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PIRINC has prepared the enclosed report, *Energy Supply Prospects and Politics: Focus on Alaska*

Since late last year, America has seen new reminders of energy supply vulnerabilities. The curtailment of Venezuelan oil exports beginning in early December added to market concerns about war with Iraq. Currently, the US is being impacted by the loss of high-quality oil from another key short-haul supplier, Nigeria. Although less visible to the public, natural gas prices also moved up sharply as exceptionally cold weather pushed up demand at a time of declining US production and stagnating production in our largest source of imports, Canada. Any search for new, large, domestic supplies of oil and gas inevitably turns to Alaska's North Slope. This report discusses the issues involved in bringing additional oil and gas from that source to market.

The politics and economics involved in tapping additional oil and gas from Alaska are very different. In the case of oil, the debate centers on opening of the section 1002 area of the ANWR (Artic National Wildlife Refuge), where, reflecting long-standing environmental concerns, production of oil and gas is prohibited under current law. The latest attempt to remove the prohibition has just been defeated in the Senate. In contrast, the politics are relatively favorable for gas, but the investment required is substantial and the economics of developing the gas uncertain.

The recent report by the National Research Council may offer a common point of departure for assessing environmental concerns regarding ANWR but does not settle the issue of whether the improvements to date in industry performance, or any level of performance, would be sufficient to open the single most promising prospect for increased domestic oil supplies. In the case of gas, the public interest is clearly served by expediting the regulatory and judicial decision-making process. Growing risks of a tighter market justify considering going further to encourage timely development.

If you have any questions or comments, please call John Lichtblau, Larry Goldstein or Ron Gold.

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Energy Supply Prospects and Politics: Focus on Alaska

Summary

Since late last year, America has been receiving new reminders of energy supply vulnerabilities. The political crisis in Venezuela that began in early December curtailed oil exports from one of the leading short-haul suppliers to the US market, pushing crude oil prices well above the $30/barrel level and adding to worries about oil-market implications of war with Iraq. Currently, the US is being impacted by the loss of high-quality crude oil from another key short-haul supplier, Nigeria. Although not as visible to the public, natural gas prices have moved up even more sharply since the beginning of the winter heating season as colder than normal weather pushed up demand at a time when production in the US has been declining. US production has declined by about 5% over the past year while production in Canada, our most important source of gas imports, has been stagnant.

Any search for new, large, domestic supplies of oil and gas inevitably turns to Alaska. About 17% of total US crude production currently comes from Alaska, mainly from the North Slope. The State accounts for about the same percentage of proven oil (crude and NGL) reserves and is estimated to contain about 30% of technically recoverable reserves from undiscovered conventional reservoirs.[1] Currently, Alaska accounts for only 2% of total US gas production but the known gas resources of Alaska amount to about 20% of US proven reserves.[2]

The politics and economics involved in tapping additional oil and gas from Alaska are very different. In the case of oil, the debate centers on opening of the so-called section 1002 area of the ANWR (Artic National Wildlife Refuge), where, reflecting long-standing environmental concerns, production of oil and gas is prohibited under current law. The section 1002 area is close to current producing areas of the North Slope and was cited in the May 2001 National Energy Policy report as "---the single most promising prospect in the United States."[3] The Administration favored Congressional authorization of exploration and development but while the Republican-controlled House of Representatives agreed, the Democratically-controlled Senate refused to consider such a measure. In 1995 Congress passed budget reconciliation bill containing a provision opening ANWR but President Clinton vetoed it, citing this provision among his reasons for taking such action. A recent attempt to include ANWR in this year's (filibuster-proof) budget reconciliation bill failed by a narrow vote in the Senate. In the case of North Slope gas political parties, the State of Alaska, and Canadian interests support a pipeline to

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[1] Based on mean values as published in Appendix G of the US Department of Energy, Energy Information Administration, **U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report.**
[2] The term "known reserves" rather than proven reserves is used because in its 1988 report on reserves, the Department of Energy, accepted the markdowns to proven reserves made by companies operating on the North Slope to account for the lack of any means to market the gas. Between 1987 and 1988, the official proven reserves of Alaska gas changed from 33.2 TCF to 9.1. There was no change in estimated technical ability to produce the gas.
[3] The report was prepared by the National Energy Policy Development Group led by Vice President Cheney and submitted to the President on May 16, 2001.

bring already known resources to market although there are divergences of interest over the route. However, while the politics are relatively favorable, the economics of developing the gas are uncertain and the companies involved are therefore approaching the decisions regarding the sizeable investment involved with great caution.

This report discusses the issues involved in bringing the oil and gas to market. In the case of ANWR, the report focuses first on resource estimates followed by a discussion of environmental concerns. The report then discusses whether potential production from ANWR is large or small compared to certain proposed conservation measures and also compared to projected imports. In any case, no set of economically reasonable supply or conservation measures could eliminate the country's reliance on oil imports.[4] However, among those measures that can make a difference, tapping ANWR stands out as being at least or more important as most conservation measures under consideration.

There is no single solution that will materially reduce or eliminate our import dependence and vulnerability. A common sense energy policy must reflect a portfolio approach. It is not a question of this or that policy but this and that. Balance and diversity should be our goals.

In the case of gas, current market projections such as those of the Department of Energy show no early need for Alaskan gas. However, there are some critical signs that projections of lower-48 gas production, and of availability of imports, especially from Canada, may be too optimistic. Given the long lead times involved, there is risk to the public interest that by time public and private perceptions incorporate such developments, it would be too late to bring Alaskan gas to market to moderate the sharply higher price pressures that would result. Government actions to encourage timely development of Alaskan gas would be a means of hedging against such a risk.

Alaska's Oil in Perspective

In 1970, US proven reserves jumped by about 9.5 billion barrels, or about 30%, the largest single-year gain in at least the last 50 years, with the booking of the discoveries of oil at Prudhoe Bay on the North Slope of Alaska. The first oil from the North Slope did not reach the market until mid-1977. Although the oil companies involved on the North Slope applied for a Federal right-of-way permit for a pipeline in 1969, Native land claims, legal action by environmental groups, delays involved in preparation of a six- volume Environmental Impact Statement (required under the Clean Air Act of 1970), and challenges to it, as well as opposition within Congress all delayed the start of any construction. Finally, in November 1973, shortly after the onset of the Arab Oil Embargo, Congress passed (with a tie-breaking vote by the Vice President in the Senate) and the President signed the Trans-Alaska Pipeline Authorization Act clearing

[4] For discussion of issues involved in formulating an appropriate energy policy, see the report, **Directions Towards a Balanced Energy Policy,** released by PIRINC in February 2001. The report may be accessed from our website at www.pirinc.org.

away administrative and judicial roadblocks to construction of the pipeline. The new law did not mean environmental concerns could be neglected. Under the Federal-right-of-way that was issued, the companies involved were to "---employ all practicable means and measures to preserve and protect the environment---" in the construction, operation and maintenance of the pipeline. Since completion of the pipeline, about 14 billion barrels of oil have moved from the North Slope to market, substantially more than the initial 1968 estimate of 9.6 billion barrels of economically recoverable reserves at Prudhoe Bay.

The table on the right summarizes Alaska's role in the nation's oil production and prospects. In 2002 through November, Alaskan oil production, 97% of which was from the North Slope, amounted to 1.05 MMB/D. Current production is only about half of the 2 MMB/D peak level of the late 1980s, but it still represents about 13% of total US oil production (crude and NGLs). With the pipeline in place, and with growing spare capacity, the economics of exploration and development of what otherwise might be marginal prospects beyond the initial Prudhoe Bay discovery become far more favorable---provided volumes remain above minimum levels for economic operation of the pipeline.

Alaska's Oil in Perspective

Crude & NGLs	
2002 Production – MMB/D	1.05
% of US Total	13%
End-2001 Proven Reserves	
Billion Barrels (BB)	5.3
% of US Total	17%
Technically Recoverable Reserves from Undiscovered Conventional Fields	
Mean Value BB	34.5
% of US Total	30%
Note: ANWR Section 1002	
Mean Value BB	7.7

At end-2001, Alaska's proven reserves amounted to 5.3 billion barrels (BB) of which about 99% were at the North Slope. They account for about 17% of US proven reserves. When North Slope commercial production began in 1977, proven reserves stood at about 9.5 BB, about 4 BB above the end-2001 value. In effect, with about 14 billion barrels of North Slope oil produced to date, the operating companies have added a cumulative total of nearly 10 billion to proven reserves through revisions and extensions of initial discoveries and new discoveries to the original estimates, thereby replacing about 70% of the oil produced.

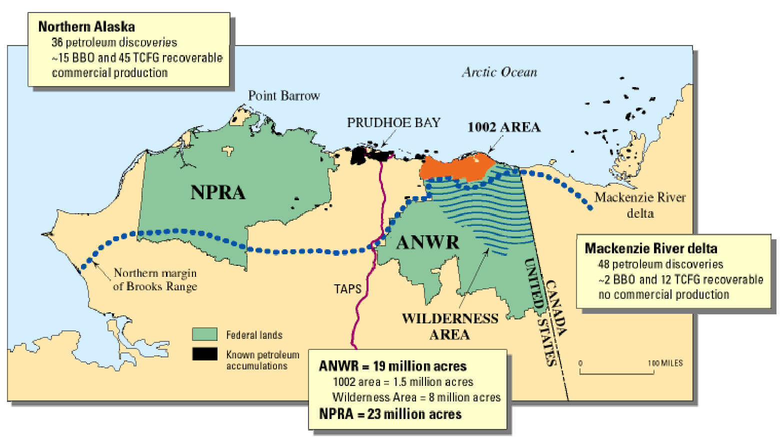
In its 2001 annual report on US reserves, the Energy Information Administration showed a mean estimate for technically recoverable U.S. oil resources from undiscovered conventionally reservoired fields of 113 BB.[5] Alaska accounted for 34.5 BB or 30% of the total.[6] The bottom of the table shows the mean estimate of technically recoverable reserves in section 1002 of ANWR,

[5] U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report, November 2002.
[6] In addition to this category of resources, the Report estimates a mean value of 81 GB from ultimate recovery appreciation in discovered conventionally reservoired fields and a further 4 GB from continuous type deposits, i.e., accumulations in share, chalk, sandstone, and coal beds, only a small portion of which are estimated to be economically recoverable now.

7.7 BB.[7] These estimated resources are all on shore or within state waters (within 3 nautical miles or 3.45 land miles of the coastline) and close to the existing production infrastructure. In contrast, of the total 34.5 BB for the state, nearly 25 BB, mainly in the Arctic, are estimated to lie in Federal offshore waters beyond three nautical miles from the coastline. Moreover, the latest USGS estimates of potential oil resources in the section 1002 area are substantially higher than those published earlier and place a much larger share of them close to existing production infrastructure.

The Section 1002 Area of ANWR

In 1960, the Secretary of the Interior designated 8.9 million acres in Northeast Alaska as the Arctic National Wildlife Range. In 1980, Congress passed the Alaska National Interest Lands Conservation Act (ANILCA), which doubled the size of the Range to 19 million acres, by extending it mainly to the south and east and renamed the enlarged area the Arctic National Wildlife Refuge. Most of the original Range, 8 million acres, was designated as "Wilderness."[8] Under section 1002 of ANILCA, the part of the Range not designated as Wilderness, the Northern coastal area of 1.5 million acres, was to be the subject of environmental studies, including the potential impact of oil and gas exploration and development, and an assessment of potential hydrocarbon resources. The section 1002 area thus accounts for about 8% of the total ANWR acreage and about 19% of the designated Wilderness area. In any case, no leasing of land or other development within ANWR can be undertaken without authorization by Congress.



The map on the right, taken from the USGS Fact Sheet, shows the location of ANWR in Northeastern Alaska.[9] The map shows within ANWR the designated Wilderness area and the 1002 area. The insert boxes show the

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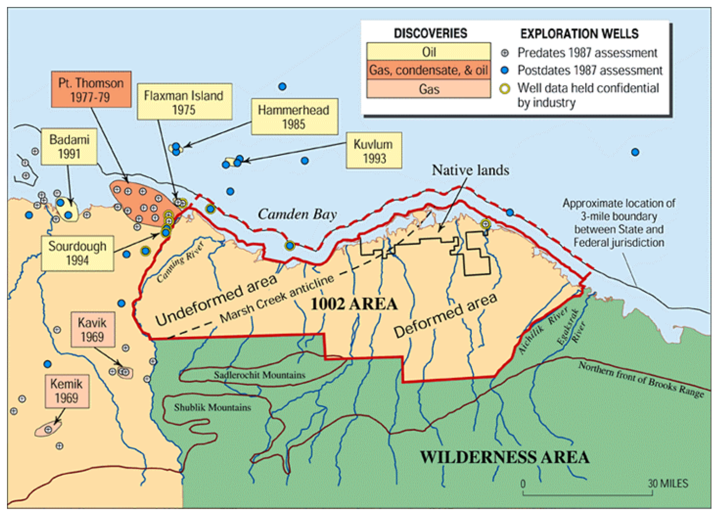
[7] From the USGS Fact Sheet, <u>Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, Including Economic Analysis</u>, April 2001.

[8] Section 4 (C) of The Wilderness Act of 1964 states "Except as specifically provided for in this Act, and subject to existing private rights, there shall be no commercial enterprise and no permanent road within any wilderness area designated by this Act---."

[9] The map also shows another Federal area, the NPRA or National Petroleum Reserve in Alaska. This area, originally designated in 1923 as Naval Petroleum Reserve No. 4, was renamed under the National Petroleum Production Act of 1976, which transferred jurisdiction from the Navy to the Department of the Interior. Lease sales were held in the 1980s but none resulted in any announced oil finds. In 1998, the Clinton Administration announced its decision to open 87% of the NPRA area to oil and gas leasing. A lease sale was held in 1999. The latest USGS estimates of technically recoverable oil for the Federal NPRA and the section 1002 area of ANWR are roughly similar (with mean values of 9.3 and 7.7 billion barrels respectively) but estimated volumes for the NPRA are spread out over a far wider area (22.5 million acres versus 1.5 for the section 1002 area).

known petroleum volumes (recoverable resources plus cumulative production) and recoverable gas resources in northern Alaska and the Mackenzie River Delta on the Canadian side of the boarder. As the map indicates, the 1002 area is close to known petroleum accumulations and its western edge is less than 100 miles from Prudhoe Bay and the Trans-Alaska Pipeline. The Trans-Alaska pipeline currently has substantial, growing, spare capacity. Oil from ANWR could help prolong the economic life of the pipeline and support the economics of developing marginal fields.

The second map, also from the USGS Fact Sheet, focuses on the section 1002 area. It shows in particular the relationship of the area to nearby discoveries, including a number made after the USGS published its 1987 assessment. That assessment was based on seismic surveys undertaken in 1984-85 and an exploratory well drilled in 1985. The map also shows the area divided into two geologically distinct areas based on rock formations, an area described by the USGS as "undeformed" in the western part of the 1002 area and a "deformed" area in the remainder.



When the USGS issued its latest, 1998 assessment, it noted improved resolution of the earlier seismic data and information based on recent nearby discoveries. The table below compares the latest assessment results with those of the 1987 assessment. Because of changes in methodology, the USGS did not offer comparisons of estimates of technically recoverable oil. Instead, they compared estimates of in-place resources.

At the 95% probability level (95% probability of finding at least a certain volume), the 1987 estimate for oil in place was 4.8 BB. In contrast, the 1998 95% probability estimate was 11.6, more than double the earlier estimate. At the high end of the range, the 5% probability level, the differences were narrower, 29.4 in 1987 and 31.5 in 1998. The estimated mean value of oil resources in place rose from 13.8 BB in 1987 to 20.7 in 1998. Apart from higher resources, the latest estimate also shifts where it estimates the bulk of the resources are located. In the 1987

1998 vs. 1987 Section 1002 Assessments

Estimated Oil Resource in Place – BB

	1987	1998
95% Probability	4.8	11.6
5% Probability	29.4	31.5
Mean Value	13.8	20.7
% of Mean Value in Western Undeformed Area	25%	85%

1998 Mean Value-Technically Recoverable Oil	
Total	7.7
Undeformed area	6.4
% of Total	84%

estimate, only 25% of the mean value of oil in place was in the western undeformed part of the section 1002 area. In the latest assessment, 85% of the much larger mean value is estimated to be in the undeformed part. In the 1998 estimate of technically recoverable oil, of the total mean value of 7.7 BB for all of the section 1002 area, 84% is estimated to be in that area closest to Prudhoe Bay and other production sites.

Environmental Concerns

In December 1995, President Clinton vetoed the "Seven-Year Balanced Budget Reconciliation Act of 1995" (H.R.2491) setting off the government shutdown that followed. Among the reasons for the veto was a provision in the Act that "---would open the Arctic National Wildlife Refuge (ANWR) to oil and gas drilling, threatening a unique, pristine ecosystem---". He added, "I want to protect this biologically rich wilderness permanently."[10] In early 2001, just before the Bush Administration took office, the U.S. Fish and Wildlife Service released its report on the potential impacts of oil and gas development in the section 1002 area of ANWR.[11] The report describes ANWR and the section 1002 area in the following terms:

> *The Refuge is America's finest example of an intact, naturally functioning community of arctic/subarctic ecosystems. Such a broad spectrum of diverse habitats occurring within a single protected unit is unparalleled in North America, and perhaps in the entire circumpolar north.---The 1002 Area is critically important to the ecological integrity of the whole Arctic Refuge, providing essential habitats for numerous internationally important species such as the Porcupine Caribou herd and polar bears. The compactness and proximity of a number of arctic and subarctic ecological zones in the Arctic Refuge provides for greater plant and animal diversity than in any other similar sized land area on Alaska's North Slope.*

The report acknowledges that advances in oil and gas exploration and development technologies have reduced some harmful environmental effects but goes on to indicate that opening the section 1002 area could mean the development of a significant infrastructure of roads, pipelines, etc., on land and vegetation slow to recover from such intrusions. The report cites potential effects on wildlife, especially Muskoxen, polar bears, caribou, and snow geese. It should be noted that the discussion of the potential for oil industry intrusion and adverse impacts appears based on the earlier 1987 petroleum resource assessment. The latest USGS assessment, as discussed in the previous section, puts the bulk of the resources much closer to existing facilities and in a more compact area, suggesting a much less sprawling infrastructure requirement.

The issue of just how much environmental damage would be caused by opening the section 1002 area remains in dispute, as indeed does the issue of how much damage has resulted from North

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[10] See: VETO MESSAGE FROM THE PRESIDENT OF THE UNITED STATES (H. DOC. NO. 104-141) (House of Representatives - December 06, 1995)

11 U.S. Fish and Wildlife Service, **Potential Impacts of Proposed Oil and Gas Development on the Arctic Refuge's Coastal Plain: Historical Overview and Issues of Concern**, January 17, 2001. The report is available on the Internet at: http://library.fws.gov/Pubs7/arctic_oilandgas_impact.pdf.

Slope development to date. The next two sections focus on oil's footprint on the North Slope, with the first looking at the recent history of oil spills and the second discussing aspects of the just-released report by the National Research Council on cumulative environmental effects of Alaskan North Slope oil and gas activities.[12]

Oil Spills

Virtually up to the minute oil-related spill information is available from the database maintained by the National Response Center. The Center serves as the "sole national point of contact for reporting all oil, chemical, radiological, biological, and etiological discharges into the environment anywhere in the United States and its territories."[13] Its database of incident reports is available to the public. In 2001, a total of about 9,500 oil-related discharges were reported to the NRC, with about 1,900 involving discharges of 1 gallon or less. In 2002, total reported oil-related discharges were somewhat lower, about 8,600, of which about 1,700 involved discharges of 1 gallon or less.[14]

The table below summarizes for 2001 and 2002 the volume of oil-related spills as initially reported to the NRC in MB for 2001 and 2002 at the North Slope, the rest of Alaska, and the total reported for the US. The reports contain initial rather than final estimates and in certain cases estimates of potential as opposed to actual volumes discharged.

[12] National Research Council, **Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope**, March 2003. At this time only a pre-publication copy is accessible. See the website at http://search.nap.edu/books/0309087376/html/.

[13] Quotation is taken from the National Response Center background statement as shown on its website at www.nrc.uscg.mil/nrcback.html. Oil-related incidents are defined as those with an oil flag entry in the database other than those described as drills.

[14] Federal requirements for reporting oil discharges are not always tied to specific quantities. Under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), a discharge that causes "---a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines---" must be reported. Alaska's own regulations require that any release of oil to water must be reported as soon as the person has knowledge of the discharge. Discharges of oil on land in excess of 55 gallons are also subject to an immediate reporting requirement. Land discharges of 10-55 gallons must be reported within 48 hours while discharges of 1-10 gallons require provision on a monthly basis of a written record. For a summary of Alaska's requirements see the Alaska Department of Environmental Conservation, Division of Spill Prevention and Response web page on the subject at www.state.ak.us/local/akpages/ENV.CONSERV/dspar/perp.reqnew.htm.

Amount of Oil Spilled in 2001 and 2002 - MB
From Incident Reports to the National Response Center

	2001	2002
Crude Oil Related*		
North Slope	2.2	0.5
Rest of Alaska	-	0.1
National Total	30.6	38.4
North Slope % of Total	7%	1%
North Slope 2001 Crude Production % of National Total	16%	
Other Oil-Related		
North Slope	0.07	0.03
Rest of Alaska	1.3	2.4
National Total	479.8**	247.5
North Slope % of Total	0.01%	0.01%

*Includes spills of crude oil, water/crude mixes, and drilling mud. Of the North Slope 2001 crude related spills, 99% was from a release of water with a 1% crude content.
**Includes an estimated potential release of 250 MB of gasoline from a Collision of vessels in the Houston Shipping Channel.

The top half of the table shows reported amounts of crude oil-related discharges where discharges in this category include crude, crude/water mixtures, and drilling mud. In 2001, crude-oil related discharges on the North Slope amounted to 2.2 MB, accounting for virtually all such discharges in Alaska. Spills are subject to stringent clean-up requirements. For example, virtually all of the 2001 North Slope total (2,200 barrels out of a total of 2,215) was from a water line at the Kuparak oil field. The reported discharged material was water with an estimated 1% crude content. A situation report dated June 24, 2001 published by the state of Alaska outlines the clean-up steps that were taken and reports that the clean up was completed. The site was to be monitored for effects if any on the tundra and surface water for evidence of hydrocarbons.[15]

The 2001 North Slope volume of crude-related spills amounted to about 7% of the national total of 30.6 MB reported to the NRC. North Slope crude oil production amounts to about 16% of the national total. Of course crude oil is not simply produced but stored and transported and potentially each of these processes can lead to spills. Indeed the largest single reported crude oil-related discharge in the U.S. in 2001 was of approximately 3.1 MB near Atwood, Kansas when lightning struck a tank farm[16]

In 2002, the volume of North Slope spills reported to the NRC was much lower, about 0.5 MB, or about 1% of the national total of 38.4 MB. The largest reported release in the country last year was 6,000 barrels of crude oil from a pipeline near Cohasset, Minnesota.[17]

Crude oil-related discharges are only one source of oil spills and at the national level, a relatively minor part. The lower half of the table focuses on these other spills related to transport, storage, and use of oil products. On the North Slope, these volumes are very small, about 70 barrels in 2001 and about 30 in 2002. Such spills in the rest of Alaska were about 20 times greater in 2001 and 70 times greater in 2002. At the national level total discharges ex crude-related amounted to nearly 480 MB in 2001 and nearly 250 MB in 2002.[18] The amounts discharged on the North

[15] The full June 24, 2001 status report is available at: www.state.ak.us/dec/dspar/perp/cpf1/status_06.htm.
[16] NRC incident report #580011 dated September 17, 2001.
[17] NRC incident reports #615614 dated July 2, 2002 and updated incident report #615640.
[18] In 2001, the largest single incident was the collision of two vessels in the Houston Shipping Channel on December 4. Reported volumes involved (although not necessarily all spilled) were 250 MB of gasoline and 5 MB of MTBE (NRC incident report #587745). The largest reported incident in 2002 was the grounding of a barge

Slope are a miniscule share of the national total, about 0.01%. As with crude oil, clean up is required. In 2002, the largest reported non-crude related oil spill on the North Slope took place on August 29th when a truck carrying diesel fuel ran off the road spilling about 1,000 gallons (about 24 barrels) of the fuel. Sandbags and sorbent boom were used to contain the spill. The diesel oil and oily water was then collected, a certain amount of soil was removed and other actions taken.[19]

Overall, the volumes of oil reported spilled on the North Slope appear very small, although clearly greater than zero. However, the stringent requirements in place for reporting and clean-up, the ongoing oversight and monitoring activities by government agencies---and availability of detailed information to the public all serve to minimize potential long-term damage to the environment.

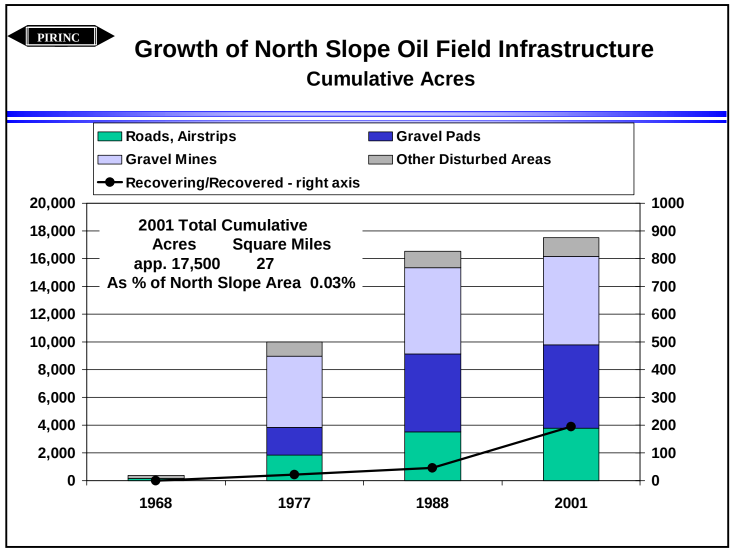
The National Research Council Report

In 2000, Congress directed the National Research Council to undertake a study of the cumulative environmental effects of Alaskan North Slope oil and gas activities. The just-released report, cited earlier, is in response to that mandate. The extent of environmental and other effects considered in the report is very broad. The report also notes the uncertainties involved in making such judgments as well as the benefits associated with oil development. There are also references to improvements in oil operations that are significantly reducing environmental impacts.

There is an extensive discussion of the impacts of the growth in infrastructure associated with oil and gas development on the tundra and wildlife, social, economic and cultural effects on native inhabitants, and effects on aesthetics where aesthetics include opportunities for solitude, and scenic values. The report presents estimates of the North Slope oil field infrastructure, including cumulative infrastructure area in acres. The acreage data are summarized in the chart below.

aground near Bayonne, New Jersey on June 3rd, with 98 MB of No. 6 fuel oil. No material was reported released in the Arthur Kill (NRC incident report #608129).

[19] NRC incident report #621418 dated August 29, 2002. The most recent clean-up details can be found in the situation report released on November 21, 2002by the Alaska Department of Environmental Conservation, Division of Spill Prevention and Response, and available at: www.state.ak.us/dec/dspar/perp/020829301/status_02.htm.



The bars of the chart summarize cumulative acres for selected years accounted for by: (1) roads (gravel and peat) and airstrips, (2) gravel pads for exploration, production, processing facilities and support sites, (3) gravel mines, and (4) other disturbed areas. The latter category includes tundra scars and disturbed areas around gravel pads.

In 1968, the year the Prudhoe Bay discovery was announced, the total oil field infrastructure area amounted to about 350 acres. By 1977, the year when the first oil began to flow through the Trans-Alaska pipeline, the infrastructure area had spread to 10,000 acres. By 1988, cumulative acreage reached about 16,500 acres. Since then, however, growth has slowed dramatically. Growth between 1988 and 2001 amounted to less than 1,000 acres, or about 5% of the 1988 total. The report gives significant credit for the slowdown to the use of new technologies. As the report states:

> *The new exploration-related technologies have reduced the overall use of gravel and presently eliminated it from the exploration-drilling process, have provided data for better siting of facilities, and have reduced the number of wells required to find and evaluate a new field.*[20]

The chart shows an additional category, Recovering/Recovered. This category is shown as a line and includes sites where the gravel pads have been removed and the sites are either recovering or in the process of recovery. Although small compared to the cumulative acreage totals, it is nonetheless growing, up from 21 acres in 1977 to 46 in 1988 and 195 in 2001.[21]

As of 2001, the total build-up of oil-field infrastructure acreage amounted to about 17,500 acres or about 27 square miles, 95% of which was in place by 1988. While the number seems large, it should be kept in mind that the North Slope encompasses about 89 thousand square miles. Thus

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[20] See Chapter 4 of the report, " History of Oil and Gas Activities," pp. 68-75 for the underlying data and the quote. In the chart, gravel and peat roads have been combined. Acreage for Recovering/Recovered gravel pad sites (from which the gravel pads have been removed) have been added back to the cumulative totals and then shown separately in the chart. The report also notes in the same chapter that newer technologies are reducing required pad size and number as well as requirements for water. Quantities of waste, mud and cuttings are smaller while reduced fuel consumption is curbing emissions.

[21] In this regard, the report in its Summary section finds that, "The lack of clear state of federal performance criteria, standards, and monitoring methods governing the extent and timing of restoration has hampered progress in restoring disturbed sites."

the infrastructure acreage amounts to a miniscule 0.03% of the North Slope territory (presumably leaving still plenty of room for the solitude and scenic values discussed in the report).

The report highlights other mitigation efforts. These include agreements to limit or move some exploration activities in the fall to reduce the effects of noise on the migratory pathways of bowhead whales---and thereby the impact on the traditional whale hunters, the Inupiat. Under a consent decree, the industry is cleaning out most old reserve pits used to hold various wastes including drilling mud, crude oil spill materials, etc. The waste is to be ground and injected into subsurface formations. In other instances, the report notes uncertainties about the impact on wildlife, as in the case of the Central Arctic Caribou Herd. The report describes periods of both increase and decrease in herd size and the problem of separating out the influence of high and low periods of insect activity.

Overall, the report offers an updated, authoritative starting point for discussion but by no means settles the question about whether the benefits of oil production justify actual and potential environmental effects. As the report states, “this is an issue for society as a whole to debate and judge.”

ANWR: Large or Small?

Whether this is a large or small number depends on one’s perspective. The number amounts to slightly less than a year’s US oil consumption---a comparison often made by opponents of opening ANWR. On the other hand, the potential production from ANWR compares favorably in its impact on the US oil balance with other proposed measures to reduce oil demand. Last year, Congress considered a number of measures to reduce oil demand, as well as the opening of ANWR. The Department of Energy provided estimates of their effects in response to Congressional requests. The table below summarizes the Department of Energy estimates for the opening of ANWR and certain other proposals and compares them in terms of their impact on projected net oil imports.

The top of the table shows the effects of opening ANWR. The figures assume Congressional approval in 2002 and, given the time lags involved in exploring and developing a new frontier area, first production in 2011. The reduction in imports based on mean values of resources amounts to 0.7 MMB/D in 1015 and 0.8 in 2020. The low to high ranges based on 95% resource

Impact of Selected Policies on Oil Imports – MMB/D
From Department of Energy Analyses of 2002 Legislative Options

Import Reduction in	2010	2015	2020
Open ANWR, 1st Production in 2011			
Mean Value	-	0.7	0.8
Low to High Range		0.60 to 0.80	0.5 to 1.5
Renewable Fuel Standard, 2 billion gallons by 2006, 5 by 2012			≈0.2
Move light trucks to new car CAFÉ mpg standard by 2008	0.4	0.6	0.8
Move CAFÉ standard to 35 mpg by 2013 for all new light duty vehicles	0.4	0.8	1.3
US net oil Imports in the Department of Energy 2003 Annual Energy Outlook Reference Case	13.8	16.2	17.7
Reference Case Wind Power*	0.12	0.15	0.16

*Converted from TWh to MMB/D assuming 33% generation efficiency. In all years shown wind accounts for less than 1% of total power generation.

probabilities are 0.6 to 0.8 MMB/D in 2015 and 0.5 to 1.5 in 2020.

Last year, the Senate version of the Energy Policy Act of 2002 contained a Renewable Fuel Standard calling for 2 billion gallons of renewable fuel, essentially ethanol, to be added to the gasoline pool by 2006, rising to 5 billion by 2012, and a constant, 2012 fraction of the gasoline pool thereafter. In 2001, about 1.5 billion gallons of ethanol was used in "gasohol," or about 1.2% of the total gasoline pool. The estimation process was complicated by the need to consider first what would happen in the base case to MTBE and the current Federal oxygenate requirement for reformulated gasoline and then what the impact would be of allowing a credit of 1.5 gallons for each gallon of ethanol produced from cellulose. In any case, the impact on oil imports is very modest, about 0.2 MMB/D in 2020.

The next proposal, contained in last year's Senate bill S. 804 called for increasing the CAFÉ standard for light trucks from the current 20.7 mpg level to 22.5 in model years 2003-4, 25 in 2005-7, and 27.5, the current standard for cars, in model years 2008 and beyond. This proposal would have early, but initially modest effects since new light truck sales in any given year amount to only about 10% of the existing fleet. By 2010, the Department of Energy estimated the proposal would reduce oil imports by 0.4 MMB/D. For 2015 and 2020, the estimates are very similar to the mean value based estimates for opening ANWR. A more ambitious proposal, contained in last year's Senate bill S. 517, called for an increase in the combined fuel economy standard to 35 mpg by 2013 (with cars moving to 38.3 mpg and light trucks to 32). The reduction in oil imports in 2010 is about the same as under S. 804, but is higher in 2015 by about 0.2 MMB/D. In 2020 the estimated reduction in imports reaches 1.3 MMB/D, about 0.5 MMB/D above the estimate for S. 804 and the mean value estimate for ANWR.

The lower part of the table shows the 2003 Reference Case projection for net oil imports, which last year totaled about 10.5 MMB/D. The projection shows net imports rising to 13.8 MMB/D in 2010, 16.2 in 2015 and 17.7 in 2020. The projected import levels, and even the projected growth in imports, are far greater than estimated reductions that would result from any of the measures shown in the table. Such a comparison simply highlights the point that in reality no set of economically reasonable conservation or supply measures could, in the foreseeable future, even come close to substantially reducing the country's reliance on oil imports.

As a notation item, the bottom of the table shows the oil equivalent of electricity generation from wind in the 2003 Reference Case (using a 33% efficiency rate for conversion purposes). In 2010, the oil equivalent for wind power is about 0.12 MMB/D, rising to 0.16 in 2020. In all three years, wind power accounts for less than 1% of total US power generation.

In such circumstances, a sensible energy policy should contain a balanced portfolio of reasonable cost measures impacting both supply and demand that would together have a significant impact on imports, or at least growth in imports. Among those measures that can make a difference, tapping ANWR stands out as being at least as important as most conservation measures under consideration. Production from ANWR would of course come too late to relieve near-term supply problems---as would CAFÉ or other conservation measures. But with international oil supply disruptions occurring on average once a decade for the last 50 years, it is unrealistic in the extreme to assume there won't be others in the future. In fact, if this were not the case, there would be no justification for the Strategic Petroleum Reserve.

Alaska's Gas

In October 1976, amid concerns about natural gas shortages in the lower 48 states, Congress passed the Alaska Natural Gas Transportation Act (ANGTA) designed to expedite the process of bringing the 26 trillion cubic feet (TCF) of proven reserves in the Prudhoe Bay field to market. In the Act, Congress declared that expeditious construction of a delivery system for Alaska's natural gas was in the national interest and that the determination of system and route involved "---questions of the utmost importance respecting national energy policy, international relations, national security, and economic and environmental impact---."[22] In effect, Congress was stating that decisions regarding Alaskan gas involved significant "externalities" or public benefits (and/or costs) beyond those entering private calculations and in this case, those entering normal regulatory considerations and procedures.

In 1977, in accordance with the provisions of ANGTA, President Carter chose a specific route for the pipeline, since referred to as ANGTS) which would run from Prudhoe Bay along the existing oil pipeline to Fairbanks, then along the Alaska Highway into Canada. Two additional segments, an Eastern and a Western leg would bring the gas to the mid-west and California markets. An Agreement on Principles with Canada regarding the route was reached the same year.23 The Agreement contained a timetable that called for completion of the entire project by January 1, 1983. Despite the political actions taken to expedite matters, more than 25 years after ANGTA, Prudhoe Bay gas has yet to reach the market. In the 1980s, the absence of any means of bringing the gas to market led the companies involved to reduce their estimates of proven reserves. In 1988, the Department of Energy agreed that only gas marketable on the North Slope would be considered "proven" and revised its official estimates downward by nearly 25 TCF. Official figures of proven reserves for Alaska shrank from about 33 TCF in 1987 to about 9 in 1988, not far from recent estimates. In the end, economics rather than politics dominated decisions regarding Prudhoe Bay gas.

In recent years, and indeed right now, sharp spikes in natural gas prices, fall-offs in domestic supply, and projections of increased demand for natural gas have all contributed to renewed public interest in Alaska's natural gas, especially the known reserves at Prudhoe Bay. The politics remain relatively favorable, although complicated by political pressures regarding the route. Different competing pipeline routes are under consideration, including a pipeline to an LNG plant at Valdez and also the possibility of a gas-to-liquids project at some point that would make use of the existing TAPS line. Although Congress failed to pass an energy bill in the last session, both the House and Senate agreed in conference that "Construction of a natural gas

[22] From U.S.C. Title 15, Chapter 15C, Section 719.
[23] The full title is: "Agreement between the United States and Canada on Principles Applicable to a Northern Natural Gas Pipeline." The Agreement has the legal status of a statute.

pipeline system from the Alaskan North Slope---is in the national interest and will enhance national energy security" and as in ANGTA, provided for an expedited approval process. The agreed language also prohibits Federal Energy Regulatory Commission from approving any pipeline with a proposed route that crosses the Beaufort Sea, or that enters Canada at any point north of 68 degrees north latitude, effectively requiring a North-South route through Alaska roughly similar to the original ANGTS route as opposed to a shorter (especially within Alaska) Northern route under consideration that would link up with Canadian McKenzie Delta Reserves.[24]

As was the case earlier, while the political environment is clearly if conditionally, favorable, the economics remain more clouded. Indeed, the Reference Case projections of Department of Energy's latest 2003 Annual Energy Outlook have no North Slope gas reaching the US market until 2021, looking primarily instead to unconventional sources in the lower 48, and higher imports of Canadian gas and LNG to meet growing US requirements until that time. The next sections consider in more detail the economic issues involved in bringing Alaskan gas to market.

Assessing the Gas Market

In the late 1970s, the gas market contemplated by the political proponents of an Alaskan gas pipeline looked very different from today. In particular, the regulatory regime in place at the time, as well as perceived supply shortages appeared to virtually guarantee the economic viability of the project. The U.S. was still regulating natural gas prices, including prices to different classes of consumers. Thus the 1977 Presidential Decision regarding ANGTS could contemplate a provision calling for the allocation of costs of expensive supplies to lower-priority users (other than residential and commercial) as a means of securing revenues for the pipeline. In today's world, these so-called lower-priority users are no longer captive markets---indeed, they are most able to shop the market for lowest-cost supplies. Presumably, because of what appeared to be the security of revenues for a proposed pipeline, President Carter felt able to exclude the financially strong North Slope gas producers from any equity participation in the proposed pipeline---although there were doubts at the time about the ability of other potential participants to finance the project. President Reagan waived this exclusion in 1981 with the approval of Congress although by then prospects of deregulation and weakening energy markets were making the project unviable in any event.[25]

With outlets and cost recovery no longer insured by regulation, prospects for Alaskan gas depend on assessments of the ability to place sustained, large, long-term volumes of gas in a competitive

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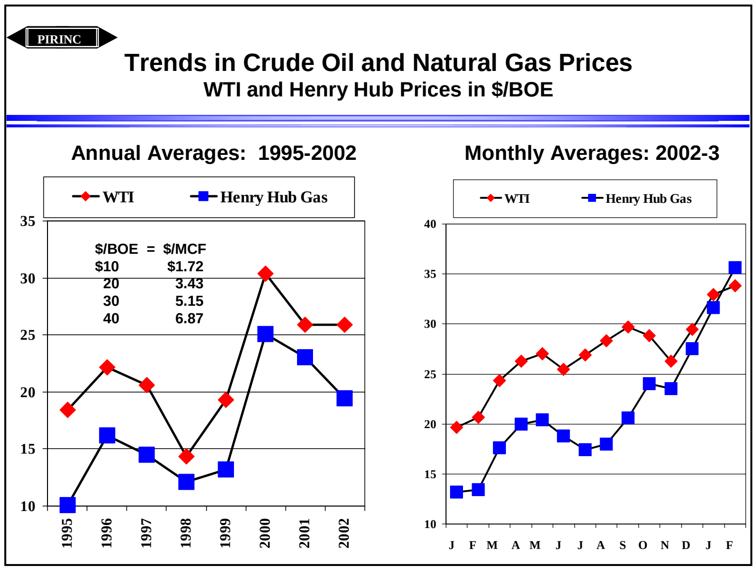
[24] The quotation and the cited prohibitions are from Title VII of the Energy Policy Act of 2002 (Engrossed Amendment as Agreed to by the Senate). A North-South route would involve about 800 miles of Alaskan territory. A Northern route would cross about 200 miles of Alaskan territory, including offshore waters. A North-South route would also offer a clear source of new gas supply to Alaskan population centers.

[25] See the Staff Report of the Federal Energy Regulatory Commission on the Alaska Natural Gas Transportation Act. Submitted to the U.S. Senate Committee on Energy and Natural Resources, January 18, 2001.

US market at prices that generate acceptable returns to producers and pipeline investors with due allowance for risks---both upside and downside. The recent price history of gas suggests this is no easy task.

Gas Prices

The next chart summarizes trends in wellhead oil and gas prices using WTI crude oil and Henry Hub gas. For comparative purposes, prices are expressed in $/BOE with an insert table showing benchmark equivalences to $/MCF. The left panel of the chart shows annual average prices for 1995-2002 while the right panel shows monthly averages from January 2002 through February 2003.



The annual data for 1995-2002 show the wellhead price of gas moving roughly in line with crude oil prices although significantly below them. Over the years shown, gas prices were on average about $5.50 BOE below crude prices. In recent years gas and oil prices have been averaging well above their 1990's levels. Although down from its $25/BOE average in 2000, average prices in 2001 and 2002 were both at or above the $20/BOE level. At the $20/BOE or $3.48/MCF or above, the gas price (in constant dollars) is at or near levels considered needed to support the bringing of North Slope gas to market.[26]

However, while the high prices of the past few years have renewed interest in bringing the gas to market, a more detailed look at recent monthly trends reveals ample reason for caution. As the panel on the right shows, in the first three months of 2002, Henry Hub prices were well below the $20/BOE level and did not surpass that level on a sustained basis until September. The low prices of early 2002 were in sharp contrast to those of the year before. In January-February 2001, gas prices averaged about $8 and $5.50/MCF respectively supported by surging gas-powered electricity generation requirements in California and a sudden cold snap in the Northern

[26] The Department of Energy's 2003 Annual Energy Outlook considers a price of about $3.50/MCF (in 2001 $) sufficient to encourage the construction of a generic pipeline to bring the gas to market. The specific market usually considered is the Chicago City Gate. In 1995-2002, Chicago city gate prices averaged about $0.11/MCF above Henry Hub Prices.

part of the country. A year later prices were down to about $2.25/MCF. Currently, in the midst of a colder-than-normal winter and soaring oil prices, gas prices as of mid-February 2003 are at nearly $35/BOE, or about $6/MCF but as recent experience demonstrates, investors would be foolhardy to count on them being sustained.

In any case, with engineering and construction time for a delivery system estimated to take at least four years plus at least two years up front for navigating even an expedited permitting process (including the preparation and approval of the required Environmental Impact Statement), and deliveries of North Slope gas extending over decades, a longer-term price perspective is required. In this regard, the table below summarizes the wellhead gas price projections contained in the Reference Cases of the Department of Energy's recent Annual Energy Outlooks. Prices have been restated to constant $2000/MCF.

U.S. Department of Energy Wellhead Gas Price Projections
From the 1999-2003 Annual Energy Outlook Reference Cases
($/MCF, Constant 2002 $)

	2000	2010	2020	2025
1999 AEO	$2.35	$2.82	$3.00	
2000 AEO	2.39	2.87	3.10	
2001 AEO	2.18	2.67	3.06	
2002 AEO	3.76	2.98	3.41	
2003 AEO	3.89	3.34	3.74	3.96

Price perceptions have clearly been moving up. In the 2001 Outlook, the 2010 price was $2.67 and the 2020 price $3.06. In the 2002 Outlook, these prices had moved up to $2.98 and $3.41 respectively while in the recently released 2003 Outlook, prices moved up further---to $3.34 in 2010 and $3.74 in 2020. The 2003 Outlook has a projected price of nearly $4 in 2025. These prices are assumed sufficient to bring North Slope gas to the US market, but not before 2021. The Reference Case assumes no new government policies to encourage investment in North Slope gas and assumes that potential investors share the same views regarding costs and future prices.[27]

The rising long-term price perceptions are associated with changing projections for the long-term U.S. supply/demand balance, especially between this year's Outlook and the 2002 Outlook. These are summarized in the table on the right.

Reference Case Gas Supply/Demand Projections
Annual Energy Outlook 2003 & 2002 - TCF

	2000	2010	2020	2025
Domestic Dry Gas Production				
2003 AEO	19.0	21.9	25.1	26.8
2002 AEO		23.5	28.5	
Net Imports				
2003 AEO	3.5	4.8	6.7	7.8
2002 AEO		4.9	5.5	
Note: Imports from Canada				
2003 AEO	3.5	4.1	5.1	5.3
Consumption				
2003 AEO	23.5	27.1	32.1	34.9
2002 AEO		28.1	33.9	

[27] The 2003 Outlook Reference Cases assumes a capital cost of $11.6 billion in $2002 for a pipeline from Alaska to Alberta. For a full list of cost-related assumptions see Table 52 of Assumptions to the Annual Energy Outlook 2003.

The 2003 outlook shows a substantial increase in domestic production, up by about 6 TCF in 2020 versus 2000, or by about one-third. Although not shown, the gains are led by substantial increases in anticipated production from unconventional sources (tight sands, shale, coal bed methane). There are further gains by 2025, when North Slope gas is in the market.

But although there is substantial growth, and despite higher projected prices, the Reference Case projections of production in this year's outlook are significantly below those in last year's outlook--- by 1.6 TCF or 7% in 2010 and 3.4 TCF or 12% in 2020. Higher imports offset part of these differences. In this year's Reference Case, imports in 2020 are nearly double their 2000 level and up 1.2 TCF from the 2002 projection.[28]

This year's Reference Case continues to look to Canada as a key source of growing imports. Imports from Canada are projected to rise from 3.5 TCF in 2000 to 4.1 in 2010, 5.1 in 2020, and 5.3 TCF in 2025. The projection for 2020 is about the same as in the 2002 Reference Case. However, these projections appear inconsistent with the analysis of Canadian energy prospects recently released for public consultation by the Canada's National Energy Board (NEB).[29] The two scenarios presented in the NEB study both project high growth in their own domestic demand for gas accompanied by in one case declining domestic production beyond 2010 and in a second case, production growth that lags demand. Neither scenario is consistent with long-term growth in exports to the US as projected in this year's Reference Case. While the NEB report is preliminary, it raises the possibility of a significantly tighter long-term US gas market than the contained in this year's Reference Case.

The remaining differences between the current and last year's Reference Cases (apart from statistical discrepancies) are reconciled via lower levels of projected demand in the latest outlook. Demand in 2020 in this year's projection is down by about 5% from the year before. Projected demand growth is nonetheless still robust, thanks primarily to rising use in power generation. Although not shown, the 2003 Reference Case looks to gas to supply just over half of the growth in electricity generation between 2000 and 2025.

This year's Reference Case projects enough domestic gas plus imports under current policies for nearly two decades to balance projected demand without North Slope gas. However, the change in perceptions between last year's Outlook and the latest one, as well as the recent NEB study, suggest a different possibility. A continuation of the markdowns in projected domestic supplies and/or a less robust time-path for imports would accelerate the timing for economic placement of North Slope gas in the market. Disappointing domestic production and stagnant Canadian

[28] About 60% of the difference is accounted for by higher projected imports of LNG, which in 2020 amount to 1.5 TCF or about 23% of total 2020 net imports. The projection requires a very substantial increase in import capability. LNG imports last year amounted to only about 0.2 TCF.

[29] National Energy Board, **Canada's Energy Future, Scenarios for Supply and Demand to 2025**, a public consultation draft released January 7, 2003. Details about the report and the report itself may be accessed at: http://www.neb-one.gc.ca/energy/sd0203/index_e.htm.

production this year despite exceptionally favorable prices suggest further pessimistic adjustments to long-term supply projections may indeed be coming. If so, the US market would welcome supplies from Alaska much sooner than the 2021 date projected in this year's Reference Case.

Financial Condition of Potential Investors

Current price levels are of course far above levels contemplated in the latest Annual Energy Outlook adding further to public interest in speeding up the timetable for bringing the gas to market. However, in a deregulated environment, private investors must allow for, and accept substantial price risks. Unlike the late 1970s, there are no captive markets that regulators can force to absorb gas at above market prices. Nor are customers likely to sign long-term contracts that would guarantee both volumes and prices.[30] With investors bearing the risks, their ability to finance such projects will depend far more than in previous years on their own financial standing. In recent years, there has been a clear narrowing of the field among those that have previously announced their intention to invest in one or another gas project.

The table below offers one measure of financial standing, market capitalization, for two particular groups. The first are the three major North Slope gas producers, and the second are the companies involved in the original ANGTS project that in mid-2001 signed a memorandum of understanding (MOU) to move forward with a new ANGTS project. The table shows market capitalization as of mid-2001 and as of mid-February 2003.

Among the three North Slope producers, mid-February 2003 market capitalizations were down by between 20% to 26% versus mid-2001. Valuations for the three remained in excess of projected costs of any pipeline project, although with clear differences between valuations for the "super-majors," Exxon Mobil and BP, and the valuation for Phillips-Conoco. Among the seven companies that signed the 2001 MOU, five companies had at the time, market capitalizations well above projected pipeline costs. Of those five, Enron has declared bankruptcy and has lost nearly all market value while three others, El Paso, Williams and PG&E show

Market Capitalizations of Potential Pipeline Investors as of Mid-2001 and Mid-February 2003 - $ Billion

	2001	2003	% change
North Slope Producers			
Exxon Mobil	305	225	-26%
BP	185	145	-21%
Phillips-Conoco	42	33	-20%
ANNGTC 2001 MOU Signatories*			
Duke Energy	32	13	-60%
El Paso Corporation	28	2	-91%
Enron	34	0	-100%
PG&	46	5	-89%
Sempra Energy	6	5	-14%
TransCanada Pipelines	6	7	+25%
Williams Companies	17	2	-91%

ANNGTC (Alaskan Northwest Natural Gas Transportation Company) was selected to build ANGTS in the 1977 Presidential Decision. The MOU was to set the stage for moving forward with a new ANGTS project. The signatories were all involved in the original ANGTS project.

[30] In LNG markets, early contracts specified minimum volumes and prices. But as markets became more competitive, minimum prices have eroded and are no longer part of new contracts.

declines of about 90%. The fifth, Duke Energy, shows a decline of 60% in market capitalization. The remaining two signatories, Sempra Energy and TransCanada Pipelines, have done much better with Sempra Energy's valuation down only 14% and TransCanada Pipelines' up 25%. Both companies have market capitalizations below projected pipeline costs.

The market capitalization estimates illustrate the financial impairments suffered by a number of prominent companies in energy-related industries. Many have been taking steps to improve their financial circumstances, and may succeed in doing so. Nonetheless, the pool of potential participants in a large-scale project for Alaskan gas has clearly been reduced while the role of the financially secure North Slope Producers in assuring project viability has become more essential then ever.

Next Steps for Gas

In 2001, the three major North Slope producers conducted feasibility studies for alternative pipeline options for bringing their gas to market. The team formally ended its work in early 2002 after spending over $125 million. The study estimated construction of either a Southern or Northern pipeline route with a 4.5 BCF/D capacity to move gas from the wellhead to the US market would cost nearly $20 billion.[31] This estimate includes costs associated with a gas-processing unit required to separate impurities from the gas before entering a pipeline. An NGL plant is also included in the design. Such a figure is bound to make any potential investor or set of investors, however strong their finances, extremely cautious in assessing the overall economics of such a large project. The producers have publicly indicated that neither route is currently commercially viable and that significant cost reductions and an improved market outlook are needed.

The Role for Government

The proper role of government in the face of a project with public interest but uncertain economics is not clear-cut. On the one hand, the U.S. government, the State of Alaska, and the Canadian government can act to expedite and otherwise reduce the cost of the permitting process. Such action was taken in the late 1970s, and it's clear the U.S. Congress and Administration would agree to similar action again. All parties should be examining the tax and royalty structures applicable to gas production and transport over the life of the project with a view to avoiding imposition of undue costs, especially should gas return to a low-price environment.

The proposed Energy Policy Act of 2002 had provisions that went well beyond simply expediting the regulatory decision-making process. It would have authorized the Secretary of

[31] See the report published in McGraw-Hill Construction, " Alaska's North Slope Gas Still Stranded by Economics," May 16, 2002.

Energy to guarantee loans for up to $10 billion for purposes of constructing a pipeline. In the event no project application for a certificate of public convenience was filed with the Federal Energy Regulatory Commission within 18 months of enactment of the Act, the Secretary of Energy was authorized to study alternatives, including the establishment of a Government corporation to construct the pipeline. Loan guarantees are a means of lowering project finance costs, although their impact would be less for financially strong companies such as the North Slope producers. The prospect of a guarantee could allow less financially secure entities to participate in a pipeline project but this should not be a government priority. In this case competition concerns should not be an issue. Any such pipeline will be subject to Federal Energy Regulatory Commission oversight regarding tariffs and open access to capacity.

As for a government corporation, it should be kept in mind that such a last resort option should apply only when risks associated with a project of clear, overwhelming, immediate public interest are too great for the private sector to bear. But this is not the case for North Slope gas. The issue today is whether Alaskan gas will in fact be needed enough, early enough, to justify an early start on the large investments required. Under current conditions, and consistent with the latest Department of Energy projections, the answer for potential private investors would be negative.

In such circumstances, the public interest concern is the risk that the US long-term gas market tightens much earlier than currently anticipated, leaving the country without the Alaskan gas that could otherwise moderate an economically damaging, sharp escalation in gas prices. Of course, if conditions develop that suggest such a risk is becoming a reality, future market assessments, including future Department of Energy Reference Cases, would reflect them. But given the long lead times involved, by the time public and private perceptions had changed it could be too late for timely relief from Alaskan gas. Some government action to encourage early development would be justified as a form of insurance against such a risk, although what measures if any to take remain a matter for Congress and the Administration to decide.

Final Notes

There is an almost schizophrenic aspect to the public debate regarding Alaska's oil and gas. In the case of ANWR, the economics appear favorable, much of the infrastructure is in place, and strategic arguments look as compelling as ever. Opposition among environmentalists and within Congress remains determined and, as the recent Senate vote demonstrated, to date successful. In the case of gas, there is broad political support but infrastructure requirements are large while the need, or market, for the gas until well into the future remains highly uncertain. However, recent production trends in the US and Canada suggest the market need may come earlier rather than later.

The recent report by the National Research Council may provide a common point of departure for assessing environmental concerns regarding ANWR but cannot settle the issue. In the end, the political choice must be made whether the improvements to date in industry performance, or any level of performance, would prove acceptable as the basis for allowing access to the single most promising prospect for increased domestic oil supplies.

In the case of gas, the public interest is clearly served by government expediting the regulatory and judicial decision-making process and by avoiding actions that otherwise push up costs and worsen the economics of potential projects. There may also be a public interest in going further. While the latest Department of Energy projections see no early or even medium-term need for North Slope gas, this assessment could be modified, especially if recent production disappointments are harbingers of a poorer outlook for long-term production in the lower-48, and if the projections for Canadian imports become more pessimistic. In such circumstances, additional government actions to encourage timely development of Alaskan gas would be justified as a means of hedging against such a risk.