ALASKA STATE LEGISLATURE

State Capitol, Room 119
Juneau AK 99801-1182
907-465-3878
Fax: 907-465-3265
800-862-3878

Fourth Special Session
Twenty-Fifth Legislature

Senate Special Committee on Energy

Tuesday July 23, 2008

Senate Finance Room 532

1:00-4:30 p.m.

- **SB 3001 Approving AGIA License for Natural Gas Pipeline Project as proposed by TransCanada Alaska Company, LLC and Foothills Pipelines Ltd. (TC Alaska) to the State of Alaska**

- **Alaska Gasline Port Authority LNG proposal: Export License Issues; Project Economics and Feasibility**
  Continued from 7/22

  Bill Walker, Project Director, AGPA
  Craig Richards, Attorney, AGPA
  Radoslav Shipkoff, Financial Advisor, Greengate LLC

- **Administration - LNG Analysis and Issues**
  Participants To Be Announced

- **TransCanada – LNG Commitments & Options**
  Tony Palmer, VP AK Business Development

Teleconference
Testimony – By Invitation

SENR SB 3001
Juneau
rm 532

presented 7-23-08
AGIA license hearing

PHONE (808) 594-1888

FAX (808) 594-1865

STATE OF HAWAI'I
OFFICE OF HAWAIIAN AFFAIRS
711 KAPI'OLANI BOULEVARD, SUITE 500
HONOLULU, HAWAI'I 96813

July 18, 2008

The Honorable Lyda Green
Senate President
State Capitol, Room 111
Juneau, AK 99801-1182

Dear Senator Green:

Hawai'i and the Native Hawaiian community are especially vulnerable to rising energy costs. For that reason, the Office of Hawaiian Affairs (OHA), a semi-autonomous state agency and trust created by the people of Hawai'i to better the conditions of Native Hawaiians, has been investigating potential cost savings to Native Hawaiian beneficiaries from lower electricity costs and revenue-generating opportunities for OHA from being involved in the importation, storage and distribution of natural gas from Alaska.

Recognition of natural gas' significant cost savings and environmental advantages to oil and renewable fuels first led to serious analysis of its use in Hawai'i by state and local policymakers in 2004. In 2006, OHA formed a partnership with the Hawai'i Natural Energy Institute (HNEI), the Hawai'i Energy Policy Forum to update the 2004 study with a comprehensive analysis in April 2007 featuring natural gas from Alaska. The study was supervised by Dr. Fereidun Fesharaki, Chairman and CEO of FACTS Global Energy, an internationally renowned energy consultant.

The findings of the analysis, initially reported at the OHA-sponsored 2007 Hawaiian Business Conference and Economic Expo, demonstrated great promise for the Native Hawaiian community and all of Hawai'i from the importation of natural gas from Alaska. With infrastructure, shipping, and storage costs to be borne by the private sector, Alaska natural gas could replace approximately 95% of the fuel oil that Hawaiian Electric Company (HECO) currently uses in power generation on Oahu.

According to the study, natural gas substitution in the power sector in Hawai'i would be approximately 1.35 million tonnes in 2013, increasing to 1.8 million tonnes in 2022. Hawai'i's natural gas demand exceeds the 1 million tonnes per annum that allow for reasonable economies of scale. Importing Alaska natural gas could reduce oil's share of the primary energy mix statewide by approximately 20% within 4-7 years of a decision to move forward.

Using natural gas instead of maintaining current fuel plans would reduce the global warming potential of Oahu's power generation by approximately 25% in 2013 and roughly by an average of 23.5% per annum through 2020. Most importantly, there are significant savings to be gained from using natural gas. The study pointed out that potential annual fuel savings to consumers would translate to tens of millions of dollars as the price of natural gas to the power plants would be less than the price forecasted for the low sulfur fuel oil (LSFO) it will replace.

Based on these findings, I wish to inform you that OHA supports the development of the natural gas pipeline from Prudhoe Bay to Valdez together with a liquefied natural gas (LNG) facility to enable shipment of LNG to other domestic markets in the US, such as the West Coast and Hawai'i, and to the growing markets in Asia.

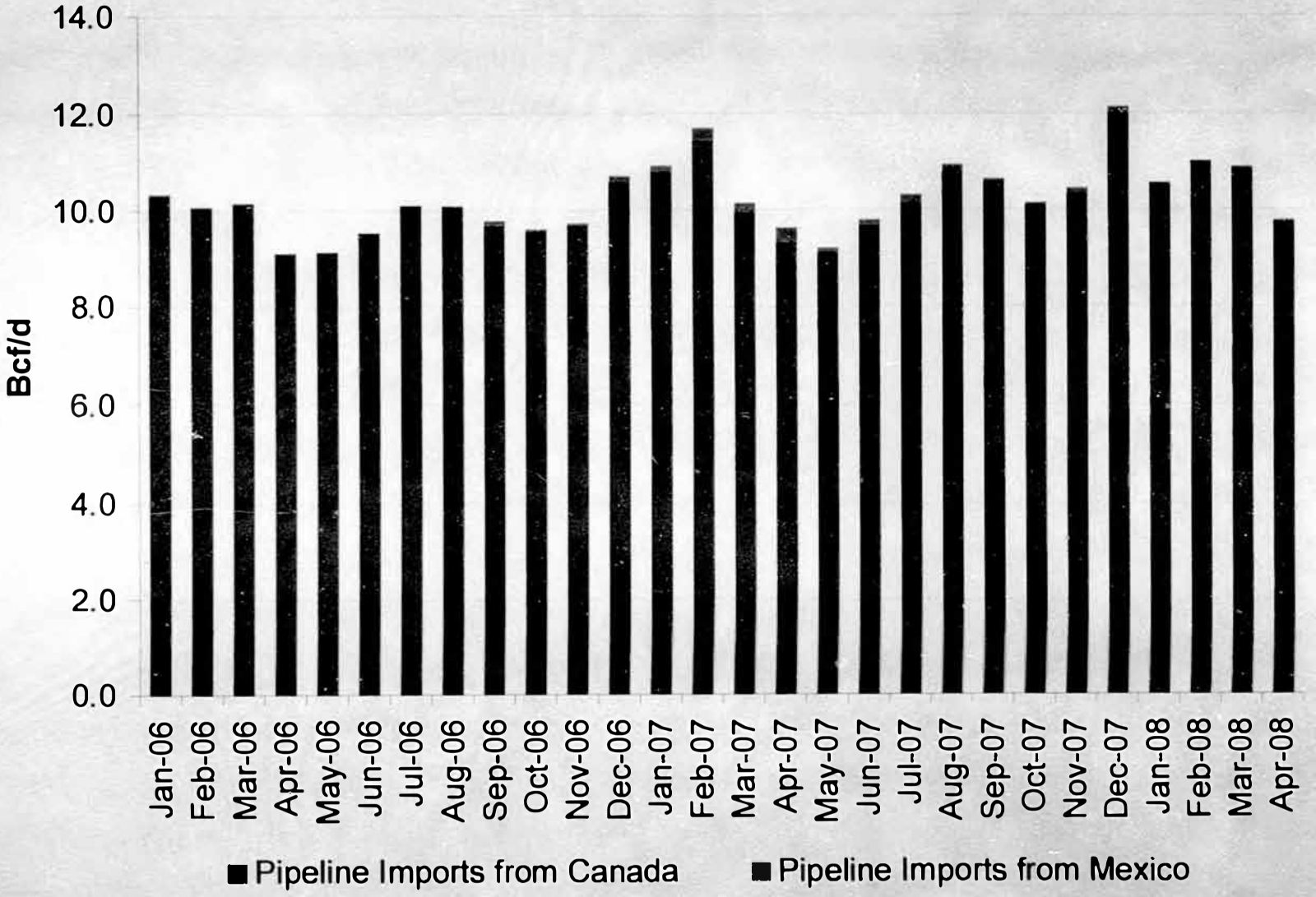
OHA believes a Prudhoe Bay to Valdez pipeline offers significant mutual benefits to both Alaska and Hawai'i. The short transportation distance from Valdez to the Hawaiian market makes Alaska LNG a highly competitive source of energy relative to other fuels. Since Hawai'i is located along the route from Asia to these markets, potential synergies exist in the LNG shipping capacity by serving Hawai'i along the way. There are huge existing markets for LNG in Japan and Korea, and the enormous potential markets of China, India and the continental US. At the same time, Alaska natural gas helps Hawai'i achieve a number of policy objectives regarding global warming, energy and economic security, air quality improvement, consumer savings, and transition to a future renewable and hydrogen energy economy.

If such a pipeline project were to proceed, OHA would be interested in working with Alaska to secure long-term natural gas contracts that could provide a reliable and affordable supply of energy for years to come.

Due to the above consideration, I urge you to advance the development of the All-Alaska Gasline/ LNG Project. Please do not hesitate to contact me if you have any questions or if I can be of service in any way.

Sincerely,

Clyde W. Nāmu'o
Administrator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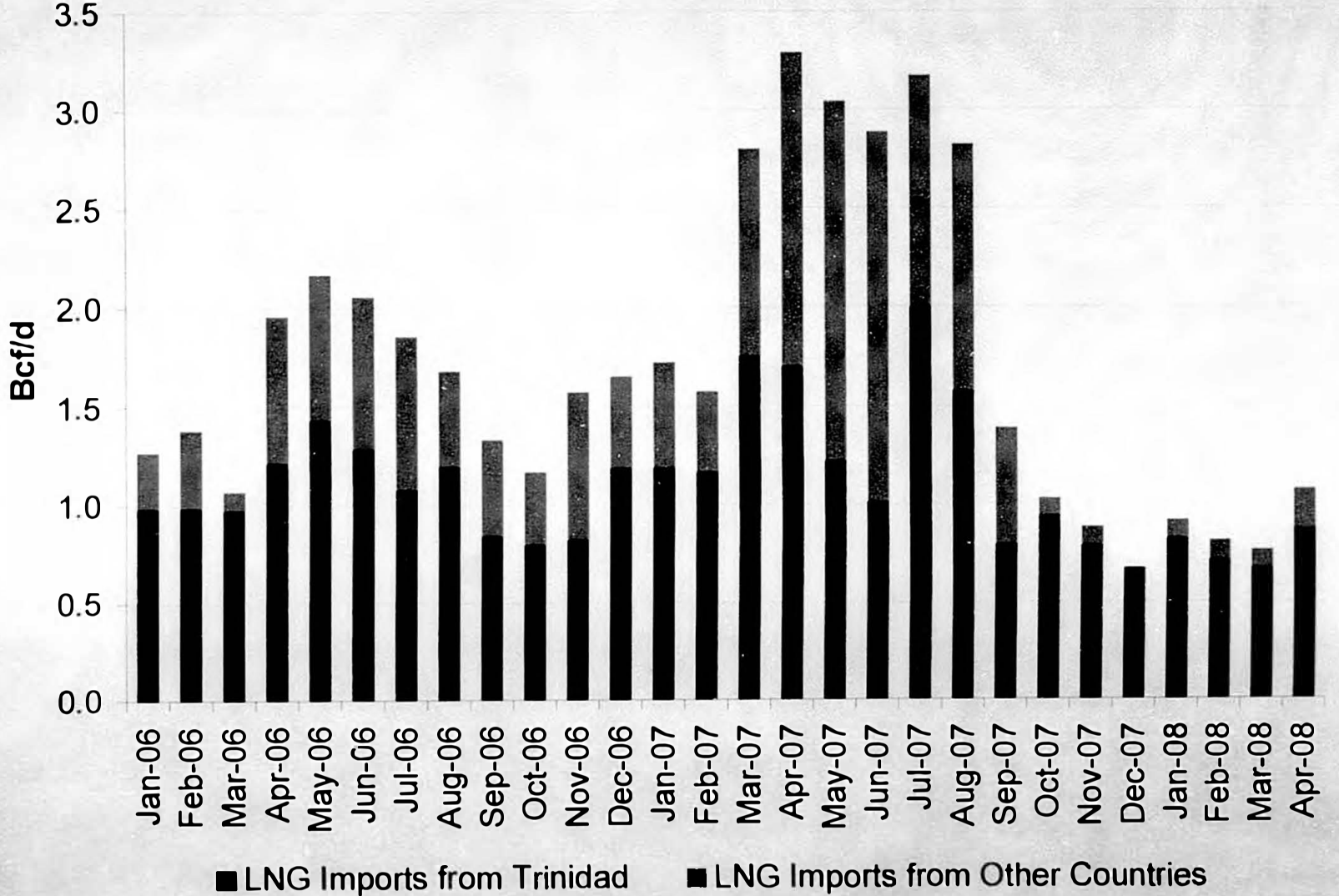
Pipeline Imports from Canada
Pipeline Imports from Mexico

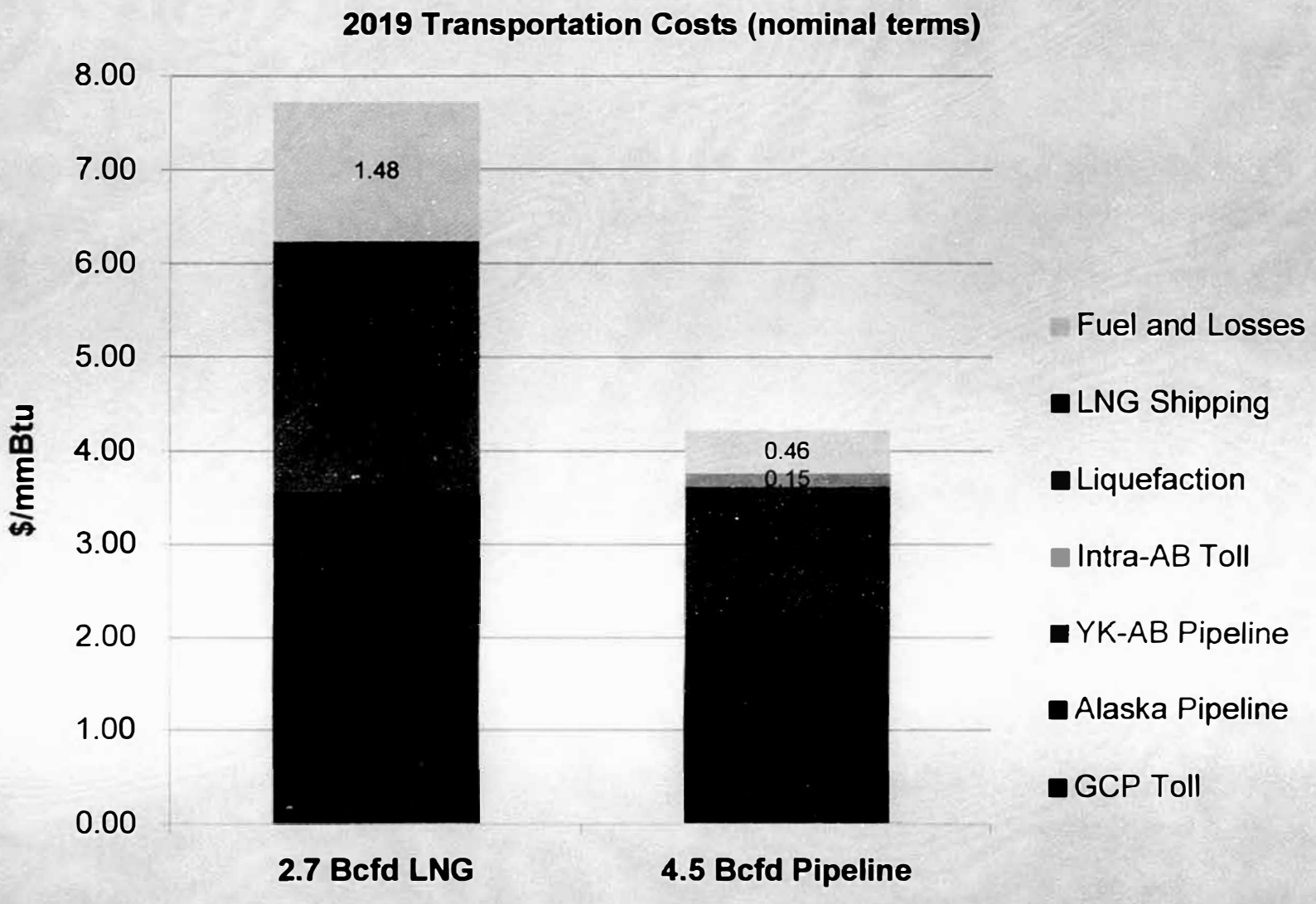
Source: EIA

U.S. Imports of LNG

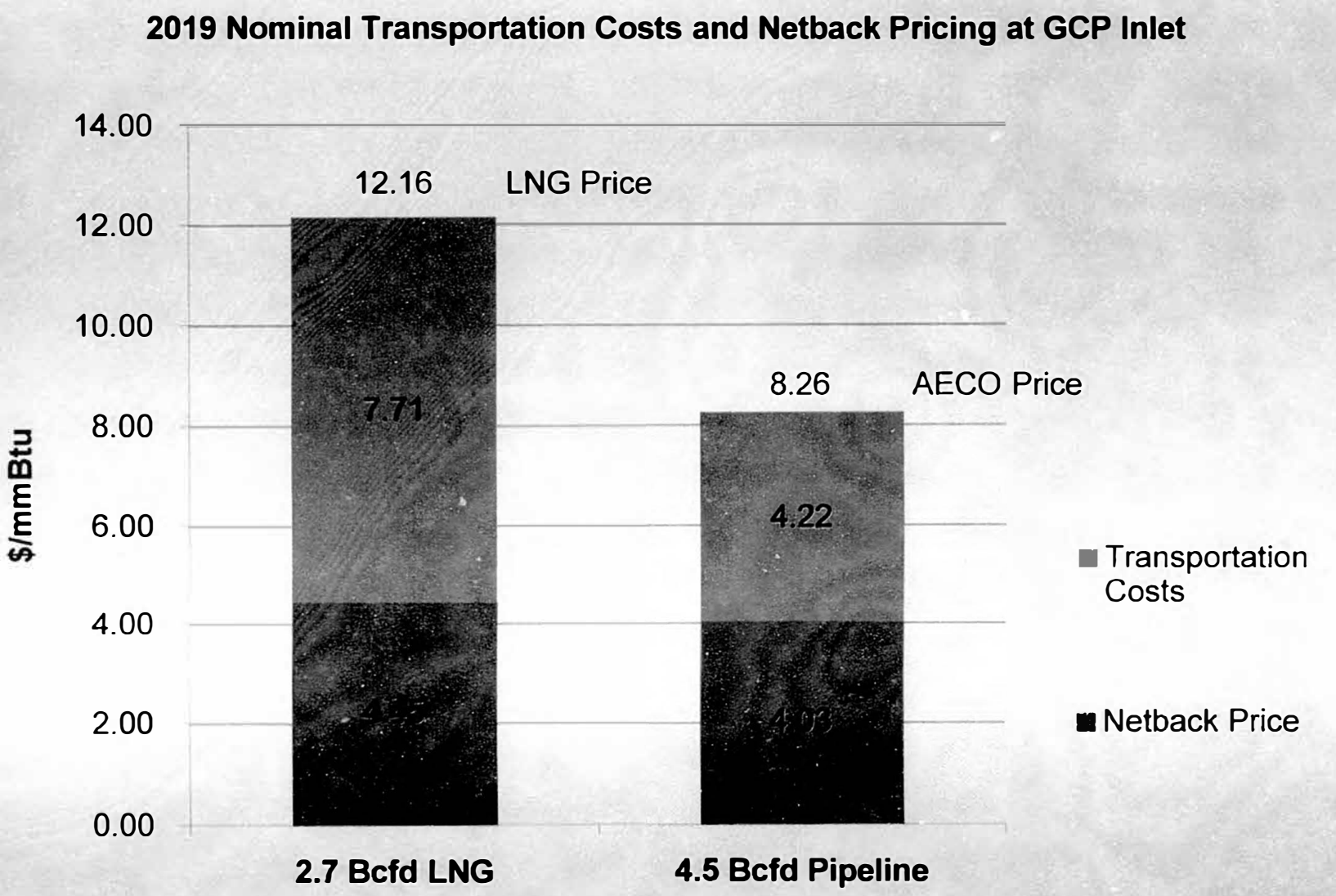


Source: EIA

Transportation Cost Comparison (2019)



Netback Pricing at GCP Inlet (2019)



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SENR
Juneau
Rm 532

presented
7-22 & 23-2008

REPORT TO THE STATE OF ALASKA LEGISLATURE ON THE FEDERAL LAW GOVERNING EXPORTATION OF NORTH SLOPE GAS

Prepared by

William Walker
Craig Richards

Walker & Levesque, LLC
731 N Street
Anchorage, Alaska 99501
(907) 278-7000

On Behalf of

Alaska Gasline Port Authority
411 4th Ave., Suite 200
Fairbanks, Alaska 99701
(907) 474-2011

This report analyzes the law relevant to the export of Alaska North Slope natural gas. As will be discussed, two federal actions are required. Unique to North Slope gas, the President of the United State ("U.S") must find the quantity, quality and price of the energy supplies available to U.S. consumers will not be effected by export. Additionally, for all domestically produced gas the Department of Energy ("DOE") must authorize export to any country for which the U.S. does not have a free trade treaty (e.g., not Canada or Mexico).

Authorization to export North Slope gas has been addressed solely in the context of the export license granted to the Yukon Pacific Corporation ("YPC") in 1989. After the requisite Presidential finding, DOE authorized the export for sale to Japan, South Korea, and Taiwan a total of up to 250 million metric tons ("MMT") of liquefied natural gas ("LNG"), at an average annually volume of 14 MMT – a bit less than 2 billion cubic feet per day ("bcfd") – for a period of 25 years beginning on the date of the first delivery.[1] The only other authorizations to export U.S. gas to a country to which the U.S. does not have a free trade treaty that the authors could locate involve the export of Cook Inlet natural gas from the ConocoPhillips/Marathon facility in Kenai, meaning the controlling precedent for DOE export approval involves export of Alaskan gas.

I. Legal Standards Under Which DOE Authorizes Export of North Slope Gas.

A. *The Natural Gas Act.*

Section 3 of the Natural Gas Act, 15 U.S.C. § 717b (2006) ("NGA"), provides the Secretary of Energy shall allow the export of gas unless he finds it will not be consistent with the public interest. If the export is to a country with which the U.S. has a free trade agreement covering natural gas, the export is deemed to be in the public interest and approved automatically.[2] If not, the DOE must consider whether the export is in the public interest.

"Section 3 creates a rebuttable presumption that a proposed export of natural gas is in the public interest and that [DOE] must grant such an application unless those who oppose the application overcome that presumption."[3]

DOE has issued a set of guidelines to help interpret Section 3, the goals of which "are to minimize federal control and involvement in energy markets and to promote a balanced and mixed energy resource system."[4] "In effect the guidelines represented a determination that it is in the public interest to let market forces, with a minimum of

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[1] *Order Granting Authorization to Export Liquefied Natural Gas from Alaska*, Department of Energy Order and Opinion No. 350, 1 F.E. 71,115, 71,144-45 (November 16, 1989), as amended by *Order Denying Requests for Rehearing and Modifying Prior Order for Purpose of Clarification*, Opinion and Order No. 350A , 1 F.E. 70,303, 71,273 (March 8, 1990).

[2] 15 U.S.C. § 717b (2006).

[3] *Order Granting Authorization to Export Liquefied Natural Gas from Alaska*, Department of Energy Order and Opinion No. 2500 at 43 (June 3, 2008).

[4] Order No. 2500 at 44.

regulatory constraints, define efficient energy production and consumptions."[5] Although the guidelines were originally promulgated for cases relating to the import of natural gas, DOE subsequently held the same policies will be applied to natural gas export applications.[6]

> The federal government's primary responsibility in authorizing imports [or exports] will be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market.[7]

DOE has also stated that "the principal focus of this agency's review of export applications in decisions under current delegated authority has continued to be the domestic need for the natural gas proposed to be exported."[8]

For YPC, and presumably for another North Slope export project, DOE set forth a three-pronged approach for evaluating domestic need.

> First, the DOE determines whether national or regional demand can reasonably be expected to exceed anticipated available domestic supplies over the term of the proposed export. If there is a reasonable expectation of demand in excess of available domestic supplies, the DOE determines the extent to which this excess demand can be met by other energy sources as or more efficiently than the proposed export. If there are sufficient alternative sources, the DOE analyzes whether there is any reason the public interest requires the proposed export, in particular, be used to meet the excess demand.[9]

As to the last prong, although "[d]omestic need is the only explicit public interest consideration identified by DOE in Delegation Order No. 0204-111 . . . the Department considers the potential effects of proposed exports on other aspects of the public interest. These other considerations include Alaskan interests, international effects, and the environment." DOE has in the past also looked at the effect of the export project on energy security.[10]

B. *ANGTA and the Reagan Findings.*

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[5] Order No. 350, 1 F.E. at 71,121.
[6] Order No. 2500 at 44 (citing Order No. 1473 at 14 and citing Yukon Pacific, Opinion and Order No. 350, 1 F.E. 70,259 at 71,128).
[7] Order No. 2500 at 44 (quoting *New Policy Guidelines Relating to the Regulation of Imported natural Gas,* 49 Fed. Reg. 6684 (February 22, 1984) (brackets in original).
[8] Order No. 2500 at 44-45 (citing DOE Delegation Order No. 0204-111 which, although no longer in effect, directed in part that exports be regulated based on a consideration of the domestic need for the gas to be exported and such other matters as found in the circumstances of a particular case to be appropriate).
[9] Order No. 350, 1 F.E. at 71,129.
[10] *Id.* at 71,134.

The Alaska Natural Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. § 719j (2006) ("ANGTA"), provides that before exportation of Alaska gas "to any nation other that Canada or Mexico, the President must make and publish an express finding that such exports will not diminish the total quantity or quality and not increase the total price of energy available to the United States."

In 1998 President Reagan issued a finding that export of North Slope gas would not affect adversely the quantity, quality or price of the energy supplies available to U.S. consumers.[11]

> In particular, the President found that 'there exist adequate, secure, reasonably priced supplies of natural gas to meet the domestic demand of American consumers for the foreseeable future.' The president acted to let 'the marketplace undertake a realistic consideration of various options concerning Alaska natural gas' by allowing 'any private party to develop this resource' and setting 'up competition for this purpose.' The President's Findings stated that 'operation of market forces is the best guarantee that Alaska natural gas will be developed efficiently and that there will be incentive to find additional reserves.[12]

If an off-slope LNG project sought a new export license, rather than to update the one issued to YPC in 1989, a new Presidential finding appears necessary. However, Congress granted the President broad power to limit natural gas exports (whether from Alaska or other locations) in the Energy Policy and Conservation Act of 2005, 42 U.S.C. § 6212 (2006), significantly diminishing the significance of an upfront Presidential finding for export of Alaska natural gas under ANGTA.[13]

AS to YPC's export license, DOE determined a North Slope export proposal will be viewed in light of ANGTA, and in fact a significant condition called the "ANGTA Condition" on the YPC export license prevented YPC from taking any action that would compel change of the ANGTA route or project timing.[14] DOE expressly stated, however, that the ANGTA condition did not apply to market decisions relating to access or development of North Slope reserves, and it instead related to increased costs of ANGTA infrastructure resulting from the export project.[15]

Since, in order to avoid the multi-billion dollar liability associated with the ANGTA project legacy, TransCanada is no longer sponsoring an ANGTA project in Alaska, and the Alaska Natural Gas Pipeline Act of 2004, 15 U.S.C. § 720a(a) (2006) ("ANGPA), specifically authorized non-ANGTA Canadian highway projects, it would

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[11] *Presidential Finding Concerning Alaska Natural Gas*, 53 Fed. Reg. 999 (January 15, 1988).
[12] Order No. 350, 1 F.E. at 71,122 (emphasis eliminated).
[13] Section 6212 provides that the President may restrict exports of: "(1) coal, petroleum products, natural gas, or petrochemical feedstocks, and (2) supplies of materials or equipment which he determines to be necessary (A) to maintain or further exploration, production, refining, or transportation of energy supplies, or (B) for the construction or maintenance of energy facilities within the United States."
[14] Order No. 350, 1 F.E. at 71,128, 142.
[15] *Id.* at 71,142.

appear ANGTA no longer has relevancy to the exportation of North Slope gas and will be ignored in this analysis except as to the requirement of a Presidential finding.

III. Various Parties' Position Before DOE Regarding a YPC Export License.

In analyzing various arguments that could be made today about why an export license should or should not be issued for North Slope gas, it is helpful to understand some of the positions of the same parties before DOE almost 20 years ago. Many arguments that would be made today have already been addressed and decided by the department.

A. *TransCanada.*

TransCanada's predecessor sponsors of the Alaska Natural Gas Transportation System ("ANGTS") Canadian highway line, Alaskan Northwest and Foothills (hereinafter "TransCanada"), held the right to build the Alaskan portion of the highway line under ANGTA. TransCanada was the only major opposing party to the issuance of a YPC export license, and it prosecuted its case vehemently.

For instance, TransCanada said YPC's application did not contain enough information to be evaluated since YPC did not have gas purchase or resale contracts, sufficient details on project infrastructure, a completed environmental impact statement or a description of all the project's participants.[16]

TransCanada also asserted North Slope gas would be needed in the lower-48.

> They contend that the excess demand in the lower-48 states cannot be met by other energy resources as or more efficiently than by the proposed export volumes. The ANGTS sponsors assert that substitute fuels for North Slope gas, such as coal and oil, would be environmentally inferior to natural gas, which burns cleaner. They maintain that increasing dependence on coal and oil would contribute to ozone layer depletion in the atmosphere, 'acid rain', and the 'greenhouse' problem of global warming, and alternative gas supplies, such as development of Canadian frontier gas, would be more costly. In addition, they assert that the commitment of North Slope gas reserves to foreign interests would jeopardize national energy security by depriving the U.S. of a source of available reserves to offset the declining energy base in the lower-48 states, and by increasing U.S. dependence on oil imports. [17]

TransCanada additionally argued that an LNG project would impair completion of a Canadian line because "there are not enough proven reserves of gas on the North Slope to support both . . . projects."[18] The Canadian government through the State Department

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[16] *Id.* at 71,125.
[17] *Id.*
[18] *Id.* at 71,125.

shared similar concerns.[19] TransCanada actually sought a condition on the export license that its project have "first call on North Slope gas for delivery to the lower-48 states, if needed to meet contractual obligations and to preserve the project's economic viability[.]"[20]

Finally, TransCanada urged "that any final authorization issued be subject to suspension, modification, or revocation upon a showing that continuation of the proposed export is no longer in the public interest."[21] That is, TransCanada wanted YPC's export license to be subject to future reopening for additional public interest before export occurred. As will be seen, DOE rejected all of these arguments.

B. *State of Alaska and Exxon.*

The State of Alaska intervened on behalf of an export license because of the benefits to Alaska that an off-slope pipeline would bring. However, it had no preference for an LNG versus Canadian project asserting that the market would decide which (or how many) systems get built, and opposed the imposition of conditions on export that would favor one gas development project over another.[22]

Exxon supported President Reagan's Findings for export and urged market-responsive development of Alaskan natural gas. It asked that DOE not impose terms and conditions "that would, in effect, place a stamp of approval on only one project or approach to development of Alaskan resources and discourage other projects or approaches."[23]

C. *Statoil.*

Statoil, the Norwegian national oil company, stated its LNG exports and those of other over-seas suppliers would be able to meet any U.S. gas demand that might go unserved if North Slope gas was exported.

IV. DOE's 1989 Decision Authorizing Export of North Slope Gas.

Unfortunately since 1989 little has changed in the debate about whether DOE should allow the export of North Slope gas. On the bright side, risks associated with seeking an export license have been significantly reduced given DOE has already addressed many of the arguments a party opposing export can make. It is thus useful to review in detail DOE's rationale for issuing YPC an export license under Section 3 of NGA.

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[19] *Id.* at 71,126.
[20] *Id.*
[21] *Id.*
[22] *Id.*
[23] *Id.* at 71,126-27.

A. *Use of Economic Studies.*

YPC and TransCanada both presented to DOE economic studies regarding when North Slope gas would become competitive in the lower-48. Quoting TransCanada, DOE held such studies were not useful in assessing the future of a particular project because the world was too complex and subject to change to forecast 12 or 20 years into the future.[24] "In fact, the inherent imprecision of using economic studies to predict the performance of a particular project is one reason that led to the shift from a government-mandated regulatory approach to a market-oriented approach that leaves private commercial parties with the flexibility to determine the basics of their projects."[25]

DOE also rejected out of hand that the need for North Slope gas in domestic markets is evidenced by the many economic models predicting North Slope gas will be used to meet domestic demand.

> Unlike the real world where private parties take a hard look at the actual costs of bringing competing supplies to market, an economic model selects the 'competitive' supply on the basis of assumptions . . . In the case of ANGTS, most economic models put the cart before the horse since they automatically assume North Slope gas will be used in the domestic market and then speculate when producers, pipeline sponsors, and financial institutions will agree that the market justifies the commitment of billions of dollars to provide the means necessary to make this 'a priori' modeling assumption feasible in the real world.[26]

However, although DOE did not find economic forecasts and studies useful in evaluating specific projects, DOE did find their information on supplies of various energy sources and anticipated demand helpful in evaluating domestic need as required under NGA Section 3.

B. *Domestic and Regional Need.*

As previously stated, in looking at future domestic need over the life of the license, DOE first looks at whether national or regional demand will exceed domestic supplies over the term of the proposed export. If so, DOE looks at whether excess demand can be met with alternative energy sources as efficiently as by the proposed export. Finally, if there are sufficient alternative energy sources, DOE analyzes the public interest nonetheless requires the proposed exported gas to be used to meet excess domestic demand.

1. *Regional Need.*

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[24] *Id.* at 71,129-30.
[25] *Id.* at 71,130.
[26] *Id.* at 71,129 n. 36. *See also* Order No. 350A , 1 F.E. at 71,270 (reaffirming that the inclusion of North Slope gas in various economic studies does not demonstrate a domestic need for it).

In YPC's case, DOE held regional need in Alaska was not a relevant issue for North Slope gas.[27] Interestingly, this is exactly the opposite position DOE took in granting the most recent extension for the Kenai export license. For Cook Inlet gas, DOE only looked at regional and not domestic supply and demand dynamics.[28] Given the Cook Inlet basin is maturing and will not be able to fully supply South Central – much less the Alaskan Interior – for the term of a Valdez export license (e.g., 25 years from first export), both domestic and regional supply and demand would likely be a factor if DOE revisits whether exportation of North Slope gas is in the public interest. Those advocating export of North Slope gas would argue that an LNG project would help meet projected gas shortfalls from Cook Inlet and would provide gas to new Alaskan markets in a manner more rapid than a project through Canada which would, if accepted by DOE, help the case for export.

2. *Domestic Need – Lower-48 Supply and Reserves DOE Will Consider in its Analysis.*

In analyzing future projected domestic supply of natural gas, DOE rejected TransCanada's argument that only proven reserves in the lower-48 could be counted as available supply. Instead DOE decided it would take a broad view of sources of gas that would be viewed as available to meet projected domestic demand. Thus for instance, DOE included in reserves estimates both unconventional (tight sands, Devonian shale, coal seams, enhanced recovery, etc.) and conventional gas, and for conventional gas included allowances for reserves growth and additional exploration.[29]

DOE also rejected TransCanada's argument that North Slope gas was needed because its cost of delivery to American consumers on a per molecule basis (i.e., in-field and transportation costs) would be lower than the cost of delivery of many of the other sources of gas included in DOE's estimate of national reserves.[30] Rather DOE thought the proper inquiry was whether "the costs of bringing some supplies to market may be so significantly higher than the anticipated market price that their use would be precluded in an efficient market."[31] So in looking at whether North Slope gas is needed domestically, the DOE will not compare the cost of delivery of North Slope gas vis-à-vis other gas supplies, but whether the non-North Slope supplies can be developed given anticipated market prices.

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[27] Order No. 350, 1 F.E. at 71,129 n. 35.

[28] DOE seemed to accept the applicants' assertions that there was no practical market for Cook Inlet gas in the U.S. because of the Jones Act, a lack of West Coast receiving terminals, and the prohibitive cost of reaching East Coast receiving terminals. Order No. 2500 at 14 ("The Applicants emphasize that the . . . Jones Act, would present a substantial regulatory hurdle. The Applicants also emphasize that there are not existing U.S. west coast LNG receiving terminals and the cost of shipping Kenai LNG to U.S. east coast or gulf coast LNG Receiving terminals would vastly exceed the cost of transporting the same LNG to Japan and/or another customer in the Pacific Rim due to the distances involved.").

[29] "Gas supply assumptions that focus solely on proved reserves and do not take into account the potential for reserve additions and production experience would severely distort forecasts of domestic need." Order No. 350, 1 F.E. at 71,131.

[30] *Id.* at 71,269.

[31] *Id.*

After reviewing various studies, DOE ultimately concluded that during the term of YPC's export proposal domestic need could be met by production from reservoirs in the lower-48 states without North Slope gas.[32] An argument could be made that DOE might not reach the same conclusion today,[33] although this is a technical decision that DOE would make only after it reviewed projected domestic supply and demand as it did in allowing Kenai and YPC exports.

3. *Domestic Need – Alternative Supply.*

Even though DOE said in 1989 that North Slope reserves were not needed domestically, DOE nonetheless stated that it is not necessary for the purpose of a Section 3 NGA determination that DOE find all future U.S. natural gas demand will be met by production in the lower-48 states. DOE may also look to alternative supplies, particularly gas imports. This includes whether import of LNG from overseas (e.g., East Coast imports), when combined with North American supply, will be sufficient to meet domestic demand without North Slope gas.[34]

4. *Domestic Need – Public Interest of Domestic Use of North Slope Gas Rather than Available Alternative Supply.*

After examining whether lower-48 and alternative supplies are sufficient to meet domestic demand, DOE next considers whether there is a public interest in the North Slope gas proposed to be exported (rather than other energy supplies) being used to meet any anticipated demand in excess of domestic supply. Harmonizing its NGA analysis with ANGTA Presidential finding requirements, DOE looked at whether the proposed project's export of North Slope gas would have an impact on matters of supply, price and quality of domestic gas.

a. Quantity.

A proposed export of North Slope gas will adversely affect the quantity available to American consumers only if it will cause available domestic supplies to be inadequate. Since DOE concluded at the time there were adequate lower 48 and alternative supplies, DOE determined an export of about 2.0 billion cubic feet per day from Alaska would not adversely affect American consumers.[35] Additionally, DOE said in the context of global energy interdependence it cannot necessarily be concluded that export of gas would diminish that available to American consumers.

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[32] *Id.* at 71,130-32.

[33] For instance, in 2004 when ANGPA was passed, it was the "sense of Congress" that "gas delivered from Alaskan North Slope will not displace or reduce the commercial viability of Canadian natural gas produced from the Mackenzie Delta or production from the 48 contiguous States." 15 U.S.C. § 720l (6) (2006). In support of that proposition, it was also the sense of Congress in suggesting a Mackenzie project should go first that "natural gas production in the 48 contiguous States and Canada will not be able to meet all domestic demand in the coming decades[.]" 15 U.S.C. § 720l (2) (2006).

[34] Order No. 350, 1 F.E. at 71,134-35.

[35] *Id.* at 71,134.

> [W]ith respect to North Slope gas, it would be unduly simplistic to conclude that exports will necessarily diminish the quantity of energy available to American consumers. In this case, the alternative to exporting North Slope gas may be that it remains undeveloped, and therefore available to no one; conversely, exporting such gas may make available on the American market gas from foreign sources that would otherwise have gone to the Pacific Rim.[36]

Thus even if domestic and alternative supplies of gas were projected to be inadequate over the term of the license, export would still be authorized if it was demonstrated that export would not diminish gas available to American consumers. This might be because, for instance, the gas would remain undeveloped without export, export of Alaskan gas would free up other supplies that would be made available to U.S. markets, or an export project would open the North Slope basin to exploration that would in turn result in additional gas being available to go to U.S. markets (either via LNG or a line through Canada).

b. Quality.

In looking at the impact on the export of North Slope gas on the "quality" of energy available to American consumers, DOE focused on arguments made by TransCanada regarding the effects of export on the environment and U.S. energy security. DOE did not believe export of natural gas from the North Slope would lead to the use of less environmentally friendly energy sources (e.g., coal).[37]

DOE also rejected TransCanada's argument that export of North Slope gas would increase imports and thereby decrease energy security on the grounds that energy security must be viewed in global terms and the development of North Slope gas would contribute to the overall performance of the North American energy market.[38] "DOE believes that true energy security lies in encouraging the most efficient operation of the North American and global energy market."[39]

c. Price.

In performing the public interest analysis and looking at whether North Slope gas should not be exported, notwithstanding there are sufficient projected lower-48 or alternative supplies, DOE will consider whether American consumers will pay more than they would if North Slope gas was not exported.

> In general, conditions in the domestic market will establish the price for whatever natural gas is used to meet domestic need, regardless of the source of that gas. Neither North Slope gas nor any other specific supply

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[36] *Id.* at 71,134.
[37] *Id.* at 71,135.
[38] *Id.*
[39] *Id.*

> will be the tail that wags the market price of natural gas. The export of a particular gas supply, such as North Slope gas, would exert upward pressure on the market price only if there were not adequate alternative supplies of energy to meet domestic need at a market-responsive price. Even then, the export would exert upward pressure only if the costs of producing and delivering the exported gas to the domestic market would be less than the costs of the energy supplies actually used to meet the marginal demand.[40]

In YPC's case, DOE felt export of North Slope gas would not have an impact on domestic prices, and found the presented economic studies "did not constitute the substantial evidence necessary to overcome the DOE's analysis of the fundamental market conditions, the section 3 presumption in favor of export approval, and the President's Finding."[41]

B. *Other Public Interest Considerations.*

In addition to the Section 3 NGA analysis relating to domestic need for North Slope gas, DOE considered a number of other public interest factors.

1. *Export's Impact on North Slope Exploration and Development.*

TransCanada indicated that the proposed export of North Slope gas might result in the non-production of some North Slope gas and questioned whether competition will spur exploration for and development of North Slope gas.[42] DOE disagreed and stated an export project would spur development of the 100 + trillion cubic feet of stranded proven and potential gas reserves.

> Thirteen years have passed since the passage of ANGTA and no North Slope natural gas has been produced commercially. The introduction of competition will encourage a realistic assessment of the potential of North Slope natural gas and its early and more efficient development. It also will provide an incentive for discovering and developing additional reserves of natural gas on the North Slope.[43]

2. *Alaskan Interests.*

In both the Kenai and YPC export authorizations DOE has recognized that significant benefits accrue to the State of Alaska and its economy from export.[44]

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[40] *Id.*
[41] *Id.* at 71,136.
[42] *Id.* at 71,137.
[43] *Id.*
[44] Order No. 2500 at 55-57; Order No. 350, 1 F.E. at 71,137.

3. *Environmental Concerns.*

For YPC and Kenai exports it was also found that environmental concerns are not important elements in DOE's public interest analysis.[45] Rather environmental issues relating to project construction are properly handled in other forums such as proceedings relating to pipeline and export terminal site authorization.

4. *International Effects – Free Trade and Balance of Payments.*

DOE believes international effects of a proposed export project are significant in the public interest determination, and weigh in favor of export. First, increasing exports has a positive effect on the U.S. balance of payments and mitigates trade imbalances with receiving Asian countries (Korea, Japan and Taiwan).[46]

Second, "Competition in world energy markets promotes the efficient development and consumption of energy resources, as well as lower prices, whereas economic distortions can arise from artificial barriers to the free flow of energy resources. Accordingly, DOE believes that the public interest in free trade generally supports approval of proposed exports."[47]

5. *YPC Cannot Pass on Project Cost to U.S. Consumers.*

DOE believes that the primary purpose of its analysis of potential exports under the NGA is to protect American consumers. In that vein, and with YPC's acquiescence, as a condition to its license YPC was prohibited from passing on to consumers in the lower-48 states any of the risks or costs associated with the LNG project.[48] However, DOE did make clear YPC was not prohibited from sending North Slope gas to U.S. markets.[49]

6. *YPC Must File Gas Sale and Transportation Contracts with DOE.*

To assist in monitoring compliance with the condition (and again with YPC acceptance) that U.S. consumers not bear the cost of the export project, DOE also required the submission of all contracts and other documents for the acquisition, transportation, and sale of North Slope gas when executed.[50] It is receipt of these contracts that DOE recently stated was the precondition to export that would result in DOE "address[ing], at that time what, if any, further review and actions would be required should [YPC] seek to use the authorization."[51]

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[45] Order No. 2500 at 58; Order No. 350, 1 F.E. at 71,139.
[46] Order No. 2500 at 58; Order No. 350, 1 F.E. at 71,136.
[47] Order No. 350, 1 F.E. at 71,138.
[48] *Id.* at 71,136.
[49] *Id.* at 71,137.
[50] *Id.* at 71,136-37.
[51] Letter to John Harris, Speaker of the Alaska House of Representatives, from Robert F. Corbin, Manager, Natural Gas Regulatory Activities, Office of Oil and Gas Global Security and Supply, Office of Fossil Energy (June 13, 2008).

Prepared Testimony of Harold Heinze of ANGDA

Before Senate Finance on July 22, 2008

The ANGDA gas spur line project links Delta Junction to the Cook Inlet area through Glennallen. It is integral to the delivery of North Slope gas for in-state utility use from either the AGIA licensee TC Alaska or the producer sponsored Denali pipeline projects.

Strong legislative support and funding has allowed ANGDA to: (1) acquire a conditional state right-of-way between Palmer & Glennallen, (2) conduct field wetland delineation between Beluga & Delta Junction, and (3) publish a myriad of focused studies on in-state gas issues.

ANGDA's strategy has focused on an aggressive time line of activities to assure that the in-state gas needs will be understood and that local utilities will have the best opportunity to participate in the FERC open season of the "big pipeline". In the first quarter of 2009, ANGDA will have the information to conduct a negotiated in-state open season to allow early interaction with the design and contract terms of either of the "big pipeline" project proposals. Alaska's gas needs will only represent 5% of the bigger project and the local utilities are greatly advantaged by being considered up-front as one of the anchor tenants.

With the passage of AGIA the competitive pressure will accelerate the pace of preparations for the FERC open season. Legislative action now on the ANGDA appropriation request of $25 million will maintain a leadership position to get North Slope gas to Alaskans under the best fiscal terms and under the most favorable timeline.

The requested $25 million appropriation funds contractor efforts to complete the pre-build preparations related to:

- Route survey and options for rights-of-way acquisition
- Design of access roads & field preparation
- Preliminary pipeline and facility design
- Project management to include a finalized Project Execution Plan
- Logistics planning to include preparation of pipe yards & port improvements
- Materials specifications, materials take-off list, and options on long-lead items
- Finalization of financing and bonding for the project

Past ANGDA funding includes:

Total operating budget expenditures of $1.6 million total over 5 years

Total capital appropriations of $11.5 million (includes $4 million just available)

With $4.5 million capital appropriation spent or committed at this time

Remaining $7.0 million capital appropriation is authorized, but not committed at this time is planned for contracting over the next year:

- TAPS proximity design
- Feasibility of high-density plastic pipe as an interim link between Delta Junction and Fairbanks
- Recalibration of cost estimates and project schedule
- LDIR data acquisition
- Preparation of spur line project EIS
- Identification of & engagement with value added industrial companies
- Gas purchase agreements
- Contract and bonding documents for aggregation of utility gas needs
- Local gas take-off point design and preliminary NGL "straddle plant" designs
- Joint venture partnership documents, initial financing plan, request for Certificate of Necessity (demonstrate fit, willing, and able), and letter agreement with shippers
- Design of feeder pipelines from Gubik, Nenana, Point Thomson, Yukon Flats, and Copper River basins
- Propane Distribution Project - Propane purchase on North Slope for "pilot" project & tank rental
- Public outreach

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TOM PHALEN, CONTRIBUTING EDITOR

Will LNG liquefaction project development prosper?

Since 1995, the volumes of liquefied natural gas (LNG) delivered have risen at a rate of over 7%/yr. Forecasts indicate that LNG deliveries will continue to grow at this rate over the foreseeable future and that LNG market pricing will continue to reach historic levels with recent quotes exceeding long term forecasts by 10%–20%. Consensus is that there will be a shortage of LNG supplies by 2014. Under normal conditions, announcements of new LNG liquefaction projects would follow, in response to these market forces. However, since the beginning of 2006, the only LNG train authorized has been the 4.2 million-tpy Pluto LNG train funded in July 2006. LNG projects continue to experience delays worldwide.

Why is the market reacting in this manner? In a word: RISK. LNG liquefaction projects are large, complex programs located in remote areas requiring significant new infrastructure. The large capacities associated with each proposed project, coupled with future market uncertainties and lengthy times-to-market for newly authorized projects (typically five years from authorization to commercial operation), expose these projects to increased risk relative to competing projects. Unprecedented price escalation further complicates project financial viability. Since 2005, all indications are that LNG project costs have escalated at the same 20%/yr rate as other upstream projects, creating a high degree of economic uncertainty for liquefaction projects.

What are price drivers? What factors are driving these sharp increases in the price of LNG facilities? Demand for engineering, procurement and construction (EPC) services, equipment and material is experiencing record growth, with all sectors of the market rapidly expanding infrastructure after years of neglect. This growth is straining existing resources in several areas. Market conditions impacting LNG facility projects include:

- Doubling of the EPC project technical resource requirements between 2005 and 2007, with CERA reporting a possible 10%–15% deficit of people to staff projects by 2010.
- Average current shop loads at 70%–100% of available capacity, as opposed to 60% average load over the previous 10 years
- Escalation in two key commodities for LNG facility construction—stainless steel pipe and large compressors and gas turbines—with total increases of 90%–150% and 20%–50%, respectively, during 2006 and 2007. Escalation for 2008 is expected to slow to 10%–20% for stainless steel pipe and 5%–15% for compressors and turbines.
- Constraints on the availability of skilled and unskilled labor to support construction, with a potential shortfall of 15% in skilled labor in 2008.

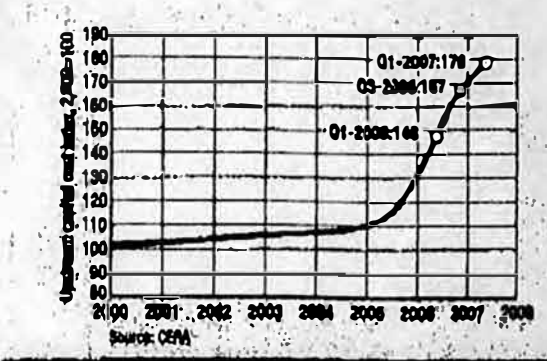

FIG. 1

What are some strategies to mitigate impacts? Strategies to combat and manage cost uncertainties confronting the LNG EPC market and to lower project risks include:

- Commitment of EPC contractors early in the project development cycle to reserve key project management, engineering and construction resources
- Utilization of multiple contractors to broaden access to key resources
- Early purchasing of key materials and equipment
- Early supplier integration to improve supply certainty for critical components
- Streamlined work processes at the site and shifting of labor to a more controlled yard environment through modularization, thereby reducing construction cost risks
- Modification of contracting strategies to improve risk sharing and reduce risk premiums and contingencies.

The use of these strategies will act to mitigate key costs and to schedule risks, improve the economic viability of potential projects and bring a higher degree of certainty to project execution. HP

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The author is vice president of upstream operations at Fluor Corp. He has over 31 years of experience in the engineering and construction industry. His career with Fluor has included assignments in process engineering, pipeline engineering, engineering management and project management, as well as general manager of the Houston office. He is presently responsible for directing Fluor's project operations for LNG facilities on a global basis.

Developing mid-scale LNG projects from the contractor's perspective

Modular liquefaction methods reduce construction and operating costs for smaller reserve developments

B. PRICE, J. FOSSELLA, S. HOFFART, Black & Veatch Corp., Overland Park, Kansas

The global market for liquefied natural gas (LNG) continues to grow rapidly. Traditionally, base-load LNG plants have provided the majority of this supply. As the industry has grown, base-load plants have grown increasingly larger. This has normally meant better economies of scale on project cost. Recently, however, base-load plants have become much more complex, and the cost is escalating in an uncontrolled fashion. The growing "diseconomies" of scale for larger units is directing more attention to development of mid-scale LNG projects that could cover the gap between LNG supply and demand.

The appeal of mid-scale projects is that they require smaller reserve bases, less total investment and should allow development in a shorter timeframe. The projects must be robust enough to overcome some infrastructure costs that occur regardless of project scale. The timeframe for development and key decision points, as well the as application of appropriate technology to these projects is necessary to control costs and bring projects online in a timely manner. Mid-scale projects are being developed in a modular fashion to enable rapid deployment and future expansion. Recent cost estimates for a variety of plant throughputs have shown that mid-scale facilities can meet economic hurdles and become reality.

Background. The development of large-scale base-load LNG facilities has dominated the industry for decades. Recent LNG plant designs have become more complex with systems of multiple refrigeration loops and ever increasing capacities. New projects are in the 10 million tpy (MMtpy) size range. This growth in complexity and cost has resulted in project developments requiring large capital expenditures approaching $1,000/tpy of capacity. Also, with the larger project sizes, development times have stretched from six years to more than a decade, further inhibiting these projects for closing the demand/supply gap. These facilities also pose an enormous risk for the engineering and construction industry. Recent announced losses on major projects are serious issues for those involved.

Operators are broadening the search for LNG capacity by looking at mid-scale projects. Generally, these projects are in the 0.5 MMtpy to 2.5 MMtpy range and involve much smaller reserve bases. Smaller facilities have appeal because of their potential for:

- Lower total magnitude of investment and risk
- Development of multiple smaller trains, staging in production
- Use of standard industry equipment types and sizes
- Shorter development times
- Reduced impact on local labor markets.

There are some issues to be overcome with mid-scale developments. Infrastructure costs for LNG storage, loading systems and jetties must be addressed. In some cases, reliable, long-term gas supply is an issue as owners focus on larger reserves. Finally, the mid-scale project must sell into a large LNG market that is set up for base-load plants with large off-takes and long-term agreements.

To address the issue of mid-scale developments, a less complex and lower cost LNG technology is needed. New LNG liquefaction processes can provide both cost reduction and operational simplicity. These processes can be used on a wide array of LNG facilities ranging from small scale peak-shaving units to base-load developments.

Mid-scale projects can also be developed for floating applications. These concepts benefit from compact, modular units. Ship designs with LNG production units from 1.1 MMtpy to 3 MMtpy have been developed and appear economically feasible. Barge-mounted facilities have been developed from 1.1 MMtpy to 6 MMtpy, representing base-load applications on floating structures.

Process selection. The first step in addressing an economical solution to the mid-scale plant development is selecting the liquefaction process, which best fits the size range of the project. Base-load process designs with multiple refrigerants and extreme complexities do not scale down well to the mid-scale sizes. The objective in mid-scale units is not to chase the last percentage of efficiency but to select a process with good efficiency and with the lowest equipment count. Simplicity of design is a key issue with mid-scale units to achieve low capital cost objectives.

In the small-scale project area, three processes are considered. The first is the *expander process*, which uses high-pressure gas expanded in turboexpanders to drive the process and achieve a partial liquefaction of the feed gas (approximately 18%). The balance of the feed gas has to be disposed of at low pressure. This can work well in peak-shaving applications near transcontinental pipelines. However, in mid-scale developments, the tail gas must be recompressed to conserve this resource. This compression addition makes the expander process not only the highest power consumer but also the highest cost of all the processes considered.

A second process that can be considered is the *nitrogen refrigeration process*. This process is similar to the expander process in that a large circulating gas stream is used to provide refrigeration in addition to using turboexpanders. This method is also very inefficient and has a capital cost comparable with the expander process. Its application has been limited to smaller units.

The workhorse of the small scale LNG industry is the *single-mixed refrigerant* (SMR) process. This process has been proven in numerous applications and a variety of sizes. The SMR process, shown in Fig. 1, represents a streamlined solution to the mid-scale plant design. The process is applied as a single refrigeration system regardless of size. Inherently modular in nature, the SMR process can be used in single or multiple parallel trains over a broad range of project sizes. A comparison of these processes has been covered in detail in previous publications.[1,2]

A recent industry paper summarized the application of the expander and nitrogen process.[3] The example applications covered are compared to the SMR process as summarized in Table 1. In essence, the expander and N_2 processes require about 50% more power than the SMR process. This is in line, but even higher than previously cited.[1] Since refrigeration compressors and drivers are the hearts of liquefaction processes, this large margin represents not only an extreme efficiency deficit but also a major cost deficit for the expander and nitrogen processes as compared to the SMR.

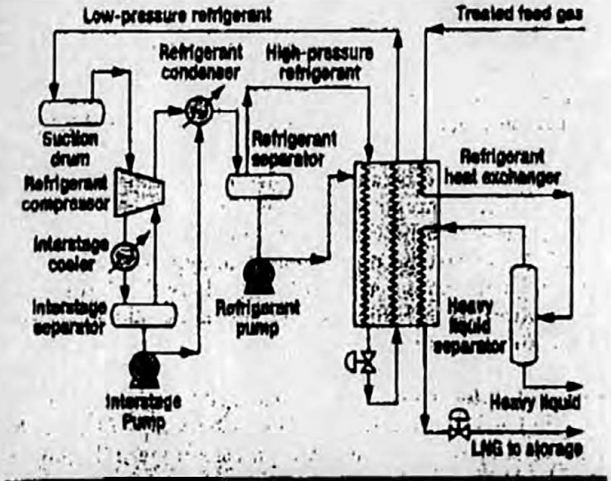

FIG. 1

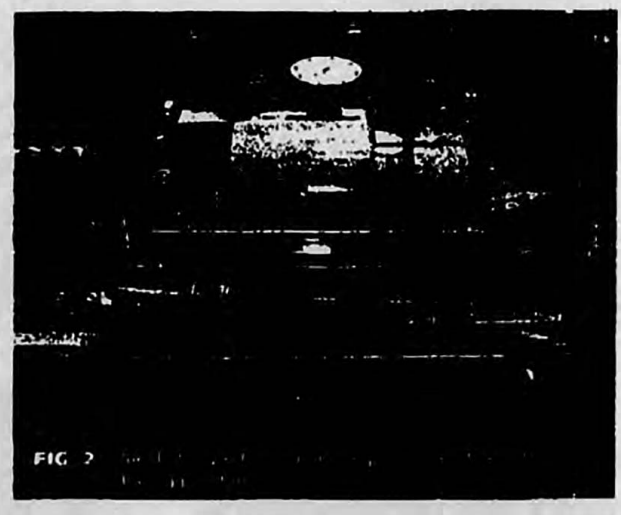

FIG. 2

Process applications. The two key components in the liquefaction system are the refrigeration compressor and the main exchanger (cold box). In the SMR process, the refrigeration compressor is a single-body, intercooled compressor. Fig. 2 shows a typical unit used in mid-scale applications. Because the compressor is a single case, a barrel-style unit can be used, which facilitates inspection and maintenance activities.

The main exchanger is constructed of plate-fin heat exchangers. A single plate-fin exchanger can be used for capacities up to about 20 MMscfd. For larger sizes, multiple plate fin cores are used in a parallel assembly. A good example of a 1-MMtpy (approximately 130-MMscfd) unit is shown in Fig. 3. This unit has eight plate-fin cores in a single cold box package. This module is 7 m × 8 m × 14 m (w × l × h), weighing about 220 metric tons. For larger capacities, multiple boxes are applied.

In the mid-scale sizes, a variety of gas turbines are used to achieve the desired capacity. Table 2 lists a representative mix of turbines to be considered. While the base-load plants have been dominated by frame turbines, the mid-scale industry is focused on the aero-derivative units due to lower fuel rates and ease of maintenance. Table 3 shows some application examples of turbine drivers and cold box sizes. Up to about 1 MMtpy, a single compressor/exchanger combination is a good choice. For larger units, such as 2-MMtpy units, dual compressors and cold boxes are considered. Thus, virtually any size of unit can be developed in a modular fashion.

Heavies extraction. Depending on the composition of the feed gas to be liquefied, heavy hydrocarbons must be removed to prevent plugging due to solidification at low temperature. For this reason, as shown in Fig. 1, a partially condensed feed gas is drawn out of the main exchanger at a specified mid-point temperature.

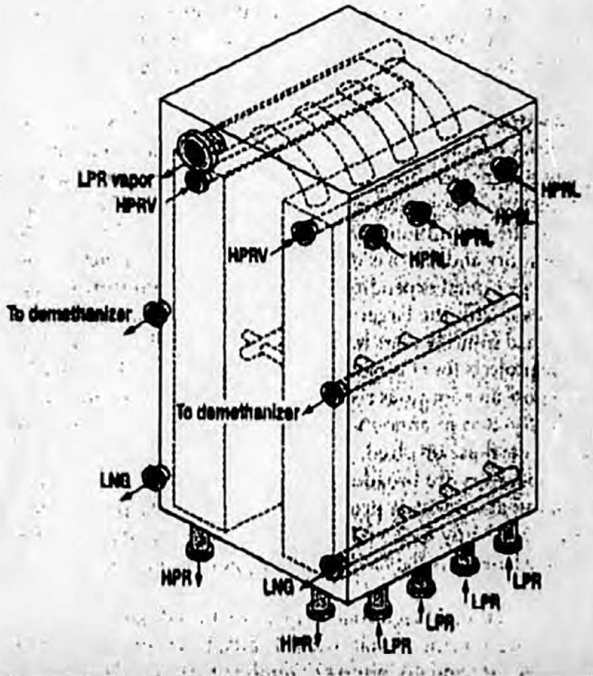

FIG. 3

TABLE 1. Process efficiencies for expander, nitrogen and SMR liquefaction processes

	Number of LM6000 to make 1.5 MMtpa
Expander with recycle	3*
Nitrogen refrigeration	3*
SMR	2
	LNG production with 2 x LM6000 chilled
Expander with C_3 refrig.	1.5*
SMR	2.1

*LNG Journal

After the condensed heavy liquid is separated, the gas is returned to the refrigerant heat exchanger where it is further cooled, liquefied and sub-cooled. If the heavy liquid is of sufficient quantity, fractionation of this liquid into products such as ethane, liquefied petroleum gas (LPG), butanes and gasoline may be economically attractive. These products can also be used for refrigerant makeup. In the majority of cases, a single C_5+ condensate product is the only liquid product. Alternatively, a full-range of natural gas liquid (NGL) products can be produced. The facilities at Skikda, Algeria, recover 60% of the ethane and essentially all C_3+ from the feed gas. Integration of the NGL recovery has been accomplished, as shown in Fig. 4.

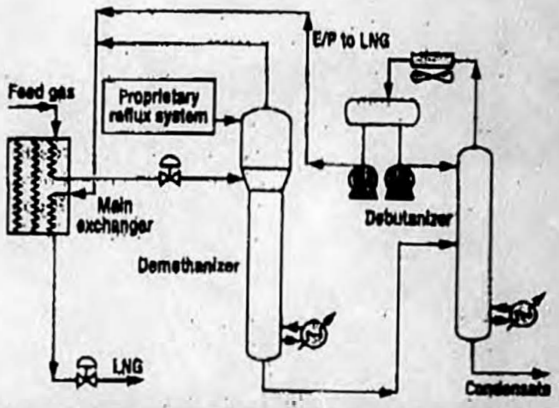

FIG. 4

Feed gas flexibility. Mid-scale projects are often to be developed for stranded gas assets. As such, the gas may come from associated gas, unassociated gas or pipeline supplies. Also, unconventional sources such as coal-bed methane (CBM) may also be alternative feeds for these plants. Many of the developments underway envision feed gas from several sources. For example, a recent project involved six different feed streams. A process with the flexibility to handle these different feeds is needed. Table 4 summarizes the differences in the various sources. The associated gas tends to be richer in NGLs and heavy hydrocarbons while CBM gas has little or no C_3+ constituents but can be high in nitrogen. The SMR process has been used in multiple instances to span this broad range of feeds.

Mid-scale applications. Mid-scale plants tend to be considered in the 0.5 MMtpy to 2 MMtpy sizes. Often, the desire is to phase in production in 0.5 MMtpy or 1MMtpy sizes. In any event, a single 160,000 m^3 or 180,000 m^3 tank is needed to support commercial sized LNG cargo ships. This size tank can support up to about 2.5 MMtpy of production, depending on the shipping logistics. An example of a two-train layout is shown in Fig. 5. The compactness and simplicity of the process plant aids in developing this process plant on a minimal plot space of about 60 acres. The total schedule for these facilities will generally be driven by the LNG tank schedule. However, in some cases, the marine development can become a critical path item. Timelines of 36–40 months are typical.

Capital cost estimates. Cost estimates have been developed for complete mid-scale liquefaction plants from 0.5 MMtpy to

2 MMtpy. Fig. 6 summarizes these discrete estimates with a total curve of cost vs. capacity. This curve is intended to include the complete facility with single tank and ship loading. One item, which is very difficult to generalize without site-specific data is the ship-loading jetty. Thus, two curves are shown. One represents a simple, short jetty with minimal dredging, and the second a more complex application with a long trestle and significant dredging. These presented costs are based on Gulf Coast labor rates and are useful for study purposes. Of course, site-specific construction costs and logistics can impact these numbers greatly.

Floating LNG systems. Floating LNG systems have been considered for many years. As gas developments move farther offshore the location of the liquefaction plant on a floating structure has several advantages. The elimination of a harbor and jetty associated with an onshore plant is a significant cost savings. In addition, with an onshore plant, long pipelines from production platforms are necessary. The LNG liquefaction facility can be integrated with the gas production system, thus eliminating production platforms entirely. Offshore systems require compact process designs, which conserve valuable deck space. The modular nature of the SMR process fits well with this objective. The low profile nature of the main heat exchanger and low equipment count are distinct advantages for offshore design. The fact that no pure component refrigerants are involved in the process leads to a small inventory of refrigerant components. This is an important factor in hazard analysis of offshore systems.

TABLE 2. Gas turbine options for LNG projects

Model	ISO Rating, hp (MW)	Fuel, Btu/hp-hr	Efficiency, %
LM2500	31,200 (23.3)	6,750	37.7
RR 6562	39,600 (29.5)	6,705	38.0
LM2500+	42,070 (31.4)	6,187	41.1
Frame 5D	43,690 (32.6)	8,650	29.4
RR 6761	44,500 (33.2)	6,290	40.5
LM2500+(G4)	45,590 (34.0)	6,175	41.2
Frame 6B	58,380 (43.5)	7,650	33.3
LM6000PC	59,355 (44.3)	5,941	42.8
Trent	70,418 (52.5)	5,939	42.8
Frame 7E	115,630 (86.2)	7,720	33.0

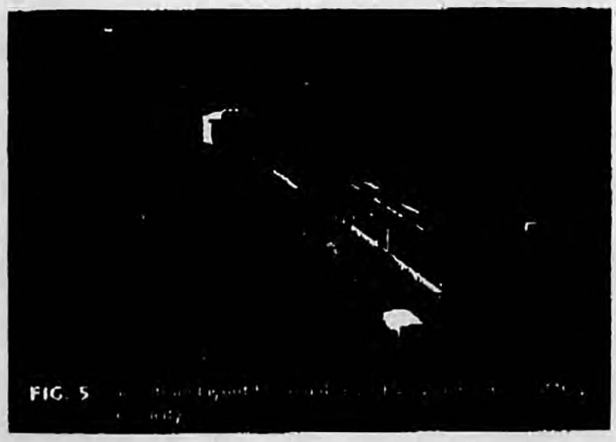

FIG. 5

Two types of floating systems have been developed: ship-based designs and barge-mounted facilities. An example of a 2-MMtpy, two train development footprint is shown in Fig. 7. The offshore environment lends itself to multi-level layouts, which facilitate compactness and the arrangement of equipment.

Barge-mounted systems have also been considered to accommodate LNG production processes. Barges of similar size to the ship-mounted systems have been developed. However, the barge-mounted concept can and has been expanded to accommodate larger LNG liquefaction process facilities. Projects up to 6 MMtpy have been developed using the SMR process and have been covered in previous publications.[4,5] The process design for 6 MMtpy can be based on integrated trains of 2 MMtpy or 3 MMtpy or multiple trains of 1 MMtpy depending on the client desire for flexibility and phased development. Fig. 8 shows a cross-section of a 2 × 3 MMtpy module.

TABLE 3. Plant capacity ranges

Nominal capacity, MMtpy	Driver example	Hp avail at 30°C	Fuel efficiency at 30°C	Main exchanger no. × cores
0.6	LM2500+	35,000	38.5	1 × 4
0.7	LM2500+(G4)	38,400	38.9	1 × 6
0.8	LM6000	45,200	38.1	1 × 6
1	RR Trent	58,400	40.0	1 × 8
2	2 × RR Trent	2 × 58,400	40.0	2 × 8

TABLE 4. Feed gas ranges

	Associated gas	Non-associated or pipeline gas	CBM
Feed gas pressure	Medium	High	Low
Heavies	Rich to very rich	Some	None
Byproducts			
Condensate	Yes	Minor amount	No
NGL	Yes	No	No
CO_2	2–12%	2–3%	0.2% and up
Nitrogen	<1%	Low to medium	4–15%

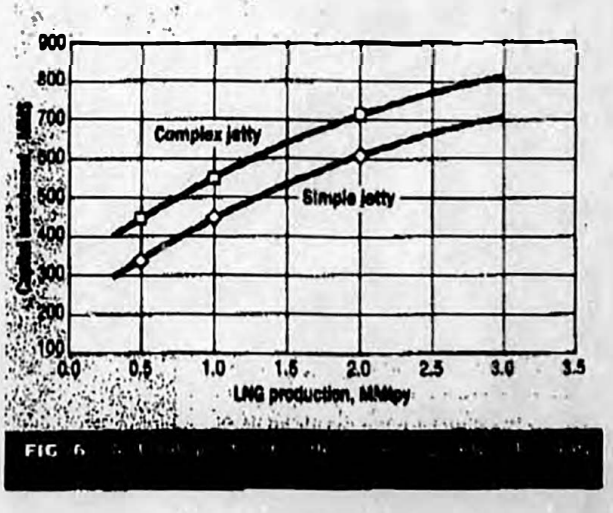

FIG. 6

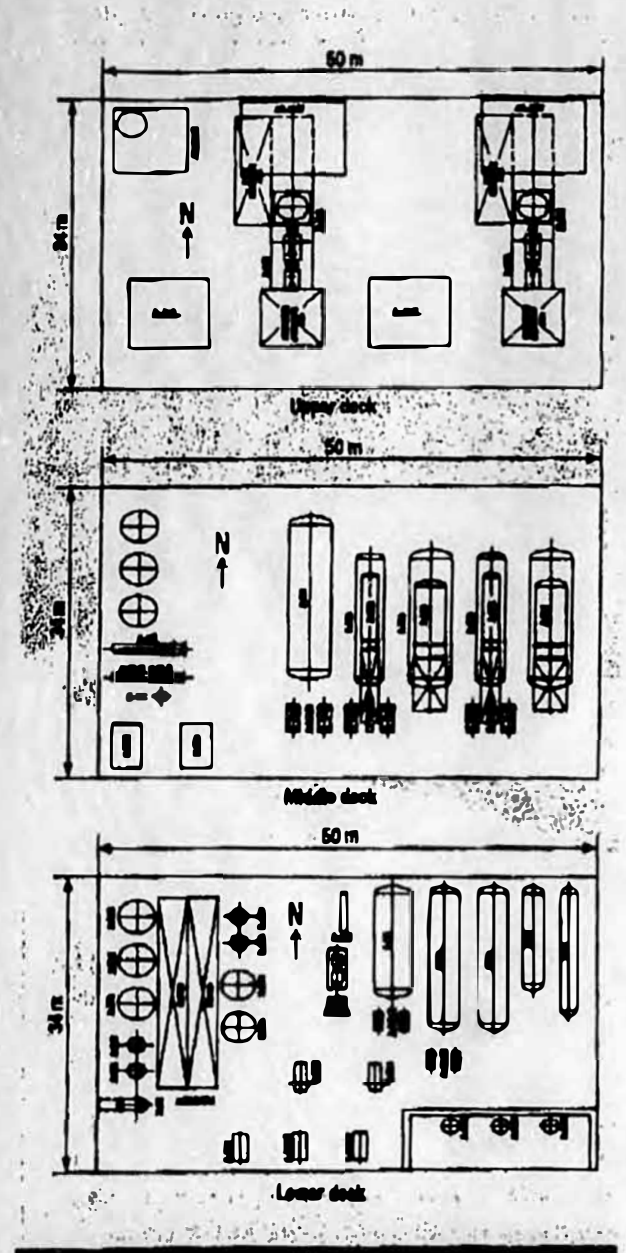

FIG. 7

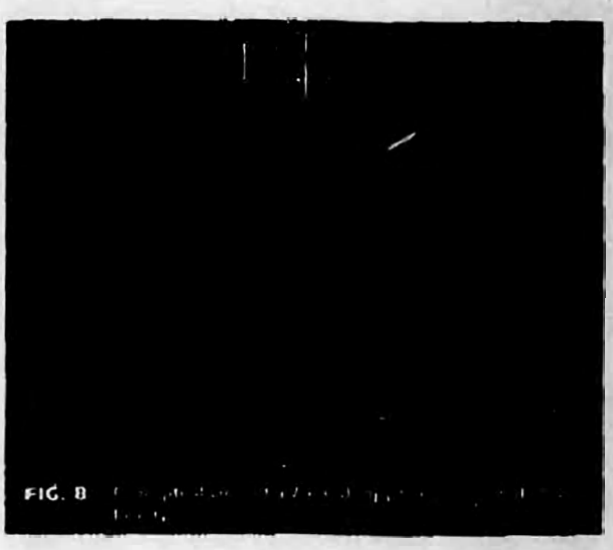

FIG. 8

Outlook. Developments of mid-scale and floating LNG process facilities are actively being pursued worldwide to broaden the target reservoirs for gas development. The SMR process, with its compact size and low cost, is an integral part of the equation to make such facilities economically feasible. Facility costs have been developed which now make these projects competitive with larger scale developments. HP

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Brian C. Price is vice president for LNG technology for Black & Veatch Corp. in Overland Park, Kansas. He is in charge of technology development and process design for LNG production facilities, LNG import terminals and related gas processing and NGL recovery facilities. Mr. Price has over 35 years of experience in gas processing and related technology areas. Prior to joining BVPI, he worked for ARCO Oil & Gas Co. in various positions, including manager of process engineering and projects manager. Mr. Price is a member of AIChE and is active in the Gas Processor Suppliers Association. He currently serves as chairman of editorial review board for the *GPSA Engineering Data Book* and is past chairman of the technical committee for Gas Processors Association. Mr. Price holds BS and MS degrees in chemical engineering from Oklahoma State University.

Joseph Fossella is vice president, Business Development for Black & Veatch Corp. in Overland Park, Kansas. He directs the worldwide sales and marketing activities for the Gas, Oil & Chemicals Division of Black & Veatch and has been focusing on the mid-scale LNG area for the past several years. Mr. Fossella has over 34 years of industry experience, the past 25 years in business development. He has been responsible for over $3 billion of sales across a broad range of technologies worldwide. Prior to joining Black & Veatch, he held business development positions with Aker Kvaerner & Predecessors (Kvaerner Process, John Brown and Crawford & Russell). Mr. Fossella graduated from the US Naval Academy and also holds an MS degree from the New Jersey Institute of Technology.

Shawn D. Hoffart is a LNG section lead for Black & Veatch Corp. in Overland Park, Kansas. He is an expert in LNG process design and has been the design lead on numerous liquefaction facilities in the US and internationally. Since joining BVPI, Mr. Hoffart has worked for 17 years in a broad range of technologies in addition to LNG including: sulfur recovery, cogeneration, NGL recovery, NGL fractionation and cryogenic CO_2 separation. Prior to joining BVPI, he worked in product development for the Goodyear Tire and Rubber Company Industrial Products Division. Mr. Hoffart is a member of AIChE and a registered professional engineer in the State of Nebraska. He holds a BS degree in chemical engineering from the University of Nebraska and an MS degree in engineering management from the University of Kansas.

Alaska Gasline
PORT AUTHORITY

Presentation to
Alaska State Senate

July 22nd, 2008 & July 23, 2008

Juneau, Alaska

1. LNG Export Issues

Export License – Overview of Federal Law

- ANGTA requires Presidential finding before North Slope gas can be exported
- NGA requires DOE to authorize all U.S. gas exports
  - Export approval for Canada and Mexico automatic
  - DOE has only addressed export for Kenai and YPC
- 1969 to present DOE authorized Kenai export
- 1990 DOE finalized authorization for YPC to export 14 MMT (~1.9 bcf/d) for 25 years starting at first delivery

Export License – DOE's Market Driven Approach

- NGA creates rebuttable presumption that license will issue

- DOE's stated goal
  - let market forces define efficient energy markets
  - minimize federal involvement

"Competition in world energy markets promotes the efficient development and consumption of energy resources, as well as lower prices, whereas economic distortions can arise from artificial barriers to the free flow of energy resources. Accordingly, the DOE believes that the public interest in free trade generally supports approval of proposed exports." (DOE Order 350).

Export License – Domestic Need

DOE uses a three pronged public interest analysis to determine if the presumption to allow export has been overcome:

1. *Will national or regional demand exceed available domestic supply?*
2. *If insufficient domestic supply, are alternative supplies available to meet demand?*
3. *If there is sufficient domestic or alternative supply, does some other public interest overcome presumption of export?*
    a. Environment
    b. Alaskan interests
    c. Energy security
    d. International effects
    e. Impact on North Slope development
    f. Lower-48 natural gas prices

Source DOE Order No. 350 (YPC); DOE Order No. 2500 (2008 Kenai).

Export License – Domestic Need

1. Will domestic demand exceed available domestic supply?

- U.S. supply and demand over term of license estimated
- DOE takes a broad view of available U.S. reserves, including allowance for
  - reserves growth
  - new discoveries
  - non-conventional gas resources
    - E.g., Tight sands, shale, coal seams and enhanced recovery
- In 1989 DOE said domestic supply sufficient to meet anticipated U.S. need
- Today, domestic reserve additions from shale gas have potential to fulfill domestic need

Export License – Alternative Supply

Alaska Gasline Port Authority

2. Are alternative supplies available to meet demand if DOE projects insufficient domestic supply?

- DOE looks at availability of gas for import including LNG from overseas
- "unduly simplistic to conclude that [ANS] exports will necessarily diminish the quantity of energy available to U.S. consumers"
  - Alternative may be ANS gas is stranded
  - Export will open ANS to exploration and development
  - ANS LNG to Asia may free up other LNG to go to U.S.
- DOE recognizes gas markets are global
- Today, increased global LNG production and U.S. receiving capacity means alternative supplies are available

Export License – Public Interest Factors

3. If there is sufficient supply, does some other public interest overcome presumption of export?

Energy Security

- "DOE believes that the true energy security lies in encouraging the most efficient operation of the North American and global energy markets."
- Also since 2005 President has broad authority to stop export of all gas

International Effects

- Competition promotes efficiency and lower prices
- Impact on Asian balance of payments and trade imbalances significant

Alaska Gasline Port Authority

U.S. Prices

- DOE wants to insure exporting ANS gas will not drive up lower-48 natural gas prices
- DOE does not consider
  - Various projections anticipating ANS gas will go to U.S.
  - Economic studies of Canadian vs. LNG project
- Rather DOE asks whether available non-ANS gas can be delivered given anticipated prices?
- Answer in 1990 and now is yes!
  - By 2030 about half of U.S. demand will be met with non-conventional gas (EIA Annual Energy Outlook 2008)
  - Non-conventional gas, as marginal supplier, will set price
  - ANS gas to the U.S. will not change the cost of meeting marginal demand or thus price to U.S. consumer

Export License – Public Interest Factor (Price)

Alaska Gasline Port Authority

Impact on North Slope development

- DOE unsympathetic to argument that proven ANS reserves needed for Canadian pipeline
  - Canadian project does not have right to ANS reserves
  - The market will decide
- DOE noted 13 years had passed since ANGTA and the ANS gas remained undeveloped
- DOE said export will encourage
  - Assessment of ANS potential
  - Earlier development of ANS proven reserves
  - Discovery and development of additional ANS reserves

Export License – Looking Forward

- AGPA strongly believes
  - YPC license will be honored, and
  - Regardless a new license would issue

- YPC license update
  - DOE stated YPC could not pass project costs on to U.S. consumers
  - Filing with DOE all contracts for acquisition, transportation, and sale of gas precondition to export

- New license
  - Presidential finding
  - DOE will undertake same export analysis it did for YPC
  - Circumstances have not materially changed

2. LNG Project Economics

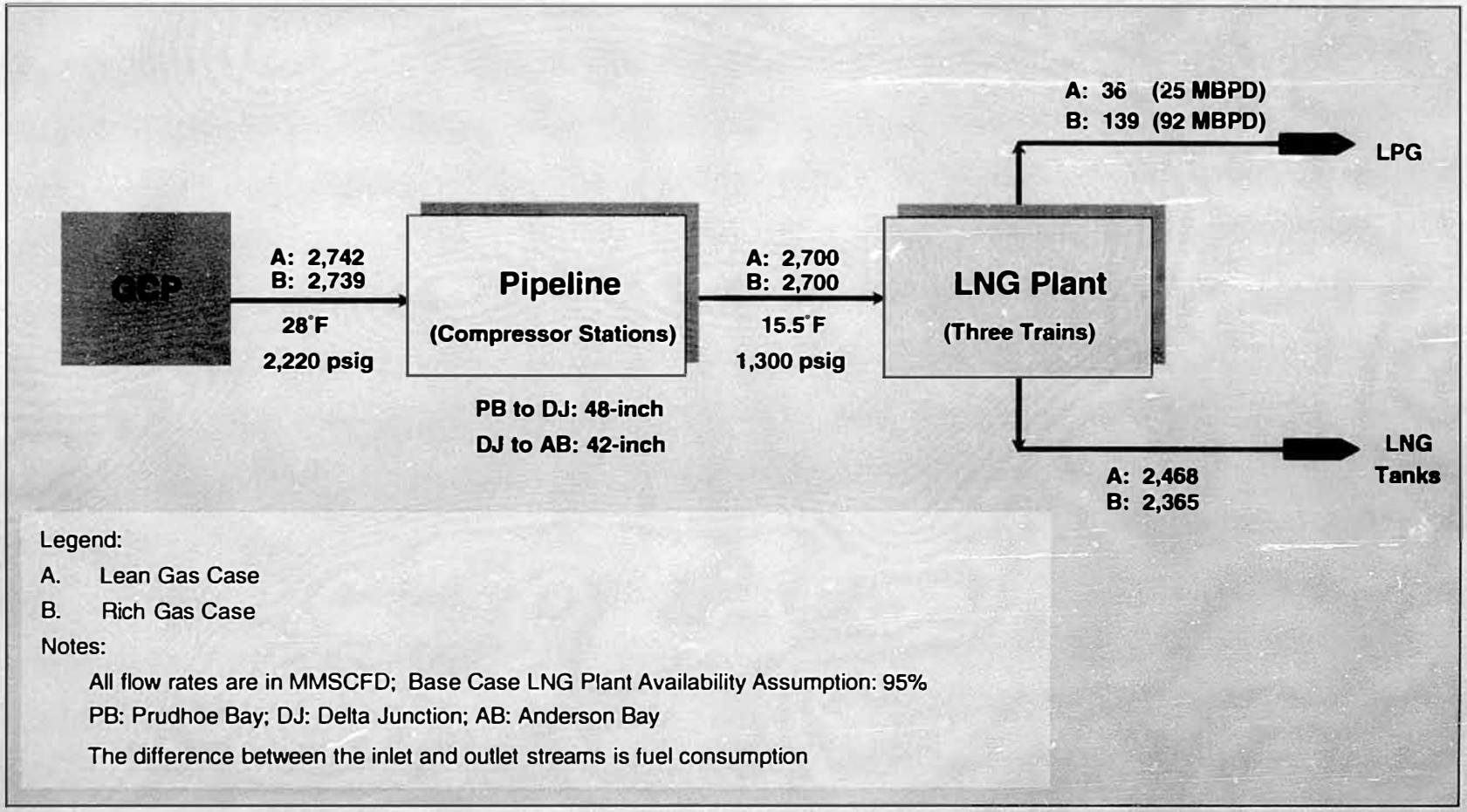
LNG Project Analyses Presented to Legislature

- Economics of an LNG project vs. Pipeline to Canada
  - Port Authority: LNG more attractive than pipeline to Canada
  - Administration: LNG less attractive than pipeline to Canada
  - EconOne: LNG either more or less attractive, depending on assumptions
- Assumptions used are key:
  - capital cost of project components
  - difference in prices in Asian LNG market and Alberta gas market

  ⇨ different assumptions result in different netback prices

Port Authority Project

OVERALL FLOW SCHEME (Gas Compositions Year 2007 Winter Conditions)



Capital Cost Assumption Comparison

	Port Authority	Administration (P50)
Pipeline from Prudhoe Bay to Valdez	$13.2 billion	$11.4 billion
LNG Facilities	$8 billion	$14 billion

- 2.7 Bcfd LNG Project
- Cost estimate includes EPC costs, owner's costs during construction, and development costs
- escalation after 2007, property taxes during construction, and AFUDC are excluded

⇨ Administration uses substantially higher capital costs for the LNG Facilities

LNG Plant Capital Cost Estimates

Alaska Gasline Port Authority

Bechtel's "bottom-up" EPC cost estimate for LNG Plant:

- 2007 EPC cost estimate
- Extensive technical work
- Site-specific and project-specific conditions accounted for
- Proven, well-established plant design
- Fewer cost uncertainty factors than the pipeline

Administration's "top-down" LNG plant capital cost:

- Not developed from detailed project-specific technical work
- Derived by "data mining" of database of other LNG projects
- Generic cost-per-ton estimate applied to Anderson Bay

Note: Administration's methodology as described in Chapter 4, Section E.3 of the Written Findings and Determination by the Commissioners of Natural Resources and Revenue for Issuance of License under AGIA

LNG Plants Are Not the Same

- LNG projects are not the same: project location, project scope, feed gas composition and other project-specific factors make valid project comparisons difficult

- Variations in LNG plant scope and configuration:

  - many LNG projects include cost of gas treatment
    - liquid slug removal
    - condensate stabilization
    - acid gas removal
    - water removal
    - mercury removal

  - for the Alaska LNG project, gas treatment occurs at the GCP on the North Slope

LNG Plants Are Not the Same (2)

- Feed gas pressure
  - high pressure feed gas from the pipeline to Valdez
  - significant reduction in the cost of compression at the Valdez LNG Plant
- Ambient temperatures at project site
  - most LNG projects in warm climate
  - Valdez plant benefits from cold climate
- Site preparation, marine terminal facilities, etc: highly location-specific
  - Bechtel estimate based on Anderson Bay site
- Different EPC market conditions for different projects

"Bottom-Up" Approach is Preferable

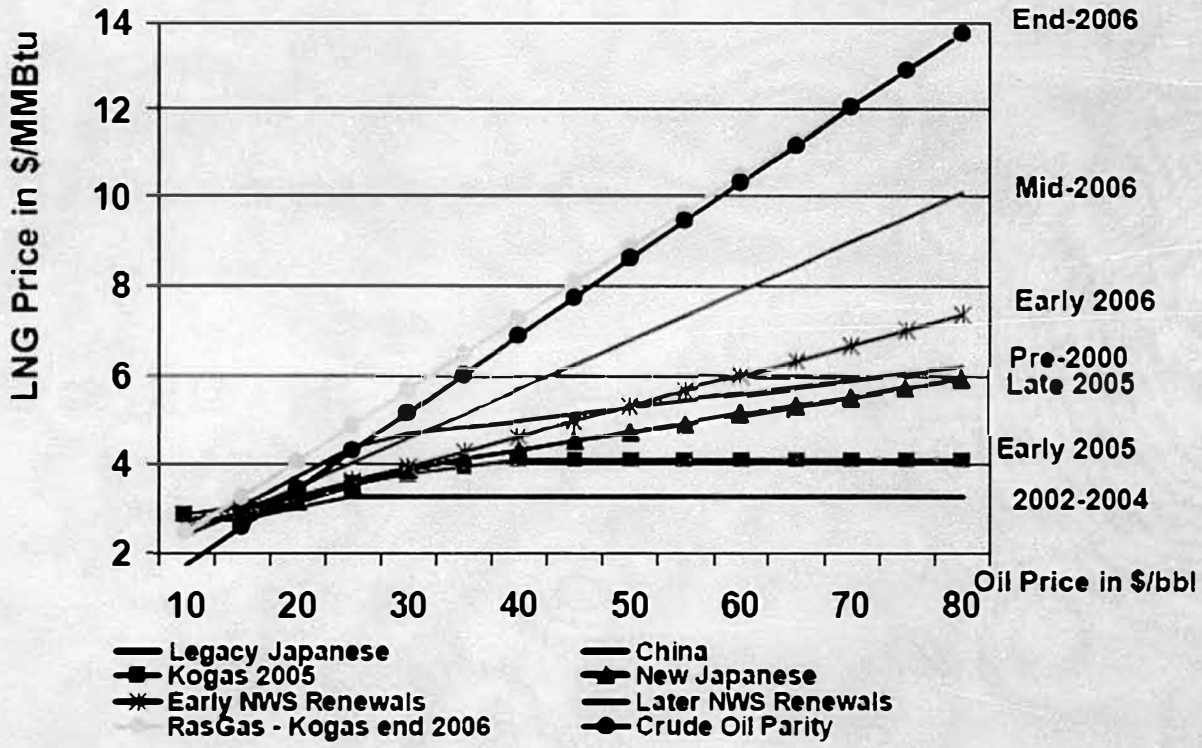
- Limitations of "database mining" approach should be recognized
  - inherent difficulty in comparing projects of different scope, in different locations and subject to different conditions
- Mixing the "top-down" approach for LNG Plant with a "bottom-up" approach for the pipeline:
  - introduces an inconsistency in methodologies
  - validity of economic comparison between the two projects is compromised

Asian LNG and North American Gas Prices

- Asian LNG Prices:
  - bilateral, long-term sales and purchase agreements
  - price formulas with oil price indexation provisions
  - pricing provisions reflect market supply and demand dynamics at time of contract execution
  - at each point in time, multiple active supply contracts, negotiated at different times, with varying pricing provisions

- North American gas prices
  - price discovery is driven by a gas spot market at regional trading hubs (e.g., Henry Hub, AECO, etc.)

Evolution of Asian LNG Prices



Source: Gas Strategies Consulting

- Recent LNG sales contracts in the Asian LNG market have been executed on terms highly favorable to sellers
- Kogas contract from late 2006: LNG price formula reportedly above parity with oil

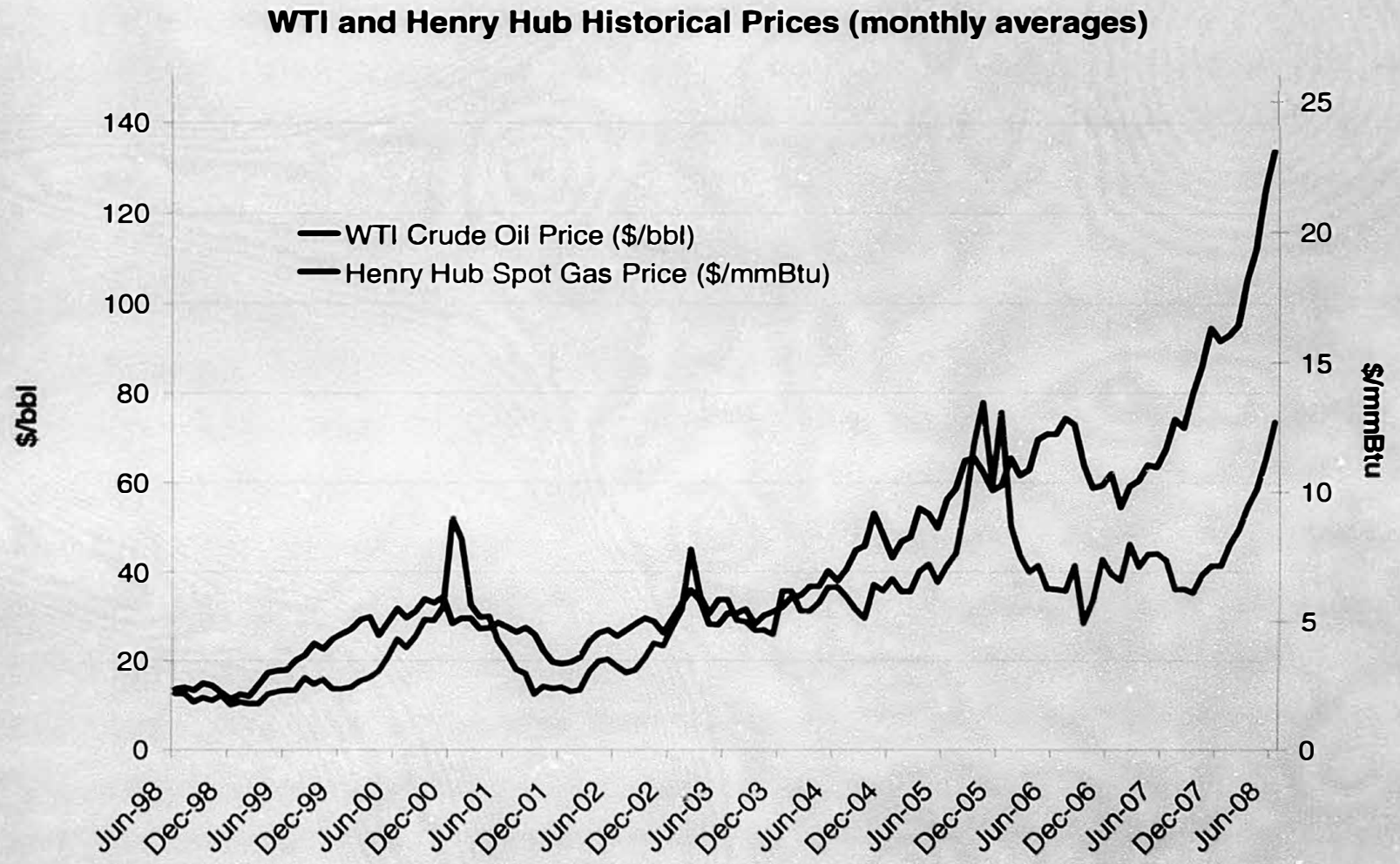
Price Assumption for Alaska LNG (E. Asia DES)

- Gas Strategies' report to the Administration projects the following price scenarios for Alaska LNG (LNG Price in $/mmBtu, Oil Price in $/bbl)*
  - Base Case: LNG Price = 0.1485 * Oil Price + 0.90
  - High Case: LNG Price = 0.162 * Oil Price + 1.00
  - Low Case: LNG Price = 0.9 * Henry Hub – 0.50

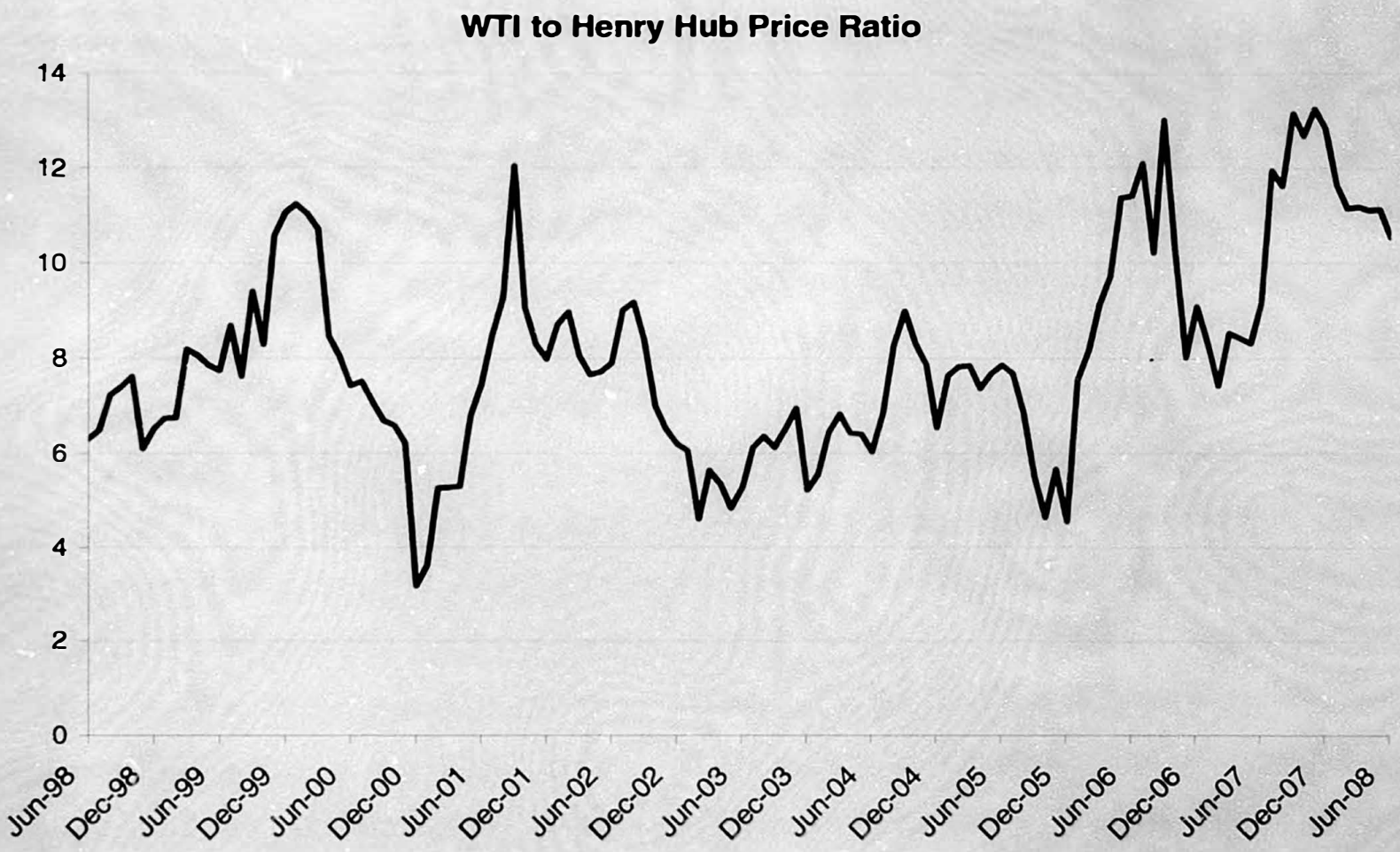
- The Port Authority assumptions:
  - current highly seller-favorable market expected to swing back towards relatively more buyer friendly terms
  - Gas Strategies' Base Case forecast appears reasonable and has been incorporated in Port Authority analysis
  - High Case generates very favorable results for the Alaska LNG Project

* Note: For simplicity, this presentation uses the term "Oil Price" interchangeably with JCC, Brent and WTI prices. In a detailed analysis, the price variations between different crude prices should be taken into consideration.

North American Prices: WTI and Henry Hub



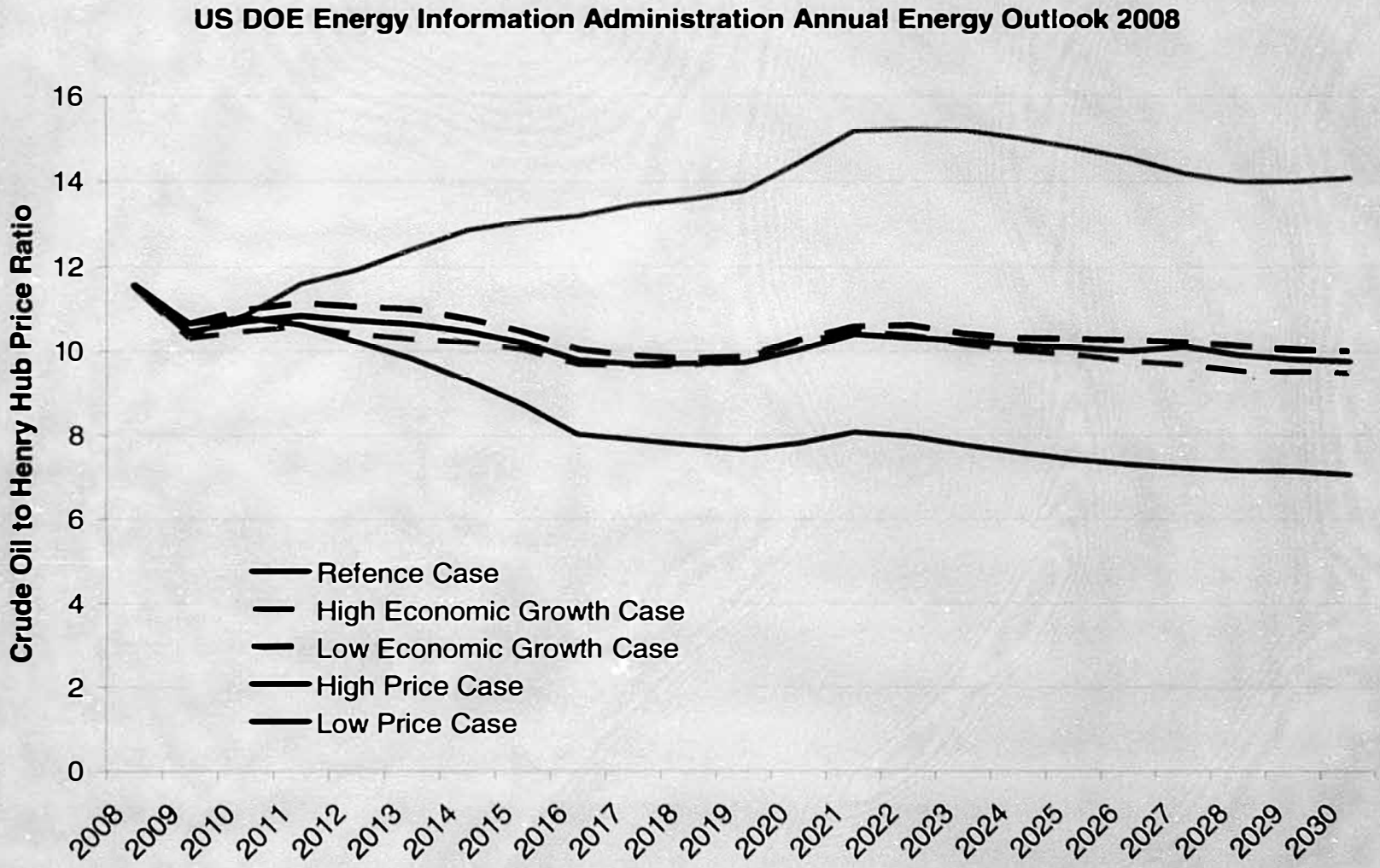
WTI and Henry Hub Price Ratio



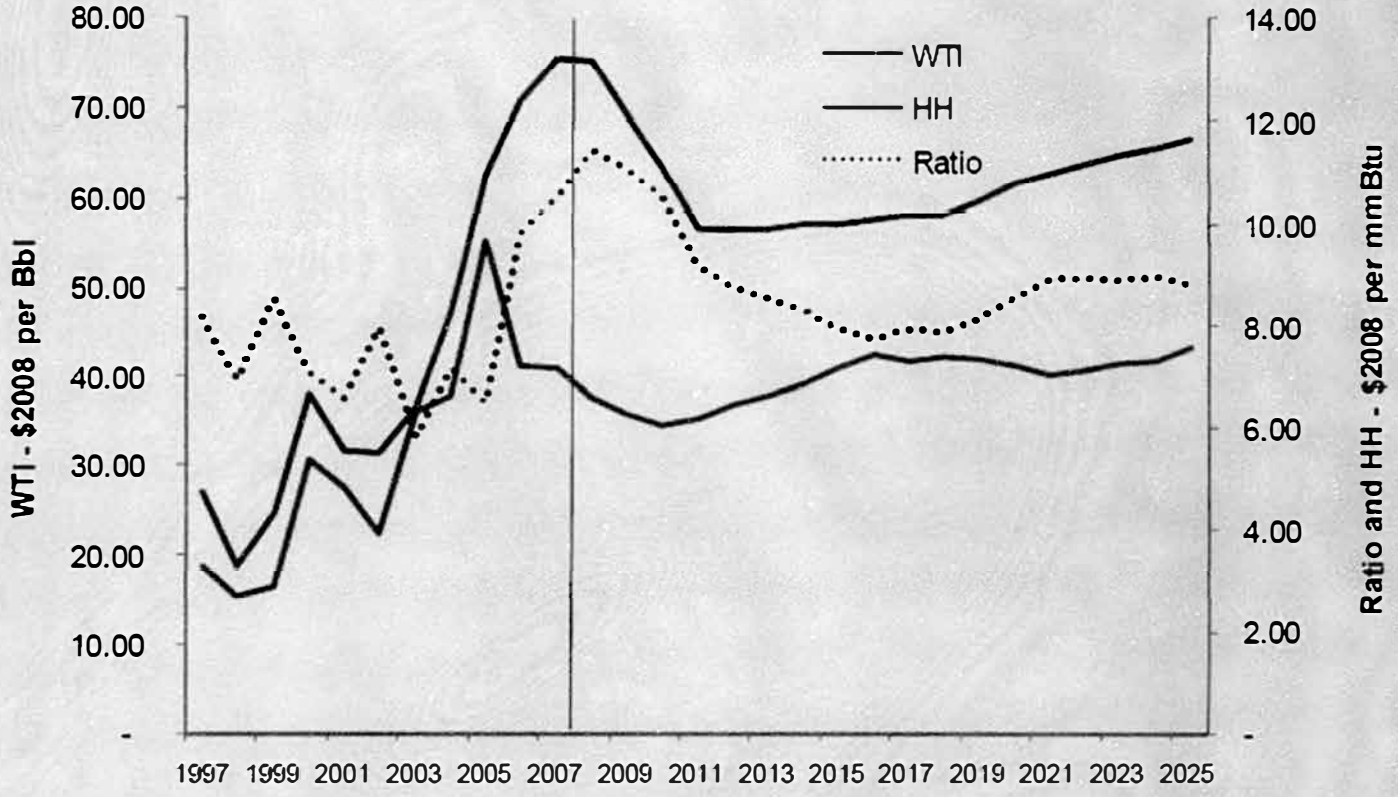
Significance of Assumed Oil/Henry Hub Price Ratio

- Higher crude oil to Henry Hub price ratio means:
  - differential between Asian LNG prices and North American gas prices is higher
  - netback prices from LNG Project are relatively more attractive
- Recently observed price ratios are significantly higher than historical values
- What is the appropriate assumption for assumed crude oil to Henry Hub price ratio for the future?

DOE EIA Forecast Price Ratios (AEO 2008)



Administration's Forecast (Wood Mackenzie)



Source: Commissioners' Findings, Appendix N: Wood Mackenzie Gas and Power Long Term Outlook Briefing Paper

Price Ratio Forecast Comparison

- Crude oil to Henry Hub price ratios:
  - historical average 1998-2008: 8.1
  - DOE EIA Annual Energy Outlook 2008 (average 2008-2030):
    - Reference Case: 10.2
    - High Growth Case: 10.1
    - Low Growth Case: 10.5
    - High Price Case: 13.4
    - Low Price Case: 8.5
  - NYMEX futures market recent prices (average 2008-2016): 12.5
  - Wood Mackenzie (Administration's analysis)*
    - above 10 until 2011
    - decreases to around 8-to-9 from 2012

* Source: Commissioners' Findings, Appendix N: Wood Mackenzie Gas and Power Long Term Outlook Briefing Paper

Netback Comparison: Capital Cost Assumptions

	2007 billions	Source of Assumption
Development Phase Costs:		
LNG Project	0.65	Administration
Pipeline to Canada Project	0.69	Administration
Execution Phase Capital Costs:		
GCP for 2.7 Bcfd LNG Project	4.9	Administration
GCP for 4.5 Bcfd Pipeline Project	8.2	Administration
GCP for 3.5 Bcfd Pipeline Project	6.4	Administration
2.7 Bcfd Pipeline Prudhoe Bay–Valdez	11.1	Administration
4.5 Bcfd Pipeline Prudhoe Bay–Border	10.5	Administration
4.5 Bcfd Pipeline Yukon-Alberta	12.4	Administration
3.5 Bcfd Pipeline Prudhoe Bay–Border	9.7	Administration
3.5 Bcfd Pipeline Yukon-Alberta	11.4	Administration
LNG Facilities	7.8	Bechtel/Port Authority

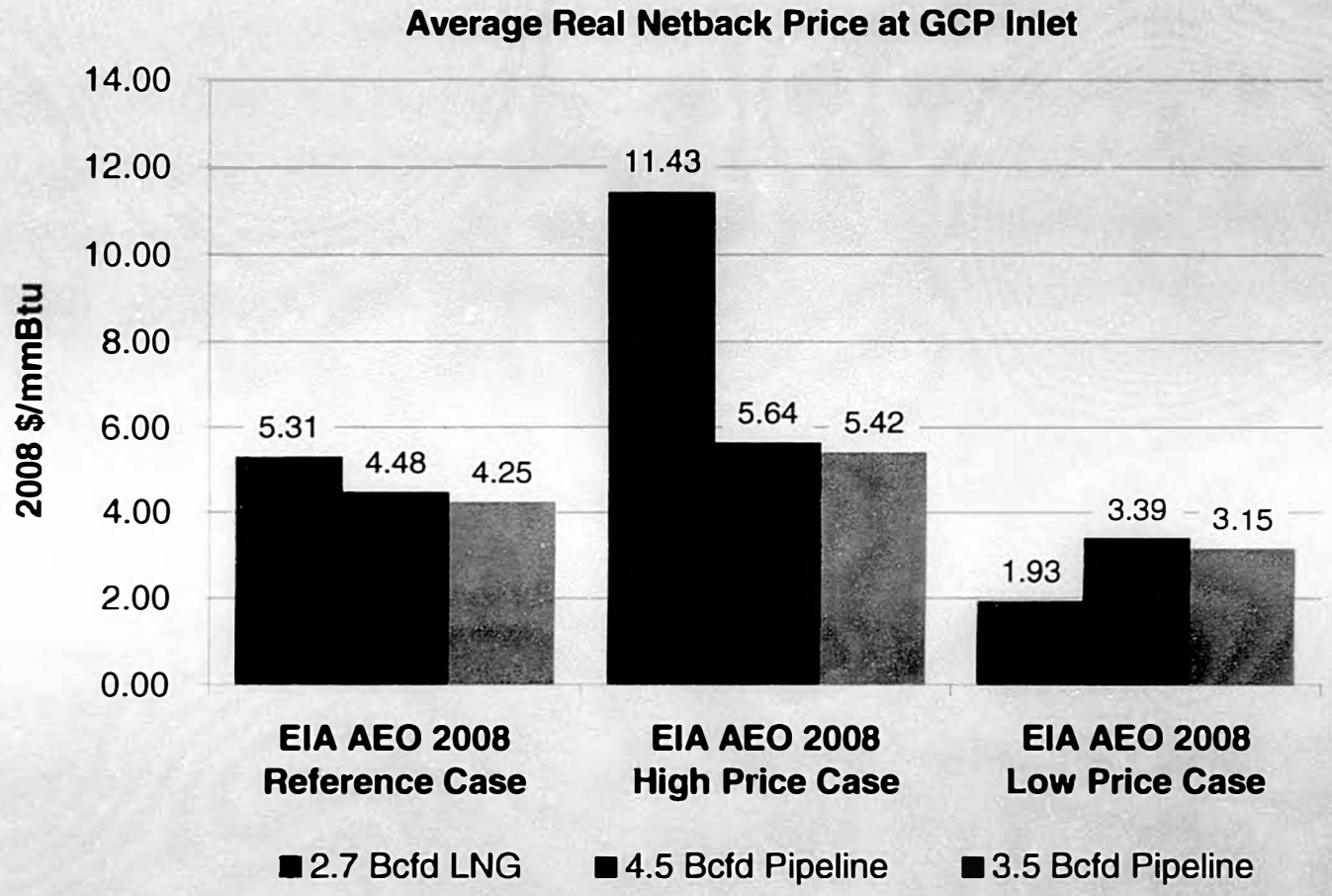
Netback Comparison: Other Assumptions

	Assumption	Source of Assumption
D:E for Tariff (Pre-Completion)	70:30	Admin/TCPL
D:E for Tariff (Pre-Completion)	75:25	Admin/TCPL
Return on Equity	14%	Admin/TCPL/EconOne
Cost of Guaranteed Debt	5.50%	EconOne
Cost of Non-Guaranteed Debt	7.00%	EconOne
LNG Plant Availability Factor	95%	Bechtel
LNG Sales Price (DES E. Asia)	0.1485*JCC+0.90	Administration
LNG Shipping Costs (incl. fuel and boil-off)	~$1.10/mmBtu [1]	MOL / PA
Pipeline Gas HHV	1133 Btu/scf	Administration
Capex Escalation	4% p.a.	Administration
Opex Escalation	3% p.a.	Administration

Notes: [1] Nominal dollars in 2019

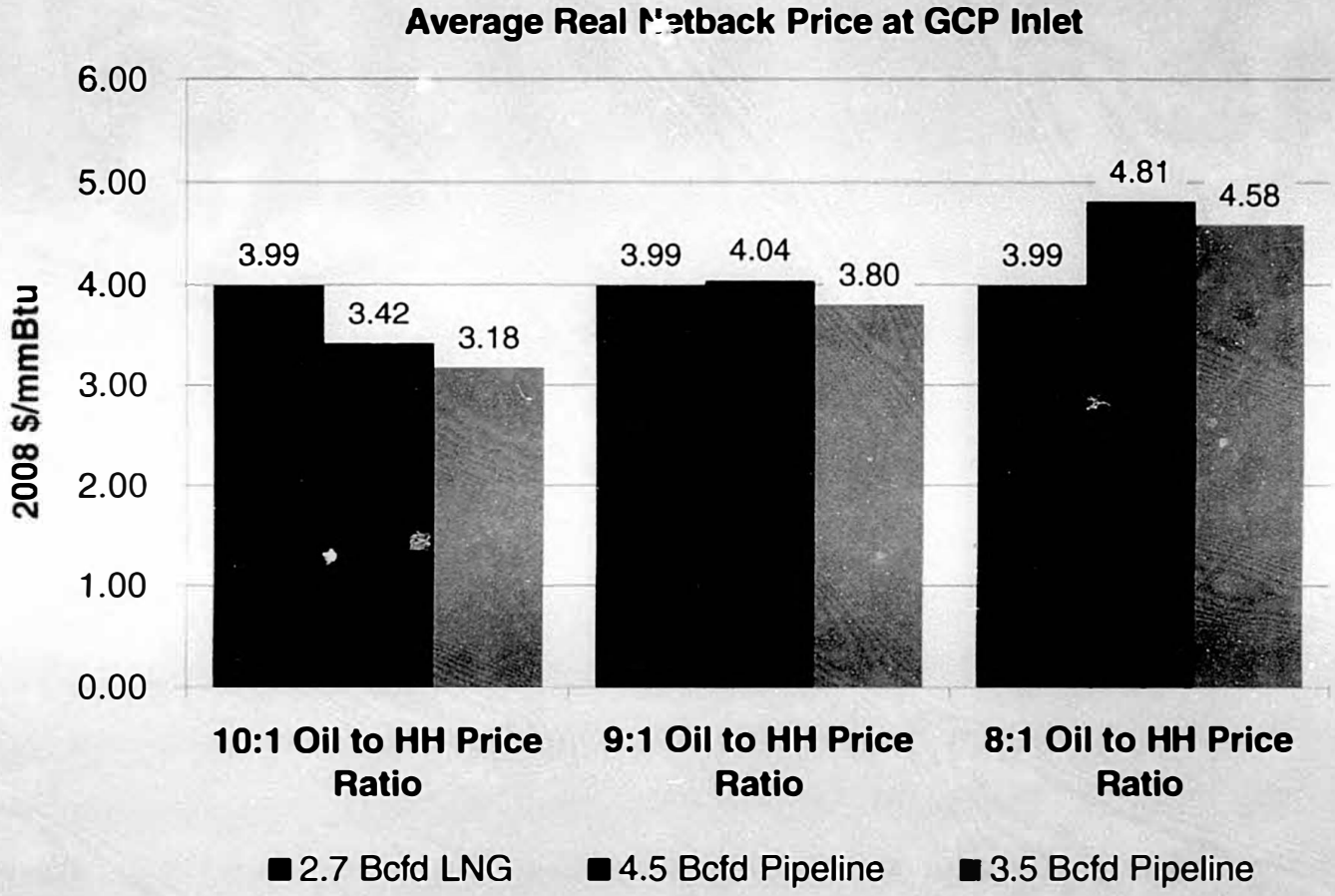
Netback Prices: EIA Price Forecasts

- Oil and HH prices from DOE EIA's 2008 Annual Energy Outlook
- 3 price scenarios shown: Reference Case, High Price and Low Price Cases



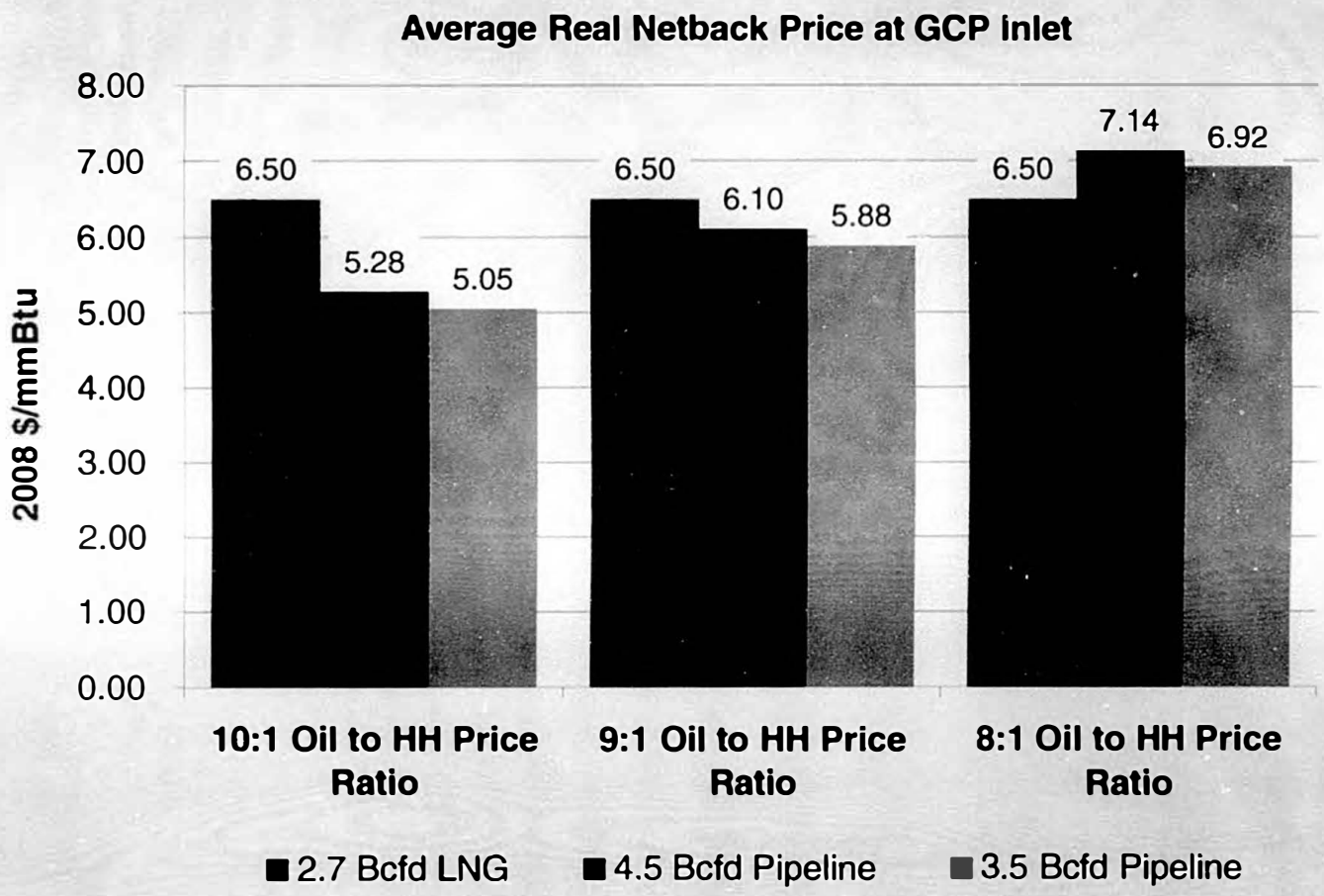
Netback Prices: $60/bbl Oil Price Cases

- Flat $60/bbl oil price (constant 2008 USD)
- 3 scenarios for oil/HH price ratio: 10:1, 9:1 and 8:1



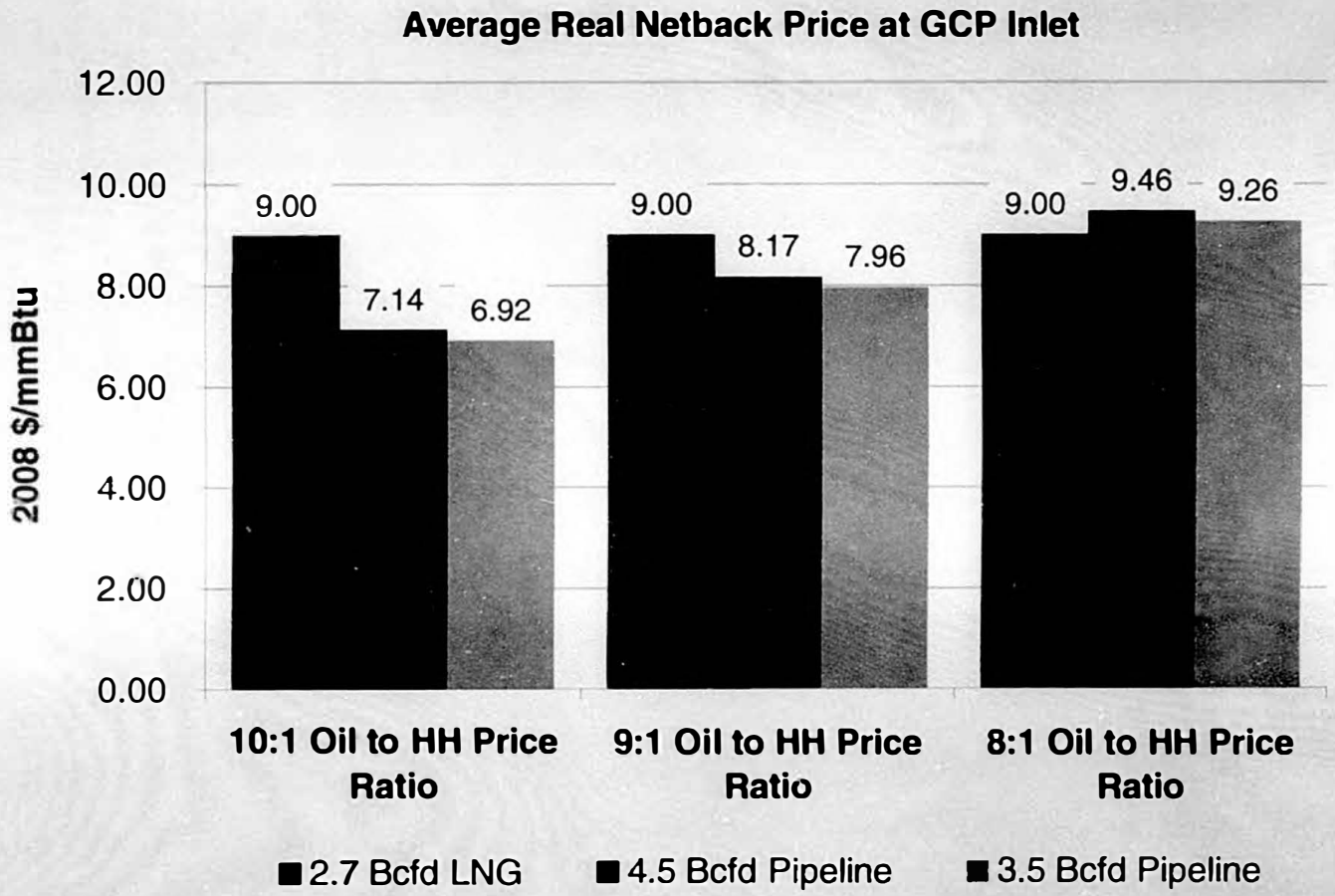
Netback Prices: $80/bbl Oil Price Cases

- Flat $80/bbl oil price (constant 2008 USD)
- 3 scenarios for oil/HH price ratio: 10:1, 9:1 and 8:1



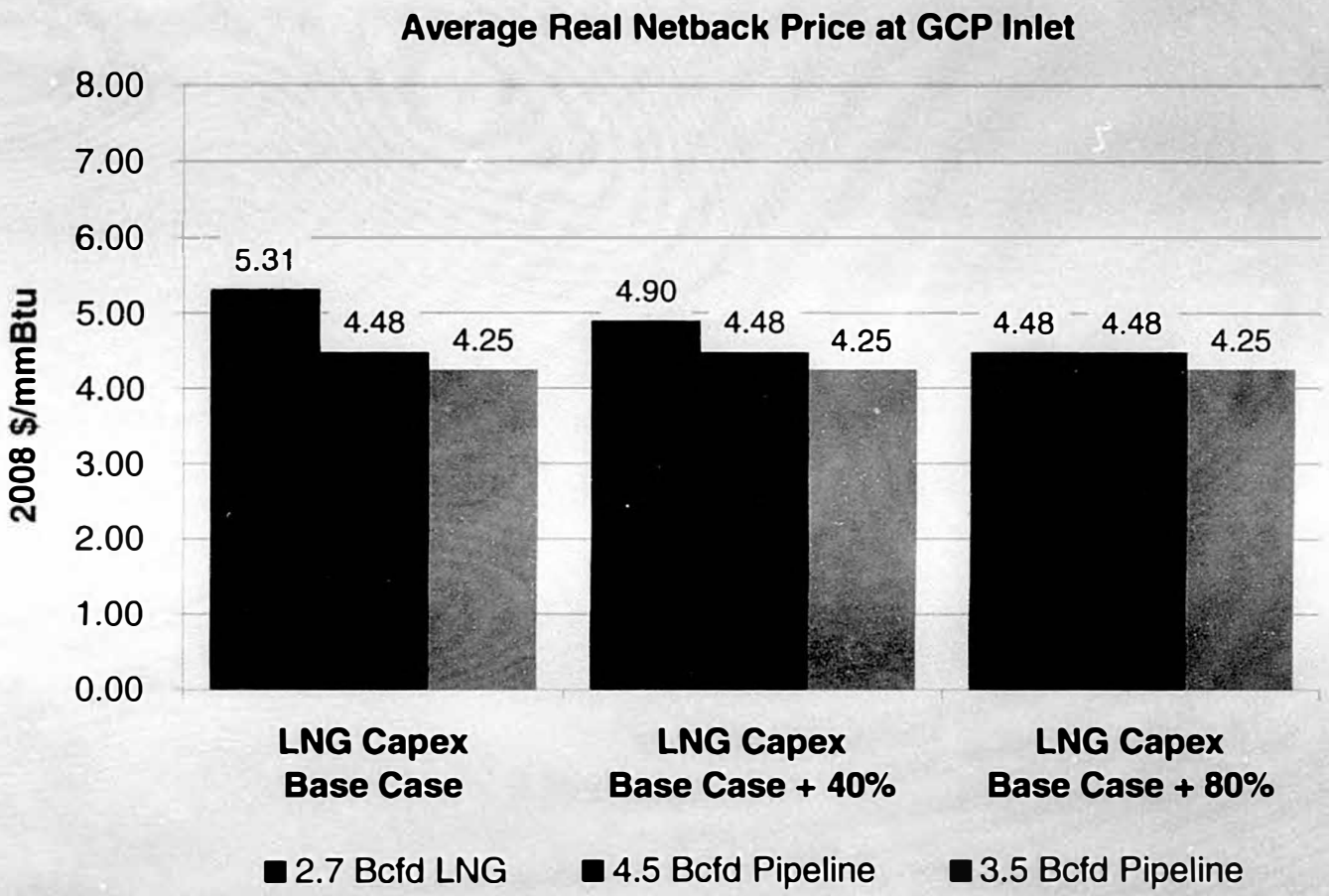
Netback Prices: $100/bbl Oil Price Cases

- Flat $100/bbl oil price (constant 2008 USD)
- 3 scenarios for oil/HH price ratio: 10:1, 9:1 and 8:1



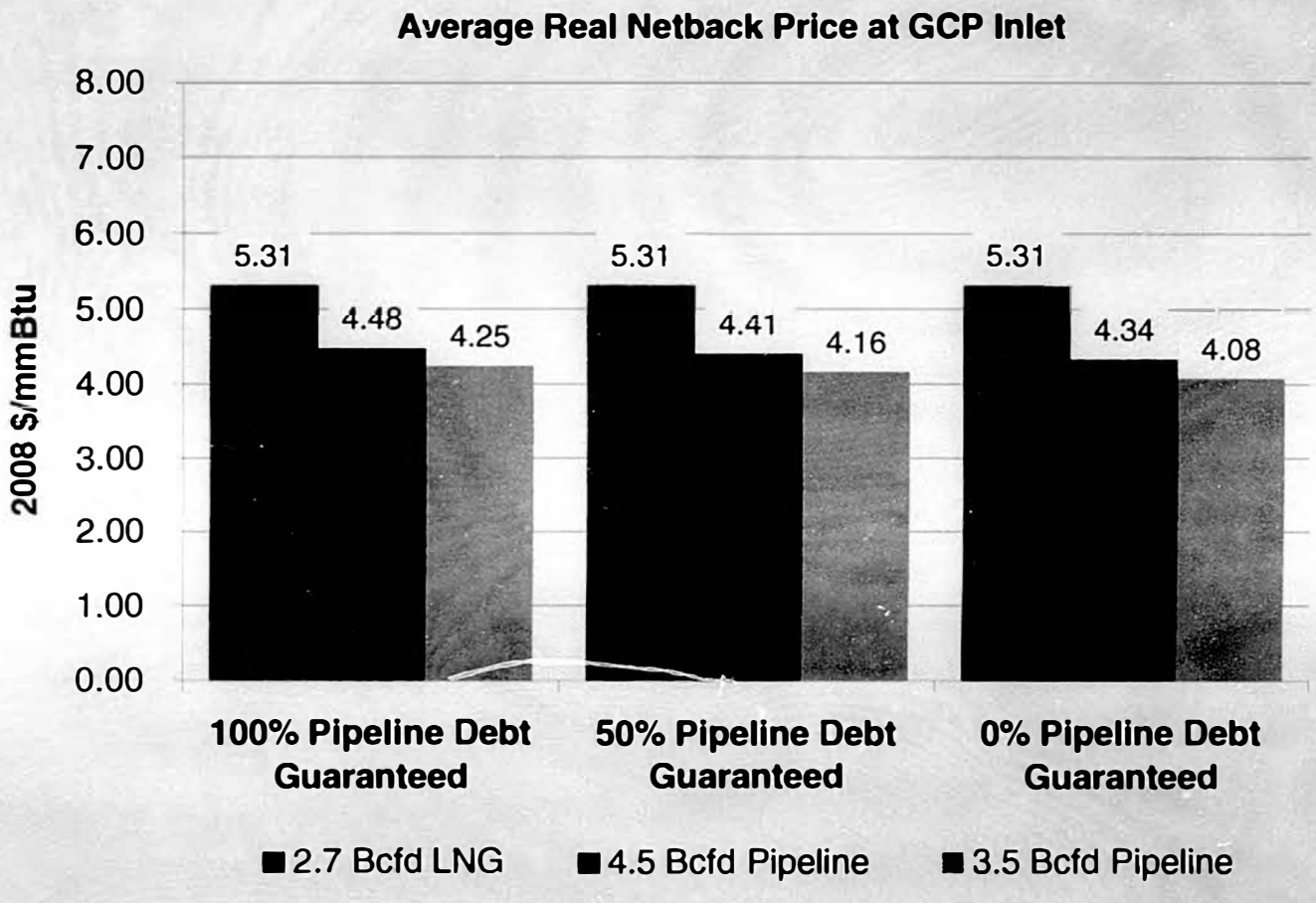
Netback Prices: LNG Capex Sensitivity

- Oil and HH prices from EIA 2008 Annual Energy Outlook – Reference Case
- 3 LNG Plant capital cost scenarios: Base Case, 40% increase and 80% increase



Netback Prices: Debt Guarantee Sensitivity

- Oil and HH prices from EIA 2008 Annual Energy Outlook – Reference Case
- Pipeline to Canada debt cases: 100%, 50% and 0% Federal guarantee



Netback Comparison Conclusions

- LNG generates higher netback prices than a Canadian pipeline under a wide range of oil and gas price assumptions
  - Gas Strategies High Case LNG price scenario, not used in this analysis, results in greater netback price advantage
  - High netback prices for LNG are preserved under substantial LNG plant cost increases
- Under comparable assumptions, Port Authority and EconOne analyses arrive at similar results

Netback Comparison Conclusions (cont'd)

- LNG Project achieves higher per-unit netback prices but lower absolute cash flow NPV, due to smaller gas volume
  - Port Authority views lower volume requirements as an advantage that enhances likelihood of success
  - LNG and pipeline to Canada should proceed – there are sufficient ANS gas resources for both
  - The first 2.7 Bcf/d volumes could be monetized at highest value via LNG, with subsequent expansions allowing for full ANS gas monetization
  - Stand-alone analysis of 2.7 LNG vs. 4.5 Pipeline ignores expansion potential

Financial Projections Disclaimer

The purpose of this presentation is to provide background information and assist the recipients hereof in obtaining a general understanding of the Alaska Gasline Port Authority's ("AGPA") project. This document is not intended to form a sole basis of any investment decision or other decision to participate in the AGPA project and should not be considered as a recommendation or invitation by AGPA to make such decision. Each recipient hereof must make (and will be deemed to have made) its own independent assessment and appraisal of AGPA and its project after making such investigation, as it deems necessary in order to determine its interest and independently (and at its own cost) to have formed its own opinions and views.

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7/22/08 SFIN - Comm Irwin

AGIA

The Alaska Gasline Inducement Act

Gas Pipeline Implementation

AGIA Gas Pipeline Implementation

- DNR, DOR, and the Governor's Office have roles in achieving a successful project
  - Monitor TC Alaska activities to ensure that it fulfills its license obligations
  - Work to ensure that the first open season is successful.
  - Monitor and audit pipeline expenditures.
  - Facilitate the issuance of environmental permits and other government approvals.

Conformance with License

- TC Alaska required to diligently pursue its work plan. A team will be assembled to ensure that it does so.
- The experts and "team" that is working to ensure compliance with the License terms will also seek out ways to work with TC Alaska to help ensure a successful open season.

"team" similar to team in RFA - Legal and consultant expertise

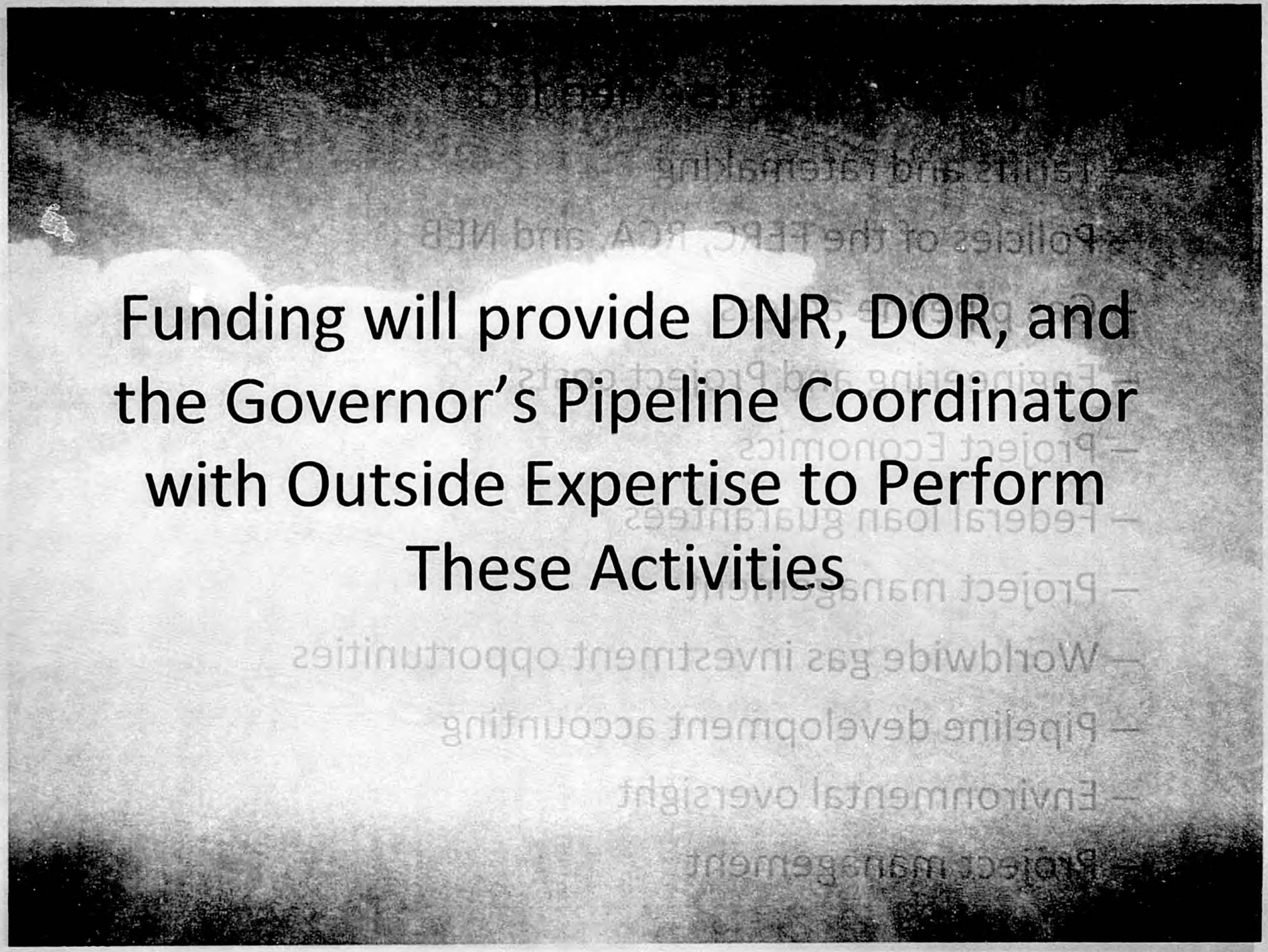
Commercial Developments and Conditions

- Implement AGIA's upstream inducements:
  - Royalty Valuation and RIV/RIK switching regulations
  - Possible fiscal certainty regulations
- Determine possible additional state inducements to help ensure success of the first open season

Team of - Technical / Financial / Commercial / Legal consultants

  - * "Resource assessments", manage State's relationship with TC Alaska, ongoing assessment of project costs and economic conditions
  - Examination of Alaska's gas fiscal regime

* Resource assessments - looking at available gas markets / consumers
Obligated to monitor TC project design / engineering / market conditions


Funding will provide DNR, DOR, and the Governor's Pipeline Coordinator with Outside Expertise to Perform These Activities

Types of Expertise Needed:

- Tariffs and ratemaking
- Policies of the FERC, RCA, and NEB
- Gas pipeline access
- Engineering and Project costs
- Project Economics
- Federal loan guarantees
- Project management
- Worldwide gas investment opportunities
- Pipeline development accounting
- Environmental oversight
- Project management

Budget

1. Conformance with license provisions	$7,500,000
2. Monitor commercial developments and conditions	$6,500,000
3. Oversight & Environmental Permit Coordination	$1,000,000
Total	$15,000,000

ALASKA STATE LEGISLATURE

Sen. Charlie Huggins, Chair
Sen. Bert Stedman, Vice Chair
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Sen. Lyman Hoffman
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State Capitol, Room 119
Juneau AK 99801-1182
907-465-3878
Fax: 907-465-3265
800-862-3878

Fourth Special Session
Twenty-Fifth Legislature

Senate Special Committee on Energy

Tuesday July 22, 2008

Senate Finance Room 532

1:00-3:00 p.m.

SB 3001 Approving AGIA License for Natural Gas Pipeline Project as proposed by TransCanada Alaska Company, LLC and Foothills Pipelines Ltd. (TC Alaska) to the State of Alaska

- **Alaska Gasline Port Authority: Export License Issues; Project Economics and Feasibility**

– Bill Walker, Project Director, AGPA

- Craig Richards, Attorney, AGPA

- Radoslav Shipkoff, Financial Advisor, Greengate LLC

Teleconference
Testimony – By Invitation

Juneau July 22, 2008 presented to SENR cmte

AGPA presentation re: Export Issues & Project Economics & Feasibility

REPORT TO THE STATE OF ALASKA LEGISLATURE ON FEDERAL LAW GOVERNING THE ISSUANCE OF AN EXPORT LICENSE FOR ALASKA NORTH SLOPE GAS

Prepared by

William Walker
Craig Richards

Walker & Levesque, LLC
731 N Street
Anchorage, Alaska 99501
(907) 278-7000

On Behalf of

Alaska Gasline Port Authority
411 4th Ave., Suite 200
Fairbanks, Alaska 99701
(907) 474-2011

This report analyzes the law relevant to the export of Alaska North Slope natural gas. As will be discussed, two federal actions are required. Unique to North Slope gas, the President of the United State ("U.S") must find the quantity, quality or price of the energy supplies available to U.S. consumers will not be effected by export. Additionally, for all domestically produced gas the Department of Energy ("DOE") must authorize export to any country for which U.S. does not have a free trade treaty (e.g., not Canada and Mexico).

The only authorization to export Alaska North Slope gas was to the Yukon Pacific Corporation ("YPC") in 1989. After the requisite Presidential finding, DOE authorized the export for sale to Japan, South Korea, and Taiwan a total of up to 250 million metric tons ("MMT") of liquefied natural gas ("LNG"), at an average annually volume of 14 MMT – a bit less than 2 billion cubic feet per day ("bcfd") – for a period of 25 years beginning on the date of the first delivery.[1] The only other authorizations to export U.S. gas to a country to which the U.S. doe not have a free trade treaty that the authors could locate involve the export of Cook Inlet natural gas from ConocoPhillips/Marathon facility in Kenai, meaning prior DOE authorizations to export Alaskan gas is the controlling law.

I. Legal Standards Under Which DOE Authorizes Export of North Slope Gas

A. *The Natural Gas Act*

Section 3 of the Natural Gas Act, 15 U.S.C. § 717b (2006) ("NGA"), provides the Secretary of Energy shall allow the export of gas unless he finds it will not be consistent with the public interest. If the export is to a country with which the Untied States has a free trade agreement covering natural gas, the export is deemed to be in the public interest and approved automatically.[2] If not, the DOE must consider whether the export is in the public interest.

"Section 3 creates a rebuttable presumption that a proposed export of natural gas is in the public interest and that the Department of Energy ("DOE") must grant such an application unless those who oppose the application overcome that presumption."[3]

DOE has issued a set of guidelines to help interpret Section 3, the goals of which "are to minimize federal control and involvement in energy markets and to promote a balanced and mixed energy resource system."[4] "In effect the guidelines represented a determination that it is in the public interest to let market forces, with a minimum of

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[1] *Order Granting Authorization to Export Liquefied Natural Gas from Alaska*, Department of Energy Order and Opinion No. 350, 1 F.E. 71,115, 71,144-45 (November 16, 1989), as amended by *Order Denying Requests for Rehearing and Modifying Prior Order for Purpose of Clarification*, Opinion and Order No. 350A , 1 F.E. 70,303, 71,273 (March 8, 1990).

[2] 15 U.S.C. § 717b (2006).

[3] *Order Granting Authorization to Export Liquefied Natural Gas from Alaska*, Department of Energy Order and Opinion No. 2500 at 43 (June 3, 2008).

[4] Order No. 2500 at 44.

regulatory constraints, define efficient energy production and consumptions."[5] Although the guidelines were originally promulgated for cases relating to the import of natural gas, DOE subsequently held the same policies will be applied to natural gas export applications.[6]

> The federal government's primary responsibility in authorizing imports [or exports] will be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market.[7]

DOE has also stated that "the principal focus of this agency's review of export applications in decisions under current delegated authority has continued to be the domestic need for the natural gas proposed to be exported."[8]

For YPC, and presumably for another North Slope export project, DOE set forth a three-pronged approach for evaluating domestic need.

> First, the DOE determines whether national or regional demand can reasonably be expected to exceed anticipated available domestic supplies over the term of the proposed export. If there is a reasonable expectation of demand in excess of available domestic supplies, the DOE determines the extent to which this excess demand can be met by other energy sources as or more efficiently than the proposed export. If there are sufficient alternative sources, the DOE analyzes whether there is any reason the public interest requires the proposed export, in particular, be used to meet the excess demand.[9]

As to the last prong, although "[d]omestic need is the only explicit public interest consideration identified by DOE in Delegation Order No. 0204-111 . . . the Department considers the potential effects of proposed exports on other aspects of the public interest. These other considerations include Alaskan interest, international effects, and the environment." DOE has in the past also looked at the effect of the export project on energy security.[10]

B. *ANGTA and the Reagan Findings*

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[5] Order No. 350, 1 F.E. at 71,121.
[6] Order No. 2500 at 44 (citing Order No. 1473 at 14 and citing Yukon Pacific, Opinion and Order No. 350, 1 F.E. 70,259 at 71,128).
[7] Order No. 2500 at 44 (quoting *New Policy Guidelines Relating to the Regulation of Imported natural Gas,* 49 Fed. Reg. 6684 (February 22, 1984) (brackets in original).
[8] Order No. 2500 at 44-45 (citing DOE Delegation Order No. 0204-111 which, although no longer in effect, directed in part that exports be regulated based on a consideration of the domestic need for the gas to be exported and such other matters as found in the circumstances of a particular case to be appropriate).
[9] Order No. 350, 1 F.E. at 71,129.
[10] *Id.* at 71,134.

The Alaska Natural Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. § 719j (2006) ("ANGTA"), provides that before exportation of Alaska gas "to any nation other that Canada or Mexico, the President must make and publish an express finding that such exports will not diminish the total quantity or quality and not increase the total price of energy available to the United States."

In 1998 President Reagan issued a finding that export of North Slope gas would not affect adversely the quantity, quality or price of the energy supplies available to U.S. consumers.[11]

> In particular, the President found that 'there exist adequate, secure, reasonably priced supplies of natural gas to meet the domestic demand of American consumers for the foreseeable future.' The president acted to let 'the marketplace undertake a realistic consideration of various options concerning Alaska natural gas' by allowing 'any private party to develop this resource' and setting 'up competition for this purpose.' The President's Findings stated that 'operation of market forces is the best guarantee that Alaska natural gas will be developed efficiently and that there will be incentive to find additional reserves.[12]

If an off-slope liquefied natural gas ("LNG") project sought a new export license, rather than update the one issued to Yukon Pacific Corporation ("YPC") in 1989, a new Presidential finding would likely be required. Note, however, that Congress granted the President broad power to limit natural gas exports (whether from Alaska or other locations) in the Energy Policy and Conservation Act of 2005, 42 U.S.C. § 6212 (2006), significantly diminishing the significance of an upfront Presidential finding for export of Alaska natural gas under ANGTA.[13]

AS to YPC's export license, DOE determined a North Slope export proposal will be viewed in light of ANGTA, and in fact a significant condition called the "ANGTA Condition" on the YPC export license prevented YPC from taking any action that would compel change of the ANGTA route or project timing.[14] DOE expressly stated, however, that the ANGTA condition did not apply to market decisions relating to access or development of North Slope reserves, and it instead related to increased costs of ANGTA infrastructure resulting from the export project.[15]

Since, in order to avoid the $10 billion liability associated with the ANGTA project legacy, TransCanada is no longer sponsoring an ANGTA project in Alaska, and the Alaska Natural Gas Pipeline Act of 2004, 15 U.S.C. § 720a(a) (2006) ("ANGPA),

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[11] *Presidential Finding Concerning Alaska Natural Gas*, 53 Fed. Reg. 999 (January 15, 1988).
[12] Order No. 350, 1 F.E. at 71,122 (emphasis eliminated).
[13] Section 6212 provides that the President may restrict exports of: "(1) coal, petroleum products, natural gas, or petrochemical feedstocks, and (2) supplies of materials or equipment which he determines to be necessary (A) to maintain or further exploration, production, refining, or transportation of energy supplies, or (B) for the construction or maintenance of energy facilities within the United States."
[14] Order No. 350, 1 F.E. at 71,128, 142.
[15] *Id.* at 71,142.

specifically authorized non-ANGTA Canadian highway projects, it would appear ANGTA no longer has relevancy to the exportation of North Slope gas and will be ignored in this analysis except as to the requirement of a Presidential finding.

III. Various Parties' Position Before DOE Regarding a YPC Export License

In analyzing various arguments that could be made today about why an export license should or should not be issued for North Slope gas, it is helpful to understand some of the positions of the same parties before DOE almost 20 years ago. Many arguments that would be made today have already been addressed and decided by the department.

A. *TransCanada*

TransCanada's predecessor sponsors of the Alaska Natural Gas Transportation System ("ANGTS") Canadian highway line, Alaskan Northwest and Foothills (hereinafter "TransCanada"), held the right to build the Alaskan portion of the highway line under ANGTA. It was the only major opposing party to the issuance of a YPC export license, and TransCanada prosecuted its case vehemently.

For instance, TransCanada said YPC's application did not contain enough information to be evaluated since YPC did not have gas purchase or resale contracts, sufficient details on project infrastructure, a completed environmental impact statement or a description of all the project's participants.[16]

TransCanada also asserted North Slope gas would be needed in the lower-48.

> They contend that the excess demand in the lower-48 states cannot be met by other energy resources as or more efficiently than by the proposed export volumes. The ANGTS sponsors assert that substitute fuels for North Slope gas, such as coal and oil, would be environmentally inferior to natural gas, which burns cleaner. They maintain that increasing dependence on coal and oil would contribute to ozone layer depletion in the atmosphere, 'acid rain', and the 'greenhouse' problem of global warming, and alternative gas supplies, such as development of Canadian frontier gas, would be more costly. In addition, they assert that the commitment of North Slope gas reserves to foreign interests would jeopardize national energy security by depriving the U.S. of a source of available reserves to offset the declining energy base in the lower-48 states, and by increasing U.S. dependence on oil imports.[17]

TransCanada additionally argued that an LNG project would impair completion of a Canadian line because "there are not enough proven reserves of gas on the North Slope

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[16] *Id.* at 71,125.
[17] *Id.*

to support both . . . projects."[18] The Canadian Government through the State Department shared similar concerns.[19] TransCanada actually sought a condition on the export license that its project have "first call on North Slope gas for delivery to the lower-48 states, if needed to meet contractual obligations and to preserve the project's economic viability[.]"[20]

Finally, TransCanada urged "that any final authorization issued be subject to suspension, modification, or revocation upon a showing that continuation of the proposed export is no longer in the public interest."[21] That is, TransCanada wanted YPC's export license to be subject to future reopening for additional public interest before export occurred. As will be seen, DOE rejected all of these arguments.

B. *State of Alaska and Exxon*

The State of Alaska intervened on behalf of an export license because of the benefits to Alaska that an off-slope pipeline would bring. However, it had no preference for an LNG versus Canadian project asserting that the market would decide which (or how many) systems get built, and opposed the imposition of conditions on export that would favor one gas development project over another.[22]

Exxon supported President Reagan's Findings for export and urged market-responsive development of Alaskan natural gas. It asked that DOE not impose terms and conditions "that would, in effect, place a stamp of approval on only one project or approach to development of Alaskan resources and discourage other projects or approaches."[23]

C. *Statoil*

Statoil, the Norwegian national oil company, stated its LNG exports and those of other over-seas suppliers would be able to meet any U.S. gas demand that might go unserved if North Slope gas was exported.

IV. DOE's 1989 Decision Authorizing Export of North Slope Gas

Unfortunately since 1989 little has changed in the debate about whether DOE should allow the export of North Slope gas. On the bright side, risks associated with seeking an export license have been significantly reduced given DOE has already addressed many of the arguments a party opposing export can make. It is thus useful to review in detail DOE's rationale for issuing YPC an export license under Section 3 of NGA.

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[18] *Id.* at 71,125.
[19] *Id.* at 71,126.
[20] *Id.*
[21] *Id.*
[22] *Id.*
[23] *Id.* at 71,126-27.

A. *Use of Economic Studies*

YPC and TransCanada both presented to DOE economic studies regarding when North Slope gas would become competitive in the lower-48. Quoting TransCanada, DOE held such studies were not useful in assessing the future of a particular project because the world was too complex and subject to change to forecast 12 or 20 years into the future.[24] "In fact, the inherent imprecision of using economic studies to predict the performance of a particular project is one reason that led to the shift from a government-mandated regulatory approach to a market-oriented approach that leaves private commercial parties with the flexibility to determine the basics of their projects."[25]

DOE also rejected out of hand that the need for North Slope gas in domestic markets is evidenced by the many economic models predicting North Slope gas will be used to meet domestic demand.

> Unlike the real world where private parties take a hard look at the actual costs of bringing competing supplies to market, an economic model selects the 'competitive' supply on the basis of assumptions . . . In the case of ANGTS, most economic models put the cart before the horse since they automatically assume North Slope gas will be used in the domestic market and then speculate when producers, pipeline sponsors, and financial institutions will agree that the market justifies the commitment of billions of dollars to provide the means necessary to make this 'a priori' modeling assumption feasible in the real world.[26]

However, although DOE did not find economic forecasts and studies useful in evaluating specific projects, DOE did find their information on supplies of various energy sources and anticipated demand helpful in evaluating domestic need as required under NGA Section.

B. *Domestic and Regional Need*

As previously stated, in looking at future domestic need over the life of the license, the DOE first looks at whether national or regional demand will exceed domestic supplies over the term of the proposed export. If so, DOE looks at whether excess demand can be met with alternative energy sources as efficiently as by the proposed export. Finally, if there are sufficient alternative energy sources, DOE analyzes whether for some other reason the public interest nonetheless requires the proposed exported gas to be used to meet excess domestic demand.

1. *Regional Need*

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[24] *Id.* at 71,129-30.
[25] *Id.* at 71,130.
[26] *Id.* at 71,129 n. 36. *See also* Order No. 350A , 1 F.E. at 71,270 (reaffirming that the inclusion of North Slope gas in various economic studies does not demonstrate a domestic need for it)

In YPC's case, DOE held regional need in Alaska was not a relevant issue for North Slope gas.[27] Interestingly, this is exactly the opposite position DOE took in granting the most recent extension for the Kenai export license. For Cook Inlet gas, DOE only looked at regional and not domestic supply and demand dynamics.[28] Given the Cook Inlet basin is maturing and will not be able to fully supply South Central – much less the Alaskan Interior – for the term of a Valdez export license (e.g., 25 years from first export), both domestic and regional supply and demand would likely be a factor if DOE revisits whether exportation of North Slope gas is in the public interest. Those advocating export of North Slope gas would argue that an LNG project would help meet projected gas shortfalls from Cook Inlet and would provide gas to new Alaskan markets in a manner more rapid than a project through Canada which would, if accepted by DOE, help the case for export.

2. *Domestic Need – Lower-48 Supply and What Reserves DOE Will Consider in its Analysis*

In analyzing future projected domestic supply of natural gas, DOE rejected TransCanada's argument that only proven reserves in the lower-48 could be counted as available supply. Instead DOE decided it would take a broad view of sources of gas that would be viewed as available to meet projected domestic demand. Thus for instance, DOE included in reserves estimates both unconventional (tight sands, Devonian shale, coal seams, enhanced recovery, etc.) and conventional gas, and for conventional gas included allowances for reserves growth and additional exploration.[29]

DOE also rejected TransCanada's argument that North Slope gas was needed because its cost of delivery to American consumers on a per molecule basis (i.e., in-field and transportation costs) would be lower than the cost of delivery of many of the other sources of gas included in DOE's estimate of national reserves.[30] Rather DOE thought the proper inquiry was whether "the costs of bringing some supplies to market may be so significantly higher than the anticipated market price that their use would be precluded in an efficient market."[31] So in looking at whether North Slope gas is needed domestically, the DOE will not compare the cost of delivery of North Slope gas vis-à-vis other gas supplies, but whether the non-North Slope supplies can be developed given anticipated market prices.

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[27] Order No. 350, 1 F.E. at 71,129 n. 35.

[28] DOE seemed to accept the applicants' assertions that there was no practical market for Cook Inlet gas in the U.S. because of the Jones Act, a lack of West Coast receiving terminals, and the prohibitive cost of reaching East Coast receiving terminals. Order No. 2500 at 14 ("The Applicants emphasize that the . . . Jones Act, would present a substantial regulatory hurdle. The Applicants also emphasize that there are not existing U.S. west coast LNG receiving terminals and the cost of shipping Kenai LNG to U.S. east coast or gulf coast LNG Receiving terminals would vastly exceed the cost of transporting the same LNG to Japan and/or another customer in the Pacific Rim due to the distances involved.").

[29] "Gas supply assumptions that focus solely on proved reserves and do not take into account the potential for reserve additions and production experience would severely distort forecasts of domestic need." Order No. 350, 1 F.E. at 71,131.

[30] *Id.* at 71,269.

[31] *Id.*

After reviewing various studies, DOE ultimately concluded that during the term of YPC's export proposal domestic need could be met by production from reservoirs in the lower-48 states without North Slope gas.[32] An argument could be made that DOE might not reach the same conclusion today,[33] although this is a technical decision that DOE would make only after it reviewed projected domestic supply and demand as it did in the Kenai and YPC decisions.

3. *Domestic Need – Alternative Supply*

Even though DOE said in 1989 that North Slope reserves were not needed domestically, DOE nonetheless stated that it is not necessary for the purpose of a NGA § 3 determination that DOE find all future U.S. natural gas demand will be met by production in the lower-48 states. DOE may also look to alternative supplies, particularly gas imports. This includes whether import of LNG from overseas (e.g., East Coast imports), when combined with North American supply, will be sufficient to meet domestic demand without North Slope gas.[34]

4. *Domestic Need – Public Interest of Domestic Use of North Slope Gas Rather than Available Alternative Supply*

After examining whether lower-48 and alternative supplies are sufficient to meet domestic demand, DOE's next considers whether there is a public interest in the North Slope gas proposed to be exported (rather than other energy supplies) being used to meet any anticipated demand in excess of domestic supply. Harmonizing its NGA§ 3 analysis with ANGTA Presidential finding requirements, DOE looked at whether the proposed project's export of North Slope gas would have an impact on matters of supply, price and quality of domestic gas.

a. Quantity

A proposed export of North Slope gas will adversely affect the quantity available to American consumers only if it will cause available domestic supplies to be inadequate. Since DOE concluded at the time there were adequate lower 48 and alternative supplies, DOE determined an export of about 2.0 billion cubic feet per day from Alaska would not adversely affect American consumers.[35] Additionally, DOE said in the context of global

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[32] *Id.* at 71,130-32.

[33] For instance, in 2004 when ANGPA was passed, it was the "sense of Congress" that "gas delivered from Alaskan North Slope will not displace or reduce the commercial viability of Canadian natural gas produced from the Mackenzie Delta or production from the 48 contiguous States." 15 U.S.C. § 720l (6) (2006). In support of that proposition, it was also the sense of Congress both that "natural gas production in the 48 contiguous States and Canada will not be able to meet all domestic demand in the coming decades" and "Federal and State officials should acknowledge that the smaller scope, fewer permitting requirements, and lower cost of the Mackenzie Delta project means it will most likely be completed before the Alaska Natural Gas Pipeline." 15 U.S.C. § 720l (2) and (4) (2006).

[34] Order No. 350, 1 F.E. at 71,134-35.

[35] *Id.* at 71,134.

energy interdependence it cannot necessarily be concluded that export of gas would diminish that available to American consumers.

> [W]ith respect to North Slope gas, it would be unduly simplistic to conclude that exports will necessarily diminish the quantity of energy available to American consumers. In this case, the alternative to exporting North Slope gas may be that it remains undeveloped, and therefore available to no one; conversely, exporting such gas may make available on the American market gas from foreign sources that would otherwise have gone to the Pacific Rim.[36]

Thus even if domestic and alternative supplies of gas were projected to be inadequate over the term of the license, export would still be authorized if it was demonstrated that export would not diminish gas available to American consumers. This might be because, for instance, the gas would remain undeveloped without export, export of Alaskan gas would free up other supplies that would be made available to U.S. markets, or an export project would open the North Slope basin to exploration that would in turn result in additional gas being available to go to U.S. markets (either via LNG or a line through Canada).

b. Quality

In looking at the impact on the export of North Slope gas on the "quality" of energy available to American consumers, DOE focused on arguments made by TransCanada regarding the effects of export on the environment and U.S. energy security. DOE did not believe export of natural gas from the North Slope would lead to the use of less environmentally friendly energy sources (e.g., coal).[37]

DOE also rejected TransCanada's argument that export of North Slope gas would increase imports and thereby decrease energy security on the grounds that energy security must be viewed in global terms and the development of North Slope gas would contribute to the overall performance of the North American energy market.[38] "DOE believes that true energy security lies in encouraging the most efficient operation of the North American and global energy market."[39]

c. Price

In performing the public interest analysis and looking at whether North Slope gas should not be exported, notwithstanding there are sufficient projected lower-48 or alternative supplies, DOE will consider whether American consumers will pay more than they would if North Slope gas was not exported.

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[36] *Id.* at 71,134.
[37] *Id.* at 71,135.
[38] *Id.*
[39] *Id.*

> In general, conditions in the domestic market will establish the price for whatever natural gas is used to meet domestic need, regardless of the source of that gas. Neither North Slope gas nor any other specific supply will be the tail that wags the market price of natural gas. The export of a particular gas supply, such as North Slope gas, would exert upward pressure on the market price only if there were not adequate alternative supplies of energy to meet domestic need at a market-responsive price. Even then, the export would exert upward pressure only if the costs of producing and delivering the exported gas to the domestic market would be less than the costs of the energy supplies actually used to meet the marginal demand.[40]

In YPC's case, DOE felt export of North Slope gas would not have an impact on domestic prices, and found the presented economic studies "did not constitute the substantial evidence necessary to overcome the DOE's analysis of the fundamental market conditions, the section 3 presumption in favor of export approval, and the President's Finding."[41]

B. Other Public Interest Considerations

In addition to the NGA § 3 analysis relating to domestic need for North Slope gas, DOE considered a number of other public interest factors.

1. *Export's Impact on North Slope Exploration and Development*

TransCanada indicated that the proposed export of North Siope gas might result in the non-production of some North Slope gas and questioned whether competition will spur exploration for and development of North Slope gas.[42] DOE disagreed and stated an export project would spur development of the 100 + trillion cubic feet of stranded proven and potential gas reserves.

> Thirteen years have passed since the passage of ANGTA and no North Slope natural gas has been produced commercially. The introduction of competition will encourage a realistic assessment of the potential of North Slope natural gas and its early and more efficient development. It also will provide an incentive for discovering and developing additional reserves of natural gas on the North Slope.[43]

2. *Alaskan Interests*

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[40] *Id.*
[41] *Id.* at 71,136.
[42] *Id.* at 71,137.
[43] *Id.*

Alaska Gasline
PORT AUTHORITY

Presentation to
Alaska State Senate

July 22nd, 2008

Juneau, Alaska

Alaska Gasline
PORT AUTHORITY

1. LNG Export Issues

Export License – Overview of Federal Law

- ANGTA requires Presidential finding before North Slope gas can be exported
- NGA requires DOE to authorize all U.S. gas exports
  - Export approval for Canada and Mexico automatic
  - DOE has only addressed export for Kenai and YPC
- 1969 to present DOE authorized Kenai export
- 1990 DOE finalized authorization for YPC to export 14 MMT (~1.9 bcf/d) for 25 years starting at first delivery

Export License – DOE's Market Driven Approach

- NGA creates rebuttable presumption that license will issue
- DOE's stated goal
  - let market forces define efficient energy markets
  - minimize federal involvement

"Competition in world energy markets promotes the efficient development and consumption of energy resources, as well as lower prices, whereas economic distortions can arise from artificial barriers to the free flow of energy resources. Accordingly, the DOE believes that the public interest in free trade generally supports approval of proposed exports." (DOE Order 350).

Export License – Domestic Need

DOE uses a three pronged public interest analysis to determine if the presumption to allow export has been overcome:

1. *Will national or regional demand exceed available domestic supply?*
2. *If insufficient domestic supply, are alternative supplies available to meet demand?*
3. *If there is sufficient domestic or alternative supply, does some other public interest overcome presumption of export?*
    a. Environment
    b. Alaskan interests
    c. Energy security
    d. International effects
    e. Impact on North Slope development
    f. Lower-48 natural gas prices

Source DOE Order No. 350 (YPC); DOE Order No. 2500 (2008 Kenai).

Export License – Domestic Need

1. Will domestic demand exceed available domestic supply?

- U.S. supply and demand over term of license estimated
- DOE takes a broad view of available U.S. reserves, including allowance for
    - reserves growth
    - new discoveries
    - non-conventional gas resources
        - E.g., Tight sands, shale, coal seams and enhanced recovery
- In 1989 DOE said domestic supply sufficient to meet anticipated U.S. need
- Today, domestic reserve additions from shale gas have potential to fulfill domestic need

Export License – Alternative Supply

2. Are alternative supplies available to meet demand if DOE projects insufficient domestic supply?

- DOE looks at availability of gas for import including LNG from overseas
- "unduly simplistic to conclude that [ANS] exports will necessarily diminish the quantity of energy available to U.S. consumers"
  - Alternative may be ANS gas is stranded
  - Export will open ANS to exploration and development
  - ANS LNG to Asia may free up other LNG to go to U.S.
- DOE recognizes gas markets are global
- Today, increased global LNG production and U.S. receiving capacity means alternative supplies are available

Export License – Public Interest Factors

3. If there is sufficient supply, does some other public interest overcome presumption of export?

Energy Security

- "DOE believes that the true energy security lies in encouraging the most efficient operation of the North American and global energy markets."
- Also since 2005 President has broad authority to stop export of all gas

International Effects

- Competition promotes efficiency and lower prices
- Impact on Asian balance of payments and trade imbalances significant

Export License – Public Interest Factors

U.S. Prices

- DOE wants to insure exporting ANS gas will not drive up lower-48 natural gas prices
- DOE does not consider
  - Various projections anticipating ANS gas will go to U.S.
  - Economic studies of Canadian vs. LNG project
- Rather DOE asks whether available non-ANS gas can be delivered given anticipated prices?
- Answer in 1990 and now is yes!
  - By 2030 about half of U.S. demand will be met with non-conventional gas (EIA Annual Energy Outlook 2008)
  - Non-conventional gas, as marginal supplier, will set price
  - ANS gas to the U.S. will not change the cost of meeting marginal demand or thus price to U.S. consumer

Export License – Public Interest Factor (Price)

Impact on North Slope development

- DOE unsympathetic to argument that proven ANS reserves needed for Canadian pipeline
  - Canadian project does not have right to ANS reserves
  - The market will decide
- DOE noted 13 years had passed since ANGTA and the ANS gas remained undeveloped
- DOE said export will encourage
  - Assessment of ANS potential
  - Earlier development of ANS proven reserves
  - Discovery and development of additional ANS reserves

Export License – Looking Forward

- AGPA strongly believes
  - YPC license will be honored, and
  - Regardless a new license would issue
- YPC license update
  - DOE stated YPC could not pass project costs on to U.S. consumers
  - Filing with DOE all contracts for acquisition, transportation, and sale of gas precondition to export
- New license
  - Presidential finding
  - DOE will undertake same export analysis it did for YPC
  - Circumstances have not materially changed

2. LNG Project Economics

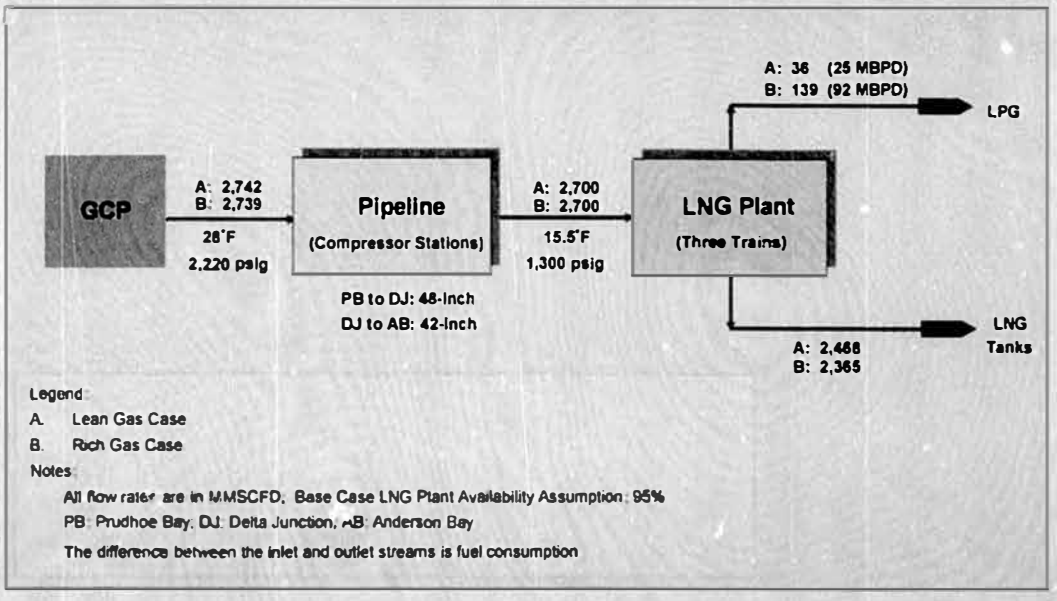
LNG Project Analyses Presented to Legislature

- Economics of an LNG project vs. Pipeline to Canada
  - Port Authority: LNG more attractive than pipeline to Canada
  - Administration: LNG less attractive than pipeline to Canada
  - EconOne: LNG either more or less attractive, depending on assumptions
- Assumptions used are key:
  - capital cost of project components
  - difference in prices in Asian LNG market and Alberta gas market

  ⇨ different assumptions result in different netback prices

Port Authority Project

OVERALL FLOW SCHEME (Gas Compositions Year 2007 Winter Conditions)



Capital Cost Assumption Comparison

	Port Authority	Administration (P50)
Pipeline from Prudhoe Bay to Valdez	$13.2 billion	$11.4 billion
LNG Facilities	$8 billion	$14 billion

- 2.7 Bcfd LNG Project
- Cost estimate includes EPC costs, owner's costs during construction, and development costs
- escalation after 2007, property taxes during construction, and AFUDC are excluded

⇒ Administration uses substantially higher capital costs for the LNG Facilities

LNG Plant Capital Cost Estimates

Bechtel's "bottom-up" EPC cost estimate for LNG Plant:

- 2007 EPC cost estimate
- Extensive technical work
- Site-specific and project-specific conditions accounted for
- Proven, well-established plant design
- Fewer cost uncertainty factors than the pipeline

Administration's "top-down" LNG plant capital cost:

- Not developed from detailed project-specific technical work
- Derived by "data mining" of database of other LNG projects
- Generic cost-per-ton estimate applied to Anderson Bay

Note: Administration's methodology as described in Chapter 4, Section E.3 of the Written Findings and Determination by the Commissioners of Natural Resources and Revenue for Issuance of License under AGIA

LNG Plants Are Not the Same

- LNG projects are not the same: project location, project scope, feed gas composition and other project-specific factors make valid project comparisons difficult
- Variations in LNG plant scope and configuration:
  - many LNG projects include cost of gas treatment
    - liquid slug removal
    - condensate stabilization
    - acid gas removal
    - water removal
    - mercury removal
  - for the Alaska LNG project, gas treatment occurs at the GCP on the North Slope

LNG Plants Are Not the Same (2)

- Feed gas pressure
  - high pressure feed gas from the pipeline to Valdez
  - significant reduction in the cost of compression at the Valdez LNG Plant
- Ambient temperatures at project site
  - most LNG projects in warm climate
  - Valdez plant benefits from cold climate
- Site preparation, marine terminal facilities, etc: highly location-specific
  - Bechtel estimate based on Anderson Bay site
- Different EPC market conditions for different projects

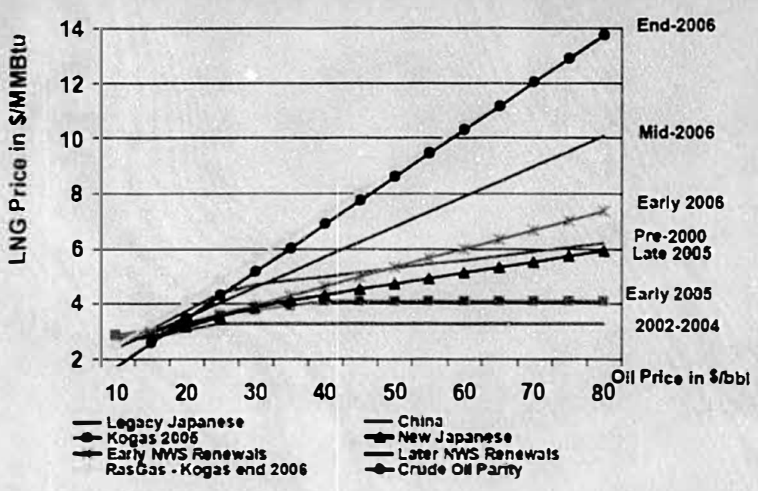
"Bottom-Up" Approach is Preferable

- Limitations of "database mining" approach should be recognized
  - inherent difficulty in comparing projects of different scope, in different locations and subject to different conditions
- Mixing the "top-down" approach for LNG Plant with a "bottom-up" approach for the pipeline:
  - introduces an inconsistency in methodologies
  - validity of economic comparison between the two projects is compromised

Asian LNG and North American Gas Prices

- Asian LNG Prices:
  - bilateral, long-term sales and purchase agreements
  - price formulas with oil price indexation provisions
  - pricing provisions reflect market supply and demand dynamics at time of contract execution
  - at each point in time, multiple active supply contracts, negotiated at different times, with varying pricing provisions
- North American gas prices
  - price discovery is driven by a gas spot market at regional trading hubs (e.g., Henry Hub, AECO, etc.)

Evolution of Asian LNG Prices



Source: Gas Strategies Consulting

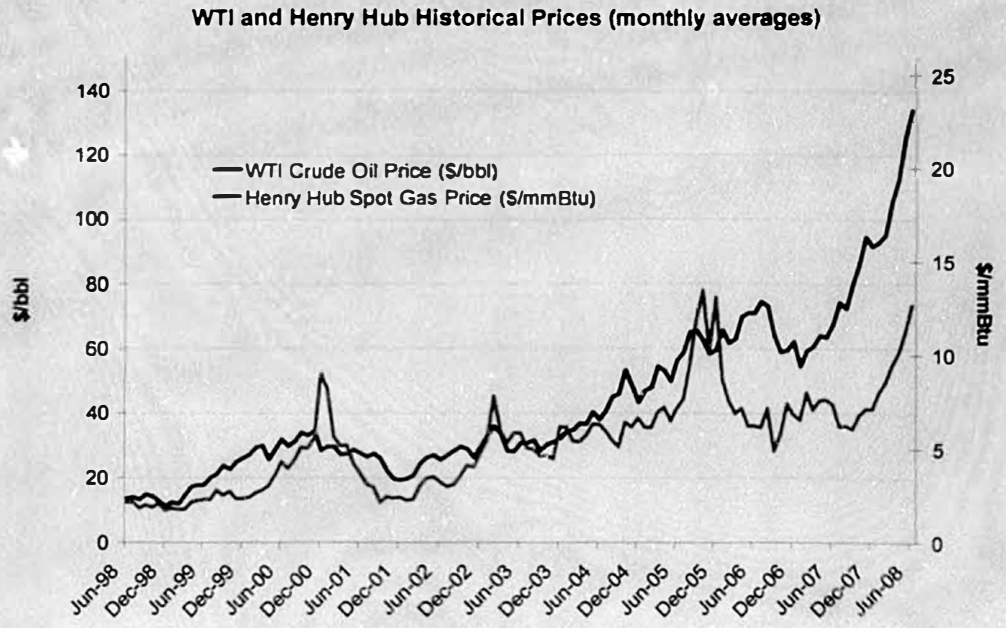
- Recent LNG sales contracts in the Asian LNG market have been executed on terms highly favorable to sellers
- Kogas contract from late 2006: LNG price formula reportedly above parity with oil

Price Assumption for Alaska LNG (E. Asia DES)

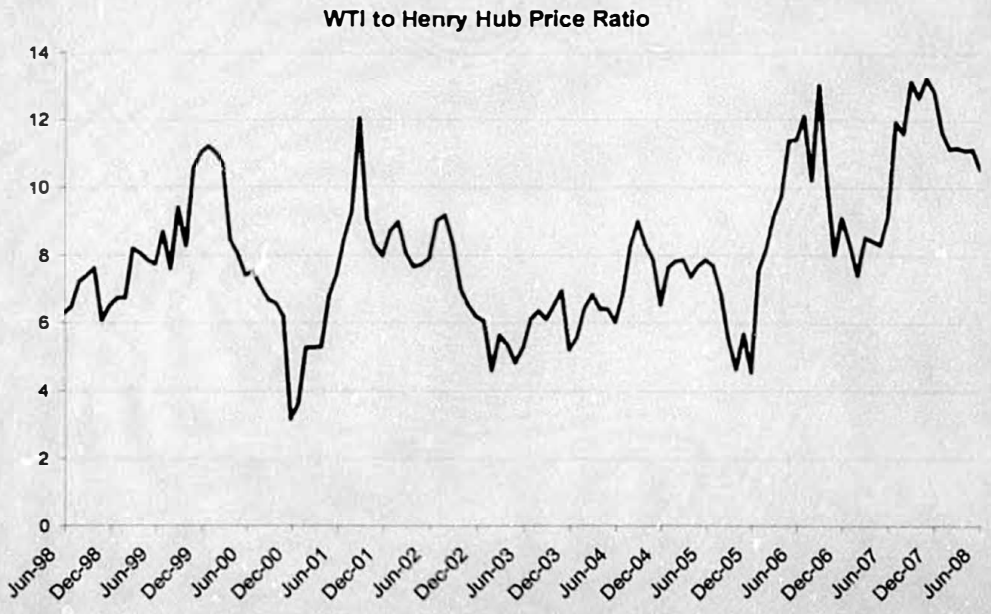
- Gas Strategies' report to the Administration projects the following price scenarios for Alaska LNG (LNG Price in $/mmBtu, Oil Price in $/bbl)*
  - Base Case: LNG Price = 0.1485 * Oil Price + 0.90
  - High Case: LNG Price = 0.162 * Oil Price + 1.00
  - Low Case: LNG Price = 0.9 * Henry Hub – 0.50
- The Port Authority assumptions:
  - current highly seller-favorable market expected to swing back towards relatively more buyer friendly terms
  - Gas Strategies' Base Case forecast appears reasonable and has been incorporated in Port Authority analysis
  - High Case generates very favorable results for the Alaska LNG Project

* Note: For simplicity, this presentation uses the term "Oil Price" interchangeably with JCC, Brent and WTI prices. In a detailed analysis, the price variations between different crude prices should be taken into consideration.

North American Prices: WTI and Henry Hub



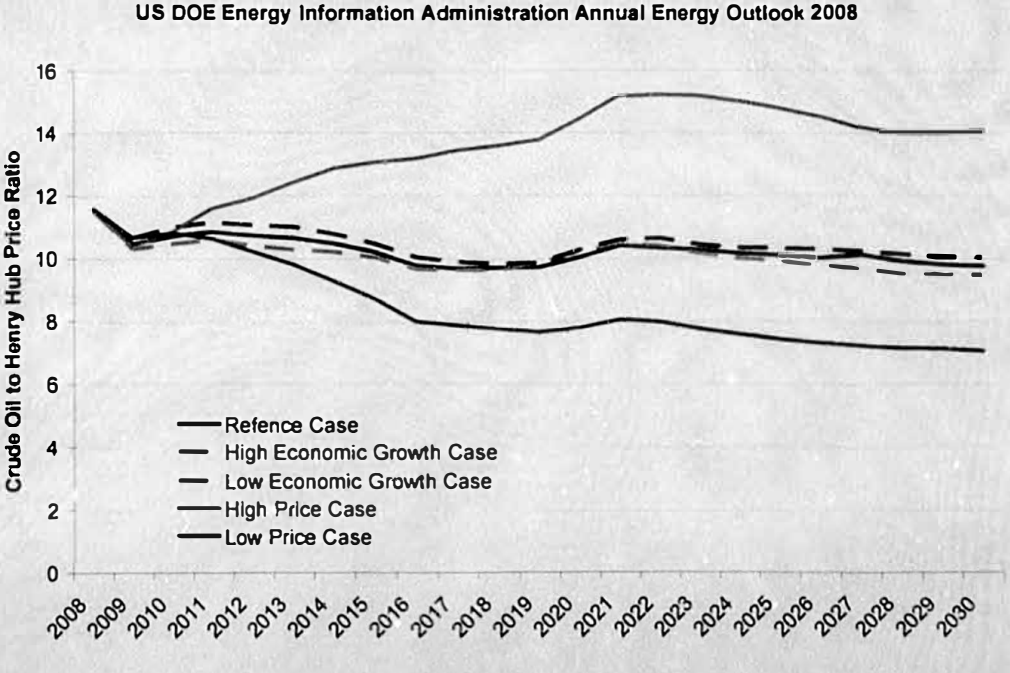
WTI and Henry Hub Price Ratio



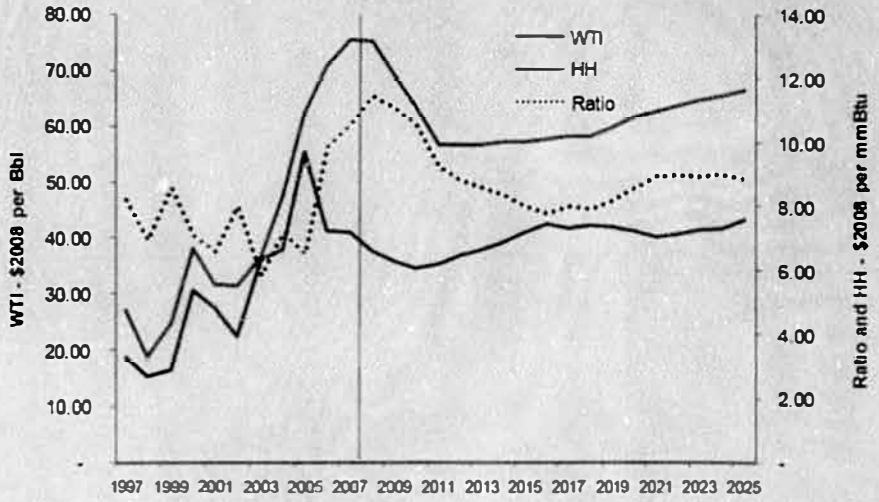
Significance of Assumed Oil/Henry Hub Price Ratio

- Higher crude oil to Henry Hub price ratio means:
  - differential between Asian LNG prices and North American gas prices is higher
  - netback prices from LNG Project are relatively more attractive
- Recently observed price ratios are significantly higher than historical values
- What is the appropriate assumption for assumed crude oil to Henry Hub price ratio for the future?

DOE EIA Forecast Price Ratios (AEO 2008)



Administration's Forecast (Wood Mackenzie)



Source: Commissioners' Findings, Appendix N: Wood Mackenzie Gas and Power Long Term Outlook Briefing Paper

Price Ratio Forecast Comparison

- Crude oil to Henry Hub price ratios:
  - historical average 1998-2008: 8.1
  - DOE EIA Annual Energy Outlook 2008 (average 2008-2030):
    - Reference Case: 10.2
    - High Growth Case: 10.1
    - Low Growth Case: 10.5
    - High Price Case: 13.4
    - Low Price Case: 8.5
  - NYMEX futures market recent prices (average 2008-2016): 12.5
  - Wood Mackenzie (Administration's analysis)*
    - above 10 until 2011
    - decreases to around 8-to-9 from 2012

* Source: Commissioners' Findings, Appendix N: Wood Mackenzie Gas and Power Long Term Outlook Briefing Paper

Netback Comparison: Capital Cost Assumptions

	2007 billions	Source of Assumption
Development Phase Costs:		
LNG Project	0.65	Administration
Pipeline to Canada Project	0.69	Administration
Execution Phase Capital Costs:		
GCP for 2.7 Bcfd LNG Project	4.9	Administration
GCP for 4.5 Bcfd Pipeline Project	8.2	Administration
GCP for 3.5 Bcfd Pipeline Project	6.4	Administration
2.7 Bcfd Pipeline Prudhoe Bay–Valdez	11.1	Administration
4.5 Bcfd Pipeline Prudhoe Bay–Border	10.5	Administration
4.5 Bcfd Pipeline Yukon-Alberta	12.4	Administration
3.5 Bcfd Pipeline Prudhoe Bay–Border	9.7	Administration
3.5 Bcfd Pipeline Yukon-Alberta	11.4	Administration
LNG Facilities	7.8	Bechtel/Port Authority

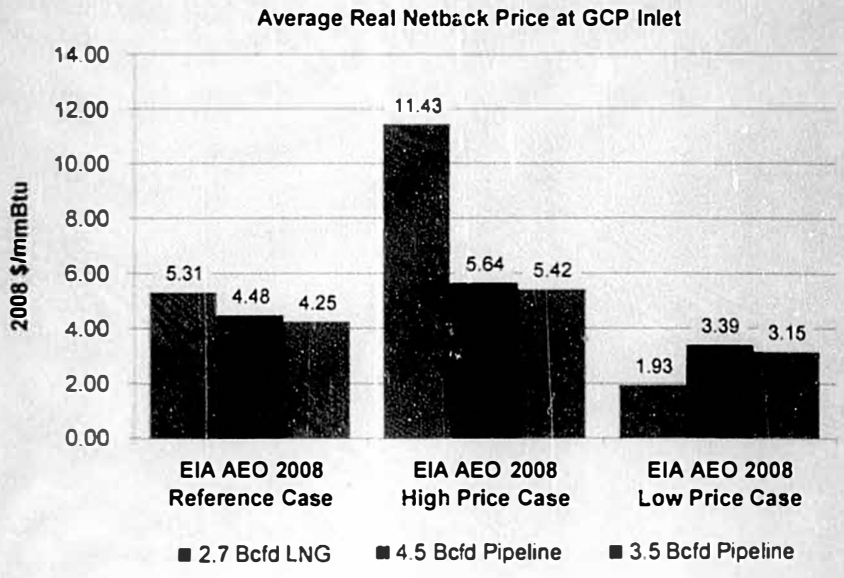
Netback Comparison: Other Assumptions

	Assumption	Source of Assumption
D:E for Tariff (Pre-Completion)	70:30	Admin/TCPL
D:E for Tariff (Pre-Completion)	75:25	Admin/TCPL
Return on Equity	14%	Admin/TCPL/EconOne
Cost of Guaranteed Debt	5.50%	EconOne
Cost of Non-Guaranteed Debt	7.00%	EconOne
LNG Plant Availability Factor	95%	Bechtel
LNG Sales Price (DES E. Asia)	0.1485*JCC+0.90	Administration
LNG Shipping Costs (incl. fuel and boil-off)	~$1.10/mmBtu [1]	MOL / PA
Pipeline Gas HHV	1133 Btu/scf	Administration
Capex Escalation	4% p.a.	Administration
Opex Escalation	3% p.a.	Administration

Notes: [1] Nominal dollars in 2019

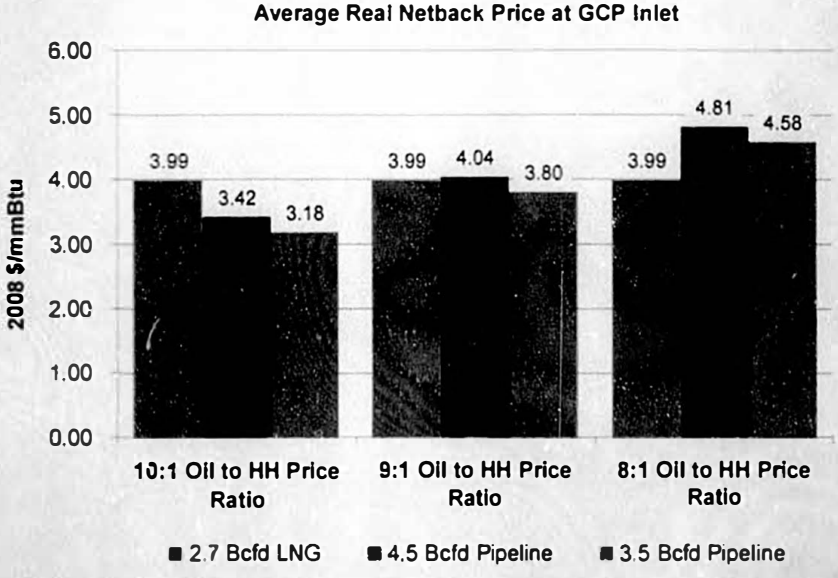
Netback Prices: EIA Price Forecasts

- Oil and HH prices from DOE EIA's 2008 Annual Energy Outlook
- 3 price scenarios shown: Reference Case, High Price and Low Price Cases



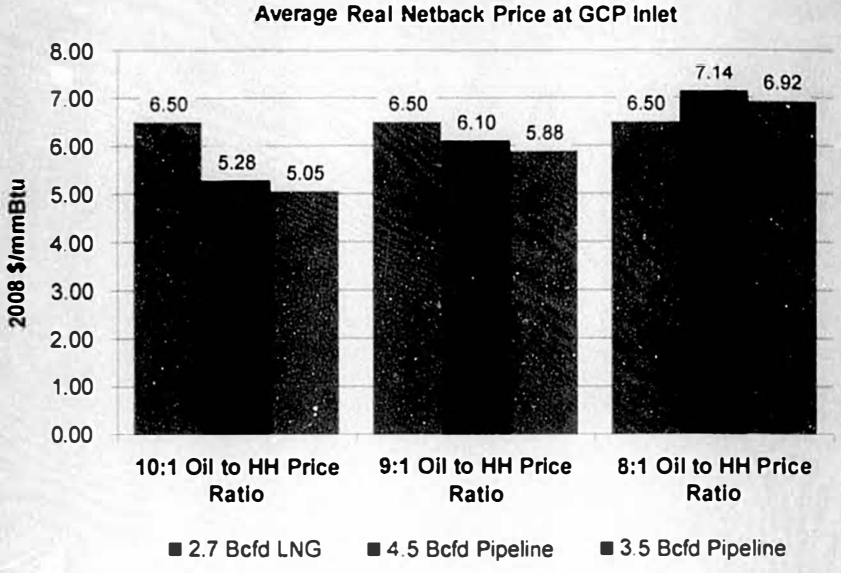
Netback Prices: $60/bbl Oil Price Cases

- Flat $60/bbl oil price (constant 2008 USD)
- 3 scenarios for oil/HH price ratio: 10:1, 9:1 and 8:1



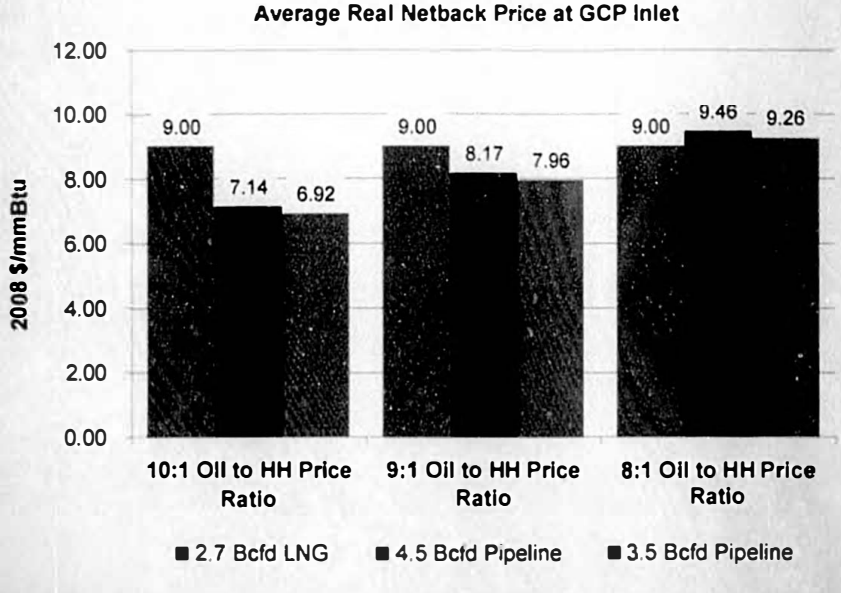
Netback Prices: $80/bbl Oil Price Cases

- Flat $80/bbl oil price (constant 2008 USD)
- 3 scenarios for oil/HH price ratio: 10:1, 9:1 and 8:1



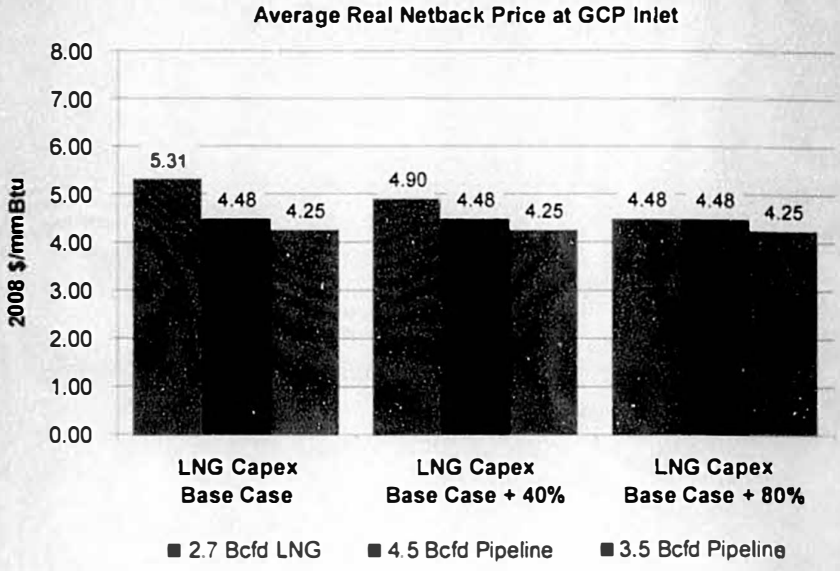
Netback Prices: $100/bbl Oil Price Cases

- Flat $100/bbl oil price (constant 2008 USD)
- 3 scenarios for oil/HH price ratio: 10:1, 9:1 and 8:1



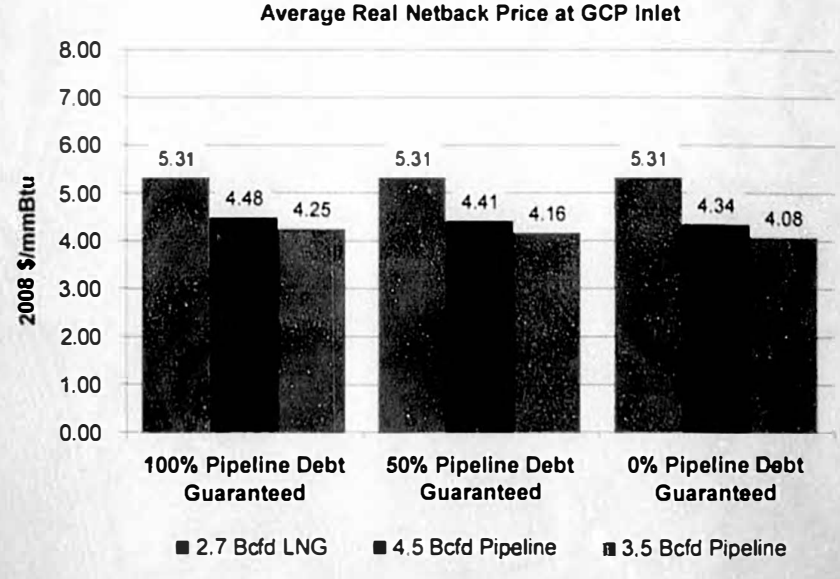
Netback Prices: LNG Capex Sensitivity

- Oil and HH prices from EIA 2008 Annual Energy Outlook – Reference Case
- 3 LNG Plant capital cost scenarios: Base Case, 40% increase and 80% increase



Netback Prices: Debt Guarantee Sensitivity

- Oil and HH prices from EIA 2008 Annual Energy Outlook – Reference Case
- Pipeline to Canada debt cases: 100%, 50% and 0% Federal guarantee



Netback Comparison Conclusions

- LNG generates higher netback prices than a Canadian pipeline under a wide range of oil and gas price assumptions
  - Gas Strategies High Case LNG price scenario, not used in this analysis, results in greater netback price advantage
  - High netback prices for LNG are preserved under substantial LNG plant cost increases
- Under comparable assumptions, Port Authority and EconOne analyses arrive at similar results

Netback Comparison Conclusions (cont'd)

- LNG Project achieves higher per-unit netback prices but lower absolute cash flow NPV, due to smaller gas volume
  - Port Authority views lower volume requirements as an advantage that enhances likelihood of success
  - LNG and pipeline to Canada should proceed – there are sufficient ANS gas resources for both
  - The first 2.7 Bcf/d volumes could be monetized at highest value via LNG, with subsequent expansions allowing for full ANS gas monetization
  - Stand-alone analysis of 2.7 LNG vs. 4.5 Pipeline ignores expansion potential

Financial Projections Disclaimer

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JUL 23 2008

3819 Locarno Drive
Anchorage, AK 99508-5021
15 July 2008

Senator Charles Huggins, Chairman
Senate Natural Resources Committee
State Capitol
Juneau, Alaska 99801

Dear Senator Huggins:

I often have found consultants to be "hired guns" who tend to report whatever the client wants to hear, and I doubt that many have visited the North Slope. The first 20 consultants' written reports to the companies for the TAPS (before being reorganized under the name Alyeska) pipeline were found to be internally inconsistent and inconsistent with one another. That caused the 4-year delay in the Department of the Interior's (DOI) granting the construction permit, during which time passage of the NEPA gave the environmental groups and the Natives leverage and the right to sue.

The TAPS original estimate of $900 million for construction of the hot-oil pipeline was made by company lease lawyers; one million per mile for the 800-mile pipeline, $100 million for the Valdez terminal (later found to be located on rotten rock), and zero for the conditioning plant at Prudhoe. 760 miles of the pipeline were to be buried. A more realistic original figure (1969 dollars) would have been on the order of about $5 billion, but the all-union craft requirement, required pipeline engineering, 5 years of inflation, and 427 miles (Alyeska, in retrospect, would have preferred 460 miles) of the pipeline above ground increased the Alyeska costs to about $9 billion. The 200-foot right-of-way (increased from the usual 50 feet) was granted to Alyeska, and I doubt that they would look very kindly to heavy equipment digging around close to the hot-oil pipeline for safety and environmental reasons. There also is no FEIS for the 360-mile area between Big Delta and the Canadian border, or for the 965-mile-long Canadian section.

The DOI, which wrote the stipulations for construction of and the monitoring of the Alyeska pipeline, possessed geologists and engineers who had walked and studied virtually every mile of the pipeline route during the quarter century prior to the construction of the pipeline. That gave the DOI a leg-up in writing the construction

stipulations and monitoring requirements. The State did not adopt these requirements for the gathering lines which are on State property, where the 206,000-gallon spill, and the other recent problems requiring replacement, have occurred. There the approach has been more the traditional one of clean up/repair/replace and cast blame.

Sincerely,

Max C. Brewer

Enclosure

cc: Senator Johnny Ellis
Representative Berta Gardner