COMPETITION LAW360

ConocoPhillips Subpoenaed By CFTC In Oil Probe

By **Elaine Chow**, *Portfolio Media, New York (June 3, 2008)*--Oil giant ConocoPhillips Co. revealed on Monday that it was subpoenaed in December by the U.S. Commodity Futures Trading Commission as part of the agency's ongoing investigation into possible price manipulation in the crude oil market.

U.S. Commodities Futures Trading Commission

- Is investigating possible fraud in trading of crude oil futures contracts

- ConocoPhillips has been subpoenaed – not charged with any wrongdoing

- Is concerned generally with particular trader transactions, rather than wholesale withholding product from the market

HB 3001
SB 3001
6/9/08
SPECIAL SESSION DOCUMENTS

AGIA
Legislative Special Session

Incentives and Mandates for Pipeline Expansions

Greg Hopper
Black & Veatch
June 9, 2008

AGIA "Must Haves" Regarding Expansion

- Bi-annual Open Season Offerings
  - Allows shippers to plan, reduces risk premiums
- Capital Structure Certainty
  - Helps to lower rates for shippers
- Rolled-in Rates
  - Shares the benefits of scale economies, level playing field

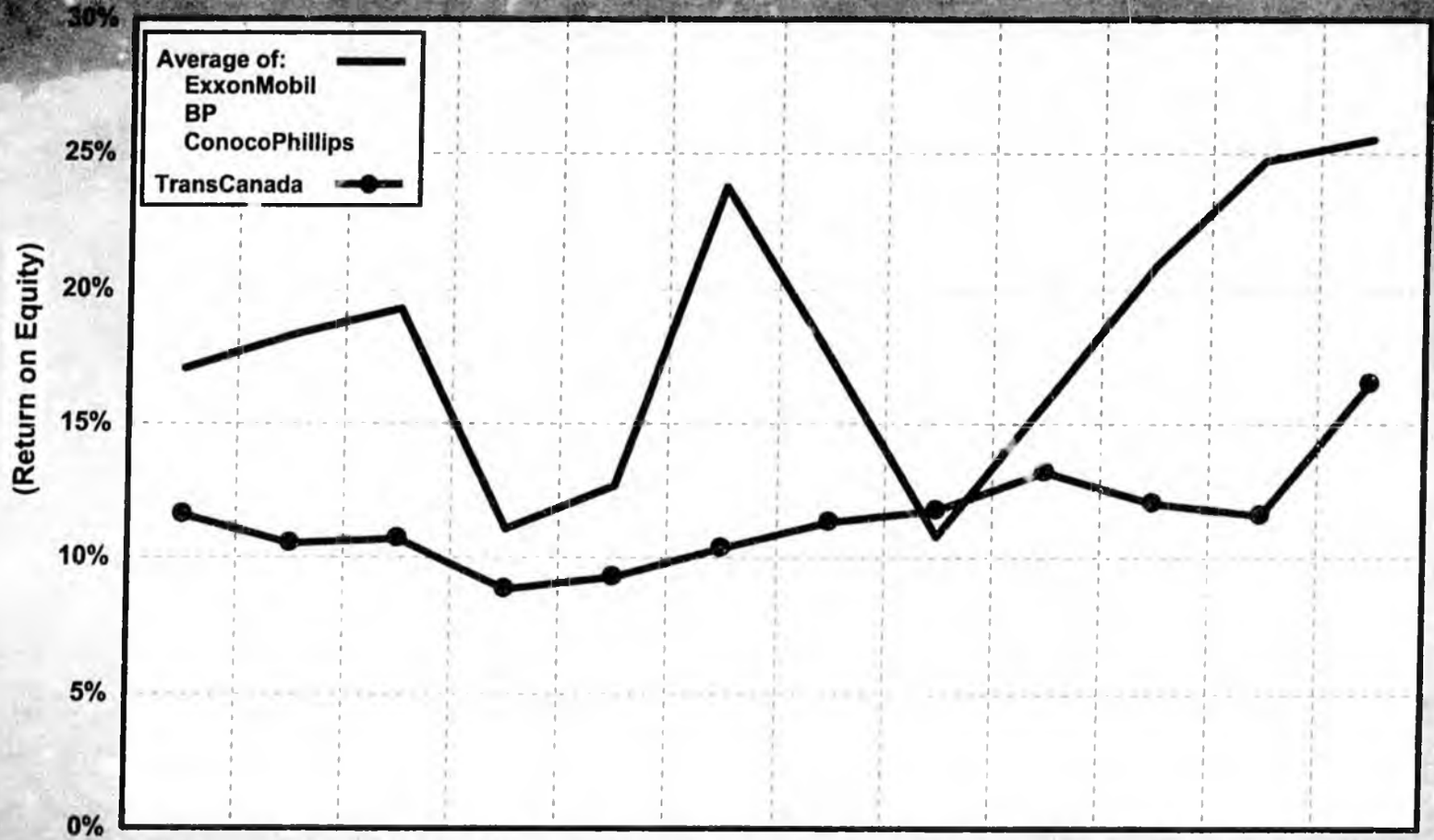
Investments are different than for expansion

Development	Expansion
• Cost control	• Outlet for increased equity production
• Operating control	• ?
• Capacity certainty	
• Expansion timing	
• Strategic	

Pipeline v. Producer Returns on Equity

- Gas pipeline regulated rates of return on equity (ROE) generally recognize lower levels of operating risks than other industries
  - FERC ROEs of 14% or less are common
  - ROEs granted to pipelines prior to in-service are often reduced in subsequent rate cases
- Exploration and Production company shareholders require relatively higher (15% – 20%+) ROEs to compensate for higher perceived risks

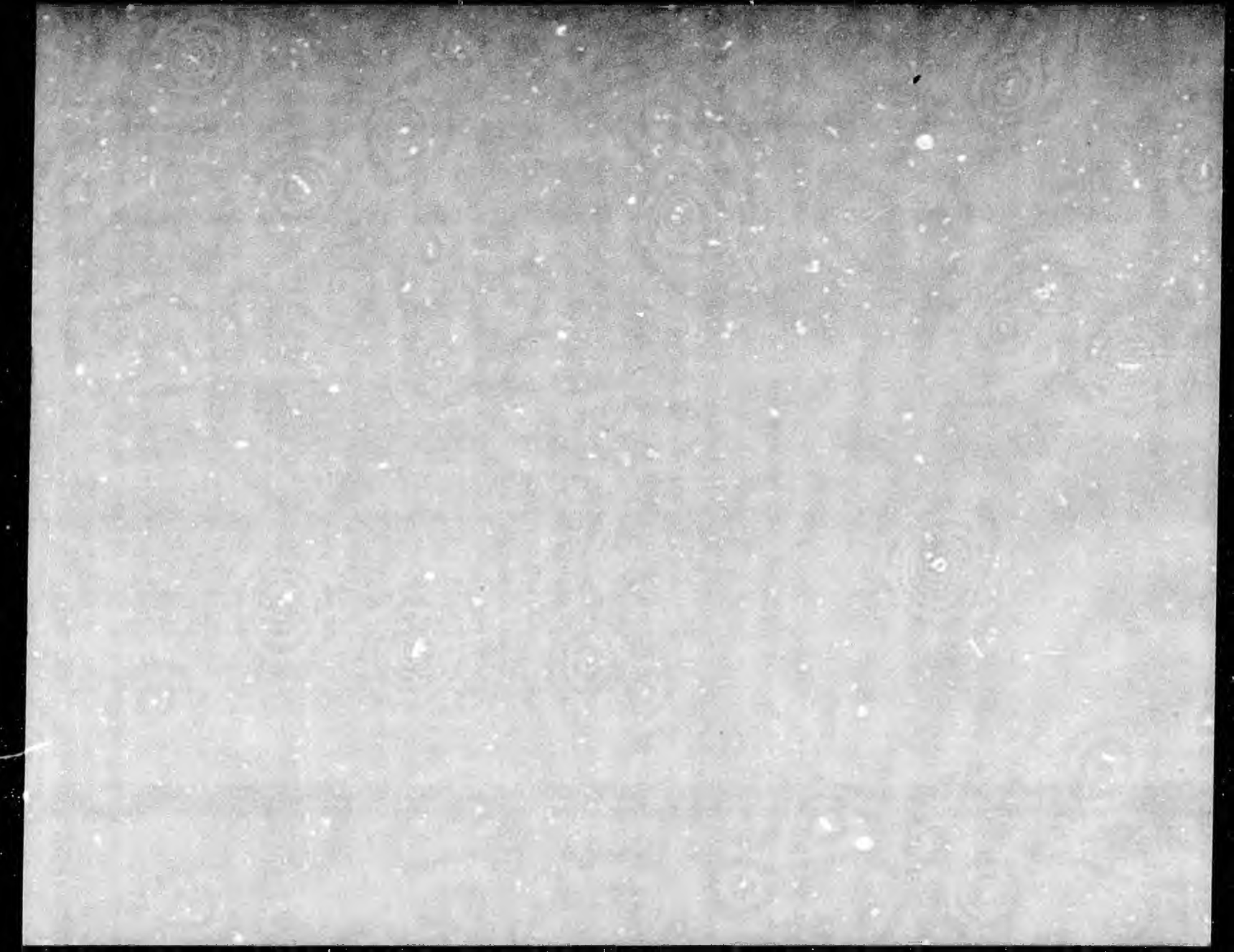
Producers Shareholders Expect Higher ROEs than do Pipeline Companies



Source: Value Line (March 16, 2007).

What is a producer's incentive to expand pipeline capacity for non-owners?

- ROEs typically will not meet a producer's required rates of return on capital
- Potential for increased competition in lease acquisition and reserves development
- Call on capital that is needed for other purposes
- It is not what they want to do (core competence)
- Regulatory complications



The Challenges in Building an Alaskan LNG Chain

June 2008

Presented by Rob Fenton – Managing Consultant Gas Strategies Consulting

Dr. Robert Fenton

- **27 years experience with Shell**
- **12 years in Gas and Power**
- **Commercial Management, Business Development, Strategy Formulation**
  - UK North Sea,
  - Turkmenistan to Turkey and Europe gas pipeline
  - USA – LNG import projects
  - Mexico LNG import
  - Shell LNG Strategy
- **4 years with Gas Strategies**
  - Principally LNG
  - Market evaluation and gas development strategies
  - Business models and strategies

LNG as an alternative to a pipeline

- Not just a choice between LNG and a pipeline but between:

- LNG to the illiquid, long-term contracted and in China's case developing, gas markets of Asia

And

- Pipeline to the deep, liquid, short term contracted market of USA

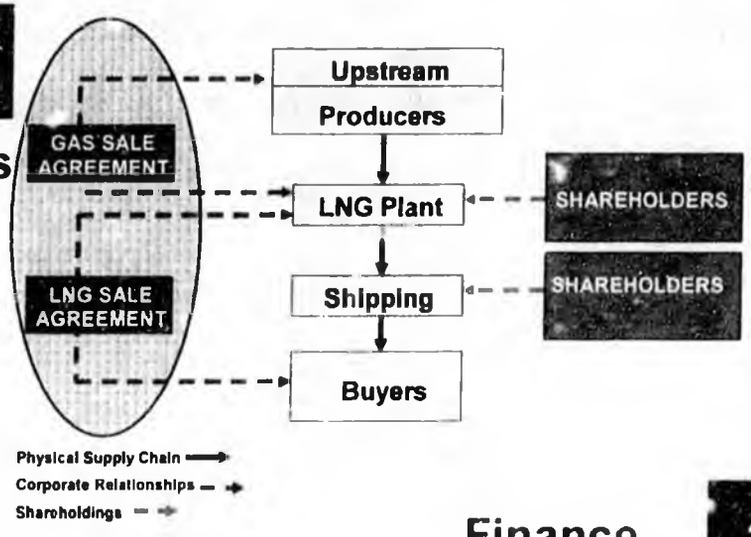
Putting an LNG chain together is complex, it varies by market and is challenging in Asia

- **Gas is not oil**
  - Oil is a truly global commodity in which demand can be assumed - price varies
  - Projects easy to launch on this basis
  - Gas is more costly to transport and more rigidly fixed to regional markets – often with a single buyer
  - Assuring demand means securing a long term buyer
  - And then building the whole delivery chain to the specific buyer
- **The US gas market is different from others**
  - US gas market is very similar to the global oil market – offtake is assured, price varies
  - Transparent gas price index
  - New gas development relatively straightforward
- **LNG is challenging- especially into Asia Pacific markets**
  - Costs are higher
  - All elements of the chain need to be connected with legal agreements to ensure the LNG once produced will be sold over the life of the project (ca. 20 years)
  - Asian markets not liquid – greater volume risk
  - Price for long term contract depends on market conditions at time of negotiation
  - The scale of projects usually means several companies will be involved (plus governments).
  - Getting and retaining alignment where there are competing projects and negotiating all agreements can be difficult.

Commercial contracts critical for viability of LNG chain to ensure financing and construction

3 Construct

1 Contracts



Finance 2

- **All elements of chain need to be connected with legal agreements to ensure the LNG produced will be sold over the life of the project (ca. 20 years) to support investment risk**
  - Before finance can be raised
  - Before construction starts
- **Makes LNG development complex**
  - Liable to delays and occasionally failure

Producers view of risk and reward

- **Pipeline (to USA) simpler by comparison:**
  - Single commitment to pipeline capacity
    - LNG requires: pipeline, liquefaction, ships, re-gasification
  - LNG requires higher level of reserves assurance
  - Assured market offtake
  - Transparent pricing
  - Single gas quality and blending
  - Producers can act independently and integrate with the rest of their North American gas sale

Are today's prices a basis for commitment to LNG for the long term?

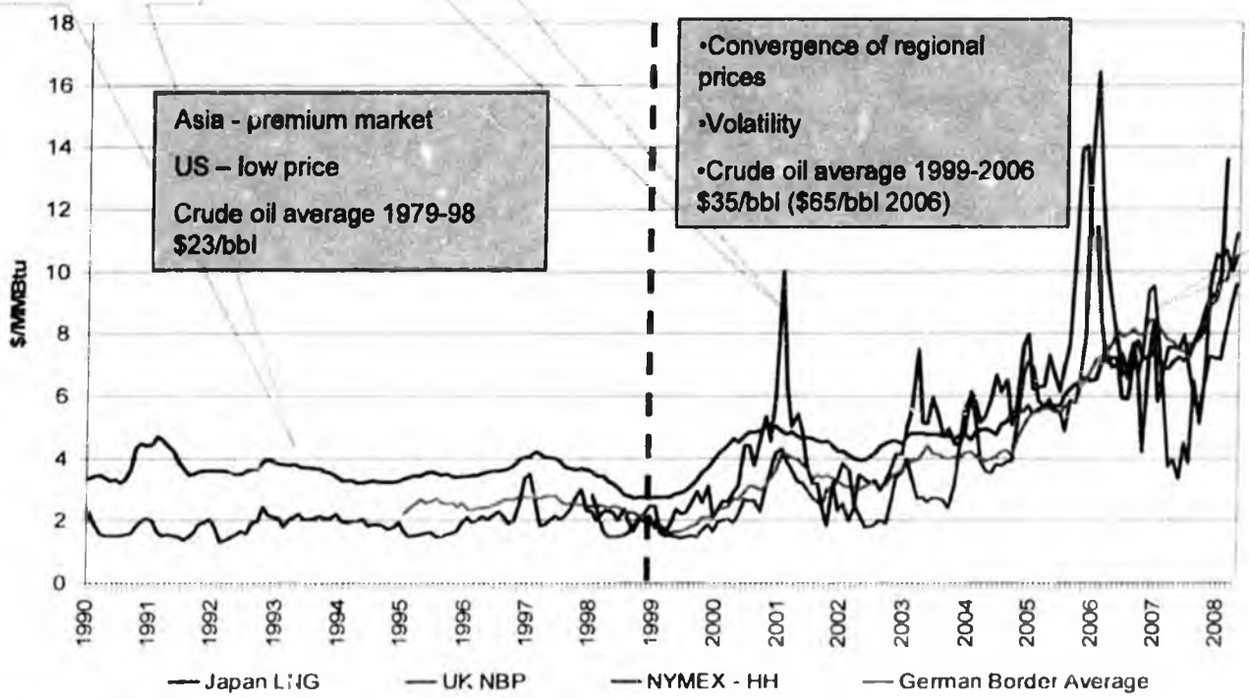
- **Oil today around $135/bbl**
- **New long term LNG contracts into Asia priced at close to oil parity**
- **Implies a significant premium of $9/MMBtu over USA prices**
- **This premium will more than compensate for the higher cost of an LNG scheme**

- **This divergence of Pac Rim LNG and USA gas prices is unlikely to sustain in the long term**
  - Fundamental price projections
  - Pac Rim LNG price drivers

Asian contract prices normally sit above HH; but in some periods they do not.

Asia markets provide higher prices
- Asia dependent on LNG
- Prepared to pay some security premium to lock in volumes

Relativity to HH very volatile



Price convergence
- LNG can be moved out of US (not as easy as oil)
- Surge of Asia LNG prices

Source: Gas Strategies Consulting

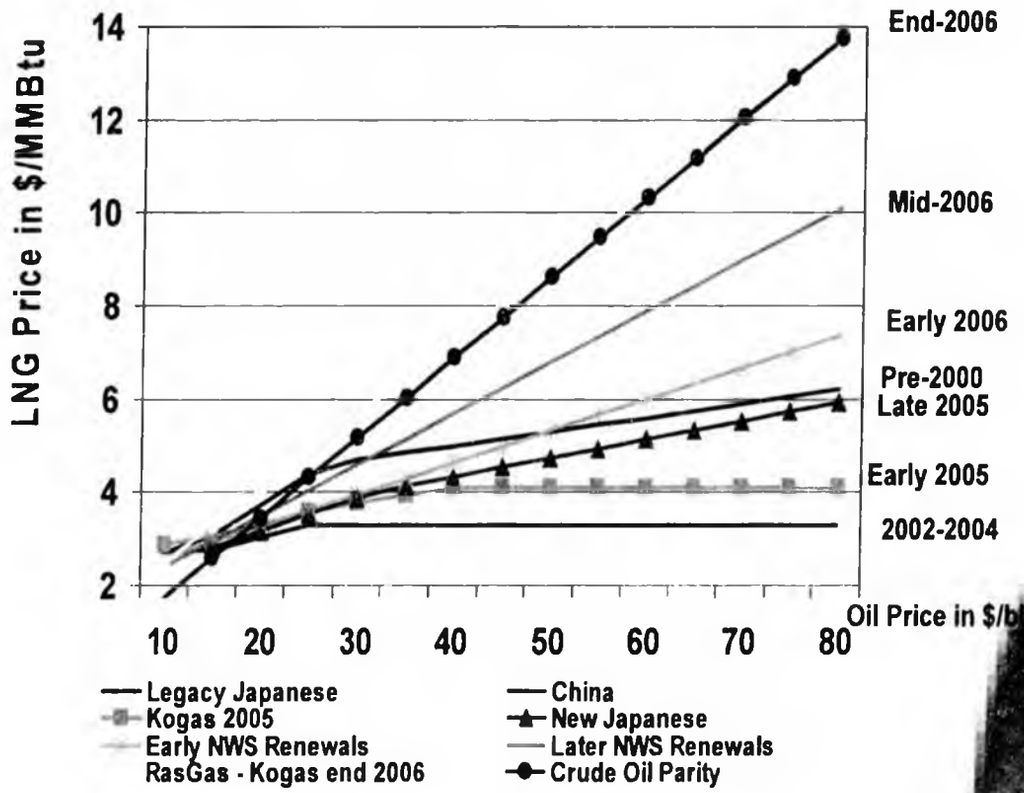
Rapid market changes lead to scatter of prices and renegotiation

2001 - 2004

- Over 10 suppliers and potential producers were offering supply
- Buyers achieved lower prices and a reduction in the oil price linkage
- Price ceilings at around $25/Bbl oil prices in some contracts
- Result was much lower LNG price at high oil prices in new contracts

2005+

- Return to "sellers' market" has strengthened position of producers
- Qatar has pushed the LNG price to crude oil parity at $100/Bbl oil in its most recent deals
- Wide scatter of price opened up by the sudden rise in oil price
- Virtually all legacy contracts renegotiating



Asian premium is limited by growing flexible supply

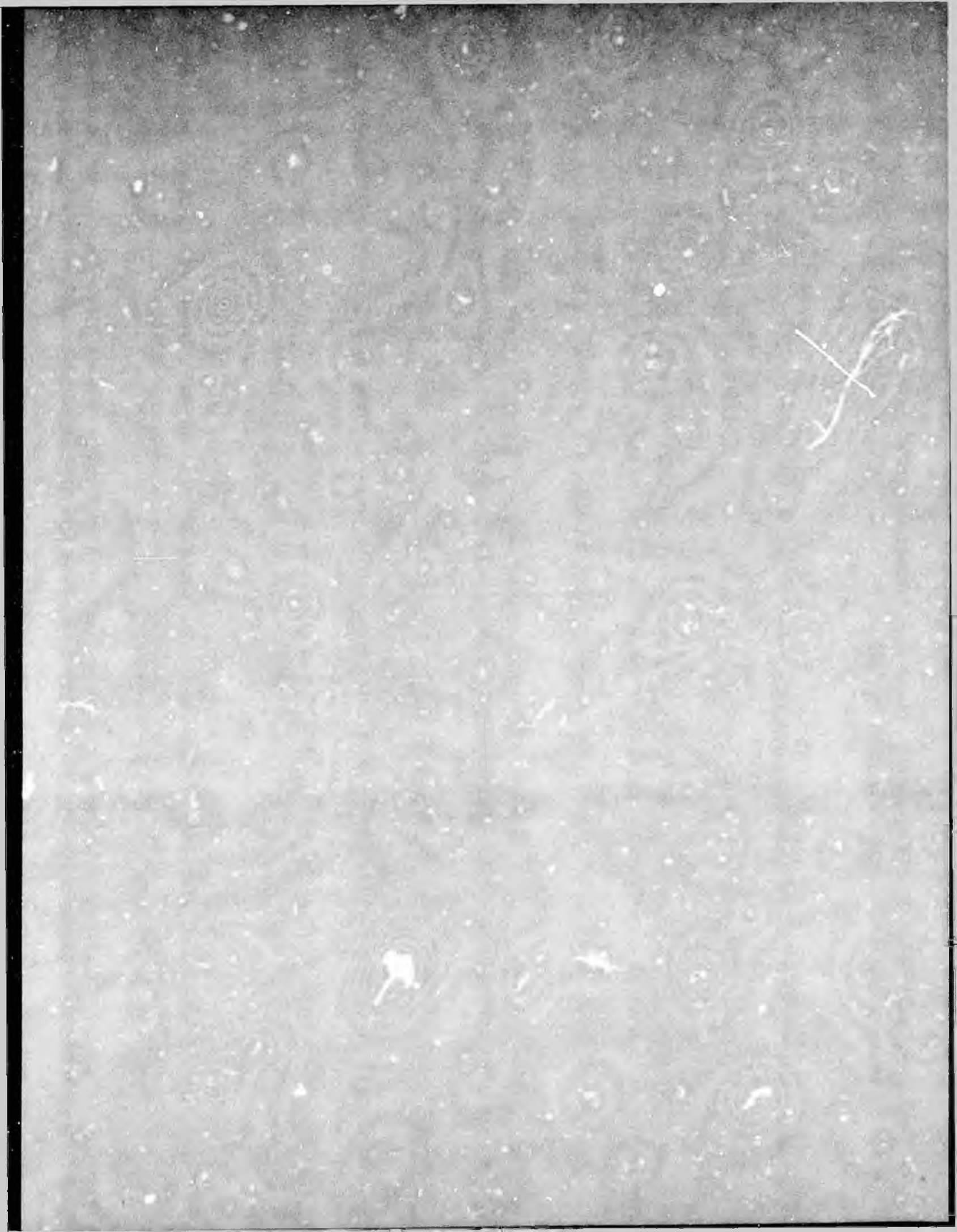
- **2007 US supply 16 mtpa**
- **50 mtpa of new supply for US, UK under construction**
- **Can potentially be diverted to Asia**
  - US, UK Markets liquid – at Seller's choice
  - Diverting Asia LNG to US requires Buyer's concurrence
- **Some Asian premium will remain driven by security concerns**

mtpa	Operating	Under Construction	Total
Pacific Basin	74.6	27.4	102.0
Middle East	47.4	53.5	100.9
Atlantic Basin	70.5	12.1	82.6
TOTAL	**192.5**	**93.0**	**285.5**

Source: Gas Strategies Consulting

Key Messages

- **LNG project carries significantly greater cost and risk of delay or failure than the pipeline project**
  - Sales negotiations complex
  - Quantity and quality constraints
  - Producer alignment hard to retain
- **Current level of Asian price premium unlikely to sustain**
- **Producers have substantial competing LNG interest in the Pacific region.**
- **Producers' perception of this risk likely to drive preference for the pipeline**



RM05-01

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIRMAN

January 28, 2005

The Honorable Ethan Berkowitz
Minority Leader
House of Representatives
Alaska State Legislature
Alaska State Capitol
Juneau, Alaska 99801-1182

Dear Representative Berkowitz:

Thank you for your January 4, 2005 letter expressing concerns regarding the ownership and operation of a future Alaskan natural gas pipeline. The successful licensing and completion of such a project is of primary national importance.

In your letter, you observe the three largest producers of Alaskan oil – BP, ConocoPhillips, and ExxonMobil – also hold more than 90 percent of the proven North Slope natural gas reserves. These three parties own the existing Trans Alaska Pipeline System (TAPS) oil transportation pipeline, and you express the concern that if they are permitted to also own a new gas transportation pipeline, they could act to frustrate the development of Alaska's energy resources. You ask whether an Alaskan gas pipeline project proposed pursuant to the Alaska Natural Gas Transportation Act (ANGTA), will be subject to regulatory oversight sufficient to identify and remedy practices prohibited under antitrust provisions. You also similarly question whether an Alaskan gas pipeline developed outside of ANGTA's authority will conform to the antitrust laws.

An Alaskan gas pipeline proposed pursuant to ANGTA, or developed outside of ANGTA to bring Alaskan gas to other states, will be subject to the Commission's jurisdiction under the Natural Gas Act (NGA). The Commission has acted under its NGA authority to promote competition in natural gas transportation by requiring open access, nondiscriminatory treatment, and the timely construction of new gas facilities. In authorizing an Alaskan gas pipeline under the NGA, the Commission will seek to promote investment in and the development of Alaskan gas reserves to expedite the delivery of these reserves to markets in and out of Alaska, in conformity with antitrust laws. In doing so, we will be mindful of the congressional and presidential pronouncements you referenced in your letter.

In the Alaska Natural Gas Pipeline Act of 2004 (ANGPA), Congress directed the Commission to prescribe open season and other rules applicable to any new Alaskan pipeline intended to transport gas from the North Slope to the contiguous states. The Commission has initiated a proceeding in RM05-1-000 to address the open season rules and is currently considering comments from the public on how to manage requests for pipeline capacity, how to price mandated capacity expansion on a new pipeline, and the issue of tying capacity allocations to other gas services. Comments submitted by prospective pipeline sponsors and shippers, and by other interested parties, identify means by which market power might be exercised, and suggest how the industry and the Commission might prevent and respond to such abuses. These comments, as well as the concerns you raise regarding the potential for gas producers to exert undue control in the event they build a producer-owned gas pipeline, will be discussed and addressed in the rulemaking proceeding.

Currently, the Commission does not have before it any application for authority to construct an Alaskan natural gas transportation pipeline. Thus, it is not possible to respond specifically to issues, including antitrust matters, which may arise once such an application is filed. However, all such issues will be carefully assessed by the Commission when an application is submitted for a pipeline project, and the Commission will do everything it can to preclude antitrust abuses and promote competition in the authorization, construction, and operation of a future Alaskan natural gas pipeline. In response to your immediate concern, it would be prudent to conclude that the antitrust issues which concerned Congress and the President over twenty years ago are still valid and will be addressed by our Commission in our proceedings.

I will place your letter and my response in our open access rulemaking docket (RM05-01). If I can be of further assistance in this matter, please do not hesitate to contact me.

Best regards,

Pat Wood, III
Chairman

AS 43.90.130(6)(B):
"reasonable engineering increments" means the amount of additional capacity that could be added by compression or a pipe addition using a compressor size or pipe size, as applicable, that is substantially similar to the original compressor size and pipe size;

RFA
2.4.1.4 General Expansion Provisions
For purposes of determining the reasonable engineering increment of capacity that can be added by the addition of pipe (commonly referred to as "looping") the Licensee shall base its calculations on: (1) the addition of a full valve section based on the original pipeline Mainline valve locations; and (2) pipe diameter that would be required were a full loop of the pipeline to be undertaken.

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June 9, 2008

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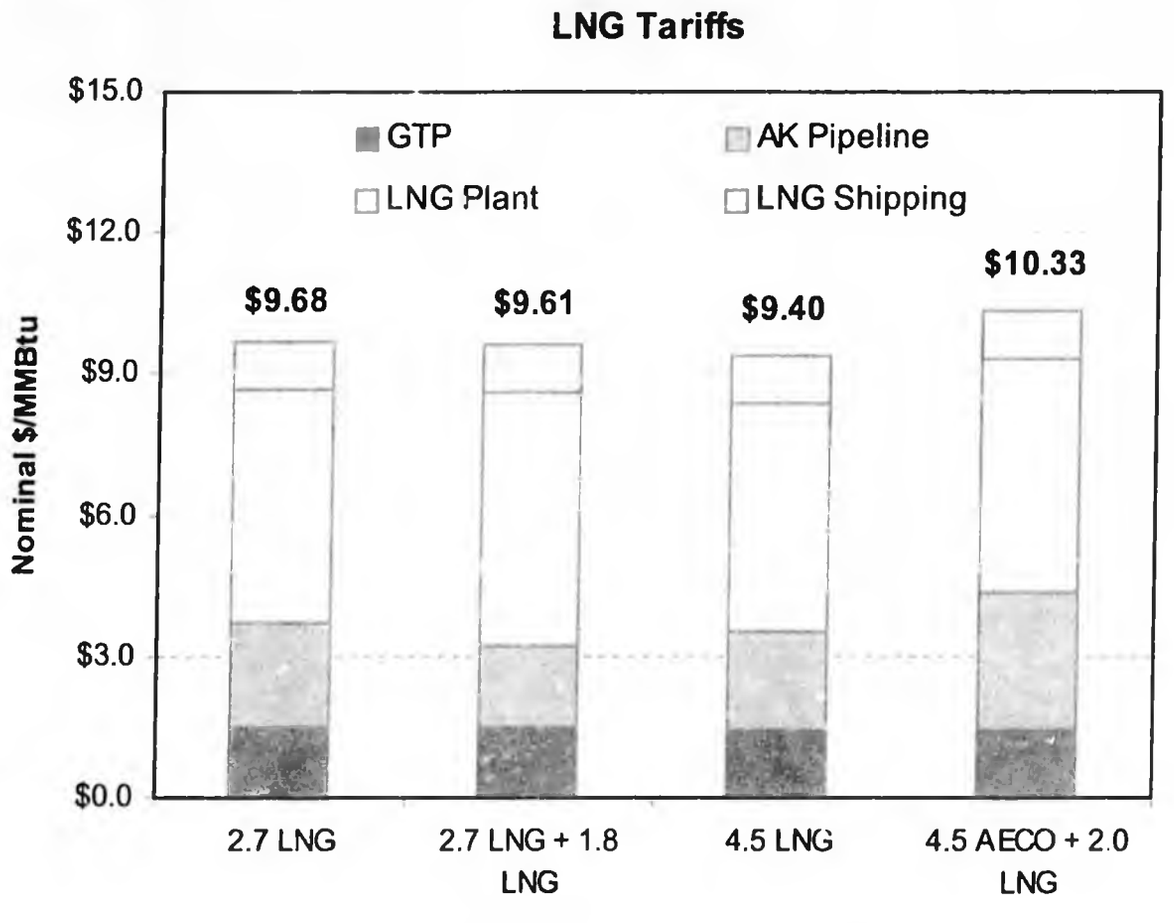
Expected LNG Tariffs for the LNG Project Configurations Considered



- Assumed same terms as TC proposal
- Differences to tariff are:
  - Higher capital
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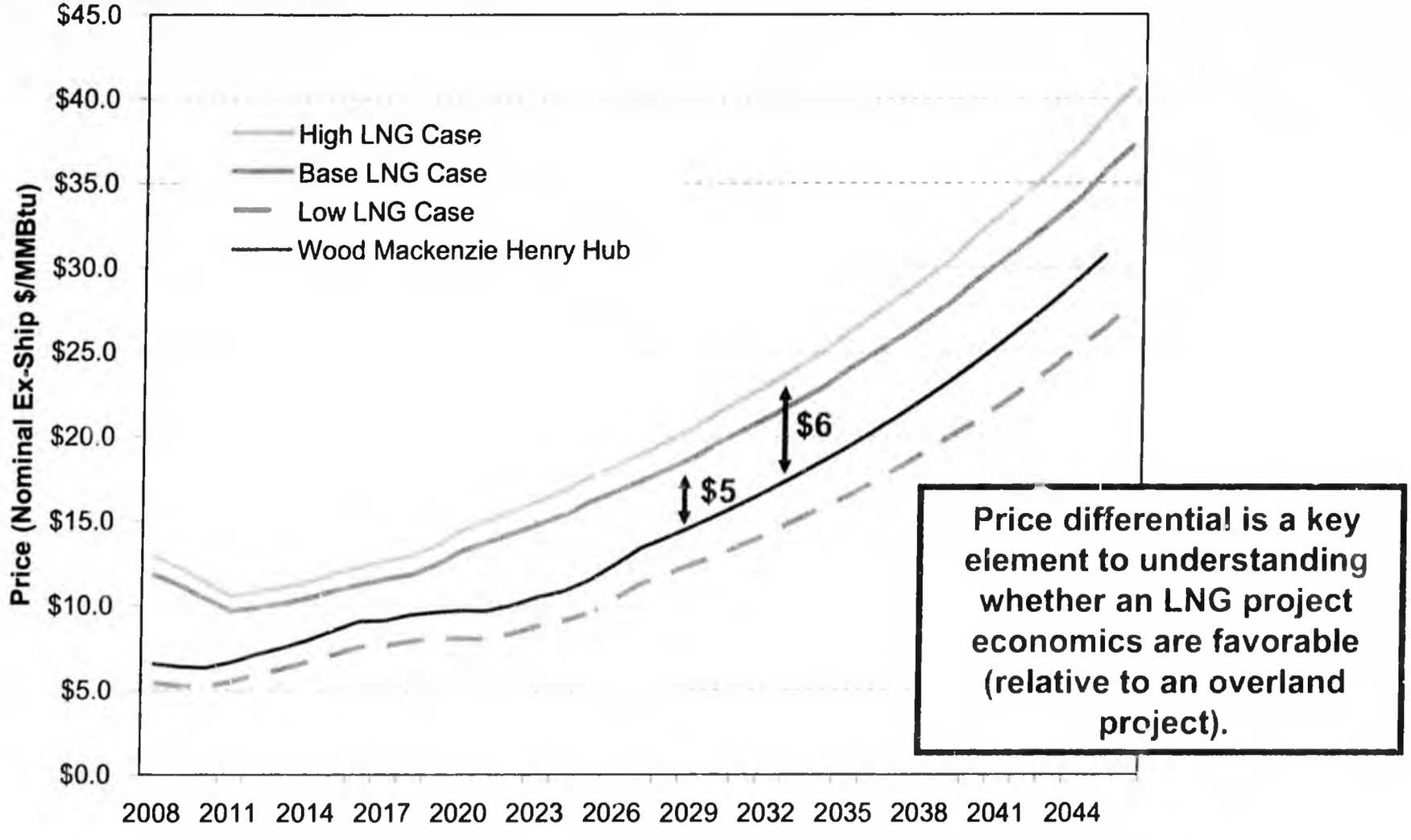
  - LNG shipping

Applying the Gas Strategies Asian Price Formula Expectations



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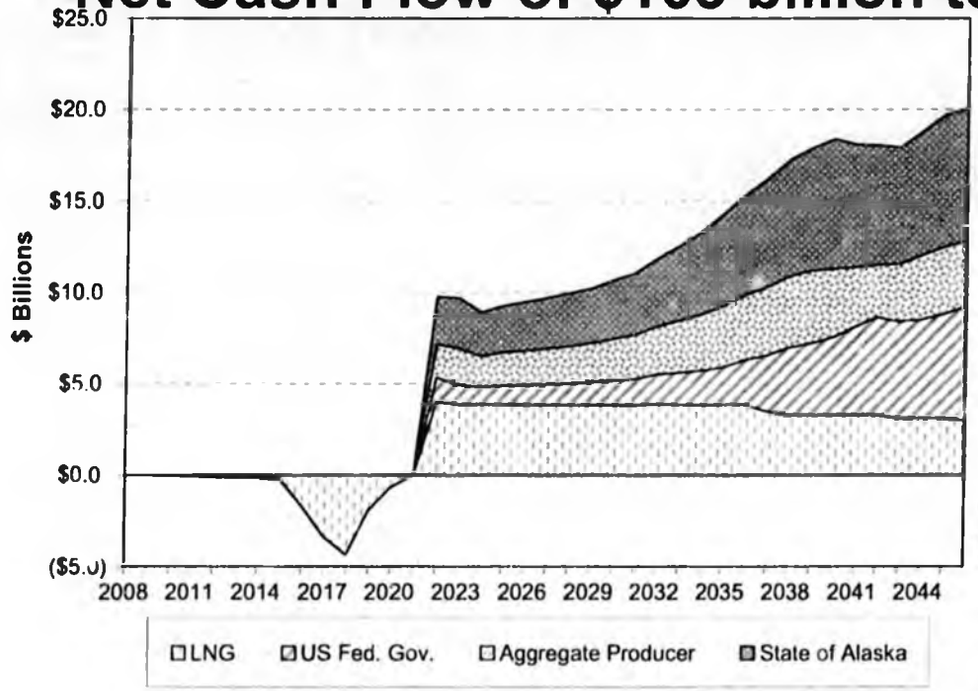

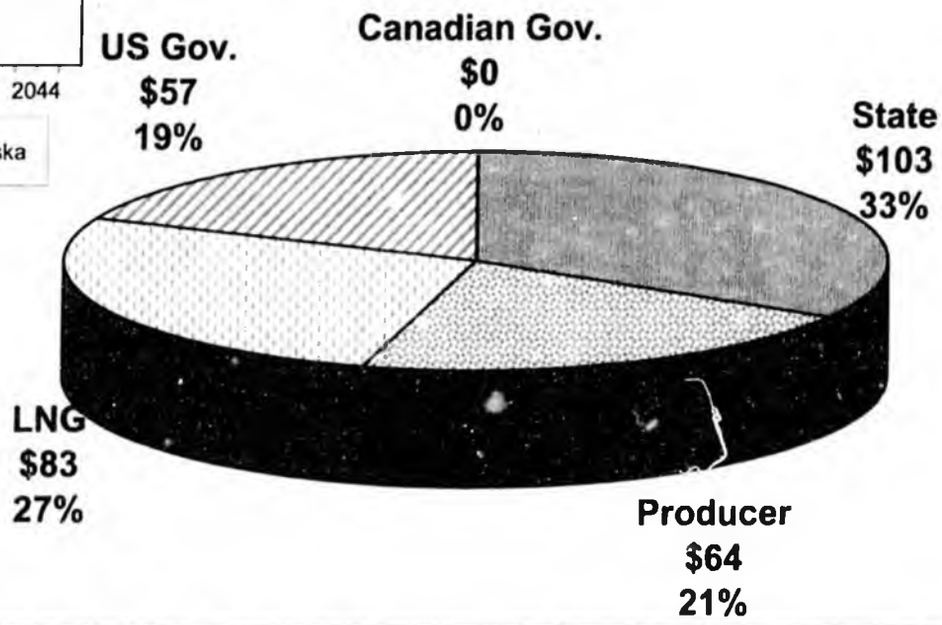

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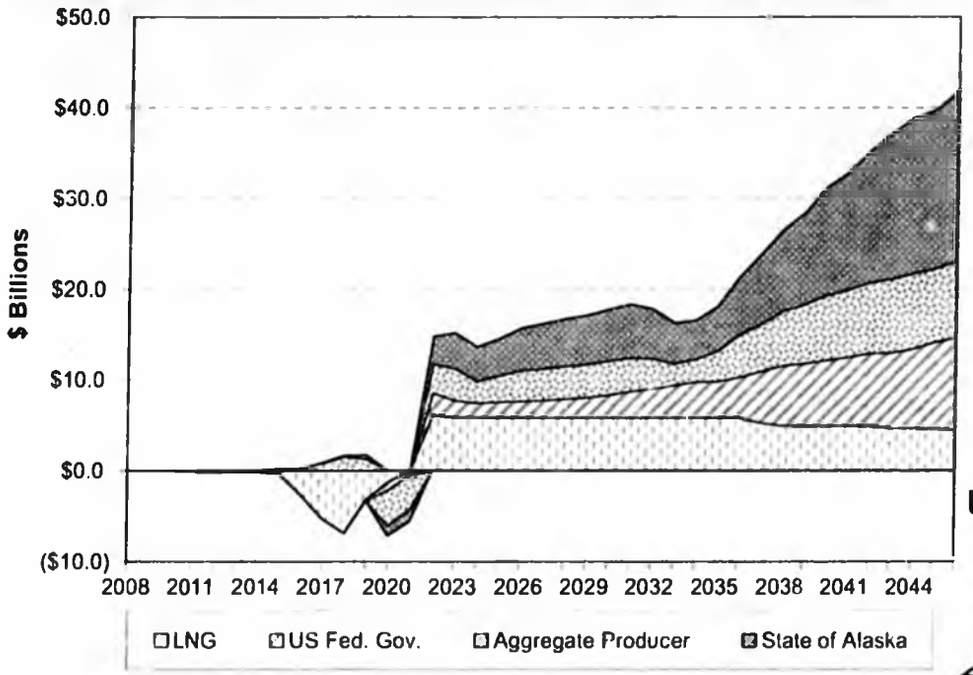

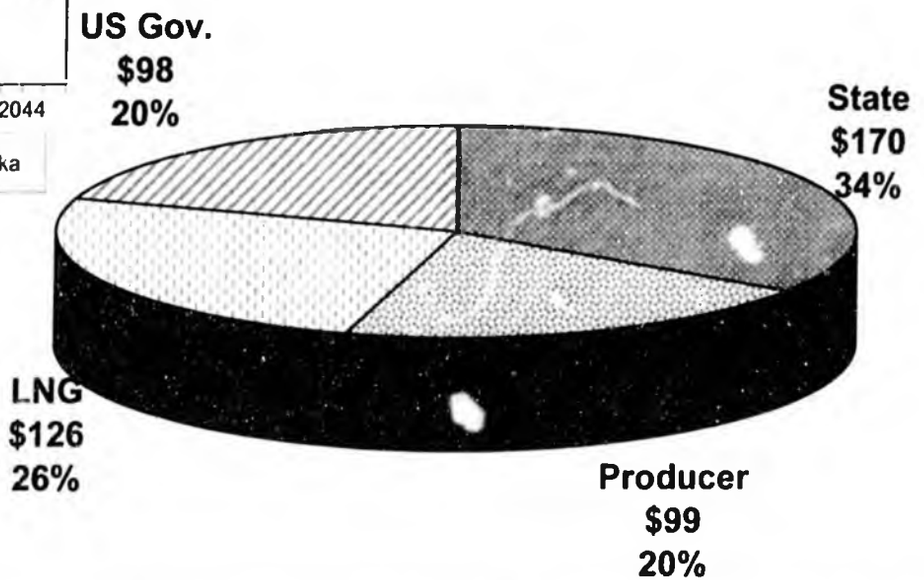

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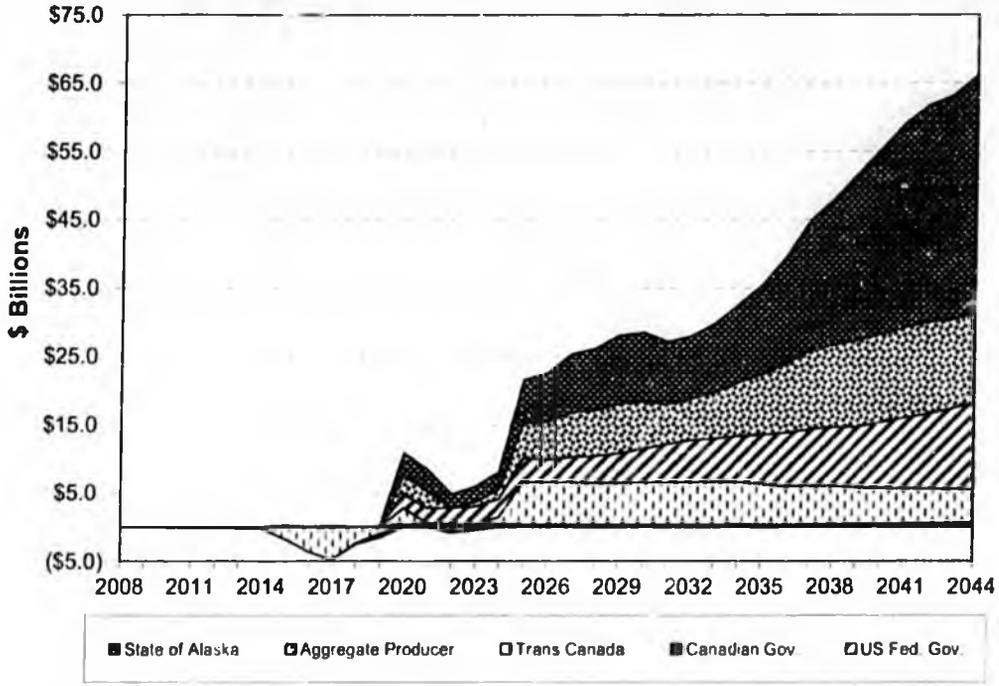

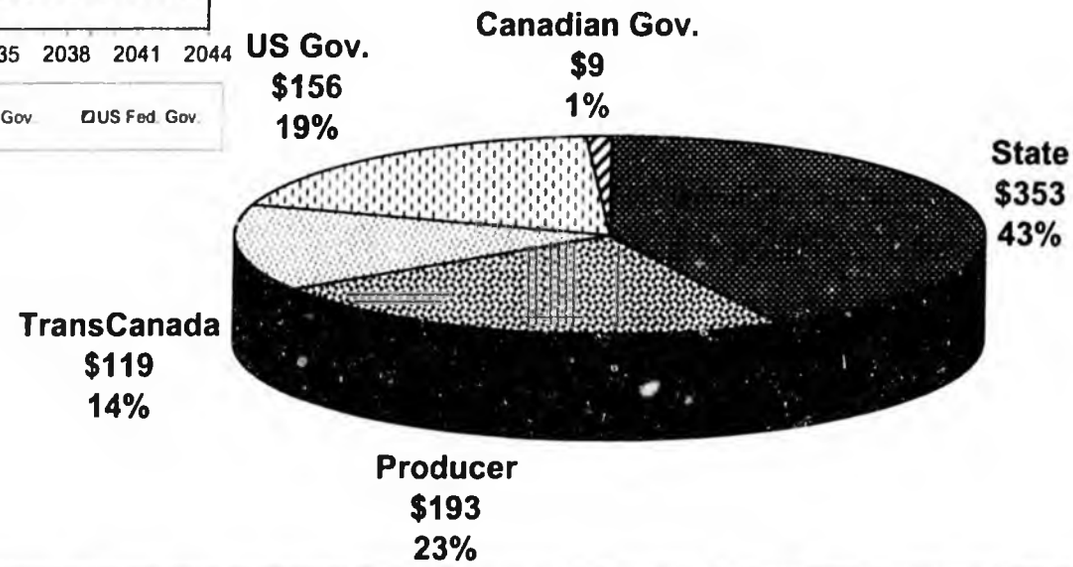

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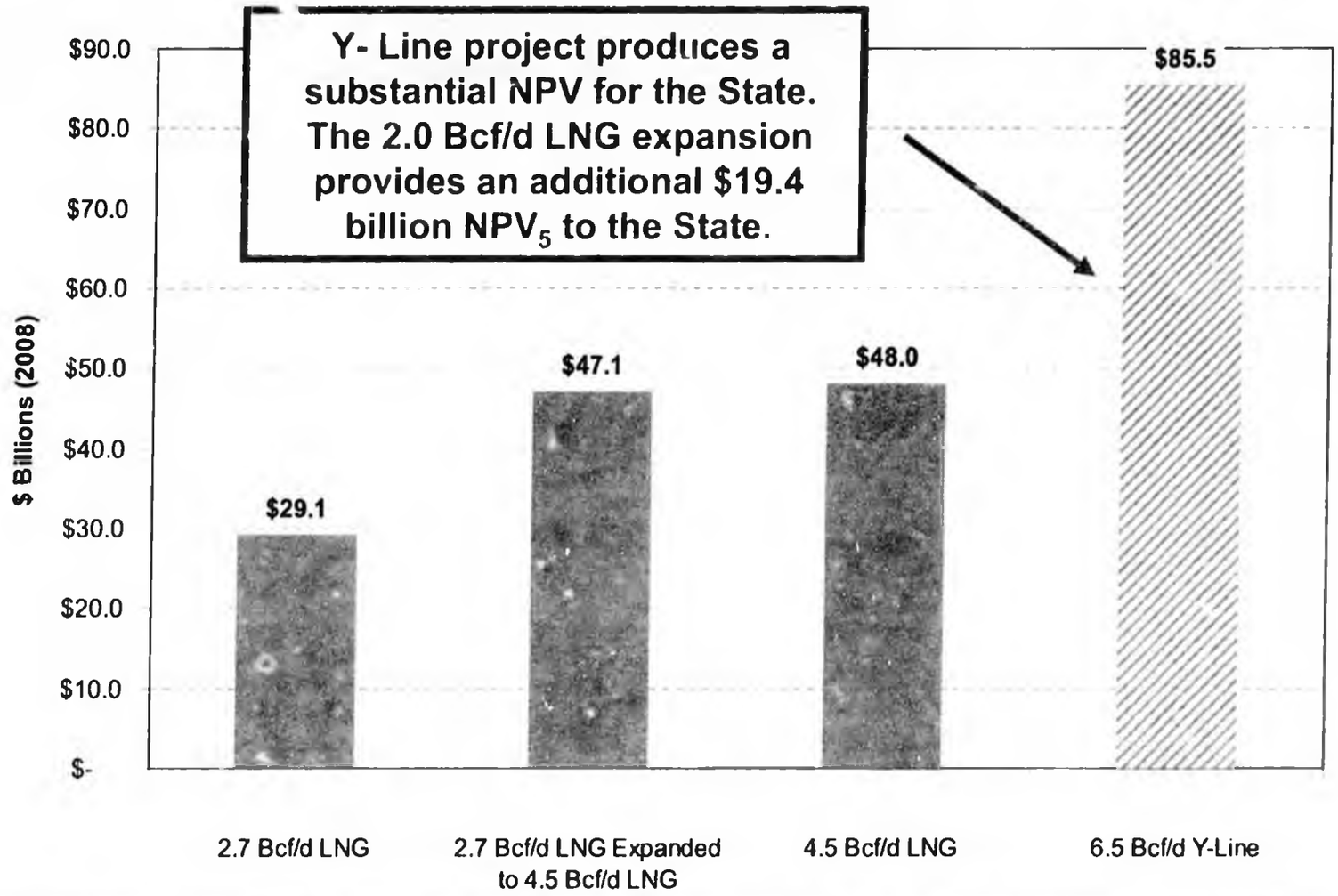

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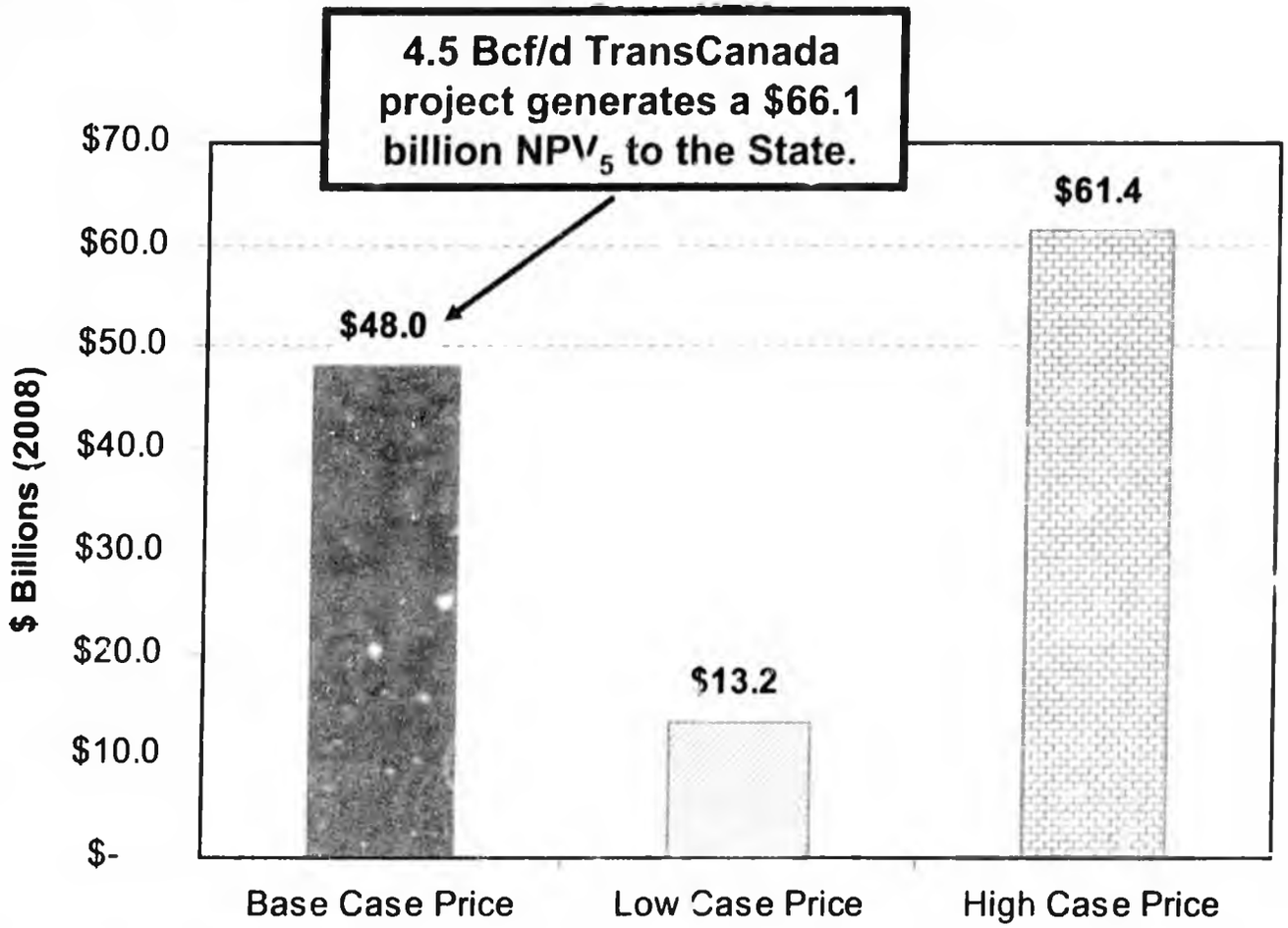

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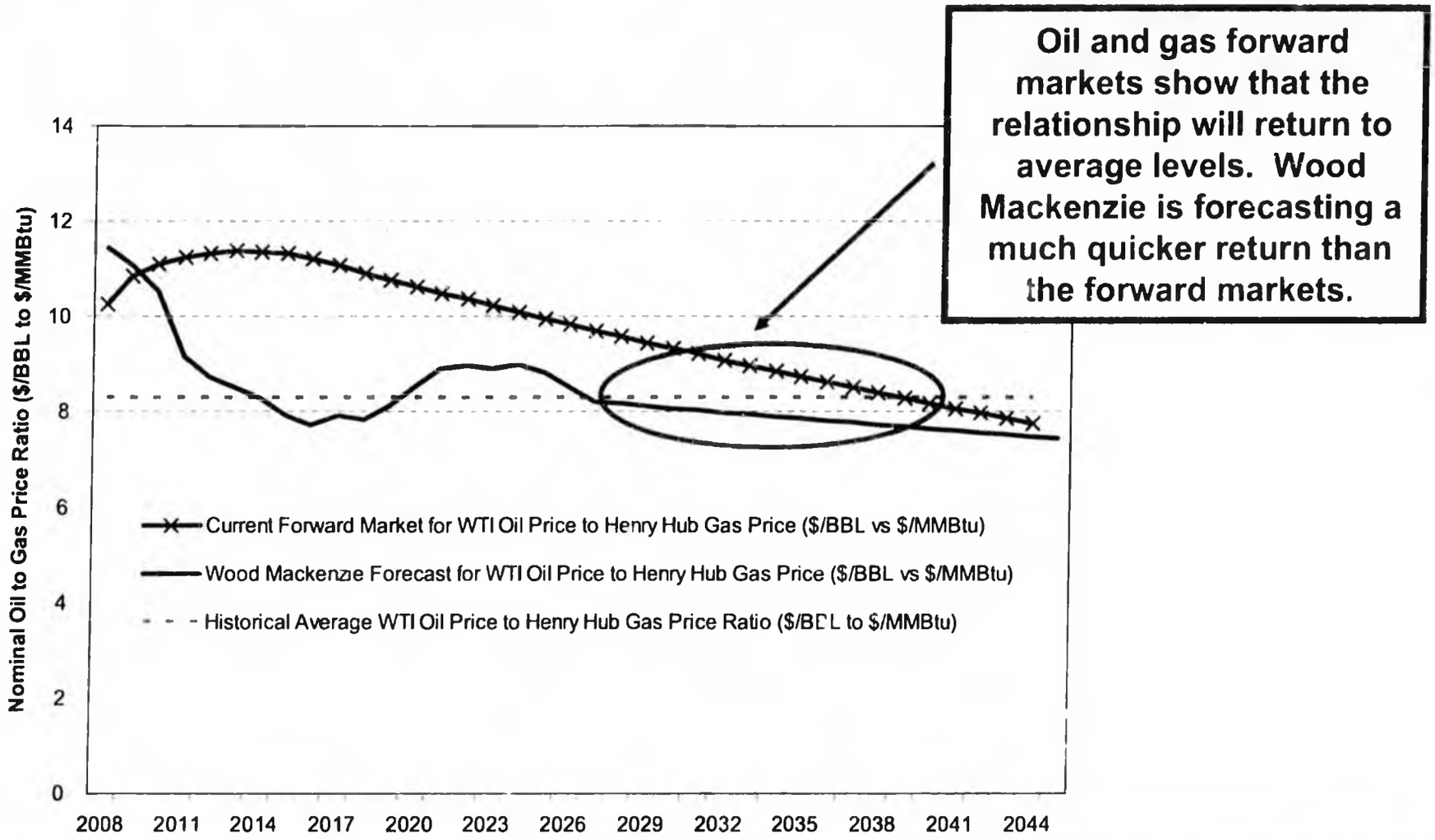

Implications to LNG Project NPV from High Oil Prices

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- Considered oil to gas price ratio assumptions of 8, 9, 10 and 11 to 1

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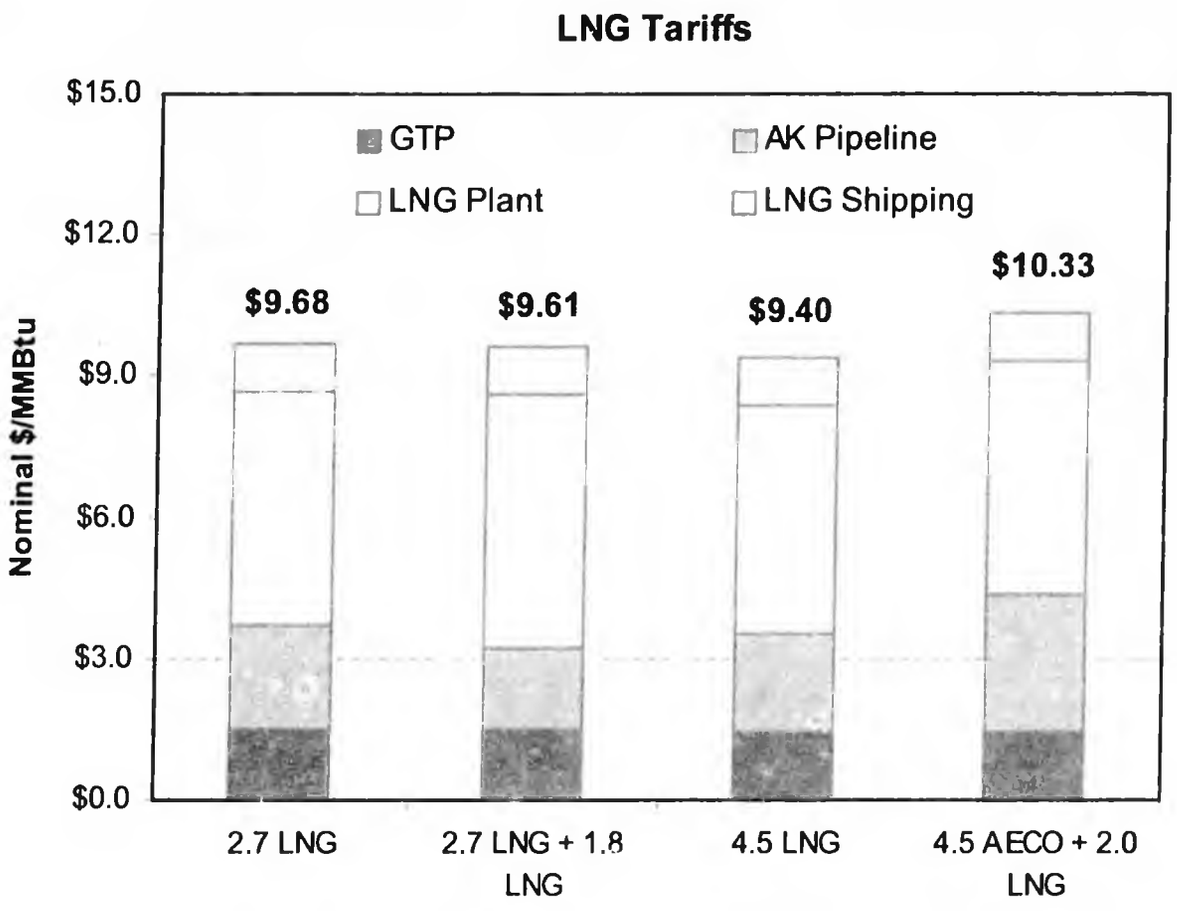

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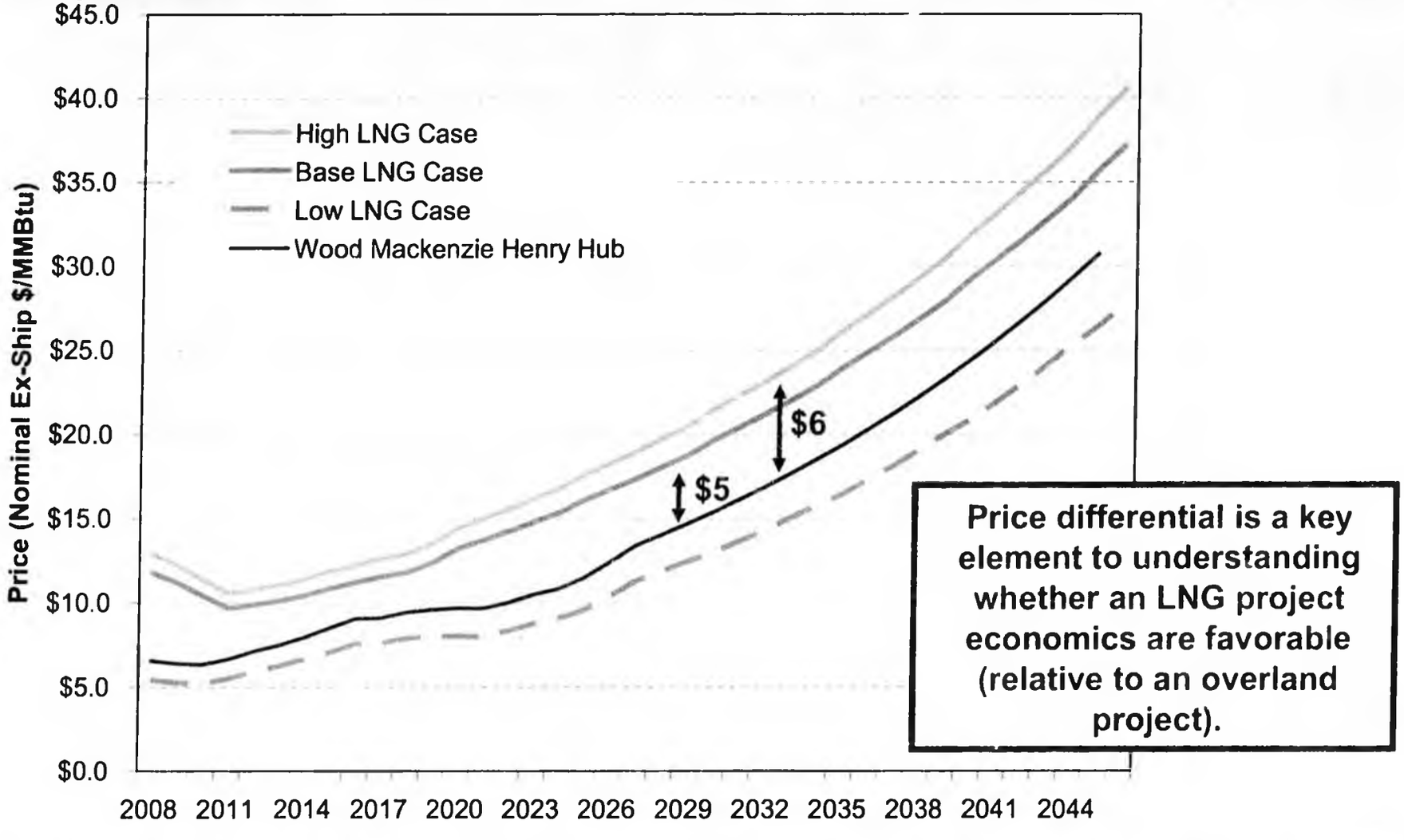

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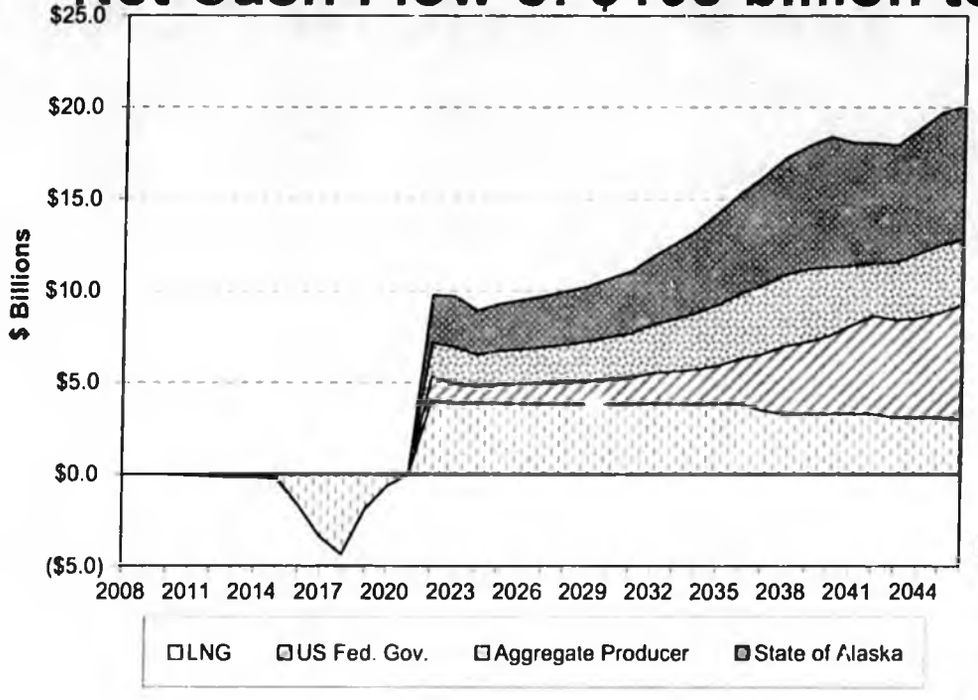

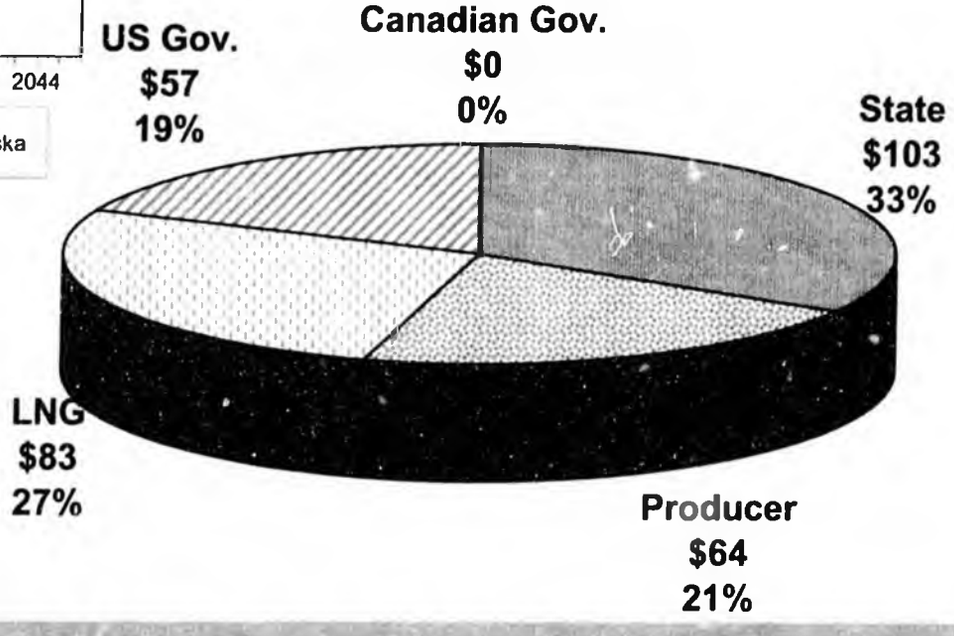

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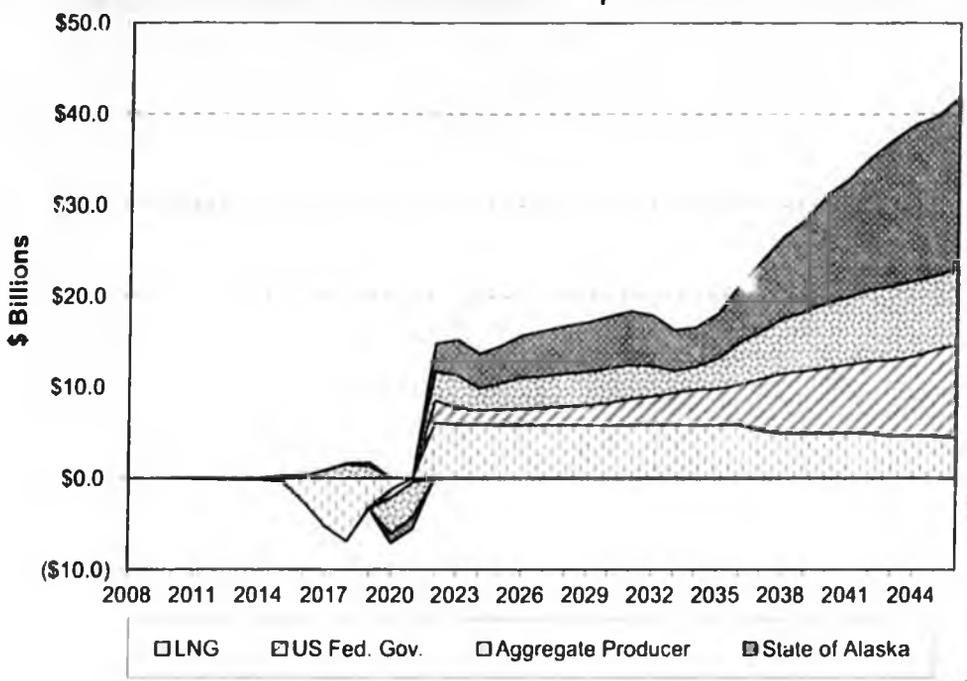

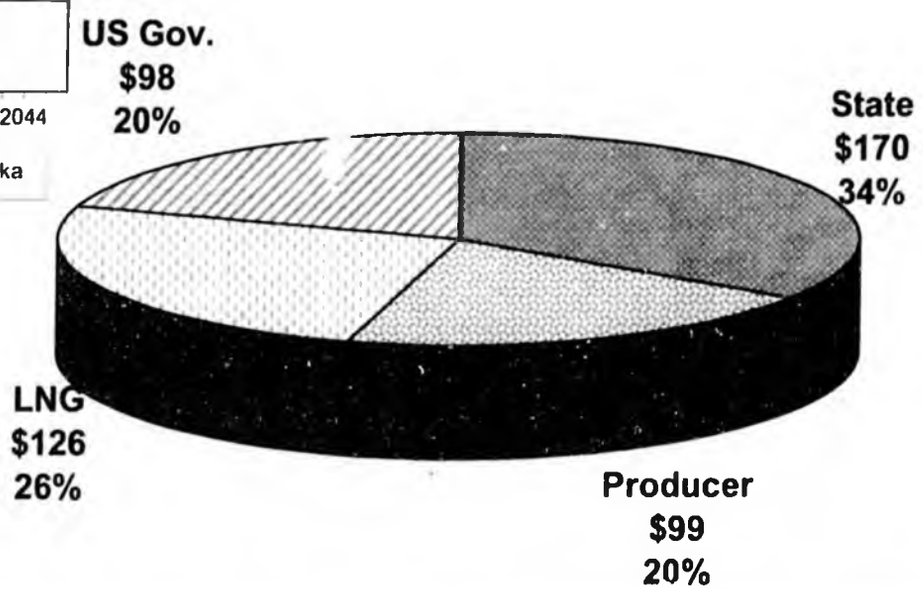

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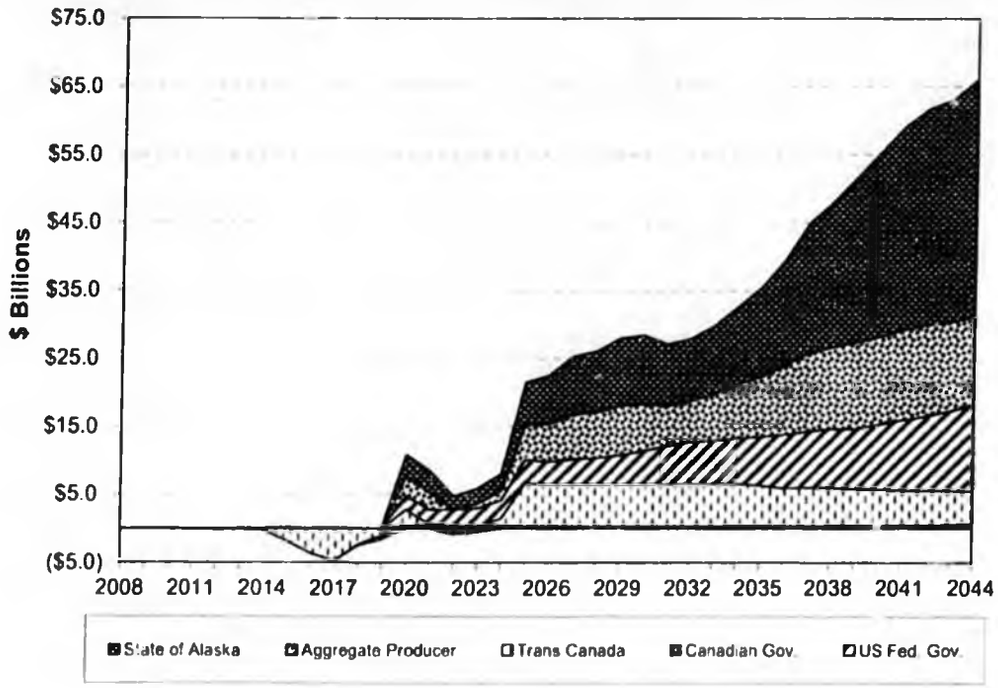

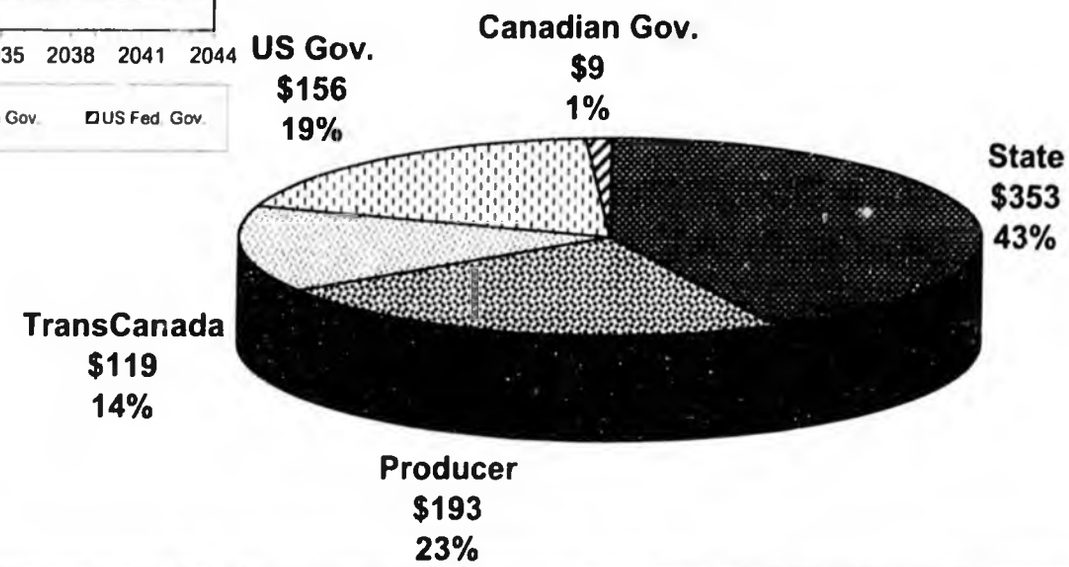

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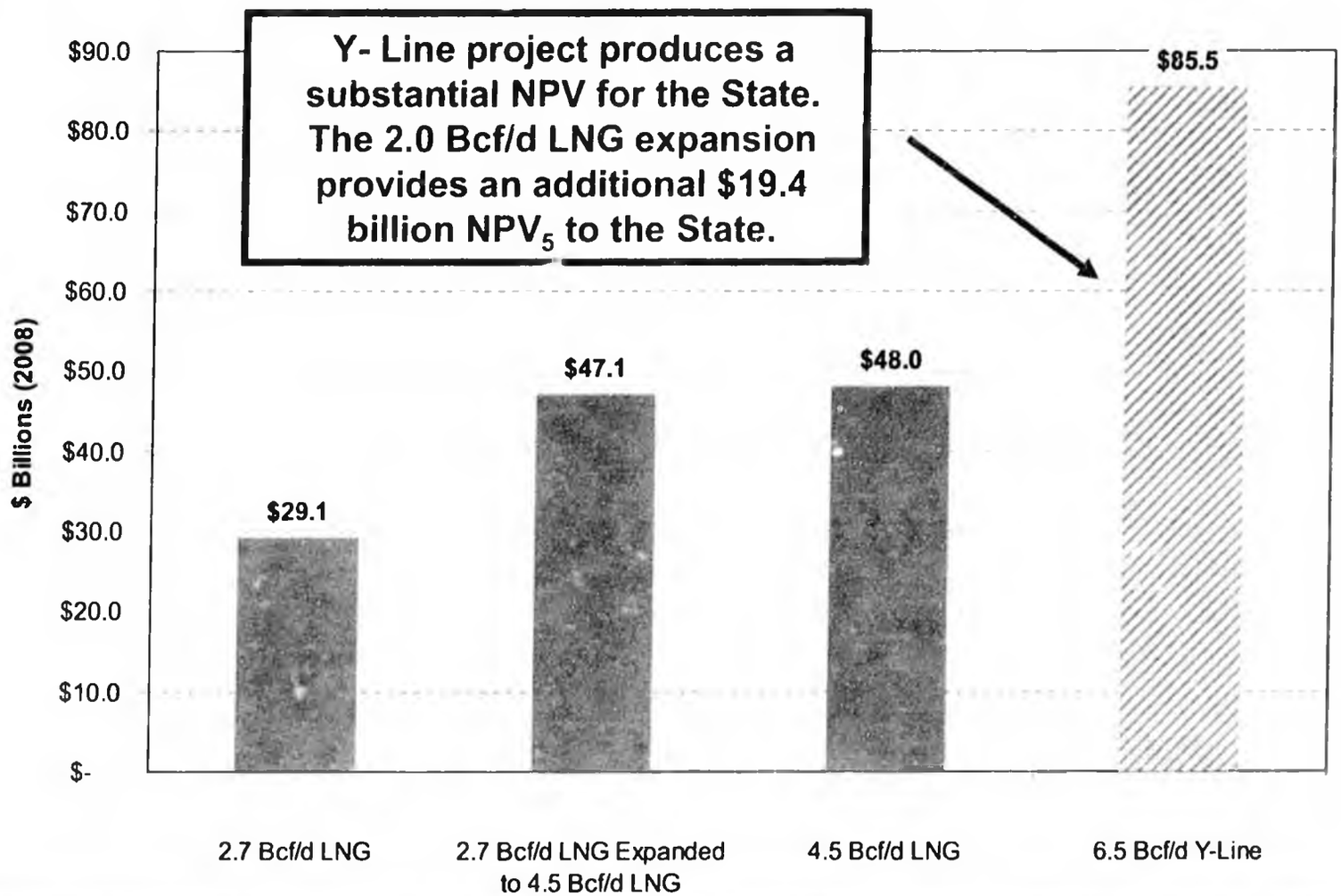

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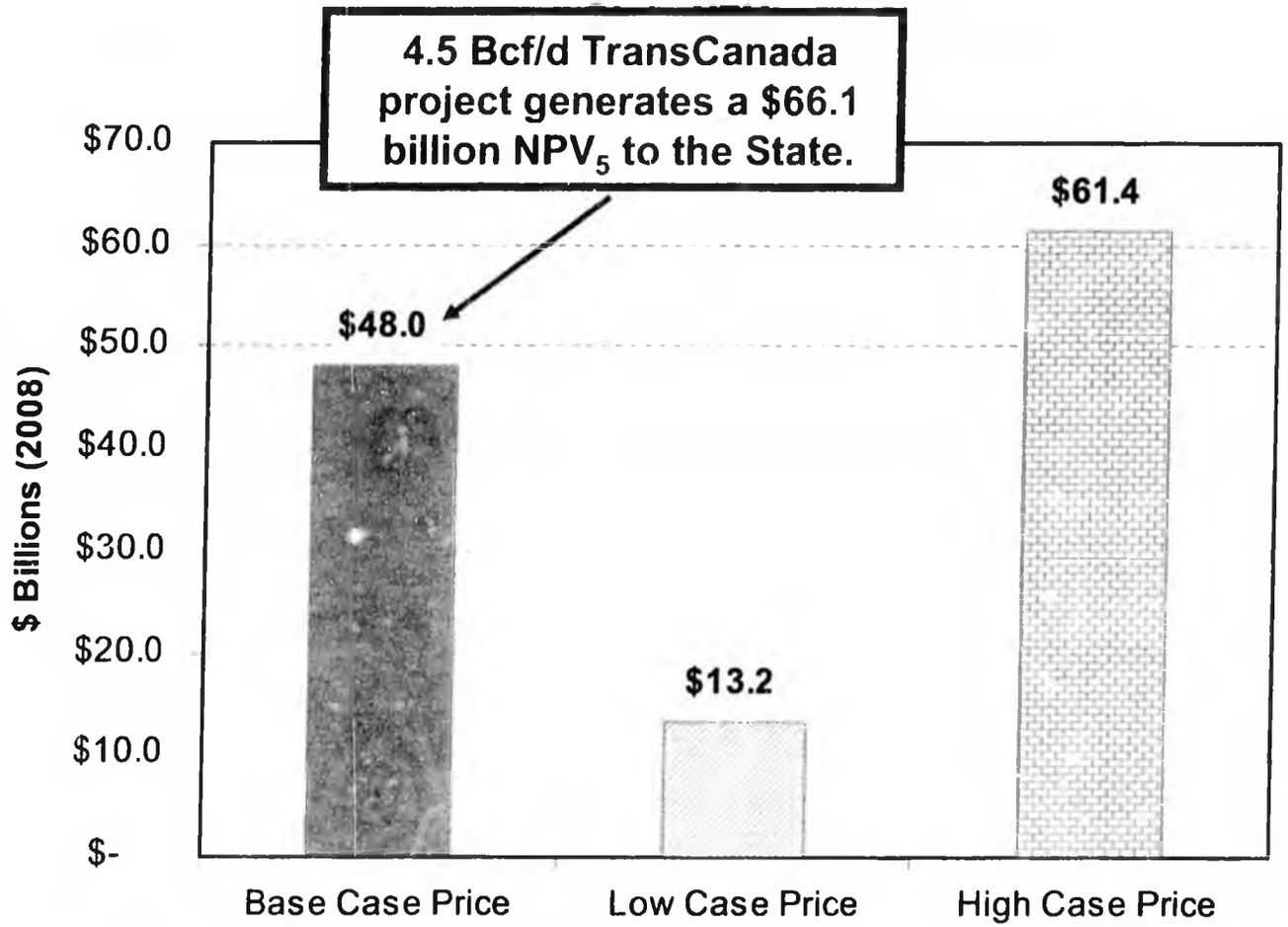

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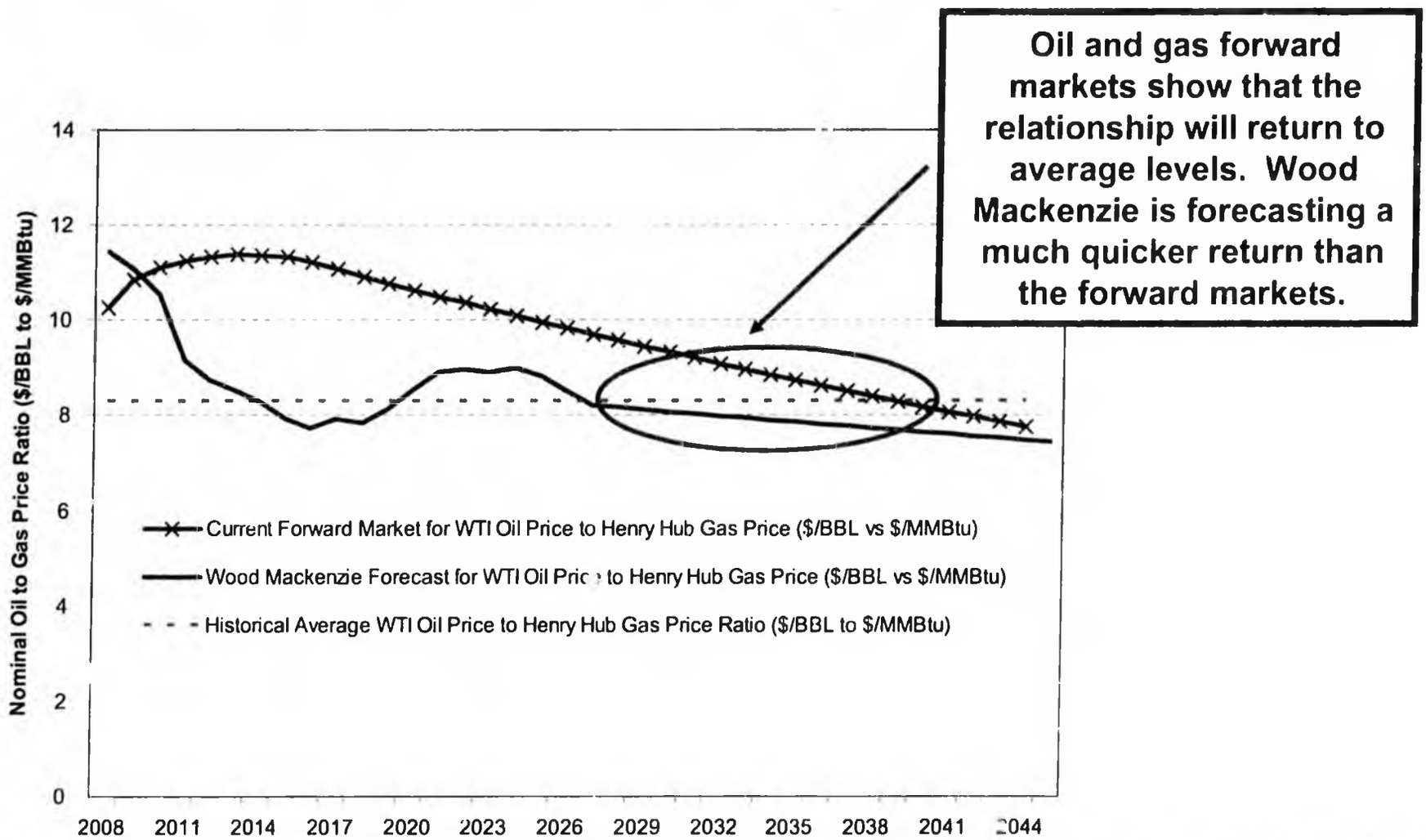

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AGIA

The Alaska Gasline Inducement Act

Producer Incentives to Expand Pipeline for Third-Party Shippers

Don Shepler

Greenberg Traurig LLP

Interests as Producers May Conflict With Interests as Pipeline Owners

"Wishing to deny the fruits of their monopoly power to nonowner shippers, the [producer-owned] pipeline would have to deny pipeline access to nonowner shippers. . . . The analysis above should make it clear that producer-ownership of the pipeline creates incentives to deny or impede such future capacity expansion."

Report of the Attorney General to Congress Pursuant to The Alaska Gas Transportation Act at 58-59.

Stranded Gas Development Act History

- Draft SGDA contract included the 10 ANGPA requirements for expansion and added 20 more conditions

- Explorers objected that they were better off with no contract expansion terms

- Draft LLC agreement provided that pipeline board representatives owed fiduciary duties not to the pipeline, but to producers that appointed them.

AGIA History

- ConocoPhillips alternative proposal provided for expansion at higher cost to new shippers than AGIA requires

- Denali proposal makes no expansion commitments

Alaska Gasline Inducement Act
Legislative License Hearings

Juneau, Alaska

June 6-10, 2008

Analysis of Project Costs/Schedule and Tariffs

AGIA Analysis Technical Team

Bill Sparger
Energy Project Consultants, LLC

Eric Briel
Westney Consulting Group, Inc

Cost and Schedule Analysis

- General analysis methodology
- Base case specific analysis methodology
- Base case cost/schedule results
- Expansion cases specific analysis methodology
- Expansion cases cost/schedule results

Why Cost/Schedule Ranges?

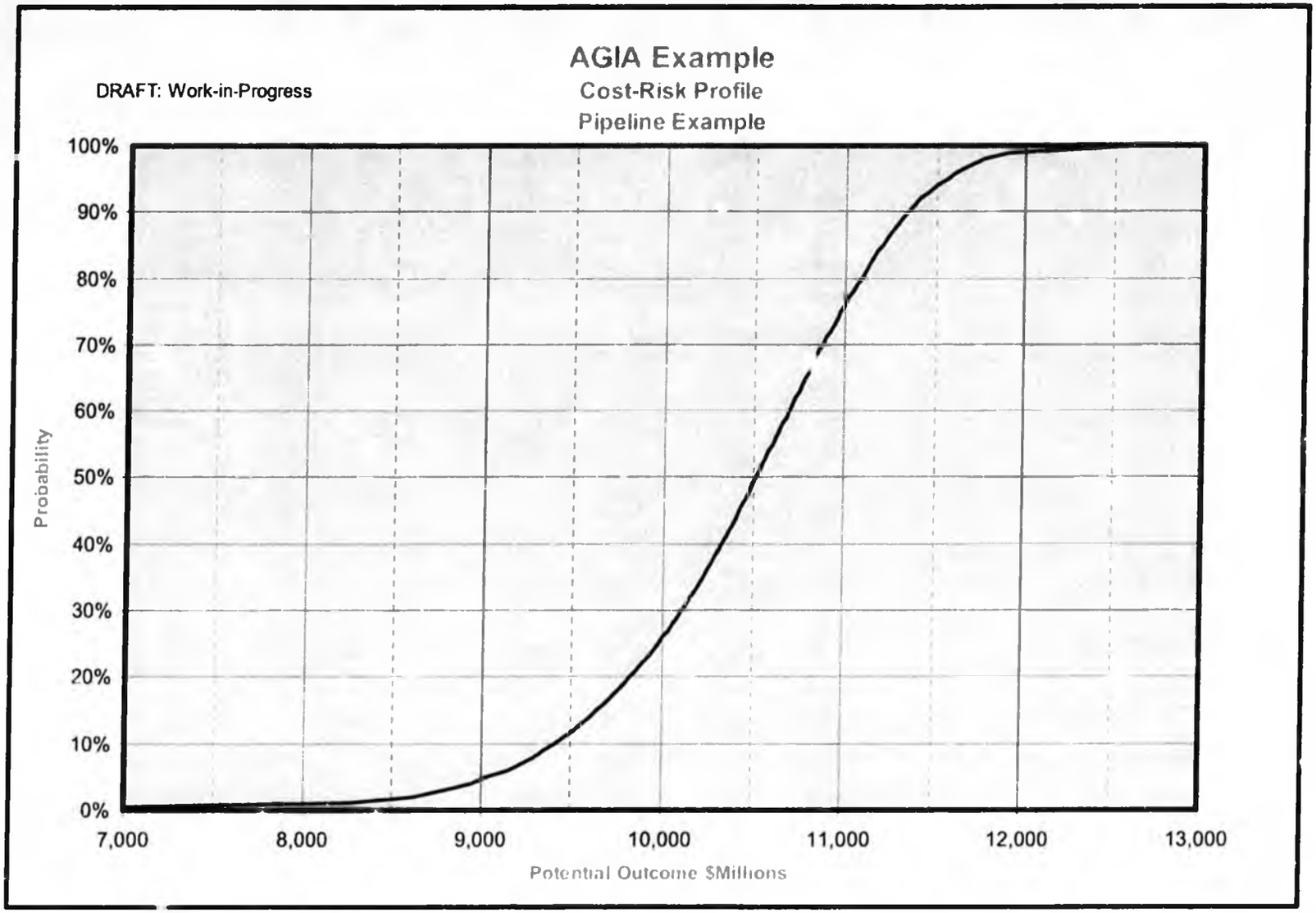
- Single point estimates for large complex projects may not be the most useful to evaluate future project outcomes
- Understanding and applying the ranges in which the costs and schedule durations are likely to fall will result in a more representative analysis of the economic expectations for a project

General Analysis Approach

- Analyze cost and schedule on a sub-project level
- Based on 2007 dollars (removes uncertain cost escalation risk from the base analysis and)
- Cost escalation is applied later in the NPV analysis as a sensitivity

Project Risk Indicative Modeling (PRIMS)™ Methodology

- Understand risks associated with project
- Apply expert judgment to establish:
  - Best and Worst case ranges
  - Distributions that reflects risks
- Perform Monte Carlo simulation, which is a well proven and long accepted method
- Provide cost and time-risk probability distributions for NPV analysis


AGIA Example
Cost-Risk Profile
Pipeline Example
DRAFT: Work-in-Progress
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Probability
7,000
8,000
9,000
10,000
11,000
12,000
13,000
Potential Outcome $Millions

4.5 bcf/d Base Case - Technical Team Input

Cost

- Development
- GTP
- Alaska Pipeline
- Canadian Pipeline
- Integrated Project
- Miscellaneous

Schedule

- Subprojects
- Integrated Project

Spend Curves (cash flow)

Costs/Schedule Analysis

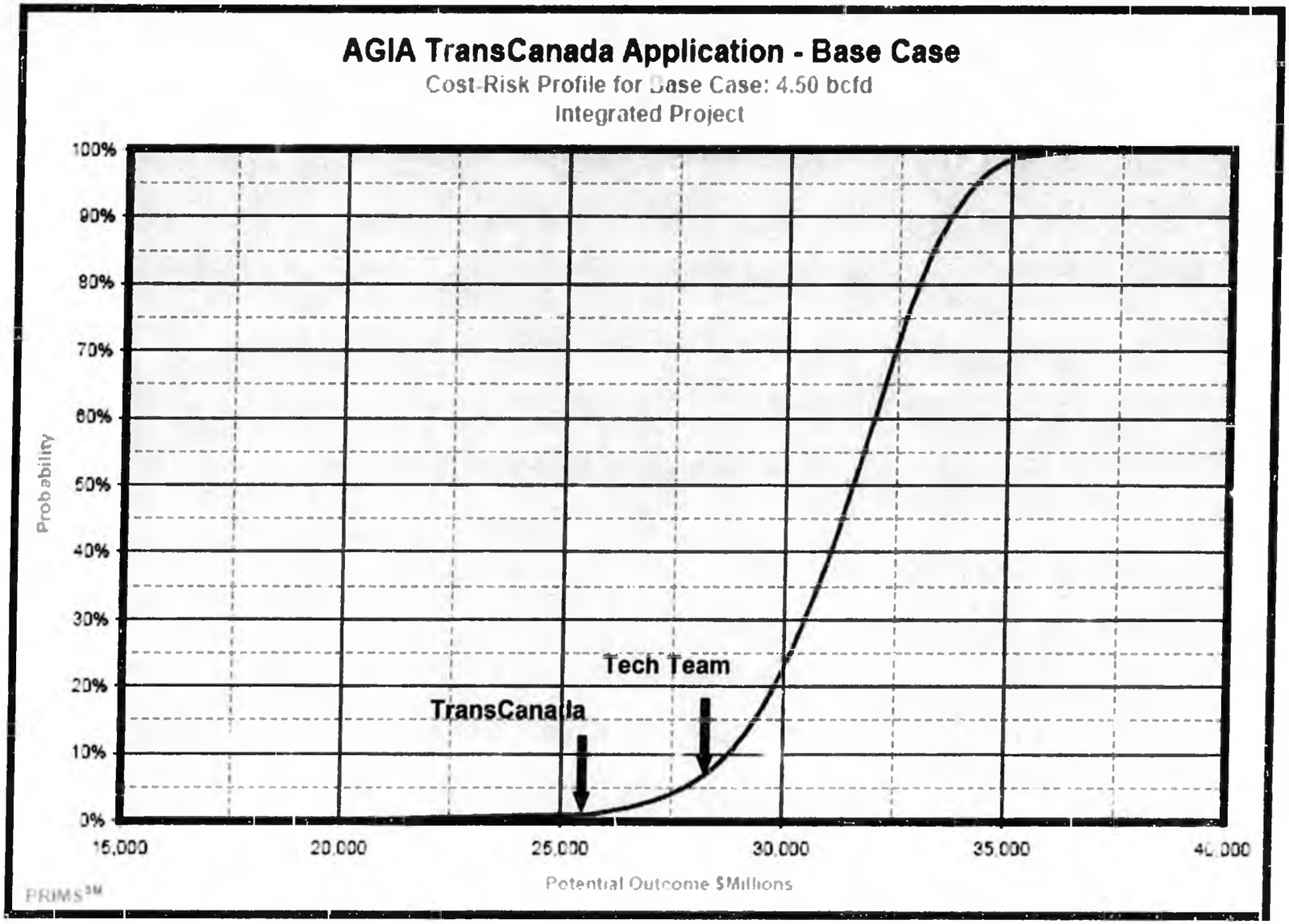
Costs

- Started with review of TransCanada cost breakdown by subproject
- Prepared independent cost estimates using same subproject breakdown
- Established best/worse case ranges
- Established other Miscellaneous Costs

Costs/Schedule Analysis

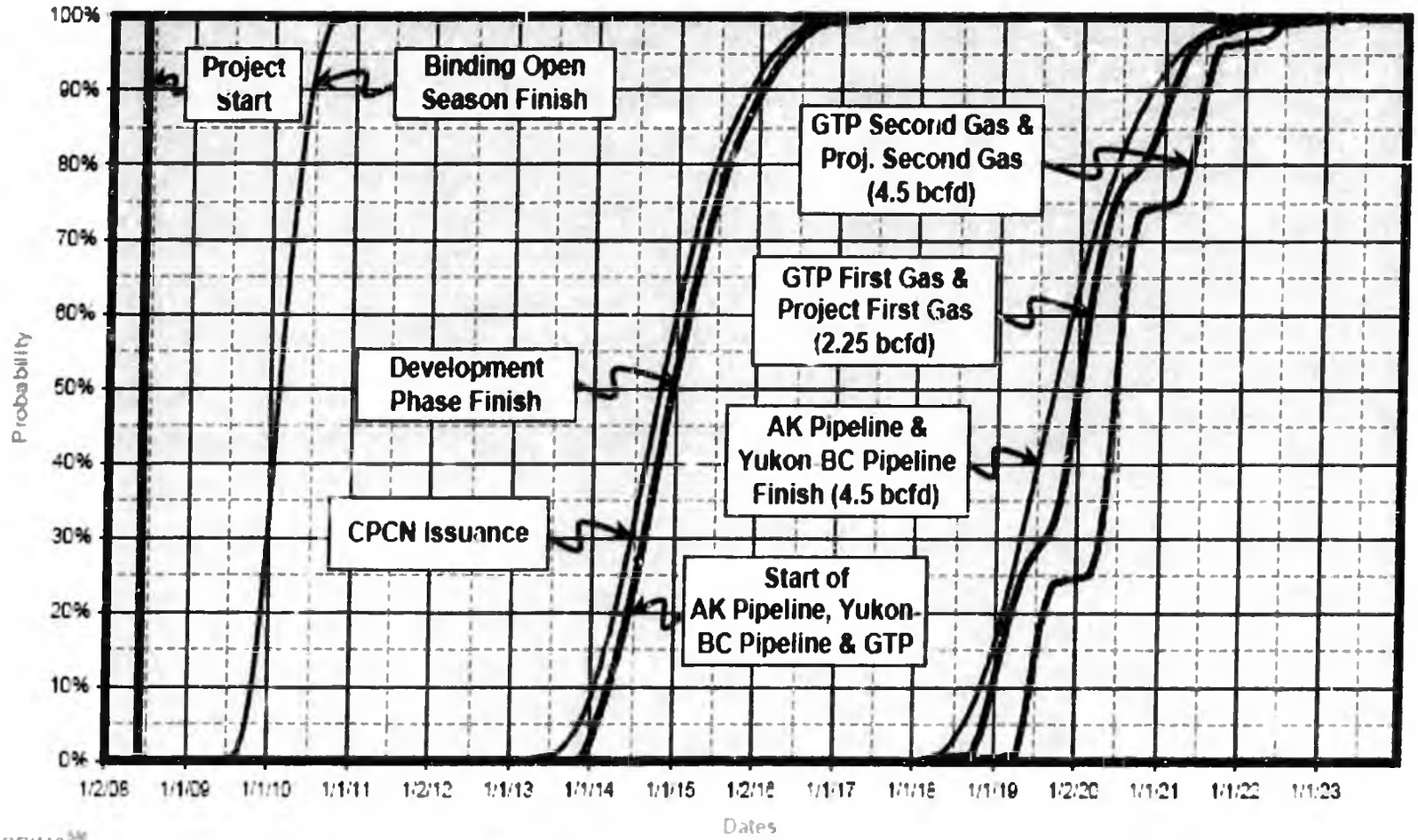
Schedule

- Started with review of TransCanada schedule by subproject
- Prepared independent schedule and activity logic
- Established final schedule for ranging
- Established best/worse case schedule activity durations


AGIA TransCanada Application - Base Case
Cost-Risk Profile for Base Case: 4.50 bcfd
Integrated Project
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Probability
Tech Team
TransCanada
15,000
20,000
25,000
30,000
35,000
40,000
Potential Outcome $Millions
PRIMS℠

AGIA TransCanada Application - Base Case

Time-Risk Model Profile for **Base Case**: 4.50 bcfd (Base Case)
Integrated Project



PRIMS℠

Miscellaneous Costs

- Line Pack
- Fuel
- Operations and Maintenance (O&M)
- Cost escalation
- Spend Curves (cash flow)

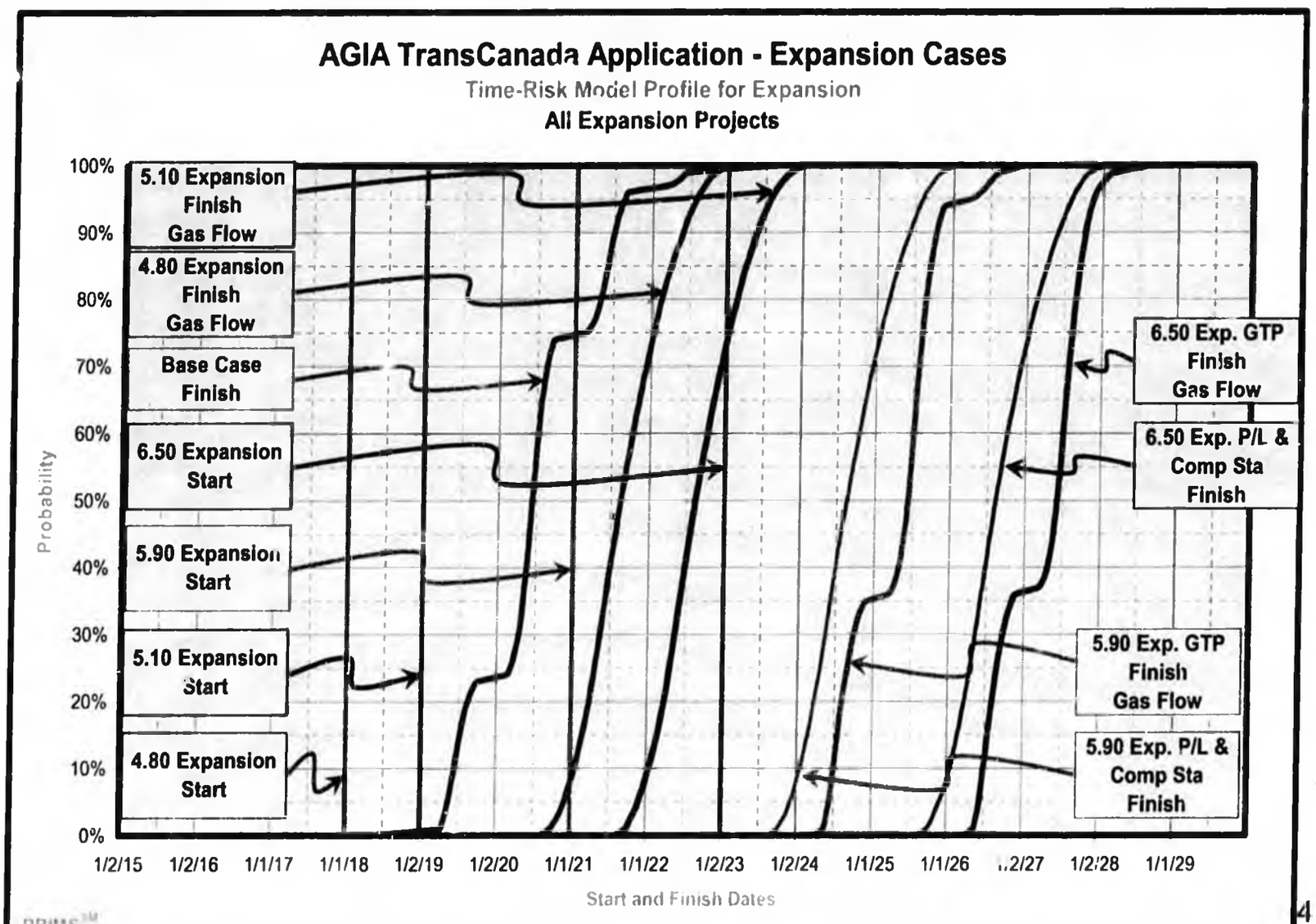
Expansion Cases

- TC Alaska has committed to a project design that will accommodate volumes between 3.5 and 6.5 bcf/d by using only incremental compression for expansion

  "Simple-Low Cost-Fast"

- Base Case 4.5 bcf/d

- Expansion Cases
  - 4.7 bcf/d
  - 4.8 bcf/d
  - 5.1 bcf/d
  - 5.9 bcf/d
  - 6.5 bcf/d


AGIA TransCanada Application - Expansion Cases
Time-Risk Model Profile for Expansion
All Expansion Projects
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Probability
5.10 Expansion Finish Gas Flow
4.80 Expansion Finish Gas Flow
Base Case Finish
6.50 Expansion Start
5.90 Expansion Start
5.10 Expansion Start
4.80 Expansion Start
6.50 Exp. GTP Finish Gas Flow
6.50 Exp. P/L & Comp Sta Finish
5.90 Exp. GTP Finish Gas Flow
5.90 Exp. P/L & Comp Sta Finish
1/2/15
1/2/16
1/1/17
1/1/18
1/2/19
1/2/20
1/1/21
1/1/22
1/2/23
1/2/24
1/1/25
1/1/26
1/2/27
1/2/28
1/1/29
Start and Finish Dates

Expansion
The Bottom Line

- Simple
- Low Cost
- Fast

HB 3001
SB 3001
6/10/08
SPECIAL SESSION DOCUMENTS

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