

THE GAS RESERVES TAX BALLOT INITIATIVE: RISKY STATE POLICY¹

by

Scott Goldsmith

**Professor of Economics
Institute of Social and Economic Research
University of Alaska Anchorage**

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On November 7 Alaskans will vote on an initiative to impose a reserves tax on gas in the two largest North Slope gas fields. Supporters believe the initiative will create an incentive to move the gas to market more quickly (commercialize the gas). In this note we review some of the history of North Slope gas, explain the initiative, and discuss its possible effects on commercialization of gas, petroleum activity generally, and state revenues.

There are vast differences in interpretation of the terms of the initiative and its potential effects. The supporters believe the initiative will speed development at no cost to a gas project and expand state revenues, while not adversely affecting future oil and gas exploration. Opponents argue that it will slow or stop gas development and reduce state revenues, while creating disincentives for both gas and oil exploration in the future.

The terms of the initiative are complex and, although there is considerable speculation and assertion surrounding its effects, public analysis and review have been limited. It is difficult for the general public to know what they might be voting for with this initiative.

In the face of this great uncertainty, the question to ask is whether the potential gain expected by initiative supporters justifies the risk of the adverse effects suggested by its critics. And it should be considered, in light of other means the state might use to try to advance the development of Alaska's gas that involve less risk and uncertainty.

A LITTLE HISTORY

This "Alaska Gas Line Now!" Initiative grew out of the frustration many Alaskans have felt over perceived delays in construction of a gas line, particularly in light of recent high gas prices and oil

ALASKA GAS LINE NOW! INITIATIVE (This is how the initiative will read on the ballot.)

"This initiative would impose a new state tax on certain oil and gas leases overlying large deposits of natural gas until a major gas pipeline system is built.

"The tax would be 3 cents a year per thousand cubic feet of taxable gas in the ground. Taxpayers who dispute taxes owed would have to deposit the amount of the taxes levied into an escrow account.

"If and when taxable gas is produced and transported in a major gas pipeline system, some of the taxes previously paid could be used as a credit against state gas production taxes due on the gas.

"Should this initiative become law?"

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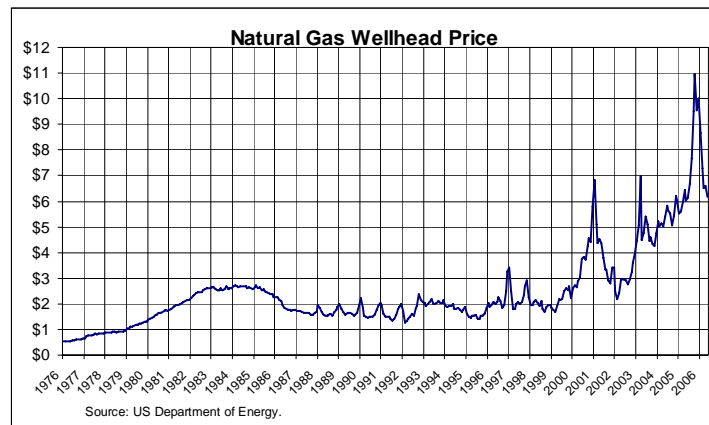
company profits. Plans for commercialization of North Slope gas can be traced back to the late 1970s, and considerable activity directed at authorization and construction did take place, but they ended abruptly when domestic gas prices fell, making gas commercialization uneconomic. The price drop was due to an increase in supply after deregulation of the price of gas at the wellhead by the federal government. Attention continued to be directed at a project to convert gas to LNG and sell it into the Asian market, but that project could not compete with other lower-cost suppliers.

During this time gas helped to increase the production of high-value oil. As the gas was produced with oil, it was re-injected back into the reservoirs, adding pressure, and allowing more higher-valued oil to be brought to the surface. This use of gas helped to increase the estimated, ultimately recoverable oil reserves at Prudhoe Bay from about 9 billion barrels when the oil pipeline was built to over 13.8 billion barrels today.² The re-injected gas was continuously recycled for this purpose and remains available for sale today.

This use of the gas is consistent with standard industry practice in fields where oil and gas are mixed. Because oil generally has higher value, it is produced first, and the gas is re-injected as it is produced. When most of the oil has been produced, the gas is finally “blown off” or sold. That time depends on many factors; but as the field ages, more gas is required to bring each barrel of oil to the surface, and the value of gas for re-injection declines relative to its sale value.³

In recent years the price of gas has increased and moved closer to parity with oil per unit of energy (Figure 1).⁴ This has renewed interest in commercialization of North Slope gas. Efforts are underway to move a project forward, but they are slow and time-consuming. Some analysts feel there is a “window of opportunity” to market Alaska gas that may close if a project is delayed. Competing projects to import LNG into the domestic market or to build coal-fired electric power plants, which would back out demand for gas, could reduce, if not eliminate, the need to move Alaska gas to market if a project did not move forward quickly.

FIGURE 1A. Historical Wellhead Natural Gas Price (nominal \$)

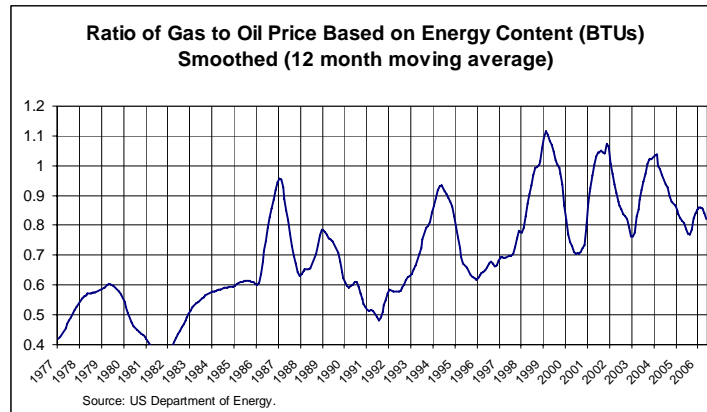


²Alaska Department of Natural Resources, Alaska Oil and Gas Report 2006. Production of oil and natural gas liquids from Prudhoe Bay has been 11.3 billion barrels through 2005. Estimated reserves at the beginning of 2006 were 2.5 billion barrels.

³In Alaska the Oil and Gas Conservation Commission determines when gas can be produced to ensure maximum physical recovery.

⁴Based on British Thermal Units, or btus.

FIGURE 1B. Historical Ratio of Price of Gas to Crude Oil (Based on BTU Values)



Could the incentives in this initiative move a project forward more quickly? The answer partly depends on one's view of how the oil industry in Alaska works.

One view is that the economics of a gas project are attractive, but commercialization involves great risks because of the sheer size of a project—estimated now to cost about \$25 billion. Because of this, the producers are moving forward cautiously with development plans. Recent activities include the expenditures made by producers on preliminary design studies, the passage of federal legislation in support of a project, and the negotiations with the state under the stranded gas act. If a project is economic, it makes sense to move quickly because time is money,⁵ but moving too quickly has risks and could add to the total cost.

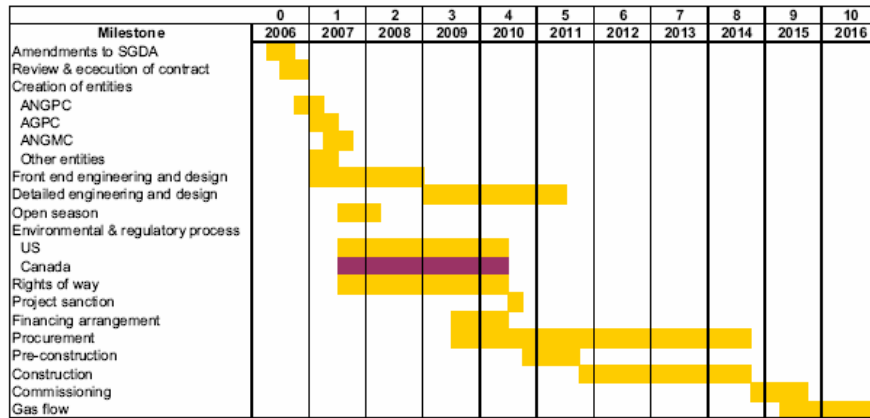
An appropriate incentive could speed the process, currently estimated to take about 10 years⁶ (Figure 2), but if the producers are committed to moving forward, the gain would be marginal. The producers, individually and collectively, have a limited ability to affect the development timetable because any project requires the concurrence of not only the producers but also the state, numerous federal agencies of the United States and possibly Canadian governments, the financial community, and others.

⁵If the internal rate of return for a company is 15%, \$1 billion in revenues this year is worth only \$860 million if not received until next year ($\$1 \text{ billion}/1.15$).

⁶The timetable for a gas project to deliver gas to the Midwest has sales beginning in 2016. The Alaska Department of Revenue, Preliminary Findings and Determination, Stranded Gas Development Act, 2006. Some analysts think a gas project based on LNG export could occur in less time.

FIGURE 2. Conceptual Project Timeline

Figure ES-3. Conceptual Project Timeline



This view is not shared by those Alaskans who feel that the producers are ‘warehousing’ the gas—purposely holding it off the market. There are several possible explanations for this “strategic” behavior.

They could be delaying in order to extract a better deal financially from the other parties involved, including the state. The longer they delay, the more concessions they may be able to extract from the state and others.

They could be waiting to develop the gas reserves on the North Slope until their reserves in other locations have been commercialized. This could either be because the North Slope gas is less profitable or because other reserves, unlike their North Slope leases, would be lost if they were not developed immediately.

They could be waiting because of strategic reasons related to their worldwide gas inventories, which they want to develop based on a long-term schedule.

They could be expecting a much higher price for gas in the future.

If producers were delaying for these or other reasons, an appropriate incentive might significantly accelerate the timing of gas commercialization, but the timetable would continue to be constrained by the necessary steps as reflected in Figure 2.

MECHANICS OF THE INITIATIVE—A TAX AND A CREDIT

The proposed initiative consists of a tax and a credit.

The tax is a levy of 3 cents per mcf (thousand cubic feet) per year on gas in the ground in the two largest fields on the North Slope—the Prudhoe Bay and Point Thompson units⁷—amounting to

⁷The state had a temporary oil and gas reserves tax (AS 43.58) in 1976 and 1977, which was credited against subsequent production taxes paid when the Alyeska pipeline began operations. The tax was not created as an incentive to speed delivery of oil to the market, but rather a means of providing funds to pay for expanded state services resulting from the economic boom associated with pipeline construction.

perhaps \$800 million per year starting in 2007⁸. The tax would remain in place until a large-scale project resulted in the sale of gas.⁹ Early elimination of the tax provides an incentive to move gas to market as quickly as possible.

After the first sale of gas, a production tax credit would allow recovery of a portion of the reserves taxes paid. The credit would reduce the gas production tax liability by 50 percent each year until the credited amount equaled the previously paid eligible gas reserves taxes, or until 2030, whichever came first.¹⁰ This tax credit for gas production is the second part of the incentive.

The current leaseholders could avoid the tax by turning their leases back to the state. The leases could then be re-bid and issued to another set of oil companies, giving them the opportunity to commercialize the gas. They could potentially move more quickly than the current leaseholders in that effort.

THE COST BURDEN OF THE INITIATIVE

If the current leaseholders decided to pay the reserves tax, the initiative would put a large but indeterminate cost burden on them. We calculate this cost burden to producers as their cumulative reserves tax liability minus the value of any subsequent production tax credits. The burden would be positive under any conditions for three reasons built into the language of the initiative.

First, the tax credits would never completely compensate for the reserves tax payments. The credits only apply to gas reserves tax payments made after a formal commitment to build a project—a milestone at least two years in the future.

Second, each dollar of credits received in the future would be worth much less than each dollar paid as taxes today.¹¹

Third, the credits would expire in 2030. If future gas prices and production taxes were not high enough, producers would not be able to recover all their eligible reserves tax payments.

⁸We assume reserves of 31 trillion cubic feet (tcf) based on the reserves estimate of the Alaska Department of Natural Resources Alaska Oil and Gas Report 2006. The royalty gas in those fields would not be subject to the tax. The estimate of \$800 million is the gross tax liability. The net liability, after offsetting reductions in the production and income taxes, would be considerably less. Estimates of the annual reserves tax liability range as high as \$1 billion.

⁹This is defined in the initiative as sales of 2 bcf (billion cubic feet) or more per day. The proposed gas pipeline from the North Slope to the Midwest would have a design capacity of about 4.5 bcf per day.

¹⁰Producers would be able to take a credit for reserve taxes paid after committing to a commercialization project, a milestone that could not be reached immediately. It would be at least two years according to the Alaska Department of Revenue, Preliminary Findings and Determination, Stranded Gas Development Act, 2006.

¹¹ At a 15% discount rate, a credit of \$1 received in 2016 is worth only 21 cents in 2006.

The cost burden on the industry would be large. At \$800 million per year, the reserves tax would be larger than the annual petroleum production tax has been in 8 of the last 10 years.¹² But it is impossible to estimate the burden with any degree of certainty for several reasons.

The size of the cost burden depends upon the amount of gas available to tax, the future price of gas, and the year when gas sales start—none of which are known. It also depends on the total tax structure of the industry today and in the future—which is currently in flux.

During the time the reserves tax would be in effect, the producers would be able to use it to offset some production taxes as well as some corporate income taxes (state and federal). The subsequent credit would increase producer taxable income after gas sales began. Because of these offsets, the net cost burden for producers would be less than the gross amount. Although it is impossible to estimate how important those offsets might actually be, if the producers could take complete advantage of them at current statutory tax rates, as suggested by some initiative supporters, the net cost burden could be half or less than the gross burden.

One way to summarize the estimated cost burden on the industry is to calculate the combined net present value of the future taxes and credits.¹³ The net present-value methodology discounts all future tax payments and credits and sums them to get a single number representing the cost if it were all paid today. Although this calculation is sensitive to the discount rate used (15% in this case), it does recognize the diminished importance of future revenues and expenses compared to those in the present.

A lower-bound estimate of the cost burden the initiative would put on the industry could be estimated based on the maximum possible tax offsets with gas sales starting as soon as possible (2015) at a high price that generates a lot of tax credits (identified as the “Most Favorable Scenario”).¹⁴ Figure 3 shows the discounted annual reserves tax liability and subsequent credit in this case. The sum of these discounted taxes and credits ranges from \$1.2 to \$1.5 billion, depending on the future price of gas (Figure 4A).

¹²Alaska Department of Revenue, Revenue Sources, Spring 2006.

¹³The following assumptions are used in the analyses in this paper: royalty share of gas =12%, industry nominal discount rate=15%, gas reserves=31 tcf, production tax rate=22.5%, state corporate income tax rate= 9%, federal corporate income tax rate=35%, construction phase of gas project=6 years. Additional gas reserves for a project come from fields not subject to reserves tax.

¹⁴This set of assumptions is most favorable in the sense that it represents a lower bound on the cost burden of the initiative on the producers.

FIGURE 3. Hypothetical Future Flow of Taxes and Credits

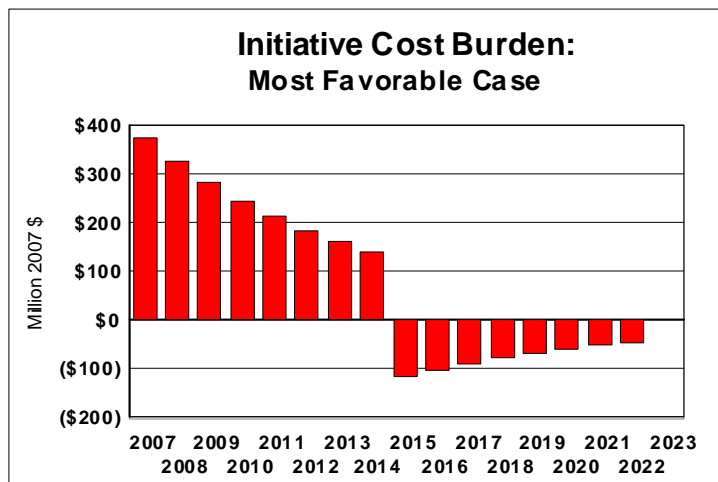


FIGURE 4A. Net Present Value Initiative Cost Burden on Producers: Most Favorable Scenario (billion \$)

Gas Price	Low	Mid	High
Gas Production Tax Revenue (million \$)	\$400	\$800	\$1,200
With full tax offsets	\$1.5	\$1.3	\$1.2

Net present value discounted at a nominal rate of 15%. Gas reserves are 31 tcf.

The cost burden estimate is not very sensitive to the future gas price because the producers would not start receiving credits for nearly 10 years under the best circumstances. But it is quite sensitive to the size of the estimated tax offsets, particularly against their reserves tax liability. Without them, the cost burden would more than double to a range of \$2.8 to \$3.3 billion (Figure 4B).

FIGURE 4B. Net Present Value Initiative Cost Burden on Producers: No Tax Offsets (billion \$)

Gas Price	Low	Mid	High
Gas Production Tax Revenue (million \$)	\$400	\$800	\$1,200
No tax offsets	\$3.3	\$3.0	\$2.8

Net present value discounted at a nominal rate of 15%. Gas reserves are 31 tcf.

The longer the reserves tax was in place, the larger the estimated cost burden would become, both because of the additional tax liability and the postponement of the subsequent credits. If gas sales were to start in 2019 with a full tax offset, the cost burden could range from \$1.7 to \$1.9 billion (Figure 4C).

FIGURE 4C. Net Present Value Initiative Cost Burden on Producers: Later First Sale with Tax Offsets (billion \$)				
Gas Price		Low	Mid	High
Gas Production Tax Revenue (million \$)		\$400	\$800	\$1,200
First Sale	2015	\$1.5	\$1.3	\$1.2
	2016	\$1.6	\$1.4	\$1.3
	2017	\$1.7	\$1.6	\$1.5
	2018	\$1.8	\$1.7	\$1.6
	2019	\$1.9	\$1.8	\$1.7
Net present value discounted at a nominal rate of 15%. Gas reserves are 31 tcf.				

Finally, without a tax offset, the cost burden from project startup in 2019 could be in the range \$3.9 to \$4.2 billion (Figure 4D).

FIGURE 4D. Net Present Value Initiative Cost Burden on Producers: Later First Sale without Tax Offsets (billion \$)				
Gas Price		Low	Mid	High
Gas Production Tax Revenue (million \$)		\$400	\$800	\$1,200
First Sale	2015	\$3.3	\$3.0	\$2.8
	2016	\$3.6	\$3.3	\$3.1
	2017	\$3.8	\$3.6	\$3.4
	2018	\$4.0	\$3.8	\$3.7
	2019	\$4.2	\$4.0	\$3.9
Net present value discounted at a nominal rate of 15%. Gas reserves are 31 tcf.				

These calculations are not meant to be a prediction of the size of the cost burden, but rather simply to demonstrate that the burden would be large but very difficult to quantify and, consequently, extremely difficult to plan around.

THE INCENTIVE EFFECT

The incentive would work in one of two ways—either by reducing the cost burden if current leaseholders moved gas to market faster or by giving other producers the opportunity to do so.

For each year trimmed from the time required to deliver gas to market, the reserves tax liability of current leaseholders would fall and their tax credits would begin sooner. This savings could be calculated as the reduction in their cost burden. The size of the incentive is directly related to the size of the cost burden.

Trimming the startup from 2016 to 2015 with full tax offsets (Most Favorable Scenario) would reduce the cost burden in a range from \$140 to \$175 million based on the earlier calculations (Figure 5A). Without tax offsets the savings would be more than twice as large, ranging from \$289 to \$347 million.

FIGURE 5A. Incentive Effect (Cost Burden Reduction) of Accelerated Development by One Year from 2016 to 2015 (million \$)			
Gas Price	Low	Mid	High
Gas Production Tax Revenue (million \$)	\$400	\$800	\$1,200
Most Favorable Scenario (with full tax offsets)	\$140	\$161	\$175
Without Tax Offsets	\$289	\$325	\$347
Numbers are the reduction in the net present value cost in Figure 4 from project acceleration by one year.			

The reduction in the cost burden would be smaller the further in the future the time savings occurred (Figure 5.B). A single-year savings from 2019 to 2018 would reduce the burden by about \$100 million with full tax offsets.

FIGURE 5B. Incentive Effect (Cost Burden Reduction) of Accelerated Development by One Year (million \$)				
Gas Price	Low	Mid	High	
Gas Production Tax Revenue (million \$)	\$400	\$800	\$1,200	
WITHOUT TAX OFFSET				
	2016 to 2015	\$289	\$325	\$347
	2017 to 2016	\$252	\$283	\$302
	2018 to 2017	\$219	\$246	\$263
	2019 to 2018	\$190	\$214	\$228
WITH TAX OFFSET				
	2016 to 2015	\$140	\$161	\$175
	2017 to 2016	\$122	\$140	\$152
	2018 to 2017	\$106	\$122	\$132
	2019 to 2018	\$92	\$106	\$115
Numbers are the reduction in the net present value cost in Figure 4 from project acceleration by one year.				

Supporters of the initiative think it could provide an incentive to overcome a delay of several years because the reduction in the cost burden is larger for multiple-year savings. A four-year acceleration, from 2019 to 2015 (to the Most Favorable Case) would reduce the cost burden in the range of \$461 to \$573 million (Figure 5C)—and more than twice that amount without tax offsets.

FIGURE 5C. Incentive Effect (Cost Burden Reduction) of Accelerated Development by Four Years Compared to One (million \$)				
Gas Price	Low	Mid	High	
Gas Production Tax Revenue (million \$)	\$400	\$800	\$1,200	
WITH TAX OFFSET				
	2019 to 2015	\$461	\$530	\$573
	2016 to 2015	\$140	\$161	\$175
WITHOUT TAX OFFSET				
	2019 to 2015	\$950	\$1,067	\$1,141
	2016 to 2015	\$289	\$325	\$347
Numbers are the reduction in the net present value cost in Figure 4 from project acceleration. Multiple year savings is the sum of individual years.				

If current leaseholders were to relinquish their leases and they were re-issued to other producers, it is the intent of the initiative that those new leaseholders would not have to pay the reserves tax and would not be eligible for the production tax credit. New leaseholders would have no financial incentives to move the gas to market beyond those already in place.

IMPACT ON GAS COMMERCIALIZATION

The initiative is designed to influence the timing of gas commercialization, but all analysts agree it also impacts the cost of gas development. Most analysts think it increases project cost, but supporters argue it actually reduces the cost of a gas project.

This difference of opinion turns on whether the producers would charge the reserves tax against future gas sales or present oil production. Although the reserves tax is nominally on the gas in the fields, gas and oil are commingled in those fields in complicated ways so the tax would not necessarily be charged against gas. If it were not, then since the credits clearly reduce the cost of gas production, the initiative would reduce the cost of a gas project.

Three different allocations of the reserves tax show how it is possible to arrive at either conclusion—that the initiative increases or reduces the cost of a gas project. (See the appendix for a more detailed discussion of different allocations and their implications.)

As we have indicated (Figure 4A), if the first sale of gas were in 2015 and full tax offsets reduced the net tax liability and subsequent credits (Most Favorable Case), the cost burden on producers from the initiative would be about \$1.2 billion.

If all reserves taxes were allocated to gas, \$1.2 billion would be the cost burden added to any gas commercialization project, and the amount by which its potential profit would fall (Figure 6, “All to Gas”). The argument for the cost burden falling on a gas project is that the reserves tax is a gas tax. Without the gas, there would be no project; and without the gas, there would be no tax.

On the other hand, if the entire reserves tax liability (\$1.7 billion) fell on oil, the cost of a gas project (“benefit” to gas) would decline by \$.5 billion because it would benefit from the tax credits without the burden of the reserves taxes (Figure 6, “All to Oil”). Supporters of the initiative argue that the reserves tax would be a “sunk cost” paid out of the profits from oil production and would not be a part of a calculation of the cost of a gas project.

An intermediate case would be that in which Prudhoe Bay oil absorbed its share of the reserves tax¹⁵—leaving future gas sales to absorb the Point Thomson share of the reserves tax as well as all the tax credits (Figure 6, “Prudhoe Bay to Oil, Point Thomson to Gas”). In this case oil would pay \$1.3 billion and the cost of a gas project would fall by \$.1 billion. The rationale for this allocation of the reserves tax is that the Prudhoe Bay field currently produces oil, so payment of the tax on that field allows oil production to continue. Since not paying the tax and relinquishing the leases would prevent oil production, the burden of the tax could be argued to fall on that oil. At Point Thomson there is little oil and no production of gas or oil. Since not paying the tax and relinquishing those leases would prevent future gas production, the burden of the tax could be argued to fall on that gas.

¹⁵Based on its share of taxable North Slope gas.

FIGURE 6. Most Favorable Scenario—Three Alternative Allocations of Initiative Cost Burden: Net Present Value (billion \$)					
	COST BURDEN				
	Total	Gas Share ("Benefit" if negative)	Oil Share	Incentive 1 year 4 year	
RESERVES TAX ALLOCATION					
1. All to Gas	\$1.2	\$1.2	-	\$2	\$6
2. All to Oil	\$1.2	-\$.5	\$1.7	\$2	\$6
3. Prudhoe Bay to Oil, Point Thomson to Gas	\$1.2	-\$.1	\$1.3	\$2	\$6
Net present value discounted at a nominal rate of 15%. Gas reserves are 31 tcf.					

A later first sale of gas increases the cost burden on both gas and oil (and reduces the "benefit" to gas). The benefit to gas falls no matter how the cost of the reserves tax is allocated. Figure 7 shows the calculated values for a first gas sale in 2019 with a full tax offset.

FIGURE 7. First Gas Sale in 2019—Three Alternative Allocations of Initiative Cost Burden: Net Present Value (billion \$)					
	COST BURDEN				
	Total	Gas Share ("Benefit" if Negative)	Oil Share	Incentive 1 year 4 year	
RESERVES TAX ALLOCATION					
1. All to Gas	\$1.7	\$1.7	-	\$1	\$3
2. All to Oil	\$1.7	-\$.3	\$2.0	\$1	\$3
3. Prudhoe Bay to Oil, Point Thomson to Gas	\$1.7	\$2	\$1.5	\$1	\$3
Net present value discounted at a nominal rate of 15%. Gas reserves are 31 tcf.					

The cost burdens are also higher without tax offsets (and the "benefit to gas is reduced). Figure 8 shows the calculated values for a first gas sale in 2015 without tax offsets.).

FIGURE 8. First Gas Sale in 2019—Three Alternative Allocations of Initiative Cost Burden: Net Present Value (billion \$)					
	COST BURDEN				
	Total	Gas Share ("Benefit" if Negative)	Oil Share	Incentive 1 year 4 year	
RESERVES TAX ALLOCATION					
1. All to Gas	\$3.3	\$3.3	-	\$3	\$1.0
2. All to Oil	\$3.3	-\$.4	\$3.7	\$3	\$1.0
3. Prudhoe Bay to Oil, Point Thomson to Gas	\$3.3	\$6	\$2.7	\$3	\$1.0
Net present value discounted at a nominal rate of 15%. Gas reserves are 31 tcf.					

Against these additional project costs is the opportunity to avoid a portion of the cost burden by accelerating the timing of gas commercialization. For the Most Favorable Scenario of a gas sale in

2015 at a high price with full tax offsets, the avoided cost would be about \$.2 billion if one year were trimmed from the schedule, rising to \$.6 billion if 4 years were trimmed (from 2019 to 2015).

Is the size of this incentive large enough to influence the timing of development of a \$25 billion project, assuming the additional project cost does not make it uneconomic?¹⁶ The answer is unknowable because we cannot say where the producers would choose to allocate the reserves tax liability.

If the producers are serious about moving forward and the project is economic with the added burden of the reserves tax, shortening the schedule by a year would lower the project cost by less than 1% in reduced taxes. In the present environment of uncertainty about future gas prices and project construction costs, an uncertain savings of that magnitude seems unlikely to be important in influencing behavior.

On the other hand if the producers are “warehousing” the gas—a decision, for example, to move the timetable up four years to a completion date of 2015 instead of 2019 could be worth \$.6 billion in tax savings—about 2% of the project cost. Whether this incentive is large enough to change the strategic behavior of the producers is unknowable; but again, the magnitude of the incentive is modest, particularly if one assumes that the profits from pursuit of strategic behavior are large.

In either case, the leaseholders could decide not to pay the reserves tax and, instead, turn their leases back to the state for re-issue.¹⁷ The state could then re-issue these leases in the hope that a different mix of producers would be willing to act more quickly to commercialize the gas. Although the process of re-issuing of the leases would take some time; doing so could ultimately trim the time to get gas to market. But there is no guarantee that a different mix of producers would or could move more rapidly than the current leaseholders.

IMPACT ON NEW OIL AND GAS

The reserves tax would apply to new gas reserves added at the Prudhoe Bay and Point Thompson fields. This is a clear disincentive to invest in the development of new gas reserves in those fields. Since the commercial viability of any gas project depends on the amount of gas available to sell, the absence of additional reserves would reduce the economic attractiveness of any project.

More importantly, gas and liquids are intermingled in the Prudhoe Bay and Point Thompson fields, so the tax would be a disincentive to drill any new wells looking for both oil and gas because any gas found in conjunction with oil would be an added financial burden on the field. At current levels of gas reserves and oil production, the reserves tax would add between \$2.50 and \$5.00 to the cost of each barrel of oil produced. Additional gas reserves would increase that per-barrel burden, independent of the price or cost of oil.

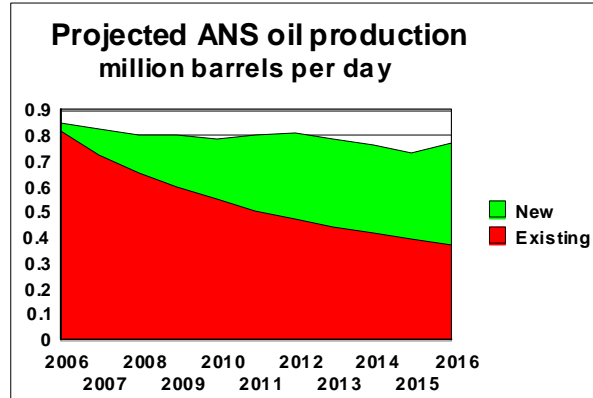
There are differing opinions about the importance of this disincentive. Supporters of the initiative argue that there is little new oil and gas to be found in these fields, so the disincentive effect is unimportant. Other analysts disagree. They point to the fact that oil reserves at Prudhoe Bay have grown by several billion barrels since the field was first developed. Similar experiences in aging fields in the rest of the United States also suggest more reserves could be found at Prudhoe Bay.

¹⁶The additional project cost would include both the cost burden and any costs associated with compressing the development timetable. The Alyeska oil pipeline is an example of how project costs were inflated due to rapid development.

¹⁷Opinions differ on whether it would be possible to separate oil and gas on the leases and also whether a new leaseholder would be liable to pay the reserves tax.

In the absence of new investment, North Slope oil production is projected to fall by more than half by 2016¹⁸ (Figure 9). New investment to replace most of that lost production is primarily projected in currently producing fields,¹⁹ including Prudhoe Bay.²⁰

FIGURE 9. Projected North Slope Oil Production



STATE REVENUE IMPACT

If the initiative worked as proposed, state revenues would increase and would be more concentrated in the near term.²¹ This “borrowing from the future” is based on the notion that a revenue “bridge” is necessary between the present and the time when gas sales will bring in much higher revenues to the state.

This assumes that combined revenues from gas and oil sales in the future will be higher than current revenues from oil. But higher revenues in the next decade depend upon high prices for gas and oil, low production costs, and additional investment to keep up oil production rates. On the other hand, current revenues—driven by high oil prices—are generating a considerable surplus.

It is important to keep in mind that the revenue-generating capacity of gas sales is less than oil for three reasons. First, the energy content of a full gas pipeline is less than a full oil pipeline.²² Second,

¹⁸Alaska Department of Revenue, Revenue Sources, Spring 2006.

¹⁹Production from fields not currently in production is projected to be less than 150 thousand barrels per day based on projections of the Alaska Department of Revenue, Revenue Sources, Spring 2006.

²⁰The Alaska Department of Revenue projects oil production at Prudhoe Bay between 2006 and 2015 to be 2.945 billion barrels. However, the Alaska Department of Natural Resources estimates oil reserves at Prudhoe Bay at the start of 2006 to be only 2.497 billion barrels.

²¹The reserves tax would presumably result in higher total state revenues for about a decade, and the tax credit would result in lower state revenues for about a decade thereafter.

²²A gas pipeline is expected to carry about 4.5 bcf of gas a day. The energy in 4.5 bcf of gas (measured in btu’s) is equivalent to about 780 thousand barrels of oil. The peak oil flow through the oil pipeline was nearly 3 times this amount—2 million barrels per day, and today is still about 850 thousand barrels per day. See Alaska Department of Revenue, Revenue Sources, Spring 2006.

gas continues to be priced at a discount to oil for equal amounts of energy.²³ Third, it is more expensive to move a unit of gas to market than it is for oil.

The current revenue surplus, the uncertainty about the level of future revenues, and the propensity of the state to spend when revenues are available rather than to develop a long-term fiscal plan based on sustainable revenues and prioritized needs, all suggest that borrowing from the future might not be the best strategy, if it could work.

But if the initiative passed and it delayed a gas project or made it uneconomic, and if investment in new exploration and development were reduced, petroleum revenues would fall, particularly in the long term. Since state government continues to be almost totally dependent on petroleum revenues, the loss of these revenue sources would have severe fiscal consequences for the future of the state.

OTHER CONSIDERATIONS

The initiative introduces at least 5 types of uncertainty into the already complex arena in which government and industry are trying to develop a plan to move forward to commercialize North Slope gas: these are interpretation of the terms, industry response, state revenues, constitutional issues, and political issues. A consequence of this uncertainty is the potential for considerable delay in moving forward as these and other issues are sorted out. That delay could jeopardize a project.

Interpretation of Terms. The initiative has been characterized as a tax on gas reserves, but much of it is likely to fall on oil production at Prudhoe Bay. This may be only one of the unintended consequences of the terms of the initiative. Determination of the volume of gas subject to the reserves tax is subject to different interpretations, as is the question of whether new gas discoveries in other fields could ever become subject to the reserves tax. It is also not clear whether newly issued leases in the Prudhoe Bay and Point Thomson units would be subject to the reserves tax.

The initiative was developed prior to the passage of the new production tax, which now does not distinguish oil from gas. There is no language in the initiative to determine how to split the production tax liability between oil and gas for calculating the tax credit. The initiative was also developed prior to the release of the contract negotiated between the state and the producers setting out the financial and other terms by which a project would move forward. The contract calls for the state to take gas in lieu of a production tax (known as “gilt” or “gas in lieu of taxes”). There is no mechanism to calculate the tax credit if the state were to take gas in lieu of taxes.

Initiative supporters acknowledge some of these uncertainties regarding interpretation of the terms of the initiative. They argue that these uncertainties would be resolved by legislation amending the initiative. But even under the best of circumstances such a process would take time, and there is no guarantee of a speedy or successful resolution on these questions.

Industry Response. This note has speculated on the possible response of producers to passage of the initiative. But the economics of oil and gas production on the North Slope is extremely complicated. Each producer has a different strategy and faces different opportunities and constraints that make it extremely difficult to say, with any degree of confidence, what the response would be.

Constitutional Issues. One predictable industry response is that the tax would be litigated on one or more issues. Litigation could significantly delay the gas commercialization planning process while the industry sorted out the implications of the initiative for their strategic plans. For example, one possible issue would be the fact that there has been no assessment to determine the value of the reserves

²³The discount for energy in the form of gas (compared to oil) has shrunk in recent years to about 10% less than oil. See U.S. Department of Energy, Energy Information Administration.

subject to the tax. It could be argued that the tax represents a “taking,” in that the sum of the tax payments exceeds the value of the asset being taxed.

Political Response. Making tax policy by initiative is a precedent the petroleum industry would view as increasing the risk of doing business in the state. There are other deposits of oil and gas on the North Slope that are not in production, and a reserves tax on those deposits might be proposed to stimulate development in those fields. The notion of Alaska “taking charge” of its resources could backfire to the detriment of future petroleum development efforts in the state.

Revenues. The recent passage of the petroleum production tax (PPT) has completely changed the method used to tax the petroleum industry in the state. Given its complexity, it will take considerable time before it becomes clear whether it is working the way it was intended—both in generating revenue for the state and in creating incentives for investment by the industry. Because the PPT is based on net revenue rather than the wellhead value of production, revenues from the tax will swing up and down more dramatically in response to changes in the price of oil than was the case before the change. Because it is impossible to predict the industry response to passage of this initiative, it would be fiscally unwise for the state to budget on the expectation of additional revenues from the reserves tax, a gas project, and continued oil and gas development. None would be assured.

ALTERNATIVES TO GET A PROJECT MOVING

Many Alaskans are frustrated that North Slope gas is not being sold today, particularly in light of current natural gas prices and oil industry profits. They want to use state policy to move a project forward as quickly as possible. The recently passed production tax is one policy with a clear intent to provide positive incentives to the industry in the form investment tax credits and a graduated tax on net revenues.

Although the intent of this initiative is to stimulate production, its effects are ambiguous and risky. Although it holds out the potential for tax credits which would improve gas project economics, in the reserves tax it contains a much larger financial burden for the industry that would fall on both oil and gas production--present and future. The incentive is modest, particularly considering the limited capacity of individual leaseholders to influence a project timeline. At the same time, the financial burden that it adds to the production of North Slope oil and gas could be several billion dollars. There is great potential risk that it would not work as proposed by supporters.

The stated objective of the initiative is to move North Slope gas to market as quickly as possible. A policy that helps reduce project cost and uncertainty without adversely impacting other elements of North Slope petroleum economics would be a better choice for the state. This is particularly the case because both the economy and state revenues will continue to be highly dependent on an economically healthy petroleum industry for many years to come.