suez Canal region to a distribution plant north of Cairo, which will reinforce the domestic grid [79].

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Western Australia Department of Minerals and Energy
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Petroleum Royalties

Royalty Systems

Generally, there are three systems used for the collection of petroleum royalties:

- well-head;
- resource rent royalty; and
- resource rent tax.

Well-head Royalty

The well-head value is derived by taking the gross value of petroleum recovered and deducting all costs incurred between a defined valve on the christmas tree and the point of sale. Deductible costs are normally confined to the processing, storage and transport of the petroleum recovered by the producer to the point of sale. All other costs, including costs associated with exploration, drilling, recovery and abandonment are not deductible.

The defined location of the well-head and the methodology for calculation of well-head value are usually included in a royalty schedule specific to each producer.

New petroleum projects landward of the outer limit of the Territorial Sea are subject to either the Petroleum (Submerged Lands) Act 1982 or Petroleum Act 1967, and in either case the well-head royalty regime have the following elements:

- royalty return - generally required to be submitted on a monthly basis;
- royalty rate - generally between 10.0% and 12.5%;
- gross value - value of petroleum recovered, generally the arms length sales value of petroleum recovered and the change in petroleum inventories;
- allowable deductions - post well-head costs; and
- deduction limit - 50% of gross value for oil projects and 90% of gross value for gas projects.

Petroleum Royalty Rates

Royalty rates between 10% and 12.5% of well-head value generally apply. The rate applied is dependant upon the type of licence from which the petroleum is

produced. Production from primary production licences attracts a rate of 10% while production from secondary licences attracts a rate of 12.5%. Primary licences are those initially issued to producers, while secondary licences are those subsequently issued to cover the width of the producing field.

Gross Value

Gross value is the value of petroleum recovered. It includes the value of arms length sales and the change in stocks of petroleum products.

Opening and closing stocks are valued according to the weighted average unit price of the past month's sales. Transactions denominated in foreign currency are converted to Australian Dollars based on Reserve Bank of Australia (RBA) mid-rates as published weekly by the RBA and daily in the *Australian Financial Review*.

Allowable Deductions

Three types of costs are allowed to be deducted against the gross value to determine well-head value:

- post well-head operating costs;
- depreciation on commissioned post well-head assets; and
- cost of borrowing on commissioned post well-head assets

Post well-head operating costs

Usually at the beginning of a project expected operating costs are itemised by a prospective producer. Post well-head percentages are then agreed between the State and for each operating cost item.

Depreciation on commissioned post well-head assets

Usually at the beginning of a project a depreciation calculation is negotiated between the State and producer and set out in an agreed schedule. A straight line depreciation calculation normally applies.

Cost of borrowing on commissioned post well-head assets

The well-head value system allows a producer to deduct from the gross value an amount in recognition of the cost of raising funds related to post well-head assets of the project. This amount is calculated from the time each post well-head assets is commissioned.

Not all costs of raising funds are allowed. A gearing allowance is determined at the beginning of the project, usually set at a maximum of 50% of the total cost of post well-head assets. The term or write-down period of the deduction is also determined at the beginning of a project and proxies the length of time it will take for the project owners to repay their borrowed funds. A standard interest rate is used instead of the actual interest rates paid for funds by individual project owners. The standard rate is usually the preceding month's 5 year term bond rate as published each month by the RBA.

Deduction Limits

Deductible costs can vary up to a limit of 50% of the gross value of production for oil projects or 90% of the gross value of production for gas projects for each royalty period. The choice of the deduction limit is determined by the 'predominant' nature of the project, and may change as a project shifts from a predominantly oil to a predominantly gas project. Any undeducted expenditure is carried forward to the next month.

Resource rent royalty

The Barrow Island Royalty Variation Agreement Act 1982 was agreed between the producer, the State and the Commonwealth as an incentive for the continued maintenance of the wells on Barrow Island to ensure optimal recovery of oil. The resource rent royalty (RRR) replaced the well-head royalty and excise system that had previously applied.

RRR is a royalty based on a percentage of net cash flow. The key aspects are as follows:

- all allowable expenditure, both current and capital, is written off when incurred. However exploration costs incurred more than a year prior to the application of the RRR are not allowable;
- any excess of costs over revenues are carried forward and compounded at a 'threshold' rate;
- any excess income over the threshold rate is charged to RRR at the rate of 40%;
- RRR is a primary tax before income tax, and is deductible against that tax; and
- the revenue is shared 75% to the Commonwealth, 25% to the State. The higher Commonwealth share reflects the far larger proportion of Commonwealth entitlements under the prior royalty and excise regime.

By agreement between the Commonwealth and the State, the State maintains full responsibility for the administration of the RRR regime.

Petroleum resource rent tax

The Commonwealth petroleum resource rent tax (PRRT) is a secondary tax on petroleum production based upon the cash flows of a given project. Royalties do not apply to fields chargeable to PRRT, but PRRT is deductible against income tax.

Home: Inside DME: Petroleum Royalty Systems

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Attachment C

**Barrow's Inc., *World Fiscal Systems for Oil*,
pp. 234-235, "Australia"**

AUSTRALIA**Environment:**

Safety and environmental protection will be dealt with through regulations which will set standards equivalent to those now applying offshore Australia.

Production Sharing:

The basic principle of the production sharing contract is that the Joint Authority owns all petroleum and, on behalf of the two countries, enters into contracts with companies to explore for and produce petroleum. In return, companies will receive a share of the petroleum produced.

The first step in the sharing process designates 10% of any production as "First Tranche Petroleum". This percentage will increase to 20% after the fifth year of production. The First Tranche Petroleum will be shared between the Joint Authority and the contractor in accordance with the sharing ratios given below. In effect this means that, for crude oil production, a royalty of between 5% and 7% will be paid to the Joint Authority during the first five years of production.

After the First Tranche Petroleum has been calculated, contractors will be allowed to recover Investment Credits for exploration and capital costs equal to the quantity of petroleum production equivalent to 127% of the exploration and capital costs incurred in each calendar year.

In addition, contractors will be able to immediately recover all exploration and operating costs, and depreciation of capital costs. Depreciation is calculated on a 20% straight line basis.

In any year in which production is insufficient to allow full recovery of investment credits and costs the remainder may be carried forward and recovered in future years.

After the recovery of Investment Credits and all costs, the remaining quantity of crude oil production is shared according to the following formula:

<u>Production Rate</u>	<u>Joint Authority Share</u>
0 - 50,000 bpd	50%
50,000 - 150,000 bpd	60%
150,000 bpd +	70%

AUSTRALIA

The Joint Authority will receive a 50% share of natural gas production irrespective of production rates, after recovery of Investment Credits and all costs.

Taxation:

Both countries will apply their tax legislation to Area A, but in such a way as to ensure that only 50% of income and 50% of expenditures will be taken into account by each country.

For individuals working in Area A, rules will apply so that residents of Australia will be subject to Australian taxes and residents of Indonesia to Indonesian taxes.

Employment:

Contractors to give preference in employment to nationals or permanent residents of Australia and Indonesia. The terms and conditions of that employment, including occupational health and safety, will be no less favorable than those applying to comparable categories of employment in both Australia and Indonesia.

Law:

Criminal law will be applied on the basis of the nationality or permanent residency of the person.

Customs Regime:

Under the provisions of the Treaty, Australia and Indonesia may apply their respective customs, migration and quarantine laws to individuals, equipment and goods entering their territories from Area A or leaving their territories for Area A.

Attachment D

"Government and Producers Boost LNG Industry"
Media Release, Senator Nick Minchin, Minister for Industry,
Science and Resources, October 10, 2000

<http://www.minister.industry.gov.au/minchin/releases/2000/october/cmr516%2D00.doc>

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GOVERNMENT AND PRODUCERS BOOST LNG INDUSTRY
10 October 2000



MEDIA RELEASE

SENATOR NICK MINCHIN

Minister for Industry, Science and Resources

10 October 2000 00/448

GOVERNMENT AND PRODUCERS BOOST LNG INDUSTRY

The Minister for Industry, Science and Resources, Senator Nick Minchin and the Chairman of the Australian Petroleum Production and Exploration Association (APPEA), Dr Agu Kantsler today launched a new policy framework to ensure Australia remains a competitive and reliable liquefied natural gas supplier.

*

"The *LNG Action Agenda* will provide a framework of joint Government and industry commitments for securing the future of the LNG industry," Senator Minchin said.

"These commitments are important, not only to traditional and prospective buyers of Australian LNG, but to investors who need to take a long-term position in the industry."

Dr Kantsler said the agenda outlines a shared vision for a strong, internationally competitive LNG industry.

"The industry is well on its way to achieving the vision. It also recognises LNG's role as a clean energy fuel," Dr Kanstler said.

The recent signing of Letters of Intent with Japanese energy companies for purchase of increased quantities of LNG points to increased buyer confidence in the Australian product.

The *LNG Action Agenda* is the joint effort of all key stakeholders - the Australian LNG industry and the Commonwealth, States and Northern Territory governments.

"This Action Agenda represents a significant milestone in the development of Australia's LNG industry," Senator Minchin said.

"Through the LNG Action Agenda the Government and industry

1 of 2 * The LNG Action Agenda may be accessed at: <http://www.isr.gov.au/resources/lng/>

3/9/01 10:57 AM

responded positively to a number of issues including:

- greenhouse gas emissions;
- taxation;
- customs and tariffs;
- Australian industry participation in LNG projects;
- Government approval processes;
- LNG marketing and promotion; and
- the Timor Gap Zone of Cooperation Treaty (ZOCA).

"The Government has made the commitment that future greenhouse gas policies and measures will promote cost effective actions so that Australian industry can remain competitive.

"Very importantly, the Government is saying that we will only implement a domestic emissions trading scheme if the Kyoto Protocol is ratified by Australia, has entered into force and there is an established international emissions trading regime.

"We've also said that we will avoid policies and measures that distort investment decisions between particular LNG projects and locations.

"We will avoid policies and measures that disadvantage those companies which have moved early in undertaking greenhouse emission abatement actions, or that discriminate against new industry entrants.

The Action Agenda announces the Government's in-principle agreement to establish a new By-law for major projects with an initial project capital expenditure of \$50 million or more, to enable duty free importation of capital equipment and components which are unavailable within Australia and integral to the project.

"With exports around \$2 billion per year - the LNG industry is a major contributor to our national and economic well being," Senator Minchin said.

"Australia's major LNG project, the \$12.1 billion North West Shelf (NWS) Project has increased GDP by 1.24%, provided Australian suppliers with \$10 billion in business since 1980 and has produced an extra 80,000 Australian jobs each year over its life.

"There are also plans for the \$2.5 billion development of the Sunrise and Troubadour fields and Methanex is looking at \$1.5 billion processing plant that would use the gas from the fields," Senator Minchin said.

A copy of the *LNG Action Agenda* can be accessed on the ISR web site at: <http://www.isr.gov.au/resources/lng/>

Attachment E

**Kentucky Revised Statutes § 132.820, relating to the
Assessment and Taxation of Unmined Minerals and Energy Resources**

Kentucky Revised Statutes

132.820 Assessment of unmined coal, oil, and gas reserves held separately from surface real property – Effect of appeal on payment of taxes.

- (1) The cabinet shall value and assess unmined coal, oil, and gas reserves, and any other mineral or energy resources which are owned, leased, or otherwise controlled separately from the surface real property at no more than fair market value in place, considering all relevant circumstances. Unmined coal, oil, and gas reserves and other mineral or energy resources shall in all cases be valued and assessed by the Revenue Cabinet as a distinct interest in real property, separate and apart from the surface real estate.
- (2) Each owner or lessee of property assessed under subsection (1) of this section shall annually, between January 1 and April 15, file a return with the cabinet in a form as the cabinet may prescribe. Other individuals or corporations having knowledge of the property defined in subsection (1) of this section gained through contracting, extracting, or similar means may also be required by the cabinet to file a return.
- (3) Any property subject to assessment by the cabinet under subsection (1) of this section which has not been listed for taxation, for any year in which it is taxable, by April 15 of that year shall be omitted property.
- (4) After the valuation of unmined minerals or other energy sources has been finally fixed by the cabinet, the cabinet shall certify to the county clerk of each county the amount liable for county, city, or district taxation. The report shall be filed by the county clerk in his office, and shall be certified by the county clerk to the proper collecting officer of the county, city, or taxing district for collection.
- (5) The notification, protest, and appeal of assessments under subsection (1) of this section shall be made pursuant to the provisions of KRS Chapter 131.
- (6) No appeal shall delay the collection or payment of taxes based upon the assessment in controversy. The taxpayer shall pay all state, county, and district taxes due on the valuation which the taxpayer claims as the true value as stated in the protest filed under KRS 131.110. When the valuation is finally determined upon appeal, the taxpayer shall be billed for any additional tax and interest at the tax interest rate as defined in KRS 131.010(6), from the date the tax would have become due if no appeal had been taken. The provisions of KRS 134.390 shall apply to the tax bill.
- (7) The collection of tax bills generated from the assessments made under subsection (1) of this section shall be made pursuant to the provisions of KRS Chapter 134.

Effective: July 15, 1998

History: Amended 1998 Ky. Acts ch. 391, sec. 3, effective July 15, 1998. -- Created 1994 Ky. Acts ch. 263, sec. 1, effective July 15, 1994.

Legislative Research Commission Note (7/14/00). 2000 Ky. Acts ch. 446 (Senate Bill 323), sec. 1, purports to amend this statute, and the General Assembly version of that bill was signed by both presiding officers and by the Governor. The Journals of the House of Representatives and Senate will reflect, however, that House Floor Amendment 1 was adopted by the House on March 27, 2000, but was not transmitted to the Senate for its concurrence when the bill was returned to that body. Thus, the bill signed did not pass both chambers of the General Assembly in the same form and did not become law. Ky. Const. secs. 46 and 88; see also Mason's Manual of Legislative Procedure sec. 737, at 508-509 (1989 ed.). Because the General

Assembly's own official records establish this constitutional deficiency, the provisions of 2000 Ky. Acts ch. 446 have not been codified into the Kentucky Revised Statutes. See KRS 7.131(2).

Attachment F

Gillis v. Yount,
748 S.W.2d 357, (1988 KY)

Gary Gillis, Secretary of the Revenue Cabinet, Movant v. William D. Yount, Scott Barbour and others similarly situated, Alison Moore, J.D. Miller, Elaine Stoltzfus and others similarly situated and The Kentucky Coal Association, Respondents; The Kentucky Coal Association, Inc., Movant v. Alison Moore, J.D. Miller, Elaine Stoltzfus and all others similarly situated, William D. Yount and Scott Barbour and all others similarly situated, Respondents

Nos. 87-SC-286-DG, 87-SC-288-DG

Supreme Court of Kentucky

748 S.W.2d 357; 1988 Ky. LEXIS 13; 100 Oil & Gas Rep. 645

March 3, 1988, Decided

PRIOR HISTORY:

[**1] ON REVIEW FROM COURT OF APPEALS, 85-CA-2662 & 2717-MR, Franklin Circuit Court Nos. 84-CI-815, 84-CI-867 & 85-CI-589.

DISPOSITION:

AFFIRMING

COUNSEL:

Attorney: for Gary Gillis: Ross T. Carter, Douglas M. Dowell, Frankfort, Kentucky.

Attorney for Amicus Curiae, League of Women Voters: Frederick W. Whiteside, Lexington, Kentucky.

Attorneys for Kentucky Chamber of Commerce: Bruce F. Clark, Gayle W. Herndon, Stites & Harbison, Frankfort, Kentucky.

Attorneys for Moore Appellees: Ira A. Burnim, Washington, District of Columbia, Phillip Shepherd, Joe Childers, Lexington, Kentucky, J. Richard Cohen, Montgomery, Alabama.

Attorney for Kentucky Coal Assn.: James R. Cox, Him, Reed & Harper, Louisville, Kentucky.

Attorney for Amicus Curiae, Kentucky Farm Bureau Federation: Wayne J. Carroll, Ewen, MacKenzie & Peden, P.S.C., Louisville, Kentucky.

Attorney for Yount and Barbour: Joseph J. Leary, Frankfort, Kentucky.

JUDGES:

Opinion of the Court by Justice Leibson. Stephens, C.J., Lambert, Vance and Wintersheimer, JJ., concur. Leibson, J. concurs in this opinion, and also files a separate concurring opinion. Wintersheimer, J. concurs by separate opinion in which Leibson, J. joins. Stephenson, J. dissents by separate opinion in which Gant, J. joins.

OPINIONBY:

LEIBSON

OPINION:

[*357] These cases challenge the constitutionality of KRS 132.020(5), which classifies unmined coal separately from other real property and then taxes it "at the rate of one-tenth of one cent (\$.001) per one hundred dollars (\$ 100) of assessed value." All other real property is taxed "for state purposes" under KRS 132.020(1) at "thirty-one and one-half [**2] cents (31 1/2 cents) upon each one hundred dollars (\$ 100) of value."

The cases are consolidated. In the first case Yount and others similarly situated, a class of real property owners, claim that the statute is unconstitutional because the General Assembly has arbitrarily classified one type of real property separately from other real property. In the second case Moore and others similarly situated, a class of automobile owners, claim that the 1 mil (\$.001) rate is unconstitutional because it is an exemption and not a tax.

The Franklin Circuit Court, after trial on the merits, entered judgment (1) rejecting the claim that the separate

classification for unmined coal was constitutionally impermissible, and (2) upholding the claim that the tax rate "bestows on unmined coal a *de facto* exemption from property taxation," [*358] and thus "is unconstitutional under Sections 3 and 174 of the Constitution."

On appeal the Court of Appeals ruled in favor of the claims of *both* plaintiffs, agreeing with the trial court that this one mil rate for unmined coal was in fact an unconstitutional exemption, and then further holding that the separate classification of unmined coal was arbitrary and [**3] therefore unconstitutional under Section 171 of our Constitution which requires that "taxes ... shall be uniform upon all property of the same class subject to taxation within the territorial limits of the authority levying the tax." n1

n1 The Court of Appeals held that another issue presented, the propriety of awarding attorneys' fees, was not preserved for appellate review because the appellants did not designate the attorneys as parties to the appeal. We have not considered this issue on discretionary review.

A majority of our Court has decided that the classification issue is the threshold issue on discretionary review. Having decided that KRS 132.020(5) is an arbitrary classification in violation of Section 171 of the Kentucky Constitution, as quoted above, the Court has elected not to consider whether the \$.001 ad valorem levy upon unmined coal is an unconstitutional tax rate.

Both sides agree that Kentucky law classifies ownership of unmined coal as an interest in real estate. As stated in *Williams' Adm'r v. Union Bank and Trust Co.*, 283 Ky. 644, 143 S.W.2d 297, 300 (1940): "it has long been the law of this State that minerals in place are real estate" [**4] And as stated in *Commonwealth v. Elkhorn-Piney Coal Min. Co.*, 241 Ky. 245, 43 S.W.2d 684, 686 (1931):

"The rights created by a coal lease constitute real estate for the purposes of taxation under our present statutes."

From 1792, when Kentucky's first property tax was levied, until the 1970's, coal was taxed only insofar as it was included in the value of the surface property. Then in the 1970's, the General Assembly enacted a new type of tax, the severance tax, first applicable only to coal and then extended to "the physical removal of [any] natural resource from the earth or waters of this State by any means" with certain exemptions and exceptions which

are not relevant to this case. KRS Chapters 143 and 143A.

The new tax is an excise tax "upon the privilege of severing and processing coal" and not a property tax. *Circle "C" Coal Co., Inc. v. Com.*, Ky.App., 628 S.W.2d 883, 885 (1982). Coal was the first mineral, and is perhaps the major one, subject to this new excise tax, the severance tax, but it is certainly not the only one. "Rock, stone, limestone, shale, gravel, sand, clay, natural gas, and natural gas liquids," are all classified as a "natural resource" [**5] (KRS 143A.010) and taxed at the same rate (KRS 143A.020), which is 4 1/2%. Under KRS 137.120 a similar tax is imposed upon "all crude petroleum produced in this state."

However, for purposes of ad valorem taxation unmined coal alone has been separately classified from other real estate. In 1976, the General Assembly classified coal separately from other real estate for the first time (1976 Kentucky Acts, Chapter 84, Section 7), and in 1978 the General Assembly followed this up with the new rate of one cent per thousand (one mil) enacted in KRS 132.020(5). The connection between classifying unmined coal separately from other interests in real property subject to ad valorem tax and then imposing the new one mil rate for such property is abundantly clear from review of the legislative history of the one mil rate.

The framers of the 1891 Kentucky Constitution, to protect the people, enacted significant constitutional limitations upon the powers of the General Assembly to impose state property taxes and create exemptions. 2 Debates Constitutional Convention 1890, 2372-2423 (1890). The primary source of tax revenue at the time was property taxes, and this is where the problems with unfairness [**6] were perceived, so these constitutional limitations, covered principally in Kentucky Constitutions Sections 170-175, deal *only* with the power to tax property, or ad valorem taxes. They require *inter alia*, that taxes "shall be uniform upon all property of the same [*359] class," (Section 171), that "all property, not exempted from taxation by this Constitution, shall be assessed ... at its fair cash value" (Section 172), and that "all property ... shall be taxed in proportion to its value, unless exempted by this Constitution; and ... shall pay the same rate of taxation" (Section 174). The constitutional exemptions are specified in Section 170, which states that "all laws exempting or omitting property from taxation other than the property above mentioned shall be void." It is almost impossible to see how the constitutional mandate on state property taxes could have been expressed in clearer or more positive terms.

The one mil rate (one cent per thousand) was devised as a method to avoid these constitutional

restrictions. See Joint Submission, Kentucky Department of Revenue, *Annual Report HS-88* (1975-76). The movant, Gary Gillis, Secretary of the Revenue Cabinet, candidly [**7] conceded that the legislative purpose behind a one mil rate is to create a *de facto* exemption, although arguing that this is constitutionally permissible. The only way to effect such a purpose, a *de facto* exemption, with reference to unmined coal was to first classify it separately from other real property, and to then designate one mil as the applicable rate. The statutes of 1976 and 1978 were enacted as a plan to effect this purpose.

The need to enact a one mil rate when the General Assembly wished to favor a certain type of property with a *de facto* tax exemption resulted from the decision of our Court in *Russman v. Luckett, Ky.*, 391 S.W.2d 694 (1965). *Russman* is the bellwether case on the subject of constitutional limitations on property taxes. It was a taxpayers' suit attacking the assessment procedures then in place by which "real estate and tangible personal property in Kentucky [were] assessed for tax purposes at varying percentages substantially less than 100 percent of fair cash value." 391 S.W.2d at 695. Our Constitution, Section 172, specifies that "all property, not exempted from taxation by this Constitution, shall be assessed for taxation at its [**8] fair cash value." Nevertheless, over a period of 75 years the practice had evolved of "substituting the test of 'uniformity' in place of 'fair cash value'." In *Russman*, our Court delivered to the executive branch and the legislature the message that in the area of property taxes, when called upon to do so, our Court was prepared to enforce the Constitutional mandate. We stated that there is "no authority which would recognize an implied repeal of a constitutional provision because of its continued violation by public officials. The suggestion is appalling." *Id.* at 697.

As admitted by the Revenue Cabinet, primarily in reaction to *Russman* the concept of a one mil tax rate developed to avoid the tax burden for certain types of property which did not enjoy constitutional exemption but which were perceived by the General Assembly as needing *de facto* exemption in the public interest. Because unmined coal was taxed as an interest in real estate, in order to favor unmined coal with this *de facto* exemption it was necessary to employ a two-stage procedure, first classifying it separately from other real estate, and then assigning to it the 1 mil rate. The question is, of [**9] course, whether this procedure is legitimate tax avoidance or unconstitutional tax evasion; does the method instituted to avoid the constitutional limitations in Section 172 impale upon the constitutional limitations in Sections 171 and 174? In answering that question there are several arguments in the present case

that track similar arguments in *Russman*, and that are fully answered by the *Russman* opinion.

Movants argue that the 1891 Constitution is "outmoded," that the stated purpose for and definition of taxation as stated in Section 171, raising revenue "to defray the estimated expenses of the Commonwealth," fails to take account of the present need to use taxation to promote economic development, and therefore the judiciary should aid and abet the General Assembly in structuring taxation free from constitutional restraints. The Revenue Cabinet's Brief claims:

"The politics and issues of Kentucky in 1890 are as foreign to this generation as the intrigues of ancient Rome. The revenue [*360] provisions of the Constitution shackled the hand of the legislature to keep it from embracing the corrupt and polluting grasp of wealthy corporations. Today there is no need to tighten those [**10] shackles to prevent the legislature from extending a benevolent hand to others [presumably the owners of unmined coal] who honor their debt to the Commonwealth in ways worthy of legislative consideration."

The record is not convincing that circumstances today are so different that constitutional restrictions on the power of the General Assembly with regard to property taxes are no longer viable. With special interests and pressure groups seemingly better organized, better financed and more powerful than ever before, we can hardly take judicial notice that the General Assembly should be free from constitutional restraint to manipulate the tax structure to extend "a benevolent hand" to those "who honor their debt to the Commonwealth in ways worthy of legislative consideration." The proponents of the special tax treatment for unmined coal in KRS 132.020(5) have yet to provide any hard information in the record or in briefs as to how this statute benefits anyone but the coal owners. The best that has been offered is an argument that it is part of an overall scheme for taxing the coal industry in which the severance tax paid by coal producers "more than makes up" for any potential loss [**11] of revenue.

Even if we were inclined to accept as fact that the people of Kentucky no longer need protection from the "corrupt and polluting grasp of wealthy corporations" (or the power of today's special interest groups), we are not free to strike the constitutional mandate. We have no power to ignore the plain meaning of the Constitution when we believe it expedient to do so. As stated in *Russman*:

"... we are dealing with our fundamental law. It is not outdated, or obsolete, or contrary to any policy we know

of... This law today is just as vital and enforceable as it was the day it was written into the Constitution." 391 S.W.2d at 697.

Where constitutional change is needed, the process is not by legislative enactment and judicial acquiescence, but by constitutional amendment. In *Fannin v. Williams*, Ky., 655 S.W.2d 480 (1983), we were faced with powerful arguments that the constitution should be circumvented in the public interest. Nevertheless, we recognized that it was our judicial duty to declare unconstitutional a statute supplying textbooks to children in the state's nonpublic schools.

"The people of Kentucky specified by the language of the Constitution ... that [**12] the type of expenditure authorized by the statute in question should be unconstitutional. If the people of Kentucky wish to change their position in this matter, it is their right to do so.

... If the legislature thinks the people of Kentucky want this change, they should place the matter on the ballot.

... We cannot sell the people of Kentucky a mule and call it a horse, even if we believe the public needs a mule." *Id.* at 484.

The movants argue that judicial intervention in matters of taxation usurps the legislative function. The judiciary intervenes only when called upon by the litigants to settle a case in controversy. But when so called upon it is part of the exercise of this function to enforce constitutional restrictions on legislative power. The judiciary cannot abdicate its responsibility by deferring to the legislature. As stated by Mr. Justice Roberts in *United States v. Butler*, 297 U.S. 1, 62-63, 80 L. Ed. 477, 56 S. Ct. 312 (1936), in reviewing the judiciary's "responsibility to render judgment in accordance with the principles established for the governance of all three branches of the Government":

"It is sometimes said that the court assumes a power to overrule or control the action [**13] of the people's representatives. This is a misconception. The Constitution is the supreme law of the land ordained and established by the people. All legislation must conform to the principles it lays down. When an act of Congress [or in our present case the General [**361] Assembly] is appropriately challenged in the courts as not conforming to the constitutional mandate the judicial branch of the Government has only one duty, -- to lay the article of the Constitution which is invoked beside the statute which is challenged and to decide whether the latter squares with the former."

The opinion continues:

"This court neither approves nor condemns any legislative policy. Its delicate and difficult office is to ascertain and declare whether the legislation is in accordance with, or in contravention of, the provisions of the Constitution; and, having done that, its duty ends."

In *Russman*, in language expressing the same concept, our Court stated:

"In the performance of our duty we are not, by this decision, in any sense changing the law of taxation, or the tax structure, or increasing the tax burden. We are simply declaring and enforcing the law [i.e., the Constitution], and the law [**14] is made by the people." 391 S.W.2d at 700.

The original 1891 proviso in Section 171 of the Kentucky Constitution specified that all state property taxes shall be "uniform upon all classes of property." In 1915 by Constitutional Amendment this was changed to specify "uniform upon all property of the same class." We took up the effect of this Amendment in *Martin v. High Splint Coal Co.*, 268 Ky. 11, 103 S.W.2d 711, 712-13 (1937). The legislation at issue in *Martin* attempted to exempt all real property from taxation, and then to separately classify "minerals" so as to permit continued taxation of mineral estates, and coal in particular. The situation was the reverse of the present case but the principles at issue were essentially the same. We held the statutory scheme unconstitutional. We stated:

"The question is *not* whether it is competent for a Legislature to either classify or exempt property from taxation *where* there are no constitutional provisions prohibiting either classification or exemption." *Id.* at 712-13. [Emphasis original.]

In *Martin*, we explained the effect of the 1915 Amendment to Section 171. The 1915 Amendment to Section 171 did not [**15] alter the fundamental constitutional injunction that all property must be taxed. *Martin v. High Splint Coal Co.*, *supra*; *Cumberland Pipe Line Co. v. Commonwealth*, 258 Ky. 90, 79 S.W.2d 366 (1935). Nor did it authorize the General Assembly to separately classify except by distinctions related to the particular characteristics of the property relevant to the purposes of taxation, and not artificial distinctions to accommodate the economic situations of a particular industry, unrelated to taxation.

According to its legislative history, the 1915 Amendment did not generate from a perceived need to favor certain classes of property in the process of taxation. On the contrary, the perceived need was to remedy "an unfair proportion of the burden of

government [being] borne by visible property [real property and other tangibles], which cannot escape taxation, and wholesale evasion by such forms of property as are easily hidden [intangibles]." Report of the Special Tax Commission, 1909, pp. 3-4. The Report states:

"The answer is found in the experience of other States which have proved that under a reasonable tax rate [for intangibles] many millions of dollars of property, [**16] previously withheld from assessment, have been listed for taxation. For the most part, men seem to prefer to deal squarely in the matter of listing their property if they can do so without suffering what they consider unnecessary confiscation." *Id.*, p. 26.

It is difficult to understand the logical underpinnings of the movants' argument that this special tax classification for unmined coal, and this special tax treatment favoring those who own unmined coal (the one mil rate), benefits economic development. The record shows that vast amounts of Kentucky's unmined coal reserves are owned by different interests than those who mine it, process it and distribute it. Those persons and corporations engaged in the production and sale of coal, generating jobs and dollars, would seemingly have a much stronger claim on the General Assembly [**362] for protective legislation than those harboring it in its natural state. The economic development arguments presented by the Revenue Cabinet and the Kentucky Coal Association, Inc. are tenuous and speculative. As we stated in the case of *Tabler v. Wallace, Ky.*, 704 S.W.2d 179, 187 (1986):

"The only apparent basis for the present legislation is that [**17] a special class ... lobbied for a statute. ... There is no social or economic basis presented to justify a special class, only their own self-interest. Other groups similarly situated do not share in their legislative windfall. Their subjective reasons will not withstand public policy analysis." *Id.* at 187.

We conclude here, as we did in *Tabler*, that "imaginative reasons that *could* exist, without anything of a positive nature to suggest that they *did* exist, do not suffice." *Id.*

Nevertheless, if we were to assume that such arguments are valid for reasons that cannot be satisfactorily explained, the critical point in this case remains that the constitutionality of the one mil tax on unmined coal does not turn on whether the General Assembly perceived that this favorable tax treatment served a public purpose, but on whether the tax classification is constitutionally permissible within the limiting language of Section 171. Thus, as stated in

United States v. Butler, quoted *supra*, our "duty" is "to lay the article of the Constitution which is evoked beside the statute which is challenged and decide whether the latter squares with the former." 297 U.S. at [**18] 63.

Under Section 171 the stated purpose for taxation is to raise revenue which, "with other resources, shall be sufficient to defray the estimated expenses of the Commonwealth for each fiscal year." As we stated in *Atlantic Coastline R. Co. v. Commonwealth*, 302 Ky. 36, 193 S.W.2d 749, 752 (1946):

"It is always to be borne in mind that the taxing statutes are framed to produce revenue."

And in *Gray v. Methodist Episcopal Church*, 272 Ky. 646, 114 S.W.2d 1141, 1143 (1938), a levy classifies as a tax if "for purposes of raising revenue." The 1915 Amendment does not change any of the other clauses of the Constitution restricting state property taxes; it simply permits the General Assembly to tax different classes of property separately. All property must still be taxed, and this must be a *bona fide* tax, i.e., one which has for its purpose raising revenue rather than exempting property from taxation.

From the historical material that has been presented to us (e.g., statements of some individuals contained in the Report of the Special Tax Commission, 1915, Chapter 4) it appears that many advocated for broader constitutional amendment, eliminating all constitutional restrictions [**19] on state property taxes. But it is clear from the limited nature of the amendment that was finally proposed and adopted, and the subsequent rejection of more expansive amendments, such as the proposed 1932 Amendment "to provide by law that real estate and/or tangible personal property may be exempted from taxation for state purposes (See 1932 Acts Ch. 141 rejected by an overwhelming majority)," that our people have never yet favored permitting any further inroads into the constitutional limitations on state property taxes. The cases and materials available to us refute this contention. Cases advocated by the movants in urging us to a different course, such as *Delta Airlines, Inc. v. Commonwealth, Revenue Cabinet, Ky.*, 689 S.W.2d 14 (1985), are inapposite because the taxes involved are *not* state property taxes, and thus not subject to the constitutional restrictions on state property taxes.

Quite obviously the 1891 version of the constitutional mandate in Section 171, that all classes of property shall be taxed the same, was changed by the 1915 Amendment. The question is, of course, what is the nature and effect of the change wrought by the 1915 Amendment. That the intended [**20] effect was

limited is evident from the fact that only *one* change was made in state property taxes.

[*363] We are aware that a *further* change was made giving the General Assembly more power over "local taxation," to wit:

"The General Assembly shall have power to divide property into classes *and to determine what class or classes of property shall be subject to local taxation.*" [Emphasis added].

But this grant of additional power in *local* taxation simply reenforces the conscious decision to make only *one* change in the restrictions on *state* property taxes, that change being to permit property of one "class" to be taxed at a different rate than property of another.

So the question is what was accomplished by this one change in the constitutional structure limiting state property taxes? What does the Constitution mean by "classes" for purposes of ad valorem taxes? The answer rests in the general principle that constitutional provisions permitting classification *always* carry with them the limitation that the classification scheme must be *reasonable*, not *arbitrary*, and this in turn requires classification on the basis of "an appreciable relevancy to the subject" [*21] *matter of the legislation.*" *Bd. of Educ. of Jefferson Co. v. Bd. of Educ., Ky.*, 472 S.W.2d 496, 498 (1971).

The subject matter in *Bd. of Educ. of Jefferson Co. v. Bd. of Educ. of Louisville* was the constitutional limits on classification effected by Sections 59 and 60 which forbid special and local legislation. But viewed as a problem in constitutional interpretation, the issue is essentially the same as the classification problem presented by Section 171. We stated the rule thusly:

"The General Assembly may indulge in class legislation if the classification is made to depend upon natural, real or substantial distinctions, inhering in the subject matter, such as suggest the necessity for or propriety of independent legislation in regard to the class specified. A classification based upon purely artificial, arbitrary or fictitious conditions is unreasonable and will not be permitted." 472 S.W.2d at 498.

The present problem does not turn on whether real property is a super class which cannot be subdivided for purposes of taxation, although that argument has been presented. We need only decide whether a separate tax classification for unmined coal treating it differently [*22] from all other interests in real estate, including other interests with similar characteristics such as oil and gas in its natural state, is a classification that is, or is not, related to the constitutionally permissible classification

for tax purposes. If it is "[a] classification based upon purely artificial, arbitrary or fictitious conditions [it] is unreasonable and will not be permitted." *Bd. of Educ. of Jefferson Co.*, as quoted *supra*. For instance, the General Assembly could not classify state real property for taxation according to size or location rather than value because this would be arbitrary classification. Differences of a nature which permit classification for one governmental function are not transferable to permit classification for a different function. In this case the function is taxation. The classification serves no legitimate purpose to promote the governmental function directly involved.

The kind of differences that justify separate classification for purposes of state property taxation are the kind of difference that was the motivation behind the constitutional amendment, justifying separate classification of real estate and intangible property taxes. [*23] See Report of the Special Tax Commission, 1909, *supra*. See also, *Kentucky Finance Co. v. McCord, Ky.*, 290 S.W.2d 481 (1956), recognizing that the Constitutional Amendment permits the General Assembly to classify intangible personalty separately from real estate and assign a different tax rate.

There is no difference between unmined coal and other unmined minerals for purposes of taxation unless it be in movants' claim that the economic importance of the coal industry to our state, standing alone, is sufficient to justify separate classification. But this argument is fatally flawed for two reasons:

1) Assuming that coal has a special economic importance qualitatively different from any other interest in real estate, this special classification and rate for unmined [*364] coal does not promote the coal industry but only one element in the industry, the coal owners. Indeed, the moral justification advanced for excusing coal owners from taxation is that the coal producers will make up the difference for the coal industry through the severance tax. But coal owners and coal producers are often two different taxpayers, so this reasoning does not withstand scrutiny. However, even [*24] if it did the severance tax (as an excise tax) would be unrelated to constitutional restrictions on state property taxes.

2) If the difference between unmined coal and other unmined minerals is the difference in the economic importance that the coal industry assigns to itself by reason of its size, size alone does not constitute a reason for classification unless that size produces other qualitative differences related to the purpose of the classification. *Bd. of Educ. of Jefferson Co. v. Bd. of Educ. of Louisville*, quoted *supra*.

On this point movants rely on language of the court in *Delta Airlines Inc. v. Comm. Revenue Cabinet, supra*.

The *Delta Airlines* case involved an assessment for sales and use taxes against airlines of fuel and food purchases in Kentucky. The airlines claimed that the tax was discriminatory because other transportation industries, notably trucks and other motor common carriers, received different and more favorable tax treatment from the General Assembly on their fuel purchases in Kentucky. We stated:

"This Court has determined that economic factors are valid considerations which the legislature may take into account in developing a [**25] legitimate tax classification. ...

The different tax treatment for airlines, truck lines, barge lines, bus lines and railroad lines can be justified by their different competitive environment and their different significance to the overall state economy. 689 S.W.2d at 18.

But these are *excise* taxes not subject to the constitutional restrictions on state property taxes in Section 171. Making tax distinctions for purposes of promoting some perceived state economic advantage rather than for purposes related to raising revenue is permissible in taxes other than property taxes because other kinds of taxes do not involve the same constitutional restrictions. Excise taxes may be varied from one type of taxpayer to another to promote competitive conditions or some perceived state economic advantage; classification may be structured to serve some purpose other than taxation. But the tax scheme for state property taxes expressed in the 1891 Constitution and unchanged by the 1915 Amendment, was exactly the opposite, i.e., taxation is permitted for the limited purpose of raising revenue and shall not be subject to manipulation to promote any taxpayer's (or group of taxpayers') economic [**26] advantage regardless of whether the General Assembly should perceive that some other public benefit may be derived by doing so.

A case similar in principle is *City of Corbin v. Louisville & N.R. Co.*, 233 Ky. 709, 26 S.W.2d 539 (1930). In that case the governmental entity, the City of Corbin, agreed to a contract with the railroad, and enacted an ordinance, providing reimbursement of a tax assessment in exchange for permission to utilize a portion of the railroad's property in constructing a sewer system. We held the ordinance and contract unconstitutional, stating "the railroad secured ... a right or privilege denied to other property owners similarly situated. ... The ordinance was for the benefit of one taxpayer." *Id.* at 540. Here the statute is for the benefit of one group of taxpayers, those owning an interest in unmined coal, who cannot be distinguished from other taxpayers for any reason related to the purpose for

property taxes stated in Section 171 of the Constitution, which is raising revenue "to defray the estimated expenses of the Commonwealth."

The judgment of the trial court holding the statute in question, KRS 132.020(5), is unconstitutional, and the decision [**27] of the Court of Appeals affirming this holding, are affirmed.

[*365] Stephens, C.J., Lambert, Vance and Wintersheimer, JJ., concur. Leibson, J. concurs in this opinion, and also files a separate concurring opinion. Wintersheimer, J. concurs by separate opinion in which Leibson, J. joins. Stephenson, J. dissents by separate opinion in which Gant, J. joins.

CONCURBY:
WINTERSHEIMER; LIEBSON

CONCUR:

I concur with the result achieved by the majority but wish to express my reasons separately.

This case specifically involves the constitutionality of KRS 132.020 (5) which classifies unmined coal differently from other real property and provides a tax rate of \$.001 per hundred of assessed valuation.

Unmined coal in place in the ground is real property distinct and separate from the surface estate. *Williams' Admr. v. Union Bank & Trust Co.*, 283 Ky. 644, 143 S.W.2d 297 (1940). Unmined coal is subject to taxation as real property. Severance of the coal from the surface has recently been affirmed by a majority of this Court in *Akers v. Baldwin, et al.*, Ky. 736 S.W.2d 294 (1987). Section 3 of the Kentucky Constitution does not permit exemptions from taxation. Section 171 of the constitution provides that annual [**28] taxes along with other resources shall be sufficient to support the expense of government and shall be uniform. Section 172 provides that all property shall be assessed at its fair cash value, and Section 174 provides that all property shall be taxed in proportion to its value. Clearly the Constitution requires uniformity and equality in taxation.

The proper way to distribute the burdens of government justly is to allow taxation to rest equally on all. See 2 Debates, Constitutional Convention 2372-2423 (1890); *Kentucky Finance Co. v. McCord*, Ky. 290 S.W.2d 481 (1956).

KRS 132.020(5) effectively exempts unmined coal from property taxation. The evidence in the circuit court indicates that it produces almost no revenue with only \$ 2,067 being recorded in 1983 on assets estimated at between \$ 6 and \$ 12 billion. The rate, \$.001, makes it uneconomical for local PVAs and the Revenue Cabinet

to assess or collect the tax because the cost of administering it far exceeds any possible yield.

Section 171 as originally adopted in 1891 did not authorize the legislature to create different classifications of property for ad valorem tax purposes. In 1915 Section 171 was amended by the addition [**29] of the words "of the same class" to the sentence which required uniform taxation. The legislature was specifically authorized to classify property for both state and local taxation. Uniformity of rate of property in the same class was still required and there was no permission to exempt any property from taxation. *Martin v. High Splint Coal Co.*, 268 Ky. 11, 103 S.W.2d 711 (1937).

In 1976 the legislature amended KRS 132.020 by adding § (5) which imposed a separate tax on unmined coal. In 1978, the legislature reduced the tax rate for the newly created classification of unmined coal from 31-1/2 cents per hundred to .001 per hundred. The sole issue is whether the separate classification by the legislature of "unmined coal" for the purposes of taxation is invalid. Constitutional limitations prohibit only such classification which is not arbitrary and unreasonable and has no fair and substantial relation to the permissible governmental purpose of the legislation. See *Department of Revenue v. Spalding Laundry & Dry Cleaning Co.*, Ky. 436 S.W.2d 522 (1968). The classification for taxation is a policy matter for legislative determination. Ordinarily the judgment of the legislature is [**30] to be deferred to if there is any just and reasonable basis to support such a decision. The question then becomes whether it was arbitrary and unreasonable for the legislature to create a separate classification for unmined coal and to tax it at a much lower rate than that applicable to other real property. The existence of vast unmined and untaxed coal [**366] reserves does not promote the coal industry and does not provide jobs in support of the economy of the state. It is difficult to see how the creation of a separate classification and the unusually low rate of taxation serves any governmental or public purpose. Consequently the separate classification for unmined coal is arbitrary and unreasonable and has no fair substantial relation to a permissible governmental purpose.

The words used in the constitution should be given their ordinary meaning. The plain meaning of the word "tax" is a charge upon property for the purpose of raising revenue to defray the cost of government. The debates which the framers of the Kentucky Constitution of 1890 recorded clearly show that the burden of taxation should be spread widely in order to distribute the cost of government among all forms of property [**31] and that all property not specifically exempted should bear a real part of the public responsibility for financing governmental services. 2 Debates, *Constitutional*

Convention, 2372-2423 (1890). The levy imposed by KRS 132.020(5) is not truly a tax within the meaning of Section 174 of the constitution. The legislature is prohibited by Section 3 from exempting any class of property from taxation and the legislature may not do indirectly what the Constitution forbids it to do directly. *Commonwealth v. O'Harrah*, Ky., 262 S.W.2d 385 (1953).

The tax rate enacted in KRS 132.020(5) has effectively allowed the owners of unmined coal to be free of contributing to the cost of government. It results in a *de facto* exemption from property tax. The freedom to classify property does not permit the legislature to exempt property. Therefore the statute, KRS 132.020 (5) is unconstitutional.

The determination that this statute is unconstitutional does not in any way affect other sections of KRS 132.020. It is not the place of this Court to determine the adequacy of a tax rate unless such a rate is so clearly and manifestly insufficient that it becomes in fact an exemption which is prohibited [**32] by the Constitution or that it is so high as to become confiscatory and unfair.

Leibson, J., concurs with this concurring opinion.

CONCURRING OPINION BY JUSTICE LEIBSON

The majority opinion should go further and address the second major issue in the case, the constitutionality of setting a one mil tax rate for unmined coal, as established in KRS 132.020(5), under Sections 3, 170 and 174 of our Kentucky Constitution.

We should address this problem for two reasons, one theoretical and one practical:

The theoretical reason is that classification and rate are not two different problems, but interrelated elements of a single problem. Sections 170, 171 and 174 of the Constitution are parts of a single plan to constitutionally control state property taxes, constitutionalized in Sections 170-175. The meaning of the words in any one part of the constitution plan can only be grasped by considering the entire plan, not by considering isolated phrases. To analyze the constitutional challenge, we must test it against the constitutional plan, rather than any single element in the plan.

The practical reason is that the same coal interests who promoted the separate tax classification and rate for [**33] unmined coal in the first place will now move with all deliberate speed to promote legislation intended to circumvent our decision, perceiving (I believe erroneously) that by failing to address the rate issue we implicitly recognize that a one mil rate would be valid if

the class were expanded. In short, to paraphrase from *Lexington Herald-Leader Co., Inc. v. Meigs, Ky.*, 660 S.W.2d 658, 661 (1983), I "conclude that the controversy before us is not moot" and is "capable of repetition."

Separate classification of property for taxation, per se, is innocuous. It has no constitutional significance until the property separately classified is assigned a different rate. The 1976 statute setting up unmined coal in a separate classification would have been meaningless as long as this type of real property carried the same [*367] tax rate as other real property. It was the next step in the plan, the 1978 enactment assigning the one mil rate, that converted the statute at issue, KRS 132.020(5), into a constitutional problem.

Sections 174, 170 and 3 of our Constitution provide in pertinent part:

1) In Section 174: "All property, whether owned by natural persons or corporations, shall be taxed in [*34] proportion to its value, unless exempted by this Constitution; and all corporate property shall pay the same rate of taxation paid by individual property."

2) In Section 170, after specifying constitutional exemptions: "and all laws exempting or omitting property from taxation other than the property above mentioned shall be void."

3) And in Section 3 (part of the Bill of Rights), for good measure: "no property shall be exempt from taxation except as provided in this Constitution"

The one mil tax rate on unmined coal is unconstitutional because it effects a *de facto* exemption rather than a revenue raising measure, and as such it violates these provisions established for our constitutional protection. It violates the constitutional command that "all property ... shall be taxed in proportion to its value, unless [constitutionally] exempted." And therefore its constitutional shortcomings will not be overcome by expanding the separate statutory classification for unmined coal to add other (or all) unmined minerals. It would still be an exemption and not a rate.

Whereas there are other types of property, such as stocks and bonds and similar intangibles, whose value is so easily [*35] determined and assessed that a low tax rate does not make the tax unworkable and thus effect an exemption, and whereas there may well be reasons related to raising revenue that may justify a very low tax rate for such other classes of property, the effect of a one mil rate for taxing unmined minerals in general, and coal in particular, necessarily creates an exemption because of the nature of the property. This was the legal conclusion reached by the trial court in holding the tax rate was unconstitutional because it amounted to an exemption

and not a tax, and findings of fact by the trial court leading to this conclusion stand unchallenged on this appeal. These include, in pertinent part:

1) The legislative history behind the one mil tax rate proves that it was deliberately developed as a "way ... to effectively exempt a class of property without amending ... the constitution."

2) "KRS 132.020(5) effectively exempts unmined coal from property taxation in basically two ways. First it produces a 'nil amount' of revenue. For example, in 1983, the last year for which there is evidence in the record, the total yield from the levy on unmined coal was at best, \$ 2,067. This yield was [*36] on assets that in 1983 were worth approximately six through twelve billion. Second, the .001 rate makes it uneconomical and irrational for the Revenue Cabinet and the Commonwealth's Property Valuation administrators ... to assess or collect a levy because, as the evidence reflects, the cost of administering the levy far exceeds its possible yield."

3) As a result "the Kentucky Revenue Cabinet does not enforce the mandate of KRS 132.020(5) that a property tax on unmined coal be administered, and in fact sanctions the failure of many P.V.A.'s to assess 'unmined coal' for taxation. ... In 1978, prior to the \$.001 rate going into effect, some 50 counties had assessments of unmined coal on their tax books; however, by 1983, this number had fallen to 23."

The trial court concluded that the "minuscule levy imposed by KRS 132.020(5) is not a 'tax' in the sense intended by the framers"; that the "plain meaning of the word 'tax', as used by the framers ... is: a charge upon property the purpose of which is to raise revenue to defray the costs of governmental operations."

The trial court reviewed the record of the 1890 Constitutional Convention on this subject (2 *Debates Constitutional* [*37] *Convention 1890*, 2372-2423 (1890)), and concluded: "When the framers required that 'all property ... be taxed', Ky. Const. Section 174, [*368] they intended that all property not specifically exempted from taxation bear a meaningful tax burden." The trial court further concluded that a levy must be "intended to increase the net financial resources of the Commonwealth" to be a tax, and that it is not a tax if it "would not under any reasonably foreseeable set of circumstances increase the financial resources of the Commonwealth." None of these findings or conclusions are refuted by the record.

The trial court correctly applied the principle of constitutional law stated in *Commonwealth v. O'Harrah, Ky.*, 262 S.W.2d 385 (1953), that "the General Assembly

may not do indirectly what the Constitution forbids it to do directly."

The Secretary of the Revenue Cabinet expressly agreed with a statement from the 1983 Legislative Research Commission report stating that the 1978 Act reducing the rate to one mil "for all intents and purposes exempted unmined coal from the state property tax." [Emphasis added.] He conceded that this rate is "used by the General Assembly to provide [**38] tax exemptions through statutory procedures rather than constitutional amendments." The thrust of the movants' argument is that "a *de facto* exemption in taxation" is not unconstitutional because "the general constitutional principle that the legislature cannot do indirectly whatever it is forbidden to do directly" does not "apply to the field of taxation."

On the contrary, there is no constitutional difference between a tax case and any other. We are not free to ignore the plain meaning of the words providing a constitutional limitation on taxation, any more than we are at liberty to do so elsewhere in the Constitution. As stated in 71 Am. Jur. 2d, *State and Local Taxation*, § 310 (1973):

"When the state constitution limits the power of the legislature to grant tax exemptions, it will not be permitted indirectly to grant an exemption which it is precluded from granting directly."

A *de facto* exemption is no more constitutional than a *de jure* exemption.

The movants' position is best described simply as frustration with the failure of the people of Kentucky to amend their constitution to permit the General Assembly to exempt property when persuaded that to do so [**39] will advance some perceived state economic interests. In sum, the movants concede that the one mil tax rate on unmined coal is a *de facto* exemption, but argue that: (1) "on its face, KRS 132.020(5) does not contravene Section 174 of the Kentucky Constitution"; (2) the reason behind the 1891 constitutional restrictions forbidding property tax exemptions "no longer exists"; and (3) therefore the General Assembly should be permitted to manipulate the state property tax in its unfettered discretion to "promote competitive conditions and to equalize economic advantage as with other taxes not subject to the same constitutional restrictions."

The nature of the movants' legal argument can be understood from a sentence in the Conclusion to the Brief filed by the Revenue Cabinet:

"If the General Assembly decides to tax certain property at one mil per one hundred dollars of value, then those

who don't like that policy must turn to the ballot box, not to the courts."

However, when the issue is the Constitution the law is exactly the opposite. It is written in the Constitution that no property shall be legislatively exempted from taxation and the people have the right of redress to the [**40] court to enforce this principle. It is those who wish to change this constitutional principle, and not those who can persuade the General Assembly to enact an exemption, who must "turn to the ballot box, not to the courts," by seeking a constitutional amendment. The power of the people to challenge the constitutionality of tax legislation in the courts is established by *Russman v. Luckett, Ky., 391 S.W.2d 694 (1965)*. Short of constitutional amendment, the people are not restricted to registering their complaint at the ballot box or to engaging in a tug of war with special interest groups in the halls of the legislature. The constitution is the first line of protection for our people, not the last line of retreat.

[*369] In *Commonwealth v. O'Harrah, supra*, when faced with a statute that violated the terms of the constitution although arguably of great public benefit, we said:

"Constitutional provisions, whether operating by way of grant or limitation, are to be enforced according to their letter and spirit, and cannot be evaded by any legislation which, though not in terms trespassing on the letter, yet in substance and effect destroy the grant or limitation." 262 S.W.2d at [**41] 389.

We stated the rule is that "the courts may not countenance an evasion or even an unintentional avoidance of our fundamental law." *Id.* This rule applies even if the General Assembly is persuaded that the legislation serves the state's economic interests, and even though the legislation would appear to have popular support. Constitutional validity is not decided by a popularity contest.

The central fact in this case is that the format for state property taxes, including restrictions and limitations, is constitutionalized. The words of the Constitution are clear in their meaning: all property must share in the tax burden ("shall be taxed in proportion to its value") and there shall be no exemptions except those expressly enumerated in the Constitution. The record of the Convention bears this out:

"The more we investigated it the more clearly it appeared to us that all exemptions, other than the property of the Government, were wrong. An exemption is a tax levied

on a part of the citizens who have no interest in it, for the benefit of others who have

....A certain amount of money must be raised to meet the expenses of the State. If the burden is borne equally [**42] by all, it rests lightly on all. If you exempt one piece of property, the sum to be raised remains the same, and you thereby increase the taxes on every other piece of property." 2 *Debates Constitutional Convention 1890*, 2382.

The 1890 Constitutional Convention would never have been held except for the people's desire to protect themselves from legislation providing special privileges and immunities in general, and property tax exemptions in particular:

"Look at the ponderous volumes of private acts passed by our Legislature within the last few years, and enumerate the horde of railroad and other corporations which have been exempted from taxation, and allowed a variety of other special privileges, while battenning like vampires upon the substance of the people" 1 *Debates Constitutional Convention 1890*, 466.

"Except for the vicious legislation and the local and special laws of all kind and character passed by the Legislatures that have met in Kentucky for the last twenty years, that no proposition to call a Constitutional Convention could ever have received a majority of the votes of the people of Kentucky." 1 *Debates Constitutional Convention 1890*, 1482.

[**43]

We have been confronted with nonjudicial arguments advanced to uphold this legislation in the face of the constitutional challenge. The essence of these arguments is that the constitutional plan for state property taxes is outmoded and should be circumvented to permit the General Assembly to create *de facto* exemptions to further the state's economic development, and that separate classification and *de facto* exemption of unmined coal "is justified because of its economic importance to the state." The Revenue Cabinet argues that "the framers of the Constitution never imagined that the complex economics of a future day would require more exemptions" than the Constitution authorizes. These arguments are simply beside the point. Our Court must occasionally interpret the Constitution, but where its meaning is clear it has only the duty to enforce it. The Revenue Cabinet's Brief states:

"We have always *freely admitted* that in creating the one mil rates the legislature was probably trying to avoid the constitutional ban on exemptions. We make that

admission because there is nothing wrong with trying to avoid outdated constitutional [**370] provisions." [Emphasis added.]

Neither [**44] the General Assembly nor this Court has the power to decide when constitutional provisions are "outdated." This is not a question for the General Assembly to decide in the name of public policy, nor for the judiciary to vote up or down. Constitutional protections and limitations are the law until they are changed by the process of constitutional amendment.

As the trial court so stated, and the Court of Appeals affirmed, the one mil property tax rate when applied to unmined coal in KRS 132.020(5) is an exemption and not a rate, and as such violates our Kentucky Constitution. It is contrary to Sections 174, 170 and 3. Our Courts should declare it so now, in this opinion, rather than leaving the subject open for future debate in the halls of the legislature.

Further, the questions of whether the one mil rate for unmined coal is in fact an unconstitutional exemption and whether the classification was arbitrary and unconstitutional are so interrelated that they cannot be properly decided separately.

DISSENTBY:
STEPHENSON

DISSENT:

DISSENTING OPINION BY JUSTICE
STEPHENSON

The engine that has driven this lawsuit from the beginning to the majority opinion is that out-of-state corporations own large tracts of coal [**45] and pay a minimal tax on such property.

I am sure that if it was possible to tax the landholding corporations at a high rate and leave alone the thousands of relatively small-holding coal owners, we would not have the hue and cry over unmined coal taxes.

Unfortunately, the majority seized upon the "classification of property" issue and did not address the tax rate issue which apparently is the real issue raised in respondents' briefs.

It is also unfortunate that these cases caught a majority of the court in one of its "we know better than the legislature or anybody else" moods.

The result of the majority opinion is to effectively repeal the 1915 amendment to Section 171 of the Kentucky Constitution. If coal is not a reasonable

classification under Section 174, then I submit there cannot be a reasonable classification.

From the Kentucky Geological Survey, I find that Kentucky contains 40,409 square miles. The following counties in Eastern Kentucky contain coal deposits: Lewis, Greenup, Boyd, Rowan, Carter, Montgomery, Bath, Elliott, Lawrence, Powell, Menifee, Morgan, Johnson, Martin, Wolfe, Magoffin, Floyd, Pike, Madison, Estill, Lee, Breathitt, Rockcastle, Jackson, Owsley, Perry, [**46] Knott, Pulaski, Laurel, Clay, Leslie, Letcher, Clinton, Wayne, McCreary, Whitley, Knox, Bell, and Harlan for a total of 10,400 square miles.

The following counties in Western Kentucky contain coal deposits: Union, Henderson, Daviess, Hancock, Crittenden, Webster, McLean, Ohio, Grayson, Hopkins, Muhlenberg, Butler, Edmonson, Warren, Christian, and Todd for a total of 4,680 square miles and a grand total of 15,080 square miles of Kentucky. This is 37% of the total area of the state. A substantial portion of this is in Eastern Kentucky and has multiple seams. If an area of coal this large is not a reasonable classification under Sec. 171, then there cannot be such a classification.

An expert, a geologist from California, filed an affidavit for the respondents, stating that forty Kentucky counties produce coal. I prefer the figures from the Kentucky Geological Survey.

The majority opinion poses the question of whether a separate tax classification for unmined coal treating it differently from all other interests in real estate, including other interests with similar characteristics such as oil and gas in its natural state, is permissible. The question is answered with the statement that [**47] there is no difference between unmined coal and other unmined minerals for purposes of taxation.

This is apparently the basis for the holding of the majority that unmined coal is not a permissible separate classification.

The astonishing conclusion is not based on any argument advanced by the respondents [**371] or any authority from this court or geological authority. The parties in the *Moore* case do not argue the separate classification issue. In the *Yount* case, the only argument that unmined coal is not a permissible separate classification is that coal is *real estate*, and real estate is taxed at 31 1/2 cents. This argument is supported by authorities that have no application to the issue decided. We have said that when an act of the General Assembly has been attacked as violating the Constitution, "the burden is upon one who questions the validity of the Act to sustain his contentions." *Manning v. Sims*, 308 Ky. 587, 213 S.W.2d 577 (1948), and cases cited therein.

Also *Johnson, Governor v. Commonwealth, ex rel. Meredith*, 291 Ky. 829, 165 S.W.2d 820 (1942).

We have not been presented with a reasoned argument regarding the separate classification of unmined coal. I suppose [**48] that the majority can make up its own argument, stating that oil and gas have similar characteristics to unmined coal and that there is no difference between unmined coal and other unmined minerals. I am amazed and I am sure that geologists will be amazed at the statement that oil and gas have similar characteristics as coal. As a matter of fact, there are no similar characteristics. The brief in the *Moore* case makes the statement that unextracted oil and gas are both taxed at the same rate as other real property. This may be true in an oil field that has been drilled and proven, or on a tract that producing gas wells have been drilled. However, that is not true as to an undeveloped tract. It is relatively easy to ascertain a tract has coal underlying the surface. The geological surveys have fairly well located the coal measures and the area of the various seams. It is another proposition with oil and gas. Oil and gas do not necessarily remain in place; they are essentially fluids, or like air, that migrate underground. They are affected by rock pressure in the field. While geological surveys can classify large areas as gas or oil fields, if a producing well is not on the property [**49] there is no way to accurately tell whether gas or oil is present in an undeveloped acreage or how much could be present. The numerous "dry holes" on various properties attest to this, including dry holes drilled near producing wells.

First, the assessor cannot say with certainty that any undeveloped tract has gas or oil. Even if an educated guess can be made that this tract does have gas and oil, there is *absolutely* no way to *accurately* assess the amount and value. While theoretically oil and gas in such a state are taxable, the practical effect is that there is no tax at all assessed on oil and gas in a tract with no wells.

So much for the "similar characteristics" and different treatment statements. As to other minerals, we are not advised in the record what other minerals, if any, are mined in commercial quantities in this Commonwealth.

The experts in the *Moore* case seem to think that it will be easy to accurately assess unmined coal. The most amazing statement is that there have been purchases of large tracts of minerals in Eastern Kentucky and that "no corporation will commit itself to such a purchase without a thorough knowledge and appraisal of the properties." [**50] This expert obviously did not inform himself of all of the financial corpses littering the Eastern Kentucky coal fields after the 70's coal boom had crashed.

In the coal fields of Eastern Kentucky, there are from one to five or more mineable seams underlying the

surface; on some tracts the coal of one or more seams are not mineable. The value of the coal seam is affected by thickness of the seam, impurities in the seam, quality of the coal, and mining conditions such as top and bottom formations. It is beyond argument that the above characteristics and quality affect the value of the coal and that the characteristics and quality of a coal seam do change even in small tracts.

I assume that the majority which says that coal must be assessed at the same rate as other real estate would also say that unmined coal is entitled to an accurate assessment as to fair value.

[*372] If the majority will agree to this, then I predict a mess. Unmined coal has never been accurately assessed in Eastern Kentucky. With all of the variations as set out and which affect value, I predict that for all

practical purposes unmined coal cannot be fairly assessed. I do not believe the state has the available resources [**51] or will attempt to commit necessary resources for an accurate assessment. *Dolan v. Land, Ky.*, 667 S.W.2d 684 (1984), set out requirements for assessing real property. If this procedure is followed, I do not see how unmined coal on a given tract of land can be accurately assessed. After all, the assessor cannot see under the mountain, nor can he ascertain the quality, etc., which certainly affects value.

I was interested in the amicus briefs filed by the Kentucky Farm Bureau and the Chamber of Commerce. Both organizations have a right to be alarmed and now the majority opinion will effectively invalidate the various properties that the General Assembly has classified separately. They are:

Property Taxed	Tax Rate Per \$ 100	Statute
Livestock and domestic fowl	.001	KRS 132.020(1)
Farm Equipment	.001	KRS 132.020(1)
Agricultural Products	.015	KRS 132.020(1)
Tobacco	.015	KRS 132.020(1) KRS 132.200(6)
Business Inventory	.001	KRS 132.020(11)
Distilled Spirits	.001	KRS 132.020(10)
Motor Vehicles owned by Religious Organizations	.001	KRS 132.020(12)
Domestic Bank Deposits	.001	KRS 132.030(1)
Retirement Plans	.001	KRS 132.043
Alcohol Production Facilities	.001	KRS 132.020(1)
Tangible Personal Property located in a Foreign Trade Zone	.001	KRS 132.020(1)
Credit Union Accounts	.001	KRS 132.047
Leasehold Interests in Certain Industrial Buildings	.015	KRS 132.020(1)
Foreign Business Intangibles	.015	KRS 132.020(2)

[**52]

If unmined coal is an unreasonable separate classification, I do not see much hope for the above.

I see by the newspapers that a thoroughbred stallion is syndicated for \$ 35 million or more. This would produce a tax of \$ 3.50 which does not seem to bother the same citizens who protest here. The same rate of .001 applies to tobacco, etc. I await developments.

Finally, *Martin* is cited by the majority as authority. As I read *Martin* the 1915 amendment to Sec. 171 as to classifications is recognized but the case held the right to

classify did not give the right to exempt. The statute in *Martin* contained a specific exemption. *Martin* just does not furnish any authority for the majority holding at all.

This case represents what I consider to be a disturbing trend. People frustrated with inability to convince the General Assembly come to the courts with their problems. We are not wise enough to solve these problems even if we should. The majority goes off on a theory not briefed or argued and a subject about which it knows little or nothing.

I do not comment on the *rate* argument advanced in
Moore, as the majority seemed to address that issue, but

not decide [**53] it.

Gant, J., joins in this dissent.

April 26, 2001

ExxonMobil
Production

The Honorable Scott Ogan
House Special Committee on Oil and Gas
Alaska State Legislature

Dear Representative Ogan:

ExxonMobil would like to express its opposition to H.B. 190 "Natural Gas Pipeline Incentive / Gas Tax". We believe the bill is entirely unjustified and that its impact would be counterproductive to advancing gas commercialization within Alaska.

The basic assumption behind the bill appears to be that Alaskan gas producers have somehow been derelict in their attempts to commercialize North Slope natural gas, and that punitive tax action is warranted to force company action. The truth is just the opposite. ExxonMobil, as well as other producers, have actively attempted to advance gas commercialization projects since the original startup of the Prudhoe Bay field. Our company alone has spent over \$110 million in the pursuit of an economic project to develop Alaskan North Slope gas. Over the years, we've actively examined an original plan to develop a lower-48 natural gas pipeline, a LNG development concept, and the application of ExxonMobil's AGC-21 gas-to-liquids conversion technology in Alaska. These projects have not proceeded due to the inherent challenges of economically and competitively commercializing Alaska's remote North Slope natural gas, rather than a lack of company effort.

ExxonMobil is currently continuing our efforts to meet this challenge by joining with BP and Phillips in a concerted effort to try to advance a lower-48 pipeline project. The beginning stage of this effort is expected to cost over \$75 million, utilize the skills of 90 full-time employees, and tap the expertise of some of Alaska's, the U.S.'s, and Canada's top contractors and consultants. Our past and current efforts reflect a continuing commitment to develop Alaska's natural gas.

The imposition of H.B. 190's gas reserves tax would, in fact, be counterproductive to the advancement of this and other gas commercialization efforts. The passage of a punitive tax at the exact time that companies are actively examining investing billions of dollars in an Alaskan gas project can only have a chilling affect. As we and others have stressed, Alaska needs a stable and supportive business and tax environment to attract the large investments needed to commercialize the state's oil and gas resources. The tax imposed by H.B. 190 only increases the risk that must be considered in any project evaluation and suggests that

April 26, 2001

Page 2

companies should be penalized while continuing their search for an economic development option. It also creates a disincentive to search for additional gas resources, and sends a clearly negative message about the business climate in Alaska.

I urge you to oppose the passage of H.B. 190.

Sincerely,

A handwritten signature in cursive script, appearing to read "R. D. Schilhab".

R. D. Schilhab

- c. Members of the House Oil and Gas Committee
 - Representative Jim Whitaker
 - Representative Eric Croft
 - Representative Beth Kerttula



Resource Development Council for Alaska, Inc.

121 West Fireweed Lane, Suite 250, Anchorage, Alaska 99503-2035
(907) 276-0700 Fax: (907) 276-3887 e-mail: Resources@akrdc.org

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NUMBER OF PAGES INCLUDING COVER SHEET 3

DATE: April 25, 2001 TIME: 4:40 AM PM

TO: Linda Hay

COMPANY: Rep. Scott Ogawa's office

FAX: 465-3265 PHONE: _____

FROM: Owens Portman Gillas Brune Jenks

RE: HB 190

MESSAGE: Please include this in Friday's

Committee packet. Thanks!



Resource Development Council for Alaska, Inc.

121 W. Fireweed Lane, Suite 250, Anchorage, AK 99503

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April 25, 2001

Representative Scott Ogan

Chair, House Special Committee on Oil and Gas

Alaska State Legislature

State Capitol

Juneau, Alaska 99801-1182

Re: SSHB 190 — Natural Gas Pipeline Incentive/Gas Tax

Dear Representative Ogan:

On behalf of the Resource Development Council for Alaska, Inc. (RDC), I am writing to express our strong opposition to the Sponsor Substitute for House Bill 190. While our members share the Legislature's eagerness to see Alaska's North Slope natural gas resources commercialized, we disagree with the manner in which SSHB 190 deals with this issue. Furthermore, we believe this bill establishes an anti-business precedent that cuts across all of Alaska's basic industry sectors and threatens future development of our natural resources.

RDC is a private, membership-funded, non-profit trade association. Our members include individuals and leading companies from the mining, timber, oil and gas, tourism and fishing industries. Also within our ranks are local communities, Native corporations, organized labor and industry support firms. Our mission is to expand Alaska's economic base through the responsible development of the state's natural resources.

Ultimately the free-market should determine when and how Alaska's North Slope natural gas reserves are developed. As partial owner of these resources, the State of Alaska has an important role to play in this process. However, SSHB 190, rather than offering an economic incentive for development, creates an artificial deadline for commercialization of North Slope natural gas and threatens the stability of Alaska's tax regime and business environment — the bill replaces the free-market with command economy disincentives. Alaska can and must do better in encouraging economic development.

Beyond the chilling message this piece of legislation sends to Alaska's oil patch, SSHB 190 sets a precedent for future moves against other resource industries. Is the Alaska Legislature prepared to tax fish that remain uncaught, hard rock minerals that remain in the ground or trees that remain uncut? Businesses do not thrive under the threat of punitive State actions. Alaska has struggled for

decades to attract new businesses and to diversify our economy. SSHB 190 drives a stake through the heart of our pledge to be "open and ready for business."

RDC understands the Legislature's mandate with regard to Alaska's natural resources spelled-out in Article VIII of the State Constitution. Unfortunately, the net effect of SSHB 190 serves the opposite purpose. Rather than encouraging maximum use and maximum benefit, this bill sends a clear anti-development message to Alaska's resource industries. Alaska's citizens will suffer the consequences.

Alaska's Constitution coupled with the State's ownership share demand that commercialization of North Slope natural gas be given the utmost attention and deliberation. Thank you for considering our position on this important issue and please feel free to contact me with any questions or comments.

Sincerely,

RESOURCE DEVELOPMENT COUNCIL
for Alaska, Inc.

A handwritten signature in cursive script that reads "Tadd Owens".

Tadd Owens
Executive Director



Alaska Supply Chain Integrators, LLC
12150 Industry Way Building Q2
Anchorage, Alaska 99515
Bus: 907 348 1600
Fax 907 348 1652

Representative Scott Ogan

April 25, 2001

Dear Representative Ogan,

I am president of Alaska Supply Chain Integrators, which utilizes internet based software developed in Alaska to provide materials management and procurement services to companies in the Alaskan and outside markets. We have expanded to about 120 employees in our first two years and we hope to develop additional business in the near future.

I would like to voice my company's objection to the proposed natural gas reserve tax in HB 190. Alaska sits on a huge opportunity to develop its gas reserves, which represent a major share of the various producers' resource base in Alaska. Historically the producers because of economics and the lack of demand have not developed this resource. Recent world developments regarding demand have raised Alaska's chances to develop this gas, however companies cannot be expected to invest in Alaskan projects (which compete globally for development funds and user markets) when the investment risk outweighs the perceived benefit.

A gas reserve tax only increases the risks and reduces the benefits for gas owners who are diligently attempting to commercialize this resource. These companies face many obstacles and risks in their development decision. Projecting market prices over a long period of time is a substantial risk. HB 190's proposed tax would destabilize the fiscal certainty the State has provided over the last decade and sends the wrong message - as you get closer to commercialization, we will raise the "bar" and risk letting another state or country supply the needed gas resource.

Canada and Sakhalin Russia are sitting on huge gas reserves, which could service the same markets as Alaska. I believe that Alaska is in a race for development since whoever arrives first with commercialization could very well preclude further development for many years. Therefore, I would encourage the state legislature to consider "incentives" to develop the North Slope gas reserves.

I want to thank you for taking the time and energy to hear my opinion and concerns.

Sincerely,


Ronald F. Riesmeyer
President



FAXED

April 27, 2001

001-GEN-048
Via Fax 907-465-3265

Alaska State Legislative Representatives and Members of the House Oil & Gas Committee

RE: House Bill 190, Natural Gas Reserves Tax

Dear Representative Scott Ogan,

For the record my name is Mike O'Connor, President of Peak Oilfield Service Company. Peak is owned equally between Nabors Alaska Drilling and Cook Inlet Region, Inc. We currently employ approximately 900 employees.

Over the last several years, the State of Alaska, Peak Oilfield Service Company as well as many other companies have enjoyed a period of strong prosperity. The state's unemployment rate has remained low. In my estimation, this is due in large part to the positive economic environment brought about by a period of legislative cooperation and tax and regulatory stability. I know this makes a large difference as our oil and gas companies make decisions on their investment and development strategies.

House Bill 190 will change all of that, creating instability and a bad economic environment. This legislation, if enacted, will serve as a disincentive for existing and potentially new companies to make investments in the state. Anadarko is currently planning North Slope exploration and seismic studies and infrastructure development to explore for gas. At a time when so many groups are aggressively looking for ways to commercialize the gas, the suggested tax sends the wrong message.

Quite frankly, the state should be considering incentives to develop North Slope gas, instead of disincentives, such as a gas reserves tax. At a time when industry has already committed over a hundred million dollars to study and permit gas development, I find this legislation both irresponsible and punitive to the only industry that carries its weight in state funding.

I would encourage the legislature to foster an atmosphere of partnership rather than develop an adversarial relationship. The state currently owns 12.5% - why not find a partner and develop the state's percentage of the gas? Why? Because it's not economical?

Please do not pass HB 190. I look forward to hearing from you on this matter. Thanks for your time and consideration.

Sincerely,
PEAK OILFIELD SERVICE COMPANYM. R. O'Connor
President

Representative Scott Swan
Representative Fred Dyson
Fax 907 465 2199

Dear Fred,

Please note the following, when reviewing
the most burdensome bill this legislative session
is HB 190 NATURAL GAS RESERVES.

This bill seeks to force development of
natural gas whether it is economically viable
or not.

This bill effectively says "Alaska is an
UNSTABLE place to do business. This bill reminds
me of California and the Electrical Generating
Companies. This type of operation does not work.
Alaska State Legislature should be considering
incentives to develop the North Slope gas, instead
of disincentives such as the gas reserve tax. Is
this the state of taxation on other undeveloped
resources, such as mining and timber.

All businesses need stability and certainty in
Alaska economic environment to be confident in investing
large sums of money here. HB 190 proposed tax would
destabilize or disrupt the fiscal certainty the State
has provided over the last decade.

Best regards,
Tony Stewart
Eagle River, AK



FOREST OIL CORPORATION

*310 K Street • Suite 700**Anchorage, Alaska 99501**(907) 258-8600 • (907) 259-8601 (Fax)*

April 26, 2001

Representative Scott Ogan
Fax: 907-465-3265

Dear Representative Ogan:

I welcome the opportunity to provide comments on HB 190 from Forest Oil, an independent producer with significant interests in the Cook Inlet and an interest in future developments on the North Slope.

Briefly, the industry does not need legislative incentives to pursue development of the natural gas resources present on the North Slope. It is good business to do so. Additional taxes on undeveloped or underdeveloped resources would be counter productive and a bad precedent. I'm confident that the industry can work together with the lawmakers of the State of Alaska to insure that a commercially sound approach to bringing North Slope gas to the marketplace in a manner that can compete with the rest of the world in supplying energy to the consumer.

Thank you for thoughtful consideration of the input that you are receiving from your friends in the industry.

Very truly yours,

Gary E. Carlson
Senior Vice President

GEC/nc

Date Modified: 4/26/01
Date Prepared: 4/26/01
nc

April 26, 2001

Open Letter to My Friends on the House Oil & Gas Committee:

Rep. Scott Ogan
Rep. Hugh Fate
Rep. Reggie Joule

Rep. Fred Dyson
Rep. Vic Kohring

Rep. Mike Chenault
Rep. Gretchen Guess

Dear Representatives:

Re: House Bill 190 - Gas Reserves Tax

I believe the best way to make a point is by looking back at actual history.

Dateline 1989:

Tom McKay is a Drilling Engineer for ARCO Alaska (now Phillips Alaska). He is assigned to ramping up and drilling literally hundreds of wells on the West Sak Heavy Oil project.

These wells will produce oil and much needed revenues for both the industry and the state. The future is bright, and ARCO has announced major capital spending plans for West Sak. Then, the Exxon Valdez spill occurs, and the Legislature unwisely and punitively punishes the entire Alaska oil industry by passing the ELF oil tax increase.

ARCO responds by canceling all work on West Sak, and Tom McKay's job is suddenly eliminated because of an oil tax increase enacted by his own Alaska Legislature.

Hundreds of other high paying West Sak jobs are also eliminated as a result.

The bright future suddenly becomes grim.

Dateline 2001:

Fast forward to today.

Tom McKay is a Commercial Analyst for the North American Natural Gas Pipeline Group, a major joint work group consisting of BP, Exxon, and Phillips employees.

NANGPG, as it is called, is tasked with making a recommendation to the three producer companies for commercializing the gas resources on Alaska's North Slope.

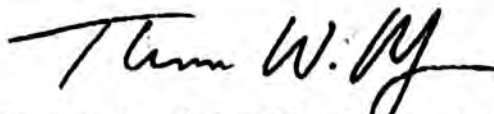
In order for this project to proceed, industry will need fiscal certainty and a stable tax policy to help bring this high-risk project into reality.

Prediction: If the gas reserves tax passes, Tom McKay's job could again be eliminated, not by market conditions, but again, by my very own legislative representatives whose primary task is to represent me and create jobs, not destroy them.

Hundreds, if not thousands of jobs could be also lost as a result if the gas pipeline is not built because of misguided government tax policy.

Please vote against HB 190. History does not need to repeat itself.

Sincerely,



Thomas McKay, P.E.
Commercial Analyst, North American Natural Gas Pipeline Group
(907) 770-8068 (work)

Our



Future

March 29, 2001

Dear Representative:

I urge you to support SSHB 190, the Reserves Tax. In 1991, the North Slope leaseholders agreed to strand our gas until at least 2005. They've spent the last ten years pretending otherwise. The Knowles Administration insists that last summer's Prudhoe Bay re-unitization eliminated these obstacles, but nobody knows for sure. Regardless, their competing projects are now beating us to our own markets. This is unacceptable. Absent the Reserves Tax, the producers won't budge.

When it comes to marketing our gas, the producers have fiddled around. The Sponsor Group LNG export study accomplished little. They said they'd spend \$75 million; they only spent \$12 million. Now, we're supposed to wait while BP, Exxon, and Phillips study overland options to the U.S., a concept facing major impediments?

Meanwhile, all three companies race to market their non-Alaskan gas. Recently, Phillips and Chevron announced separate projects that will put a combined 9 million tons of Australian LNG into California, a market that rightfully belongs to Alaska. BP just initialed an agreement to put Indonesian LNG into Mainland China and plans to develop an Egyptian LNG project, possibly for the U.S. market. Finally, Exxon strives to move Sakhalin gas into Japan.

Phillips' and Chevron's Australia-California volume would have supported a profitable Alaskan LNG project. Phillip's argues that their Australian LNG paves Alaska's way into California. Hogwash. They hijacked our market.

Make no mistake. This is a crisis. It may be only weeks before some other project usurps Alaska's rightful place in the Asian markets--and strands our gas for another decade or two. We can't afford that. Cook Inlet gas reserves are rapidly diminishing. Several studies have predicted dire consequences for Southcentral Alaska's economy, absent access to our stranded North Slope gas.

Although they claim there is no Asian market and that North Slope gas can't compete, the producers are stranding our gas precisely because there is a market and our gas can compete with the producers' foreign reserves.

The solution is obvious: We need a lever to pry our gas loose. SSHB 190 provides that lever. If the producers really are making every effort to market our gas as they insist, they will succeed, and SSHB 190 won't hurt them.

Please co-sponsor and vote for SSHB 190. This legislation must reach the House and Senate floors as soon as possible. Every hour SSHB 190 sits in Committee, some foreign project comes closer to capturing our markets, leaving Southcentral and Interior Alaska without clean-burning, affordable energy, and threatening Alaska's future.

Sincerely,

Scott R. Heyworth
Director, Our Gas, Our Future

Subject:**Date:** Thu, 29 Mar 2001 10:08:59 -0900**From:** "Scott R. Heyworth" <heyworth@alaska.net>

To: "Mike Chenault" <Representative_Mike_Chenault@legis.state.ak.us>,
"Norman Rokeberg" <Representative_Norman_Rokeberg@legis.state.ak.us>,
"Carl Moses" <Representative_Carl_Moses@legis.state.ak.us>,
"Carl Morgan" <Representative_Carl_Morgan@legis.state.ak.us>,
"Ken Lancaster" <Representative_Ken_Lancaster@legis.state.ak.us>,
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"Jim Whitaker" <Representative_Jim_Whitaker@legis.state.ak.us>,
"Con Bunde" <Representative_Con_Bunde@legis.state.ak.us>,
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"Eric Croft" <Representative_Eric_Croft@legis.state.ak.us>,
"Ethan Berkowitz" <Representative_Ethan_Berkowitz@legis.state.ak.us>

☐ #2 letter to Juneau Representatives.doc**Name:** #2 letter to Juneau Representatives.doc**Type:** Winword File (application/msword)**Encoding:** base64**Download Status:** Not downloaded with message



WARD

**Development
& Construction Management
INCORPORATED**

Friday, April 27, 2001

The Honorable Scott Ogan, Chairman
House Special Committee on Oil and Gas
State Capitol, MS 3100
Juneau, AK 99801

RE: HB 190

Mr. Chairman and Members of the Committee:

I would like to go on record as opposed to House Bill 190, which creates a gas reserves tax.

It is my understanding that the sponsor of this legislation believes creation of such a tax would somehow act as an incentive toward the commercialization of North Slope gas. Quite frankly, I believe that it would have the opposite impact.

Over the last several years, our state's economy has been strong. Unemployment has been low, and in many businesses, including mine, have experienced prosperity.

From my perspective, a major contributing factor to our state's prosperity has been the leadership you and your colleagues have demonstrated by ensuring a stable business environment by cutting government and exercising fiscal discipline. Departing from that philosophy now by considering a gas reserves tax is foolhardy.

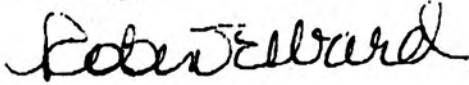
As you know only too well, the economy is strongly tied to oil and gas exploration and development. Our state's economic history has clearly shown us that when the oil and gas industry does well, so do the majority of Alaskans!

Being a businessperson in an industry as volatile as new construction and real estate, I know only too well the importance of a healthy oil and gas industry that is not afraid of investing in our state.

Let's keep the industry investing by keeping our business environment stable in the areas of taxation and regulation. All Alaskans will benefit from such.

I urge your consideration and opposition to HB 190.

Sincerely,

A handwritten signature in cursive script, appearing to read "Robin E. Ward".

Robin E. Ward



ALASKA STATE LEGISLATURE

Please enter into the record my testimony to the House Oil and Gas

Committee Name

Committee on HB 190 Natural Gas Reserves Tax Dated May 8th, 2001

Bill / Subject

I am a Carlile Transportation Systems employee living in Fairbanks and I am opposed to HB 190-Natural Gas Reserves Tax.

As you already know, a large amount of the Interior's businesses are closely related to the oil industry operating on the North Slope. This winter we were one of a few trucking firms that hauled over 1,400 truckloads of insulated pipe from Fairbanks to the North Slope. That operation alone generated a large amount of revenue, not only for Carlile Transportation, but also for the majority of businesses within the Interior. It is a project like that that keeps our skilled people in the Interior and in Alaska. We need more projects like that magnitude to train our apprentices and to keep our journeymen employed in Alaska. I do not feel HB 190 provides an incentive to generate projects like Flowlines.

I feel HB 190 is sending a negative message to the gas producers. We want to send encouraging messages to bring new business into the interior. We need to generate jobs that keep our children in Alaska and improve our quality of living. We took almost 15 years to approve the GVEA's Inter-Tie. That lengthy process sent a negative message to businesses not only in Alaska, but also outside our state. It left a foul taste in the minds of business people because it took too long to approve. We do not need any more situations like the Inter-Tie. Businesses need stability and certainty in Alaska's economic environment to be confident in investing large sums of money here. HB 190 proposed tax would destabilize and disrupt any fiscal certainty the state has provided over the last decade.

In the goal of developing Alaska, we need to generate incentives to commercialize North Slope Gas. The nature of HB 190 is a punitive penalty and it will not help in achieving the common goal of commercializing North Slope Gas. This gas reserve tax will create a poor business/government relationship, which serves as a disincentive for existing and potentially new companies to make investments in Alaska. At the time when so many organizations endeavor to commercialize the gas, HB 190 is making the effort counter productive. In looking at it another way, if HB 190 passes, what kind of precedent will it set for other undeveloped resources, such as mining and timber?

Keep Alaska opened for business. Give our children an incentive and reason to stay and live in Alaska. Do not pass HB 190.

Sincerely,

Karl I. Gohlke

SIGNED:

Karl I. Gohlke
Testifier

Carlile Transportation Systems
Representing

900 Aurora Drive, Fairbanks, Alaska 99709
Address / Phone Number

**FAX COVER SHEET**

900 Aurora Drive Fairbanks, AK 99701 Phone 907-451-7155 Fax 907-456-5889

To: Scott Ogan

From: Karl Gohlke

Fax: (907) 465-3265

Date: May 8th, 2001

Phone:

Pages: 2

Ref:

CC:

☐ Urgent ☐ For Review ☐ Please Comment ☐ Please Reply ☐ Please Recycle

-Comments:

PETRO STAR INC.

Telephone: (907) 344-2661
Fax: (907) 267-6124

201 Arctic Slope Avenue, Suite 200
Anchorage, Alaska 99518-3030

STEPHEN T. LEWIS
Chairman / CEO.

April 30, 2001

FAX Message to the Members of the House Oil & Gas Committee:

Representative Scott Ogan, Chair
Representative Fred Dyson
Representative Mike Chenault
Representative Hugh Fate
Representative Vic Kohring
Representative Gretchen Guess
Representative Reggie Joule

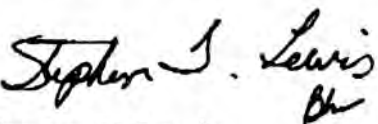
I learned about HB 190, "Natural Gas Reserves Tax", which would levy a tax on undeveloped North Slope natural gas reserves, after your scheduled hearing on Friday, April 27.

Even though I could not submit my opinion prior to or during the hearing, I would like to go on record as being opposed to HB 190 and the message it sends to current and potential new companies considering investing in Alaska's resources. The State's attitude of creating new taxes, or increasing existing taxes on natural resources, or more specifically aiming taxation toward those companies that are currently spending (or considering investing) untold dollars to develop our state resources, only creates a risky, unstable, uncertain atmosphere in which to commercialize Alaska's resources. The message being sent to the shareholders and management of these companies is that investing in Alaska is risky and the risk outweighs perceived benefits.

The commercialization of North Slope gas has almost become a reality. A group of producers has made a commitment to spend over \$75 million to determine whether there is a commercially viable project for bringing North Slope natural gas to market. Until it is economically viable to develop this or any resource, the signal you are sending is that the State of Alaska will penalize and force uneconomical resource development instead of providing incentives.

This gas reserves tax increases the risks and reduces the benefits for natural gas owners who are diligently attempting to commercialize this resource.

Thank you for allowing me to express my opinion and I respectfully request that you do not support or pass out of committee, HB 190.


Stephen T. Lewis
Chairman/CEO

PETRO STAR INC.

201 Arctic Slope Avenue, Suite 200
Anchorage, AK 99518-3030

PHONE: 907.344.2661

FAX: 907.267.6124

FAX TRANSMITTAL

Total Pages: (2)

DATE: April 30, 2001

TO: Rep. Scott Ogan	FAX# 465-3265
Rep. Fred Dyson	FAX# 465-4587
Rep. Mike Chenault	FAX# 465-2833
Rep. Hugh Fate	FAX# 465-3883
Rep. Vic Kohring	FAX# 465-3818
Rep. Gretchen Guess	FAX# 465-6615
Rep. Reggie Joule	FAX# 465-4586

FROM: Brenda L. Moser
Phone: 907.267.6110

MESSAGE: Opposition to HB 190.

* * * * *

Testimony of Jack Laasch on SS HB 190
April 27, 2001

Mr. Chairman and members of the committee my name is Jack Laasch, and I am a member of the executive board of the Alaska Support Industry Alliance. The Alliance represents those companies in Alaska that depend on a healthy oil and gas industry to provide employment for Alaskans and the sale of goods and services within Alaska.

I am writing this letter to express my views on HB 190 which proposes to enact an ad valorem tax on natural gas reserves on the North Slope.

I am opposed to HB 190 because it increases the risks that producer companies already face in developing Alaska's gas resources. It is important that companies that are instrumental in building the foundation of Alaska's economy be given every opportunity to succeed.

Alaska's Oil and Gas Industry support contractors and vendors depend on a healthy industry to provide employment and opportunities to generate revenues. These contractors and vendors also have a significant investment in Alaska.

In the past, the major producers have been willing to invest in Alaska's high risk projects. Successful development has resulted in many benefits to the communities of Alaska through contributions to charitable organizations and community enhancement projects. In addition, Alaskan companies have been contracted to provide manpower and equipment for services such as construction, maintenance, drilling, fabrication,

module assembly and many others. Since the initial discovery of North Slope gas, many hundreds of millions of dollars have been spent to commercialize this gas. Recently the producers have committed to spend an additional \$75 million on a study to determine how to bring North Slope gas to market. Many Alaskan companies will participate in this study and the subsequent contracts leading to the construction of a gas pipeline project.

I feel that the State of Alaska needs to present itself as a good partner with the industry in striving for a win win situation on both sides. In doing so the State needs to create incentives for producers to pursue commercialization of gas and hence create opportunities for Alaska's residents and the companies doing business in Alaska.

The Gas Reserve Tax does not create this incentive.

J A Larch

HB190

I'm Sally Ann Cary, Alaskan resident and Secretary of The Support Industry Alliance. I appear before you today, to offer my negative thoughts on further consideration of HB190.

If the State of Alaska is open for business this bill doesn't reinforce that message to the long term developers of our oil & gas fields nor does it foster their intent/desire to expend the enormous funds they ^{currently} spend providing jobs for workers and buying from Alaskan vendors of goods & services.

It also does not send a message to other developers & business who we would like to have coming to Alaska to pursue operations and businesses.

If this bill is what is to persist then (don't confuse) such a
"Quota and punitive" tax to only oil (which has been and
is a "major" source of Alaska's employment and revenue)
expand this ill thought bill to tax: any fish that go
uncatched, any tourist who hasn't or might visit, timber
that goes uncut and any minerals unmined! Better
yet, how about air we have not breathed!!

This tax is not an incentive; it is very much the
opposite.

Sally Ann Carey
(907-561-9977)

Testimony by Bob Stinson

Subject: House Bill 190

My name is Bob Stinson, President, CONAM Construction Company and Vice President of the Alaska Support Industry Alliance. I have a few brief comments on House Bill 190.

I do not support this bill. It is not good for Alaska because it is counterproductive to sustaining the Oil and Gas Industry. Sustaining the Oil and Gas Industry is important because it is the largest contributor to the State's economy. Passage of this bill would send the wrong message to current and future gas producers who look to the State for a stable and reasonable leasing and tax policies.

If this bill is an attempt to provide an incentive to current producers of gas on the North Slope to accelerate the Alaskan Gas Pipeline Project, I think it is at least premature, and at most could cancel the project. Let me be more specific. If there were a tax on gas reserves that are imposed by a certain date if a pipeline didn't get built, why would the current Alaskan producers spend the money to try to find more gas in the interim to increase the reserves? Why would new companies look to Alaska to explore for gas if they knew they might be taxed for any newly discovered reserves without the certainty of getting it to market? Increasing reserves helps the overall economics of the project. The more gas you have, the more money you make, and the more the State makes.

I think the best way to ensure that a pipeline gets built is to work with the producers and assist in doing the things they need to do to make the project work, not to work against them in an adversarial role. What if ANWR opened? Would prospective leaseholders there assume there might be the threat of similar taxes, and decide not to invest in exploration and production of oil and gas in a place that is already one of the most expensive places in the world to produce it? I think they might look elsewhere.

This issue is premature because the feasibility process the producers are going through now has to be done regardless of the implications of a gas reserves tax. As an Alaskan pipeline contractor, who has recently designed, built *and permitted* a pipeline project, I know how long it takes to go through the process. For an 8-mile project, it took me 16 months and 2 million dollars to work through the permitting process. The current group of Phillips, BP and Exxon has committed to doing it in roughly 9 months for a 1,900-mile project, *with* the largest gas conditioning plant in the world, compressor stations, a natural gas liquids plant and more pipelines to the Lower 48. I think we need to be patient and work with the producers through this process.

This bill does not provide an incentive to build a gas line; it provides an impediment to it, and the future of the oil and gas industry in Alaska.

**Phillips Alaska, Inc.
Testimony Against HB-190
For
House Special Committee on Oil and Gas**

Mr. Chairman, for the record, my name is George Findling. I am the External Strategies Manager in ANS Gas Commercialization for Phillips. Thank you for the opportunity to provide testimony outlining Phillips' opposition to SSHB-190, version F, a bill that would add tax and lease disincentives concerning Alaska Gas commercialization into the statutes.

For the record, Phillips joins and endorses the testimony provided by the Alaska Oil and Gas Association. My comments here are to elaborate on Phillips' perspective.

To summarize, HB-190 would negatively impact the exploration for and development of Alaska's gas resources; opportunities that Phillips is proactively pursuing. We are focussing on developing a cost competitive gas project and yet this bill would go in the opposite direction by adding costs and risks to any project.

The fundamental assertion made by supporters of this bill is that it is needed to insure timely ANS gas commercialization; suggesting that Phillips is not sincerely emphasizing and moving forward on Alaska gas commercialization. We think that the facts say otherwise.

Phillips' Prudhoe Bay gas resource represents one of the largest undeveloped assets in our company portfolio. On a pro forma basis for this year, commercializing this gas would increase our company's booked reserves by more than 30%. In fact, in Phillips, Prudhoe Bay gas is what we call a "legacy asset"; if you will, one of our crown jewels. This has motivated Phillips to deploy substantial resources to prudently commercialize this asset in the shortest practical time. Further, I can assure you that the top executives in Phillips are engaged in this effort on Alaska gas.

After substantially increasing its interest in the Prudhoe Bay gas last year through its purchase of the stock of ARCO Alaska, Inc., Phillips, in concert with the BP and ExxonMobil, immediately initiated the now \$75 million North American Natural Gas Pipeline effort. The vision is to commercialize ANS gas via an overland pipeline to the L-48/Canadian market. As stated in the past, Phillips sees a fundamental improvement in the supply/demand picture in this large and growing market. We see a very real opportunity for ANS gas to be placed in the market, if a cost competitive pipeline system can be achieved. Phillips simply does not accept the assertion from the nay-sayers here in Alaska that this North American market opportunity is not real, and that this market will be captured by others. The strength of our conviction is demonstrated by the magnitude of our commitment of time and money into the effort.

Despite our optimism about the L-48 gas pipeline opportunities, Phillips has not ruled out other options. We continue to lead the Alaska North Slope LNG project. This \$15 million effort was initiated in 1998 and the Sponsor Group has made significant strides

by designing a project sized for reasonable market entry. Currently the Sponsor Group is focussed on commercial ways to next try to make this market entry project cost competitive. We want to position Alaskan LNG so that it can capture the Pacific Rim market opportunities that we believe may develop later in the decade.

In concert with the other major producers and other companies, no one is deploying more monetary and human resources to advance Alaskan gas commercialization.

An argument made by supporters of this bill is that if Phillips is sincerely and expeditiously commercializing gas, then there should be no concern, since the tax will never take effect. The problem with this line of thinking is that it does not consider all of the unforeseeable circumstances and unintended consequences that are likely to arise. These would be both out of the leaseholder's control and would frustrate our good faith efforts to commercialize the gas.

Under U.S. and Canadian laws, there are many mechanisms available to people, such as the anti-development environmentalists, to impede projects. It is realistic to imagine cases where these mechanisms are used in Alaska in the belief that greater revenues at a lower impact could be generated by triggering a gas reserves tax before the project can be realized. We can not see how it helps a project to penalize leaseholders with a tax for events out of our control. We firmly believe that there are many other unintended and negative consequences like these lurking in HB-190.

The gas sales requirements of HB-190 also are very raise additional concerns. As drafted, the bill seems to contemplate gas sales will be only be to middlemen who have some permit position rather than directly to end users or established brokers. Basically, these provisions would frustrate the operation of a free market by artificially shifting the negotiating power away from the state royalty and gas owners to a limited class of middlemen, who may have no demonstrated market. We wonder how the state can realize the highest wellhead basis for tax and royalty purposes if lessees are to sell at artificially low wellhead values under the combined influence of a limited class of permissible buyers and the specter of a gas reserves tax.

HB-190 also has flaws relative to the lease revocation provisions. Alaska long ago adopted bonus bid leasing on state specified tracts as the method to induce private parties to acquire the right and burden of exploring for and developing state oil and gas resources. The first step of this process is the competitive lease sale. A fundamental underpinning of the lease sale is that the lease terms are known as the bid is being prepared. The amount of the bid, in part, reflects the value of these terms. In reliance on the terms of the leases, the lessees then expend considerable sums to explore for and develop the leases and to market the production. It would be neither fair nor prudent for the State to change the rules now, on existing leases, after the lease sale, and after substantial investments, by imposing a requirement that the lessees enter into a gas sales contract with a middleman as a condition to continued lease retention.

Phillips also believes that requiring a gas sales contract with a middleman, as a term in new oil and gas leases, will have a long term chilling effect both on the size of bonus bids as well as the overall interest in leasing and exploring in Alaska. For example,

companies will factor in to their bids that they might lose their interest in an oil prospect that they are expeditiously developing in good faith because of an arbitrary requirement for a sales contract with a middleman for any gas associated with the oil. Further, one would wonder whether any company would have any motive to acquire oil and gas leases if such a law were on the books.

To summarize, commercializing Alaska's North Slope Gas resources will require developing a cost competitive project that can secure a sufficiently large market. Phillips is sincerely and constructively going in this direction, but we certainly see HB-190 as contrary to our efforts. HB-190 would discourage, not encourage commercialization of Alaska's gas resources because it necessarily would increase not decrease costs, uncertainties and risks. HB-190 would have many unforeseen and negative impacts: it would lead to instability and uncertainty. A project simply can not be taxed into existence. Despite its title, HB-190 is a disincentive act.

Mr. Chairman, thank you again for providing Phillips with the opportunity to express our opposition to HB-190. I would be glad to respond to any questions.

ALASKA MINERS ASSOCIATION, INC.

3305 Arctic Blvd., #202, Anchorage, AK 99503 Ofc 907-563-9229 Fax 907-563-9225
email ama@alaskaminers.org www.alaskaminers.org

TO: Name: House Oil & Gas Committee

Fax: (907) 465-3265

FROM: Tom Crafford

Fax: (907) 563-9225

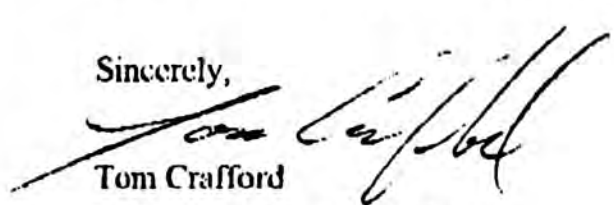
SUBJECT: Testimony RE: SSHB-190

Dear Chairman Ogan and Members of the House Oil & Gas Committee:

Due to the number of individuals testifying at the teleconference this morning, the Alaska Miners Association was unable to present its testimony re: SSHB-190. Following are the written comments that the AMA was prepared to read into the record at that time. We respectfully request that these written comments be incorporated into the record.

Thank you for the opportunity to comment.

Sincerely,


Tom Crafford

Executive Director, Assistant

PAGES TO FOLLOW 2 (Not including this cover page.)

Testimony of the
Alaska Miners Association
To the House Oil and Gas Committee
Re: SSHB-190

April 27, 2001

Mr. Chairman and members of the House Oil & Gas Committee, Thank you for the opportunity to testify today regarding HB-190. My name is Tom Crafford and I am here today representing the Alaska Miners Association.

The Alaska Miners Association does not ordinarily 'weigh-in' on Oil & Gas issues, but the AMA's objections to SSHB-190 are so strong, and our concern that this bill could establish a bad precedent that might spill over to other resource industries, including mining, is so severe that we felt we should clearly express our opposition to SSIIB-190.

A fundamental concern is that in situ taxation of any resource is bad public policy. By discouraging the thorough evaluation and delineation of a resource in advance of its development, in situ taxation fosters inefficiency and waste, the direct opposite of what SSIIB-190 purports to support. But beyond that, SSHB-190 sends the message to all resource industries that the State of Alaska is ready, willing and able to change the rules in the middle of the game. This is not a message that will attract and encourage resource industries to invest in Alaska. In recent years, American mining companies that had focussed their exploration and development efforts in foreign countries have been returning to the US because foreign countries did not provide the political, fiscal and regulatory certainty that they had come to rely upon. Legislation like SSIIB-190 goes a long ways towards eliminating a major advantage that Alaska has over much of rest of the world. With today's global competition for investment dollars, this simply does not make sense.

I know that others here are similarly testifying in opposition to in situ taxation and to the punitive approach of SSHB-190, so I would like, instead, to address my remaining comments to a different troubling point. Section 3 not only requires a lessee to agree to a lease amendment requiring the lessee to enter into a gas sales contract as a condition for extending the lease, but it establishes an extremely awkward arrangement wherein the lessee must sell

to the 'qualified bona fide purchaser' who, in the commissioner's opinion offers the 'greatest long-term return to the state.' You don't have to think too hard to figure out how a petroleum company, or any company for that matter, is going to react to having the state tell them who they must sell their product to.

Furthermore, this creates the potential for business conflicts and expensive, time-consuming legal challenges. Non-governmental organizations seeking to halt or delay gas development could file suit claiming that a sales contract did not provide for the greatest long-term return to the state. Losing bidders could file similar challenges. A producer could conceivably be forced to sell its product to a subsidiary of its major rival. None of these are situations that promote the timely and efficient development of a resource.

I hope these comments have helped to illustrate the flaws in SSIIB-190 and have helped to convince the committee that SSIIB-190 is bad for the Oil & Gas industry, bad for resource industries in general, and bad for the State of Alaska and its citizens.



Alaska State Legislature

Please enter into the record my testimony to the HOUSE OIL & GAS
committee name

Committee on HB 190, dated 4/27/01
bill # / subject

- Brian Quesnel
Lived in Kenai / Nikiski 32 years
- Airgas, 4 employees

- I am able to live here and raise my family here due to a direct relationship with the exploration and development of oil and gas reserves.
- We should be encouraging more development of these reserves, not discouraging the very ones that provide financial backbone to this State.
- By levying a penalty tax like HB190 are we trying to tell the major investors of this state we know when to spend their money better than they do? These companies like all the support companies and industries have one thing in common and that is to make a profit. Who do you think does a better job of knowing when to invest money? Those who own the money or those who only want to control the money?
- Big oil has spent billions of dollars in this state in high-risk projects. Now let us let them decide when to bring these reserves on line, even if it is possible to bring them on line. They know when to spend their money in the most fiscally responsible way.
- Lets provide a friendlier environment for future exploration and development by providing incentives rather than punishment. Alaska's future depends on stability and certainty with regard to encouraging confidence in investing large sums of money here.

I URGE YOU TO VOTE AGAINST HB 190

- Thank you

Signed:

Brian L. Quesnel
Testifier

AIRGAS, INC. / ALLIANCE
Representing (optional)

PO Box 1225, Kenai, AK 99611
Address

907-283-6118
Phone number



Alaska State Legislature

Please enter into the record my testimony to the House Oil & Gas
committee name

Committee on HB 190, dated 4-27-01
bill # / subject

The oil & gas industry is the largest in the Kenai area, employing about 700 people directly with over \$60,000,000 in payroll and spends well over \$200,000,000 for goods and services. The industries total impact is 4,273 jobs with \$176,000,000 in payroll. The Oil & Gas industry is also the largest benefactor to non-profit organizations. With that said, why would we want to force these companies to develop a resource when the risk may be higher than the reward? With this bill, these companies are being asked to invest in projects when the risk may outweigh the perceived benefits. Remember, Alaska is still competing world-wide for investment dollars and we should continue providing incentives, not dis-incentives. The proposed gas tax is more like a punitive penalty and will not help achieve the goal of commercializing North Slope gas. Alaska needs to continue providing a stable economic environment as it has for the last decade. Let's not start plucking the feathers of the goose that lays the golden eggs.

Signed:

Jim Evans
Testifier

THE ALLIANCE KENAI PENINSULA
Representing (optional)

PO Box 2932 KENAI, AK 99611
Address

283-7141
Phone number

**AkPIRG****Alaska Public Interest Research Group**P.O. Box 101093
Anchorage, AK 99510507 E Street, Suite 213
Anchorage, AK 99501p: 907.278.3661
f: 907.278.9300

HB 220 – Exploration and Development Incentive Tax

Mr. Chair and Members of the House Special Committee on Oil and Gas:

AkPIRG, the Alaska Public Interest Research Group, opposes this bill for two reasons. First, in a time of fiscal shortfalls, this bill would give a tax break to developers who don't need it. Energy costs have been skyrocketing in Alaska and across the nation. Large oil and gas companies are posting record profits and do not need these types of incentives to continue exploration.

In fact, such tax incentives continue the State down the wrong path. The State should be providing incentive tax credits for capital investments and annual service costs of projects that relate either to **energy efficiency** or **alternative power generation**. Both of the avenues have been proven economically beneficial as well as environmentally preferable. Alaska successes are sparse in the realm of alternative energy but they provide ample examples of what can be done. A small wind farm up in Kotzebue is providing power to 200 homes up there at a cost cheaper than the state-subsidized diesel. The state expends \$15-17 million a year in order to make this inefficient fuel available to the bush. Clearly it is time to change. The Anchorage Post Office Processing Center is powered by the largest fuel cell generator in the nation. It is producing so much power that it sends it excess back to the grid. Both of these project examples can be scaled down to fit the needs of individual home owners.

These are the types of projects for which Alaskans should receive tax incentives. We urge you to vote against this legislation.

HB 190 – Alaska Natural Gas Pipeline Incentive Act

AkPIRG supports HB 190 because this forward-looking legislation is an effort to ensure that Alaska's resources remain the property of Alaskans. This guarantees that Alaskans will continue to receive its share in the development of these resources. In addition, it will provide for the natural gas and energy needs of Alaskans directly from the North Slope.

This is an attempt to ensure the cost to North Slope producers not to commercialize, delay commercialization, or inhibiting commercialization of North Slope natural gas is prohibitive, that is, this would prohibit companies from accruing value on commercially-viable natural gas by sitting on it in the ground.

A policy on non-commercialization, delaying commercialization, or inhibiting commercialization when commercialization is economically feasible is contrary to the spirit and intent of the Constitution of Alaska and will not benefit Alaskans. It will only serve to increase the profits of gas producers who wish to increase their share of Alaska's wealth.

We urge quick passage of this bill.

FAX 415-3265

Thank you Mr. Chairman for allowing me the opportunity to speak.

My name is Matthew Fagnani and I am president of WorkSafe, Inc. I am here to offer testimony ^{on} ~~or~~ HB 190, Natural Gas Reserve Tax. I would like to think that, as a business operator here in Alaska, I represent a very important constituent. We are small companies that are not oil service companies, yet we service oil service companies. My business is dependent on a healthy oil and gas, transportation, tourism, fishing and mining industries, among others.

I have been involved in working with the Alaskan economy since I left the military in 1992. Alaska is a beautiful place to live but does offer unique challenges to companies who choose to be involved in the Alaskan economy. As Alaskans, we are faced almost daily with ~~the~~ extreme issues and higher costs of just being remote from the rest of the lower 48 states. We have limited options to grow and expand our customers to surrounding states because of our remoteness.

Because of this, when I read about legislation like HB 190- "Natural Gas Reserve Tax" it worries me. It concerns me that oil and gas

companies will find that Alaska is not a stable market to work in. Businesses need stability and certainty in Alaska's economic environment to be confident in investing large sums of money here. HB 190's proposed tax would de-stabilize or disrupt the fiscal certainty the State has provided over the last decade.

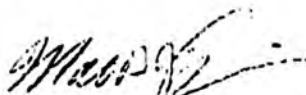
I would prefer that the Legislature work on issues that offer incentives ^{bill like this which can be viewed as} to develop the North Slope gas instead of disincentives. Incentives will put Alaskans to work. It would show that we are serious about being open for business.

^{were}
If this incentive/gas tax ~~was~~ on the other foot and you were the company being asked to develop a resource before its time and market, how would you react? As you are all aware, a business decision needs to make economic sense. These projects need to stand on their own merit. If the numbers add up, then Alaskans will have a project. The oil companies have invested billions of dollars in developing commercially viable projects. It would appear to me that they would do the same with natural gas once it becomes a viable project.

I am also concerned that this type of legislation is just bad for the State. I fear that this type of legislation would hamper growth and future interest in Alaska Project. My company and that of the other businesses in Alaska need a progressive and viable oil and gas project. *Industry.*

I would urge you to not let this bill pass out of this committee. Send a message to Alaska business that we are open for business.

Thank you for allowing me the opportunity to speak.


Matthew T. Fagnani

President

WORLD SALES, INC.



Alaska State Legislature

Please enter into the record my testimony to the House Oil & Gas Committee
committee name

Committee on HB 190, dated 4/27/01
bill # / subject

Alaska oil, north slope gas representatives make-up a major share of the development of natural gas that would go to market. These Company's can not be expected to develop a project that doesn't generate margins needed to be viable. The State needs to give incentives and tax breaks so companies and other businesses will invest more in the state via facilities & jobs for Alaskans. This tax bill don't promote good business relations from the States stand point. And I oppose this Bill HB 190

Signed: Todd Pizzuto (Todd Pizzuto)
Testifier

Representing (optional)

Box 8113 NIKISKI, AK 99635
Address

907-776-8441
Phone number

Forwarded Message:

Subj:	HB 190
Date:	4/26/01 11:42:07 AM Alaskan Daylight Time
From:	TRMJR1
To:	Representative Scott Ogan@legis.state.ak.us

I am very much opposed to this bill. It will certainly discourage gas exploration at a time when proven reserves on the North Slope are grossly insufficient to supply either the Highway Pipeline or the Valdez LNG schemes. Proponents of this bill say the gas owners are warehousing North Slope gas but never mention that every day gas liquids worth \$1.5 million are recovered from the reinjected gas produced with oil at Prudhoe Bay and the natural gas based pressure maintenance project has increased ultimate recovery 35% yielding a \$95 BILLION increase in the value of oil production. Gas in the ground at Prudhoe Bay is far better for the State than money in the bank. Nationwide, natural gas sold during the first quarter of 2001 averaged \$6.45 mcf, 2 1/2 times the average price of \$2.46 during the first quarter of 2000! Thank Heaven our gas has been saved on the slope instead of being sold for "peanuts" in money losing export schemes.

I worked for an independent gas producer in Wyoming in the early 1950's when a reserves tax was proposed by the livestock interests after a heavy late spring snow had decimated the lamb and calf crop. The proposed tax was dropped when the ranchers realized that counting reserves was not at all like counting sheep because there can be a wide difference of opinion among qualified reservoir engineers and geologists due to uncertain well control, interpretation of gas in place, and reservoir continuity. The ranchers withdrew the bill after deciding it could become a Reservoir Engineers Job Security Act.

Thank You.

Tom Marshall

Retired Petroleum Geologist and former State Land Selection Officer



Resource Development Council for Alaska, Inc.

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Founded 1973

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April 25, 2001

Representative Scott Ogan
Chair, House Special Committee on Oil and Gas
Alaska State Legislature
State Capitol
Juneau, Alaska 99801-1182

Re: SSHB 190 — Natural Gas Pipeline Incentive/Gas Tax

Dear Representative Ogan:

On behalf of the Resource Development Council for Alaska, Inc. (RDC), I am writing to express our strong opposition to the Sponsor Substitute for House Bill 190. While our members share the Legislature's eagerness to see Alaska's North Slope natural gas resources commercialized, we disagree with the manner in which SSHB 190 deals with this issue. Furthermore, we believe this bill establishes an anti-business precedent that cuts across all of Alaska's basic industry sectors and threatens future development of our natural resources.

RDC is a private, membership-funded, non-profit trade association. Our members include individuals and leading companies from the mining, timber, oil and gas, tourism and fishing industries. Also within our ranks are local communities, Native corporations, organized labor and industry support firms. Our mission is to expand Alaska's economic base through the responsible development of the state's natural resources.

Ultimately the free-market should determine when and how Alaska's North Slope natural gas reserves are developed. As partial owner of these resources, the State of Alaska has an important role to play in this process. However, SSHB 190, rather than offering an economic incentive for development, creates an artificial deadline for commercialization of North Slope natural gas and threatens the stability of Alaska's tax regime and business environment — the bill replaces the free-market with command economy disincentives. Alaska can and must do better in encouraging economic development.

Beyond the chilling message this piece of legislation sends to Alaska's oil patch, SSHB 190 sets a precedent for future moves against other resource industries. Is the Alaska Legislature prepared to tax fish that remain uncaught, hard rock minerals that remain in the ground or trees that remain uncut? Businesses do not thrive under the threat of punitive State actions. Alaska has struggled for

decades to attract new businesses and to diversify our economy. SSHB 190 drives a stake through the heart of our pledge to be "open and ready for business."

RDC understands the Legislature's mandate with regard to Alaska's natural resources spelled-out in Article VIII of the State Constitution. Unfortunately, the net effect of SSHB 190 serves the opposite purpose. Rather than encouraging maximum use and maximum benefit, this bill sends a clear anti-development message to Alaska's resource industries. Alaska's citizens will suffer the consequences.

Alaska's Constitution coupled with the State's ownership share demand that commercialization of North Slope natural gas be given the utmost attention and deliberation. Thank you for considering our position on this important issue and please feel free to contact me with any questions or comments.

Sincerely,

RESOURCE DEVELOPMENT COUNCIL
for Alaska, Inc.



Tadd Owens
Executive Director

I would like to thank the ^{4th} ^{and} committee for letting me testify

My name is Jim Plaguet, I am a former business agent for the Operating Engineers Local 302, currently I am a heavy equipment operator member of local 302 ~~and~~ ^{and worked} in Prudhoe Bay this past winter. This winter organized labor had many Prudhoe Bay projects with B.P. Exploration and Phillips Alaska. Prudhoe Bay projects this past winter employed over 700 ^{plus} Fairbanks workers that helped support their families ^{financially}. Besides creating job opportunities, supporting local businesses ~~and~~ ^{and} bring business to Fairbanks companies, it further strengthen our community.

It took Alaskans working together with the industry to build the trans-alaskan pipe line and bring Prudhoe Bay oil to market. Many Alaskans

(2)

worked very hard to make the pipeline a reality. Future opportunities such as gas commercialization can only happen if there is a commitment from Alaskans and the industry to achieve our goals by working together.

We as Alaskans should be looking for ways to make development of our gas more economical, rather than seeking ways to thwart future development. Alaska should be open and ready for business and willing to provide a regulatory and tax climate in which we can compete in the global market.

I'm optimistic that as long as we make production of oil and gas in Alaska economically attractive the industry like any for profit

corporation, will aggressively pursue development of new oil fields in Alaska as well as commercialization of North Slope gas. Economically, Alaska and its residents need this continued investment from the oil industry. Working together we have seen projects recently such as Alpine, Tarn, Badami, Northstar and most recent the Meltwater oil field development. Thousands of Alaskans have worked on these projects to support their families. The industry has invested billions of dollars in Alaska. Working as a partnership with Alaskans I think they'll invest billions more.

HB 1903 proposed tax will not help in achieving our common goal of commercializing North Slope gas.

Working ~~to~~ together as a partnership will ^{achieve our common goal} and Alaskans will continue to have a bright future. Thank-you

Representative Scott Ogan, Chair

Representative Fred Dyson, Representative Mike Chenault, Representative Hugh Fato, Representative Vic Kohring, Representative Gretchen Guess, Representative Reggie Joule

Lady and Gentlemen:

My name is Maynard V. Tapp of Hawk Construction Consultants, Inc. I am also on the Board of the Alaska Support Industry Alliance (The Alliance). I have over 25 years experience in the oil and gas industry including construction of the TAPS line, international work, and over 15 years experience in Alaska.

We all agree that commercialization of Alaskan gas will be excellent for the State of Alaska, the United States, and the environment.

I think we can agree that the producers are in the business to make money from their share of resources located here in Alaska. Gas commercialization must be able to make a reasonable return on this investment (some say as high as \$18 billion). I believe the producers are ready and willing to make the commitment. It makes good business sense.

Historically, the oil and gas industry has averaged about 4.5-6% net income from their investments. If all they wanted to do is make money they could invest in the stock market which averages about 14% per year since 1900. Thankfully, they recognize the importance of this resource (oil and gas) as a major contributor fueling the economy of Alaska, the USA and the world.

These companies make investments where years if not decades elapse prior to their gaining any return on their investment. The significant amounts of money and effort involved in bringing a project of this magnitude to market is not easily justified to those holding the purse strings. The last time a group attempted to put together this project was during the Carter Administration. I have been told up to \$250 million was expended in that effort. **Who reimbursed the producers for that expenditure?**

Currently a reported \$75 million dollars is committed to study the feasibility of bringing gas to market.

By introducing a tax on the reserves on the North Slope of Alaska, we could destabilize a very sensitive calculation used to determine the viability of this project. It sends the wrong message to Alaska's partners, that we Alaskan's are so ready and willing to tax any thing that moves (or doesn't move).

Alaska's problem is its need to raise revenues to cover our state operating expenses. If we use President Reagan's and our current President Bush's models for raising public revenues, it is **NOT BY RAISING TAXES**. Is there a way the Alaska Legislature can facilitate stimulating capital investment and thereby benefiting from the growth. The governors mantra of being "open and ready for business", should guide our policies and public agenda.

We need to find ways to encourage development not scare it away.

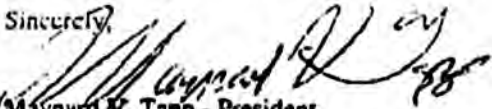
1. In the mid 1990's the State of Alaska commissioned a report by Dr. Pedro Van Moers (sp). In this report he felt that a **Tax Holiday** (property tax) would help bring gas commercialization closer. **WHY NOT FIND A TAX INCENTIVE RATHER THAN A TAX DISINCENTIVE?**
2. Does the State of Alaska have a proactive plan or organization in place to encourage gas commercialization?
3. Have we "partnered" with the Federal and Local governments to determine the fastest way to bring this project online as soon as possible?
4. Is there an office of "one-stop shopping" for the producers to go to for applying, mitigating, resolving problems associated with the project?
5. I personally have experienced a project in Alaska, where the Federal and State agencies had different agendas, and expectations. Has the state and federal government proactively addressed these issues?

All Alaskan's must work together to build an unbreakable foundation for our Oil and Gas industry.

As stated by former President Bush "**READ MY LIPS.... NO NEW TAXES**" or, to coin a new phrase "**RAISE PRODUCTION... NOT TAXES**"

Thank-you for your time and consideration.

Sincerely,


Maynard V. Tapp - President

HAWK CONSTRUCTION CONSULTANTS, INC.

Testimony before House Special Committee on Oil and Gas

**Provided by NANA Development Corporation
Friday April 24, 2001**

Chairman Ogan, members of the committee, for the record, my name is Joe Mathis, Senior Operations Manager for NANA Development Corporation. I appreciate the opportunity to testify today and provide the position of NANA Development Corporation in opposition to HB 190.

NANA Development Corporation is a major employer and contributor to the economy in Alaska. We employ 1,500 people who work for NANA's 35 subsidiary companies and business affiliates, 30 per cent of which are heavily involved in working with the oil industry. Our businesses are focused on generating profits and providing opportunities for 10,000 shareholders represented by our parent company, NANA Regional Corporation.

NANA is a leader in developing resources in the State of Alaska. Our corporation is the owner of the resources at the Red Dog Mine, the largest zinc deposit in the world, and a partial owner of the Endicott oilfield which, as you know, also contains significant gas reserves. Because of our status as a broad resource developer in the state, NANA would be negatively impacted by this legislation, as would the producers that are partners with NANA in generating economic prosperity in Alaska. It is NANA's view that HB 190 does the opposite of what the sponsors intend, which

is to facilitate the commercialization of North Slope natural gas. In fact, the imposition of a tax, if the gas were not commercialized within what seems an arbitrary time frame, would add to the risk of bringing the gas to market. Producers are already trying to get the resource to market as quickly as they can but certain economics have to be in place for commercialization. As you know, the producers have joined together to determine whether there is a commercially viable project for bringing the gas to market.

The most concerning aspect of the legislation is the dangerous signal its passage would send to all resource development activities.

Anytime there is a tax on resource reserves; there is a disincentive to explore. Exploration, already the highest risk dollars is discouraged because Alaska has decided it is willing to tax people on the product of exploration regardless of their ability to produce it. The legislation would create an environment of fear on the part of producers of all other undeveloped resources, whether oil or minerals.

In the case of Endicott, if HB 190 becomes law, NANA and other producers are going to be discouraged from exploring for more oil or gas because of the probability of also discovering gas that could be taxed even if it is not commercialized or exempted from the legislation in AS 43.58.220 (for consumption, field operations, or sold for use in production activities). NANA already pays the state a 20 percent royalty and 80 percent of the net profit from oil production at Endicott. Our analysis is that

applying these types of taxes to the existing or new gas reserves discovered may absorb most of NANA's profit on that field. This certainly doesn't encourage us to invest more money.

NANA's position is that it is simply bad public policy to consider carving out a tax on just one resource.

We are equally concerned about the potential of a future tax on mineral reserves or other undeveloped resources that the Legislature decides should be commercialized. There is a multitude of resources in remote areas that could be of great benefit to the state if developed but, again, the economics must be favorable for the producers to bring those resources to market. More important, they need to be found in the first; and less will even look if they think they will be punished for success.

I urge members of the committee to abandon this legislation and let the producers group complete their feasibility studies of the gas project. Why establish an antagonistic relationship between the state and producers before we even have information about the feasibility of the project?

We are in a competitive world; the Legislature should be in the role of providing incentives to develop the North Slope gas, instead of a disincentive such as the gas reserve tax.

Thank you for the opportunity to provide comment.

*Read
into the
Record*

Testimony regarding HB 190 before the House Oil & Gas Committee

April 27, 2001

Mr. Chairman and esteemed members of the Committee.

My name is Mary Shields and I am General Manager of Northwest Technical Services.

Northwest Technical Services provides long and short term contract and temporary employees in the State of Alaska both within and outside the oil industry. Last night we held our 20th Anniversary celebration; we have been actively involved in many work and civic related activities in our State for all of those years.

Upon reading this proposed piece of legislation, I became very concerned that the tax stability we have fought so hard to achieve in Alaska could be seriously eroded. How can we expect companies to invest in projects when the risk – a gas reserves tax - outweighs the probable benefit?

This is a lose/lose situation: it is certainly a disincentive for any firm to move forward with new exploration until a guaranteed method of transporting the gas to market is operational and it is not the way to keep Alaskan's working.

The companies involved in exploration and development in Alaska have not shied away from high-risk projects. If they had, the North Slope fields would have never been developed; exploration would have stopped before the discovery of Prudhoe Bay.

Over the years companies have spent millions of dollars in the search to find a way to commercialize our gas resources and are now in the process of spending \$75 million or more to determine whether there is a commercially viable project which will bring the North Slope Gas to the market.

**Testimony of the
Alaska Support Industry Alliance
On SSHB 190
Before the House Oil and Gas Committee
April 27, 2001**

Mr. Chairman and members of the committee. My name is Larry Houle and I am the General Manager of the Alaska Support Industry Alliance. The Alliance membership consists of 400 contractors, suppliers and individuals that provide products and services in support of the Alaska Oil and Gas industry. Our membership collectively represents almost 30,000 people working in Alaska; over 25,000 are year around Alaska residents.

None of the oil producing companies are members of the Alliance. Instead, we are the 25,000 working men and women that weld pipe, clean rooms, drill wells, drive machinery, day in and day out in Alaska's oil patch.

I am here today to confirm The Alliance's opposition to Sponsor Substitute for HB 190, a bill that proposes to tax Alaska's proven gas reserves on state leases purchased by private companies. House Bill 190 represents a huge disincentive; in fact, it is a deterrent to those Producer Companies that are today working to commercialize North Slope natural gas.

Labeled as an "incentive" we see the bill as punitive, representing poor public policy. To tax proven reserves even before they are pulled from the ground sends a strong signal to the world that Alaska is no longer "open for business." We believe the precedent set by a gas reserves tax goes beyond gas and in fact is a threat to future natural resource development in Alaska.

If this Alaska legislature is willing to apply a tax to gas reserves what is to stop some future legislature from taxing miners for claims situated on the outer limits of transportation routes or stranded timber reserves in roadless areas or even commercial fishermen not willing to fish certain runs or species?

The Alaska Support Industry Alliance has always supported commercial development of natural gas on the North Slope in Cook Inlet and wherever else resources abound in our state. We do not pretend to know what is the best method for production, the best resulting commodity or the best transportation routes. Only those who must invest and risk huge amounts of money to bring natural gas to market can determine what is economically feasible.

For more than a decade Alaska has had a stable and certain tax structure. Within Alaska's stable tax structure natural resource companies and others have invested billions of dollars. New fields and wells have been brought on line, production decline has been reversed and most importantly to my membership employment has generally been robust.

Right now contractors and suppliers are at full employment. New projects are being bid daily; optimism is truly at a high point throughout the State. An unstable tax climate, as represented in SSHB 190, will have the same effect on production as a low price climate. Less profit and more uncertainty equates to less capital investment.

Today's stable and predictable tax climate has been the key to the last decade of successful investment in Alaska. A continuation of a stable and predictable tax climate is essential for investors making decisions on future projects, especially a project as large as the commercialization of North Slope natural gas.

Increased taxes can only serve to make Alaska gas more expensive, and thereby less competitive, in a world market that has huge and abundant known gas reserves.

The Alliance membership represents what I will call your "meat and potatoes constituents." They are those men and women that get up in the morning put on the Carhartts and with sweat on their brow earn an honest daily wage. They are the drillers, derrick workers, bull cooks and cat operators, Mr. Chairman these constituents are the **first** to be laid off when oil and gas production slows. They are 25,000 Alaskan residents with families, mortgages, and car or truck payments to make.

In the **Mat-Su Valley** the Oil and Gas industry **directly** employs 353 people representing \$36 million in payroll. **Indirectly**, in Mat-Su the industry's total impact represents over 4,000 jobs and \$158 million in payroll. This figure represents almost 16% of the total regional payroll for Mat-Su.

In the **Fairbanks North Star Borough**, the industry **directly** employs 565 people, pays out \$40 million in annual payroll and spends \$190 million for goods and services. The industries **indirect** impact is 4,143 employees

representing 12% of the areas nonmilitary jobs equal to 16% of the North Star Boroughs total payroll.

(These figures are from a recent independent survey completed by Information Insights of Fairbanks and the McDowell Group. The sample year was 1999 an off year for the Oil Industry when barrels of oil were priced at \$9. Copies of the Executive Summary are available at your request.)

We believe the legislature should be considering true incentives that promote sound development and commercialization of North Slope gas. Natural resource legislation is good public policy when it reduces costs and minimizes risks while protecting our environment.

In summary, SSHB 190 in its short title makes reference to a Natural Gas Pipeline Incentive Act. We do not read "incentive" into this substitute bill. In fact the words "tax" or "taxation" appear 40 times in the 10-page document. We see the bill as punitive and destabilizing with the potential to erode any competitive advantage in the world markets that we have gained in the last decade in Alaska. HB 190, if passed, will most certainly result in the loss of jobs for Alliance contractors and suppliers...those "meat and potato constituents" living in your districts.

Thank you for the opportunity to testify today.

Testimony of the
Alaska Oil and Gas Association
On SSHB 190
Before the House Oil and Gas Committee
April 27, 2001

Mr. Chairman and members of the committee. My name is Judy Brady and I am the Executive Director of the Alaska Oil and Gas Association. AOGA is an industry trade association whose 16 members represent the great majority of the petroleum industry in Alaska: Alyeska Pipeline Service Company, Anadarko Petroleum Corporation, BP Exploration (Alaska) Inc., Chevron U.S.A. Inc., Cook Inlet Region Inc., Cross Timbers Oil Company, ExxonMobil Production Company, Forest Oil Company, Marathon Oil Company, Petro Star, Inc., Phillips Alaska, Inc., Shell Western E&P Inc., Tesoro Alaska Company, TotalFinaElf E&P USA, UNOCAL, and William Alaska Petroleum Inc.

I am here today to present AOGA's opposition to Sponsor's Substitute for House Bill 190, which proposes to enact an ad valorem tax on natural gas reserves on the North Slope and to impose a limit on the issuance or extension of oil and gas leases containing natural gas.

AOGA strongly opposes this bill as both poor economic policy and poor public policy. The Alaska Oil & Gas Association considers this legislation to be a direct disincentive to the commercialization of North Slope natural gas. AOGA's concern is that this will also be the view of market analysts who track and report local actions affecting gas commercialization on a worldwide basis for the purpose of informing potential lenders about project viability.

HB 190 represents a radical departure from sound economic and fiscal policy by substituting "pain" for "gain" as the reason to invest in the commercialization of North Slope natural gas. This bill apparently presumes that if shareholders and management are threatened and punished, they will be more likely to invest in Alaska. The bill seems to be based on the premise that an ANS gas project has *already* been found to be commercially viable and that free market incentives have failed when it comes to decisions to invest in the commercialization of North Slope natural gas.

This bill represents an odd and disruptive counterpoint to the building public/private momentum now underway as the result of industry commitment to and investment in the commercialization of the North Slope gas reserves. Of greater concern from a competitive market perspective, by signaling a significant move away from Alaska's stable public tax policy, HB 190 actually threatens to slow the momentum for the commercialization of the North Slope gas reserves.

Since the initial discovery of North Slope gas reserves in the 1960's, the oil and gas industry and others have spent over \$1 billion seeking ways to

commercialize North Slope gas. Such efforts include attempts to develop gas pipelines to the Lower-48, LNG projects and gas-to-liquids (GTL) projects. Despite these efforts, a commercially viable project has yet to be identified. However, there is more hope today than ever before that North Slope gas will become commercial because of a number of factors—most important to Alaska is that markets are changing.

This committee has heard testimony from various companies regarding the status of their commercialization efforts. The momentum, the focus and the commitment to the commercialization of North Slope gas are here now and building:

- As you know, in December 2000, the three major North Slope gas producers signed a joint work agreement on an Alaskan gas pipeline project. This project involves expenditures in excess of \$75 million with 90 employees and over 500 contractors and subcontractors. The first contract awards to Alaskan and joint venture Canadian firms were recently announced.
- Construction of BP's \$86 million gas-to-liquids five-year demonstration project in Nikiski is fully underway in Nikiski with completion scheduled for 2002.
- The Sponsor Group, comprised of Phillips, BP, Foothills Pipeline and Marubeni, is seeking a way to make an Alaska North Slope LNG project commercially viable. The effort, begun in 1998, now at Stage 2, is focusing on commercial activities needed to be cost competitive with other grass roots LNG projects potentially serving the Pacific Rim.

Some may think that a gas reserves tax would create an incentive for producers to speed up the development of this resource. But, in fact, this tax would only create an additional expense for the gas producers without improving any of the fundamental market factors that determine the economic feasibility of gas commercialization. In other words, it would bring Alaska no closer to solving the market obstacles to gas development, but would merely punish the producers for conditions outside their control. Rather than being an "incentive", HB 190 would be a direct disincentive to the commercialization of North Slope natural gas.

As proposed tax legislation, HB 190 sends a signal to the market that the State of Alaska's public policy of stable taxation is eroding. Just as the market has considered a stable tax policy to be critical to attract investment to the new commercial oil projects in the past ten years, so will the market consider a continued stable tax policy to be critical to attract the additional billions of dollars in financing necessary for new commercial gas projects.

A gas reserves tax would have other unintended and adverse effects on the prospects for gas commercialization. Today the *known* North Slope resource is estimated to be 35 Tcf of natural gas. If a project or projects are found to be

economic based on the current estimated reserves, clearly the economics would be improved significantly if, instead, there were 50 or 75 Tcf of gas over which the costs of the projects could be spread. But if HB 190 is enacted, anyone who plans to explore specifically for new gas reserves on the Slope, in the next several drilling seasons, will know that any gas they find would be subject to the reserves tax. Thus, HB 190 would deter the very exploration efforts that might prove to be essential for long term gas commercialization to come about.

Finally, HB 190 risks future investment in Alaska not only for the oil and gas industry but for other industries as well. Resource-development industries with long lead times for exploration and development require fiscal stability and certainty. The clear message of HB 190 would be: although long lead times are part of your business, if it takes you longer to develop your resources in a free market than the political arms of the government thinks it should, you will be punished even if the delay is not your fault.

Since, in the final analysis, the deciding factors will be commercial and market vitality which is most improved by reducing costs and risks, both industry and the state must focus their efforts on those factors that make Alaska's fiscal regime for gas more competitive against those elsewhere in the world.

The present Legislature — as well as the legislatures of the past decade — have strongly conveyed the message that Alaska is "open for business". Let's not change that message now, when we are in the very midst of a worldwide market competition to make North Slope gas projects economic. We should all work together to understand better how Alaska can more effectively compete in this worldwide market and how to bring about the commercialization of North Slope gas. Then let us work together to do what is necessary to make it happen.

Thank you for the opportunity to testify to you today.

**Testimony Before House Special Committee on Oil and Gas
Provided by NANA Colt Engineering, LLC
Friday April 27, 2001**

Chairman Ogan, members of the committee, for the record, my name is John Minier, President of NANA Colt Engineering. I appreciate the opportunity to testify today in opposition to HB 190.

NANA Colt Engineering is equally owned by NANA Development Corporation and Colt Engineering, and is one of the many NANA businesses heavily involved in the oil sector. We support Phillips Alaska with engineering, procurement, and construction management services for their Western North Slope activities, and we perform significant project engineering work for BP. NANA Colt supports, in some fashion, most of the North Slope and Cook Inlet operations currently underway. I personally have lived in Alaska for over 25 years, and have worked in the oil industry developing the North Slope oil and gas reserves for over twenty years. I strongly oppose House Bill 190.

I appreciate, and laud, the Legislature's effort to facilitate the commercialization of North Slope natural gas. But forcing the producers to commercialize the gas through a tax is not the way to accomplish what both the producers and their partners are already trying very hard to do.

Why would the oil support industry be opposing a bill that many believe would facilitate development of the North Slopes gas when we'd seem to be the obvious benefactors of this bill. Second, if we believe the owners are making, and will continue to make every effort to market their gas, what's the problem with this bill? It's onerous taxation and lease implications would likely never be applied.

The answers are simple. It is bad public policy to impose a tax on a specific segment of what drives the economic engine of this state. It is unnecessary. It changes to rules yet again. It says to companies "If you're looking for a stable place to do business, look elsewhere". It creates divisiveness and disincentive rather than fostering cooperation and development.

The owners have a long and proven track record of pursuing every potential avenue for gas commercialization. They have spent hundreds of millions of

dollars on studies of gas pipelines, LNG facilities, spike and super spike options, and gas-to-liquids conversion projects.

Recently, conceptual engineering contracts were awarded to various companies by the North America Natural Gas Pipeline Group. NANA Colt and our partners in the "AlasCan Group" joint venture were awarded engineering for one of the pipeline segments to send the gas to the lower 48. The producers have committed \$75 million to determine whether this project is feasible. This is yet another example of their aggressiveness and strong desire to commercialize North Slope gas.

As businessmen and women, we request better approaches than this. As citizens, we demand better than this. Why? Because our friends, our partners – the North Slope Owners and Producers – have earned, and deserve, better than this.

Thank you for the opportunity to provide comment.

BILL STAMPS
ALASKA SUPPORT INDUSTRY ALLIANCE
TESTIMONY ON HB190

April 27, 2001

Members of the House Oil and Gas Committee, good morning. I am Bill Stamps, Manager of Business Development and External Affairs for Peak Oil Field Service Company. I am also serving as president of the Alaska Support Industry Alliance this year. Today I am speaking on behalf of both my company and The Alliance.

Peak is an Alaskan based general contractor with offices in Anchorage, Prudhoe Bay, Nikiski and Valdez. We provide construction, fabrication, facility and equipment maintenance, heavy hauling and equipment support for the oil, gas and chemical industry. Peak currently employs approximately 1,100 people. All of our business is dependent on the oil and gas industry.

The Alliance membership includes nearly 400 businesses that contract directly with producer companies to provide products and services in support of oil and gas activity. Collectively we employ about 30,000 people in Alaska ... 25,000 are permanent residents of the state. The Alliance mission is to advocate safe and environmentally sound

petroleum exploration, development and production for the benefit of all Alaskans.

The Alaska Support Industry Alliance is extremely disappointed and alarmed over the introduction of House Bill 190 – Taxation on in-place North Slope Natural Gas. We believe this bill is the most onerous of the session, with provisions and messages that put our industry's health and future in jeopardy.

HB 190 amounts to coercion. It is akin to taxing the farmer for not planting a profitless crop. It is comparable to imposing a stiff fee on the commercial fisherman who is unwilling to fish for salmon in untested waters. It is the same as taxing the miner whose undeveloped claim now lies too far from reasonable transportation. It is like assessing the sawmill for not spending a fortune to airlift timber from otherwise inaccessible forest lands. HB 190 doesn't levy taxes on farmers, fishermen, miners or loggers. It singles out the oil and gas industry.

Sponsors reference the HB 190 assessment as an "incentive." This takes a myopic view of the very global, very competitive oil and gas industry. Alaska may be rich in natural gas, but so are many, many other areas of the world ... areas with infrastructure already in place, areas with less harsh environments, areas that cost less to do business in and areas that

welcome oil and gas developers with tax relief, not additional tax burdens.

Alaska gets approximately 80% of its unrestricted revenue from the oil and gas industry so we clearly are a state dependent on natural resource development. Yet with a bill such as this, the Legislature is conveying a message to developers and potential developers around the world that Alaska has no stable tax base. When developers are deciding where to invest their money in resource development they will see the tax structure in Alaska as a moving target. A gas reserves tax only increases the risks and reduces the benefits for gas owners. Let's call HB 190 what it is. HB 190 is all about the "T-word" – in fact, "tax" is noted in the bill about 40 times. This bill is a *dis-incentive*. It's also unfair and irresponsible.

Is it even legal? Original North Slope oil and gas leases were not sold with the promise, assumption or expectation that new taxes on undeveloped resources would be levied as part of the lease agreement. If that was the case, we can safely assume that far fewer leases would have been sold. How can we justify placing additional fiscal provisions on an already agreed-upon contract between the state and leaseholders? At best, this brands Alaska with an image of instability. We cannot afford

that, especially as the potential for commercializing gas comes closer within our grasp.

If we look at the historical contributions of oil and gas activity, we can be assured that Alaskans statewide stand to gain a great deal from natural gas development in the future. Even now, with declining oil production, the oil and gas industry spends over \$2.1 billion on payroll, goods and services – roughly equal to the State of Alaska's general fund spending. And that does NOT count the \$1.5 billion paid in royalties and taxes to government.

That spending gets personal when you consider the high-paying jobs that have displaced poverty in some communities. For example, within the Kenai Peninsula Borough, the industry employs over 4,000 people, with paychecks that represent 36 percent - *over one-third* - of the area's payroll. This information comes from the recent study "*Economic Impact of the Oil and Gas Industry in Alaska.*," which was released to the legislature in January.

Natural gas development will have a huge, positive impact on the State of Alaska, all of its residents, and closer to home - to Peak as a company and to our employees and their families, as it will to other members of the Alliance and their employees and families.

However, this development must be done when the companies who will be investing in that development believe the time is right and not when members of the Alaska Legislature believe it is right. A bill such as this sends a very negative message to potential investors in Alaska resource development. It also sends a very negative message to the voters in Alaska who depend on having a healthy oil and gas industry to continue to help provide a good environment in which to live and to prosper.

While the potential gains with natural gas development are profound, Alaskans also stand to lose a great deal if our lawmakers handle matters poorly, creating a business environment that is risky, not responsive. If Alaska is to bank on our natural gas, we had better project an image of stability.

As business people, we urge government to leave the economics of business to business people. We urge you to carry out your constitutional duty to "encourage the development of state resources by making them available for maximum use consistent with the public interest."

Thank you for the opportunity to comment.

April 27, 2001

Post-it® Fax Note 7671		Date 4/27	# of pages 4
To Barbara		From Mark Krolak	
Co./Dept. Kevin Meyer's office		Co. CIRI	
Phone #		Phone # 274-8638	
Fax # (907) 465-3476		Fax # 263-5182	

Mr. Chairman and Members of the Committee. My name is Barbara Donatelli and I am Executive Vice President of Cook Inlet Region, Inc. ("CIRI"). I am here today on behalf of CIRI to testify in opposition to House Bill 190 as proposed.

As you know CIRI is an Alaska Native Regional Corporation formed pursuant to the Alaska Native Claims Settlement Act of 1971 ("ANCSA"). CIRI operates as a for profit corporation, serving the economic, social and cultural needs of its approximately 7,200 Alaska Native shareholders. CIRI is interested in House Bill 190, in part, because we are in the oil and gas business, as a lessor and landowner, not only of currently producing properties, but of large tracts of prospective oil and gas lands which we would like to see explored in the future. We are also interested in the bill because we are in the oilfield service business, where the success of such operations, including the employment of many shareholders, is dependent upon a robust oil industry which is duly incentivized to explore and aggressively pursue new oil and gas prospects.

The most important reason CIRI is interested in the bill, however, is not because of its direct impact on these particular business lines, which make up a limited part of CIRI's total investment portfolio. Rather, we are concerned because CIRI is an Alaskan company - in some ways a uniquely Alaskan company, as over 2/3 of our 7,200 shareholders live, work and raise their families in the state. They understand, as we do, that sending a message to the world outside that Alaska is truly "open for business", in the best and most

responsible sense of that concept, is crucial to the economic well-being of the State and its people. This bill sends the opposite message.

As others have noted, this bill, which would tax North Slope natural gas reserves in place, will not, and cannot, be expected to spur development of natural gas any faster than market forces (that is, the true market demand for natural gas in out-of-state markets) would otherwise allow. If natural gas cannot be produced and sold for a reasonable profit, it simply will not be produced and sold. This bill, rather than providing a valuable incentive to development, appears to simply place an additional tax burden on the oil industry, thereby increasing the overall cost of development and exploration in the State of Alaska. This result is detrimental to all Alaskans in that it may inhibit economic growth and vitality in the crucial resource sector of the state economy.

Even more directly, the bill provides a disincentive for producers to explore for new gas reserves, because such reserves will become immediate liabilities on a producer's books if they are not found in quantities sufficient for near-term development and sale. While the bill purports to limit its effects in this regard to the North Slope, it sends a clear message to producers statewide that they face a similar fate at the hands of the state in an era of declining oil revenues. The effect may be to lock up further oil exploration just at the time when we most need new discovery and development.

The increasing viability of large scale gas production on the North Slope offers significant opportunities for the state, and it is important that the state government, at all levels, do

what it can to encourage prompt and responsible development of this resource. However, the State should not rush to judgment with a short-term fix which has the potential to backfire in the end. Rather, the state should proceed with due deliberation giving careful consideration to all options for maximizing the prompt development of North Slope gas reserves, while at the same time avoiding any approach which burdens the industry to the point of discouraging future investment.

In summary, while CIRI supports prompt and aggressive development of North Slope natural gas reserves, we do not think that House Bill 190 is the way to ensure that this is accomplished. We respectfully urge you not to advance this bill out of this committee.

Thank you for affording me the opportunity to speak on this measure.

Testimony of the
Alaska Oil and Gas Association
On SSHB 190
Before the House Oil and Gas Committee
April 27, 2001

Mr. Chairman and members of the committee. My name is Judy Brady and I am the Executive Director of the Alaska Oil and Gas Association. AOGA is an industry trade association whose 16 members represent the great majority of the petroleum industry in Alaska: Alyeska Pipeline Service Company, Anadarko Petroleum Corporation, BP Exploration (Alaska) Inc., Chevron U.S.A. Inc., Cook Inlet Region Inc., Cross Timbers Oil Company, ExxonMobil Production Company, Forest Oil Company, Marathon Oil Company, Petro Star, Inc., Phillips Alaska, Inc., Shell Western E&P Inc., Tesoro Alaska Company, TotalFinaElf E&P USA, UNOCAL, and William Alaska Petroleum Inc.

I am here today to present AOGA's opposition to Sponsor's Substitute for House Bill 190, which proposes to enact an ad valorem tax on natural gas reserves on the North Slope and to impose a limit on the issuance or extension of oil and gas leases containing natural gas.

AOGA strongly opposes this bill as both poor economic policy and poor public policy. The Alaska Oil & Gas Association considers this legislation to be a direct disincentive to the commercialization of North Slope natural gas. AOGA's concern is that this will also be the view of market analysts who track and report local actions affecting gas commercialization on a worldwide basis for the purpose of informing potential lenders about project viability.

HB 190 represents a radical departure from sound economic and fiscal policy by substituting "pain" for "gain" as the reason to invest in the commercialization of North Slope natural gas. This bill apparently presumes that if shareholders and management are threatened and punished, they will be more likely to invest in Alaska. The bill seems to be based on the premise that an ANS gas project has *already* been found to be commercially viable and that free market incentives have failed when it comes to decisions to invest in the commercialization of North Slope natural gas.

This bill represents an odd and disruptive counterpoint to the building public/private momentum now underway as the result of industry commitment to and investment in the commercialization of the North Slope gas reserves. Of greater concern from a competitive market perspective, by signaling a significant move away from Alaska's stable public tax policy, HB 190 actually threatens to slow the momentum for the commercialization of the North Slope gas reserves.

Since the initial discovery of North Slope gas reserves in the 1960's, the oil and gas industry and others have spent over \$1 billion seeking ways to

commercialize North Slope gas. Such efforts include attempts to develop gas pipelines to the Lower-48, LNG projects and gas-to-liquids (GTL) projects. Despite these efforts, a commercially viable project has yet to be identified. However, there is more hope today than ever before that North Slope gas will become commercial because of a number of factors—most important to Alaska is that markets are changing.

This committee has heard testimony from various companies regarding the status of their commercialization efforts. The momentum, the focus and the commitment to the commercialization of North Slope gas are here now and building:

- As you know, in December 2000, the three major North Slope gas producers signed a joint work agreement on an Alaskan gas pipeline project. This project involves expenditures in excess of \$75 million with 90 employees and over 500 contractors and subcontractors. The first contract awards to Alaskan and joint venture Canadian firms were recently announced.
- Construction of BP's \$86 million gas-to-liquids five-year demonstration project in Nikiski is fully underway in Nikiski with completion scheduled for 2002.
- The Sponsor Group, comprised of Phillips, BP, Foothills Pipeline and Marubeni, is seeking a way to make an Alaska North Slope LNG project commercially viable. The effort, begun in 1998, now at Stage 2, is focusing on commercial activities needed to be cost competitive with other grass roots LNG projects potentially serving the Pacific Rim.

Some may think that a gas reserves tax would create an incentive for producers to speed up the development of this resource. But, in fact, this tax would only create an additional expense for the gas producers without improving any of the fundamental market factors that determine the economic feasibility of gas commercialization. In other words, it would bring Alaska no closer to solving the market obstacles to gas development, but would merely punish the producers for conditions outside their control. Rather than being an "incentive", HB 190 would be a direct disincentive to the commercialization of North Slope natural gas.

As proposed tax legislation, HB 190 sends a signal to the market that the State of Alaska's public policy of stable taxation is eroding. Just as the market has considered a stable tax policy to be critical to attract investment to the new commercial oil projects in the past ten years, so will the market consider a continued stable tax policy to be critical to attract the additional billions of dollars in financing necessary for new commercial gas projects.

A gas reserves tax would have other unintended and adverse effects on the prospects for gas commercialization. Today the *known* North Slope resource is estimated to be 35 Tcf of natural gas. If a project or projects are found to be

economic based on the current estimated reserves, clearly the economics would be improved significantly if, instead, there were 50 or 75 Tcf of gas over which the costs of the projects could be spread. But if HB 190 is enacted, anyone who plans to explore specifically for new gas reserves on the Slope, in the next several drilling seasons, will know that any gas they find would be subject to the reserves tax. Thus, HB 190 would deter the very exploration efforts that might prove to be essential for long term gas commercialization to come about.

Finally, HB 190 risks future investment in Alaska not only for the oil and gas industry but for other industries as well. Resource-development industries with long lead times for exploration and development require fiscal stability and certainty. The clear message of HB 190 would be: although long lead times are part of your business, if it takes you longer to develop your resources in a free market than the political arms of the government thinks it should, you will be punished even if the delay is not your fault.

Since, in the final analysis, the deciding factors will be commercial and market vitality which is most improved by reducing costs and risks, both industry and the state must focus their efforts on those factors that make Alaska's fiscal regime for gas more competitive against those elsewhere in the world.

The present Legislature — as well as the legislatures of the past decade — have strongly conveyed the message that Alaska is "open for business". Let's not change that message now, when we are in the very midst of a worldwide market competition to make North Slope gas projects economic. We should all work together to understand better how Alaska can more effectively compete in this worldwide market and how to bring about the commercialization of North Slope gas. Then let us work together to do what is necessary to make it happen.

Thank you for the opportunity to testify to you today.