Alaska Gas Pipeline Tax Mechanism

Submitted to:
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Executive Summary

Natural gas is a clean fuel, of which there are large resources in the U.S. and Canada. Use of natural gas tends to reduce dependence on imported energy from outside NAFTA and decrease emissions of carbon dioxide, a greenhouse gas believed to contribute to global warming. The Alaska Gas Pipeline (AGP) will enable a major new source of domestic energy to be brought to market at a time when new sources of clean natural gas will likely be needed.

- The AGP will strengthen the North American natural gas supply portfolio by increasing the proportion of long-lived supplies.
- The additional supplies will moderate future natural gas price increases and will reduce the risk of price spikes in the future.
- It will benefit the U.S. and Canadian economies, providing regional economic benefits in the form of jobs and investment during construction, and durable benefits of lower cost energy to all consumers. North American nominal GDP will increase by about $35 billion in 2015, $65 billion in 2020, and more in later years.
- Tax credits will likely cost the government nothing. Any payments will be temporary, due to unusual market conditions, and very small relative to benefits to consumers.
- The new source of supply will quickly be absorbed. Markets will have ample time to adjust. The tax mechanism is not a price floor and will not create market distortions or prevent market prices from moving to keep supply and demand in balance.
- The U.S. and Canadian natural gas exploration and production industries will remain buoyant.
- Government support for the ANS pipeline would not violate the WTO subsidy code.
- The ANS gas pipeline tax mechanism is clearly within the spirit of existing, effective governmental incentives provided by the U.S. and Canada.

1. The AGP Will Strengthen the North American Supply Portfolio.

Natural gas is a vital component in the national energy mix. The primary sources are domestic U.S. and Canadian production, sources less prone to disruption than those providing the nation's oil. The U.S. Energy Information Administration (EIA) appears to capture a consensus when it forecasts steady growth in natural gas demand such that U.S. demand in 2015 will be 40% higher than in 2000 – a 30 TCF economy. This demand growth is driven by natural gas qualities of security of supply, flexible pricing, convenience, cleanliness and suitability in new technologies. In particular, new power generating plants are increasingly being based on natural gas because of the high efficiency of combined cycle turbines.

Further into the future, increased supplies of natural gas will enable new technologies to flourish if economic, such as distributed generation using micro-turbines or fuel cells, and transportation systems based on fuel cells. Concerns over global warming could lead to policies limiting greenhouse gas emissions, which would be aided by a low carbon fuel such as natural gas. Indeed, all the market uncertainties that arise from emerging energy technologies and environmental policy initiatives are in the direction of increased natural gas demand, with very little chance for less robust demand growth unless supply limits cause dramatically higher prices.

Forecasts of natural gas demand show a remarkable consensus that the U.S. natural gas demand will reach the 30 TCF mark before 2015, an increase of some 40% over 2000 levels. For the past decade, natural gas prices have shown only a gradually increasing trend, even though production has increased dramatically. This has been possible only because rapid technology developments, including 3D seismic exploration technology and horizontal drilling, have lowered costs of locating and drilling for natural gas, offsetting the cost increases that would otherwise have occurred due to depletion of conventional, lower 48 gas resources. Decline rates for new natural gas wells are becoming increasingly severe. Some industry analysts believe that the availability of new prospects needed to replace depletion of rapidly declining new gas fields is limited. Over time, it will become more and more difficult for technology to keep cost down and replace conventional gas reserves.

The Alaska gas pipeline (AGP) will contribute approximately 4 BCF/D (1.5 TCF per year) of natural gas that would otherwise be of no economic value to North American supplies at a time when increasing amounts of natural gas from nonconventional resources will be required. Alaskan North Slope gas is one such resource. The provision of this large additional supply source will further increase security, reduce some of the projected increase in prices to consumers, and increase the use of this clean energy form. In particular, the AGP would strengthen the North American natural gas supply portfolio by increasing the proportion of long-lived supplies in the supply mix.

In preparing this analysis, Charles River Associates, Inc. (CRA) considered the recent projections in the Energy Information Administration's 2002 Annual Energy Outlook (EIA AEO2002), in particular reviewing the Reference Case and the Slow Technology Case. We also reviewed the National Petroleum Council 1999 study (NPC 1999) Reference Case.[1] In light of information available since the EIA AEO2002 was prepared, as described below, we expect that the future trajectory of natural gas supply, demand and prices will most closely resemble the EIA AEO2002 Slow Technology Case. This is not because we expect a cessation of technological progress. However, the supply, demand and price cycle of 2000-2001 has provided new information not available to the EIA that leads us to believe that the natural rate of decline of recent prolific gas well discoveries will drag down total production more than expressed in the EIA models.

Accordingly, we have constructed a CRA Likely Case that closely resembles the scenario depicted in the EIA AEO2002 Slow Technology Case, and have analyzed the impact of AGP supplies compared to this CRA Likely Case. We now consider that the EIA AEO2002 Reference Case reflects a low price environment. Therefore, we have constructed a CRA Low Case that resembles this scenario. We have also analyzed the impact of AGP supplies compared to this CRA Low Case.

Demand is expected to grow strongly

Recent publicly available projections call for natural gas demand to increase substantially from 2000 through 2020.

Table 1: Projections for U.S. Natural Gas Demand

TCF	2000	2010	2015	2020
EIA AEO2002 Reference Case	22.8	28.1	31.3	33.8
EIA AEO2002 Slow Tech Case	22.8	27.5	30.0	31.2
NPC 1999	22.8	29.0	31.3	n/a

Most consumption segments are expected to increase by 15-20% over the twenty-year period. However, demand for natural gas to generate electricity is expected to grow much more rapidly than other sectors. In all the projections reviewed, demand is expected to more than double over

[1] U.S. Energy Information Administration, *Annual Energy Outlook, 2002*, and National Petroleum Council, *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand*, 1999. Similar conclusions about the outlook for Natural Gas Markets are found in INGAA Foundation, *Pipeline and Storage Infrastructure for a 30Tcf Market: An Updated Assessment*, 2002, and Energy Information Administration, *U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply*, December 2001. In developing our outlook for Canadian gas supplies and prices we also relied on National Energy Board, *Canadian Energy Supply and Demand to 2025*, 1999, and Natural Resources Canada (NRCan) *Energy Outlook Update* and *Canadian Natural Gas: Market Review and Outlook,* May 2001.

the next twenty years, and 2020 demand for natural gas in power generation the Reference Case is 20 % higher than that. The availability of a large new source of natural gas through the AGP will enable this increase in natural gas demand. Further, it will enhance supply stability which will provide a good foundation for the development of other desirable technologies such as micro-turbines and fuel cells that can be used in distributed generation and in new transportation systems.

The AGP will complement other natural gas supply sources

The AGP will complement other supply sources, and will provide insurance against the possibility of more rapid decline in traditional supply basins. Decline rates for new natural gas wells are becoming increasingly severe. Some industry analysts believe that the availability of new prospects needed to replace depletion of rapidly declining new gas fields is limited. The Gulf of Mexico Continental Shelf provided roughly half the increase in domestic natural gas production from 1995 to 2000. While further increases are likely through 2010, the pace of increase will be dampened by the increasing burden of rapid decline in the base production, and may turn into a net decline in the 2010s.

The EIA notes that the number of months between first production from a gas well and the moment when it declines to 50% of its original flow fell from 40 months in 1990 to 24 months in 1999. Roughly half the increase in domestic natural gas production from 1995 to 2000 came from the Gulf of Mexico, whose prolific wells decline at 20-50% per year. NPC 1999 projections reflect the decline of currently prolific areas in the Gulf of Mexico and the Western Canadian Sedimentary Basin. Despite the higher prices post 2010, the NPC shows declining production from the major natural gas provinces in the Gulf of Mexico and the Western Canadian Sedimentary Basin (WCSB). This is consistent with anecdotal evidence from our clients active in exploration and production in these areas, who note the difficulty in sustaining, let alone growing production from areas in which new discoveries decline very rapidly. A notable conclusion of the NPC study is that WCSB production is projected to decline from 2010 to 2015 despite a two thirds increase in gas well completions from 3,000 to 5,000 per year.

The AGP is expected to be completed by around 2012. This is the time when NPC projections start to show declines in production from the Gulf of Mexico and WCSB. The availability of a new source of natural gas will complement these declining supply sources and assure that total net supplies can continue to support demand growth.

Notwithstanding declines in certain provinces, the natural gas production industry in North America will still be extremely healthy, with production volumes substantially higher than in 2000, and with prices higher than those prevalent in the late 1990s.

2. The Additional Supplies will Reduce Risks of Future Price Spikes

In this section, we discuss the outlook for natural gas prices, and explain why we have chosen to base our CRA Expected Case on the EIA AEO2002 Slow Technology Case, and to use the EIA AEO2002 Reference Case as the basis for the CRA Low Case.

The recent natural gas price cycle, in which spot prices soared during 2000 and the fell back sharply in 2001 caused considerable disruption. Consumers were hurt by having to pay higher prices for natural gas and electricity. Producers and their suppliers were hurt by the price decline, and responded by radically reducing natural gas drilling. Extreme cycles of this type are in no one's interest.

We have analyzed carefully this price cycle, and have concluded that it provides two important learnings. First, supply is quite inelastic in the short term. Despite a doubling in the number of rigs employed in natural gas service, production only increased by 0.5 TCF in 2001 compared to 2000. Second, the rate of decline of existing production allows supply to be reduced quickly, and contributes to a rapid rebalancing of supply and demand. Our view is that cycles such as this, with steep, longer peaks and shallow, shorter troughs will be a recurrent feature of natural gas markets in the future. Incremental stable supplies from the AGP will act to reduce the probability of such damaging cycles.

Further, we consider that the 2000-2001 price cycle has provided information that points to longer term gas prices being higher than previously expected. It seems likely that decline rates from existing production in the Gulf of Mexico and the WCSB, the provinces that have provided most of the increase in production during 1995-2000, will be increasingly difficult to overcome. Higher prices will be needed to encourage additional drilling and deployment of new technology in support of new sources of natural gas production.

Future price cycles will bias prices upwards from the trend

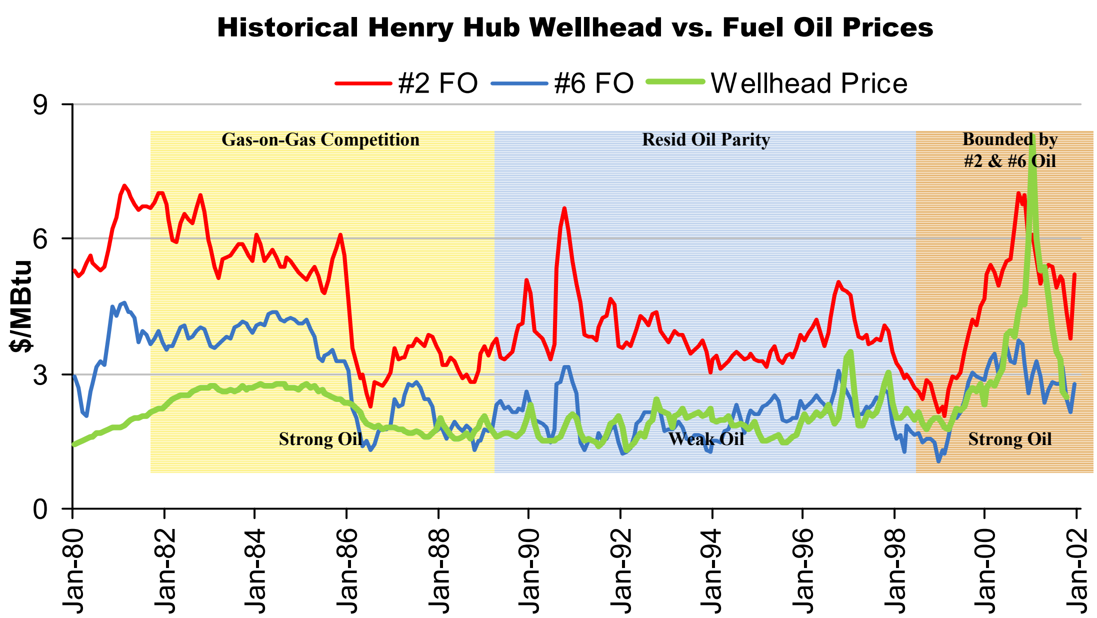
Analysis of supply, demand and prices over the period 2000-2002 suggests that future price cycles may be different than in the past. The price cycle during the period 2000-2002 presents the possibility that future price cycles may be asymmetric, with steep longer highs and shallow shorter lows. The dynamics underlying the 2000-2002 cycle are still not fully clear. However, the fact is that a dramatic increase in drilling for natural gas failed to produce any significant increase in supplies in 2001, and the subsequent decline in prices from 2000 highs rapidly returned U.S. production and prices to 2000 levels.

There are two possible explanations for the failure of natural gas production to increase despite an almost doubling of drilling rigs in natural gas service from early 1999 to early 2001. The first is that the rigs were at work on marginal extension and in-fill projects that were inherently low yield. A second, more disturbing theory is that the rigs were addressing a prospect portfolio including a normal distribution of industry projects, but that the rapid underlying decline rate of recent new fields overwhelmed the contribution of new discoveries and development wells.

The fact is that high prices in 2001 resulted in only a 0.5 TCF increase in domestic production. Consequently, the bulk of the adjustment to high prices had to come from the demand side from fuel switching, conservation and ultimately lower economic output. Fuel switching certainly played a role. Residual fuel oil demand for the first four months of the year increased by nearly 30 % from 788 MBD in 2000 to 1,011 MBD in 2001, and has returned in 2002 to 787 MBD, almost exactly the 1999 level. Most likely, but more difficult to measure due to seasonality effects, distillate fuel demand also increased. Distillate fuel is the back-up fuel for natural gas turbines, since residual fuel oil use risks damaging turbine blades. The relationship between oil prices and natural gas prices appears to have changed again.

As shown in Figure 1, prior to 1990 natural gas prices were formed by strong gas-on-gas competition, reflecting significant surplus deliverability capacity. In the 1990s, natural gas was mostly around residual fuel oil parity. Some observers believe that natural gas prices may now be bounded by distillate and residual fuel oil prices. To the extent that demand adjustments continue to play the largest role in balancing supply and demand during price surges, this suggests a higher average gas to oil price ratio in the future than in the past.

Figure 1: Historical Henry Hub Wellhead vs Fuel Oil Prices



Figures 2 and 3 suggest that adjustments to the down side of the cycle now appear to be quite rapid. In May 2002, within six months of Henry Hub prices hitting falling from $10/MCF to $2.00/MCF, production was back to where it was in 1999 and prices are again where they were in 2000. Many industry participants expect another price surge by winter 2003/4 if not in the coming winter.

Figure 2: Prices have recovered to around 2000 Levels

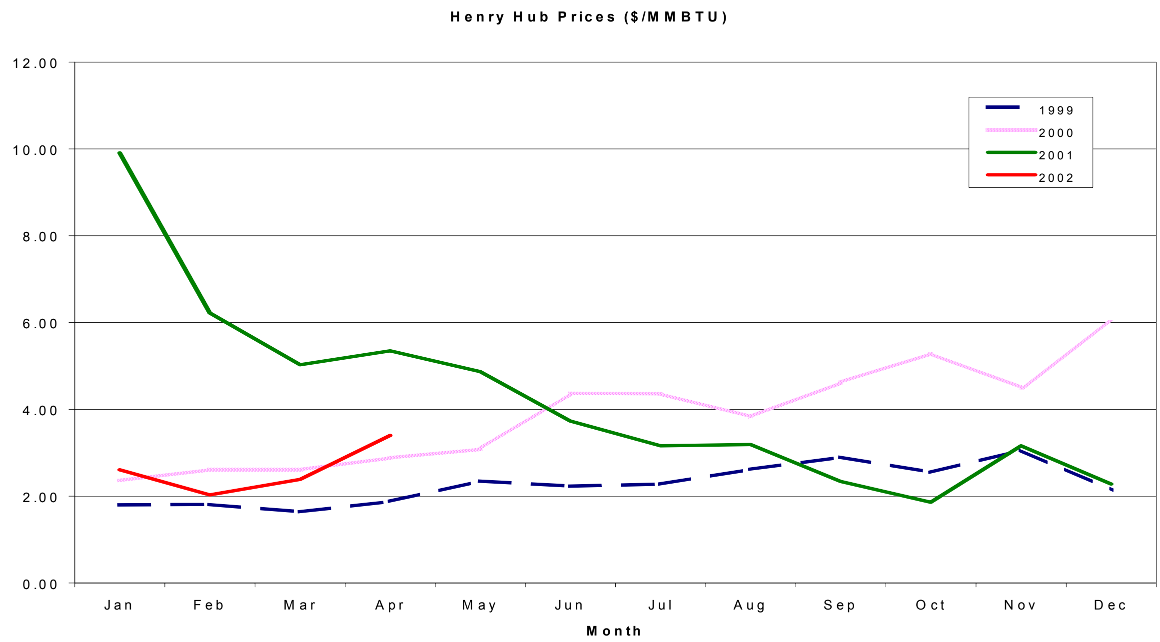
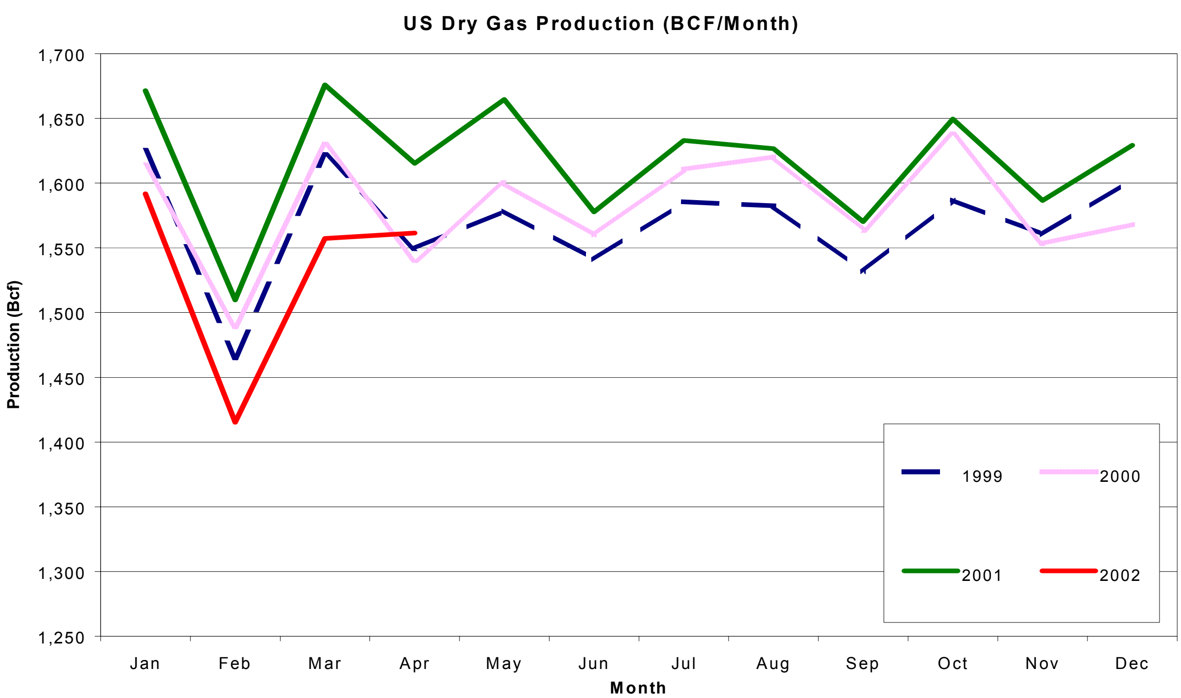


Figure 3: Natural Gas Production has Fallen Back to below 1999 Levels



By reducing the number of wells at work on the GOM shelf, producers very rapidly cause production to drop. This dynamic was not present a decade ago. The combination of reversal of fuel switching and the natural decline of prolific wells on the Gulf of Mexico continental shelf, onshore Gulf of Mexico and South Texas have resulted in a new dynamic of rapid recovery from a price collapse. Cycles with steep, higher peaks and shorter, shallow troughs seem likely to be the norm in the future.

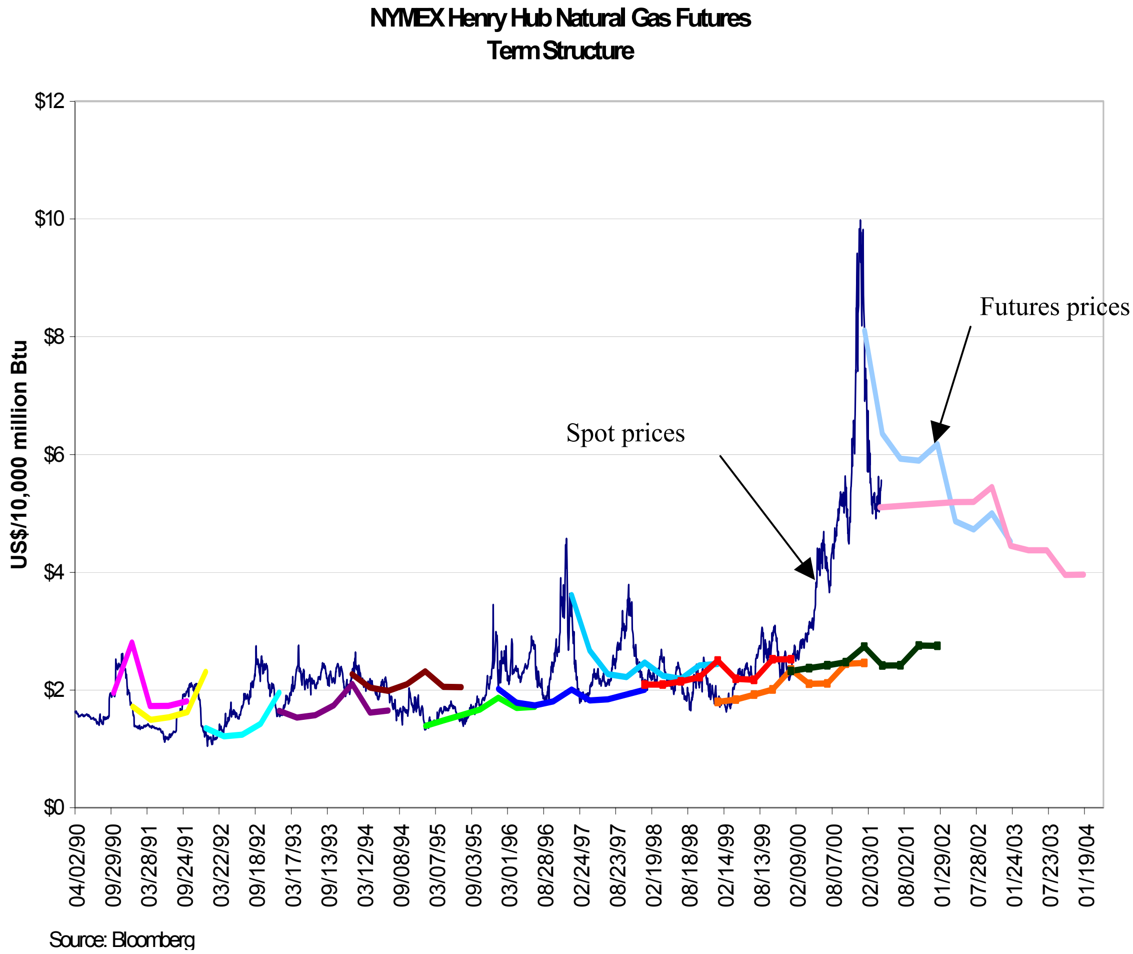
The Lessons of 2000-2001 Point to Higher Long Term Natural Gas Prices

Spot and medium term futures prices have stepped up to a new mean

Futures markets reveal market assessments of how prices will change in the future. Natural gas markets have exhibited a consistent pattern over the last decade, in which futures prices have tended to return toward the mean value of spot prices. The most liquid market is at the Henry Hub, where a full set of spot and futures markets exist. Between 1990 and 1999, the mean value of Henry Hub spot prices rose from about \$1.75 to about \$2.25. Between late 1999 and early 2001, spot prices exploded, and ran up to unprecedented levels. Since June 2001, spot prices have dropped, and in recent months have averaged around \$3.50.

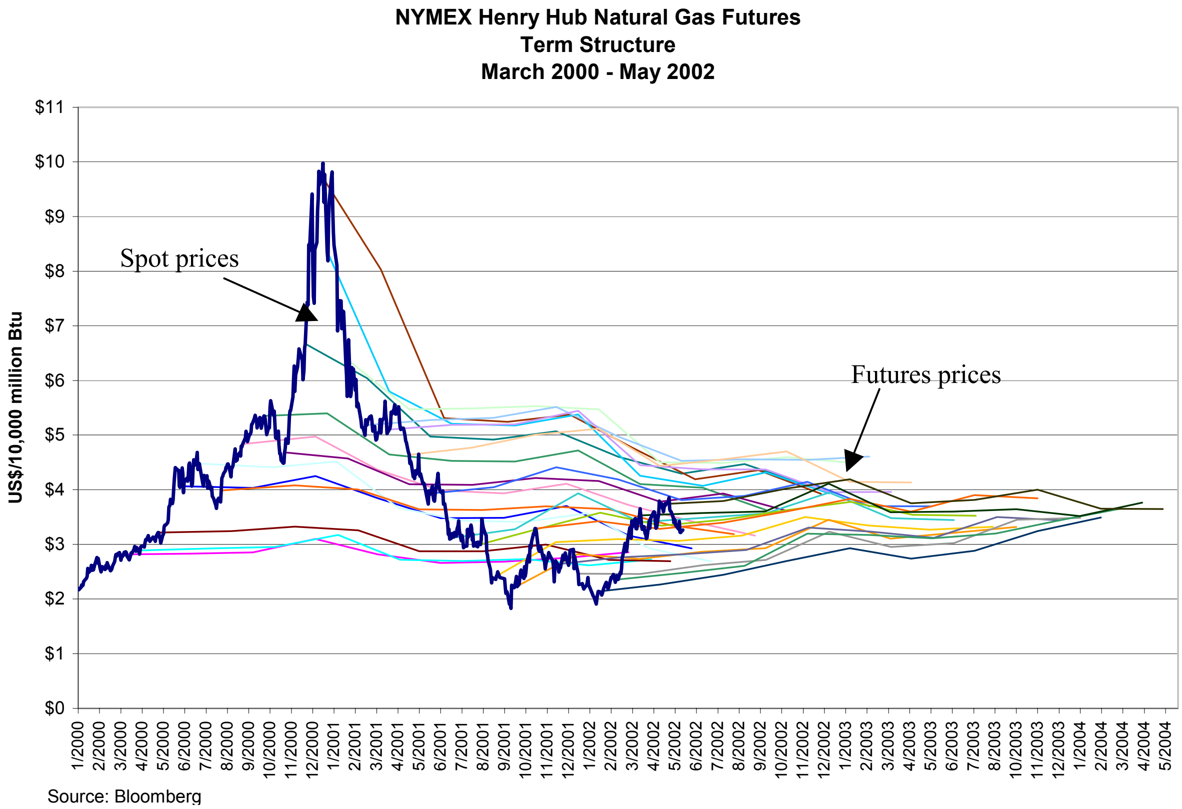
There is a robust market for NYMEX futures contracts at Henry Hub with maturities ranging from three months to three years (35 months). Figures 4 and 5 plot the spot (expiring contract) and futures prices at Henry Hub. Spot prices are plotted every day (the jagged continuous line) and the futures price strip is plotted at intervals. Through early 2000, the 35-month futures contract was very close to the average spot price (Figure 4). In the 1990s, 35-month futures contracts were below \$2.00. By the beginning of 2000, the 35-month futures contract had climbed to about \$3.00. The combination of spot and futures price behavior provided very strong evidence throughout the 1990s that natural gas prices formed what is known as a “mean reverting process with a trend,” meaning that underneath all the price volatility in the market, natural gas prices always returned to a mean value. That value grew from below \$2.00 in 1990 to \$2.50 - \$3.00 by 2000.

Figure 4: Spot and Futures Prices at Henry Hub (1990 – 2002)



Since the market volatility that lasted from October 1999 to June 2001, there has been a dramatic change in the futures market. Since June 2001, the 35-month futures contract has indicated a price range of $3.50 to $3.75 (Figure 5). This signals a market expectation that over the long term natural gas prices will be considerably (about $1.00) higher than they were expected to be before 1999. Between 1999 and 2002, the combination of spot and futures markets actually indicate a consistent growth rate in natural gas prices of over 5%, which implies increasing, rather than decreasing, from their current level in the mid-$3 range. The resulting price outlook would be more consistent with the EIA and NPC low technology cases than with any of their reference cases.

Figure 5: Henry Hub Spot and Futures Prices: 2000 – 2004)



A Higher Long Term Natural Gas Price Projection now Seems Appropriate

The landmark 1999 NPC study on natural gas supply was optimistic on supply, with 2015 domestic production essentially the same as projected by the EIA, but projected significant increases in natural gas prices after 2010 (Table 2). The assumptions behind this study, of impending decline in the most prolific natural gas provinces, now seem well founded. Accordingly, we have selected the EIA AEO2002 Slow Technology Case as the basis for our CRA Likely Case, rather than the EIA AEO2002 Reference Case. This Case has lower prices than the 1999 NPC study Reference Case, after adjustment for inflation since 1998, and may still prove to be optimistic in the sense of projecting low natural gas prices. However, we believe it s an appropriately conservative basis for analyzing the impact of the AGP on future North American natural gas supply, demand and prices, and for estimating the impact on the North American economy.

Table 2: Projections for Average Wellhead Natural Gas Prices

	2000	2010	2015	2020
EIA AEO 2002 Reference Case (converted to current $/MCF)	3.60	3.65	4.48	5.56
EIA AEO 2002 Slow Technology Case (converted to current $/MCF)	3.60	4.12	5.16	6.93
NPC 1999 Henry Hub (converted to current $/MCF)	3.23	4.12	5.57	n/a

In summary, during natural gas price up-cycles, we expect prices to rise to distillate fuel oil parity (potentially putting pressure on supplies of that product), producing a sharp and prolonged increase. During down-cycles, we expect supply and demand to come rapidly into balance around residual fuel oil price parity. This asymmetry in cycles will bias natural gas prices upwards from previous oil to gas price relationships. Futures prices demonstrate the expectation of natural gas prices around $3.75/MCF by 2005, having internalized the lessons of the severe 2000-2001 price cycle. Our view is that these lessons point in the direction of greater stress on the natural gas exploration and production segment from rapid decline in existing production requiring greater efforts in other areas to increase production.

3. The AGP Will Benefit the Economy

The Alaska Gas Pipeline (AGP) project will provide net benefits to the U.S. economy with a discounted present value of about $40 billion (in year 2000 dollars) under the most likely future market scenario.[2] Constructing the Alaskan Gas pipeline will make it possible to deliver 1.5 TCF of gas that otherwise would be stranded on the Alaskan North Slope and thereby provides a less costly source of energy than the alternatives that would be required in the absence of the pipeline. This fundamentally favorable ratio of benefits to costs is the underlying reason for all the economic benefits of the Alaska gas pipeline project. The cost of natural gas provided by the AGP includes the cost of producing natural gas on Alaska's North Slope, building a processing plant in Alaska and a pipeline to Alberta, and the cost of transportation the rest of the distance to U.S. markets (Chicago, to be specific). Producers and the U.S. and Alaska treasuries share in the difference between the cost of producing and delivering Alaskan gas and the price at which it is sold. Consumers benefit from the lower price they pay, compared to the market price of natural gas without Alaskan supplies. Indeed, the value of gas in the U.S. will grow over the life of the pipeline, but the costs of extracting and transporting Alaskan gas will remain relatively constant. On this fundamental basis, Alaskan gas provides benefits to the economy greater than the cost of developing, producing and delivering the gas.

[2] Macroeconomic benefits are estimated with CRA's Multi-Sector Multi-Region Trade model (MS-MRT), which contains a detailed representation of the U.S. and Canadian economies and energy sectors and their trade relationships with the rest of the world. A mathematical description of MS-MRT can be found in Paul Bernstein, W. David Montgomery and Thomas Rutherford, "Trade Impacts of Climate Policy: The MS-MRT Model." *Energy and Resource Economics* 21 (1999): 375-413.

These benefits will appear in many ways in the economy. The largest share of benefits will go to consumers, in the form of lower energy prices. These energy price savings will be experienced directly by households that use natural gas for heating and cooking, and by all households that use electricity, because lower natural gas prices lower costs of electricity generation and electricity prices for consumers. In addition, consumers will benefit from lower prices for all the other goods produced using natural gas the households consume. The agricultural sector will benefit from lower costs for natural gas used for fuel and crop drying, and also from lower cost fertilizer produced from natural gas. Energy consuming industries, including iron and steel, aluminum, pulp and paper, and chemicals will benefit from lower natural gas and electricity prices. The AGP will also make available additional supplies of natural gas liquids, which will be extracted from Alaskan gas where it is delivered into the existing pipeline system. These liquids will be valuable to chemical and other industries.

Direct benefit to natural gas consumers

In the absence of Alaskan gas supplies, market prices of natural gas are expected to increase by about $1.15 per Mcf between 2000 and 2012, and by about $3.80 between 2000 and 2020, as more and more costly incremental supplies are required to meet growing demand. The increased supplies of affordable gas provided by the Alaskan natural gas pipeline will reduce these price increases, to about 55 cents in 2012 and $3.00 in 2020, resulting in direct savings by consumers of about $15 Billion per year (in nominal dollars) 2012 and about $25 Billion per year in 2020. Residential energy use is about 20% of natural gas consumption, so that households will experience about $3 - $5 billion per year in lower natural gas bills between 2012 and 2020. Electricity generation is another 20% of natural gas consumption, so that there will be a $3 - $5 billion saving in the cost of electricity and a $9 - $15 billion saving in the cost of other goods produced with natural gas over the same time period. Alaskan gas will also contribute to more stable prices, by providing a long-term supply that can be produced at nearly constant cost from year to year.

Ripple effects benefiting other segments

Lower natural gas prices will lead to increasing spending power for consumers and lower costs for domestic manufacturers. As a result, economic activity will increase, with U.S. GDP increasing by about $10 billion annually during pipeline construction and by $38 to $65 billion annually after gas begins flowing. Terms of trade for U.S. companies will improve, as the cost of U.S. gas imports fall and the profitability of exports rise. Exports of manufactured goods, farm products, chemicals and other products of energy intensive industries will be higher and imports of energy products will be lower. Since lower prices will lead to a 3% to 5% increase in natural gas use for domestic power generation, greenhouse gas emission rates from power plants will be lower.

Benefits of construction

Construction of the pipeline is estimated to cost about $19 Billion, much of which will be in the form of domestic materials and labor. The jobs will be distributed between the U.S. and Canada. In addition, to the extent that these jobs increase incomes and employment in Alaska and Western Canada, there will be a multiplier effect on the local economy. The investment in the pipeline will provide a stimulus to GDP, as well as providing a valuable asset for the future. We see this in an increase in total U.S. investment and GDP during and beyond the construction period.

Trade impacts

The U.S. will benefit from lower energy imports as a consequence of the Alaska Gas Pipeline, but some portion of the steel pipe used in the pipeline may be imported because of the lack of capacity in the U.S. to produce 52" pipe to the required standards for a high-pressure pipeline. Over time, the reduction in energy imports more than offsets the effects of increases in other imports. As a result, the pipeline improves the U.S. terms of trade even if the majority of steel used in the pipeline is imported.

Additional natural gas supplies from Alaska will reduce the cost to the U.S. economy of natural gas imports, by shifting the North American gas market toward lower prices overall. U.S. natural gas imports are projected to rise from 3.5 TCF in 2000 to about 5 TCF in 2020 in the absence of Alaskan supplies. The lower cost of imported gas will save the U.S. economy $1 - $2 billion per year after the pipeline is completed.

The U.S. steel industry can be expected to benefit from greater steel demand worldwide during the construction of the pipeline, and a permanent improvement in comparative advantage due to lower energy costs. A significant opportunity exists for the North American steel industry to supply the high-pressure pipe and other oil country tubular goods and steel products required for pipeline construction and oilfield services. After the pipeline is completed, lower energy costs will make the steel industry – and other energy intensive industries – more competitive. These effects lead to increased steel production, and to lower net steel imports. Overall, energy intensive industries benefit because of lower costs due to lower natural gas prices. This also contributes to an improvement in the U.S. terms of trade.

Effects on Canada

Construction of the pipeline will provide additional jobs and tax revenues in Canada, as well as contributing to infrastructure development and making both natural gas and gas liquids available to Canadian consumers if desired. Studies done for the Yukon Territories indicate total employment increases in Canada during peak construction years of 35,000 to 45,000 jobs for a comparable project.[3]

Since the Alaska gas pipeline will reduce natural gas costs throughout North America, households and energy consuming industries in the Canadian economy will benefit from lower natural gas prices in the same way as households and industries in the United States.

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[3] *The Alaska Highway Pipeline Project: Economic Effects on the Yukon and Canada*, April 2002, Informetrica, Ltd for Yukon Energy, Mines and Resources.

Since Canada's industrial mix is heavily weighted toward energy intensive industries such as chemicals, pulp and paper, steel and aluminum, lower energy costs will provide an important improvement in Canada's competitiveness and terms of trade. Canadian steel output and exports will have a permanent boost because of lower energy costs, following the added demand arising from pipeline and gas field construction.

4. The Natural Gas Production Sector Will Remain Buoyant

The outlook for the North American natural gas producing industry is buoyant whether or not the AGP is built. As we have noted, there are powerful forces driving natural gas demand upwards. Imports from outside North America are constrained by long lead times in developing new LNG or transnational pipeline projects, as well as by limitations on receiving terminal capacity. Even at EIA Reference Case price projections, total revenues into the sector will increase strongly after 2010.

The forces driving natural gas demand growth have been described in Section 1 above. This demand growth will translate into revenue growth for the petroleum exploration and production sector in the U.S. and in Canada. EIA Reference and Slow Technology Case projections include an increase in LNG imports to fill the capacity of existing terminals, with no further increases beyond 2010. At prices below the EIA Reference Case, LNG supplies could well be attracted from the U.S. to more lucrative markets in Europe and the Far East. With the AGP in place, demand will be slightly higher than if the AGP had not been built due to slightly lower prices. This higher demand will benefit U.S. and Canadian producers and will mitigate the effect of lower prices.

Even assuming that LNG supplies were not reduced by the introduction of the AGP, the outlook is for growing revenues to U.S. and Canadian producers outside Alaska through the 2010s. Table 4 shows revenues accruing to domestic natural gas producers and to Canadian producers from exports to the U.S. (collectively referred to as North American Supply):

Table 4: North American Natural Gas Production and Revenues (Current $)

Low Price Case	**2000**	**2010**	**2012**	**2015**	**2020**
Base Case					
North American Supply (TCF)	25.46	31.51	33.00	34.89	37.41
Average Wellhead Price ($/MCF)	3.60	3.64	4.10	4.68	5.91
Base Case Revenues ($ Bn)	91.7	114.7	135.3	163.3	221.1
AGP Case					
North American Supply (TCF)	25.46	31.51	33.47	35.38	37.89
Average Wellhead Price ($/MCF)	3.60	3.64	3.80	4.30	5.41
AGP Revenues ($ Bn)			6.2	7.0	8.9
Other N. America Revenues ($ Bn)	91.7	114.7	120.9	145.2	196.1
% Change		25%	5%	20%	35%
Most Likely Case	**2000**	**2010**	**2012**	**2015**	**2020**
Base Case					
North American Supply (TCF)	25.46	31.5	32.5	34.09	35.45
Average Wellhead Price ($/MCF)	3.60	4.13	4.53	5.22	7.06
Base Case Revenues ($ Bn)	91.7	130.2	147.2	177.9	250.4
AGP Case					
North American Supply (TCF)	25.46	31.5	33.0	34.56	35.90
Average Wellhead Price ($/MCF)	3.60	4.13	4.28	4.95	6.63
AGP Revenues ($ Bn)			6.4	7.4	9.9
Other N. America Revenues ($ Bn)	91.7	130.2	134.8	163.6	228.1
% Change		42%	4%	21%	39%

Table 4 shows that gross revenues to U.S. and Canadian natural gas producers will increase strongly in the 2010s, even in the CRA Low Case, painting a picture of a vibrant and dynamic industry with significant growth opportunities.

5. AGP Supplies Will Be Quickly Absorbed

It is reasonable to question whether the introduction of a large new supply source might lead to market distortions, either by creating congestion in the supply system, or because of government actions to support the project. There are three ways in which the AGP could result in market distortions. First, the introduction of such a large additional supply source under certain market conditions could lead to an extended period of gas-on-gas competition. Second, The new supplies could distort inter-regional supply patterns. Third, the mechanisms chosen by government to support the AGP project could themselves cause local or global distortions. None of these sources of distortion appear likely to result from encouraging early construction of the AGP.

The AGP will have a beneficial impact on natural gas prices

As described in the previous section, natural gas price cycles in the future seem likely to be different from cycles in the past. There will likely be higher and longer peaks and shorter and shallower troughs than historical patterns.

Introduction of AGP volumes will reduce for a while the probability of natural gas price peaks. This is clearly in the interest of consumers. However, it is recognized by thoughtful producers to be in the interests of producers also. Frequent supply crises will inhibit natural gas market development and result in lower demand, and may also result in legislation or regulation that would be detrimental to the industry. More stable, moderate prices are ultimately in the interests of both consumers and producers.

There will be ample time for producers and shippers to anticipate construction of the pipeline and additional supplies, so that even with a rapid ramp up of production there will be no surprises. AGP supplies will be signaled well in advance of their actual entry, giving all participants plenty of time to adapt. Volumes will be phased upwards over the first year of operation, providing further time for adaptation. Production is expected to begin in 2011, at a rate of about 2.5 BCF/day (0.9 TCF/year) and ramp up in 2012 to 4.3 BCF/day (1.5 TCF/year). Thereafter there is limited capacity for expansion, to a maximum of no more than 5.4 BCF/day (1.9 TCF).

The AGP volumes of 1.5 TCF per year represent 6 percent of the 2012 domestic production of approximately 25 TCF. On the surface, this seems a substantial increment to supplies. However, a combination of demand growth and natural decline in existing fields will allow the new AGP gas to be accommodated quickly without significant market disruption. The full capacity is equivalent to 2-3 years of demand growth at the pace projected for 2010-2015 by EIA. But decline rates for recently completed gas wells have been around 25% per annum. The top thirty producing companies' natural gas production fell by 4.8% from 1Q01 to 1Q02 despite increased drilling in the peak gas price environment of 2000/2001, which should have uncovered new reserves. The combination of phased in operations, demand growth and decline of existing production should allow the orderly entry of the new volumes over the first year of operation.

Overall, we project that the introduction of Alaskan gas into the North American market will not have a disproportional effect on Alberta prices. Even with Alaskan supplies, wellhead prices will continue to increase, but that increase will be reduced about 27 cents per Mcf in 2012 and 43 cents per MCF in 2020.

The natural gas transmission system will adapt

The Alaska Gas Pipeline project includes plans for adequate takeaway capacity from the Alberta market. A combination of increased utilization of spare capacity, expansion of existing pipelines or building an entirely new pipeline into the lower 48 can provide sufficient additional capacity out of the Alberta market to prevent disproportional impacts on Alberta prices. Additional pipeline capacity in Canada and the lower 48 is required in any event as the U.S. moves toward a 30 TCF market over the next decade. That expansion requires investment that has not yet occurred, and the system therefore remains flexible to remove bottlenecks and create sufficient capacity to move Alaskan supplies throughout the U.S. market.

EIA projections call for an increase in natural gas supplies to the U.S market from 23 TCF in 2000 to 28 TCF in 2010 and 31 to 34 TCF in 2020. This supply increase will require considerable expansion in pipeline capacity. The NPC 1999 study, which followed a similar demand profile to the EIA AEO 2002, projected that an investment of $11 billion (1998$)

between 1999-2015 in new pipeline and storage infrastructure would be required. AGP merely rearranges that new investment regionally, with a requirement for additional investment in North-South routes.

The NPC study projected that the basis between AECO vs. Henry Hub would decline from its recent levels of close to $1/MCF to $0.5/MCF in 2003, but would again widen to over $1/MCF in 2006 before collapsing to $0.25/MCF in 2010. Our analysis implies a basis of $0.65/MCF by 2020 in the Likely AGP Case. It is our belief that, once the AGT is under construction, pipeline companies will have an incentive to add takeaway capacity to provide AECO gas with outlets to markets in California, the Midwest and New England. The length of construction time for the AGP will allow plenty of time for pipeline companies to file expansion proposals with regulatory bodies, secure permits and build new capacity.

Mackenzie Delta supplies will not be stranded

Significant increases in demand for natural gas for Alberta oil sands extraction and processing are projected to occur at about the same time that Mackenzie Delta supplies will start flowing. This demand will be in location that the Mackenzie Delta is in a favorable position to supply, and should be sufficient to absorb the increased natural gas production.

6. The Tax Mechanism Will Not Create Market Distortions

The tax mechanism proposed in Senate Bill S.1766 is a simple device to increase the expected return on the AGP and lower certain market-price related risks. Its market impact is neutral. Although the Bill references a price at AECO below which tax credits will be triggered, ***this is not a floor price.*** The price at AECO will be whatever the market dictates regardless of the tax mechanism. The only difference between the situation with the tax mechanism in place and a hypothetical situation without the tax credit is a potential allowance by the IRS of tax credits to companies that produce natural gas on the Alaska North Slope (who in all likelihood will have invested in the pipeline). This will not affect prices at AECO or elsewhere. The only effect on market prices comes from construction of the pipeline and availability of Alaskan supplies. Any incentive, or market development, that caused the pipeline to be built would have the same effect on markets as the proposed tax mechanism.

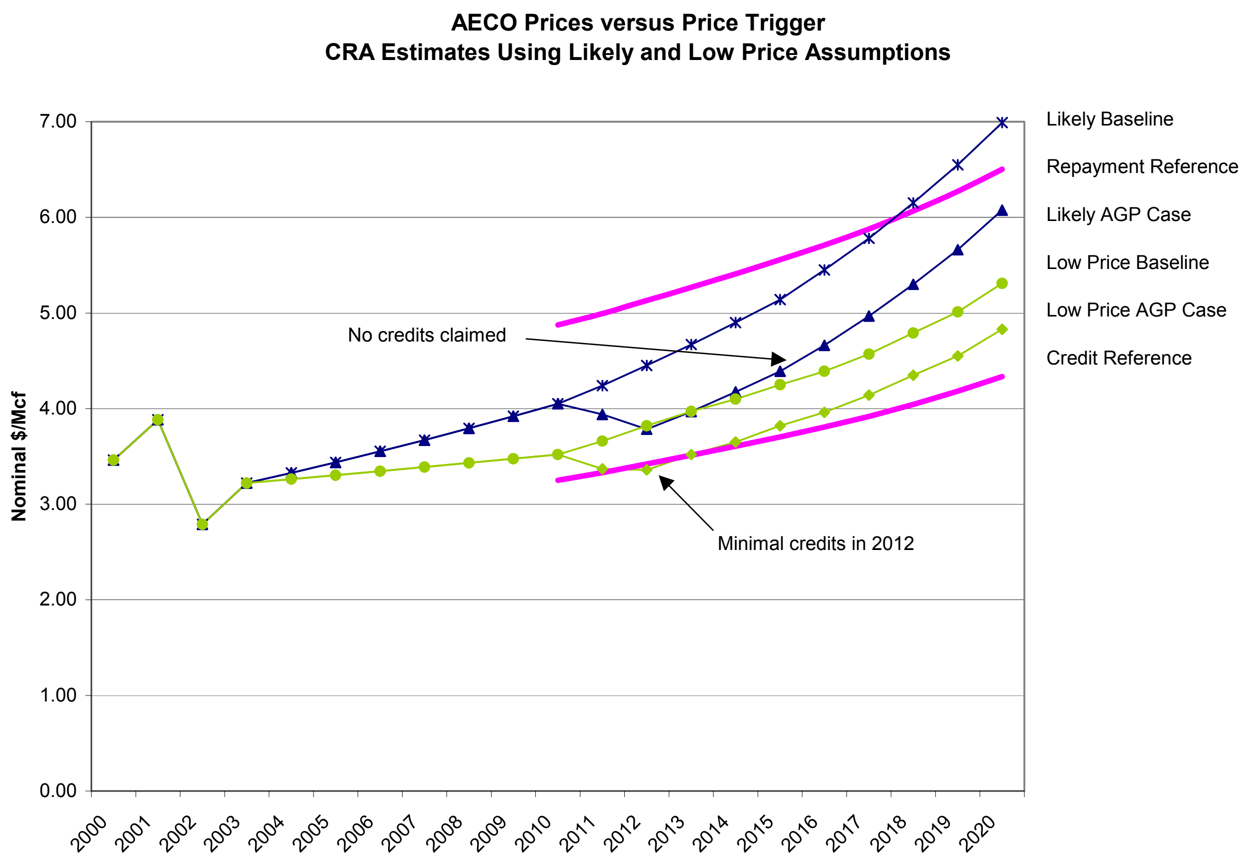
Once the pipeline is built, economics will encourage producers to produce the maximum possible flows of gas and transport them along the AGP. This may reduce prices at AECO below what they would otherwise have been for a short time (see discussion above). However, once the AGP is built, prices will not in any way be influenced by the tax mechanism. The tax mechanism only affects the probability that the AGP will be built.

In summary, the AGP will most likely have a beneficial effect on natural gas prices. It will lower the probability of disruptive price spikes to the short term benefit of consumers and the long term benefit of producers. The new volumes should be accommodated in an orderly manner over the first year of operations of the pipeline. The AGP will rearrange, but not alter in absolute terms, inter-regional pipeline construction in a way that will not significantly change regional price bases. Except for potentially bringing in Alaskan supplies, the tax mechanism in S. 1766 is entirely neutral to natural gas markets.

7. Utilization Of the Reference Price Mechanism Would Not Result In Significant Payments

In the most likely case, prices at the AECO-C hub in Alberta would remain comfortably above the level that would allow producers to claim the tax credit in any year, even after the effects of additional Alaskan supplies on market prices are taken into account (Figure 6).[4] This is consistent with the decision by the Joint Tax Committee to score the tax mechanism with zero budget impact.

Figure 6: Natural Gas Prices at AECO Relative to Tax Credit Reference Price (Nominal $)



[4] Estimates of price impacts were developed using CRA's own model of North American natural gas markets. The estimated price impacts are consistent with the EIA study *The Effects of the Alaska Oil and Natural Gas Provisions of H. R. 4 and S. 1766 on U.S. Energy Markets*, February 2002

It is conceivable that in a soft market payments would occasionally occur. Indeed, were this not possible, the proposed tax mechanism could have no effect on decisions to develop the pipeline project. Within the likely pricing band for gas at AECO, the likelihood of payments is small. Figure 6 shows that even when low North American wellhead prices consistent with the EIA reference case are further reduced by the introduction of Alaskan gas supplies (Low Price AGP Case), the AECO price remains above the $3.25 credit reference price (adjusted for inflation after 2010) in all but one years after the pipeline begins operation. Lower wellhead prices or higher basis differentials to AECO could depress the price further, but such a combination is highly unlikely

In the Low Price AGP Case, there is a very small revenue effect, with AECO prices dipping below the level that allows tax credits by a few cents in the two years after full flow is achieved. It would take prices significantly below levels with the Low Price Case that is consistent with the EIA reference forecast to trigger total claims for tax credits greater than a total of $100 million for all time. This unlikely possibility needs to be balanced against the much more likely outcome that the AGP will provide net benefits as large as $40 billion.

As discussed earlier, market risks are predominantly that prices will be higher than the Low Price case, which makes payments even less likely. Should prices move from the low case projections in early years to the more likely price projections in the outwears, prices at AECO would approach levels at which repayments could occur. Contrary to some claims, these repayments would not cause production to be shut in, because prices net of the repayment would remain sufficiently high that continued production would be profitable.

The Alaskan tax mechanism is a hedge against higher natural gas prices. In exchange for a small probability of providing limited tax credits – even under the worst conditions of low U.S. natural gas prices and high basis differentials to Alberta – residential and industrial energy consumers gain insurance that under conditions of tight supplies and rising market prices they will save tens of billions of dollars every year.

8. The Alaska Price Mechanism Is Not A Violation of U.S. Obligations Under the WTO Subsidy Code

The subsidy code applies only to the direct effect of subsidized exports on the domestic market of the importing country, and “world price” effects are not grounds for a complaint. The pipeline project is designed to move gas to the lower 48, and since it will be accompanied by adequate increases in takeaway capacity from Alberta, the project will have effects identical to a direct link between Alaska and the lower 48. Competition between Canadian gas and Alaskan gas will occur in the U.S. market, since the project is premised on creation of adequate takeaway capacity from Alberta. Effects on Canadian producers come from effects on the price in the U.S. and the North American market in general. There will be no net exports to Canada from the pipeline. Thus effects on the market are “world price” effects under the WTO code.

9. There Is Ample Precedent For This Type Of Government Incentive

There have been two consistent policy purposes of incentives for energy production.

- One is to share the risks and benefits of developing unconventional supplies, where the scale of the project and market, technology and regulatory risks are disincentives to development of additional domestic energy supplies that would be in the national interest. This is the stated intent of the alternative fuels production tax credits, royalty relief, enhanced oil recovery, and oil sands incentives.

- The other purpose is to prevent fixed royalty and severance tax payments that are deducted from gross revenue from discouraging otherwise economic energy production during periods of low energy prices. This is the purpose of the deepwater royalty relief program and the marginal well tax credit -- which are also triggered when market prices fall below a specified level, and Canadian royalty relief.

The Alaska natural gas tax mechanism is consistent with both these purposes, and is much more limited in scope than other programs: it applies only if prices fall to low levels relative to market expectations, it allows for recapture when prices are high, and it has only a small likelihood of actually being used.

Comparable measures include:

- The Section 29 alternative fuels production tax credit provides a tax credit that is currently greater than $1.00 per Mcf for gas produced from coal bed methane and tight formations. In FY 2002, Section 29 credits are estimated to cost $900 million. Section 29 credits phase out at prices above $8.00 per Mcf, but have no pay-back mechanism.

- Deepwater Gulf of Mexico Royalty Relief was instituted in 1995 for purposes very similar to the ANS Gas Tax Credit: to encourage development of deepwater oil and gas in the Gulf of Mexico, including investment in technology and pipelines to market. The Act eliminated the 12.5% royalty payments on the first 87.5 million boe produced from a field in deepwater. The credit phases out at $3.50 per Mcf, with no payback mechanism. This is similar insurance to the ANS price mechanism, because it provides for lower taxes when prices fall to levels where an investment becomes uneconomic.

- Section 43 tax credits allow a credit equal to 15 percent of costs of qualified enhanced oil recover (EOR) projects. The credit phases out at high oil prices, and has no payback provision. Its purpose is to stimulate development and use of advances oil recovery techniques to increase domestic reserves.

- The Energy Bill also includes a marginal wells tax credit, which will provide credits to keep marginal (high-cost) wells in production when prices fall.

- Canadian Oil Sands incentives are principally in the form of accelerated depreciation, and are expected to cost the federal and provincial governments $820 million (C). The oil sands incentives amount to about 4.6% of the investment in oil sands. These incentives have contributed to a dramatic expansion of Canadian heavy oil production towards an estimated 2.8 MMBD by 2010, with investments expected to reach a cumulative Cdn $ 35 billion.

- Canadian Hibernia incentives were provided by the federal and Newfoundland governments to spur development of the Hibernia offshore oil field: Government incentives came in the form of grants, tax exemptions, loan guarantees, interest free loans and an equity investment in the project. The equity investment alone was almost $1 billion, loan guarantees were made available in excess of $2 billion, and other grants and tax benefits exceeded $1 billion in value.

- Northwest Territories, Newfoundland and Labrador provide royalty relief intended to encourage investment in hostile northern and offshore environments. Royalties are reduced significantly until the investment in a project (including a "fair rate of return" on capital) is recovered, and then rise to levels comparable to Alaska and Alberta. The reduction in royalties provides protection for the investors against higher project costs or low prices, by allowing reductions in royalty payments until the investment is recovered. The longer that recover takes, the longer reduced royalties will be in effect.