Opportunity Cost and Comparison of Subsidizing an In-State Gas Pipeline vs. the Benefits to Alaska of a Mainline to the Lower 48 States

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I. Summary

The direct and indirect benefits to the State of Alaska and its residents of a large-volume North Slope natural gas pipeline to serve in-state and Lower 48 markets would be substantial. Tax and royalty revenues would be significantly higher than from a small in-state-only gas pipeline; a large-volume mainline to Lower 48 markets would spur increased investment in new oil and gas exploration in Alaska; and the pipeline tariff for gas deliveries within Alaska would be substantially less with the economies of scale of a mainline. This paper reviews the opportunity cost to the state of a potential subsidy of a small in-state gas line vs. the option of possibly applying the same amount of state leverage to a larger mainline project.

II. Introduction

Many people fear that Southcentral Alaska is running out of natural gas for residential and commercial heating and electrical generation. For decades the sole source of gas has been Cook Inlet fields. Large volumes of gas from these original fields have been withdrawn, depleting the reservoirs, and it is uncertain whether sufficient new reserves will be discovered and produced on a schedule to meet the region's needs for later this decade and past 2020. Cook Inlet gas production peaked in 1996 at an average 610 million cubic feet per day (mmcf/d). By 2009, average daily production was down to 380 million cubic feet.[1]

In an attempt to ensure future gas supplies, the Legislature has adopted several tax incentives to promote additional Cook Inlet exploration and development, including tax and regulatory incentives to promote development of gas storage facilities to allow utilities to buy and hold gas for peak winter needs. ENSTAR, the Southcentral gas utility, is moving ahead to develop a natural gas storage facility, which it expects could be in operation by late 2012. Southcentral

[1] State of Alaska Department of Natural Resources, Division of Oil and Gas, "Alaska Oil & Gas Report," November 2009, p. 26.

utilities also are looking into importing foreign LNG to meet demand — if even on a short-term basis — until new Cook Inlet fields can come online or a pipeline is built to deliver North Slope gas to Southcentral.

Regardless of the success of Cook Inlet exploration and development efforts, North Slope gas is seen by many as a potential long-term gas supply to meet Alaska's in-state needs. Although large-volume Lower 48 customers would be needed to provide the significant financial underpinning for a large-diameter North Slope gas pipeline to serve Lower 48 markets ("mainline"), it is expected that any such mainline would include off-takes for smaller spur lines to serve Alaska customers, eliminating the need for Southcentral to rely solely on Cook Inlet gas while also allowing the expansion of gas distribution elsewhere in Alaska.

Because of the significant economies of scale realized with pipeline transportation, the cost of shipping gas consumed in Alaska would be relatively low on a mainline that moves most of its gas to Lower 48 markets. Federal law requires mileage-based tariffs for Alaska customers on a pipeline serving Lower 48 markets, providing in-state users with low tariffs on their small volume of gas, with the larger customers at the end of the line paying most of the project costs. Alaskans need to understand, however, that applies only to the shared cost of the mainline; Alaska gas buyers would have to pay the entire cost for any local spur lines.

The amount of North Slope gas that would be consumed in Alaska would be relatively low compared to gas shipped out of state. A mainline — as proposed by the Alaska Pipeline Project (TransCanada and ExxonMobil) and Denali (ConocoPhillips and BP) — would carry 4.5 billion cubic feet per day (bcf/d). In 2008, about 208 mmcf/d was consumed in Southcentral either as space heat or for power generation,[2] less than 5 percent of the flow from the proposed mainline. That total does not include two large industrial consumers: The Agrium fertilizer manufacturing plant at Nikiski, which shut down in 2008, or the ConocoPhillips/Marathon gas liquefaction plant at Nikiski, which has significantly cut back its production in recent years and has just two years left on its federal LNG export license.

Though the Cook Inlet gas distribution network does not reach Fairbanks, it is assumed that the state's second largest city and other smaller towns along the Railbelt would tap into a North Slope mainline or spur line, if offered the opportunity. Without new, large-volume industrial or manufacturing customers, it is estimated that 260 mmcf/d of natural gas would be consumed in the Railbelt the first five years of a North Slope pipeline (heating and power generation), and 290 mmcf/d in years 10-15.[3] It is unknown how much of that demand would be supplied by existing or new Cook Inlet gas fields and how much might come from the North Slope.

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[2] State of Alaska Department of Natural Resources: 43 bcf for power generation and 33 bcf for gas utilities.

[3] Northern Economics, "In-State Gas Demand Study Volume 1: Report prepared for TransCanada Alaska Company, LLC," January 2010, p. ES-2.

Although many Alaskans talk hopefully of large-volume in-state industrial and manufacturing customers to boost in-state demand for natural gas, no such committed customers exist at this time and the economics are challenging. The combination of the cost of new gas (at a higher cost than gas from the Cook Inlet legacy fields over the past five decades) and a North Slope pipeline tariff would impose high feedstock costs on any industrial buyer. (At least two proposed mining projects have expressed interest in buying gas for their electrical power needs). Depending on the customer's distance from the mainline or existing Southcentral distribution grid, the additional tariff on a small-volume spur line could be substantial.

Meanwhile, two project development teams — Alaska Pipeline Project and Denali — have held open seasons to measure shippers' interest in contracting for long-term capacity in a North Slope pipeline to serve Lower 48 markets. Bid results could come in early 2011, though significant economic hurdles remain before any developer would proceed to project sanction. Both teams estimate the earliest gas could flow would be 2020.

Because of the uncertainty of a mainline to Lower 48 markets and accompanying spur line(s) to serve in-state customers, many Alaskans are pushing for construction — perhaps with state financial backing — of an exclusively in-state gas line, also called the bullet line or Alaska stand-alone pipeline, to meet Alaska's gas needs sooner than waiting for a mainline. The proposal is for a small-diameter, small-volume pipeline from the North Slope to serve Fairbanks, the Matanuska Valley, Anchorage and the Kenai Peninsula — with the option of possibly liquefying and shipping Alaska LNG overseas.[4]

Because of the high costs of Arctic construction and the economies of scale involved in pipeline transportation, it is assumed for this analysis that an in-state line would need to carry at least 500 mmcf/d in order to bring down the tariffs to within sight of reasonable levels, and even then the costs would be high. The Alaska Gasline Development Corporation, created by the 2010 Legislature to develop a business plan for an in-state line, is focusing on a 500 mmcf/d line, assuming there will be large, in-state industrial customers or expanded LNG exports to carry much of the load beyond the demand for residential and commercial heating and power.

A capacity of 500 mmcf/d is a maximum threshold at this time for an in-state line involving state support. Anything more and the state could face a treble damages claim from TransCanada Corporation under a provision of the state-issued Alaska Gasline Inducement Act (AGIA) license that the company holds for development of a mainline. The statute (AS 43.90.440) says the state would owe the AGIA licensee three times its project development expenses, "If, before the commencement of commercial operations, the state extends to another person preferential royalty or tax treatment or grant of state money for the purpose of facilitating the construction of a competing natural gas pipeline project in this state." State support of a pipeline of less than 500 mmcf/d capacity would not trigger the damages provision in statute.

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[4] The economic problems of purchasing and transporting gas for feedstock to supply a price-competitive LNG export plant would be challenging, in addition to securing federal authorization to export Alaska gas.

Regardless of the capacity of an in-state pipeline, it is not clear how much North Slope gas actually would be needed to meet local demand because of the unknown of continued Cook Inlet production. It would depend in great part on how much new gas is discovered and produced in Cook Inlet. Currently, the state estimates Cook Inlet economically recoverable gas resources at 2.4 trillion cubic feet (tcf), with an active exploration program:[5]

All fields: Proved, developed, producing	0.9 tcf
All fields: Probable	0.3 tcf
Additional from existing fields: High confidence	0.4 tcf
Additional from existing fields: Lower confidence	0.6 tcf
All fields: Higher-risk contingent reserves	0.3 tcf
Total	2.4 tcf

However, these reserves will require a high degree of exploration success, and an estimated investment of $2 billion to $3 billion to develop.[6]

As we stated, the tariff for an in-state line would be high. The Alaska Gasline Development Corporation (AGDC) issued a July 1 report: "Alaska Stand Alone Gas Pipeline Project Update and FY 2010 Deliverables". The AGDC report's base-case tariff estimate to Southcentral consumers for a 500 mmcf/d pipeline from the North Slope to Fairbanks, with a 450 mmcf/d pipeline from Fairbanks to Southcentral, would be $8.65 per million Btus (mmBtu) (about 1,000 cubic feet). This is based on a $7.4 billion cost[7] and assumes large-volume industrial or export customers to almost double the pipeline capacity from what would be needed solely for in-state electrical generation and heat. We have verified the tariff estimate with detailed segment modeling. That includes pipeline and gas treatment capital and operating costs, but does not include the price of the gas itself or the cost of the local distribution system. The AGDC report estimates Southcentral local distribution costs at $1.11/mmBtu; Fairbanks local distribution costs would be higher because of the expense of building a new gas distribution system in the community.

[5] State of Alaska Department of Natural Resources, Division of Oil and Gas and Division of Geological & Geophysical Surveys, "Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves," December 2009.

[6] Petrotechnical Resources Alaska, "Cook Inlet Gas Study – An Analysis for Meeting the Natural Gas Needs of Cook Inlet Utility Customers," prepared for ENSTAR Natural Gas Company, January 2010.

[7] The AGDC report estimates the total project cost at $7.8 billion, but for this analysis we have removed the natural gas liquids extraction component, as explained at the top of Page 5. That results in a capital cost of $7.4 billion.

And while the AGDC report included 58 cents/mmBtu as a natural gas liquids (NGL) extraction cost to Southcentral consumers, we have excluded those costs here because it is possible a large share of those liquids could be extracted for other customers, who would then likely cover those costs.

With local distribution costs of $1.11/mmBtu, the total transportation cost to Southcentral customers would be $9.76/mmBtu, exclusive of the cost of the gas. Even before adding the cost of the gas, $9.76 is about 22% more than what Southcentral customers paid for natural gas deliveries in October 2010.

Because the tariff is so high, some legislators and many Alaskans have suggested that the state partially subsidize construction of the in-state line. Dan Fauske, CEO of the Alaska Housing Finance Corp., parent company of the AGDC, has been upfront in his public presentations that the line would require significant state investment to bring the tariff to affordable levels, and that it would be up to elected officials to make that policy decision.[8]

The purpose of this analysis is to examine what the amount of such a subsidy might be, and what the opportunity cost of the subsidy might be when compared to the benefits to the state and its residents of the mainline and accompanying in-state spur line(s).

III. <u>Pipeline Configuration for In-State Line</u>

Using the AGDC report, the estimated capital cost for a 500 mmcf/d in-state line is $7.4 billion, including the pipeline and gas treatment plant. This does not include the purchase price of the gas or local distribution costs. The $7.4 billion, per the report, equates to a levelized nominal tariff of $8.65/mmBtu, including depreciation, capital recovery, operating costs and taxes. The $7.4 billion total does not include NGL extraction facilities. It also does not include cost overruns, which are always a risk on big projects.

The base case operates as follows: 500 mmcf/d of Prudhoe Bay gas exits the gas treatment plant and goes to Fairbanks; 50 mmcf/d of gas (methane/ethane) with a 1,035 Btu/cf content is removed for Fairbanks consumers; the line then carries 450 mmcf/d to Southcentral.

Southcental pays for its share (based on volume of gas) of the pipe to Fairbanks (excluding the short spur line required to move the gas the final miles from the line into Fairbanks), plus the entire pipe from Fairbanks to Southcentral.

[8] For example, see Anchorage Daily News, “State would be on the hook for some gas pipeline costs,” Aug. 9, 2010, or Alaska Journal of Commerce, “State pursues customers for proposed bullet gasline,” Sept. 17, 2010.

The detailed capital costs are as follows (in billions of 2010 dollars):

Gas treatment plant	$2.5
Pipeline North Slope to Fairbanks	$3.0
Spur line to Fairbanks	$0.1
Pipeline Fairbanks to Southcentral	$1.8[9]
Total	$7.4

IV. The Subsidy

The cost of North Slope gas at the wellhead is assumed for this analysis to be $2/mmBtu nominally. An approximate current consensus forecast among industry analysts as to where Lower 48 gas prices could settle after 2020 is about $7/mmBtu. A $2/mmBtu wellhead price in Alaska equates to $7/mmBtu gas in the Lower 48, after subtracting a rough estimate of total gas treatment and transportation costs from the North Slope.[10]

The $2/mmBtu at the North Slope wellhead is a plausible minimum acceptable price to producers, representing a reasonable value for in-state gas sales where a third-party is purchasing the gas on the North Slope for a fixed price and the producers assume neither firm transportation nor market risk.

Adding $2 at the wellhead to the estimated AGDC tariff produces a cost of gas delivered to Southcentral utilities at $10.65/mmBtu, before any local distribution costs.

To analyze a possible one-time subsidy of capital costs to reduce the pipeline tariff for Alaska customers, we calculated from our modeling that about 25% of the AGDC's in-state line tariff is non-capital (operating costs and ad valorem property taxes, assuming private ownership of the pipeline). We presumed that 25% portion would not be subsidized, leaving the capital part of the tariff, $6.49/mmBtu (0.75 X $8.65), as the maximum possible subsidy target.

We assumed the subsidy would be structured to result in a gas price for Southcentral consumers similar to what they would be paying for Cook Inlet gas. Most Cook Inlet gas supply contracts are indexed to Lower 48 gas prices, with a time lag to average out the highs and lows. Lower 48 prices were very high in recent years but have come down quite a bit since. They peaked at $13.68/mmBtu in July 2008, but were in the $3.50/mmBtu range at the start of November 2010. The cost of Cook Inlet gas delivered to ENSTAR, the area's largest consumer utility, averaged $8.69/mcf in 2010 and $7.12/mcf in January 2011.

[9] The pipeline from Fairbanks to Southcentral follows the Railbelt. The AGDC report concluded this was less expensive than a route through Glennallen.

[10] The $5/mmBtu transportation charge consists of a $3.50/mmBtu cost from Prudhoe Bay to Alberta per the Alaska Pipeline Project or Denali cost estimates, and the current tariff of about $1.50/mmBtu on existing pipelines from Alberta to the Lower 48.

Accordingly, we assumed $7/mmBtu delivered to utilities as the subsidy target. At $7, the price is less than what Southcentral utilities paid during 2007-2009 but perhaps more than what prices will be in the near-term if Lower 48 markets remain oversupplied and prices low.

Another variable is that the anticipated option of commercial gas storage in Cook Inlet in late 2012 could reduce the need for short-notice, high-priced peaking gas in the winter, but those storage costs would be substantial and utilities would need to pass on the costs to their customers. Those added costs, however, would apply only to the gas injected and withdrawn from storage, not all of a utility's gas purchases for the year.

Also, in the event Southcentral utilities begin to import liquefied natural gas (LNG), depending on how world LNG markets evolve, those prices could exceed $7/mcf or, at times of competitive pricing, could be less than $7/mcf.

To bring down the cost of North Slope gas through a 500 mmcf/d in-state line to $7 delivered to utilities would require a subsidy of $3.65/mmBtu ($10.65 delivered cost - $3.65 savings from a construction subsidy = $7 gas, plus local distribution). This represents 56% of the capital component of the tariff ($3.65 out of $6.49). A 56% reduction in the capital cost of the project would require a subsidy covering $4.2 billion of the estimated $7.4 billion construction estimate.

Any cost overruns on the in-state line would increase the required subsidy.

Of course, a state subsidy could take other forms, such as no-interest loans or an ongoing subsidy of natural gas prices to consumers, but for the sake of this analysis we assumed a one-time state subsidy of construction costs to reduce the investment components embedded in the tariff.

The market dynamics for energy costs are much different between Fairbanks and Southcentral. Whereas Southcentral is paying $7/mmBtu for natural gas energy, most consumers in Fairbanks are using heating oil priced off crude oil, resulting in prices near $20/mmBtu.

There is some gas service in Fairbanks; the gas is liquefied at a small plant in the Matanuska Valley and trucked to Fairbanks, where it sold at $23.35/mcf in October 2009, more than three times the price of Southcentral. Accordingly, the in-state line would be relatively more valuable to Fairbanks than Southcentral.

However, most of the gas from the in-state line would be destined for Southcentral, and sharing the costs with Southcentral would greatly reduce gas costs to Fairbanks. While there is no question that Fairbanks has high energy costs, and those problems warrant attention, Southcentral consumption would anchor the in-state line. Thus this analysis focuses on the dynamics of the subsidization surrounding Southcentral energy markets.

To help understand how the variables for the price of gas delivered to Southcentral utilities and the price of gas paid to producers on the North Slope could affect the estimated subsidy, Table 1 shows what the subsidy would need to be at North Slope wellhead gas purchase prices of $1 to

$3 and Cook Inlet delivered gas prices of $5 to $9. Again, our base case is a $2 North Slope purchase price and a $7 Cook Inlet delivered price to utilities.

TABLE 1
REQUIRED SUBSIDY (500 mmcfd line)
($billions)

		Cook Inlet Gas Price ($/mmBtu)				
		$5.00	**$6.00**	**$7.00**	**$8.00**	**$9.00**
North	**$1.00 :**	**$5.3**	**$4.2**	**$3.0**	**$1.9**	**$0.7**
Slope Gas	**$2.00 :**	**$6.4**	**$5.3**	**$4.2**	**$3.0**	**$1.9**
Purchase Price	**$3.00 :**	**$7.6**	**$6.4**	**$5.3**	**$4.2**	**$3.0**
($/mmBtu)						

An even smaller 250 mmcf/d in-state line — a project that assumes no large industrial or export customers — would cost $6 billion with a $14.12/mmBtu tariff. With a $2 gas purchase cost and a target price of $7 Cook Inlet, the subsidy would come to $5.2 billion, about 24 percent more than the 500 mmcf/d line.

However, instead of a billion-dollar-plus subsidy to prop up the economics of an in-state line, perhaps the state could try leveraging the same amount of money in some form to boost the economic viability of the larger mainline (which could include a spur line from the mainline, near Fairbanks, to Southcentral). This contribution could be, for example, in the form of property tax relief during construction, low-interest long-term financing, production tax incentives, an actual capital infusion — or a combination of any or all of the above. The purpose would be to reduce the project's risk with the goal of securing a construction commitment from project sponsors.

Just one example: As a direct capital contribution, the same $4.2 billion that would be needed to reduce the tariff on a 500 mmcf/d in-state line to bring about $7/mmBtu gas to Southcentral would reduce the tariff on the mainline by $0.37/mmBtu. Over 25 years that would add over $15 billion in pre-tax undiscounted cash flow to the project and return large benefits to the state through increased production tax and royalty revenues on larger volumes and a higher wellhead value for the gas. But, as stated, there are other ways the state could consider leveraging its participation with the goal of securing a project commitment.

If state financial involvement could mean the difference as to whether the mainline is ever built, the state would be far better off committing the equivalent investment toward the mainline project rather than as an in-state pipeline subsidy. The most profitable measure of how the state would be better off is through much greater public revenues (taxes and royalties). In addition, the heavier demand for gas by a larger pipeline would do much more to spur increased oil and gas exploration and production on the North Slope than a smaller in-state line, which would not pull enough gas from the North Slope to require any exploration for new reserves.

Of course, the economic viability of the mainline is dependent upon investors believing that long-term market conditions will justify the risks associated with the multibillion-dollar construction project. Certainly, today's short-term market outlook and current gas prices are not sufficient to make the project feasible, and it's unlikely that any state financial assistance or fiscal terms could overcome long-term, low-price market conditions. But if at some time North Slope producers and investors believe in a long-term natural gas market of higher prices and growing demand, state financial assistance or a restructured tax regime could make a meaningful contribution to the project's economics.

V. Revenue Estimates: In-State Line vs. Mainline

There are four state oil and gas revenue streams: royalties, production tax, property tax and corporate income tax. The estimated revenue numbers in this analysis are based on the following assumptions:

- 500 mmcf/d for the in-state line.
- 4.5 bcf/d for the mainline, with an off-take to serve Fairbanks and a 450 mmcf/d spur line from Fairbanks to Southcentral. The additional capital cost for the pipeline capacity for the in-state gas is considered *de minimis*.
- All gas for the in-state line comes from Prudhoe Bay.
- The mainline gets 1.1 bcf/d from Point Thomson and the balance from Prudhoe Bay.
- The wellhead value at Prudhoe Bay is $2/mmBtu.
- The transportation deduction between Prudhoe Bay and Point Thomson is $0.22/mcf.
- The gas delivered to customers has a Btu content of 1,035/cf.
- Because the details of the final disposition of NGLs with an in-state line and a mainline are unknown, for simplicity we assume neither project includes marketing of the heavier NGLs (propane plus C4+). Though certainly the NGLs would be marketed, leaving them out of both projects (in-state and mainline) maintains equality in this analysis.

Royalties

For royalties we assume the following in this analysis:

- The Prudhoe Bay royalty rate is 12.5%.
- The Point Thomson royalty rate is 15%.
- Under these assumptions, we get an annual royalty to the state of $47 million with the in-state line and $527 million with the mainline. At least 25 percent of this would go to the Alaska Permanent Fund.[11]

Production (Severance) Tax[12]

For the production tax we assume the following for this analysis:

- All gas produced and consumed in the state as fuel is subject to an 18 cents/mcf tax, as provided for in state statute as a benefit to in-state consumers.
- Any gas sold out of state is subject to the higher production tax rate (25% of net value) for such gas sales, as defined in state statute (ACES).
- In-state gas sales total 500 mmcf/d in both scenarios (in-state line and mainline).
- 250 mmcf/d of in-state gas is assumed to be used for residential and commercial heat/power and is taxed at the lower rate. The other 250 mmcf/d of in-state gas is assumed to be used for industrial/manufacturing. Of this, half (125 mmcf/d) is assumed to be for fuel and subject to the lower rate, and half (125 mmcf/d) is assumed not to be fuel, perhaps LNG or fertilizer for export. In total then, 375 mmcf/d of the in-state gas is assumed to be used for fuel and taxed at the lower rate, and 125 mmcf/d is assumed to be taxed at the higher rate.
- Oil and gas have been decoupled for the production tax.[13]
- There are no incremental costs to produce gas. The upstream costs will be deductible against the oil and so incrementally no costs are allocated to gas. Hence the net value of the gas is the same as the gross value. (With decoupling of the production tax in state statute, there likely would have to be some allocation of field costs between oil and gas. But for the purpose of this analysis, and for the sake of simplicity, we assumed all of the costs will be attributed to ongoing oil production. To the extent

[11] Leases issued before 1979 have a 25% Permanent Fund contribution rate. Leases issued after 1979 have a 50% rate. Prudhoe Bay and Point Thomson were both leased before 1979.

[12] This assumes the current production tax rate. However, it is not improbable the law would be changed before mainline construction.

[13] Under the production tax the progressivity element is based on the per-unit value of oil and gas combined on a Btu basis. Because oil and gas have such disparate Btu values, it is possible that a major gas sale could decrease overall production taxes from what they were solely with oil. We assume the legislature will fix this prior to a major gas project.

some upstream costs are allocated from oil to gas, gas taxes would be less and oil taxes would be more.)

Thus we get an annual production tax of $57 million for the in-state line and $901 million for a mainline project.

Property Tax

The property tax is 20 mills (2%) assessed annually on the state-determined valuation of the investment. Oil and gas pipeline property (such as steel pipe and equipment) is subject to the tax as soon as it enters the state and during construction, which may be several years before it enters service. The in-state line (assuming it is privately owned) could pay over a half-billion dollars in property tax before it enters service; the mainline nearly $1.1 billion. While the tax is important for communities in dealing with the inevitable social and economic impacts during construction, these large up-front costs depress the economic feasibility of the project.

In addition, given that the property tax is based on cost, it exacerbates the negative impact of a cost overrun; not only are costs higher, but so are property taxes.

Per the AGDC report, the capital cost of the in-state line would be $7.4 billion. This would amount to $175 million (with inflation) in property tax in the first year of pipeline operation. Approximately 50% of this would go to the North Slope Borough, 10% to the Fairbanks North Star Borough, 20% to the Matanuska-Susitna Borough, 5% to the Municipality of Anchorage, and the remaining 15% would go to the state, based on the physical location of the pipeline, compressor stations and gas treatment plant.

Per the Alaska Pipeline Project's open-season documents, the mid-price range for the Alaska portion of the mainline and North Slope gas treatment plant are $11.3 billion each ($22.6 billion) in 2010 dollars, or about $29 billion in nominal dollars. In addition, a 500 mmcf/d spur line from Fairbanks to Southcentral would cost $1.8 billion (this analysis assumes a spur line to Southcentral, developed by someone other than the mainline project sponsors). This would equate to $622 million (with inflation) in property taxes in the first year of mainline pipe operations. Approximately 60% of this would go to the North Slope Borough, 5% would go to the Fairbanks North Star Borough, and the remaining 35% would go to the state. Property taxes also would be owed to the municipalities and state on any privately owned spur lines off the mainline, but we did not calculate those estimates.

State Corporate Income Tax

There are two net-income streams generated. First, there is the return on equity in the pipeline. This starts high and decreases as the unrecovered investment declines each year. Second, there is the net-income tax on the production of the gas after deducting severance and property taxes. Since the return-on-equity component on the pipeline is relatively modest, it's expected that the state corporate income tax take on the gas would be worth far more than on the pipeline itself.

Though income is subject to worldwide apportionment under state law (allocating a percentage of business activity to Alaska), we have modeled the tax as if Alaska was a stand-alone entity. Though simplistic, it is easier for this analysis and still indicative of the relative state take. The tax rate of 9.4% was applied to the income.

We estimated state corporate income tax in year one at $47 million for the in-state line and $283 million for the mainline. Those estimates include the income tax on the pipeline and the gas.

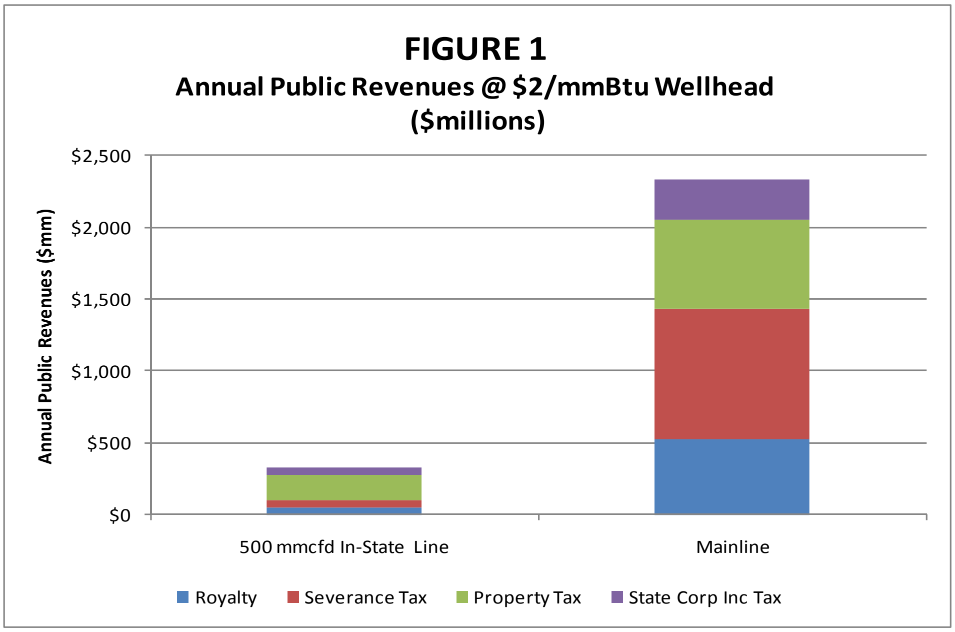
Summary

Table 2 summarizes the difference in public revenues between the in-state line and the larger mainline to serve Lower 48 markets.

Table 2
Annual Public Revenues @ $2/mmBtu Wellhead
($millions)

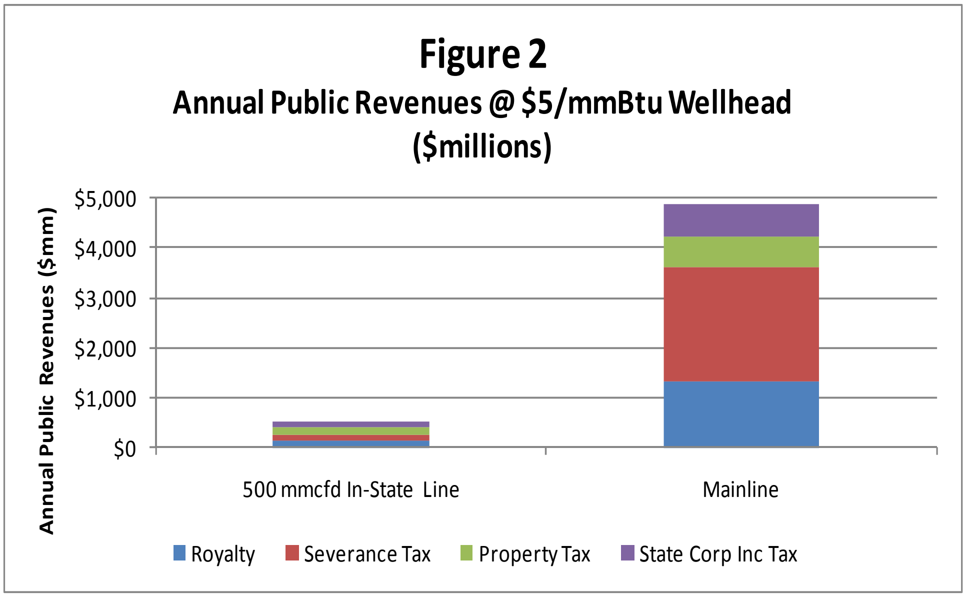
	500 mmcfd In-State Line	Mainline
Royalty	$47	$527
Severance Tax	$57	$901
Property Tax	$175	$622
State Corp Inc Tax	$47	$283
TOTAL	$326	$2,333

Figure 1 illustrates these differences graphically.



Again, these are predicated on a $2 wellhead price, which equates to Alaska gas selling for about $7 in the Lower 48. At higher prices the spread in state revenues between the in-state line and mainline widens further. One reason is that the production tax for in-state gas is fixed in statute at 18 cents/mcf regardless of price, while the production tax rate on gas sold out of state increases as the value of the gas rises. For example, at a $5 wellhead price ($10 Lower 48 price), the in-state line would pull in $502 million a year in total taxes and royalties, while the mainline would generate ten times more at $4.9 billion.

These differences are shown in Figure 2.



For a smaller 250 mmcf/d pipeline, at a $2/mmBtu wellhead value, the relative revenue estimates would be $208 million for the in-state line vs. $2.2 billion for a 4.5 bcf/d mainline (with an additional 250 mmcf/d going to Southcentral). At a $5/mmBtu wellhead the figures are $267 million vs. $4.4 billion, respectively.

VI. Cost of Gas to Southcentral with a Spur Line off the Mainline

Finally, what would the price of gas be to Southcentral consumers with a mainline and off-takes to supply Fairbanks and Southcentral? The gas would realize major economies of scale traveling with the large volume of gas as far as Fairbanks — about half the total journey within Alaska.

With the mainline, the cost of gas would be the sum of four elements: purchase price of the gas (we will assume again that the purchase price of gas is $2), the tariff on the gas treatment plant (GTP), the tariff on the mainline between the North Slope and Fairbanks (or wherever the spur line taps into the mainline), and the tariff on the spur line between Fairbanks and Southcentral.

Per the Alaska Pipeline Project's open-season documents, the mid-point 20-year negotiated tariff for the GTP is $1.41/mmBtu and the in-state portion of the mainline is $0.78/mmBtu, for a total of $2.19.[14] Add in the cost of gas presumed at $2 for this analysis, and deliveries to the Fairbanks off-take could be as low as $4.19/mmBtus, before local distribution costs to consumers.

The estimated capital cost for a 450 mmcf/d spur line between Fairbanks and Southcentral is $1.8 billion. This equates to a tariff of $2.56/mmBtu. Again, the lack of economies of scale on a costly pipeline to move a relatively small amount of gas makes this an expensive segment. This

[14] TransCanada Alaska Co., "Open Season Plan Documents Submitted in Connection with Request for Commission Approval of Detailed Plan for Conducting an Open Season: Volume I of III," FERC Docket No. PF09-11-001, p.10.

would result in a total gas cost to Southcentral utilities of $6.75, or $0.25 lower than our 2020 base price and much less than the unsubsidized cost of $10.65 for a small in-state line. The state certainly could assist in the finances of the spur line to lower the tariff, or use the significant tax and royalty revenues from a mainline to assist residents with their energy costs.

VII. Conclusion

Pipeline economics are significantly affected by economies of scale. Tariffs on smaller-diameter pipelines will be much higher than on large ones, and these differences become increasingly exaggerated with the long pipelines necessary in Alaska. It is difficult to predict significant industrial demand for North Slope natural gas, and it also is unclear how much indigenous Cook Inlet production will endure to meet most or much of local demand in the years ahead.

It will require a significant state subsidy to bring down the cost of gas on an in-state line to reasonable levels; the opportunity costs of such a subsidy are not trivial. An alternative to the in-state line subsidy could be state financial participation toward enhancing the economic feasibility of a pipeline to the Lower 48 that also would bring affordable gas to the Railbelt. The public benefits of such a mainline would dwarf the in-state line:

- Taxes and royalties would be much higher.
- The larger volumes would promote increased North Slope exploration.
- And because of the economies of scale, consumers would get gas priced similarly to a heavily subsidized in-state line.

If the point of an in-state line subsidy is simply to provide lower-cost energy to Alaskans, there are other alternative subsidies that could provide energy at low prices. For example, developing additional hydroelectric power for the Railbelt would free up limited Cook Inlet gas supplies for space heat. Of course, hydro power would not produce any royalty or production tax payments to the state, nor prompt increased investment in North Slope oil and gas exploration. Estimated North Slope gas resources may exceed 100 trillion cubic feet in conventional exploration targets, with that much more possible in unconventional gas hydrates, shale and coal bed methane.[15] In the absence of a major gas line, there has not been a reason to explore for these reserves.

Finally, there is the risk of proceeding with an in-state gas pipeline and having the mainline built later. At that time a large portion of the in-state pipeline project would be redundant, resulting in economic inefficiencies.

[15] National Energy Technology Laboratory, "Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline," DOE/NETL-2009/1385, April 8, 2009.