



**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

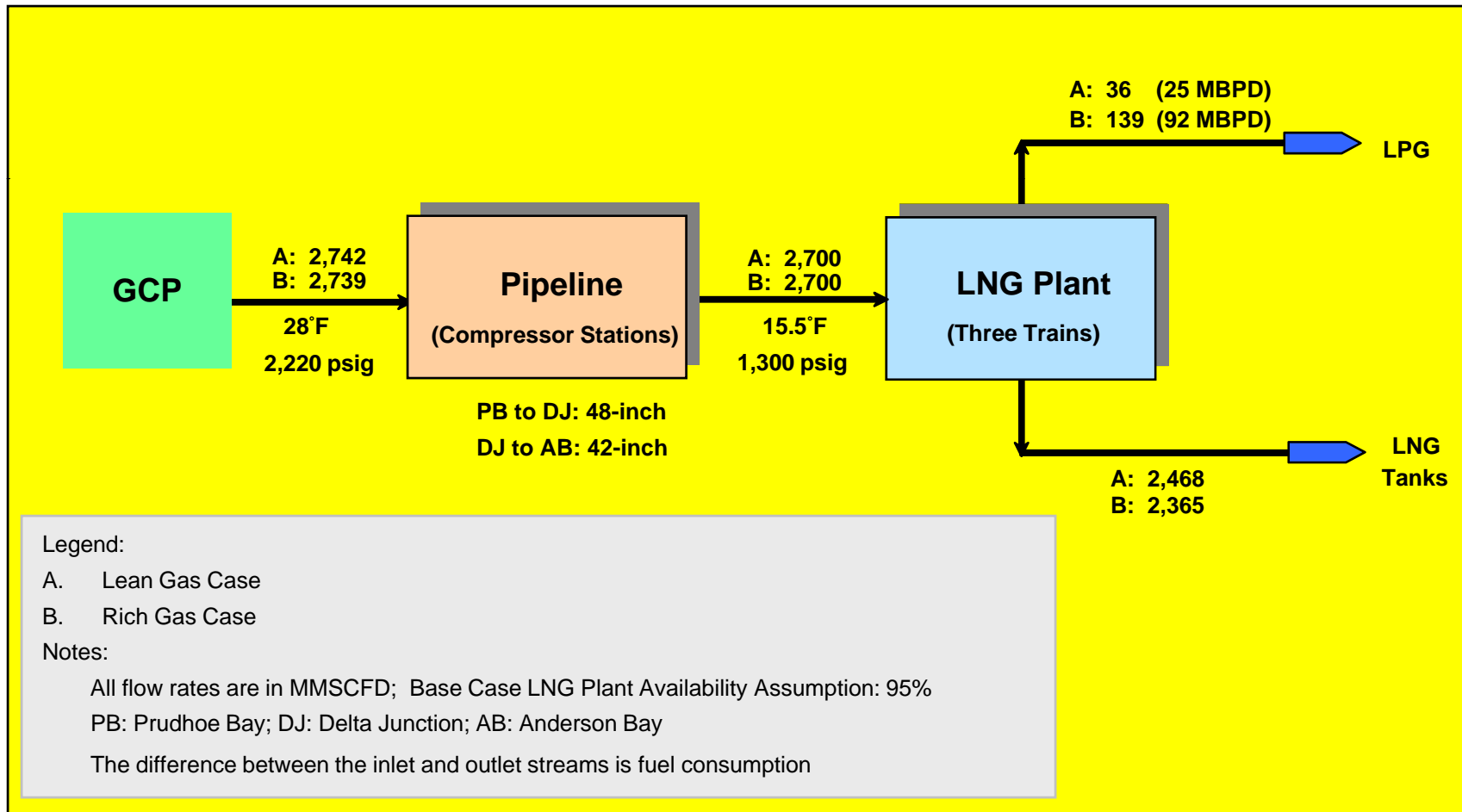


- Economics of an LNG project vs. Pipeline to Canada
 - Port Authority: LNG more attractive than pipeline to Canada
 - Administration: LNG less attractive than pipeline to Canada
 - EconOne: LNG either more or less attractive, depending on assumptions
 - Assumptions used are key:
 - capital cost of project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

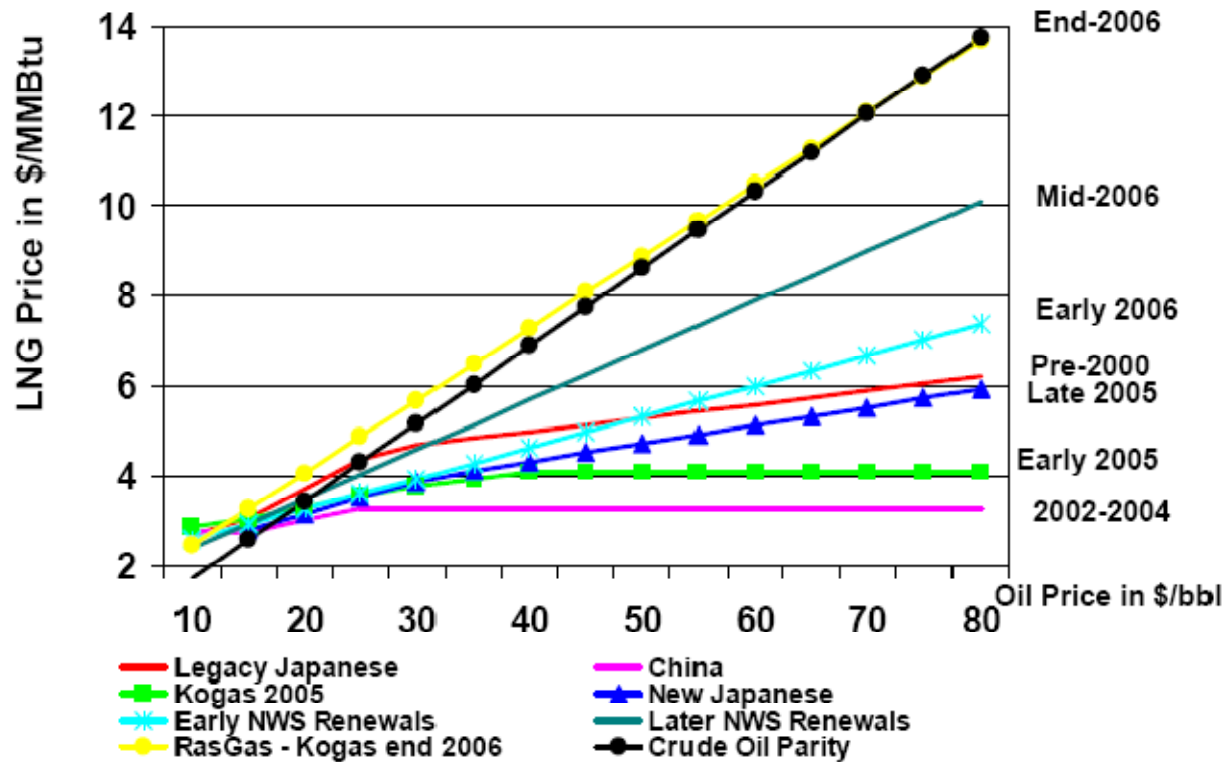
Asian LNG and North American Gas Prices



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

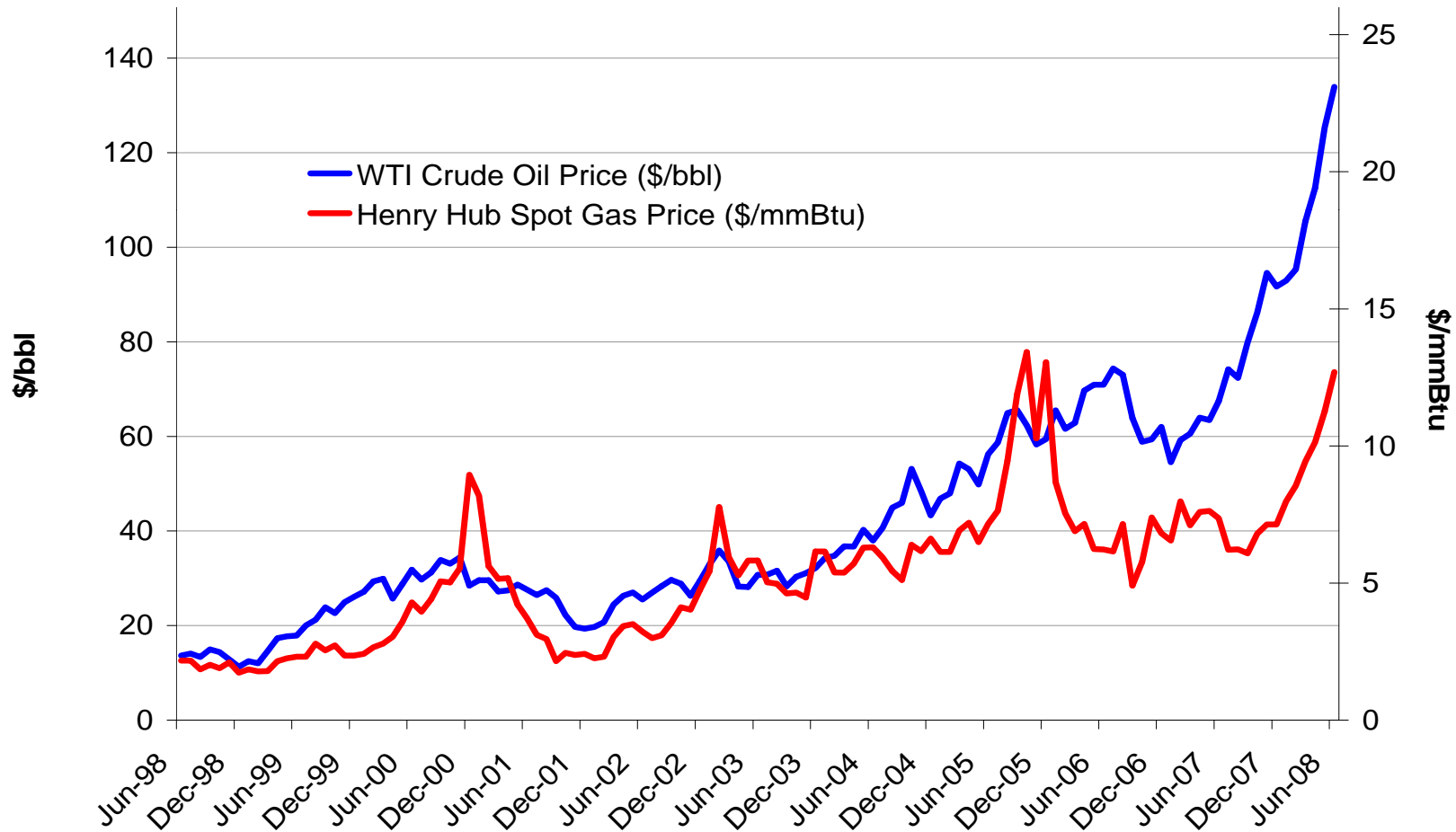
- The Port Authority assumptions:
 - current highly seller-favorable market expected to swing back towards relatively more buyer friendly terms
 - Gas Strategies' Base Case forecast appears reasonable and has been incorporated in Port Authority analysis
 - High Case generates very favorable results for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



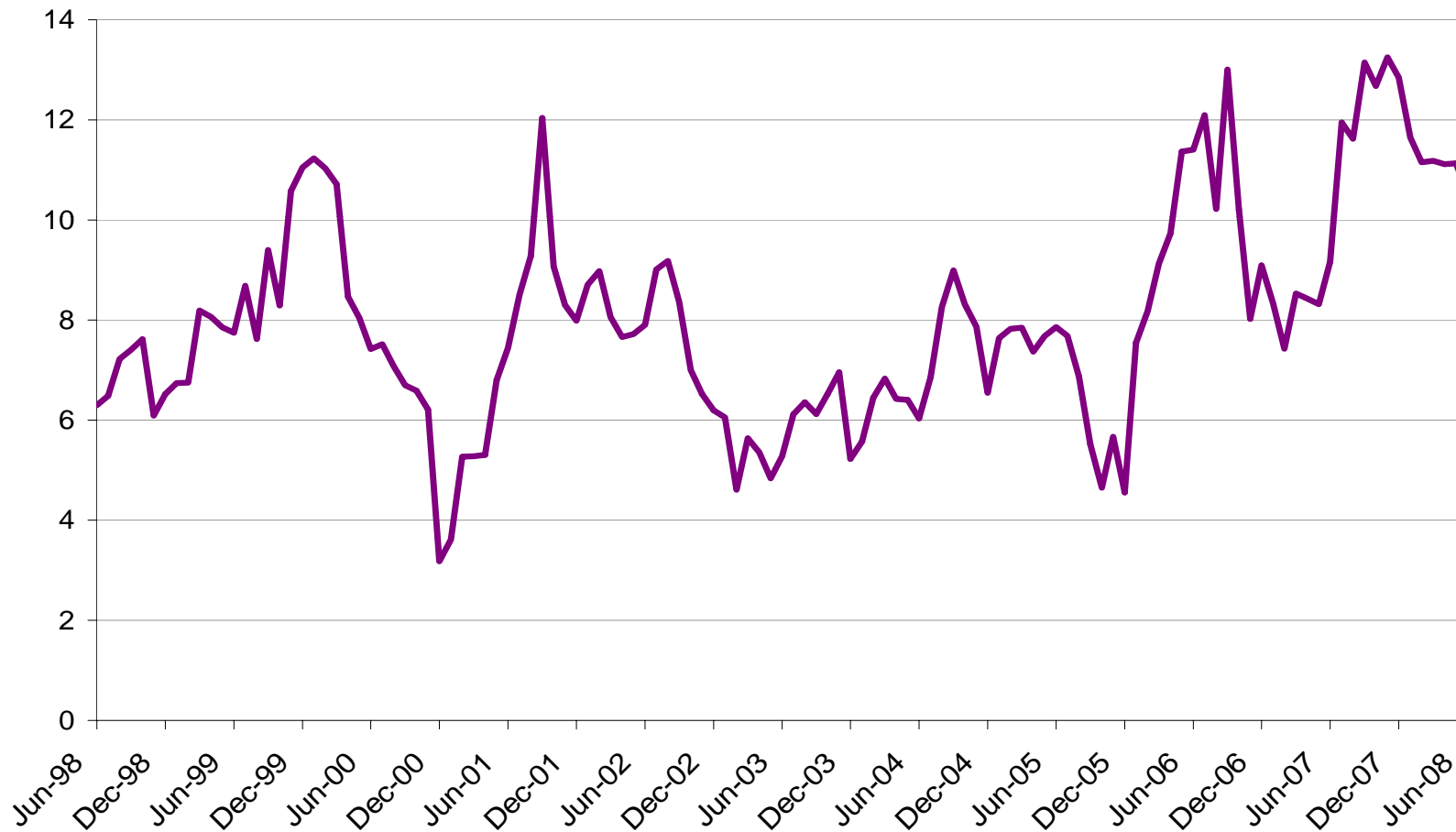
WTI and Henry Hub Historical Prices (monthly averages)



WTI and Henry Hub Price Ratio



WTI to Henry Hub Price Ratio



Significance of Assumed Oil/Henry Hub Price Ratio

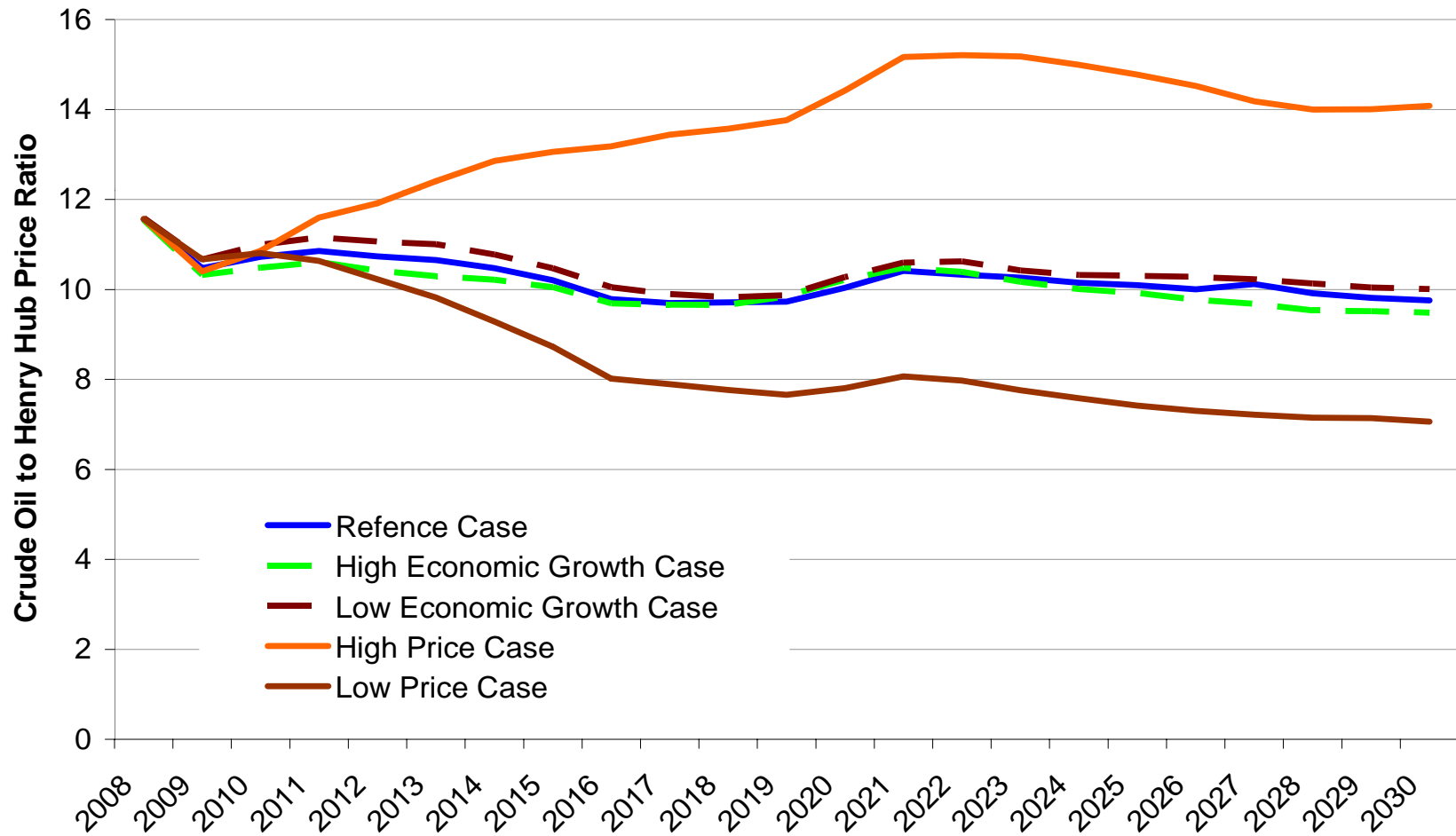


- Higher crude oil to Henry Hub price ratio means:
 - differential between Asian LNG prices and North American gas prices is higher
 - netback prices from LNG Project are relatively more attractive
- Recently observed price ratios are significantly higher than historical values
- What is the appropriate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

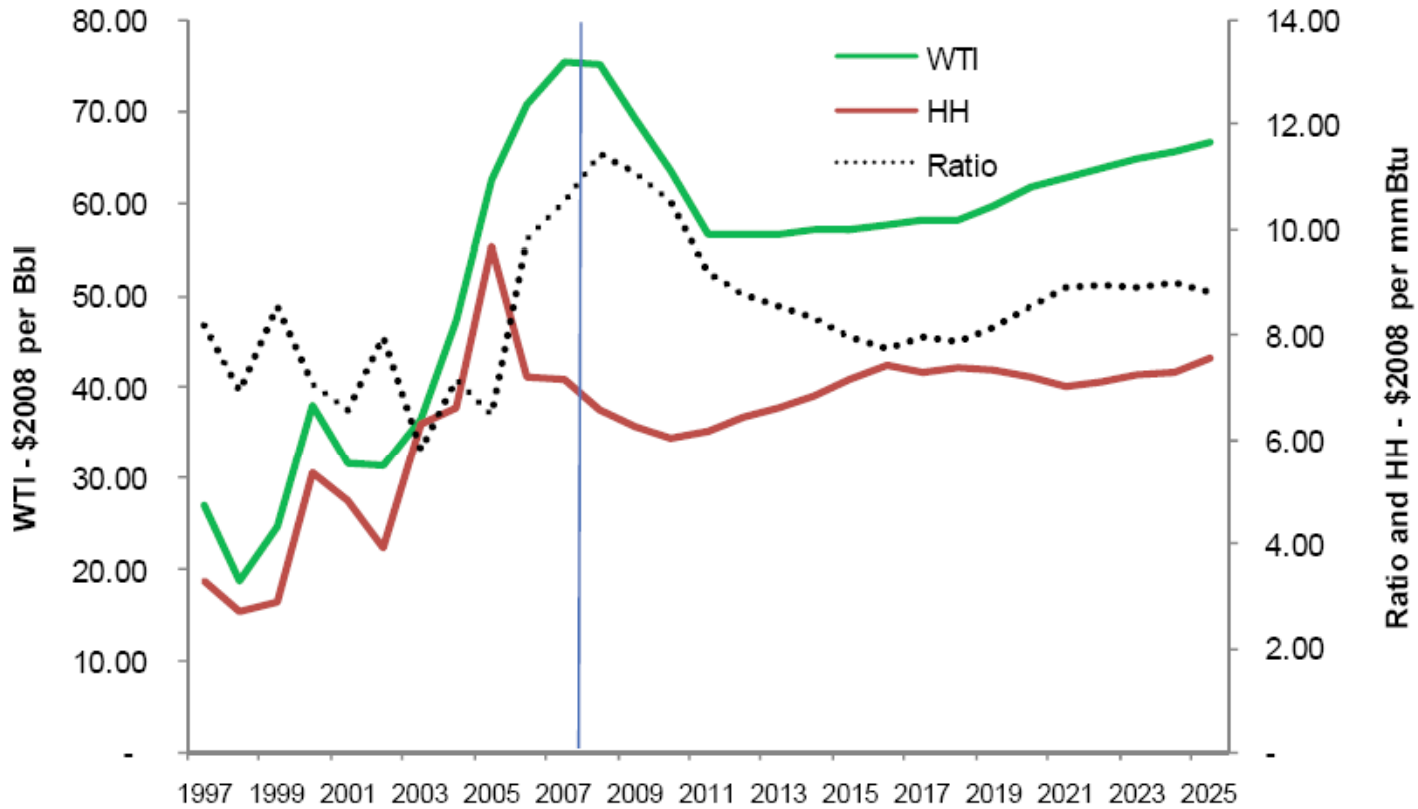
DOE EIA Forecast Price Ratios (AEO 2008)



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



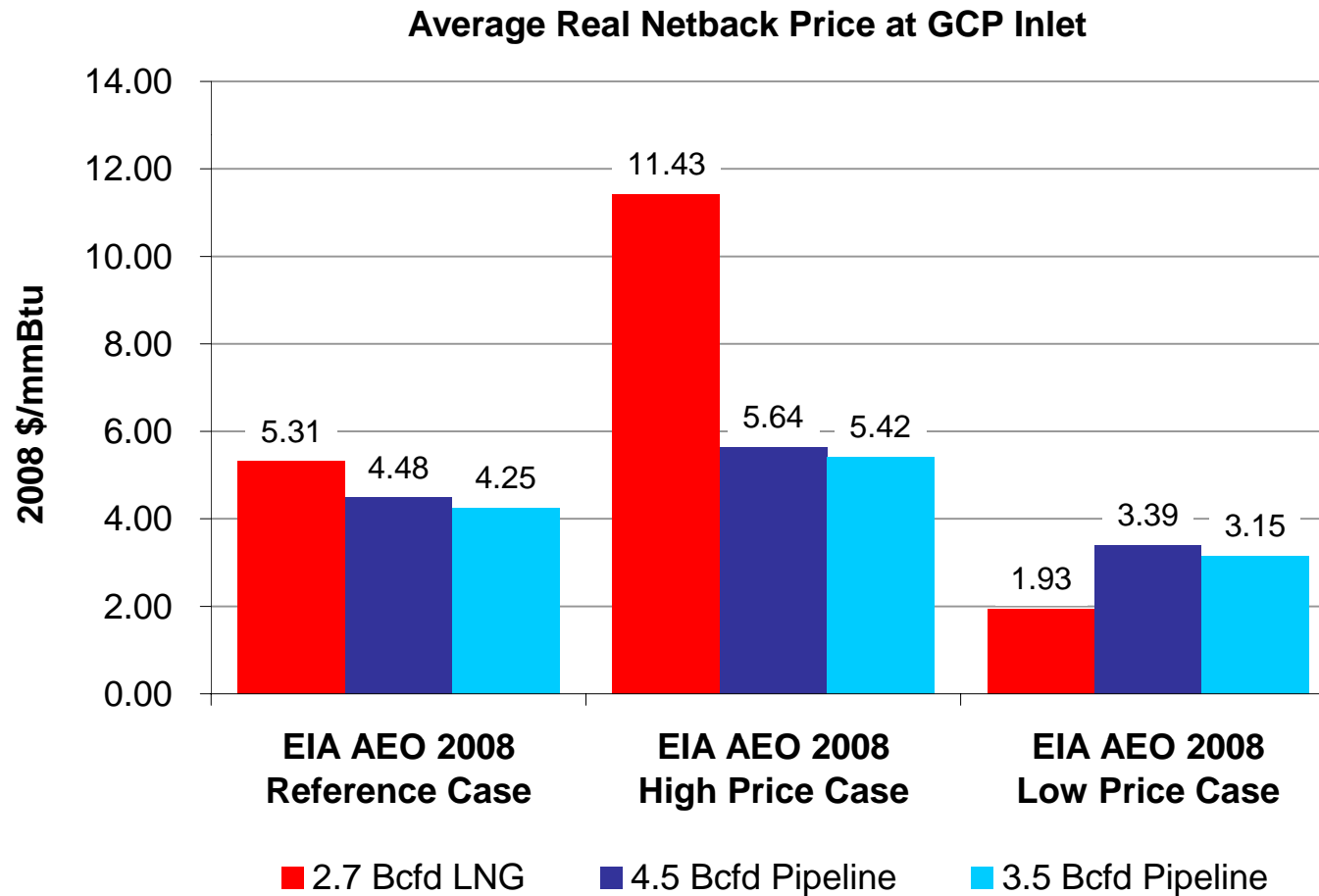
	Assumption	Source of Assumption
D:E for Tariff (Pre-Completion)	70:30	Admin/TCPL
D:E for Tariff (Pre-Completion)	75:25	Admin/TCPL
Return on Equity	14%	Admin/TCPL/EconOne
Cost of Guaranteed Debt	5.50%	EconOne
Cost of Non-Guaranteed Debt	7.00%	EconOne
LNG Plant Availability Factor	95%	Bechtel
LNG Sales 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



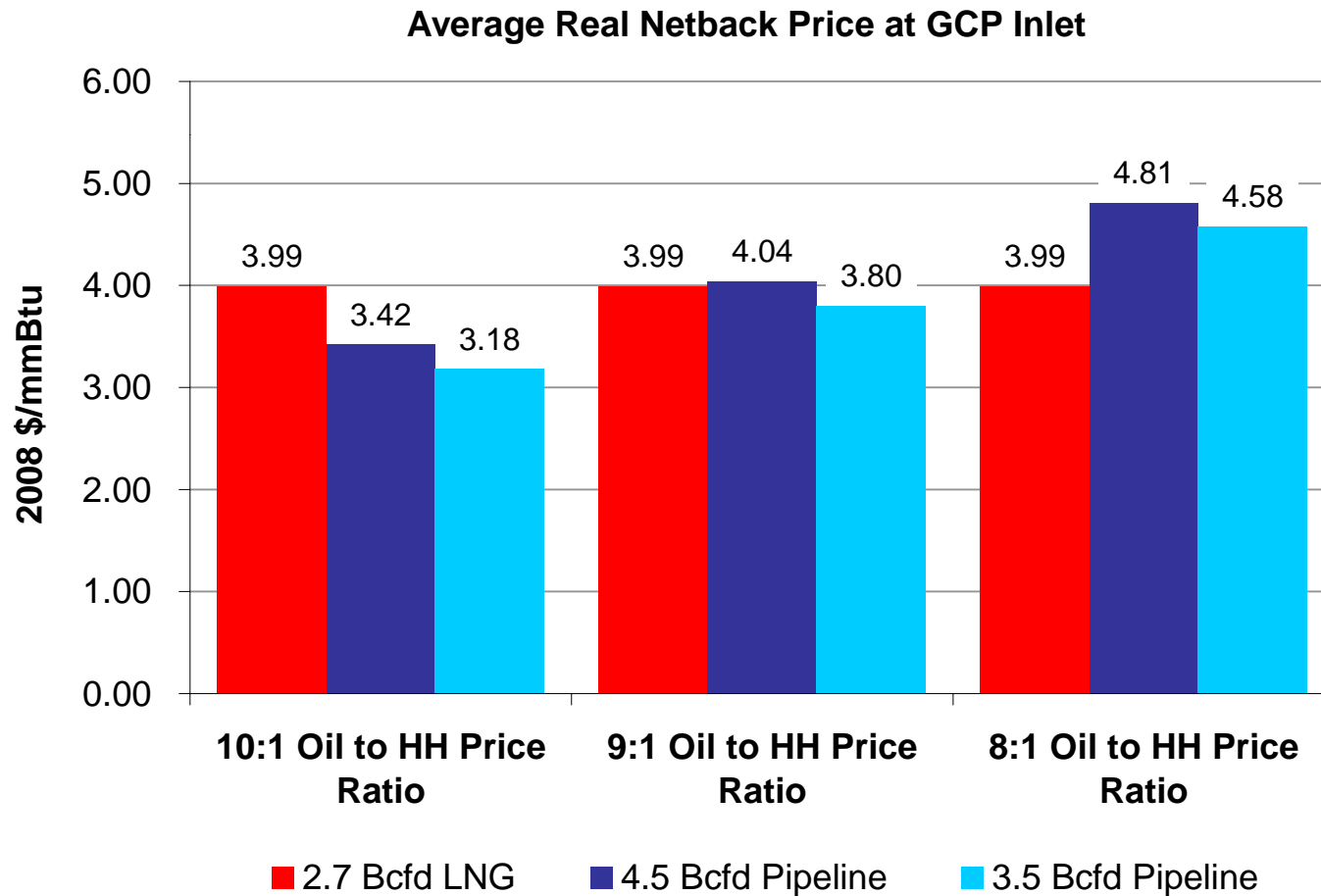
- Oil and HH prices from DOE EIA's 2008 Annual Energy Outlook
- 3 price scenarios shown: Reference Case, High Price and Low Price Cases



Netback Prices: \$60/bbl Oil Price Cases



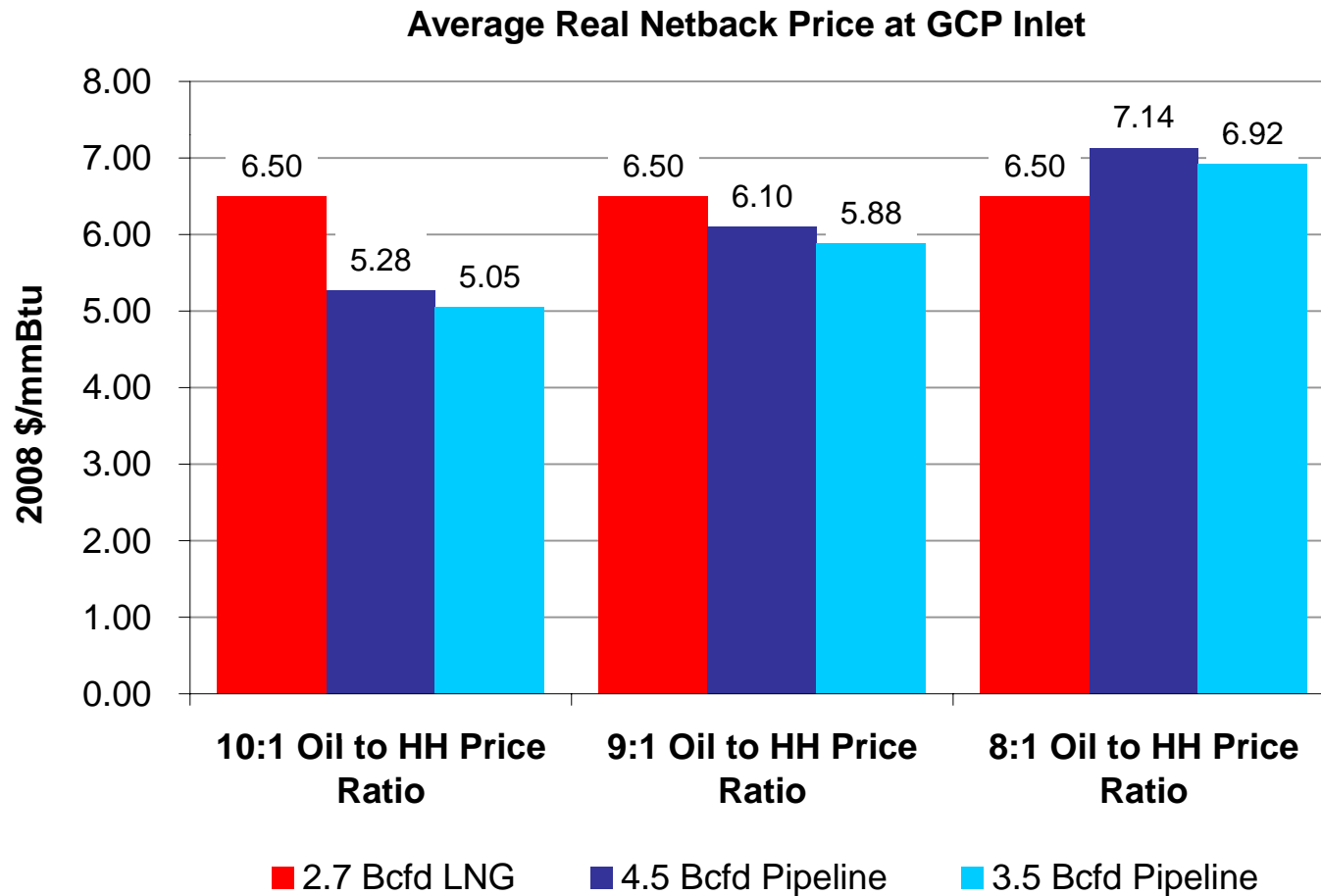
- Flat \$60/bbl oil price (constant 2008 USD)
- 3 scenarios for oil/HH price ratio: 10:1, 9:1 and 8:1



Netback Prices: \$80/bbl Oil Price Cases



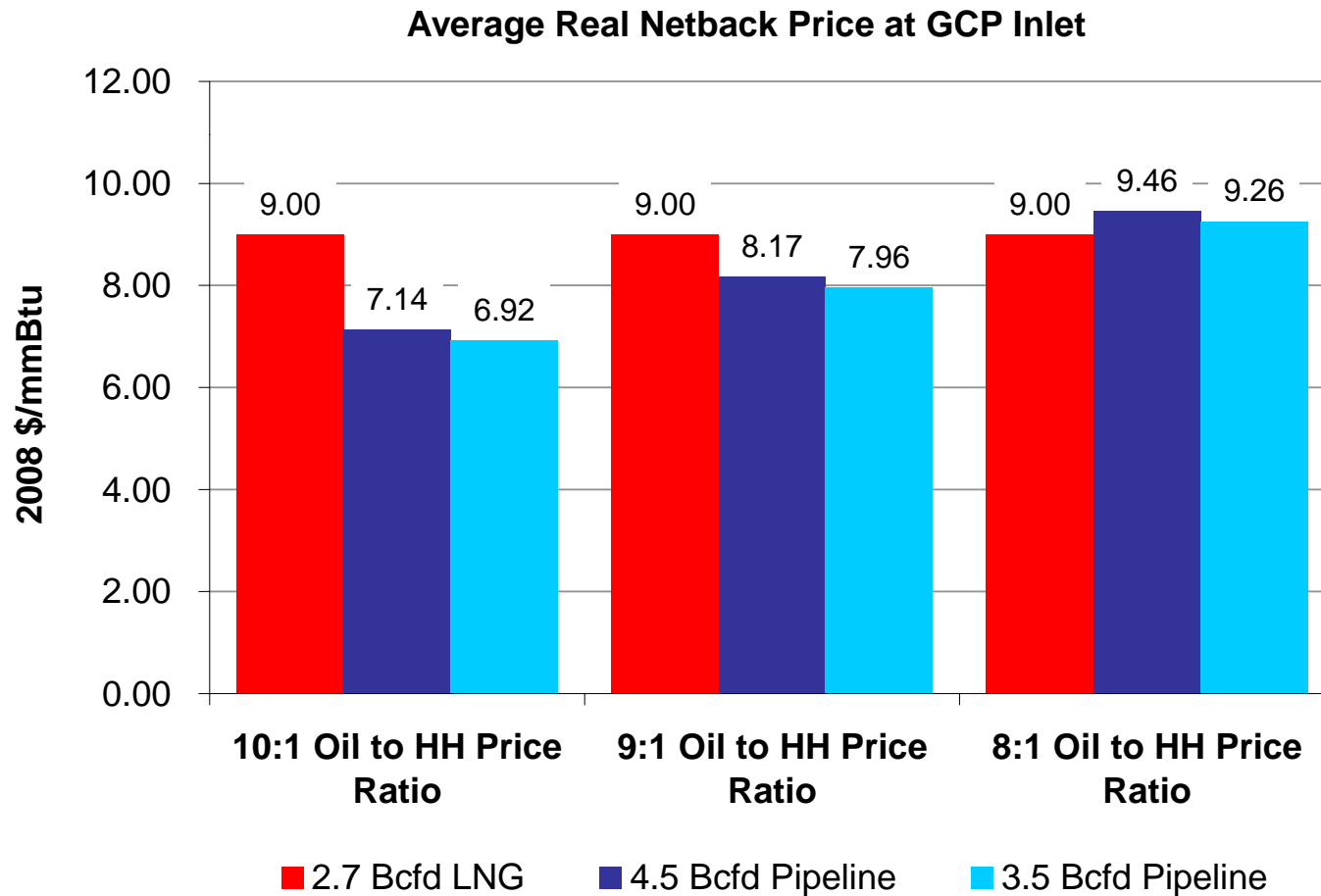
- Flat \$80/bbl oil price (constant 2008 USD)
- 3 scenarios for oil/HH price ratio: 10:1, 9:1 and 8:1



Netback Prices: \$100/bbl Oil Price Cases



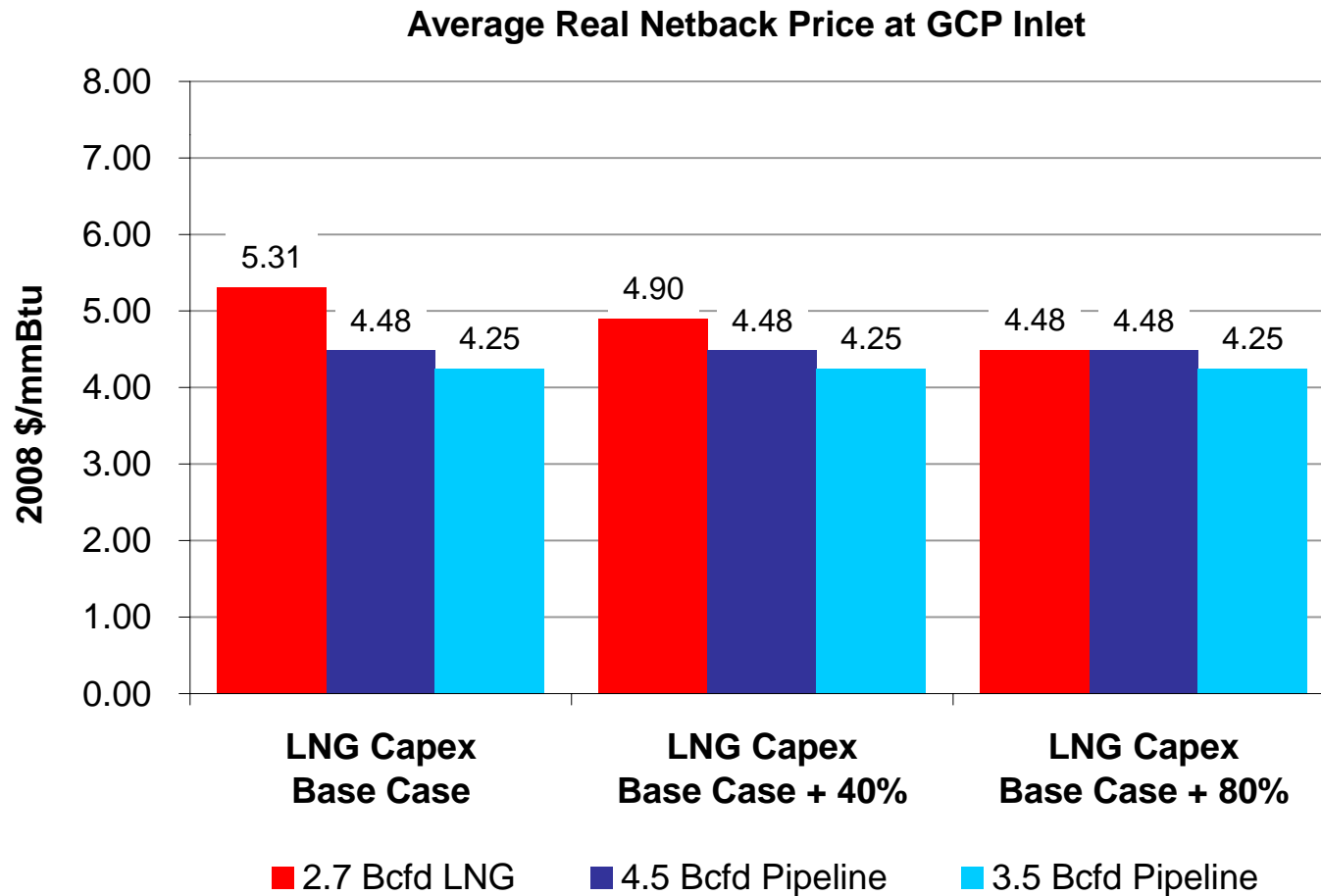
- Flat \$100/bbl oil price (constant 2008 USD)
- 3 scenarios for oil/HH price ratio: 10:1, 9:1 and 8:1



Netback Prices: LNG Capex Sensitivity



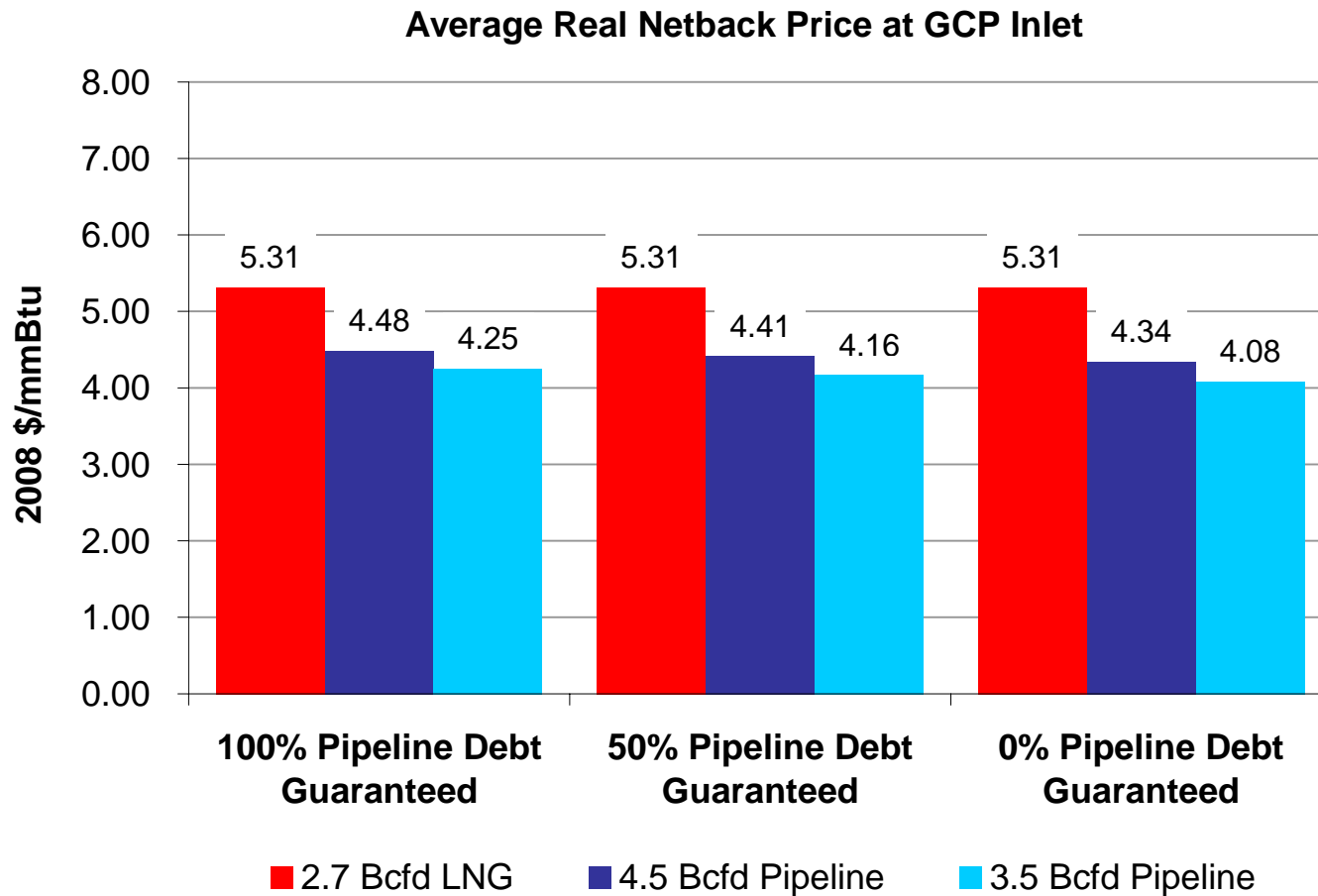
- Oil and HH prices from EIA 2008 Annual Energy Outlook – Reference Case
- 3 LNG Plant capital cost scenarios: Base Case, 40% increase and 80% increase



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

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