

HB 3001

SB 3001

7/22/08

SPECIAL

SESSION

DOCUMENTS



STATE OF HAWAII
OFFICE OF HAWAIIAN AFFAIRS
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HONOLULU, HAWAII 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.

Honorable Lyda Green
July 18, 2008
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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.

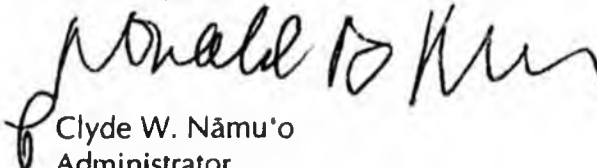
Based on these findings, I wish to inform you that OHA supports the development of the natural gas pipeline from Prudhoe Bay to Valdez together with a liquefied natural gas (LNG) facility to enable shipment of LNG to other domestic markets in the US, such as the West Coast and Hawai'i, and to the growing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



**Presentation to
Alaska State Senate**

July 22nd, 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

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

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

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



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

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

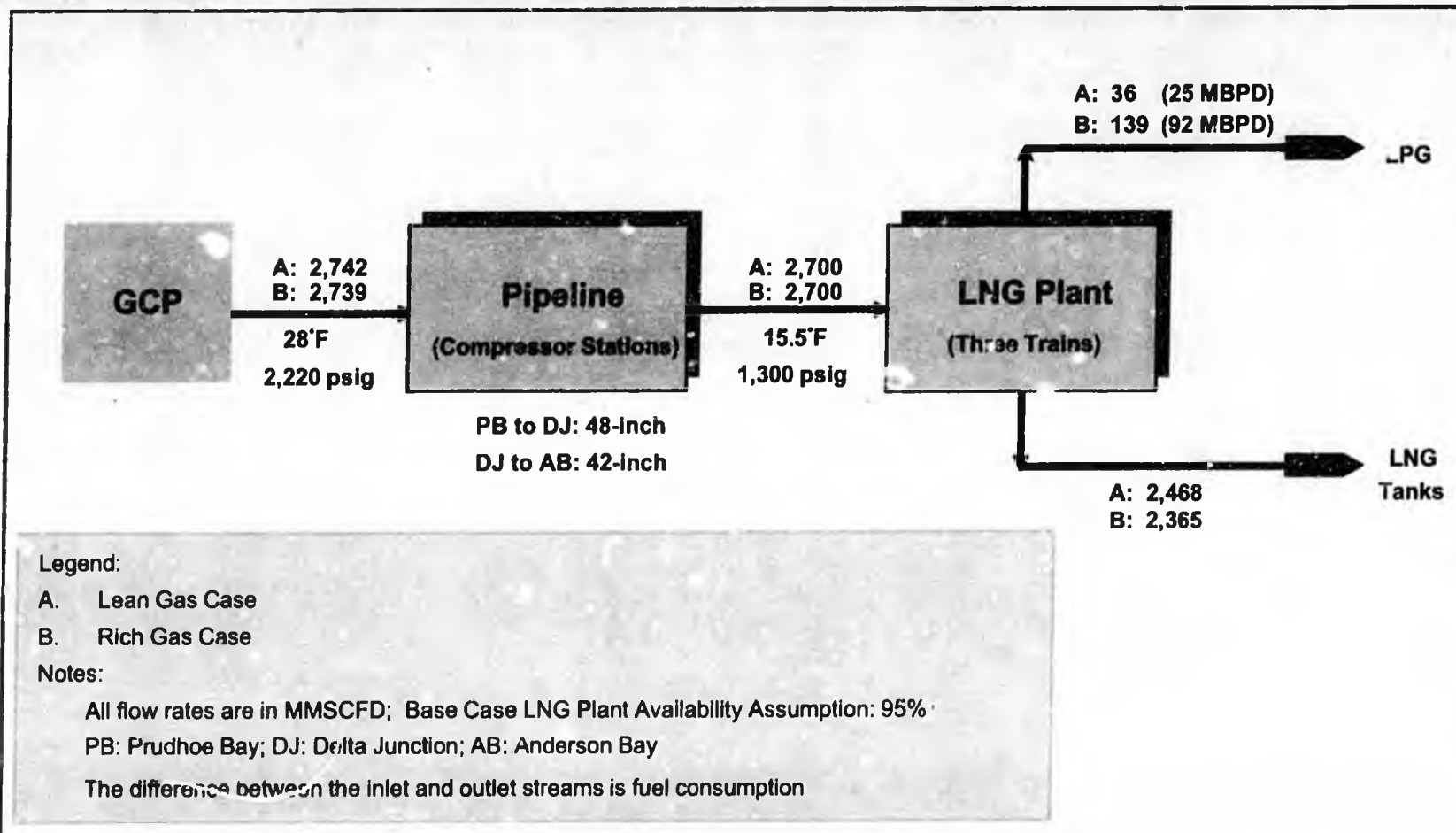


- Economics of an LNG project vs. Pipeline to Canada
 - Port Authority: LNG more attractive than pipeline to Canada
 - Administration: LNG less attractive than pipeline to Canada
 - EconOne: LNG either more or less attractive, depending on assumptions
 - Assumptions used are key:
 - capital cost of project 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

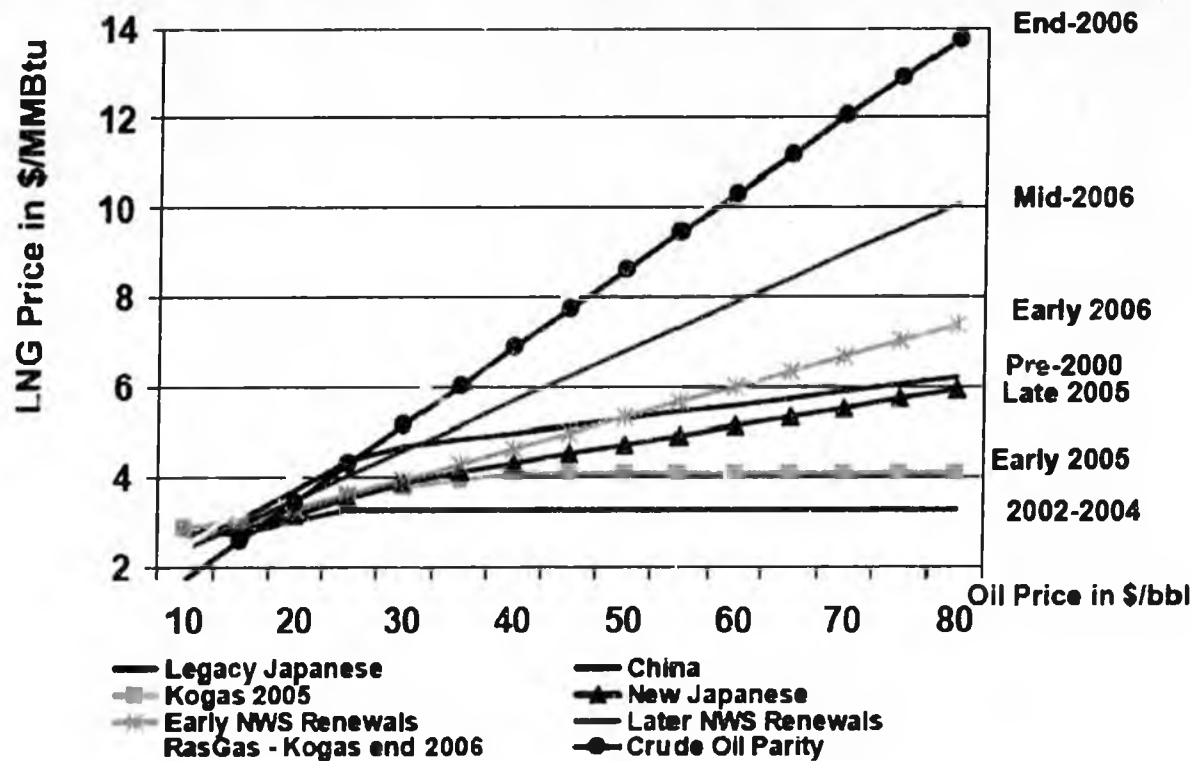
Asian LNG and North American Gas Prices



- 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 = $0.1485 * \text{Oil Price} + 0.90$
 - High Case: LNG Price = $0.162 * \text{Oil Price} + 1.00$
 - Low Case: LNG Price = $0.9 * \text{Henry Hub} - 0.50$

- 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

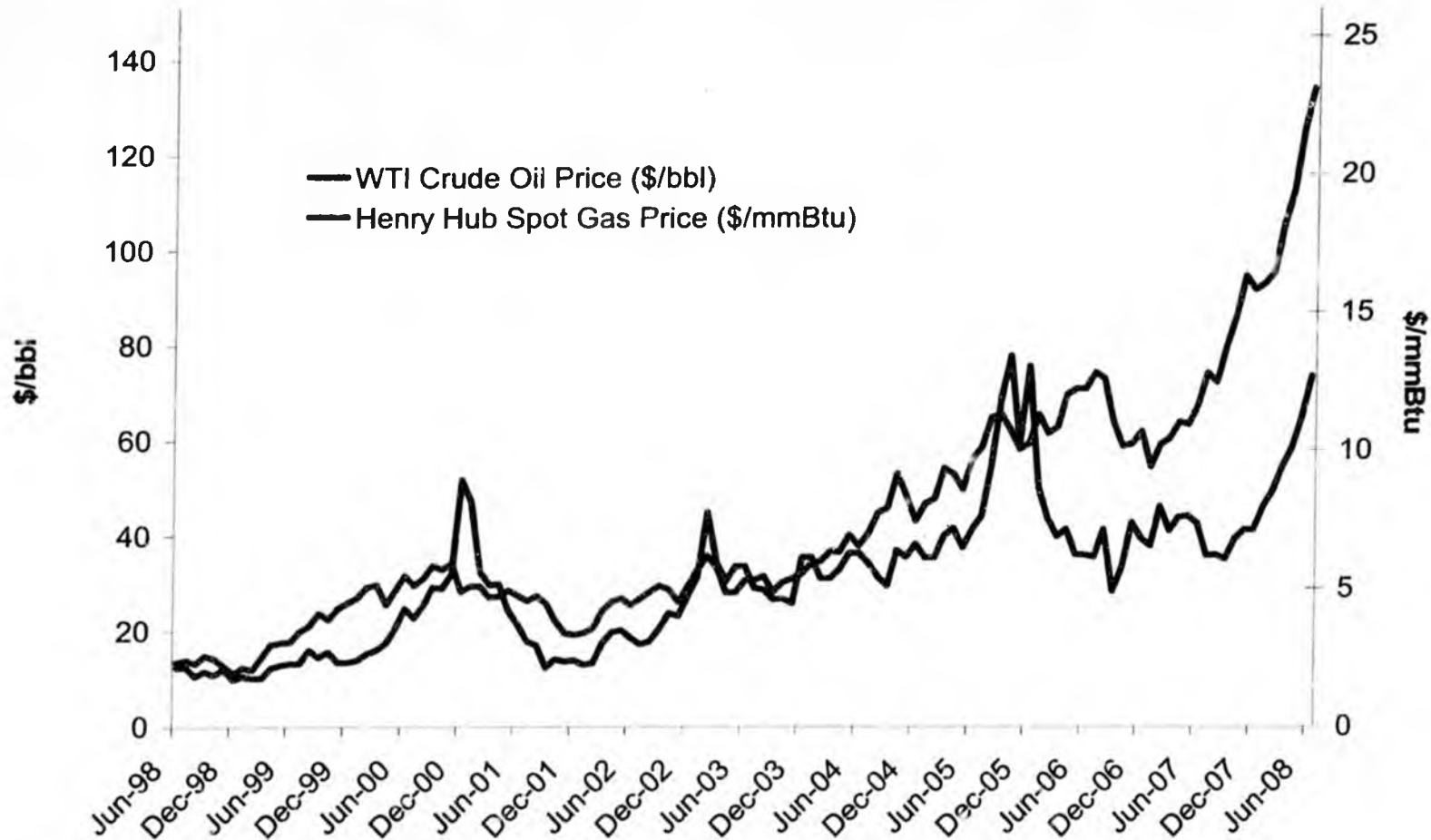
 - High Case generates very favorable results for the Alaska LNG Project

* 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



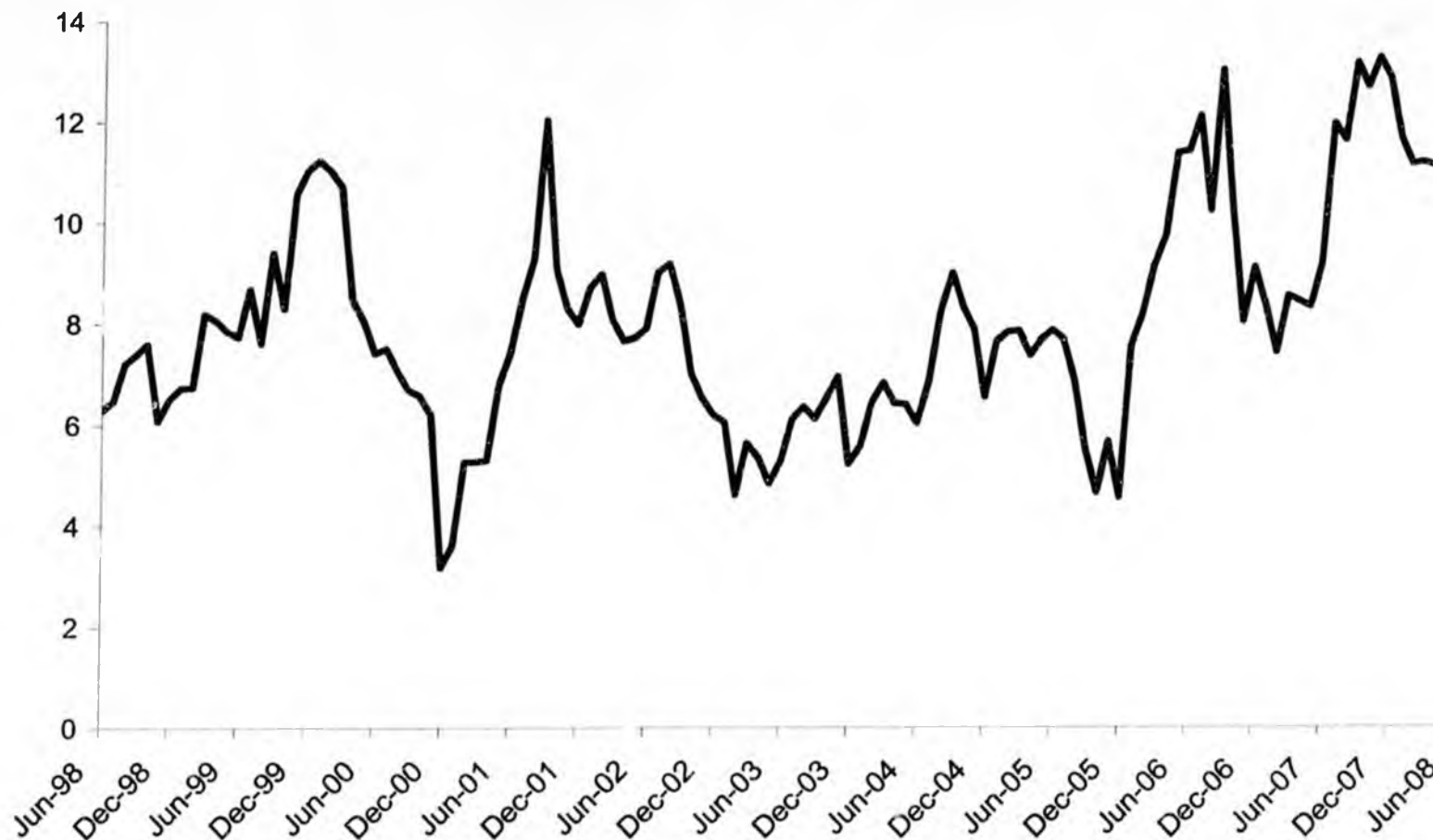
WTI and Henry Hub Historical Prices (monthly averages)



WTI and Henry Hub Price Ratio



WTI to Henry Hub Price Ratio



Significance of Assumed Oil/Henry Hub Price Ratio

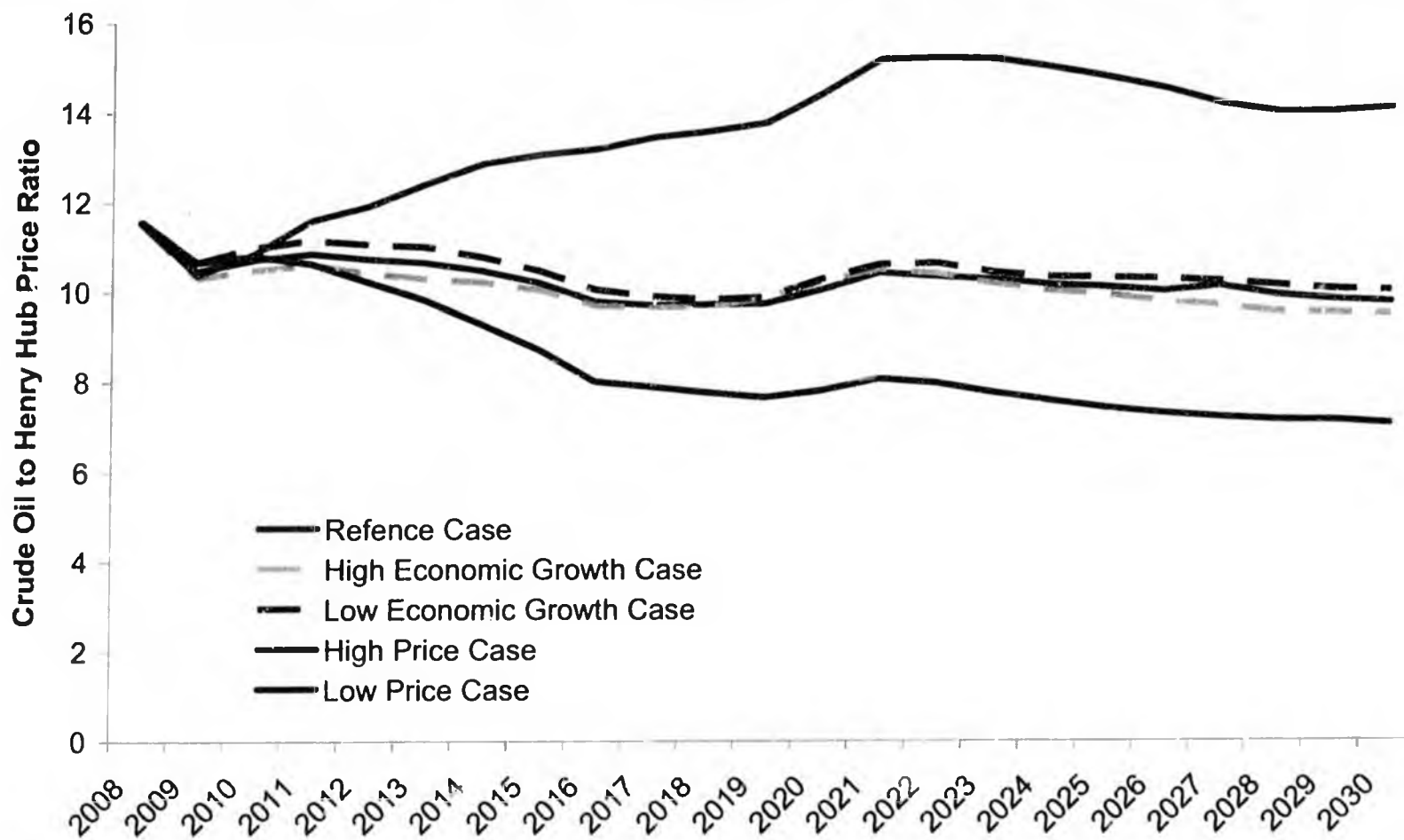


- Higher crude oil to Henry Hub price ratio means:
 - differential between Asian LNG prices and North American gas prices is higher
 - netback prices from LNG Project are relatively more attractive
- Recently observed price ratios are significantly higher than historical values
- What is the appropriate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

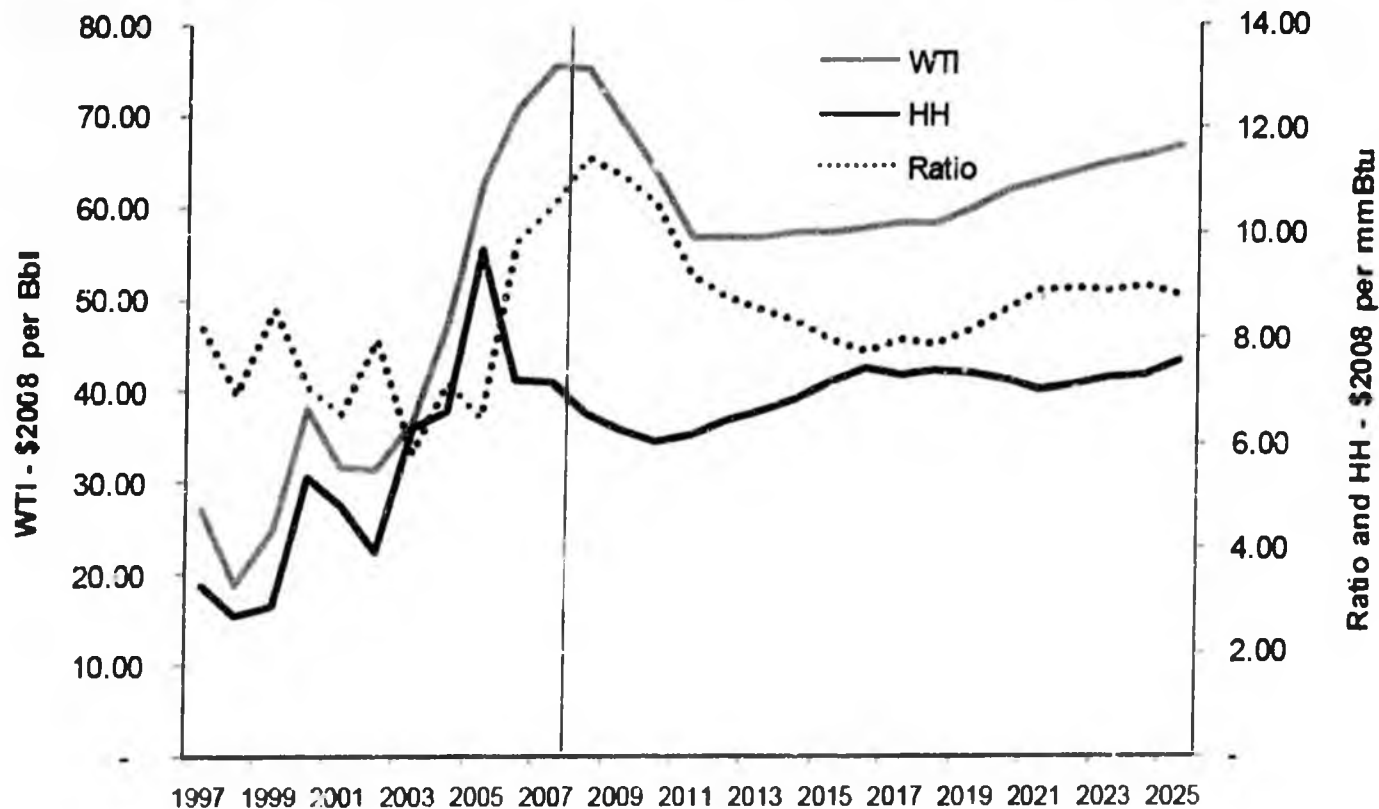
DOE EIA Forecast Price Ratios (AEO 2008)



US DOE Energy Information Administration Annual Energy Outlook 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
<u>Development Phase Costs:</u>		
LNG Project	0.65	Administration
Pipeline to Canada Project	0.69	Administration
<u>Execution Phase Capital Costs:</u>		
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)	$\sim \$1.10 / \text{mmBtu}^1$	MOL / PA
Pipeline Gas HHV	1133 Btu/scf	Administration
Capex Escalation	4% p.a.	Administration
Opex Escalation	3% p.a.	Administration

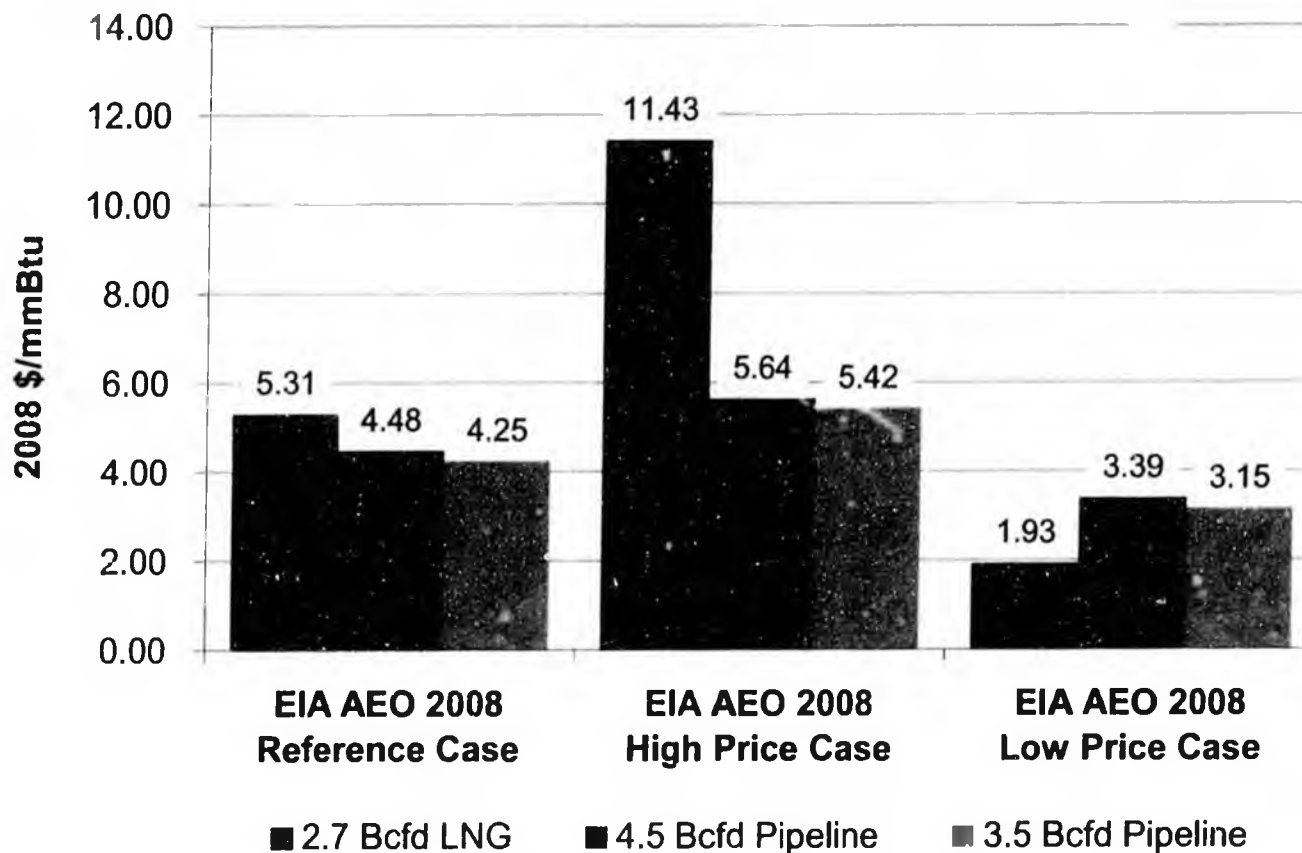
Notes: ¹ Nominal dollars in 2019

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

Average Real Netback Price at GCP Inlet

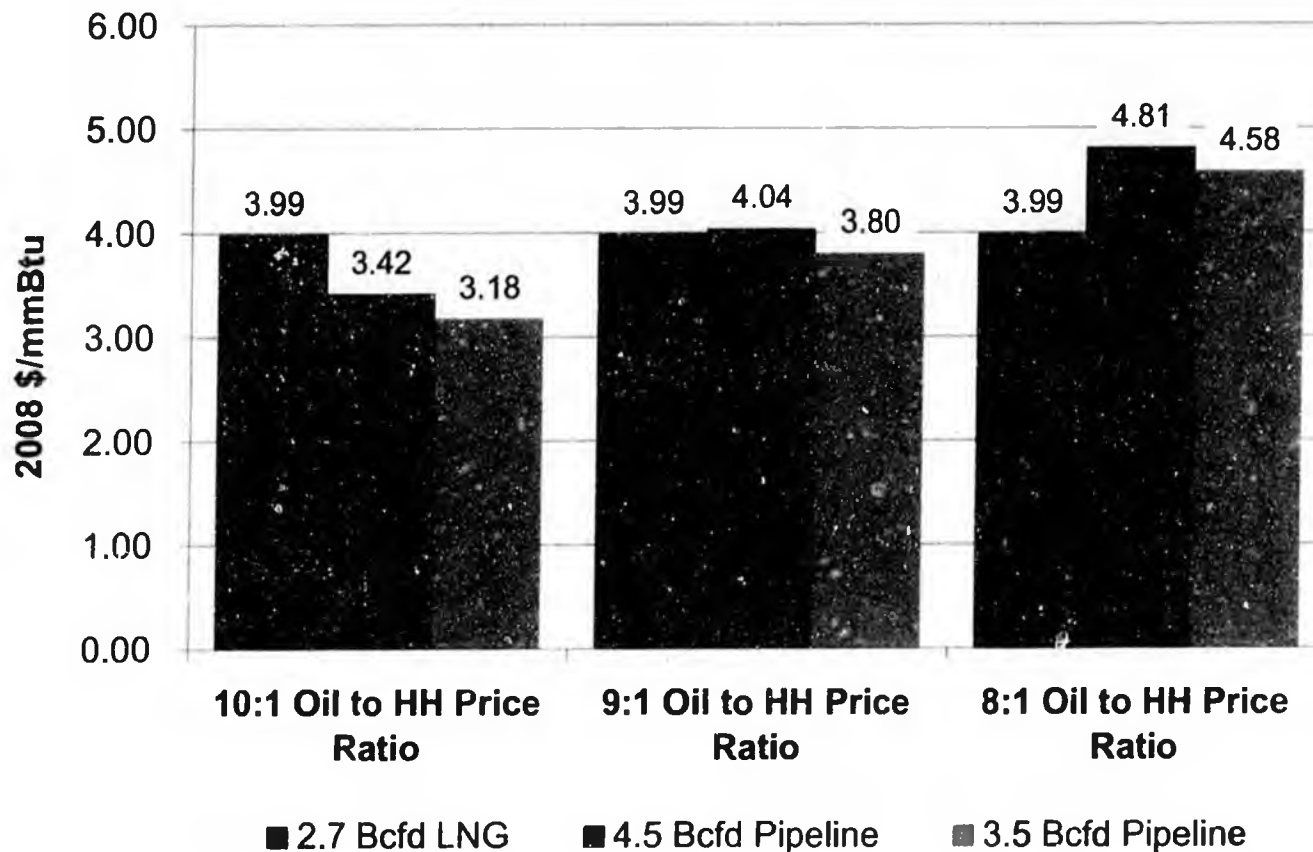


Netback Prices: \$60/bbl Oil Price Cases



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

Average Real Netback Price at GCP Inlet

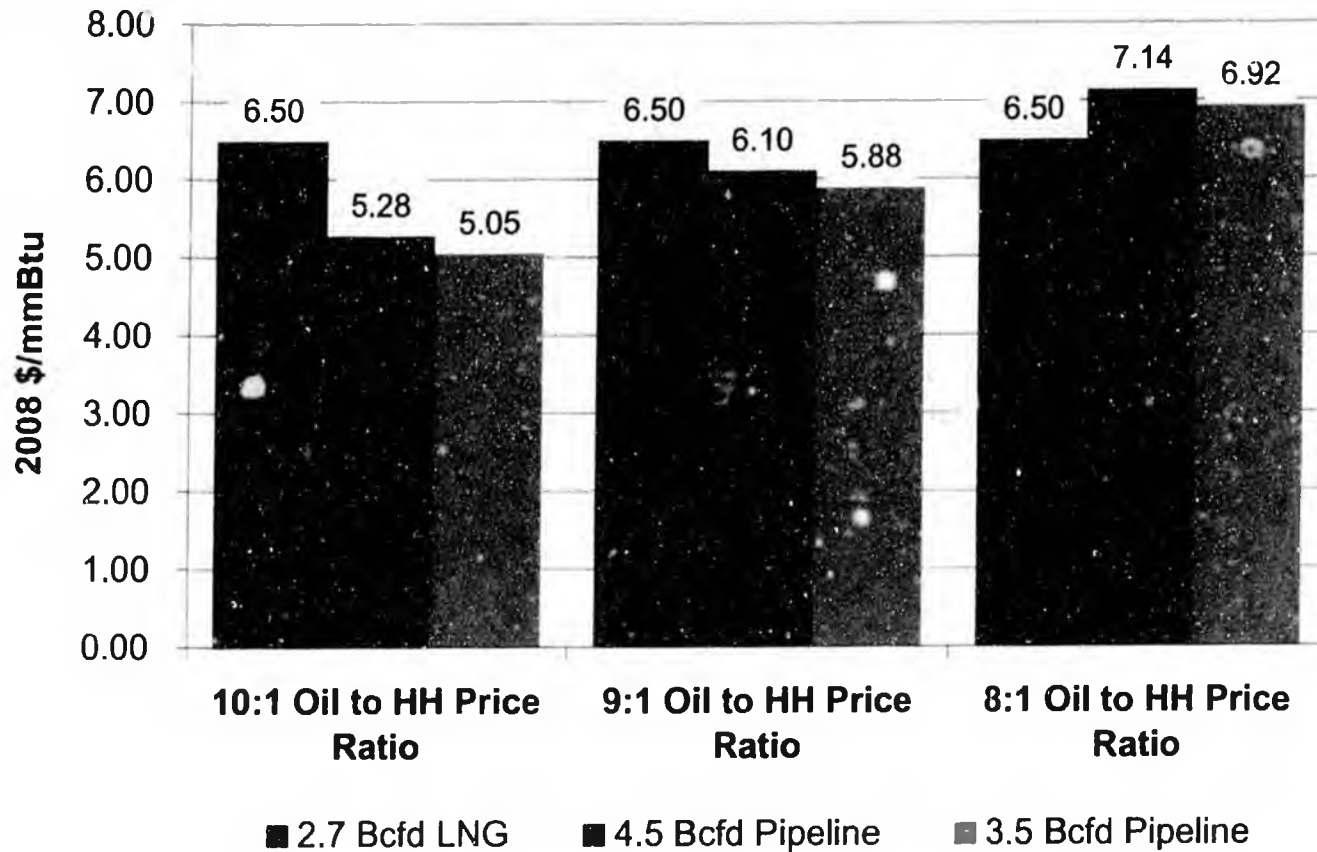


Netback Prices: \$80/bbl Oil Price Cases



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

Average Real Netback Price at GCP Inlet

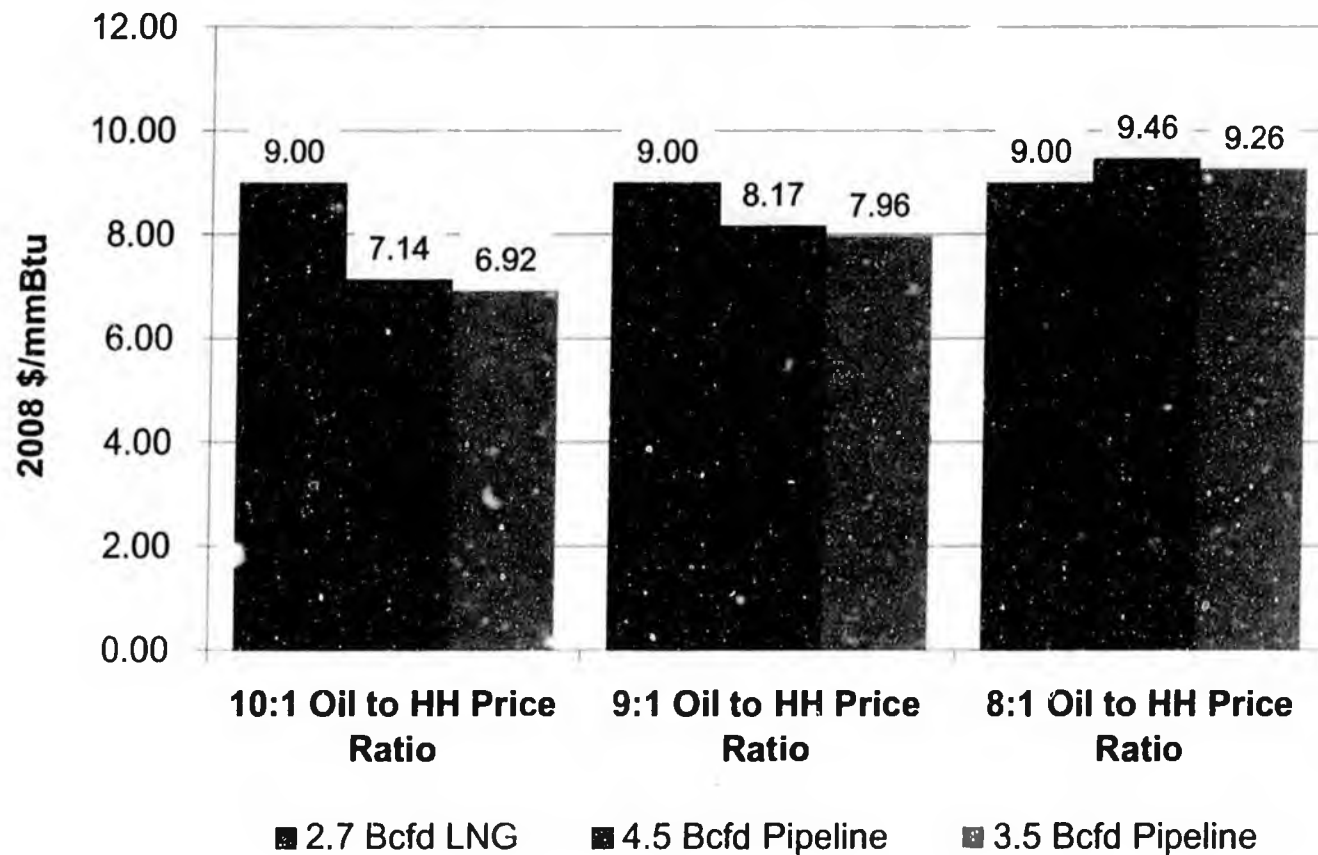


Netback Prices: \$100/bbl Oil Price Cases



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

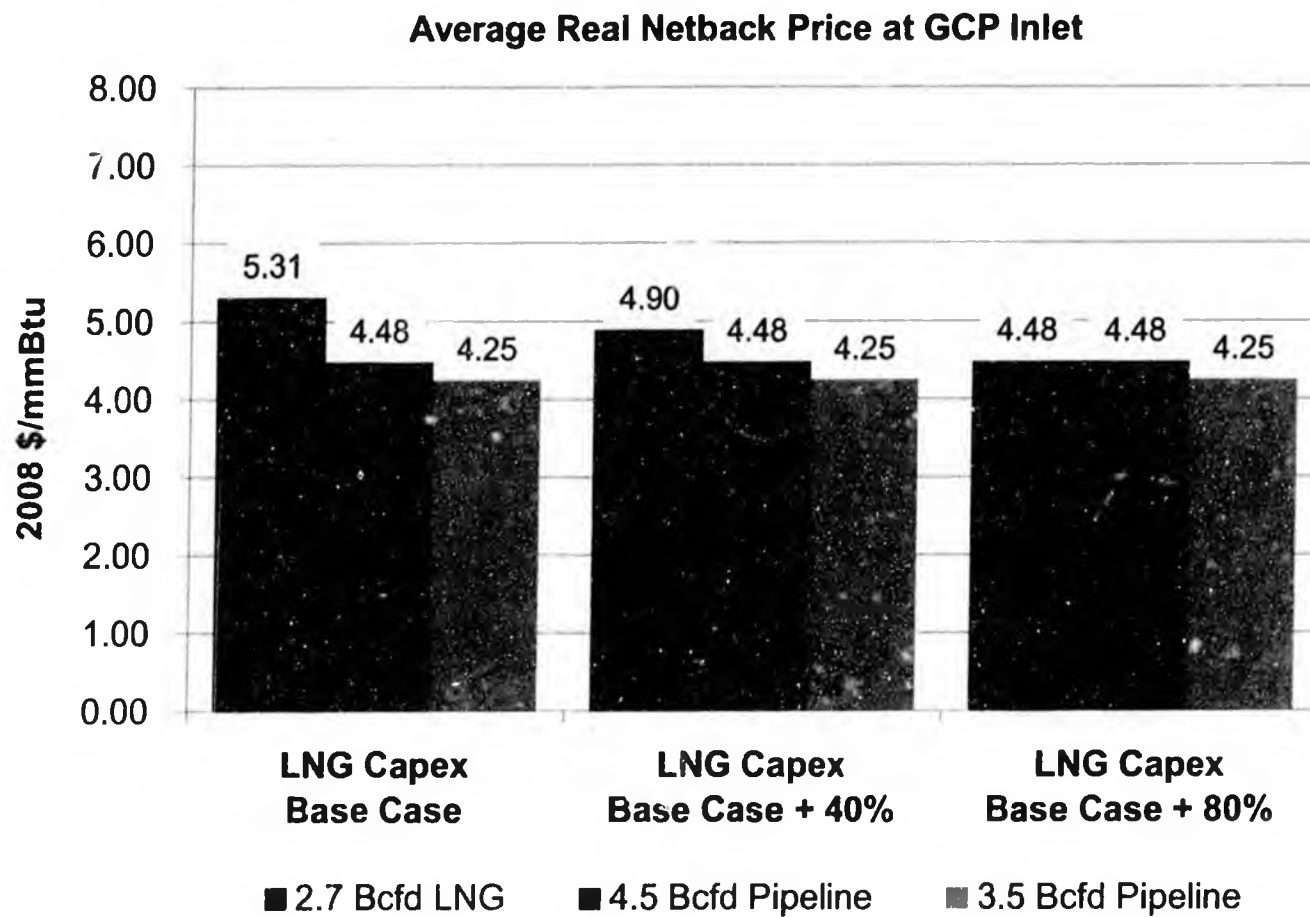
Average Real Netback Price at GCP Inlet



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

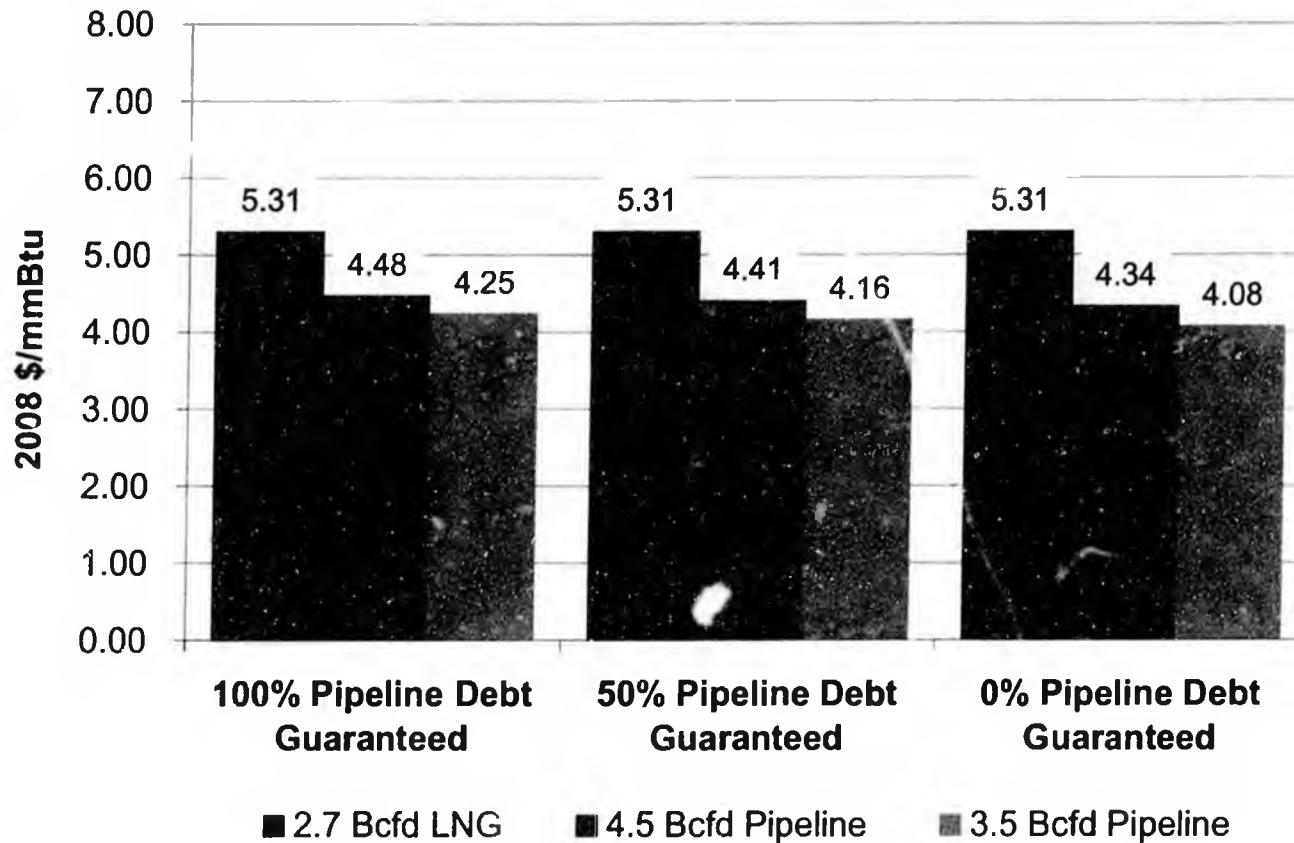


Netback Prices: Debt Guarantee Sensitivity



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

Average Real Netback Price at GCP Inlet



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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