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The Effects of the Alaska Oil and Natural Gas Provisions of H. R. 4 and S. 1766 on U.S. Energy Markets

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I. Introduction

On December 20, 2001, Sen. Frank Murkowski, the Ranking Minority Member of the Senate Committee on Energy and Natural Resources requested an analysis of selected portions of Senate Bill 1766 (S. 1766, the Energy Policy Act of 2002) and House Bill H.R. 4 (the Securing America's Future Energy Act of 2001)[1]. In response, the Energy Information Administration (EIA) has prepared a series of analyses showing the impacts of each of the selected provisions of the bills on energy supply, demand, and prices, macroeconomic variables where relevant, import dependence, and emissions. The analysis provided is based on the *Annual Energy Outlook 2002*[2] (*AEO2002*) midterm forecasts of energy supply, demand, and prices through 2020.

Because of the rapid delivery requested by Sen. Murkowski, each requested component of the Senate and House bills was analyzed separately-- that is, without analyzing the interactions among the various provisions. Because of the approach taken:

- The combined impact of the individual policies cannot be determined by simply adding the individual policy impacts together. For example, a provision establishing a renewable portfolio standard (RPS) for electricity production, and one that establishes a bio-diesel program for transportation fuels, each increases the use of biomass. The simultaneous enactment of the two provisions would be likely to increase biomass costs because of the competition for land and other needed resources. The estimated fossil energy displaced will, therefore, be lower than the sum of the two individual policy impacts because of the higher resource costs. Stated another way, the impacts of multiple simultaneous policies are non-linear.

- Some policies will interact to increase the overall response while others may interact to mitigate the impacts of each other. For example, when two separate policies increase demand and, consequently, production of an advanced technology, the reductions in manufacturing costs expected from increased production are likely to be accelerated, making the technology even more attractive in later years. The total adoption of the advanced technology in this case could be greater than the sum of the parts.

In addition, the following should also be noted:

- Computation of expected benefits and costs of equipment installed at the end of the forecast horizon (e.g., 2020) requires estimates of costs and prices for a number of years beyond this period. Since EIA does not project costs, prices, or benefits past 2020, the estimates of the benefits after 2020 must be assumed for equipment installed by 2020. For example, analyzing consumer product standards for air conditioners through 2020 requires an estimate of the savings through 2036, because of the expected operating life of the new equipment that is projected to be installed. *AEO2002*, however, only produces projections through 2020. For the remaining years from 2021 to 2036, we have assumed the savings remain constant at

[1] Letter from Sen. Murkowski to Mary J. Hutzler, dated December 20, 2001. On Feb. 6, 2002, Sen. Murkowoski provided specifications for the scenarios to be considered.

[2] *Annual Energy Outlook 2002, With Projections to 2020,* U.S. Department of Energy, Energy Information Administration, DOE/EIA-0383(2002), December 2001.

2020 levels. Such estimates of savings are highly uncertain and could be higher or lower than this estimate.

- Some aspects of the bills cannot be modeled because of lack of specificity. For example, several provisions of the bill require the Department of Energy (DOE) to evaluate the desirability of setting standards for stand-by power and other electronic devices. Because the legislation does not state what the standards will be, EIA cannot quantitatively analyze them.

EIA's projections are not statements of what will happen but what might happen, given known technologies, technology and demographic trends, and current laws and regulations. Thus, the *AEO2002* provides a policy neutral reference case that can be used to analyze energy policy initiatives, as has been done in each of these studies. EIA does not propose, advocate or speculate on future legislative or regulatory changes. Laws and regulations are assumed to remain as currently enacted or in force in the Reference Case; however, the impacts of emerging regulatory changes, when clearly defined, are reflected.

Models are simplified representations of reality because reality is complex. Projections are highly dependent on the data, methodologies, model structure and assumptions used to develop them. Because many of the events that shape energy markets are random and cannot be anticipated (including severe weather, technological breakthroughs, and geo-political disruptions), energy market projections are subject to uncertainty. Further, future developments in technologies, demographics and resources cannot be foreseen with any degree of certainty. These uncertainties are addressed through analysis of alternative cases in the *AEO2002*.

This paper addresses the Alaskan oil and natural gas provisions of H.R. 4 and S. 1766. The estimated effects of the provision in H.R. 4 proposing crude oil production in the Arctic National Wildlife Refuge (ANWR) and of the provision in S.1766 concerning the construction of a pipeline bringing Alaskan natural gas to the Lower 48 States are presented below. This paper does not incorporate the other provisions of S. 1766 or H.R. 4, such as new appliance standards or new car efficiency standards.

II. Opening the Coastal Plain area of the Arctic National Wildlife Refuge to Crude Oil Production

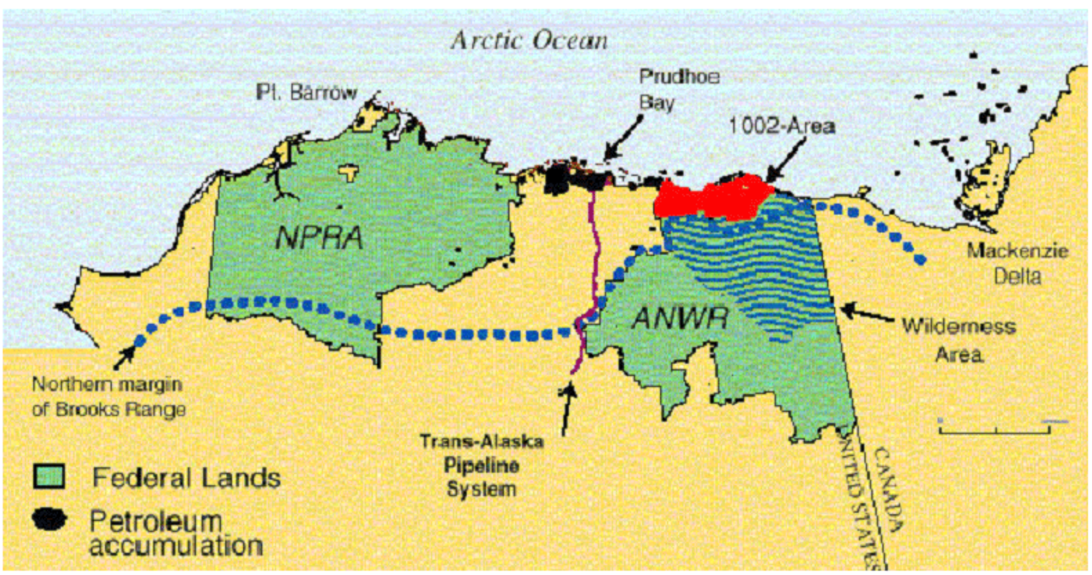
Summary of Results

Title V of H.R. 4, "Arctic Coastal Plain Domestic Energy Security Act of 2001," calls for establishing a competitive oil and gas leasing program in the coastal plain of the Arctic National Wildlife Refuge (ANWR), resulting in an "environmentally sound" program for the exploration, development and production of oil and gas resources in this area. EIA's analysis shows that opening ANWR to crude oil production will likely increase domestic production, and reduce foreign oil dependence. Using the mean estimates of the available resources, opening ANWR to crude oil development is expected to add 800,000 barrels per day to U.S. crude oil production in 2020, 9 years after production in ANWR is projected to begin. The increased production, relative to the AOE2002 reference case, is projected to reduce the net share of foreign oil used by U.S. consumers in 2020 from 62 to 60 percent, while increasing domestic production by 14 percent. A high resource sensitivity case projects that adding ANWR production could add as much as 1.5 million barrels per day to total Alaskan production and reduce import dependence to 57 percent. In a low resource sensitivity case, ANWR adds 590,000 barrels per day by 2015, before production declines to 510,000 barrels per day in 2020. Since the natural gas resources in ANWR are estimated to be about one-eighth the size of the oil resources, opening ANWR to natural gas production is not considered to have as significant an impact on U.S. energy markets, and is not considered in this analysis.

Background

The Federal Government now prohibits oil and natural gas development in ANWR. ANWR is located on the northern coast of Alaska, due east of Prudhoe Bay, the largest oil field ever discovered in the United States, and the National Petroleum Reserve-Alaska (NPRA) (Figure 1.) Surveys conducted by the U.S. Geological Survey (USGS) suggest that between 5.7 and 16.0 billion barrels of technically-recoverable oil are in the coastal plain area of ANWR (also referred to as the 1002 Area), with a mean estimate of 10.4 billion barrels, divided into many fields.[3] (Technically-recoverable resources are resources that can be recovered with today's technology.) This estimate includes oil resources in Native lands and State waters out to a 3-mile boundary within the coastal plain area. The mean estimated size of oil resources on Federal lands alone is 7.7 billion barrels. In comparison, the estimated volume of technically-recoverable undiscovered oil in the rest of the United States is 136 billion barrels. Ultimate recovery at the Prudhoe Bay field, including production to date, is estimated to be 13.0 billion barrels.

Figure 1. Map of Northern Alaska and Northeastern Canada Showing ANWR and the Coastal Plain 1002 Area



Source: *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment*, SR/O&G/2000-02, May 2000.

[3] US Geological Survey, USGS Fact Sheet FS-04-98, May 1998.

ANWR was created by the Alaska National Interest Lands Conservation Act (ANILCA) in 1980. Section 1002 of ANILCA deferred a decision on the management of oil and gas exploration and development of 1.5 million acres of potentially productive lands in the coastal plain of ANWR. Title V of H.R. 4 proposes to open this coastal plain area to exploration and production. The coastal plain area represents about 8 percent of the total area of ANWR. The USGS estimates that 74 percent of the oil resources in ANWR's coastal plain area are on Federal lands, with the remaining 26 percent on State and Tribal lands.

To date, there has been no assessment of the oil and natural gas resources in the rest of ANWR outside of the coastal plain area. However, it is unlikely that the non-coastal plain area of ANWR has the same levels of resources that are estimated to be in the coastal plain area, due to differences in geology. The "Arctic Coastal Plain Domestic Energy Security Act of 2001" only calls for opening the coastal plain area to development, and does not include any provision to open any of the rest of ANWR.

Methodology and Assumptions

The effects of opening the coastal plain area of ANWR were determined by incorporating the ANWR region into the Oil and Gas Supply Module of the National Energy Modeling System (NEMS.)[4] The key assumptions required to forecast crude oil production from the coastal plain of ANWR are discussed below.

- ***Timing of first production***

At the present time, there has been no exploration and development activity in the coastal plain region. An earlier EIA report, *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment* (Report # SR/O&G/2000-02) suggested that between 7 and 12 years were required from an approval to explore and develop to first production from the coastal region of ANWR. The study further noted that the time to first production could vary significantly based on time required for leasing after approval to develop is awarded, and that environmental considerations and the possibility of drilling restrictions also could significantly affect projected schedules.

Following the earlier study, this analysis assumes that passage of the current legislation in 2002 will result in first production from the ANWR area in 2011.

- ***Field size distributions***

The current analysis uses the USGS assessment of potential field sizes in the coastal plain area, based on its assessment of the underlying geology. For the purposes of evaluating the impact of opening ANWR for U.S. markets, EIA assumed that State and Tribal lands within the coastal plain of ANWR would be opened for development.

In the mean resource expectation case, the total volume of technically recoverable crude oil projected to be found within the coastal plain area is 10.4 billion barrels. The largest projected field in ANWR is nearly 1.4 billion barrels. While considerably smaller than the 13 billion barrel

[4] For additional information on NEMS, please see EIA's *The National Energy Modeling System: An Overview*, DOE/EIA-0581(2000).

Prudhoe Bay field, this would be larger than any new field brought into production in decades. Subsequent fields are expected to be considerably smaller, with two additional fields with 700 million barrels of oil, five additional fields each with 340 million barrels of oil, and a large number of smaller fields. To put this in context with recent domestic oil discoveries, the Alpine Oil field in Alaska – the largest field to start producing in recent years – is estimated to have 413 million barrels of ultimate recovery.

- ***Production profiles***

Potential production from ANWR fields is based on the size of the field discovered and the production profiles of other fields of the same size in Alaska with similar geological characteristics. In general, fields are assumed to take 3 to 4 years to reach peak production, maintain peak production for 3 to 4 years, and then decline until they are no longer profitable and are closed.

- ***Timing of continuing development***

This study assumes that the much of the oil resources in ANWR, like the other oil resources on Alaska's North Slope, could be profitably developed given the current levels of technology. This study assumes that new fields in ANWR will begin development 2 years after the last field was opened. It is assumed that larger fields will be developed before smaller fields.

The decision to use a 2-year lag in bringing ANWR fields into production is driven by four factors. First, there is the size of the fields in ANWR themselves. Second, there is considerable investment infrastructure required to both begin production in these fields and to link these fields to the Trans-Alaskan Pipeline System (TAPS). Third, there is competition of resources from other projects, including the projected development of oil fields in National Petroleum Reserve - Alaska, that potentially limits the resources available for ANWR development. Finally, increasing the rate of ANWR development could also require an expansion of TAPS capacity.

This study does not assume that the expected rate of technological change in the oil and gas industry will affect the rate of development of ANWR. While a higher rate of technological development may reduce costs and lead to more efficient development of ANWR resources, the impediments to the development of ANWR resources are the legal restrictions and the infrastructure required to bring the ANWR fields into production and tie ANWR fields to TAPS.

- ***ANWR Natural Gas***

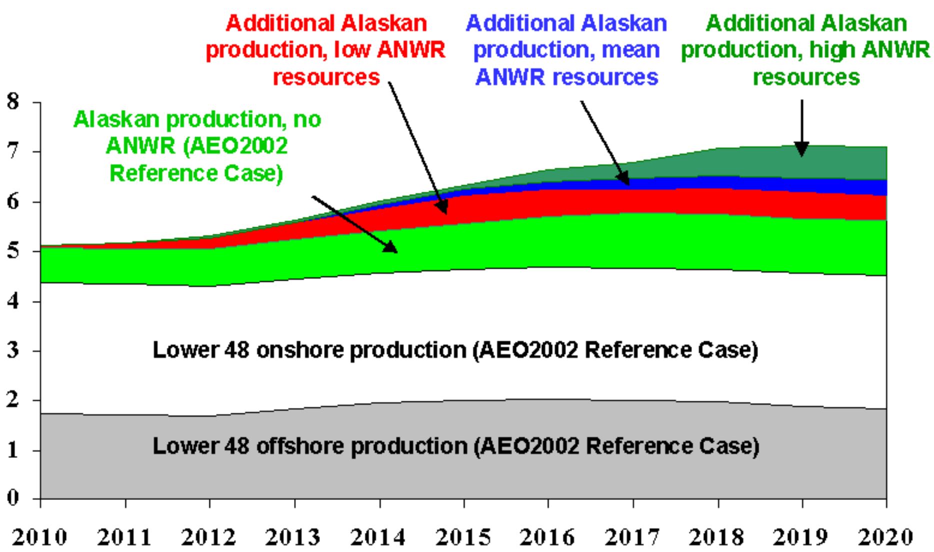
The USGS estimates the total volume of non-associated, technically-recoverable natural gas resources available in ANWR to be between 0 and 10 trillion cubic feet (Tcf), with a mean estimated value of 3.5 Tcf. An additional 2.0 to 5.5 Tcf of technically-recoverable natural gas is estimated to exist in ANWR as associated gas, with a mean estimate of 3.6 Tcf. The 35 Tcf of stranded natural gas assets estimated to have been found already in Prudhoe Bay and other areas of the North Slope is not currently being commercially developed. These reserves would most likely be developed first if the infrastructure is developed to market North Slope natural gas. Therefore, this paper does not project ANWR’s natural gas resources to be developed commercially over the forecast period.

Results

Total Alaskan oil production after opening ANWR is estimated to reach 1.9 million barrels per day in 2020. Total Alaskan production in 2020 is projected to be 800,000 barrels per day higher than it is in the *AEO2002* Reference Case, which does not include opening ANWR. The projected volume of production from ANWR represents roughly seven-tenths of 1 percent of projected world oil production in 2020. Total U.S. crude oil production is projected to reach 6.4 million barrels per day, compared to 5.6 million barrels per day in the Reference Case (Figure 2.)

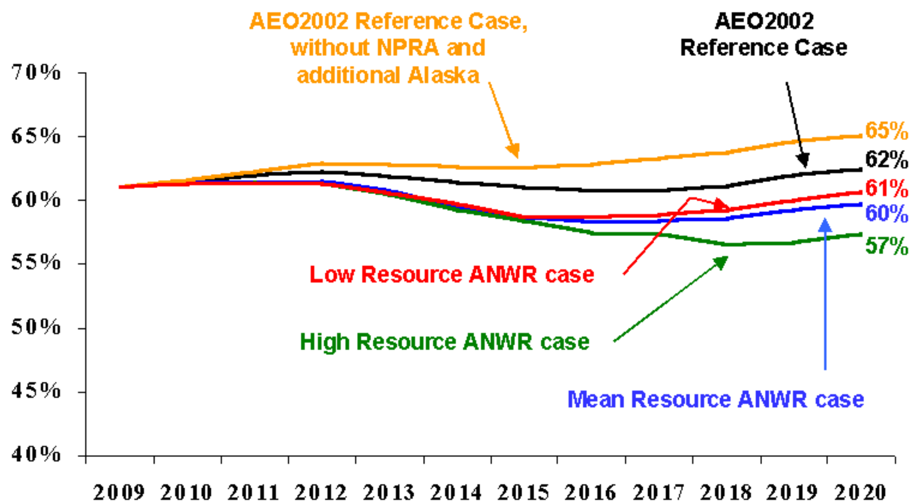
The increase in ANWR production would lead to a decline in the U.S. dependence on foreign oil. In the *AEO2002* Reference Case, net imports are projected to supply 62 percent of all oil used in the United States by 2020. Opening ANWR is estimated to reduce the percentage share of net imports to 60 percent (Figure 3.) Nearly 89 percent of the offset imports come from reducing crude oil imports, with the rest of the offset coming from product imports. Opening ANWR is also projected to increase U.S. employment in the oil and gas sector, but estimating the size of the employment effects is beyond the scope of this analysis.

Figure 2. Total US Crude Oil Production including ANWR, with Reference Case World Oil Prices, 2010 - 2020 (million barrels per day)



Sources: anwr_bs.d012202a, anwr_lo.d012202a, anwr_hi.d012202a, and aeo2002.d102001b.

Figure 3. Net Share of Oil Consumed in the United States Supplied by Imports for 5 Cases (percent)



Sources: anwr_bs.d012202a, anwr_lo.d012202a, anwr_hi.d012202a, aeo2002.d102001b.

The High Resource ANWR case

Because the coastal plain of ANWR has had little exploration activity, there is considerable uncertainty in the size of the oil resources that might be eventually recovered. The High Resource ANWR Case has been developed as a sensitivity analysis, to project how production might be different if the volume of crude oil resources were at the high end of the USGS distribution instead of at the mean.

The High Resource ANWR Case is based on the USGS estimate of 16 billion barrels of technically recoverable resources in the coastal plain area. This estimate is at the high end of the range of recoverable resources that the USGS considers possible. The USGS estimates that it is 95 percent likely that the volume of recoverable oil is less than 16 billion barrels. The USGS estimates that there is only a 1 in 20 chance that the volume of actual recoverable resources of oil will be as high as it is in the High ANWR Resource Case.

In the High Resource ANWR Case, the field size distributions are adjusted upwards, based on field size distributions developed by the USGS. The timing of initial production, schedule of subsequent development, and production profiles of the new fields are unchanged from the mean ANWR case.

The expected volume of crude oil resources in the largest field is 2 billion barrels in the High Resource ANWR case. This compares to the Kupurak River field, also in North Alaska, which was discovered in the late 1960's and has a total estimated ultimate recovery of 2.7 billion barrels.

Alaskan production reaches 2.6 million barrels per day in 2020, 1.5 million barrels per day higher than projected production in the *AEO2002* Reference Case and 0.6 million barrels per day higher than in the Mean Resource ANWR Case (Table 1.) This level of production would exceed historical Alaskan production, and thus, poses logistical problems. Historically, the Trans-Alaskan Pipeline System (TAPS) has been limited in throughput to a maximum of 2.2 million barrels per day. In order to accommodate the increased crude flows in the High Resource ANWR case, the capacity of TAPS would have to be expanded beyond its historical levels. This might be accomplished by reopening closed pumping stations, and redesigning and rebuilding parts of the line; however, expanding the pipeline above its historic capacity could be a costly engineering challenge. The share of imported oil drops to 57 percent in the High Resource ANWR Case by 2020.

The Low Resource ANWR Case

The Low Resource ANWR Case is based on the USGS estimate of 5.7 billion barrels of technically-recoverable oil in the coastal plain area. The USGS estimates that there is a 5 percent chance that total recoverable oil will be smaller than 5.7 billion barrels, and a 95 percent chance that the total volumes will exceed 5.7 billion barrels. The USGS estimates that there is only a 1 in 20 chance that the volume of actual recoverable resources of oil will be as low as it is in the Low ANWR Resource Case.

The field sizes are correspondingly smaller in the Low Resource ANWR Case, with no expected field size exceeding 1 billion barrels. Under this case, Alaskan production reaches 1.6 million barrels per day in 2020. The change in the underlying field sizes between the Low Resource ANWR Case and the Mean Resource ANWR Case is not as great as the change between the Mean Case and the High Case, and therefore the change in production between the Low Resource and the Mean Resource cases is also not as great.

Table 1. Impact of Opening ANWR to Development

	2015				2020			
	AEO 2002	Low ANWR	Mean ANWR	High ANWR	AEO 2002	Low ANWR	Mean ANWR	High ANWR
Alaskan Crude Oil Production (million barrels per day)	0.90	1.50	1.60	1.70	1.10	1.62	1.92	2.58[a]
Total U.S. Production (million barrels per day)	5.56	6.14	6.24	6.33	5.63	6.13	6.41	7.06
Net share of foreign oil [b]	61%	59%	58%	58%	62%	61%	60%	57%

[a] Production on Alaskan North Slope, including ANWR, exceeds historical pipeline capacity.

[b] EIA uses net import figures to indicate the level of import relative to total supply, since it takes U.S. exports into account. (See James M. Kendell, “Measures of Oil Import Dependence,” *Issues in Midterm Analysis and Forecasting 1998*.) In gross terms, the import percentages in 2020 are 66 percent in AEO2002, 61 percent in the high ANWR case, 63 percent in the mean ANWR case, and 65 percent in the low ANWR case.

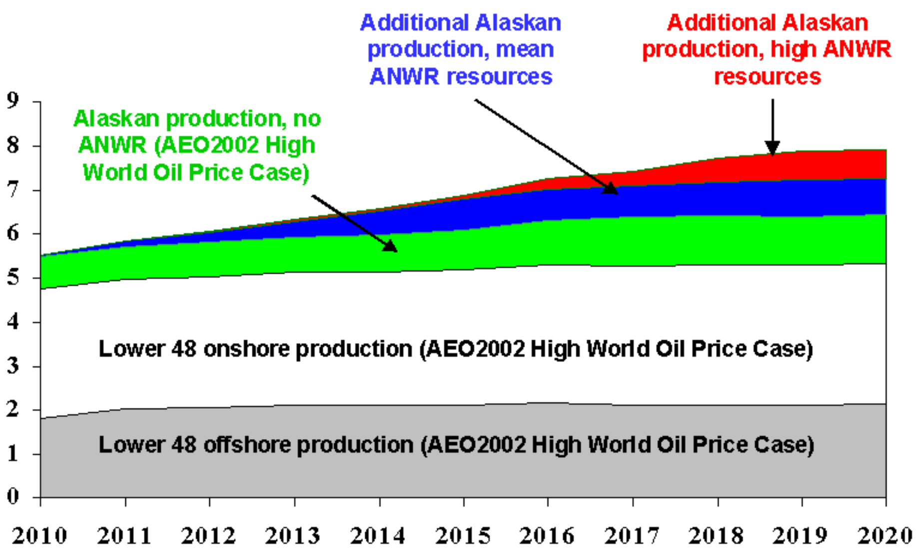
Source: anwr_bs.d012202a, anwr_lo.d012202a, anwr_hi.d012202a, and aeo2002.d102001b.

Opening ANWR with High World Oil Prices

In the *AEO2002*, a high world oil price case was presented to reflect alternative assumptions regarding the expansion of crude oil production capacity in the Nations comprising the Organization of Petroleum Exporting Countries (OPEC). In the *AEO2002* High World Oil Price Case, world oil prices are projected to reach $30.58 per barrel by 2020, compared to $24.68 per barrel in the *AEO2002* Reference Case (prices in 2000 dollars.)[5] Domestic production is higher in the High World Oil Price Case than in the Reference Case while consumption is lower. This results in a reduction in the share of net imports of consumption in 2020 from 62 percent in the Reference Case to 57 percent in the High World Oil Price Case.

The High World Oil Price Mean ANWR Resource case shows how oil production from ANWR (equal to the volumes in the Mean Resource ANWR Case) influences U.S. markets when world oil prices follow the price path set by the High World Oil Price Case of the *AEO2002*. Total domestic production in 2020 is projected to be 7.2 million barrels per day in the High World Oil Price Mean ANWR Resource Case, compared to 6.4 million barrels per day in the *AEO2002* High World Oil Price Case (Table 2 and Figure 4). The share of oil production from Alaska increases from 17 percent of total domestic production to 27 percent. The share of imported oil in 2020 is projected to be 54 percent (Figure 5), which is expected to be the same net share of foreign oil consumed in 2001.

Figure 4. Total US Crude Oil Production with High World Oil Prices, including ANWR, 2010 - 2020 (million barrels per day)

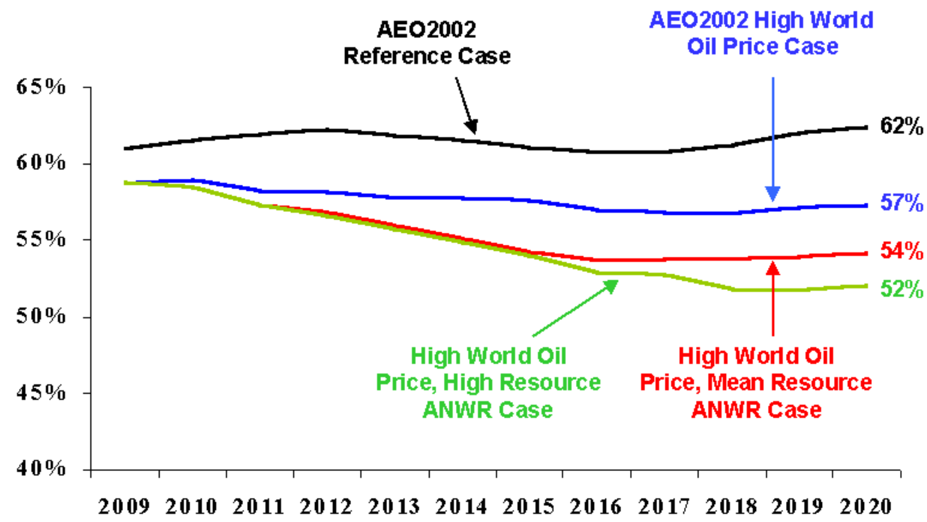


Sources: anwr_bs.d012202a, anwr_lo.d012202a, anwr_hi.d012202a, and aeo2002.d102001b.

As an additional sensitivity, the high ANWR resource assumptions were combined with the high world oil price assumptions to make the High World Oil Price High ANWR Resource Case. In this case, total production is projected to be 7.9 million barrels per day, including 2.6 million barrels of Alaskan production per day. Once again, projected Alaskan slope production is greater than the historical peak TAPS throughput. The net share of petroleum imports in 2020 is projected to be 52 percent.

5 All projected prices in this study have been adjusted for inflation and are presented in 2000 dollars.

Figure 5. Net Share of Oil Consumed in the United States Supplied by Imports under Two ANWR cases and the High World Oil Price Assumptions (percent)



Sources: hanwrhwop.d020502a, hwanwrfd.d012802a hw2002.d102001b, and aeo2002.d102001b.

Table 2. Impact of Opening ANWR to Development under High and Low World Oil Prices						
	2015			2020		
	AEO2002 High World Oil Price	High World Price, Mean ANWR Resources	High World Price, High ANWR Resources	AEO2002 High World Oil Price	High World Price, Mean ANWR Resources	High World Price, High ANWR Resources
Alaskan Crude Oil Production (million barrels per day)	0.92	1.62	1.71	1.12	1.93	2.59[a]
Total U.S. Production (million barrels per day)	6.10	6.79	6.88	6.43	7.21	7.86
Net share of foreign oil [b]	58%	54%	54%	57%	54%	52%
[a] Production on Alaskan North Slope, including ANWR, exceeds historical pipeline capacity.						
[b] In gross terms, the import percentages in 2020 are 61 percent in AEO2002 High World Oil Price Case, 58 percent in the High World Oil Price Mean ANWR Resource Case, and 56 percent in the High World Oil Price High ANWR Resource Case.						
Source: hanwrhwop.d020502a, hwanwrfd.d012802a, and hw2002.d102001b.						

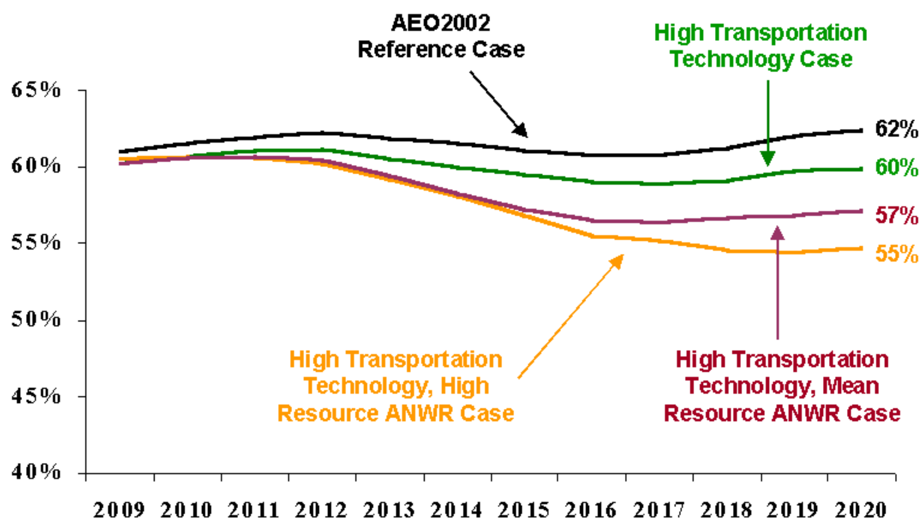
Opening ANWR with High Transportation Technology

The effects of opening ANWR were also modeled in a low-demand case, based on the Transportation High Technology Case developed in the *AEO2002*. This case assumes that there will be lower costs, higher efficiencies, and earlier introduction of energy-saving technologies than the AEO2002 reference case assumes, leading to a 9 percent decline in total transportation energy use. Higher average fuel efficiency in the light duty vehicles is the largest component of the difference in demand between the Transportation High Technology Case and the reference case, accounting for 76 percent of the change in energy consumed in transportation.[6]

The increased rate of technological change in transportation leads to lower oil consumption, and a lower share of total oil supplied by foreign imports than the *AEO2002* Reference Case. By 2020, total projected consumption of oil is 24.9 million barrels per day in the High Transportation Technology Case, compared to 26.7 million barrels in the reference case. The projected share of oil supplied by imports is 60 percent, compared to 62 percent in the *AEO2002* Reference Case

In the High Transportation Technology, Mean ANWR Resource case, lower total demand and increased domestic production due to opening ANWR leads to an even lower share of net imports (Table 3 and Figure 6.) Assuming that ANWR resources are produced following the assumptions outlined above, opening ANWR with total recoverable resources at the mean of the USGS estimates causes the projected net share of foreign oil to be 57 percent in 2020. In the High Transportation Technology, High Resource ANWR case, ANWR crude oil resources are assumed to be equal to the high end USGS estimates, and the net share of foreign oil drops to 55 percent.

Figure 6. Net Share of Oil Consumed in the United States Supplied by Imports under Two ANWR Cases and the High Transportation Technology Assumptions (percent)



Sources: hanwrldem.d020402c, htrantec.d020402b, banwrldem.d020502a, and aeo2002.d102001b.

[6] For more information on the Transportation High Technology Case, see EIA's *Annual Energy Outlook 2002 with Projections to 2020*, Dec. 2001, http://www.eia.doe.gov/oiaf/aeo/index.html, pg. 71. The case run for this study uses the same assumptions developed for the *AEO2002*, but as part of an integrated NEMS run rather than as just a transportation analysis, as the *AEO2002* did.

Table 3. Impact of Opening ANWR to Development in Transportation High Technology Cases						
	2015			2020		
	Transport High Tech Case	Transport High Tech, Mean ANWR Resources	Transport High Tech, High ANWR Resources	Transport High Tech Case	Transport High Tech, Mean ANWR Resources	Transport High Tech, High ANWR Resources
Alaskan Crude Oil Production (million barrels per day)	0.90	1.60	1.70	1.10	1.92	2.57 [a]
Total U.S. Production (million barrels per day)	5.56	6.17	6.26	5.63	6.39	7.02
Net share of foreign oil [b]	60%	57%	57%	60%	57%	55%
[a] Production on Alaskan North Slope, including ANWR, exceeds historical pipeline capacity.						
[b] In gross terms, the import percentages in 2020 are 64 percent in Transportation High Technology Case, 61 percent in Transportation High Technology Mean ANWR Resource Case, and 59 percent in Transportation High Technology Case High ANWR Resource Case.						
Source: htrantec.d020402a, banwrldem.d020502a, hanwrldem.d020402c.						

ANWR Production Uncertainties

There are several areas of uncertainty when considering the impact of opening ANWR on U.S. energy markets:

- *The size of the underlying resource base*. There has not been an extensive geological study of the ANWR area. Determining the precise size of oil resources within ANWR will take further study and exploration. The size of the resource will determine the potential ultimate recovery in the region as well as the potential yearly production.

- *The underlying field structure*. The size of reservoirs that are found in ANWR will determine the rate at which ANWR oil and gas resources are developed. If the reservoirs are larger than expected, production will be larger in earlier years.

- *The costs of developing oil resources in ANWR*. This analysis assumes that the costs of developing ANWR are not significantly different than developing oil resources in other parts of northern Alaska. If these costs are higher, ANWR production may be delayed.

- *Timing of ANWR production*. This analysis assumes that production in ANWR will not begin until 2011. Other studies have suggested that production could begin as early as 2009, or later than 2011. This analysis also assumes that based on historical experience and the size of the fields that are projected to be discovered in ANWR, production in each new field could open two years after production begins in the last field to be previously opened. The actual timing of ANWR production could vary significantly from the timing assumed in this study.

- *Environmental considerations.* Environmental restrictions could affect access for exploration and development.

III. The Impacts of the Alaska Natural Gas Pipeline Act of 2002

The "Alaska Natural Gas Pipeline Act of 2002" contained in Title VII of S. 1766 calls for federal action to expedite the construction of a natural gas pipeline from North Alaska to the Lower 48

States. The provisions of the Alaska Natural Gas Pipeline Act are projected to result in the earlier construction of a pipeline than would be the case without this Act. The *AEO2002* Reference Case, does not project the pipeline's construction during the forecast period, out to 2020. Using the same basic assumptions adjusted for the provision of the Alaska Natural Gas Pipeline Act, this analysis projects that a pipeline linking northern Alaskan gas to Lower 48 markets would begin operating in 2020, lowering the lower 48 wellhead price by $0.06 per thousand cubic feet. The Low Oil and Gas Technology Case, developed as a sensitivity analysis for the *AEO2002*, assumes slower growth in technological change in the exploration and development of these energy resources, resulting in higher natural gas prices than in the *AEO2002* Reference Case. This case also does not project the construction of a pipeline before 2020. However, under the proposed provisions in the Low Oil and Gas Technology Case, the pipeline would begin operation in 2014, and result in Lower 48 wellhead prices that are $0.32 per thousand cubic feet lower than the corresponding case without the provision by 2020.

Background

Alaska's North Slope has extensive hydrocarbon reserves, including natural gas. To date, 35 trillion cubic feet of natural gas have been discovered. These are considered to be marketable reserves, which could be developed at low cost with existing technology, if there was a market for this production. Currently, Alaskan gas is not marketed in the lower 48 since there is no infrastructure to deliver gas produced in Alaskan fields to consumers in the rest of the United States. A pipeline connecting Alaskan fields with lower 48 consumers would allow the natural gas reserves that have already been identified to be marketed profitably, along with other undiscovered Alaskan gas resources. Increasing domestic supply could also reduce the prices paid by consumers for natural gas.

A pipeline for Alaskan natural gas has been discussed since the 1970's. In 1977, the United States and Canada signed an agreement in principle for the Alaska Natural Gas Transportation System (ANGTS) that proposed the delivery of 2 billion cubic feet per day from the Alaskan North Slope, along the Alaskan-Canadian highway to near Calgary, Alberta, and down to the lower 48. Initial cost estimates for ANGTS, including delivery to the lower 48, were $14.6 billion (1988 estimate, in 1988 dollars.)[7]

With deregulation of U.S. natural gas and the development of lower-cost resources both in the Lower 48 States and Canada, interest in ANGTS waned. Discussion of a natural gas pipeline from Alaska resurfaced in 1999 and 2000, when high gas prices led to a re-evaluation of the feasibility of developing "stranded" Alaskan gas reserves. Phillips, BP, and ExxonMobil formed a partnership to investigate the potential of developing a gas pipeline, following roughly the route proposed by ANGTS or an alternate route across the Beaufort Sea to the MacKenzie Delta in Canada and then down to Alberta. The results of this study have not been released, but one preliminary report suggests that even though estimated pipeline costs are lower than they have been in other studies, the pipeline project is not feasible given current economic conditions.[8]

Alaska Gas Pipeline Methodology and Assumptions

In order to model the potential impacts of a natural gas pipeline running from Alaska to markets in the lower 48, several assumptions about the project were required. These assumptions are

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[7] Fact Sheet, Foothills Pipe Lines Ltd., Nov. 19, 1999
[8] Remarks by Ken Konrad, BP, "Progress on an Alaska Gas Pipeline," Resource Development Council Conference, Nov. 29. 2001, http://www.bp.com/alaska/index_alaska_ngas.htm.

based on available information in reports and articles supplemented with consultation with industry and other government sources.

- ***Resources***

The known reserves of 35 trillion cubic feet are considered to be stranded natural gas, or natural gas that could be developed but does not have a ready market, in this case due to geographic isolation. This analysis assumes that 26 trillion cubic feet of the 35 trillion cubic feet of reserves are available for commercial sales. The other 9 trillion cubic feet are assumed to be required for North Slope oil operations, including injection into oil reservoirs to maintain production. Developing 26 trillion cubic feet of the 35 trillion cubic feet may decrease potential oil production in the later years, particularly at Prudhoe Bay.

EIA assumes that these stranded reserves will be developed at a wellhead price of $0.80 per thousand cubic feet. This cost is substantially below projected average wellhead prices in the lower 48, but is consistent with the wellhead prices of stranded natural gas in other regions of the world. The lower price for stranded reserves is due to lower exploration costs associated with these reserves and the lack of other options for the owners of the stranded resource. Without other potential alternate buyers, the owners of stranded gas resources are willing to accept a lower price than they would in areas with easier access to markets.

- ***Pipeline specifications and costs***

EIA's estimates envision a pipeline capable of carrying 4 billion cubic feet per day, or 1.5 trillion cubic feet per year, from Alaska to the lower 48. The capital cost of the project from the North Slope to Alberta is assumed to be $10 billion (2000 dollars), based on more recent cost estimates.[9] The estimated cost is lower than the original cost estimate for ANGST due to improvements in pipeline technology, such as composite construction materials.

The cost estimates that underlie EIA's assumptions are based on a route roughly following the original ANGST proposal. The cost of the pipeline is sensitive to the proposed route, and a pipeline following an alternate route would likely have different costs.

- ***Required lower 48 prices***

Based on the estimated cost of gas at the wellhead, capital costs, operating costs, and required rates of return, Alaska gas delivered by the proposed pipeline is estimated to be competitive when lower 48 wellhead prices are sustained at $3.15 per thousand cubic feet. This estimate includes a $0.70 per thousand cubic foot price differential between Alberta and the Lower 48, based on the historical price differentials in these markets. However, given the uncertainties inherent in these estimations and the historic pattern of sharp year-to-year volatility in natural gas prices, as well as the potential for natural gas prices to drop once the pipeline opens, EIA assumes that construction of the pipeline will only begin with sustained lower 48 wellhead prices of at least $3.50 per thousand cubic feet. This $0.35 cent risk premium ($3.50-$3.15) is assumed to compensate investors for the uncertainties, and is a contingency factor used by investors to estimate potential profitability.

- ***Pipeline Timing***

[9] CERA, 1999, and phone conversations with Mike Metz, Yukon Pacific, 2000.

EIA assumes that the pipeline will require 4 years to build after an initial planning and permitting period of 3 years. Construction will commence only if the average lower 48 wellhead price stays above the trigger price for each year in the planning period. The pipeline is assumed to operate at half capacity the first year it begins production (2 billion cubic feet per day), and then operate at full capacity each year after the first.

- ***Pipeline and Resource Expansion***

EIA's methodology assumes that there will be additional natural gas resources available beyond the 35 trillion cubic feet of previously-discovered reserves, albeit at a higher cost. The costs of these additional reserves are higher because of the exploratory costs that will be required to bring these undiscovered resources into production. EIA also assumes that given high enough prices, additional pipeline capacity could be added at a latter date. This study does not consider either of these factors.

- ***Pipeline is not constructed under the assumptions in the AEO2002 reference case***

Given these assumptions, the AEO2002 did not project that an Alaska natural gas pipeline would be constructed in its reference case, since projected prices do not exceed the required trigger price of $3.50 during the forecast period.

Modeling the Effects of S. 1766, Title 7, "Alaska Natural Gas Pipeline Act of 2002"

The Alaska Natural Gas Pipeline Act is designed to expedite the creation of a transportation system to deliver Alaska natural gas to the lower 48 states. The Act does this by calling for expedited approval and environmental review, as well as the appointment of a Federal coordinator to "coordinate the expeditious discharge of all activities by Federal agencies with respect to an Alaska natural gas transportation project." In addition, the act authorizes the Secretary of Energy to guarantee up to 80 percent of the principal of any loan made to finance the construction of the pipeline. The size of the loan guaranty is capped at $10 billion dollars, and the Act gives the Secretary the right to determine the loan requirements and issue any other regulations required to carry out the loan guaranty.

The provisions of the Alaska Natural Gas Pipeline Act of 2002 are reflected in EIA's methodology in three major ways:

- Increased Executive Branch oversight (Section 705) and expedited environmental and legal reviews (Sections 706 and 707) are assumed to reduce the planning time in EIA's methodology from 3 years to one year.

- The loan guarantee provisions for a qualifying project by the Department of Energy (Section 707) are assumed to reduce the cost of financing the pipeline, by allowing a pipeline builder who meets the Secretary's requirements to borrow money at a lower cost. The estimated effect is to reduce the required pipeline tariff, and therefore the trigger price, by $0.10.

- Finally, this study assumes that given the loan guaranty and increased Federal oversight, the additional $0.35 added to the trigger price to account for uncertainties is not required.

> Combined with the reduction in costs, the trigger price with the proposed Act is assumed to be $3.05, compared to $3.50 without the proposed Act.

The net effect is to project the construction of the pipeline with less delay and at a lower price than it would be constructed in the absence of S. 1766. The assumptions about construction costs, the required time for actual construction, and the underlying Alaskan natural gas resources are unchanged.

Results and Sensitivity Analysis

Without the provisions of the proposed pipeline Act, the *AEO2002* Reference Case does not project the construction of an Alaska natural gas pipeline before 2020, the end of its forecast period. However, using the same assumptions used in the *AEO2002* Reference Case, and the including the assumptions of a loan guaranty and expedited review provided by the proposed "Alaska Natural Gas Pipeline Act of 2002," this study projects that an Alaska natural gas pipeline would be implemented. Construction of the Alaska natural gas pipeline is projected to begin in 2016, and the first year of deliveries to the lower 48 is projected in 2020. Production in Alaska rises by 800 billion cubic feet (Figure 7.) In the first year that the pipeline is open, 730 billion cubic feet of natural gas is transported to the lower 48, with the rest of the additional production being used as pipeline fuel. The lower 48 wellhead price is projected to be lower than it would be without the pipeline (Figure 8.) Prices in 2020 are $3.20 in the case with the Pipeline Act, compared to $3.26 per thousand cubic feet in the *AEO2002* reference case.

To show the potential effects of the Pipeline Act with higher projected natural gas prices, an alternate scenario was generated using the Low Oil and Gas Technology Case from the *AEO2002*. In this Case, the rate of technological advance in the oil and gas supply sector is projected to be lower than it has been historically, making it more difficult to add natural gas reserves and leading to higher natural gas prices.[10]

In the Low Oil and Gas Technology Case, lower 48 wellhead prices reach $4.06 per thousand cubic feet in 2020, compared to $3.26 in the *AEO2002* Reference Case. Even though the price by the end of the forecast period in the Low Oil and Gas Technology Case is well above the trigger price, the price is not sustained at a high enough level for long enough for the pipeline to be completed by 2020 under the *AEO2002* assumptions, which include no guaranties or expedited Government review. However, construction on the pipeline in this case is projected to begin in 2018.

With the Pipeline Act, the Alaska natural gas pipeline is economically feasible earlier. Construction on the Alaska natural gas pipeline in the Low Oil and Gas Technology Case is projected to begin in 2010. The pipeline is expected to begin transport in 2014, and reach full capacity of 4 billion cubic feet per day, or 1.5 trillion cubic feet per year, by 2015. The volume carried by the pipeline represents about 5 percent of the total natural gas consumed in 2015. By 2020, the total projected volume of natural gas consumed in the Low Oil and Gas Technology Case with the Pipeline Act is 31.8 trillion cubic feet, compared to 31.1 without the Pipeline Act. Forty-three percent of the pipeline's volume serves to meet new demand brought on by lower prices, while the rest offsets other sources of supply from imports and lower 48 production.

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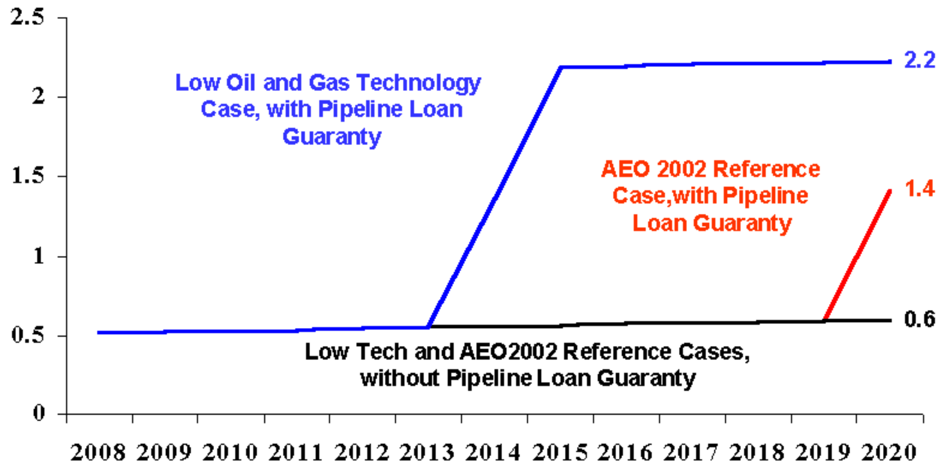
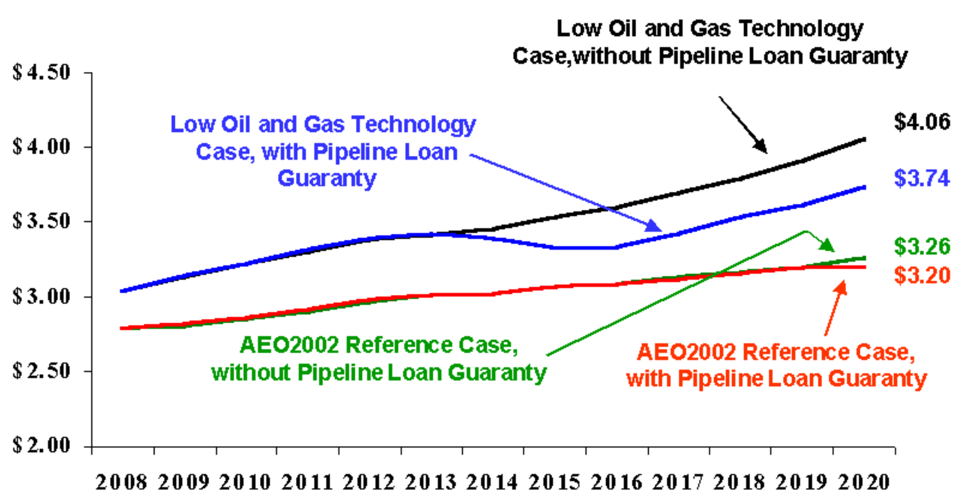
[10] The Low Oil and Gas Technology side case is described in EIA's *Annual Energy Outlook 2002 with Projections to 2020,* Dec. 2001, http://www.eia.doe.gov/oiaf/aeo/index.html, pg. 85.

Figure 7. Alaska Natural Gas Production 2008 - 2020 (trillion cubic feet per year)



Sources: angts.d020602a, angts_lt.d020602a, aeo2002.d102001b, and ogltec02.d102501a

Figure 8. Lower 48 Natural Gas Wellhead Prices With and Without the Pipeline Loan Guaranty in Two Case, 2008 - 2020 (Constant 2000 dollars per thousand cubic feet)



Sources: angts.d020602a, angts_lt.d020602a, aeo2002.d102001b, and ogltec02.d102501a

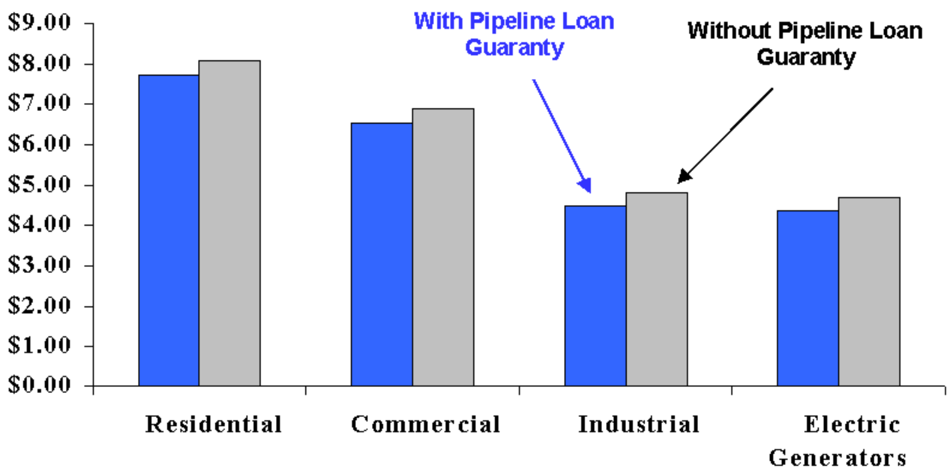
Opening the pipeline earlier leads to lower natural gas prices. In 2020, lower 48 natural gas wellhead prices in the Low Oil and Gas Technology Case with the Pipeline Act are $3.74 per thousand cubic feet, about 8 percent lower than they are projected to be without the Pipeline Act (Table 4.) Lower wellhead prices result in lower prices to consumers (Figure 9.) The residential price of natural gas in 2020 is $8.07 per thousand cubic feet in the Low Oil and Gas technology case without the Pipeline Act, and is $7.72 with the Pipeline Act. Other prices are similarly lower.

Table 4. Impact of the Alaska Natural Gas Pipeline Act

	2015				2020			
	AEO 2002	AEO 2002 with Act	Low Oil and Gas Tech	Low Tech with Act	AEO 2002	AEO 2002 with Act	Low Oil and Gas Tech	Low Tech with Act
Lower 48 Natural Gas Wellhead Price (2000 dollars per thousand cubic feet)	3.07	3.07	3.54	3.33	3.26	3.20	4.06	3.74
Alaskan Natural Gas Production (trillion cubic feet per year)	0.57	0.57	0.57	2.19	0.60	1.41	0.60	2.23
Total U.S. Production (trillion cubic feet per year)	26.3	26.3	24.9	25.6	28.5	28.8	25.9	27.0
Total U.S. Consumption (trillion cubic feet per year)	31.3	31.3	29.9	30.3	33.8	33.9	31.1	31.8

Sources: angts.d020602a, angts_lt.d020602a, aeo2002.d102001b, and ogltec02.d102501a

Figure 9. Delivered Natural Gas Prices in the Low Oil and Gas Technology Case With and Without the Pipeline Loan Guaranty, 2020 (Constant 2000 dollars per thousand cubic feet)



Sources: angts_lt.d020602a and ogltec02.d102501a.

Alaska Natural Gas Pipeline Uncertainties

The Alaska natural gas pipeline is a major project. There are several uncertainties in the estimate of its impact on U.S. markets, including:

- *The availability of stranded gas to feed the pipeline*. While the Alaska natural gas pipeline is one mechanism to bring stranded Alaskan gas to the Lower 48 States, there are other technologies that could allow these resources to be developed profitably. Alternate technologies include liquefied natural gas (LNG) and gas-to-liquids (GTL), both of which have been discussed as possible ways to market Alaskan natural gas. If either of these technologies or other alternatives can provide a higher rate of return for the owners of Alaskan gas reserves, a pipeline may be not be the most economic alternative, though it would support demand in the Lower 48 States.

- *The decision-making process behind building a pipeline*. The EIA methodology makes very simple assumptions to determine if investors will decide to build the pipeline. In reality, this decision is very complicated, and is based on future expectations, Government support for the project, and the profitability of other competing investment opportunities. In the absence of explicit governmental support for the project, the sustained lower 48 price required to trigger the project could be higher than the required price estimated in this study. Therefore, given the perception of higher risk, a sustained price of $3.50 may not be enough to trigger the pipeline, and the actual required trigger price could be as high as $4 or higher. In addition, there are environmental and Native rights issues that are raised by the construction of the pipeline, which could serve to slow or even halt the proposed pipeline unless these issues are resolved.

- *The capital cost of the pipeline*. At the time EIA developed its cost assumptions, many of the available cost estimates were either outdated or preliminary. The cost estimates from the joint BP-Phillips-ExxonMobil study have not been made available to the public as of this writing. In addition, the cost of the pipeline is sensitive to the route chosen. Finally, the cost assumptions used in this analysis are based on the best estimates of current costs, but do not reflect possible technological development which could lower these costs in the future. Therefore, there is considerable uncertainty in the assumptions used for the capital cost of the proposed Alaska natural gas project. Changes to the capital cost assumption could also change the timing of pipeline construction.

  For example, if the cost of the Alaska to Alberta pipeline were 20 percent higher than assumed in this analysis, or $12 billion, the trigger price would be $0.30 higher than it was projected in this study. At this higher projected pipeline cost, the new trigger price for the pipeline with the loan guaranty would be $3.35, assuming that the other assumptions remained unchanged. Since the projected lower 48 wellhead price never exceeds this new trigger price in the AEO2002 reference case, the pipeline would not be constructed by 2020. In the Low Oil and Gas Technology Case including the loan guaranty, initial deliveries with the new higher trigger price would be expected to start 3 years later than deliveries are projected to start based on the $10 billion pipeline cost estimate.

- *The effects of the loan guaranty on investor's perceptions of risk.* The proposed Act gives the Secretary of Energy broad latitude in determining the requirements and the size of the loan guaranty. The specific policies adopted by the Secretary will influence the investor's perceptions of risk. In this analysis, the loan guaranty is assumed to allow investors to begin the project as soon as Lower l8 natural gas prices indicate that a pipeline is feasible. However, even with the proposed loan guaranties and Federal oversight, investors may still feel that the project is risky enough that they will not commit to build the pipeline until the lower 48 wellhead price is well above the expected minimum level for profitability. Therefore, once all of the provisions of the proposed Pipeline Act are determined and implemented, the Act could have less of an impact on the prices required to trigger an Alaska natural gas pipeline than this study assumes.

Appendix A:

Letters of Request from Senator Frank Murkowski

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

ENERGY.SENATE.GOV

December 20, 2001

Dr. Mary Hutzler
Acting Administrator
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC, 20585

Dear Acting Administrator Hutzler:

The Senate is considering comprehensive legislation to update U.S. national energy strategy in light of the volatility of energy markets in calendar year 2000 and the growing energy security concerns in light of recent events that highlight our dependence on foreign imported oil. To this end, there have been several legislative proposals introduced in the 107th Congress on the subject of national energy policy, and the Majority Leader has indicated that the Senate will debate energy policy early in the next session of Congress. Our decisions will benefit from an analysis of the strengths and weaknesses of the various energy policy proposals that have been introduced to date.

With that in mind, I request that the Energy Information Administration (EIA) analyze the potential costs and benefits of proposed legislation to update and revise our national energy strategy, namely, H.R. 4 as passed by the House of Representatives in August 2001, and S. 1766 as proposed by Senators Daschle and Bingaman earlier this month. I understand that EIA has the ability to conduct such analysis, including the use of both sectoral and economy-wide energy models. Using the most recent *Annual Energy Outlook 2002* as a reference case, I ask that EIA assess the impacts of these energy policy proposals on, at minimum:

- macroeconomic indicators (jobs, Gross Domestic Product, trade balance, etc.);
- energy supply and demand by fuel and process;
- energy prices to consumers (residential, industrial, and commercial) by fuel;
- dependence on foreign oil imports and impacts on energy security;
- impacts on energy infrastructure (transmission, pipelines, refineries, etc.); and
- emissions of greenhouse gases and air pollutants.

As the Daschle/Bingaman bill (S. 1766) contains several "placeholders" reserved for future legislative proposals, I ask that for the purposes of your analysis, you include for Section 801 of S. 1766, S. 804, introduced by Senators Feinstein, Snowe and Reed making changes to the Corporate Average Fuel Economy (CAFE) program. For Section 1821 of S. 1766, use the provisions contained in S. 1746, introduced by Senator Reid on nuclear facility security. Also, to ensure a consistent comparison, please exclude from your analysis of H.R. 4 the amendments to the tax code contained in Division C of that bill. I expect to request from EIA a follow-up analysis of the tax-related proposals contained in H.R. 4 and an expected Senate Finance Committee mark at a subsequent date.

When assessing the costs and benefits of these legislative proposals, please be sure to point out which specific policy actions have the most significant positive or negative impacts on the factors outlined above. In order to inform our deliberations on national energy policy which are due to begin in the next several weeks, I ask that the requested information be made available by January 23, 2002. In addition, I request that a briefing of your results prior to release of any written report.

If you have any questions regarding this request, or desire further clarification with respect to translating legislative proposals into assumptions you will use in your analysis, please contact Bryan Hannegan with my Senate Energy and Natural Resources Committee staff at 224-7932. Thank you for your timely attention to this request, and for your efforts to ensure that our Nation's energy policy decisions are informed with the best available analysis.

Sincerely,

Frank H. Murkowski

Frank H. Murkowski
Ranking Member

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

ENERGY.SENATE.GOV

February 6, 2002

Dr. Mary Hutzler
Acting Administrator
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC, 20585

Dear Acting Administrator Hutzler:

As a follow-up to my letter of December 20, 2001 in reference to analysis of comprehensive energy legislation, please find below additional information to assist you in your analysis of key portions of S. 1766 and H.R. 4 identified as follows:

Renewable Portfolio Standard (RPS): For H.R. 4, assume no changes in current law. For S. 1766, assume a 2.5% mandate for new renewable electricity starting in 2005, increasing 0.5% each year through 2020 (10% new renewables by 2020). In addition, please provide analysis of a new scenario that reflects a 20% RPS by 2020 under the same provisions as in S. 1766. Key analysis questions include: whether or not such amounts of new renewable energy are possible with reasonable technology improvements, what renewable technologies benefit most, whether consumer retail electricity costs are affected by the RPS, and how the higher incremental costs of renewable electricity generation are absorbed by generators, utilities and/or consumers. Also, please describe the effect of the civil penalty imposed for failing to meet the RPS and whether that affects estimates of renewable electricity production, economic impacts, and macroeconomic effects.

Alaska Oil Production: For S. 1766, please provide your baseline Annual Energy Outlook 2002 (AEO) forecast without production from ANWR and compare it with several scenarios for H.R. 4: (1) median USGS ANWR production estimate and AEO 2002 world oil prices; (2) high-range USGS ANWR production estimate and AEO 2002 world oil prices; (3) high-range USGS estimate, using your "High Oil Price" side case; and (4) high-range USGS estimate, using your AEO 2002 "High Technology" side case that assumes rapid transportation technology development. Key variables to consider include the percentage of U.S. foreign oil dependence, and a summary of crude oil supply, demand, and disposition.

Alaska Natural Gas: For H.R. 4, assume no changes in law. For S. 1766, please analyze the impact of the proposed $10 billion loan guarantee (Sec. 6501-6512) on project economics and timing of construction assuming that the "over the top" route for the pipeline is prohibited (Sec. 701). Key analysis variables should include: the date at which natural gas from Alaska is first delivered to market in the Lower 48, the impact of the pipeline on the price of natural gas, and the sensitivity of these variables to higher or lower natural gas prices in the U.S. market.

Automobile Fuel Economy Standards (CAFE): For H.R. 4, assume increases in CAFE standards for model years 2004 through 2010 so as to decrease total gasoline consumption by 5 billion gallons over that period of time. For S. 1766, assume the adoption of provisions of S. 804 (Feinstein) – require 25 mpg for SUVs and light trucks produced between model years 2005 and 2007 and 27.5 mpg for SUVs and light trucks produced thereafter. Use as a reference case technology frozen at model year 2002 levels and performance, and assume further no change in fuel economy for passenger vehicles. Please analyze a second case which assumes a 5% increase in fuel economy standards over model year 2000 levels by model year 2005 for both passenger vehicles and SUVs/light trucks, with a further 5% increase for all vehicles by model year 2010. In all cases, please provide analysis on total net costs to consumers (e.g. up-front additional costs minus life-cycle fuel economy savings), macroeconomic effects on non-agricultural jobs, whether such fuel economy goals can be meet through reasonable technology assumptions, and estimates of carbon dioxide emissions.

Renewable Fuels/MTBE: For H.R. 4, assume no change in current law, and use the Annual Energy Outlook 2002 reference forecast as the base case. For S. 1766, assume a renewable fuel standard of 2.3 billion gallons renewable fuel by 2004 increasing per Section 818 of the legislation to 5.0 billion gallons by 2012. Include in your analysis of S. 1766 a ban on MTBE within four years and assume that, given the opportunity to opt out of the 2% oxygenate requirement, California RFG and East Coast RFG areas do so. Also, please analyze a third case where the renewable fuel standard is as proposed in Section 818 of S. 1766, but assume complete repeal of the 2% oxygenate standard, and that States are given the ability to ban MTBE if they wish starting in 2003 or 2004. Key analysis variables should include effects on motor gasoline and RFG prices and fuel imports, GDP, and energy expenses, and estimates of carbon dioxide emissions.

Air Conditioning/Heat Pump Standard: For H.R. 4, assume a 12 SEER/7.4 HSPF standard for air conditioners and heat pumps manufactured for Federal agency use only on or after date of enactment, and for S. 1766 assume a 13 SEER/7.7 HSPF standard enacted for all air conditioners and heat pumps manufactured on or after January 23, 2006. Key analysis variables include: electricity savings, net energy cost savings (increased up-front stock cost minus life cycle energy bill savings), and carbon dioxide emissions evaluated relative to the current 10 SEER standard.

Other Provisions: Pursuant to my letter of December 20, 2001, please also provide qualitative analyses for the following provisions:

Price-Anderson Act	S. 1766 (Sec 501-508) and H.R. 2983
Energy R& D	S. 1766 (Sec. 1211-1245) H.R. 4 (Corresponding provisions in Division B)
Other Consumer Product Standards	S. 1766 (Sec. 921- 929) H.R. 4 (Sec. 142-143)
Alternative Fuel Programs	S. 1766 (Sec. 811, 812, 814-819) H.R. 4 (Corresponding provisions in divisions A,B)
Hydro Relicensing	S. 1766 (Sec 301-308) H.R. 4 (Sec. 401- 402)

Pursuant to your conversations with my Energy Committee staff, I understand that your analysis will be issued in phases once available, starting with the Air Conditioning/Heat Pump Standard analysis delivered to me on January 23, 2002. As the Senate appears to be moving towards consideration of S. 1766 during the week of February 11th, I hope you can deliver as many of these phases as you and your staff are able to complete prior to that time and brief interested staff and Senators as appropriate at the earliest opportunity.

If you have any further questions regarding this request, or desire further clarification, please contact Bryan Hannegan with my Senate Energy and Natural Resources Committee staff at 224-7932. Thank you for your continued timely attention to this request, and for your efforts to ensure that our Nation's energy policy decisions are informed with the best available analysis.

Sincerely,

Frank H. Murkowski

Frank H. Murkowski
Ranking Member