

SCOMM

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Alaska Gasline Port Authority

Presentation to Senate Special Committee on Natural Gas Development



Project Economics

August 3-4, 2006



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Overview

- Introduction of the Analysis
- Price Assumptions
- LNG Project Concept and Gas Volumes
- Cost Assumptions
- Netback Calculations
- Upstream Returns to the Producers
- PTU Case
- Comparison of State Revenues
- Conclusions / Questions



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Introduction of the Analysis



Project Component Terms

- Upstream
 - Lease production activities

- Midstream
 - Feeder lines
 - GCP
 - Alaska pipeline(s)
 - LNG Facility
 - Canadian pipeline(s)

- Downstream
 - LNG marine transportation
 - Regasification and takeaway pipelines to market
 - NGL extraction in Alberta



Project Component Terms (continued)

- AGPA project components: owned, built and financed by AGPA
 - Pipeline(s) from Prudhoe Bay to Valdez and possibly to Canadian Border
 - LNG Facility in Valdez
- Producer project components: owned, built and financed by Producers
 - GCP
 - Feeder pipelines
 - Upstream production activities
 - Canadian route components (if not provided by Third Parties)
- Third Party project components: provided by third parties
 - LNG marine transportation
 - Regasification and downstream takeaway pipelines to market
 - Canadian route components (if not provided by Producers)



Price Assumptions

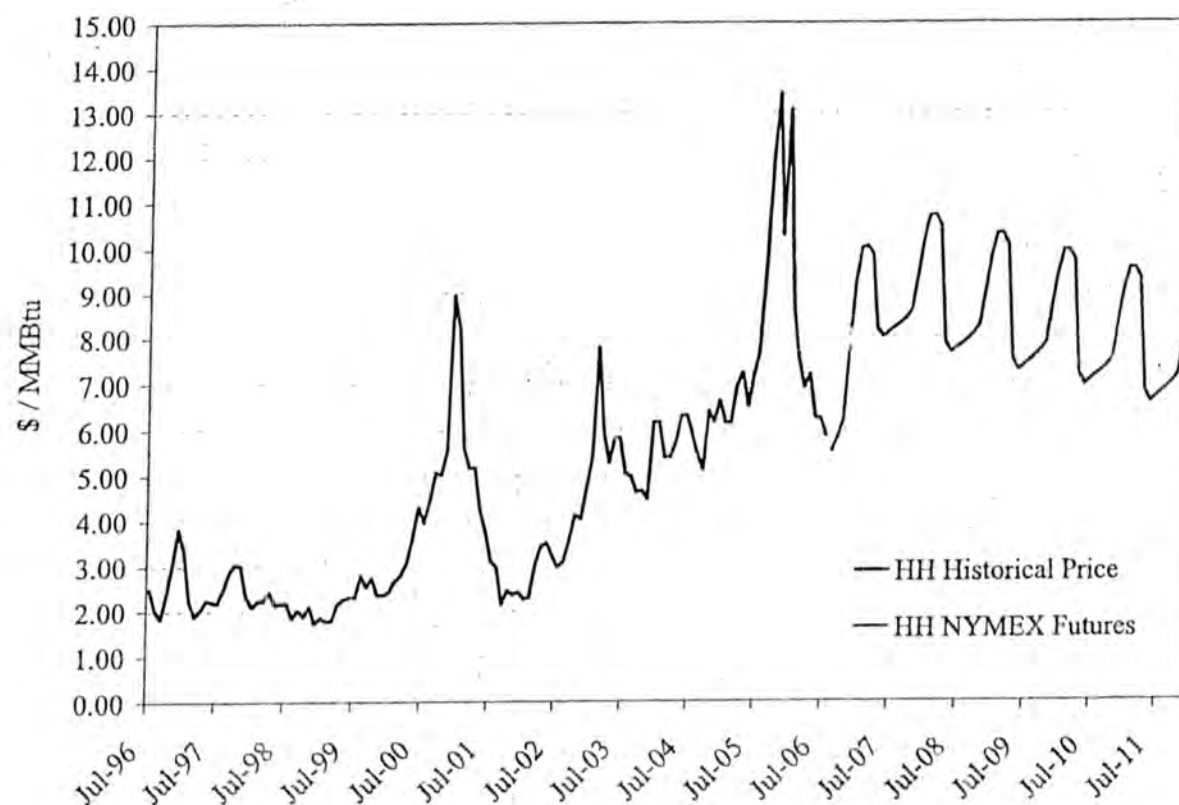


Gas Price Assumptions

- Henry Hub price:
 - considered the benchmark U.S. gas price
 - most forecasts for U.S. gas prices refer to Henry Hub pricing
 - used for the benchmark NYMEX physical and financial gas price futures contracts
- Regional gas prices are typically expressed as a differential above or below Henry Hub pricing (“basis”)

Henry Hub Price Assumption

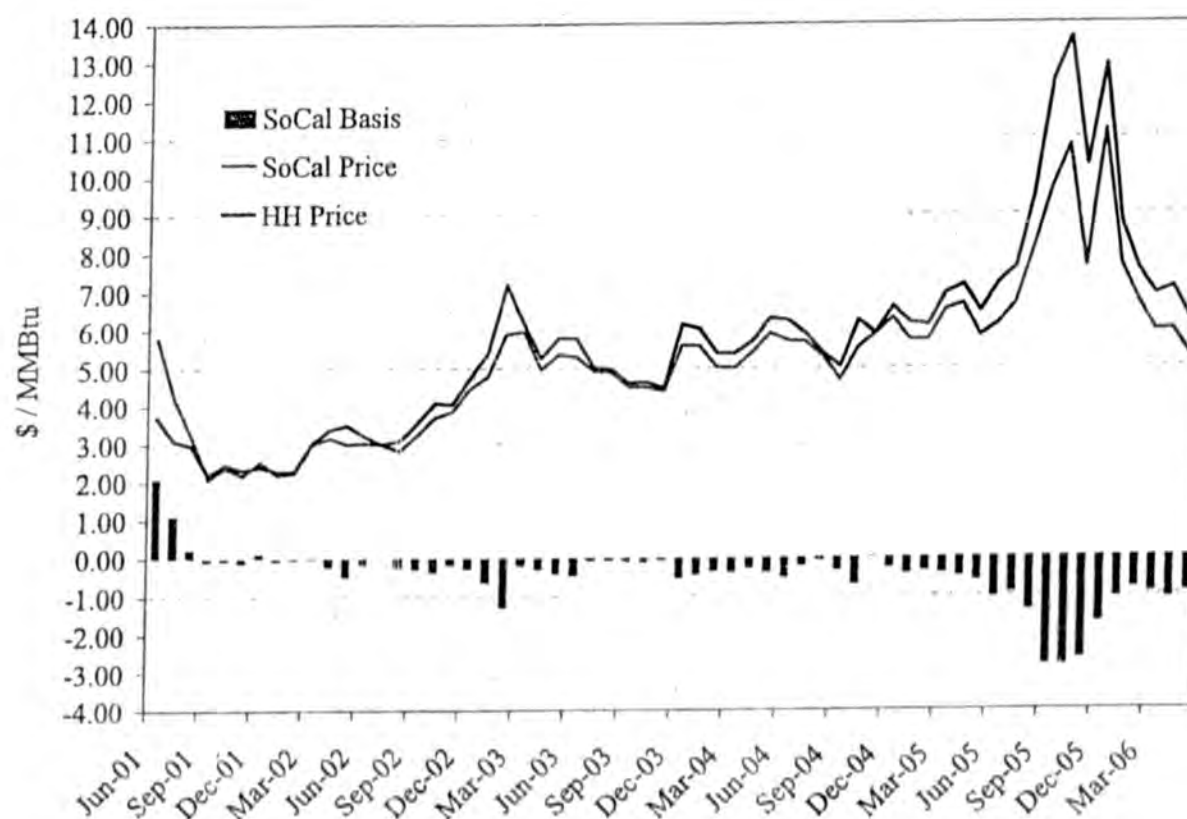
- Henry Hub historical 5-year average price: \$5.68 per MMBtu
- Current forward pricing on NYMEX: \$7.70 per MMBtu (average of distant 12 months)
- AGPA base case assumption: \$5.50 per MMBtu (constant 2005 dollars)



Source: Bloomberg, NYMEX

SoCal Gas Price Assumption

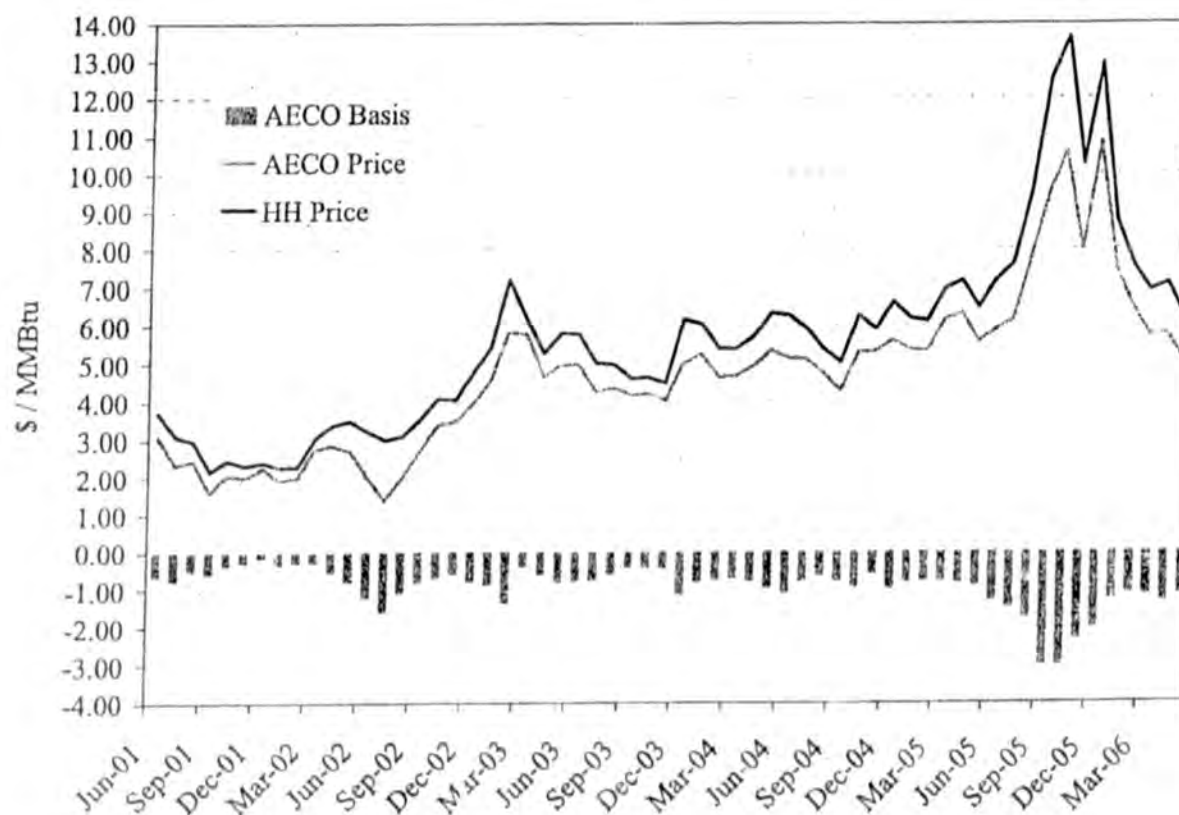
- 5-year average SoCal basis: \$(0.47) per MMBtu discount to HH
- After an increase to over \$(2.00)/MMBtu, SoCal basis has been narrowing and is expected to decrease further
- AGPA base case assumption: \$(0.47) per MMBtu discount (flat nominal terms)



Source: Bloomberg

Alberta Gas Price Assumption

- 5-year average AECO-C basis: \$(0.93) per MMBtu discount to HH
- AGPA base case assumption: \$(0.93) per MMBtu discount (flat nominal terms)



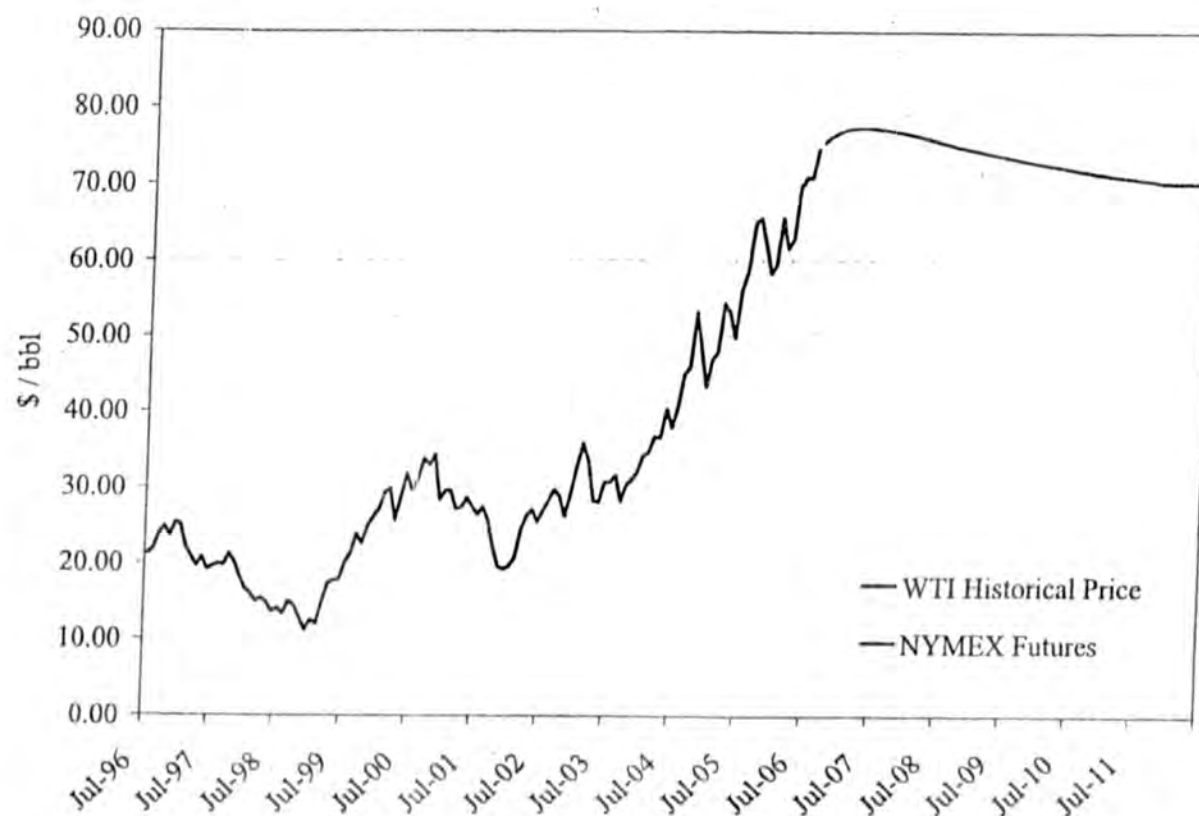
Source: Bloomberg



Crude Oil Prices

- WTI historical 5-year average price: \$40 per bbl
- Current forward pricing on NYMEX: ~ \$70 per bbl

- What is a reasonable WTI price assumption consistent with a certain Henry Hub gas price assumption?



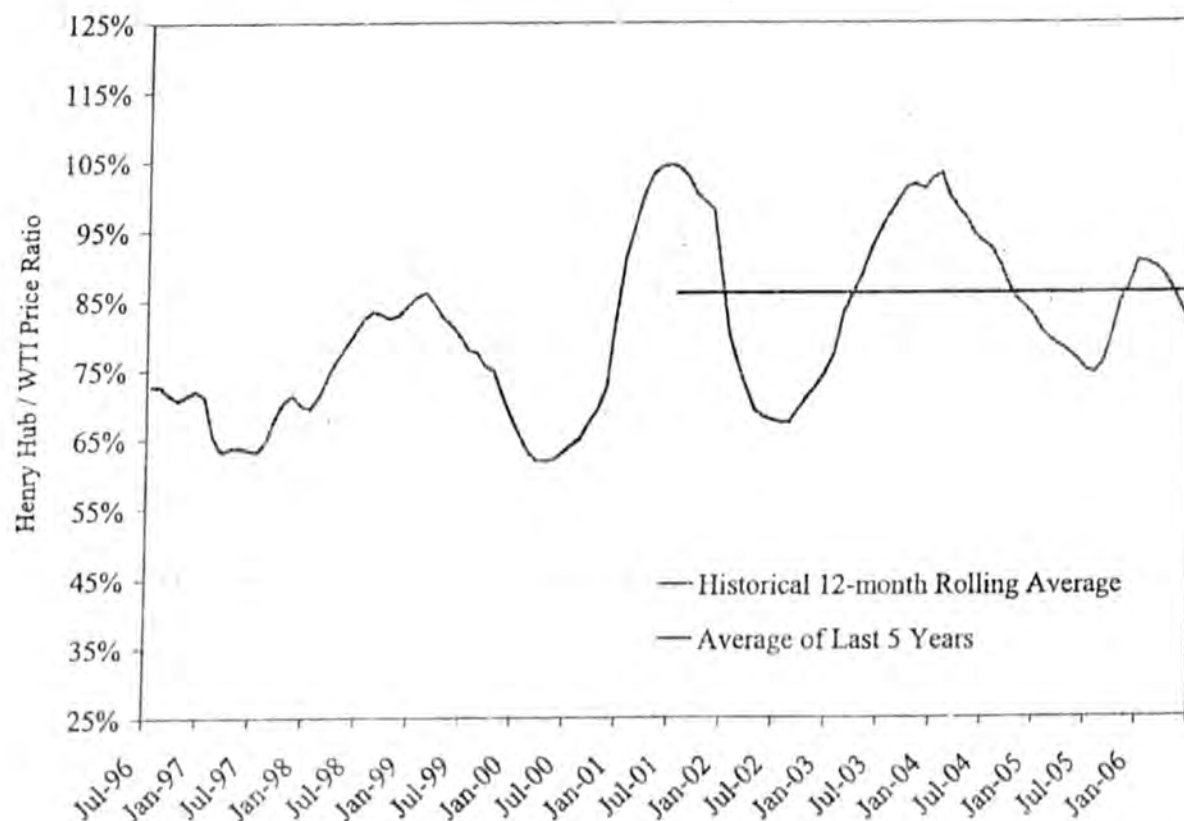
Source: Bloomberg, NYMEX

Crude Oil Prices (continued)

- Henry Hub prices and oil prices historically have not been closely correlated
- Henry Hub / WTI historical 5-year average price ratio: 86%

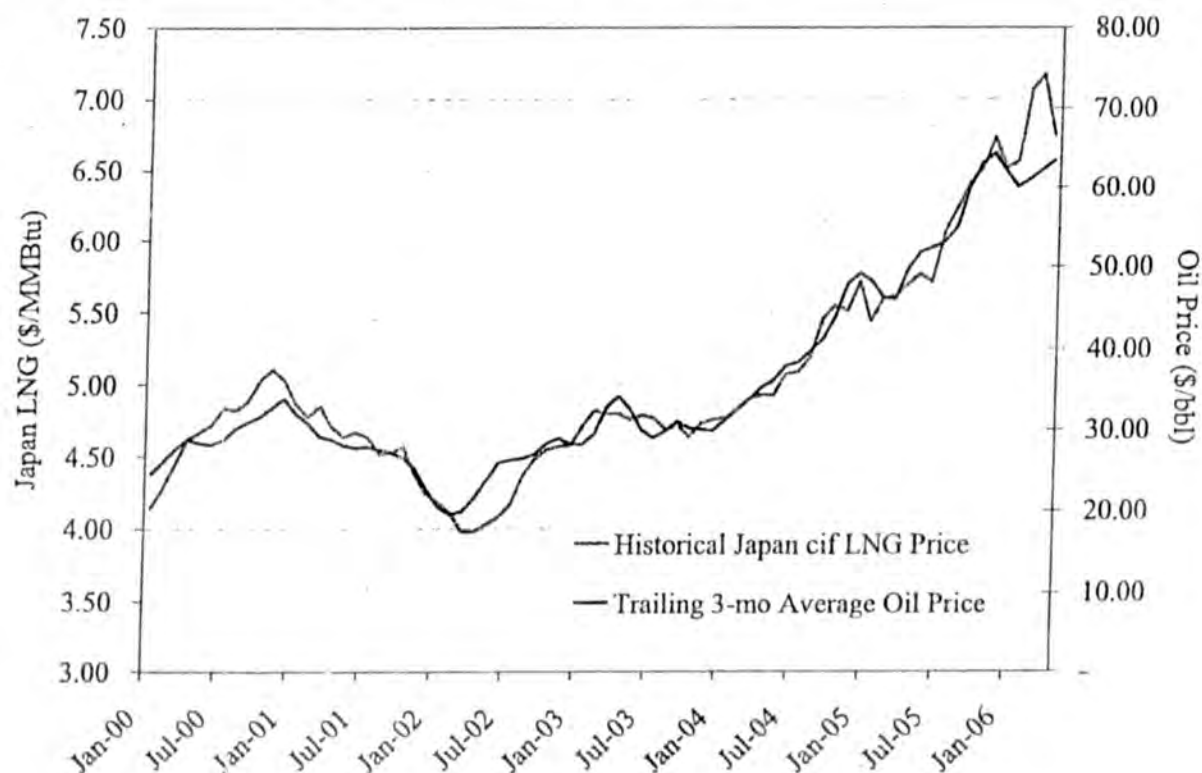
- A \$5.50/MMBtu Henry Hub assumption would be equivalent to a WTI assumption of \$37/bbl, assuming a 86% HH to WTI price ratio

- AGPA WTI base case assumption: \$36/bbl



Japan LNG Prices

- Japan LNG sales prices are typically expressed in contract formulas indexed to JCC (basket of crude oil imports to Japan)
- Japan LNG prices, therefore, are closely correlated with oil prices
- The AGPA model calculates Japan LNG prices on the basis of the assumed oil price and the historical price relationship



Source: Bloomberg

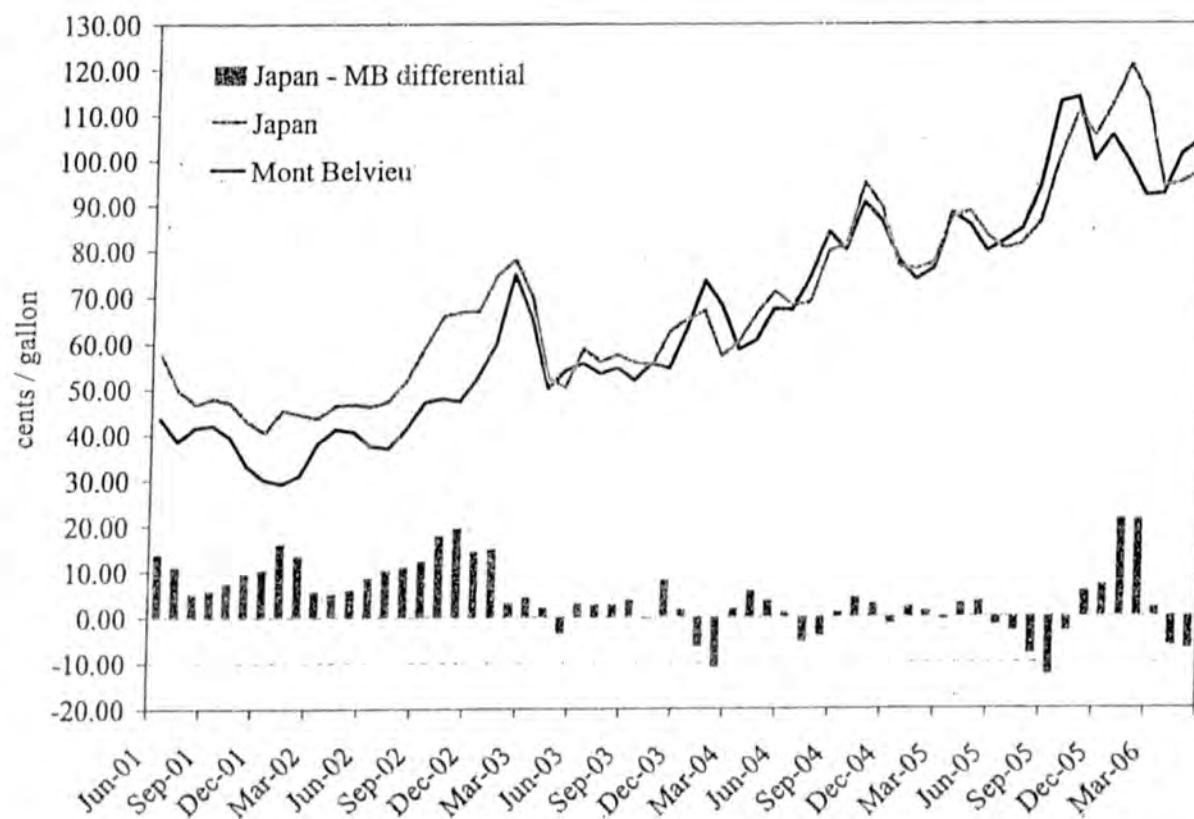


Propane Price Assumptions

- Mont Belvieu propane price:
 - benchmark U.S. Gulf Coast price
 - Mont Belvieu is the deepest propane market in the U.S.
 - used for the NYMEX propane futures contract
- MB propane prices have been historically correlated with both WTI and Henry Hub prices
- AGPA's financial model calculates Mont Belvieu propane prices on the basis of the assumed WTI and Henry Hub prices, using the historical price relationship
- Regional propane prices are assumed on the basis of historical premium/discount to Mont Belvieu

Propane Price Assumptions: Japan

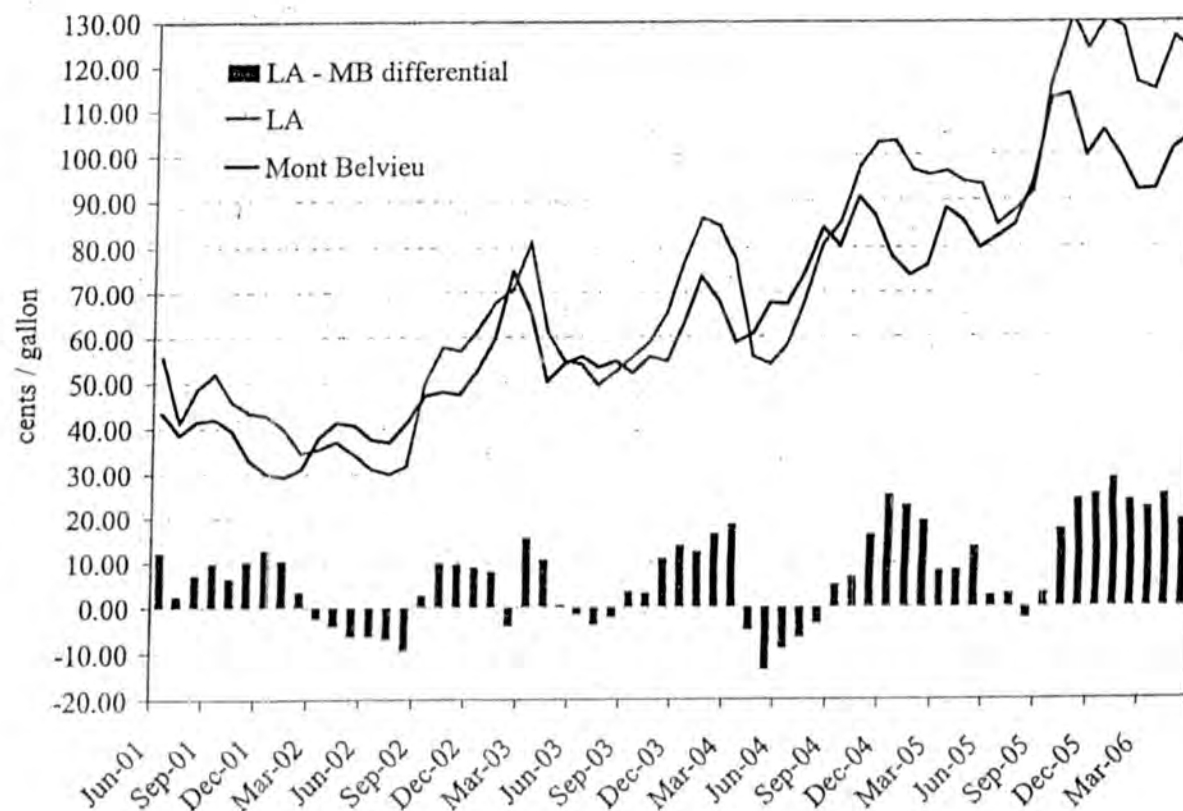
- 5-year average Japan premium to MB: 4.4 cents/gallon
- AGPA assumption: 4.0 cents/gallon premium over MB



Source: Bloomberg

Propane Price Assumptions: LA

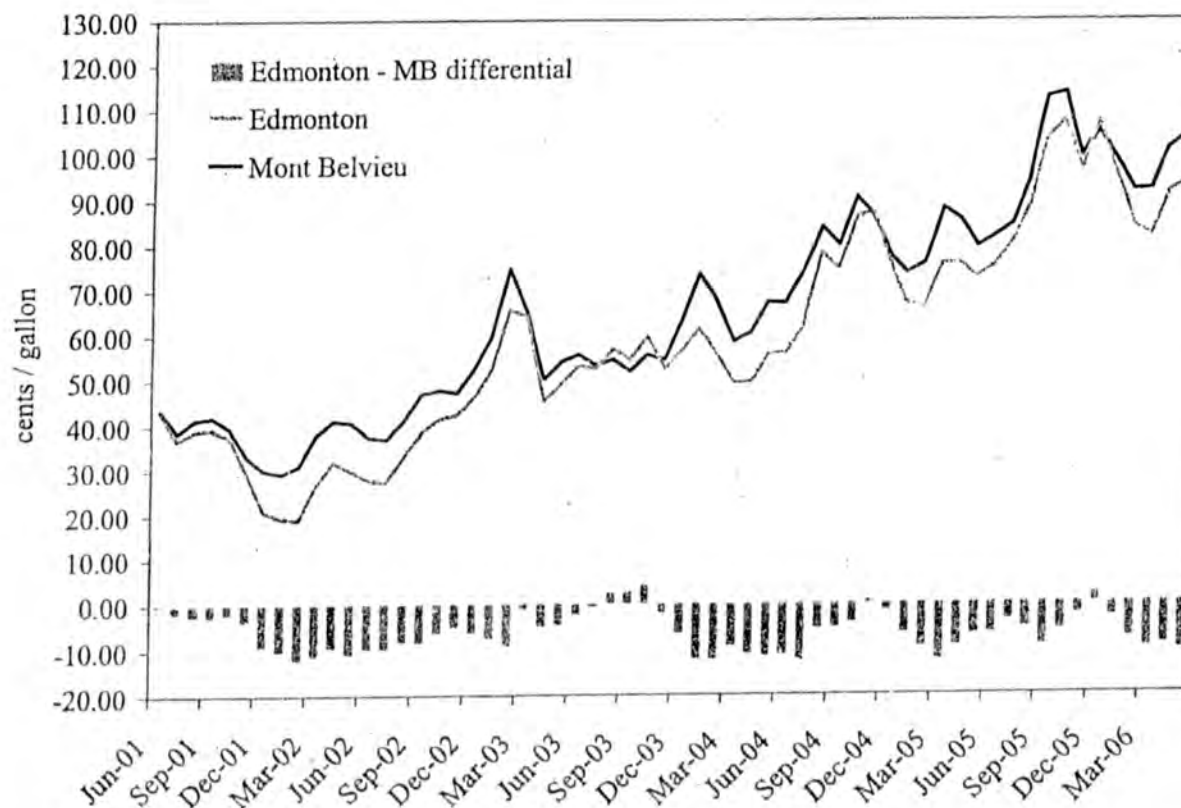
- 5-year average LA premium to MB: 7.6 cents/gallon (flat nominal terms)
- AGPA assumes most LPGs will go to East Asia, but there is opportunity for higher premium in LA market



Source: Bloomberg

Propane Price Assumptions: Alberta

- 5-year average Alberta discount to MB: (6.2) cents/gallon (flat nominal terms)
- AGPA assumption: (6.0) cents/gallon discount to MB



Source: Bloomberg, Duke Energy



Butane Prices

- Assumed on the basis of historical differential between butane and propane in respective markets (East Asia and Alberta)
- Japan butane – propane differential: 9 cents/gallon (flat nominal terms)
- Alberta butane – propane differential: 10 cents/gallon (flat nominal terms)



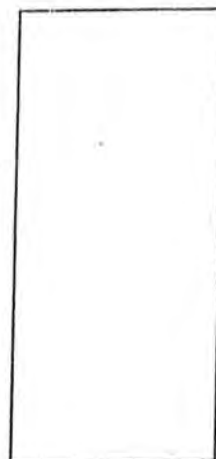
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LNG Project Concept and Gas Volumes

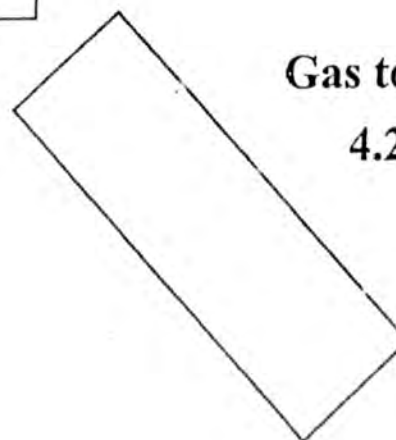
Highway Project Proposal

Year: 2016

4.3 Bcf/d



Pipeline from Prudhoe Bay



Gas to Canada

4.2 Bcfd



AGPA Proposal: Immediate Implementation

Year: 2012

1.2 Bcf/d

Pipeline from Prudhoe Bay



Alaska LNG

1.1 Bcfd





AGPA Proposal: Immediate Implementation (continued)

- The AGPA project can be implemented immediately
- Brings value to State and Producers during the period 2012 – 2016+ that would not be otherwise created
- The Highway Project can be implemented at a future date, when ready
- How will volumes be distributed if and when the Highway Project is ready to proceed?



AGPA Proposal: Y-Line Scenario A – Constrained Volume

Year: 2016

4.3 Bcf/d

No reason to limit total
volume to 4.3 Bcf/d

Pipeline from Prudhoe Bay

Reduction in volume
to Canada results in a
potential value
reduction due to loss
of economy of scale

Alaska LNG
1.1 Bcf/d

Gas to Canada
3.1 Bcf/d

AGPA Proposal: Y-Line Scenario B – Incremental Volume

- It has been suggested that AGPA's Y-Line proposal is disadvantageous because the reduction of volume to Canada results in a loss of economies of scale, and hence, lower value for the gas
- This reasoning is premised on limiting total volume at the pipeline inlet to 4.3 Bcf/d (the same amount as under the Highway Project proposal)
- There is no reason to limit the total volume to 4.3 Bcf/d
 - LNG volumes could be in addition to the 4.3 Bcf/d to Canada
 - total volume at pipeline inlet in Prudhoe Bay: 5.5 Bcf/d
 - the Highway Project at 4.3 Bcf/d requires 49 Tcf over 30 years
 - a 5.5 Bcf/d Y-line project would require 62Tcf over 30 years
 - the known discovered resource on ANS is 35 Tcf
 - the Highway Project would require substantial new discoveries to proceed (both as a stand-alone project and part of a Y-line)
 - the stand-alone LNG project, however, can proceed immediately



AGPA Proposal: Y-Line Scenario B (continued)

Year: 2016

Incremental value
in addition to
Highway Project

5.5 Bcf/d

Shared line improves cost for
both destinations

Alaska LNG
1.1 Bcfd

No loss of value relative
to Highway Project

Gas to Canada
4.2 Bcfd



Stand-Alone LNG Project Concept

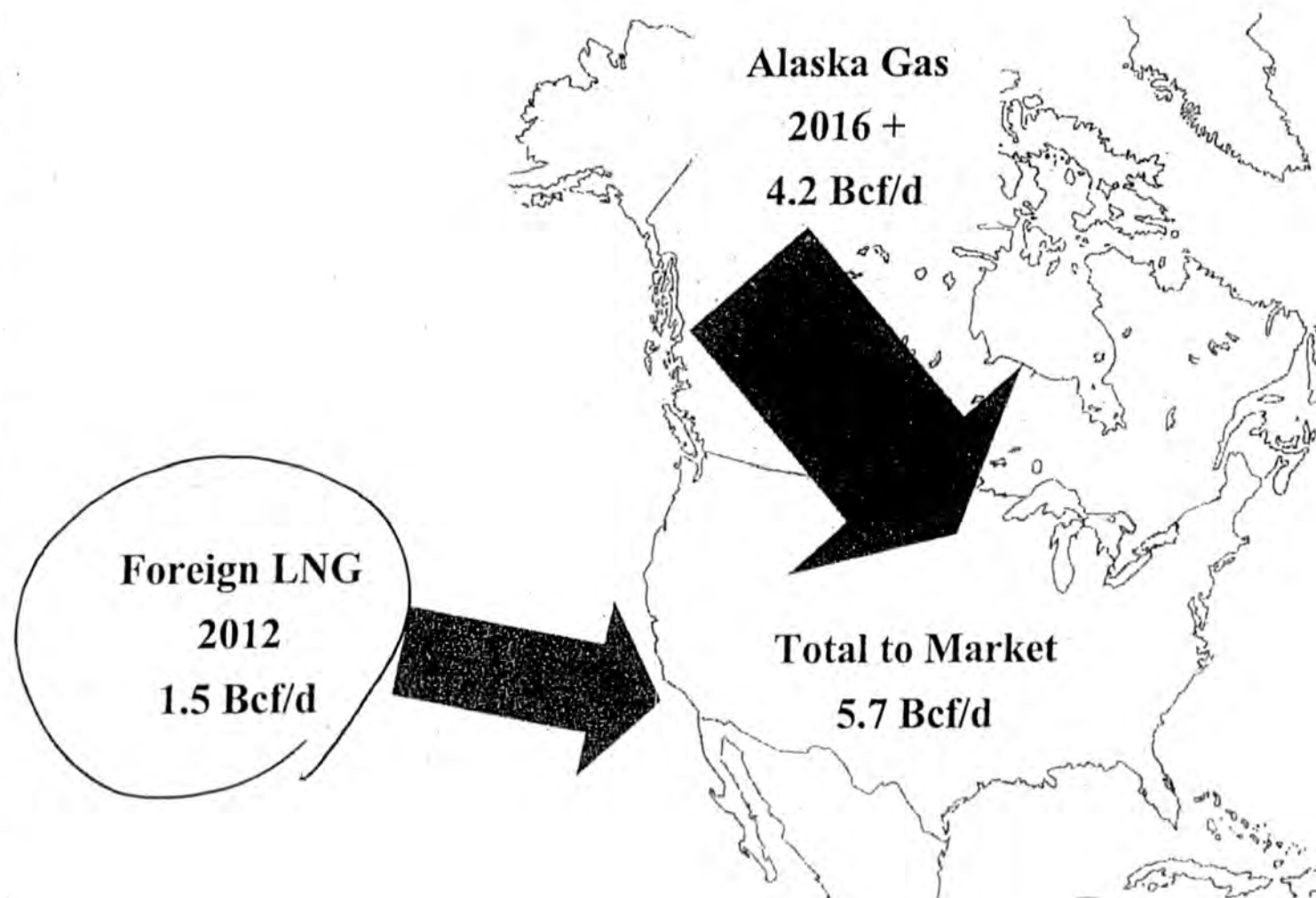
- The issue is whether the AGPA project is economic on a stand-alone basis, as there will be no guarantee in 2012 that the expansion volumes from the Highway Project will ever materialize
- The subsequent sections elaborate on the economics of the stand-alone LNG project
- The projections show robust economics, with both high returns for the Producer and revenues for the State that would be incremental to the revenues from a potential Highway Project to be implemented later

The Market Context

- Does a combined Y-Line of 5.5 Bcf/d deliver too much gas to market?
- The total gas to market is likely to be the same, but Alaska would capture a larger share, which would otherwise go to foreign LNG suppliers

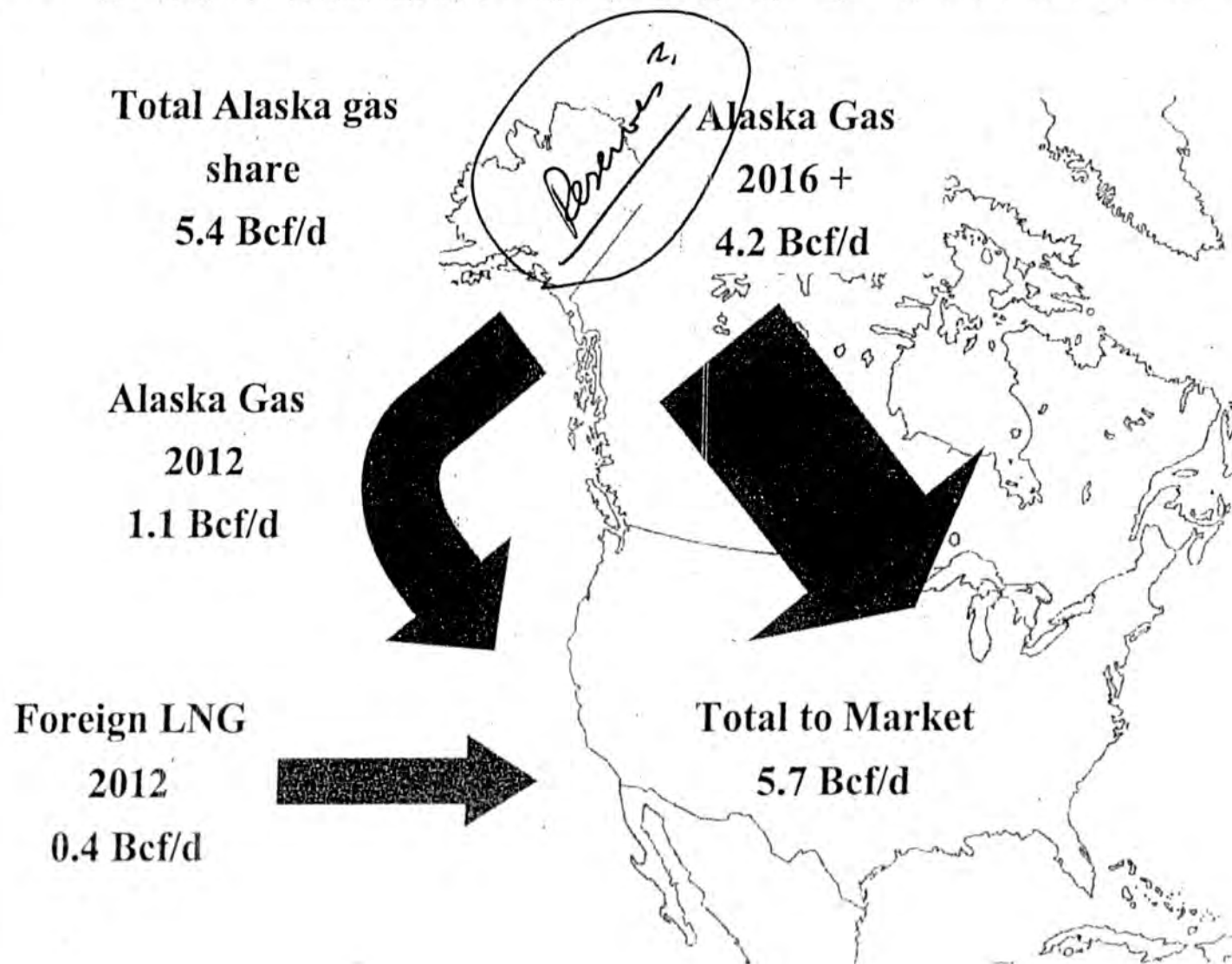


Gas Flows to North America Under the Highway Proposal



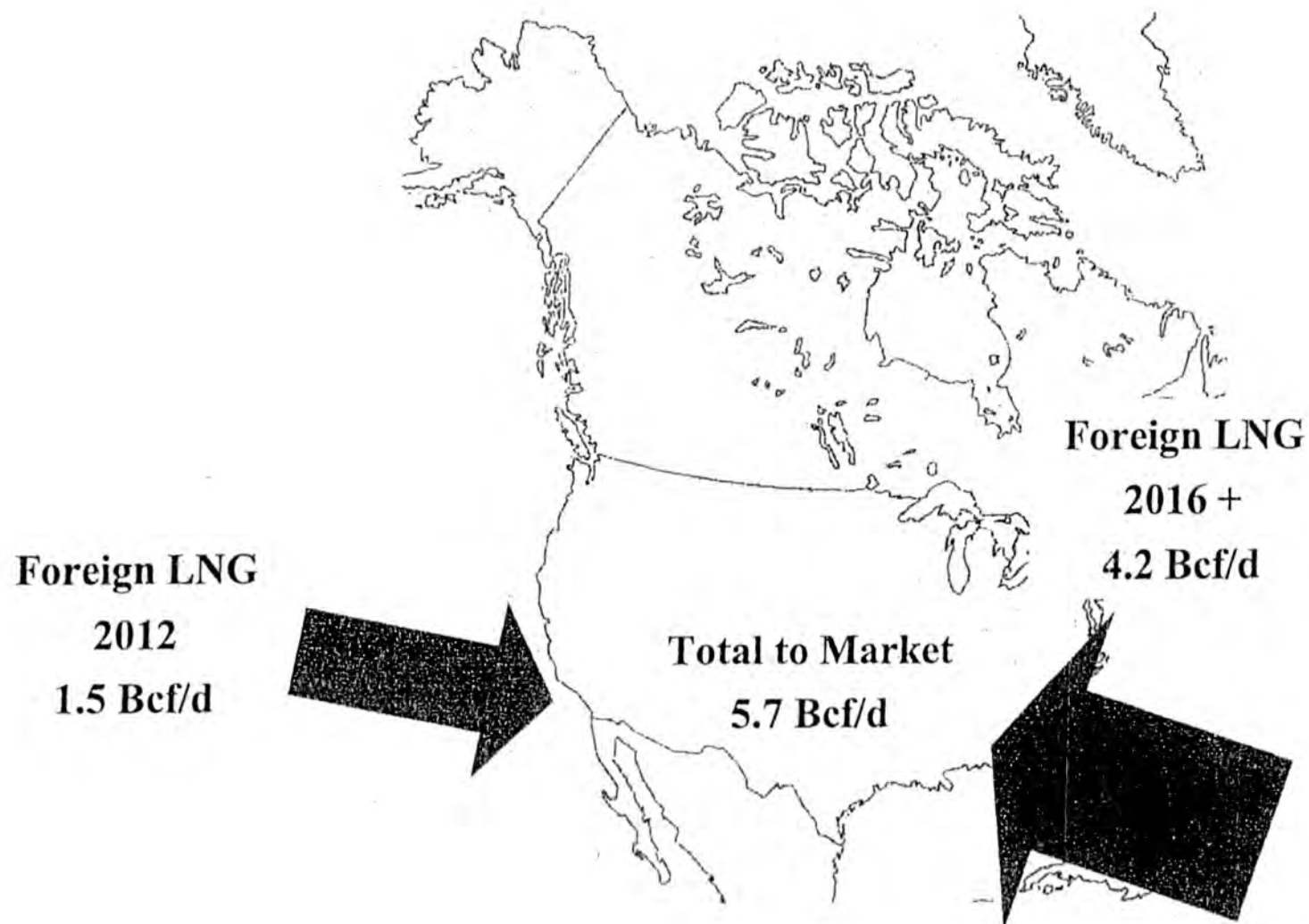


Gas Flows to North America Under AGPA Proposal





Alaska's Risk: A Real Possibility?





Additional Strategic Considerations

- Full commercialization of the Alaska gas resource requires a large scale project and additional exploration
- Independent explorers have expressed concern that they will be shut out of a potential Alaska gasline
- Without certainty as to whether pipeline capacity will be available, an explorer will not have an incentive to spend capital for exploration
- An AGPA line sized to accommodate future expansion and Y-line volumes will send a signal that there is free capacity and will spur exploration which will not occur otherwise

More AGPA
by future
AGPA



Additional Strategic Considerations (continued)

- The LNG project will make the implementation of the Highway Project more likely
- The Producers will have an incentive to participate in the value of the LNG Project and to take steps to fill the spare capacity of AGPA's pipeline
- The LNG project will give Alaska access to additional markets that would not be accessible to the Highway Project



Additional Markets for Alaska LNG

LNG to
Japan/East Asia

?

LNG to West
Coast

2012

1.1 Bcf/d

Foreign LNG

2012

0.4 Bcf/d

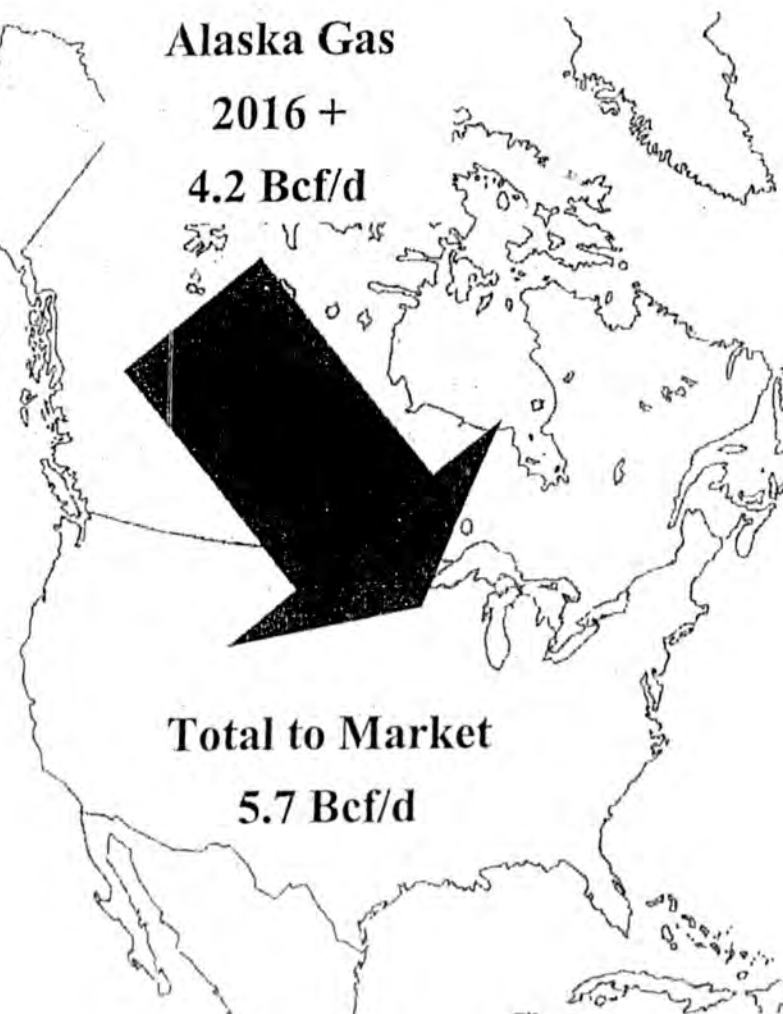
Alaska Gas

2016 +

4.2 Bcf/d

Total to Market

5.7 Bcf/d





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Cost Assumptions

[illegible]



Consistency of Capital Cost Assumptions

- Importance of consistency of capital cost numbers across project components
- Same components for different projects should have the same assumed costs in a comparison
- AGPA pipeline cost assumption in April 2005 (Sempra and AGPA proposal to State and Producers):
 - 3.0 Bcf/d, 48-inch diameter
 - \$8.4 billion EPC cost (2005 detailed cost update)
- FIF assumption (May 2006) for Alaska component of Highway line:
 - 4.3 Bcf/d, 52-inch
 - \$5.9 billion capex



Consistency of Capital Cost Assumptions (continued)

- Why are the capital costs estimates so different?
 - the mileage difference of Highway route vs. Valdez route of 8% clearly cannot alone explain the 42% higher cost of AGPA's *smaller* line
- Difference in methodology of estimate and cost inclusions
 - date of estimate
 - accuracy of estimate
 - contingencies included
- Some comparisons between the AGPA project and the proposed Highway Project (FIF, PFC) have failed to make an adjustment for consistency across capex numbers
- The following slides describe the appropriate adjustments that need to be made for a proper comparison of alternatives



Consistency of Capital Cost Assumptions (continued)

- AGPA's previously publicized capital cost figures include:
 - Contractor's contingencies ranging from 10% to 15%, depending on project component
 - Contractor's escalation allowance during construction period
 - Contractor's profit and risk premium
 - Owner's contingency in addition to Contractor's contingency
 - Owner's insurance cost during construction
- It appears that the above items have not been included in the capital cost estimates made public in the FIF
- A comparative analysis should use the same approach for both projects, as the risk mitigation and related cost premiums and contingencies associated with a given contracting strategy would be available to both projects



Consistency of Capital Cost Assumptions (continued)

- The magnitude of such consistency adjustments is significant:
- AGPA has previously used a \$2.1 billion estimate for the LNG Facility
- Stripping away the various risk premiums and allowances (both contractor's and owner's) that are not included in estimates for an alternative project reduces the capital cost assumption to \$1.5 billion

How Reliable are the Cost Estimates?

- AGPA's cost estimates are the result of extensive engineering work performed by Bechtel in 2000, with a detailed cost update study performed in 2005
- The technical details of Bechtel's work have been shared with the State's consultants
- There appears to be considerable uncertainty surrounding the publicized cost estimates for the proposed Highway project

Project Component	2001 Producer Estimate	2006 FIF Assumptions
GTP	\$2.6 billion	\$2.6 billion
Pipeline from Prudhoe Bay to Alberta	\$11.0 billion	\$11.6 billion

Source: Fiscal Interest Findings; Presentation titled "Alaska Producer Pipeline Presentation May 2002" and 2004 SGDA testimony by Producer group

AGPA Base Case Capital Cost Assumptions

■ Midstream components (2005 dollars):

- LNG Facility: \$1.5 billion
- pipeline from PB to Valdez (initial 1.2 Bcf/d capacity): \$5.3 billion
- expansion of PB-Delta Junction segment to accommodate incremental volume: \$0.9 billion
- Delta Junction to Alberta pipeline: \$8.5 billion
- GCP: based on the \$2.6 billion assumption in the FIF, adjusted for volume
- all midstream components include a 10% capex contingency and a 5% owner's contingency
- real 2005 numbers are escalated at 2.5% p.a.

■ Upstream (PBU, PTU, other ANS fields and yet-to-find gas): \$8.4 billion

~~\$18.8 billion~~

\$10.3 bill



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Netback Results

Netback Pricing

- Tariff Assumptions on midstream components
 - debt to equity ratio 80:20
 - interest on debt 5.50% (assumes Federal guarantee under ANGPA)
 - pipelines ROE 14%
 - LNG facility ROE 12%

*regulated
rate of
return*

14% Pipeline
12% LNG

- Combined pipeline and LNG facility tolls:
 - \$2.50 per mmBtu nominal terms in 2012
 - \$2.17 per mmBtu in real 2005 terms

*4.00
3.47*

Downstream components plus total fuel consumption and losses:

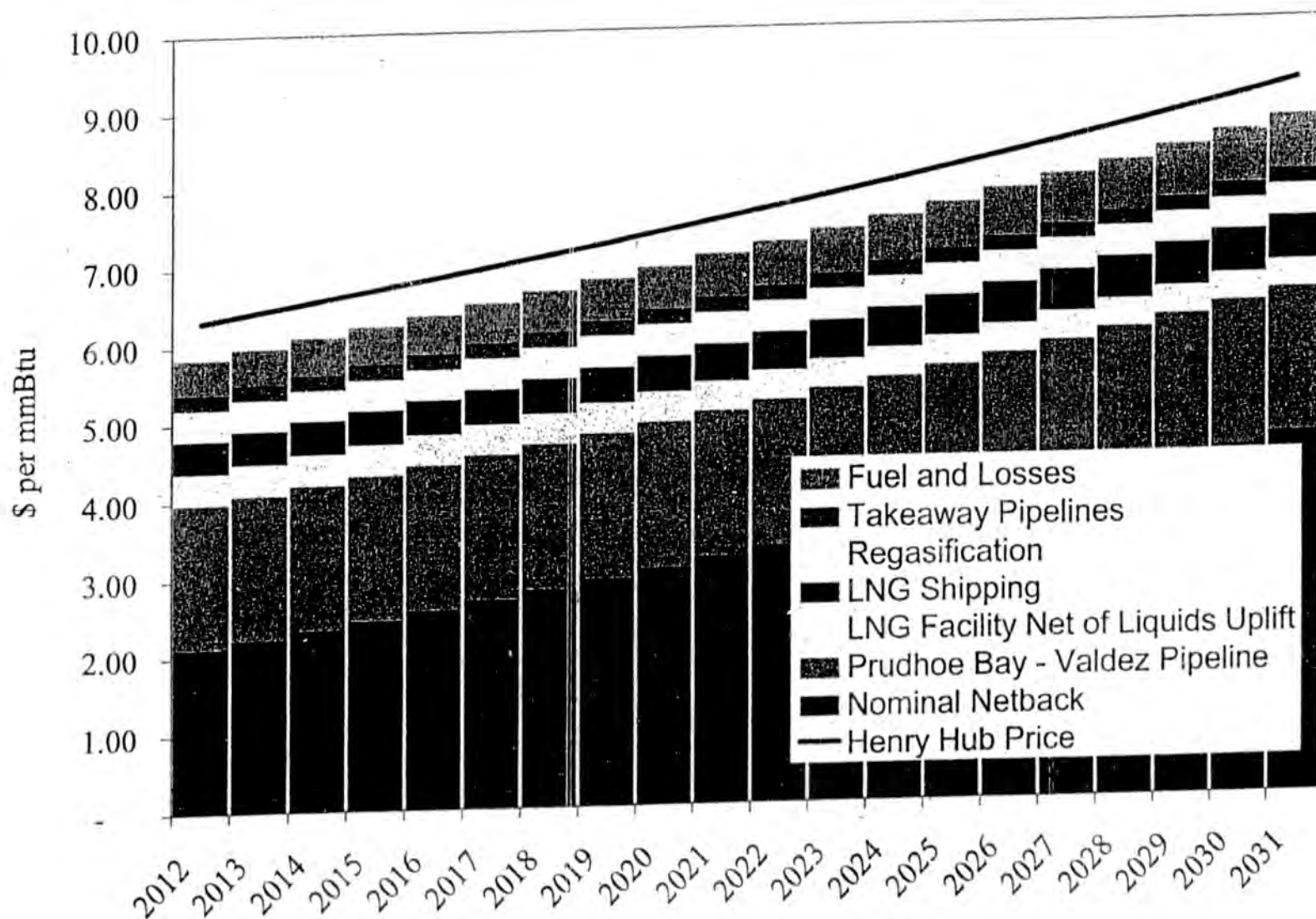
- \$1.50 per mmBtu nominal terms in 2012
- \$1.30 per mmBtu in real 2005 terms



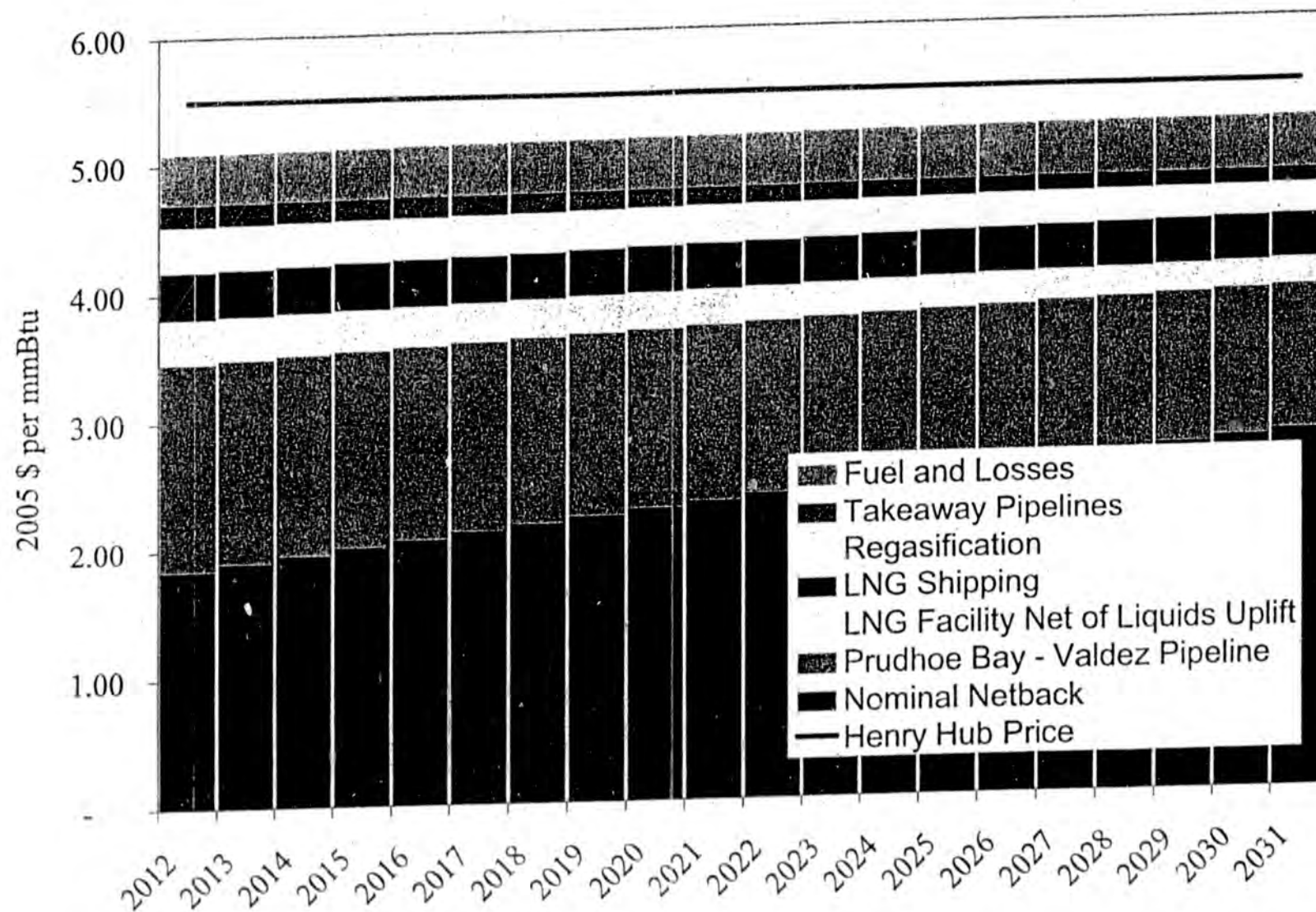
Netback Pricing (continued)

- Uplift from liquids extracted in Valdez:
 - \$0.23 per mmBtu nominal terms
 - \$0.20 per mmBtu in real 2005 terms
- Nominal netback prices at the pipeline inlet are in the range of \$2.11/mmBtu in 2012 to \$7.87/mmBtu in 2041
- Real at the pipeline inlet are in the range of \$1.84/mmBtu in 2012 to \$3.86/mmBtu in 2041
- Nominal prices at the point of production (net of GCP toll and shrinkage and feeder pipeline costs) are in the range of \$1.47/mcf to \$7.16/mcf

Nominal Netback at Pipeline Inlet



Real Netback at Pipeline Inlet (2005 \$)



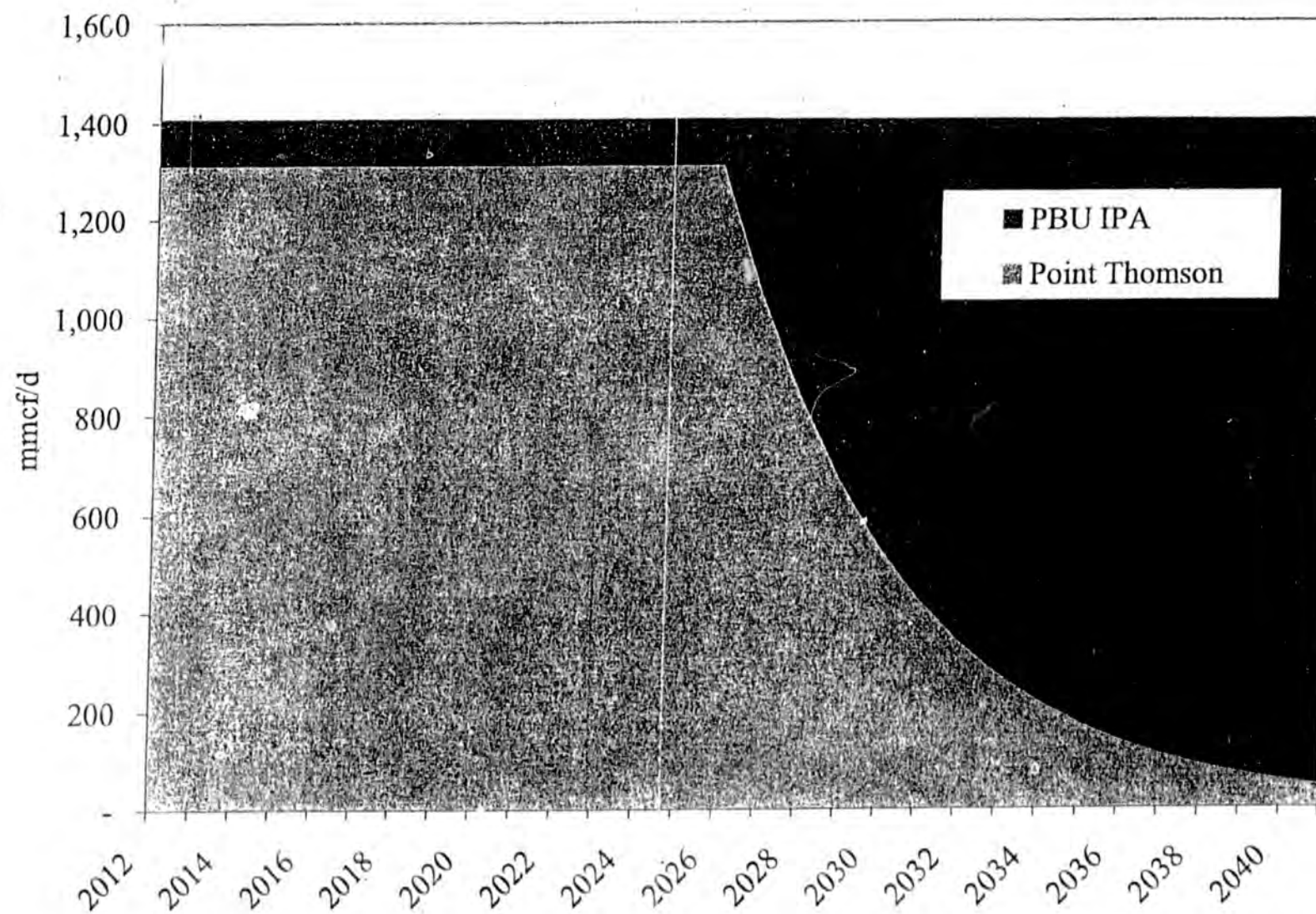


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Producer Results



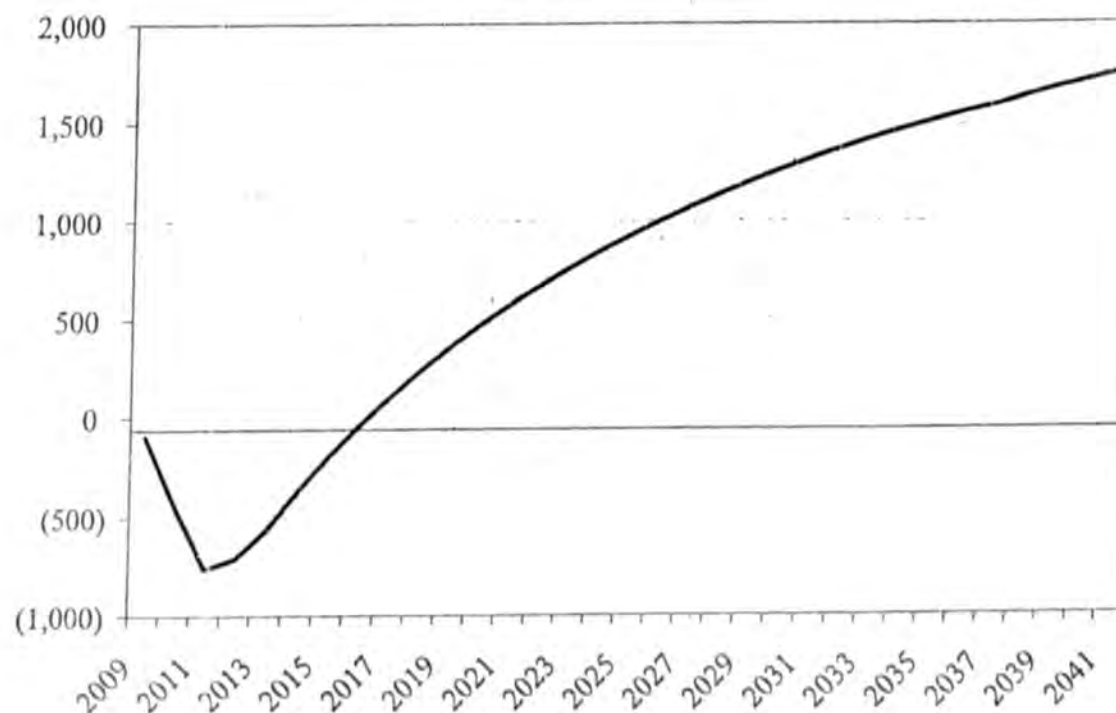
Assumed Upstream Production



Producer Returns

- Upstream Producer returns at the Base Case Henry Hub price of \$5.50/mmBtu
 - NPV @ 12% discount rate: \$1.7 billion
 - IRR: 27.4%

Producer Upstream NPV@12



- Discounted payback is achieved rapidly – within the first six years of operations



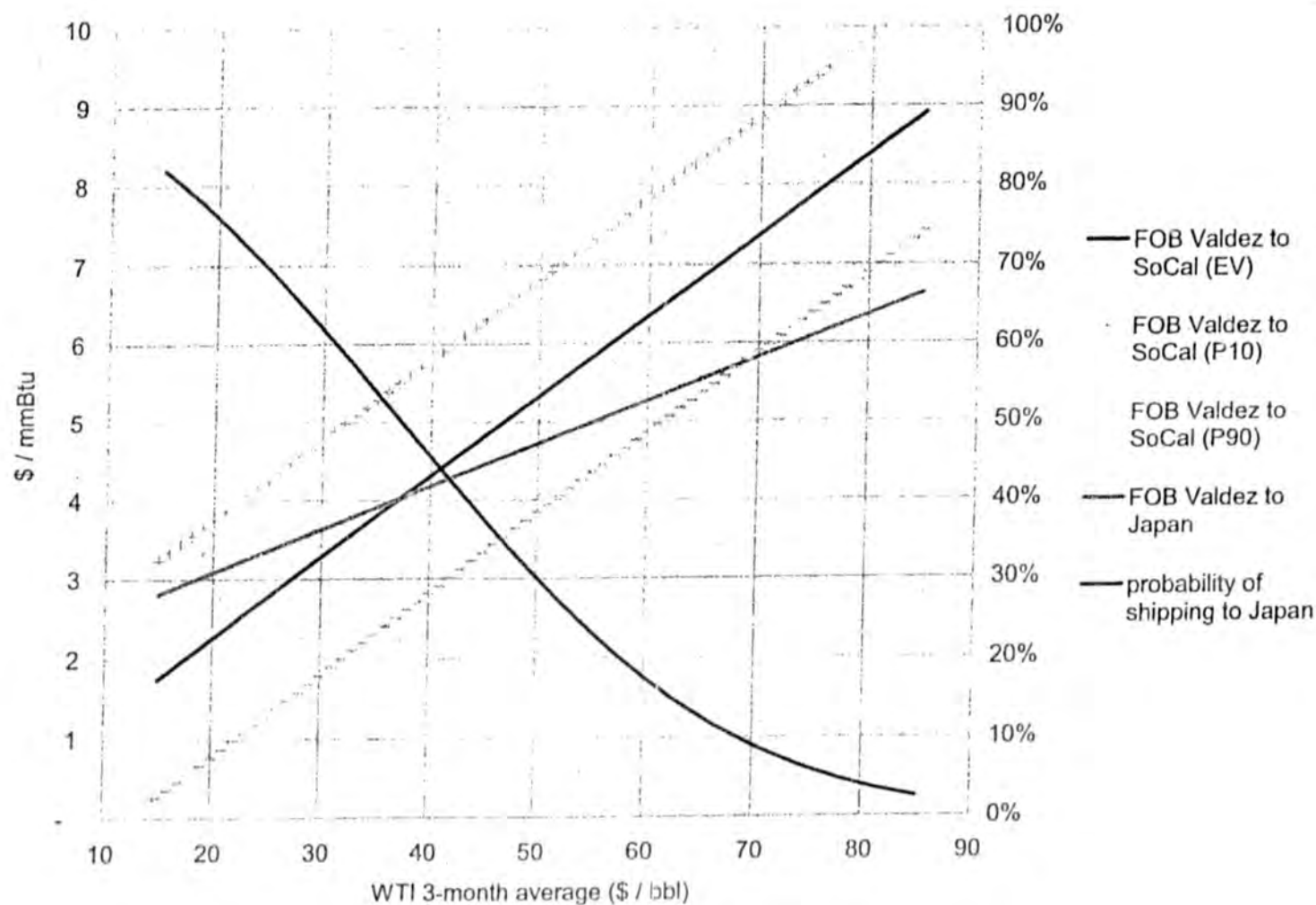
Sensitivity of Producer Returns

- Producer upstream returns at the high price scenario (\$7.70/mmBtu Henry Hub and \$70/bbl WTI):
 - NPV @ 12% discount rate: \$4.6 billion
 - IRR: 52.4%
- The breakeven Henry Hub price (at which the Producer IRR equals 12%) is \$4.30/mmBtu
- At the low prices scenario (stress case) (\$4.00/mmBtu Henry Hub and \$27/bbl WTI), the netback from Japan is significantly higher:
 - \$1.55/mmBtu at the pipeline inlet and \$0.95/mcf at the point of production in 2012 (nominal terms)
- The LNG project's option to divert production to higher value markets (e.g., Japan) has a significant value

Value of Diversion Option

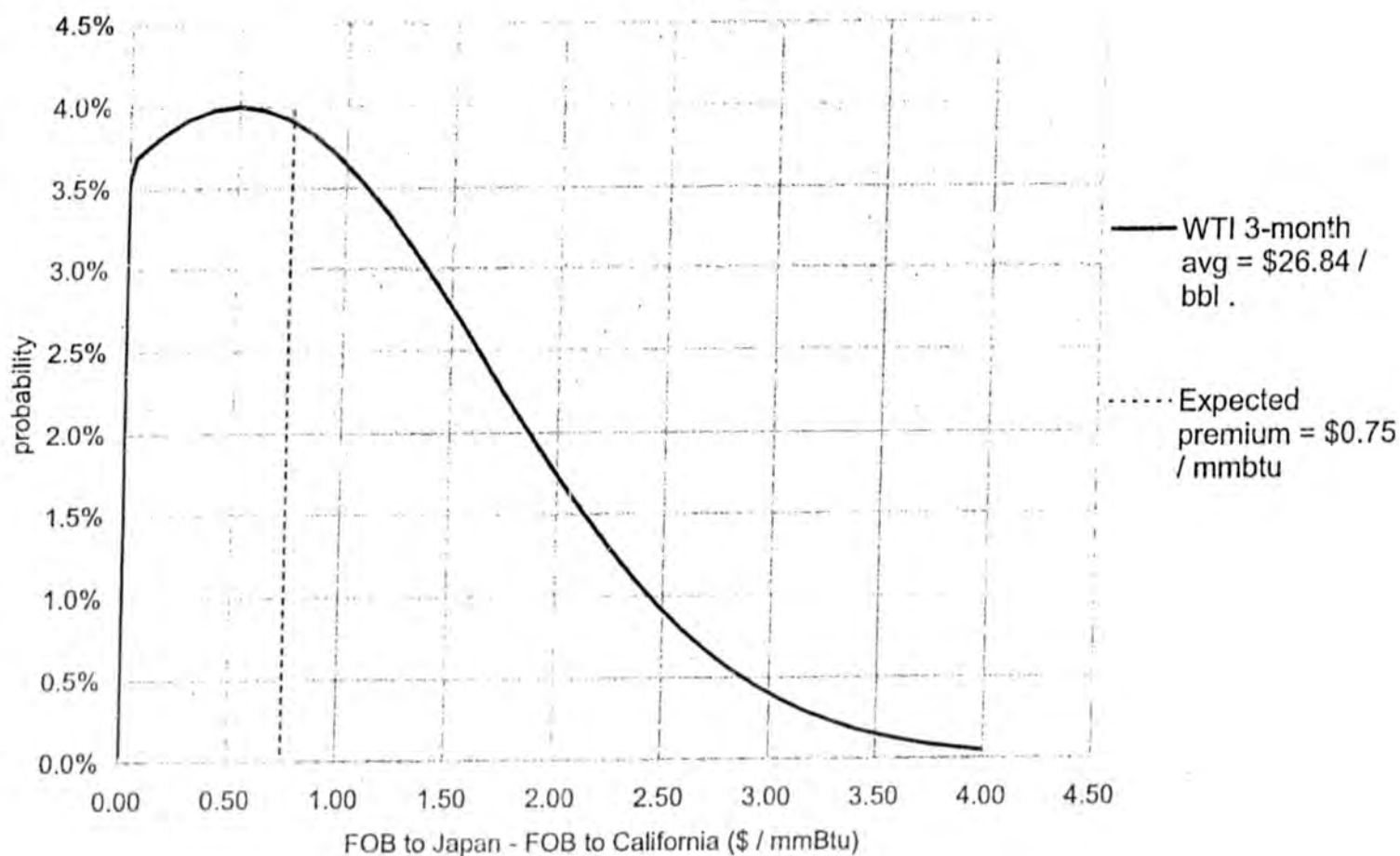
- Japanese LNG c.i.f. prices are highly correlated with oil prices (R^2 of 0.96)
 - primarily due to contractual linkages to JCC
- US gas prices (including SoCal) are not highly correlated with oil prices, and by extension, Japanese LNG prices
- This low correlation gives increases the likelihood that prices in Japan will be high during periods of low U.S. prices, making it worthwhile to divert cargoes
- An analysis has been performed using both an algebraic approach and a Monte Carlo simulation to estimate the value of this option to divert cargoes to the high-prices market
- At AGPA's base case prices, the expected value of the diversion option is estimated to be \$0.49 per mmBtu of LNG produced

Value of Diversion Option (continued)

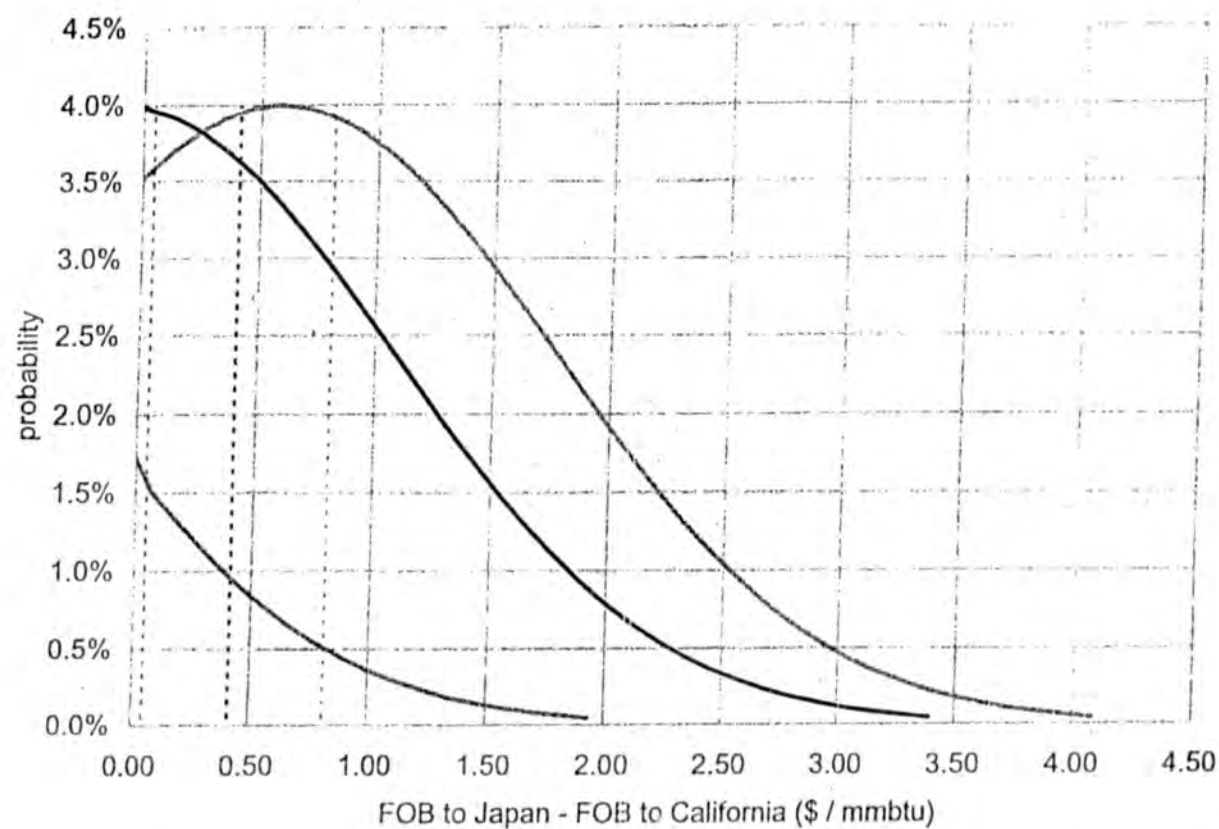


Value of Diversion Option (continued)

Example of diversion option value at a given oil price (\$26.84/bbl in this case)



Value of Diversion Option (continued)



— WTI 3-month avg = \$25.00 / bbl .

— WTI 3-month avg = \$39.36 / bbl .

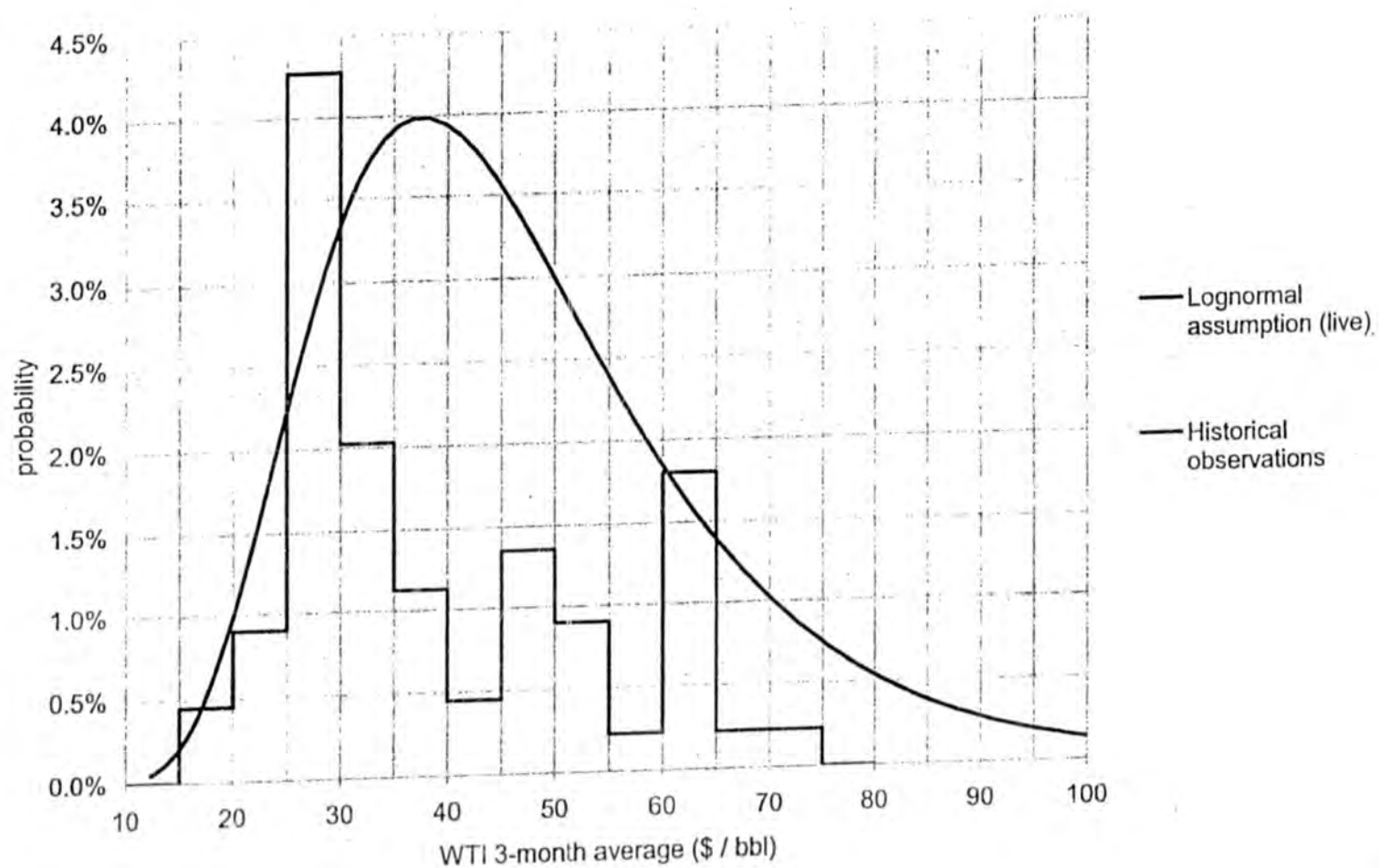
— WTI 3-month avg = \$70.00 / bbl .

..... Expected premium = \$0.81 / mmbtu

..... Expected premium = \$0.41 / mmbtu

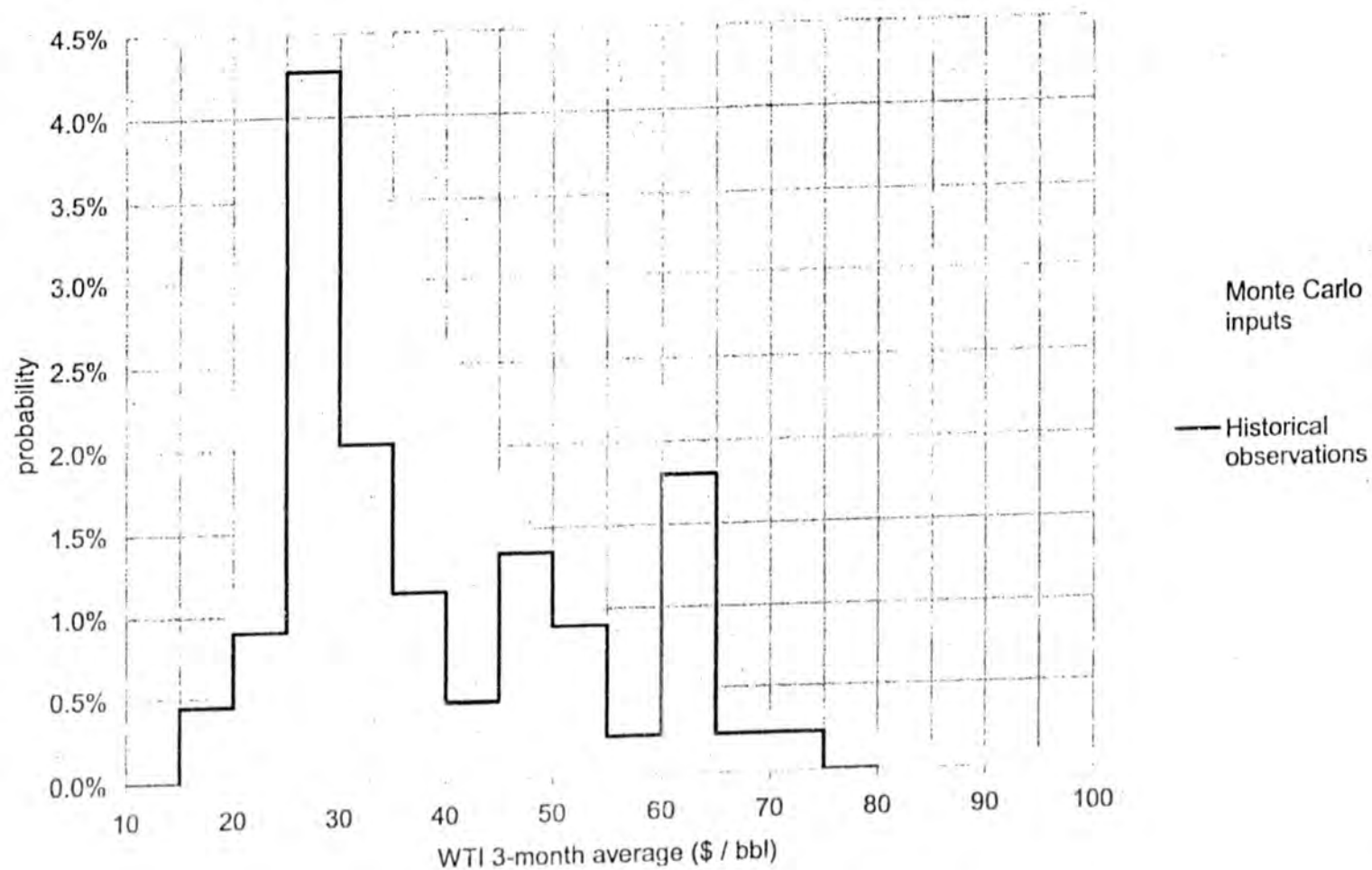
..... Expected premium = \$0.05 / mmbtu

Value of Diversion Option (continued)

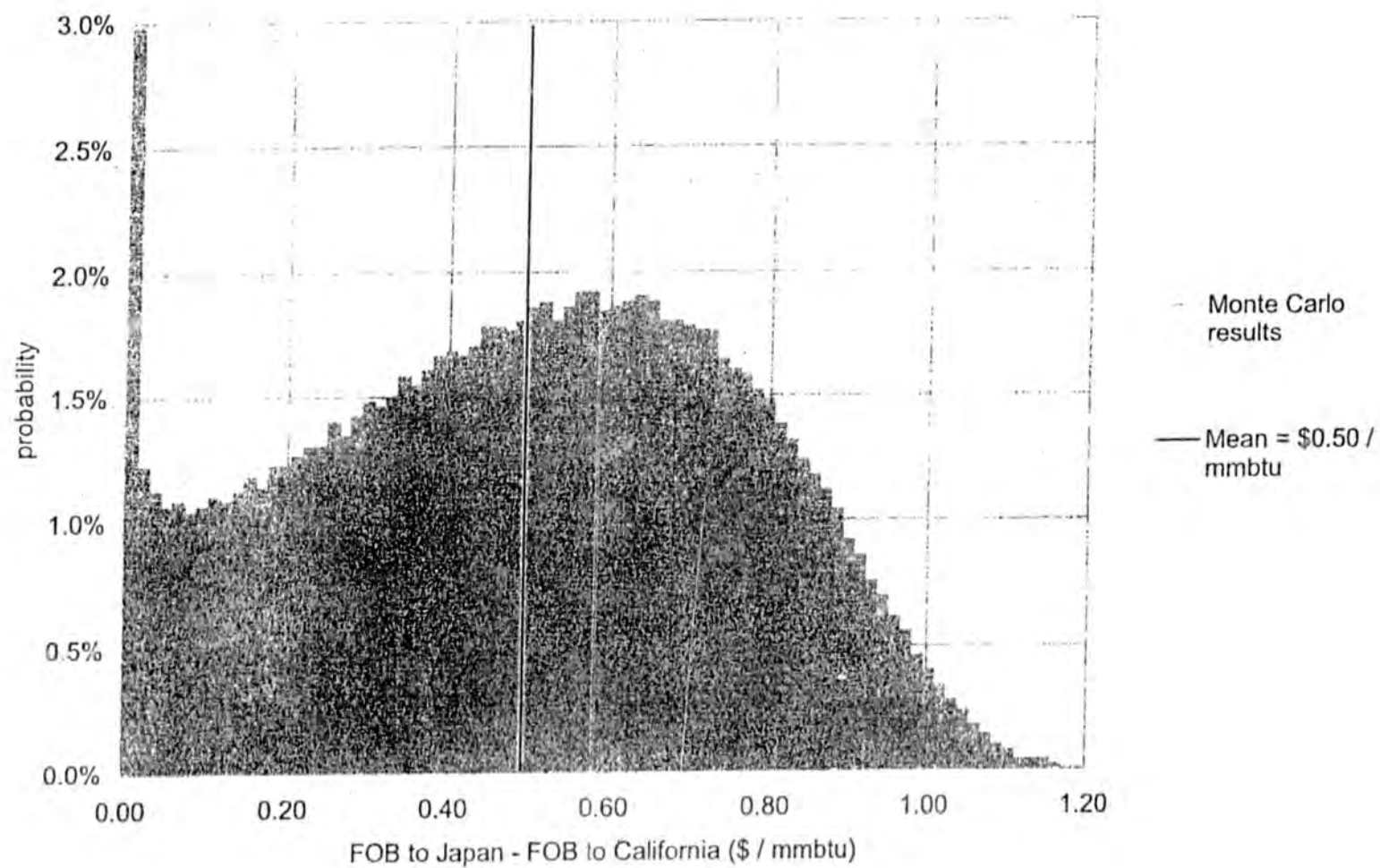




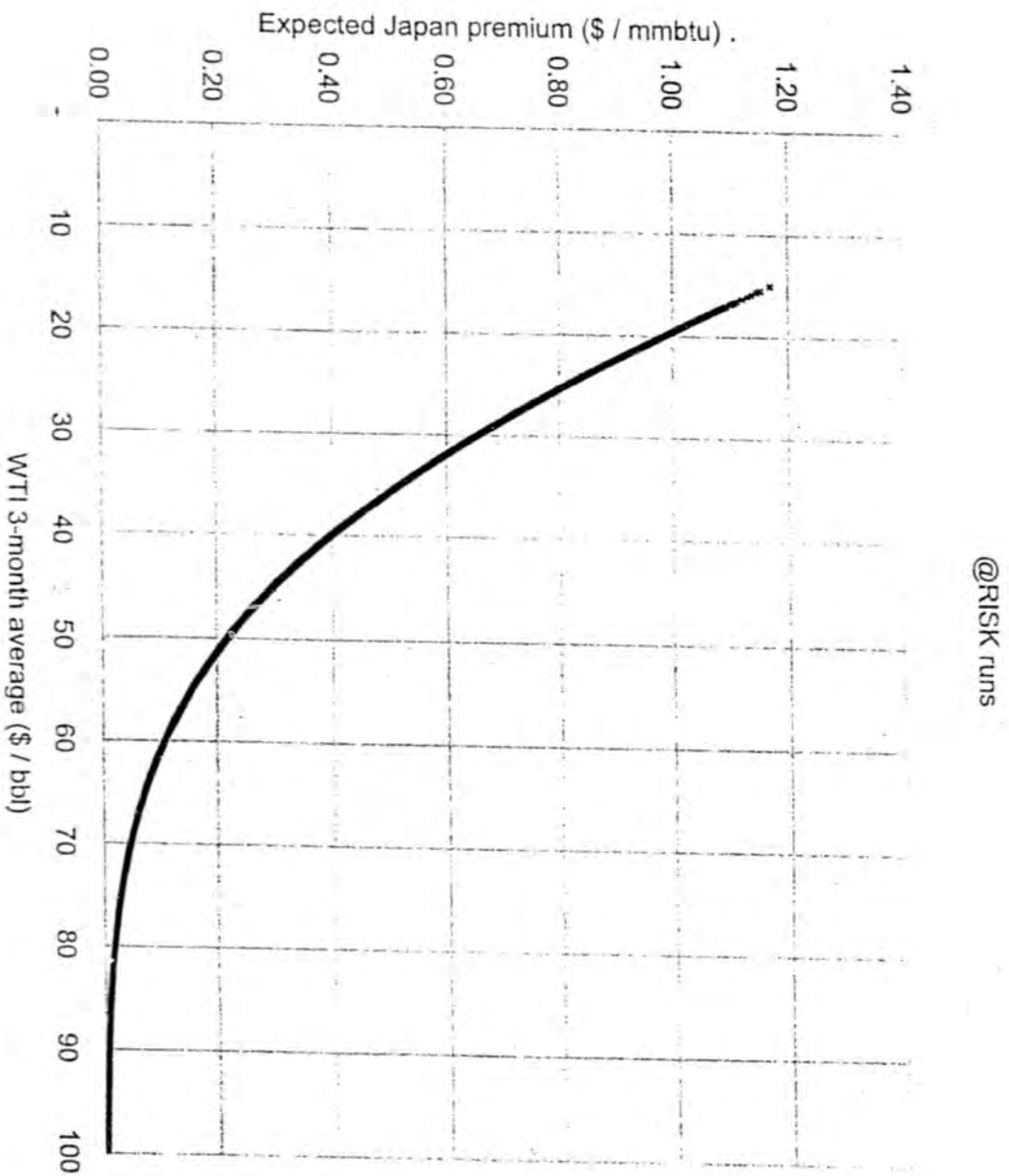
Value of Diversion Option (continued)



Value of Diversion Option (continued)



Value of Diversion Option (continued)



Producer Returns With Diversion Optionality

- The diversion option value enhances the upstream returns significantly
- Upstream Producer returns with option value (Base Case prices)
 - NPV @ 12% discount rate: \$2.2 billion (increase of \$0.5 billion)
 - IRR: 31.9%
- The diversion option reduces the breakeven threshold price
 - breakeven HH price without diversion option: \$4.30 per mmBtu
 - breakeven HH price with diversion option: \$3.74 per mmBtu



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Economics of Y-Line Expansion

Producer Returns and State NPV with Y-Line

- It is assumed that the Highway Project commences operations in 2016
- Producer NPV
 - standalone LNG Project (2012): \$2.2 billion
 - standalone Highway Project (2016): \$10.8 billion
 - Y-Line (1.2 Bcf/d in 2012 + 4.3 Bcf/d in 2016): \$13.1 billion
- Netback price for the Highway Project improves from \$4.23/mmBtu to \$4.34 in 2012 (nominal terms) due to cost savings associated with shared line
- State NPV @ 7% discount rate, assuming status quo fiscal regime
 - standalone LNG Project (2012): \$5.1 billion
 - standalone Highway Project (2016): \$16.5 billion
 - Y-Line (1.2 Bcf/d in 2012 + 4.3 Bcf/d in 2016): \$21.8 billion



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Sensitivity Case: Point Thomson Only

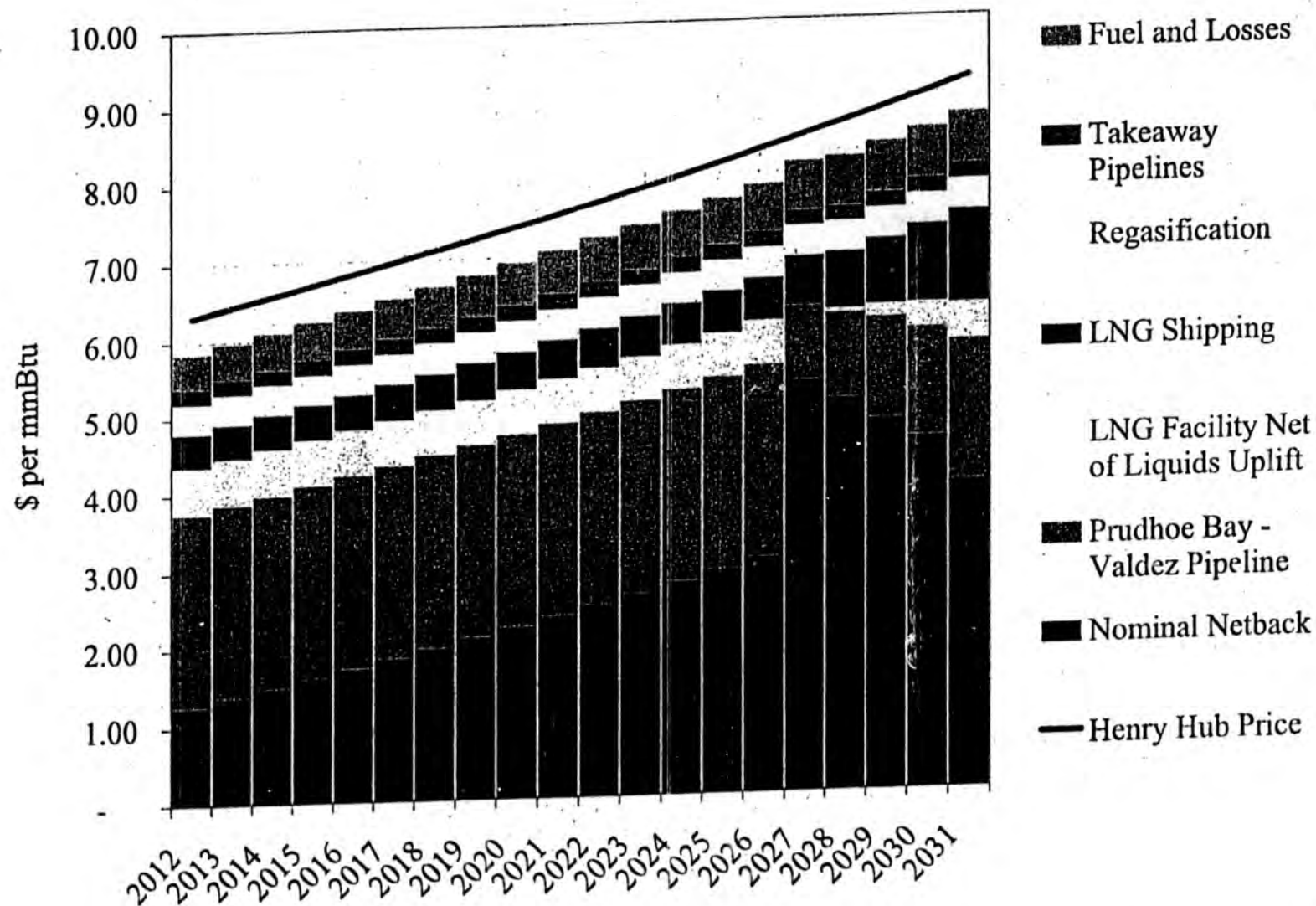


Scenario Description

- Only PTU is made available to supply project
- Case is analogous to LNG stand-alone project, but with slightly lower volume and shorter project life
- Does not take into account economics of liquids/condensates from PTU
- Assumed that production is curtailed when wellhead netback becomes negative due to production decline
- Without counting the value of the diversion option, negative wellhead netback occurs after 22 years of production
- Midstream capital is assumed to be repaid in 15 years, when production decline sets in, with about 20% of PTU remaining



PTU Only: Nominal Netback Price at Pipeline Inlet (No Option)

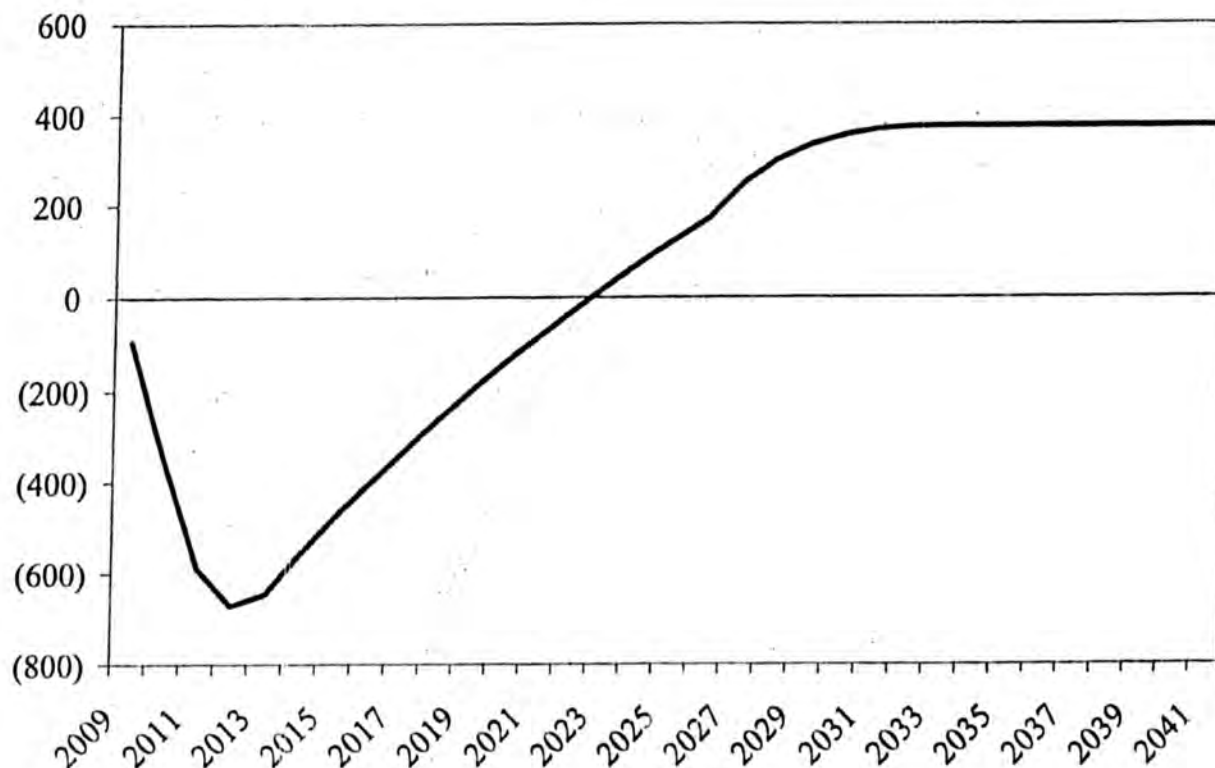


PTU Case: Base Case Producer Returns (No Diversion Option Value)

- Upstream Producer returns at the Base Case Henry Hub price of \$5.50/mmBtu
 - NPV @ 12% discount rate: \$375 million
 - IRR: 17.1%

Producer Upstream NPV@12

- Discounted payback is achieved – after 12 years of operations





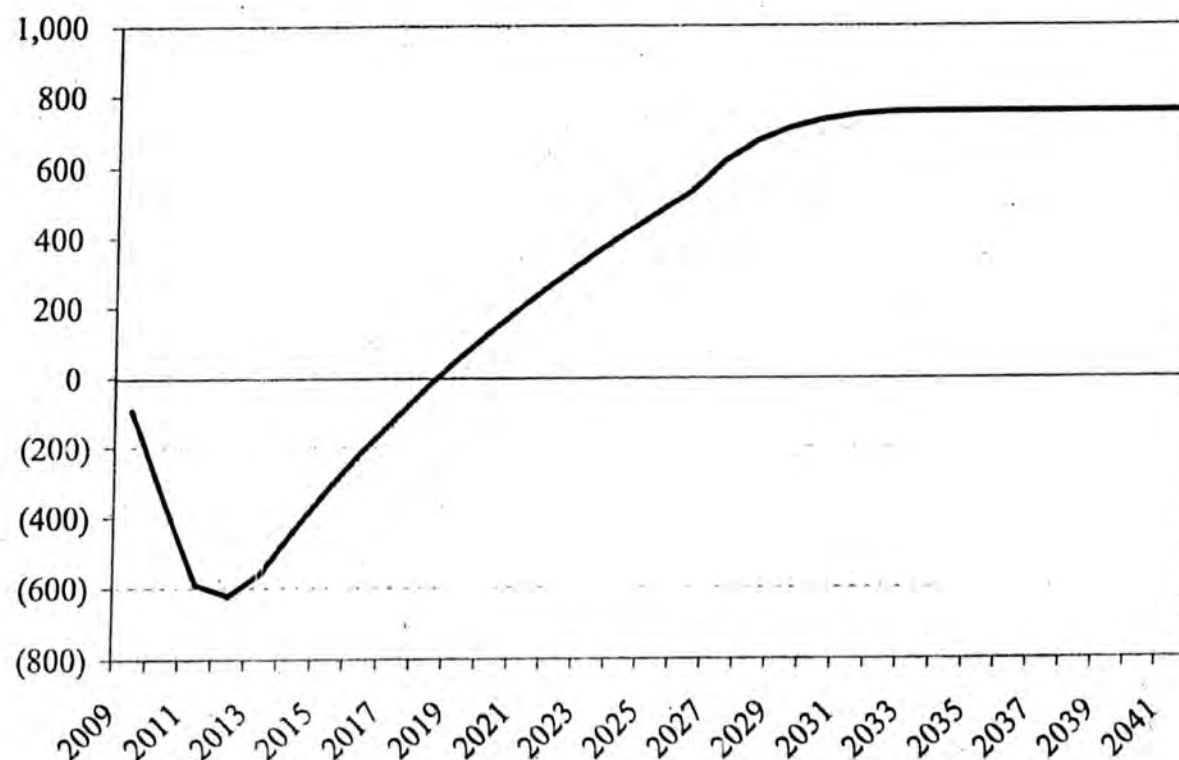
PTU Case: Sensitivity of Producer Returns (No Diversion Option Value)

- Producer upstream returns at the high price scenario (\$7.70/mmBtu Henry Hub and \$70/bbl WTI):
 - NPV @ 12% discount rate: \$2.7 billion
 - IRR: 46.8%
- The breakeven Henry Hub price (at which the Producer IRR equals 12%) is \$5.26/mmBtu

PTU Case: Base Case Producer Returns (With Option Value)

- Upstream Producer returns at the Base Case Henry Hub price of \$5.50/mmBtu
 - NPV @ 12% discount rate: \$753 million
 - IRR: 22.4%

Producer Upstream NPV@12



- Discounted payback is achieved – after 8 years of operations

PTU Case: Sensitivity of Producer Returns (With Option Value)

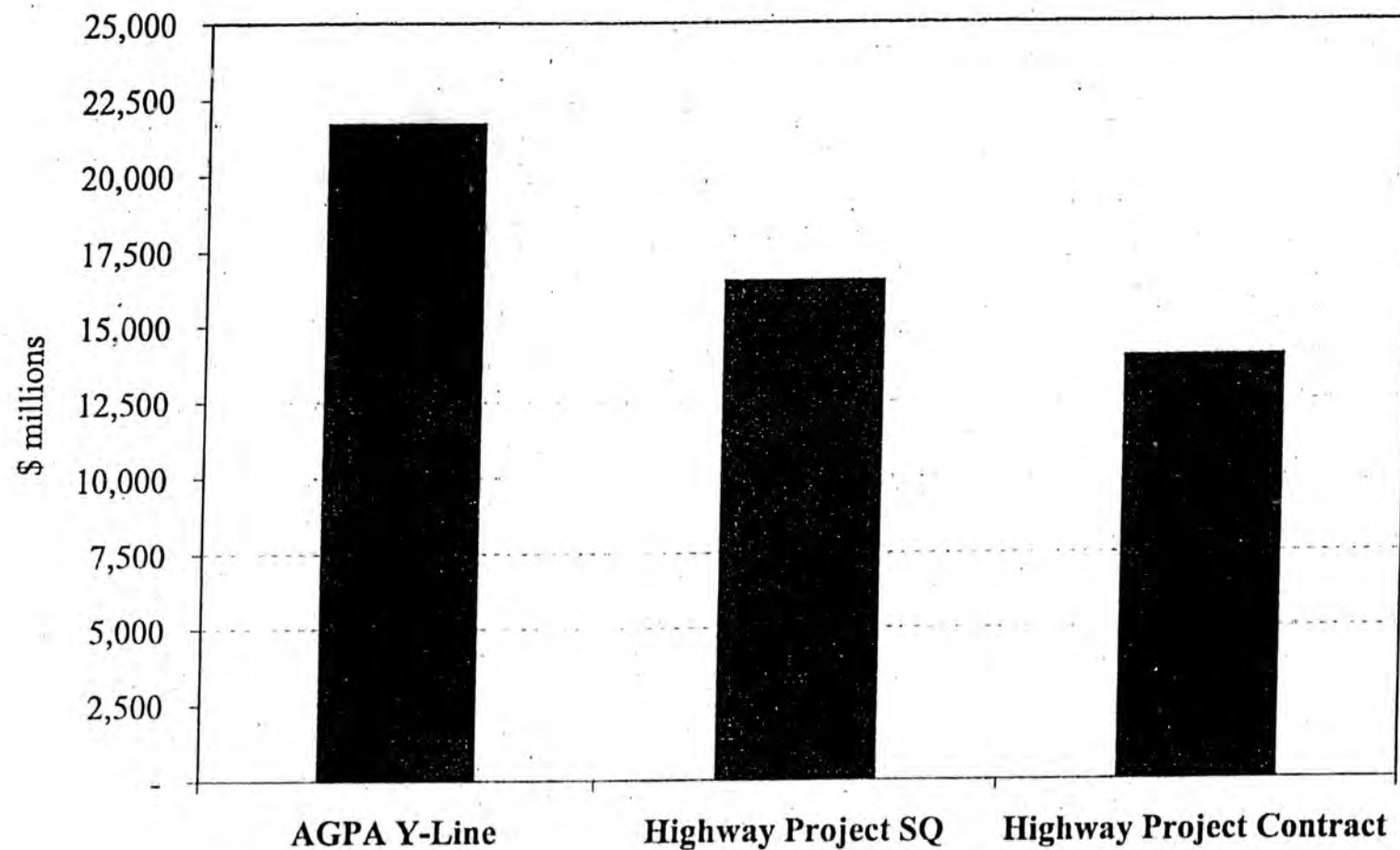
- Producer upstream returns at the high price scenario (\$7.70/mmBtu Henry Hub and \$70/bbl WTI):
 - NPV @ 12% discount rate: \$2.8 billion
 - IRR: 47.5%
- The breakeven Henry Hub price (at which the Producer IRR equals 12%) is \$4.67/mmBtu
- The sensitivity results above understates the true economics of the PTU-only case because:
 - condensates and NGL are excluded
 - midstream capital cost is not optimized for reduced volume
 - LNG vessel fleet is not optimized for reduced volume



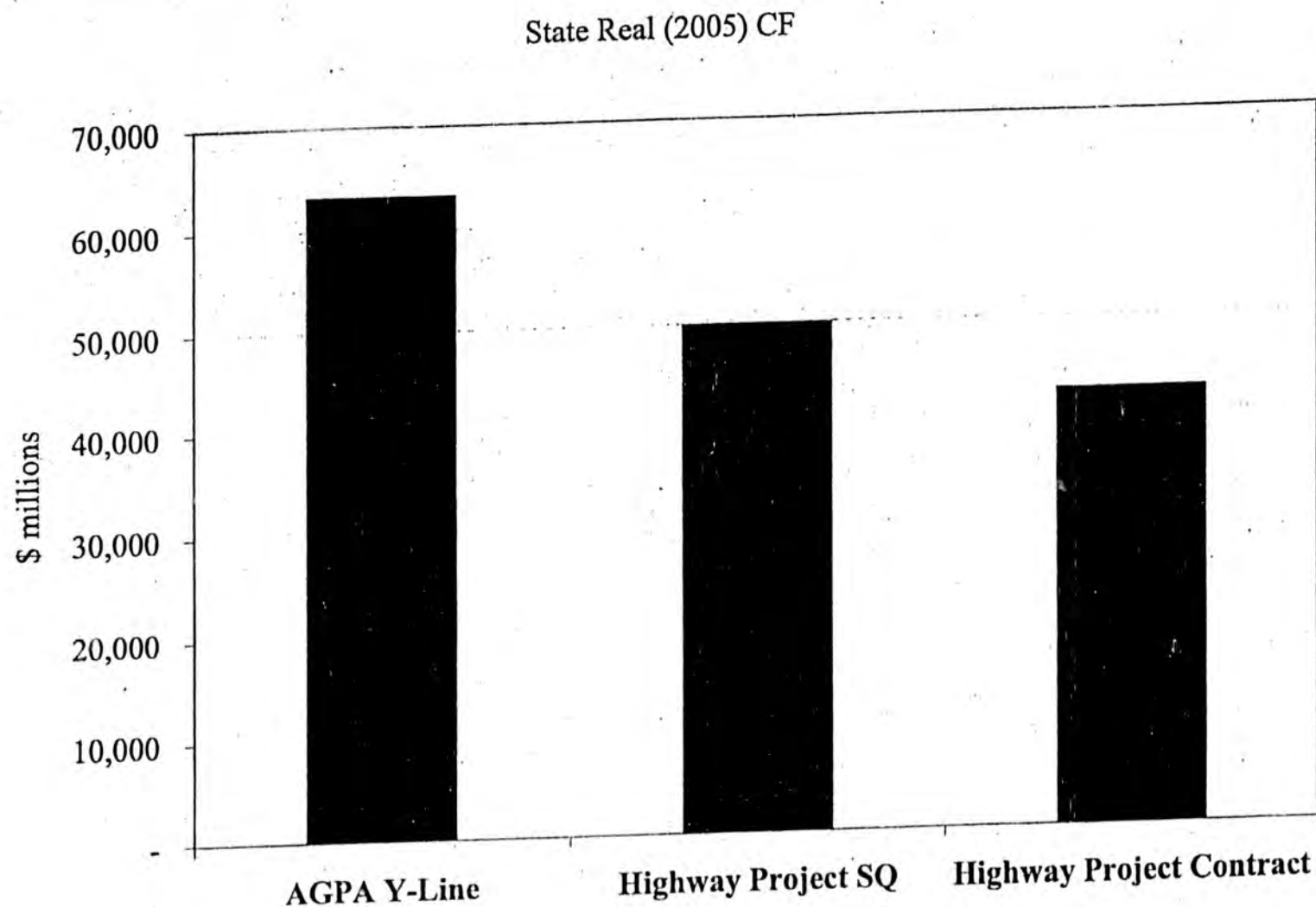
Comparison of State Revenues

Comparison of State NPV

State NPV@7%



Comparison of State Real Cash Flows (2005 dollars)





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Conclusions / Questions