

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

**Economics of AGIA's rolled-in rate provisions
Presentation to Senate Finance Committee
5/1/2007**

Rolled in Rates Question has been answered



- Fair
 - One service, one price. Not a subsidy!
 - Canadian pipelines and shippers apply this methodology
 - US market did likewise until pipeline grid adequately matured
- Effective
 - Alberta example: roughly 75 Tcf of known reserves has become over 200 Tcf of production with that much more yet to be produced
- Required
 - Frontier basin development requires different methodology than developed supply basin
 - FERC recognized this when it established the rolled-in rate presumption

Summary of economics of AGIA rolled-in rate provisions



- AGIA rolled-in rates promote competition, exploration and development.
- Rolled-in rates are in the state's interest given uncertainty of where expansion gas will come.
- Despite protests to the contrary, the objective evidence indicates that rolled-in rates:
 - impose relatively modest costs on Producers
 - are significantly off-set by AGIA's \$500M
 - are unlikely to affect Producer decisions to ship

Rolled-in Rates What They Are - Illustration



Initial Cost

\$100

Throughput

100

Initial Toll

\$100/100

= **\$1.00/unit**

Expansion Cost

\$30

Exp. Throughput

18

Rolled in Toll

$\$(100+30)/(100+18)$

= **\$1.10/unit**

Expansion Cost

\$30

Exp. Throughput

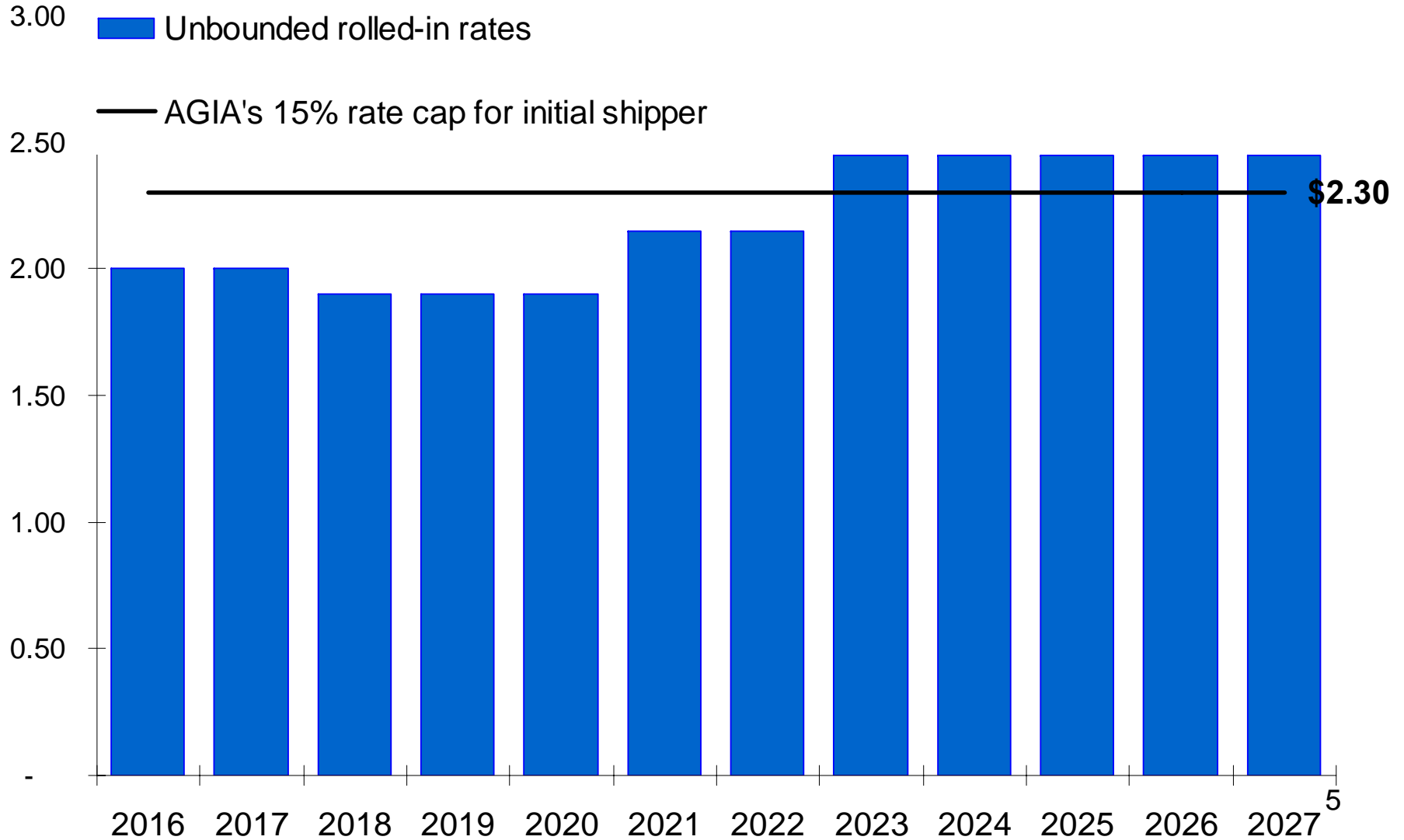
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Increment. Toll

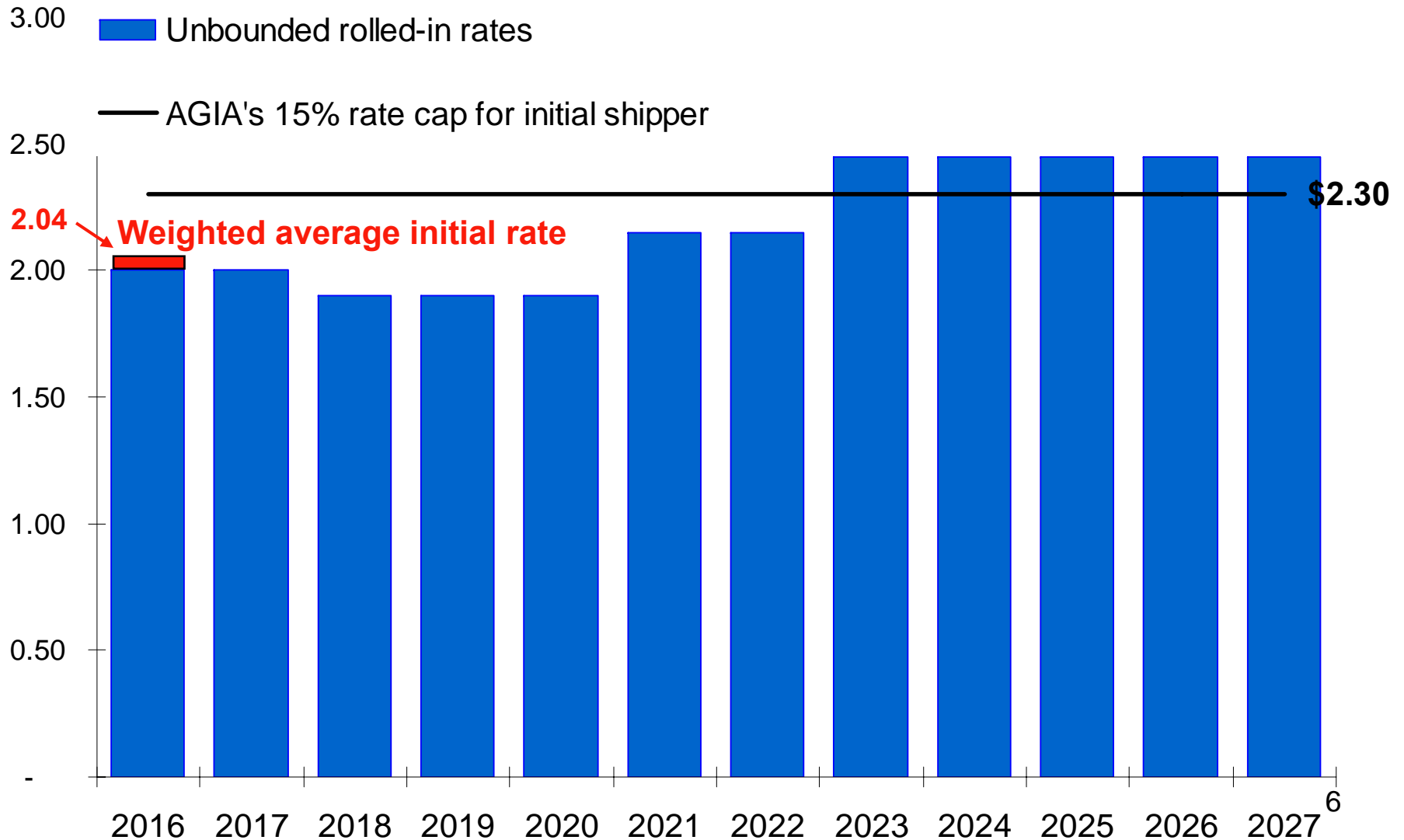
\$30/18 unit

= **\$1.67/unit**

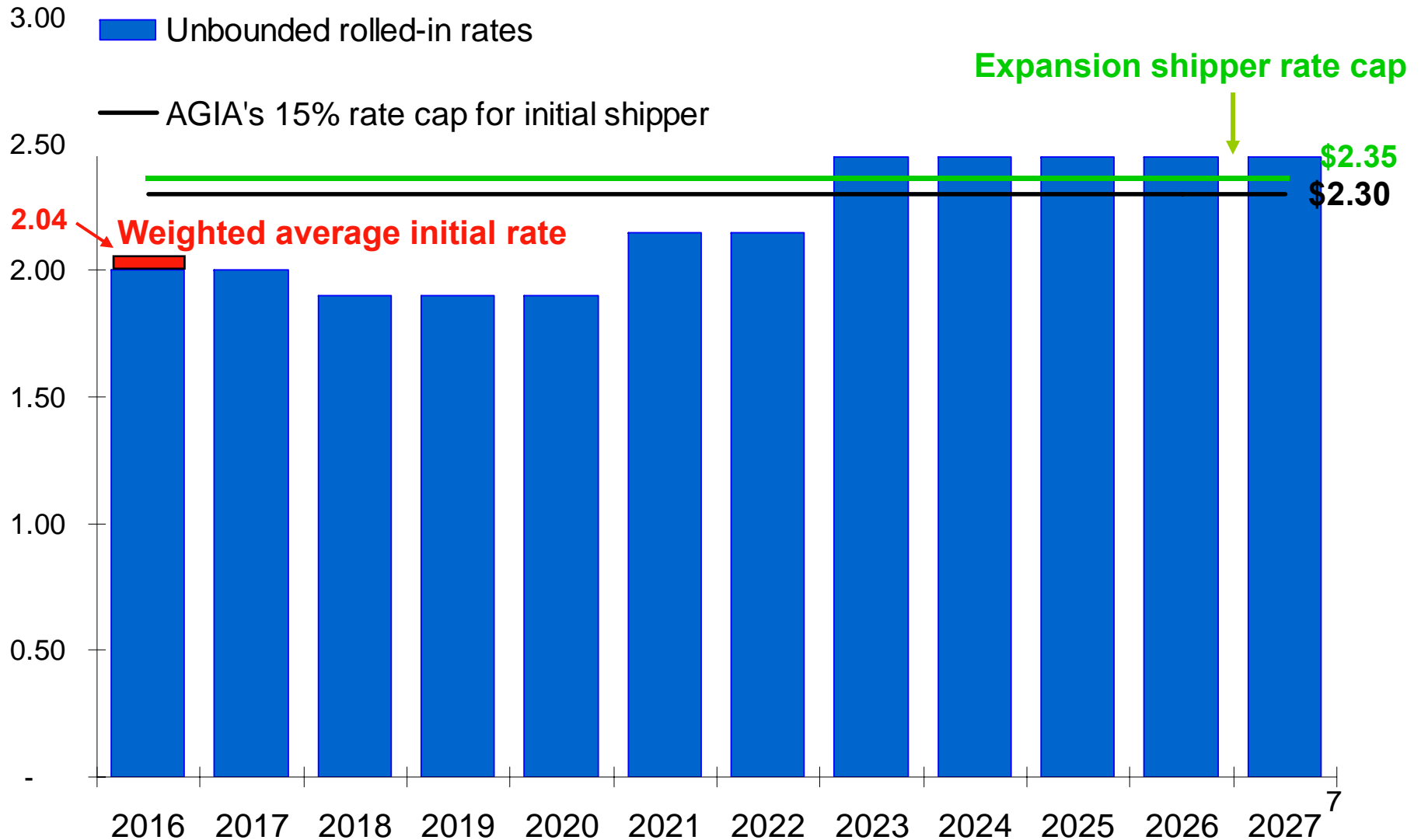
Illustrating AGIA's roll-in Cap for Initial Shippers



Illustrating AGIA's roll-in Cap for Expansion Shippers



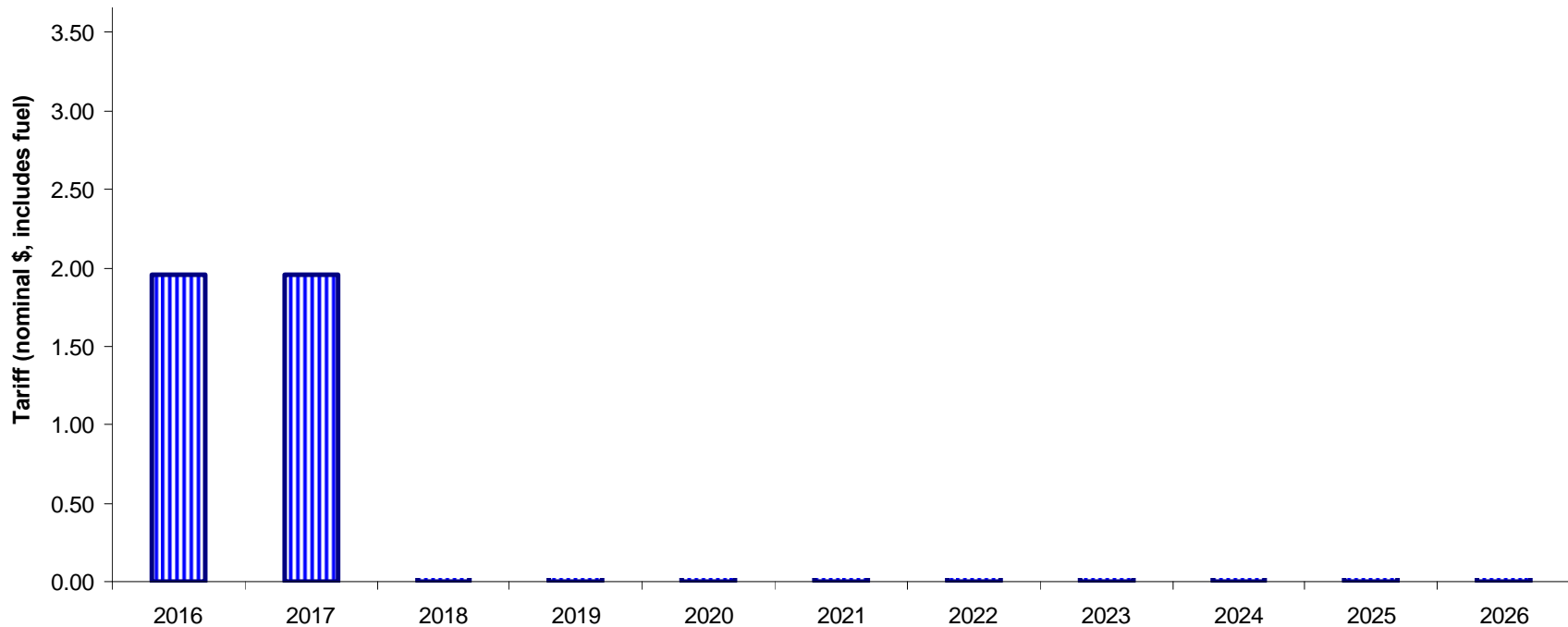
Illustrating AGIA's roll-in Cap for Expansion Shippers



Tariff Effects of Expansions FERC-L48 Rate Policy (\$5.50)



■ Lower-48 FERC policy, Initial Shippers' Rates



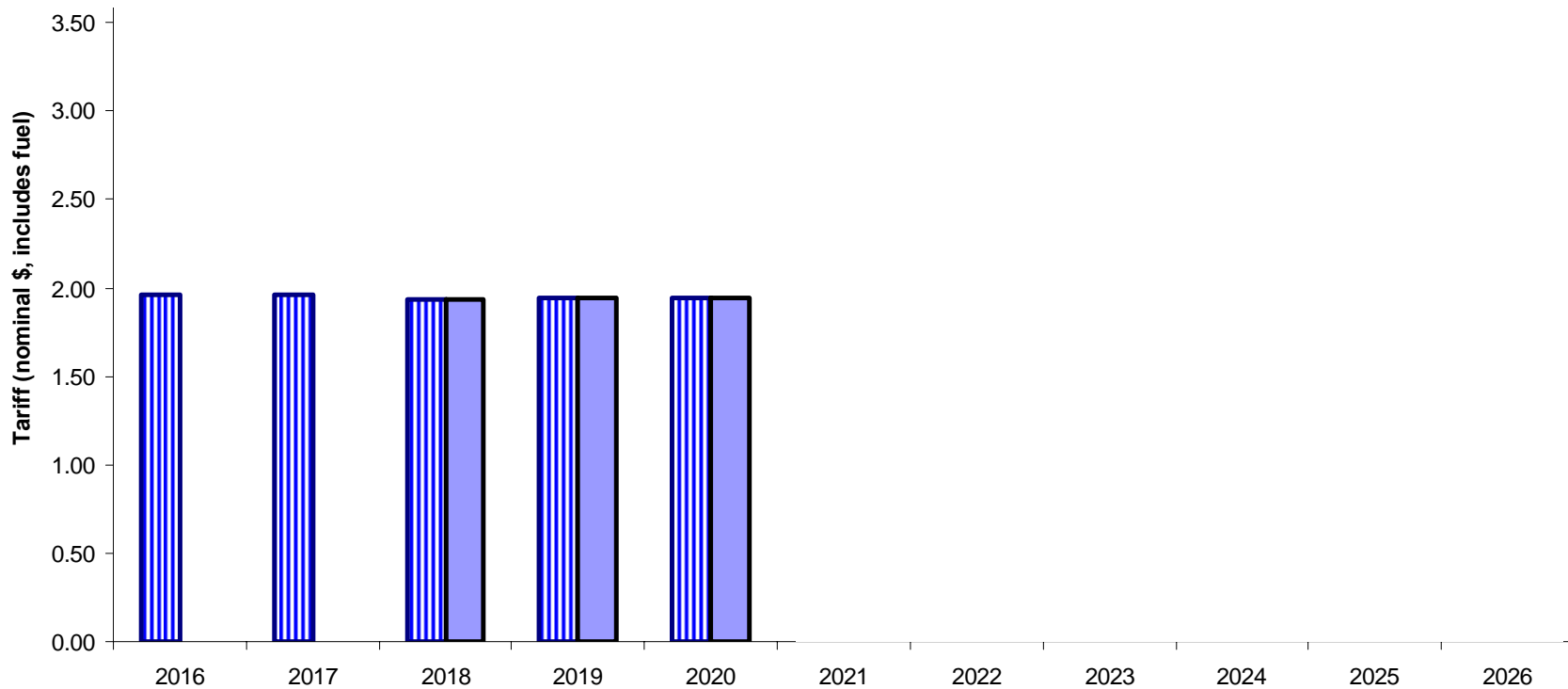
Assumes \$5.50 real Chicago gas prices

Tariff Effects of Expansions FERC-L48 Rate Policy (\$5.50)



▨ Lower-48 FERC policy, Initial Shippers' Rates

▣ Lower-48 FERC policy, 1st Expansion (2018) Shippers' Rates

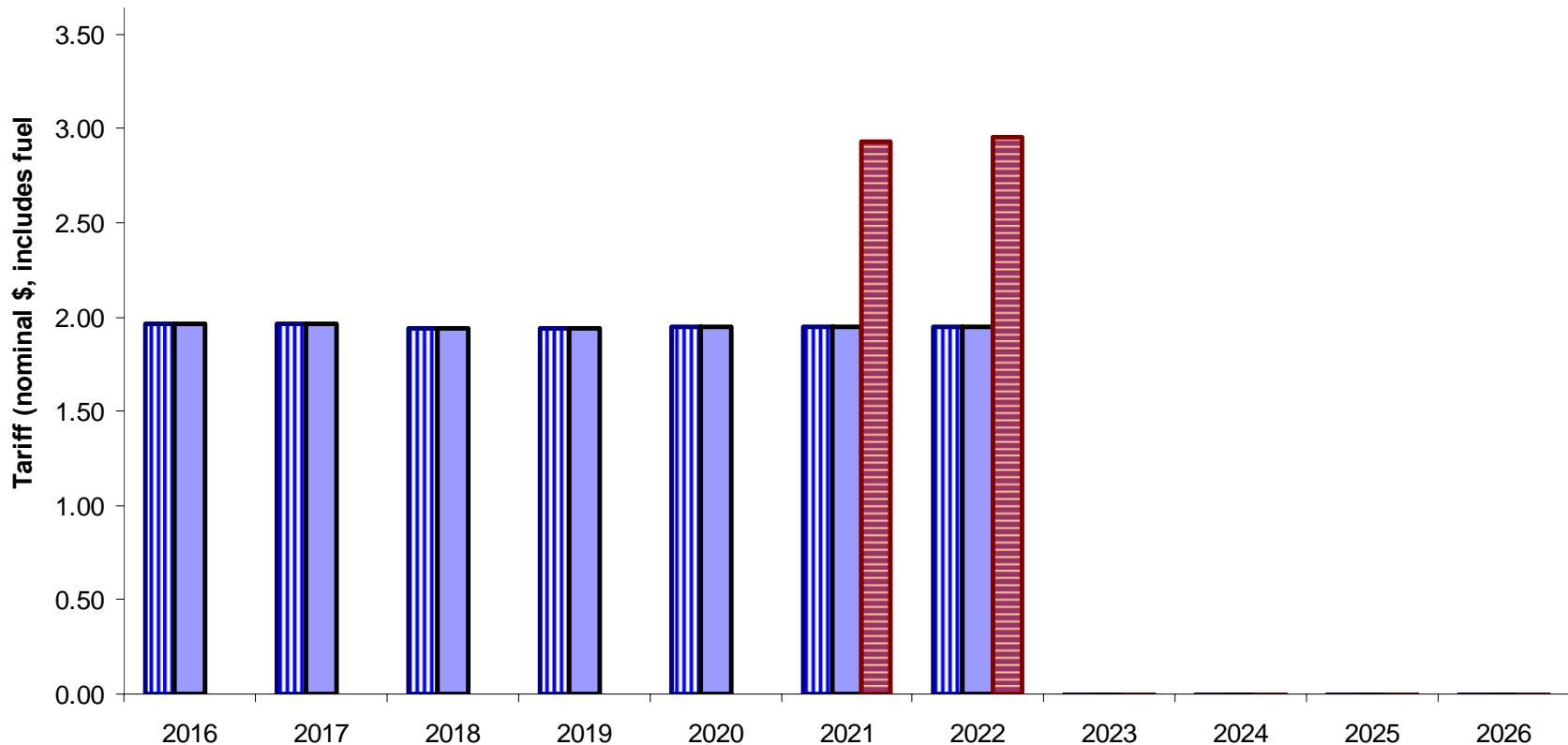


Assumes \$5.50 real Chicago gas prices

Tariff Effects of Expansions FERC-L48 Rate Policy (\$5.50)



- Lower-48 FERC policy, Initial Shippers' Rates
- Lower-48 FERC policy, 1st Expansion Shippers' Rates (2018)
- Lower-48 FERC policy, 2nd Expansion Shippers' Rates (2021)

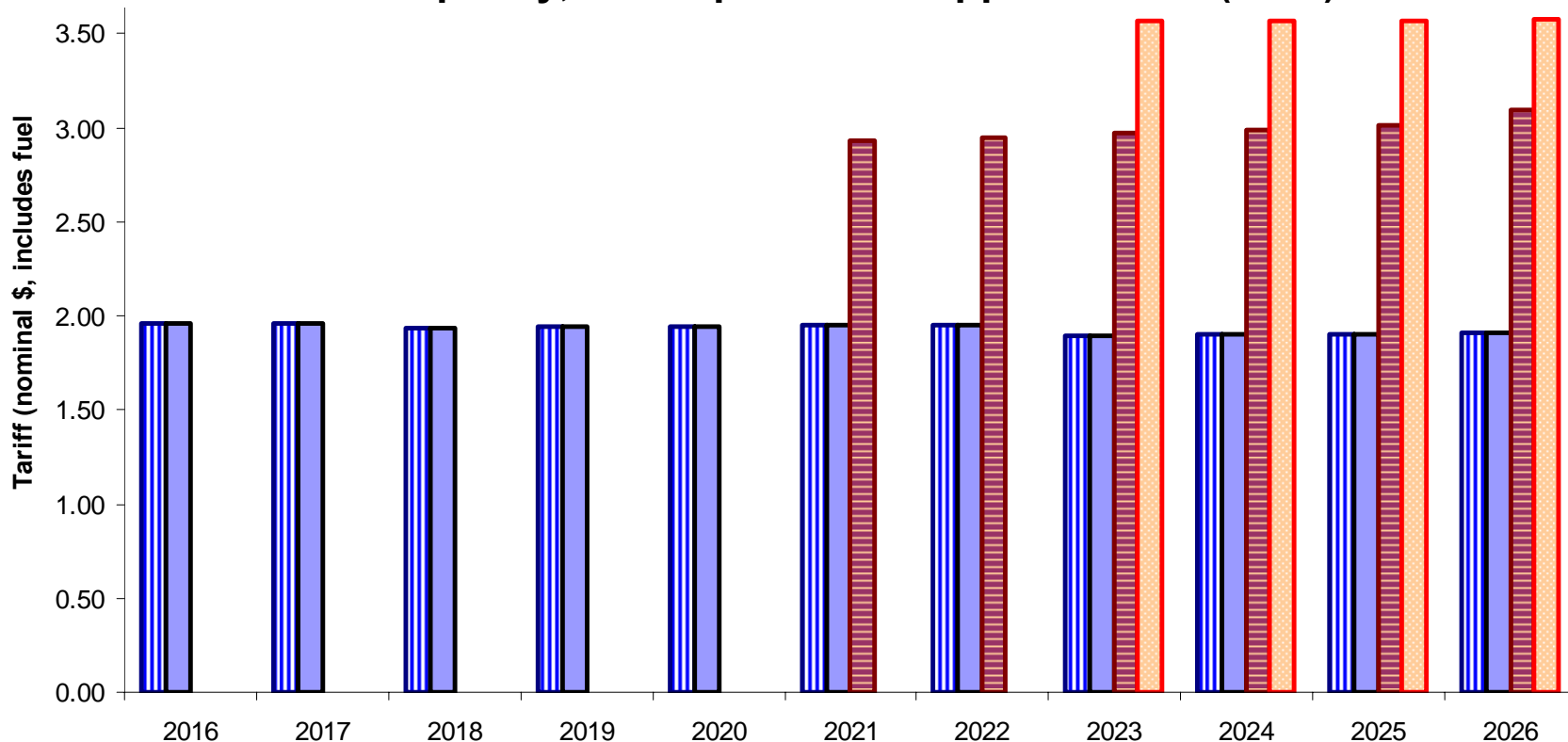


Assumes \$5.50 real Chicago gas prices

Tariff Effects of Expansions FERC-L48 Rate Policy (\$5.50)



- ▨ Lower-48 FERC policy, Initial Shippers' Rates
- ▨ Lower-48 FERC policy, 1st Expansion Shippers' Rates (2018)
- ▨ Lower-48 FERC policy, 2nd Expansion Shippers' Rates (2021)
- ▨ Lower-48 FERC policy, 3rd Expansion Shippers' Rates (2023)

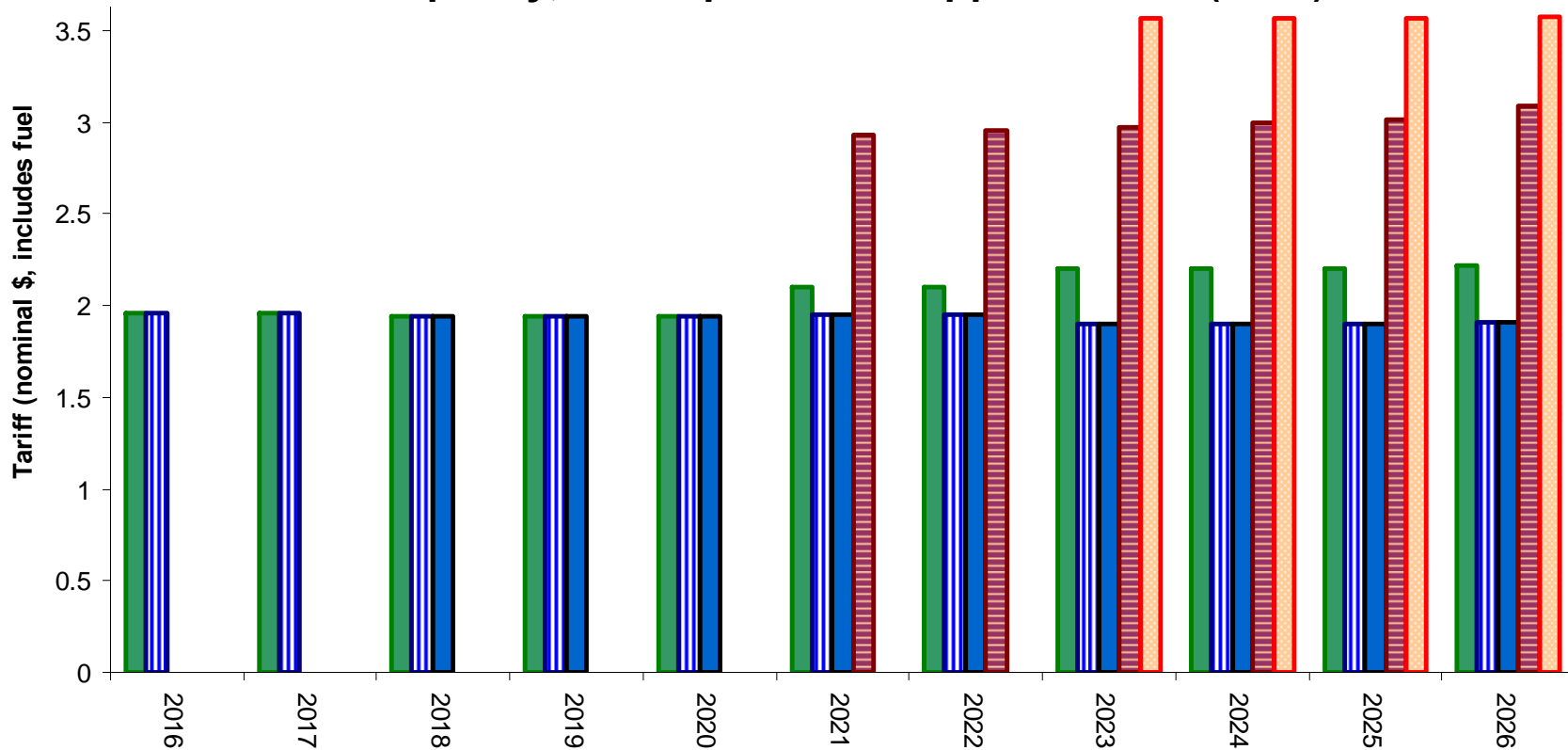


Assumes \$5.50 real Chicago gas prices

AGIA vs. FERC-L48 Rate Policies (\$5.50)



- AGIA policy; Initial, 1st and 2nd Expansion Shippers' Rates
- ▨ Initial shippers rates - FERC Lower-48 policy
- Lower-48 FERC policy, 1st Expansion Shippers' Rates (2018)
- Lower-48 FERC policy, 2nd Expansion Shippers' Rates (2021)
- Lower-48 FERC policy, 3rd Expansion Shippers' Rates (2023)

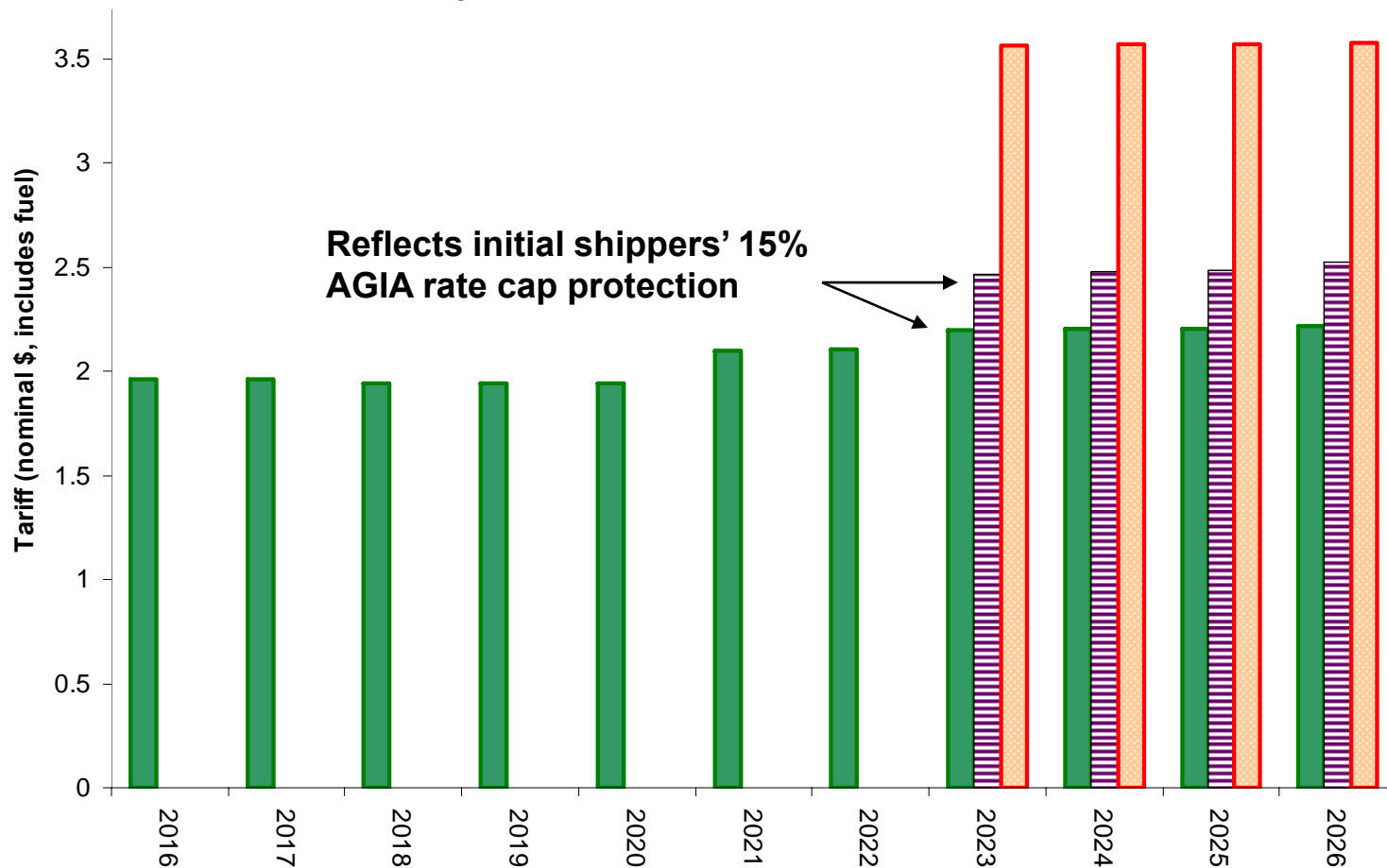


Assumes \$5.50 real Chicago gas prices

AGIA vs. FERC-L48 Rate Policies (cont.) (\$5.50)



- AGIA policy, Initial, 1st and 2nd Shippers' Rates
- ▨ AGIA policy, 3rd Expansion Shippers' Rates (2023)
- ▨ Lower-48 FERC policy, 3rd Expansion Shippers' Rates (2023)



Assumes \$5.50 real Chicago gas prices

Exploration economics AGIA vs. FERC policy



- Without rolled-in rates it is **unlikely** that 3rd (looped) expansion will occur.
- Expected value of generic prospect is very **negative** under incremental rate treatment:
 - \$15.7** million for OCS prospect
 - \$19.7** million for onshore prospect
- Expected value of generic prospect is **positive** under AGIA rate treatment:
 - \$18.1** million for OCS prospect
 - \$6.4** million for onshore prospect

Exploration economics AGIA vs. FERC policy (cont.)



- Without rolled-in rates it is **unlikely** that 2nd expansion (full in-fill compression) will occur.
- Expected value of generic onshore prospect is **negative** under incremental rate treatment:
 - \$4.1 million for OCS prospect
 - \$4.6** million for onshore prospect
- Expected value of generic prospect (both on and offshore) is **positive** under AGIA rate treatment:
 - \$29.5 million for OCS prospect
 - \$14.9 million for onshore prospect

State Revenue, AGIA Rate Provisions: Summary



- State revenue from an expansion depends on where the gas comes from
 - State lands: 12.5% royalty + PPT
 - Federal lands: 1/2 fed. royalty + PPT
 - Outer Continental Shelf (OCS): 0% royalty, no PPT
- We don't know from where gas for a given expansions will come
- Given such uncertainty it turns out that the state is clearly better off with AGIA's rolled-in rate provisions

State Revenue: Background To Scenarios (\$5.50 gas)



- **Base Case: 4.5 Bcf/day, pipeline to Alberta, 2016**
 - Initial tariff of \$1.96 (includes GTP)
- **1st Expansion: 1 Bcf, infill compression, 2018**
 - Capital cost of \$1.2 billion
 - Tariff of \$1.96
- **2nd Expansion: 1 Bcf, infill compression, 2021**
 - Capital cost \$2.1 billion
 - Tariff of \$2.93/\$2.10 for incremental/rolled-in rate treatment
- **3rd Expansion: 1 Bcf, looping, 2023**
 - Capital cost \$3.8 billion
 - Tariff of \$3.56/\$2.47 for incremental/rolled-in rate treatment

Note: Volumes reported at pipe inlet;
rates include fuel

State Revenue: Background To Scenarios (\$5.50 gas)



Case A: "State gas first"

- 1st bcf from state lands (2018)**
- 2nd bcf from NPR-A (2021)**
- 3rd bcf from OCS (2023)**

Case B: "State gas second"

- 1st bcf from NPR-A (2018)**
- 2nd bcf from state lands (2021)**
- 3rd bcf from OCS (2023)**

Case C: "State gas last"

- 1st bcf from OCS (2018)**
- 2nd bcf from NPR-A (2021)**
- 3rd bcf from state lands (2023)**

State Revenue, AGIA Rates: All Expansions Occur



- Without rolled-in rates it is **very unlikely** all expansions would occur. But if they did:
 $[AGIA \text{ revenue}] - [L48 \text{ FERC revenue}] =$

	State NPV ₅ difference, \$2007 (billion)			
	<u>Case A</u>	<u>Case B</u>	<u>Case C</u>	<u>Expected Value</u>
	State gas first	State gas 2nd	State gas last	
\$3.50	(0.91)	(0.79)	0.15	(0.52)
\$5.50	(0.75)	(0.58)	0.25	(0.36)
\$7.00	(0.71)	(0.52)	0.05	(0.39)

State Revenue, AGIA Rates: No Looping



- Without rolled-in rates it is **very likely** the **last** expansion **won't occur**. If it doesn't:
 $[AGIA \text{ revenue}] - [L48 \text{ FERC revenue}] =$

	State NPV ₅ difference, \$2007 (billion)			
	<u>Case A</u>	<u>Case B</u>	<u>Case C</u>	<u>Expected Value</u>
	State gas first	State gas 2nd	State gas last	
\$3.50	(1.13)	(1.05)	0.85	(0.44)
\$5.50	(0.74)	(0.65)	3.30	0.64
\$7.00	(0.56)	(0.46)	5.00	1.33

State Revenue, AGIA Rates: No Looping, No Full in-fill



- Without rolled-in rates it is *likely neither 2nd nor 3rd* expansion occur. If they don't:
 $[AGIA \text{ revenue}] - [L48 \text{ FERC revenue}] =$

	State NPV ₅ difference, \$2007 (billion)			
	<u>Case A</u>	<u>Case B</u>	<u>Case C</u>	<u>Expected</u>
	State gas first	State gas 2nd	State gas last	<u>Value</u>
\$3.50	1.71	1.67	2.18	1.85
\$5.50	5.63	5.57	6.28	5.83
\$7.00	8.51	8.45	9.27	8.75

Producer Upstream Returns

Base case cost = \$20.5B



	NPV₁₀ (\$B)	IRR	P/I	NPV₁₀ per BOE
\$4.00	6.1	39.7%	4.3	\$0.74
\$5.50	12.1	62.9%	7.5	\$1.46
\$7.00	17.8	79.2%	10.5	\$2.15

Prices are real, \$2007, escalating at 2%/year

Worst-Case Producer Effects of AGIA Rates



- The following shows Producer upstream investment measures given the three expansions under the “worst case” of no producer gas in any of the expansions.

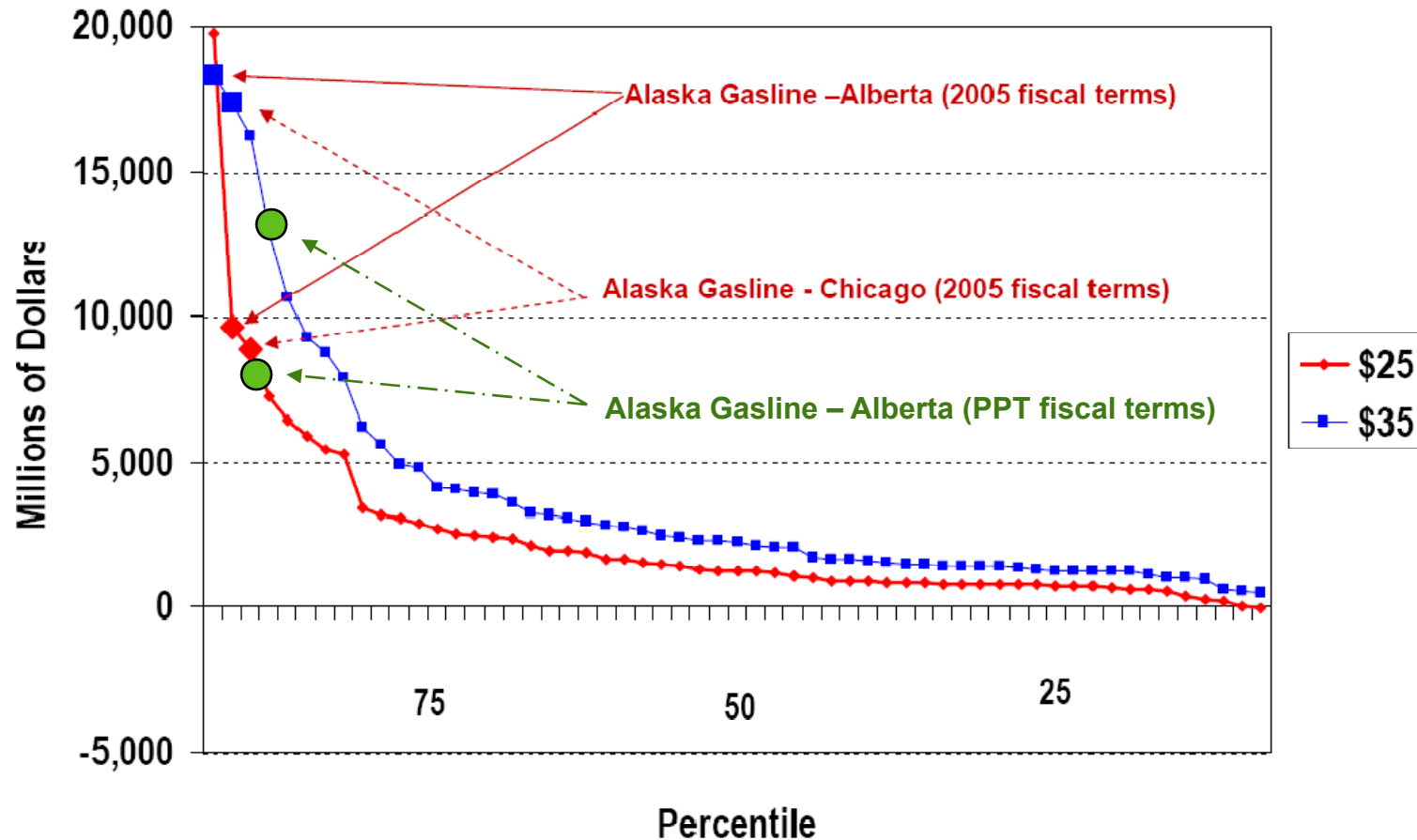
	<u>NPV₁₀ (\$B)</u>	<u>IRR</u>	<u>P/I</u>	<u>NPV₁₀ per BOE</u>	<u>% Δ NPV</u>	<u>Δ IRR</u>	<u>% Δ P/I</u>
\$4.00	5.8	39.6%	4.1	\$0.70	-5.4%	-0.10%	-4%
\$5.50	11.7	62.8%	7.3	\$1.41	-3.3%	-0.10%	-3%
\$7.00	17.4	79.0%	10.3	\$2.10	-2.3%	-0.13%	-2%

Prices are real, \$2007, escalating at 2%/year

Project Comparison

Producer Net Cash Flow (NPV10)

(\$35 and \$25 oil and 6/1 oil/gas ratio)

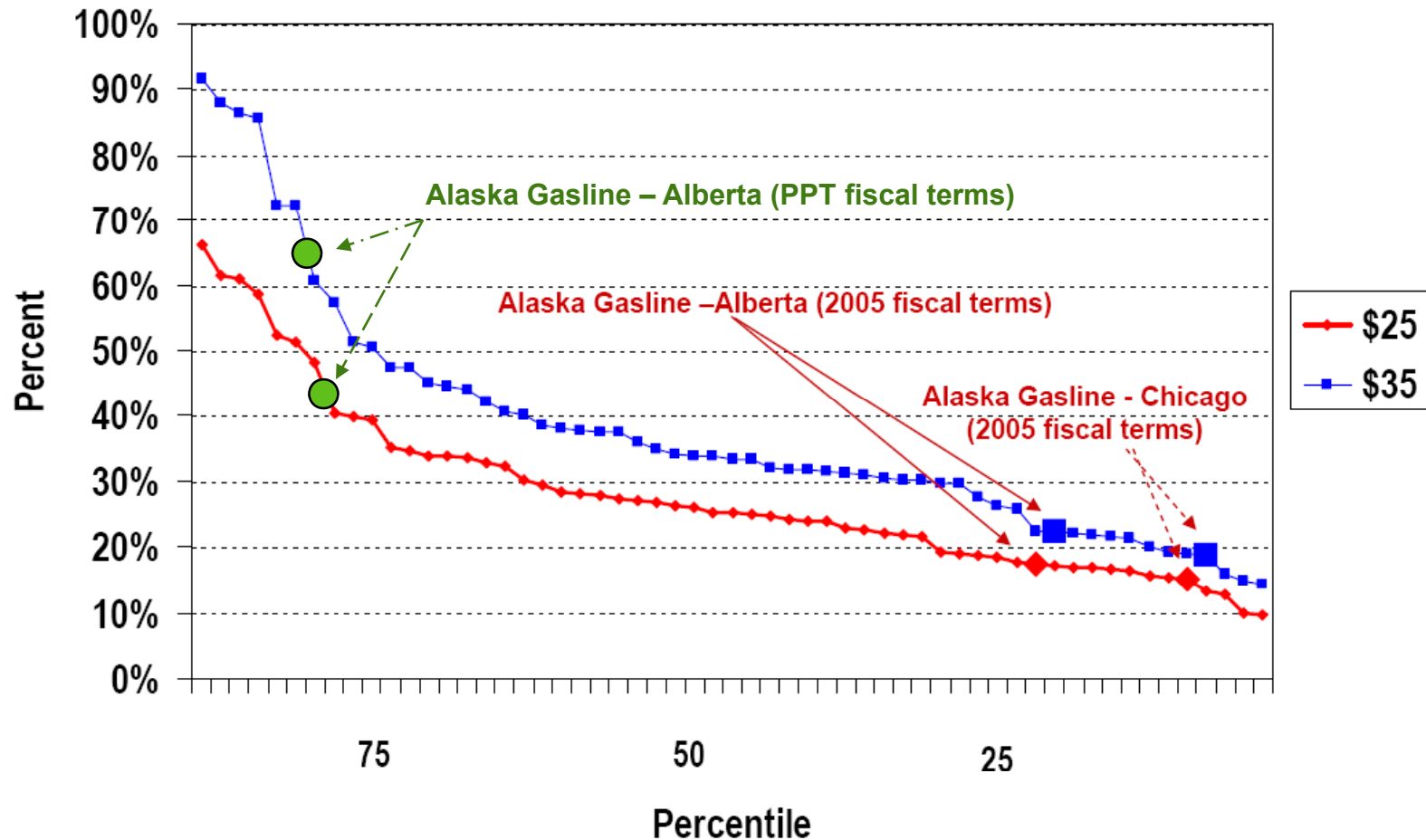


Project comparison data from EconOne presentation to LB&A Committee, 6/14/06. EconOne data 24
 assumes 100% Producer pipeline ownership; upstream return data assumes 0% pipeline ownership.

Project Comparison

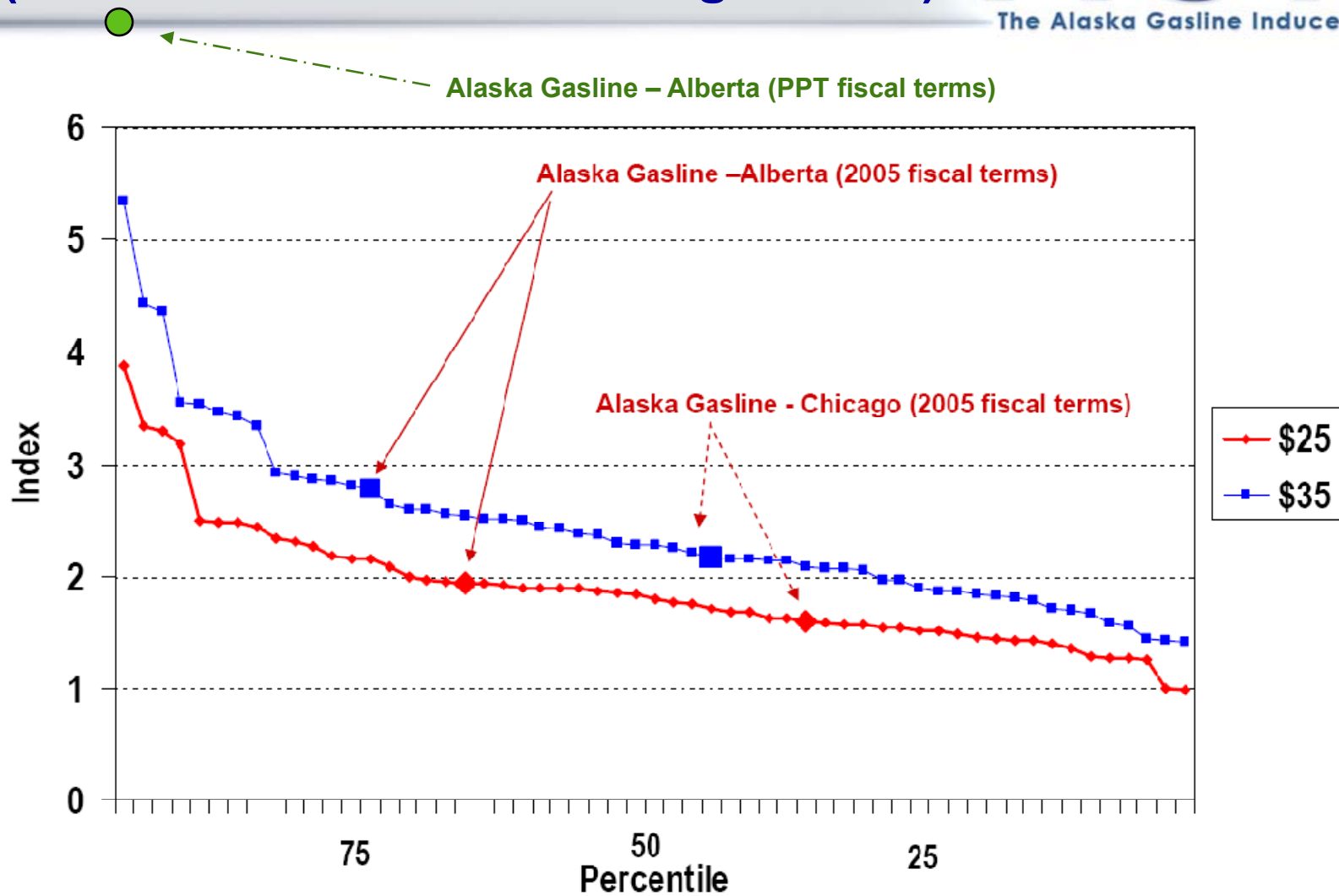
Internal Rate of Return (IRR)

(\$35 and \$25 oil and 6/1 oil/gas ratio)



Project comparison data from EconOne presentation to LB&A Committee, 6/14/06. EconOne data 25
 assumes 100% Producer pipeline ownership; upstream return data assumes 0% pipeline ownership.

Project Comparison Profitability Index Ratio (PIR10) (\$35 and \$25 oil and 6/1 oil/gas ratio)

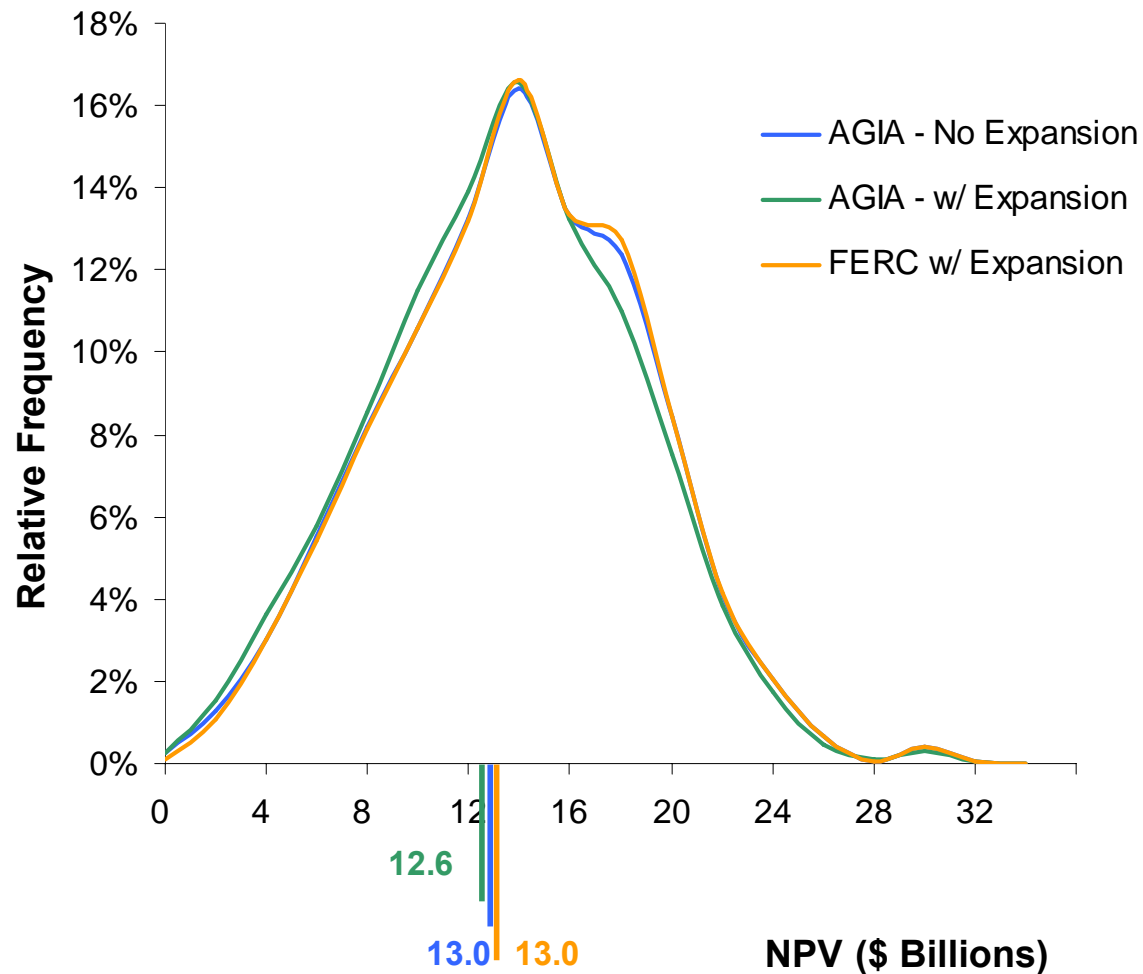


Project comparison data from EconOne presentation to LB&A Committee, 6/14/06. EconOne data assumes 100% Producer pipeline ownership; upstream return data assumes 0% pipeline ownership.

Worst-Case Producer Effects of AGIA Rates - NPV



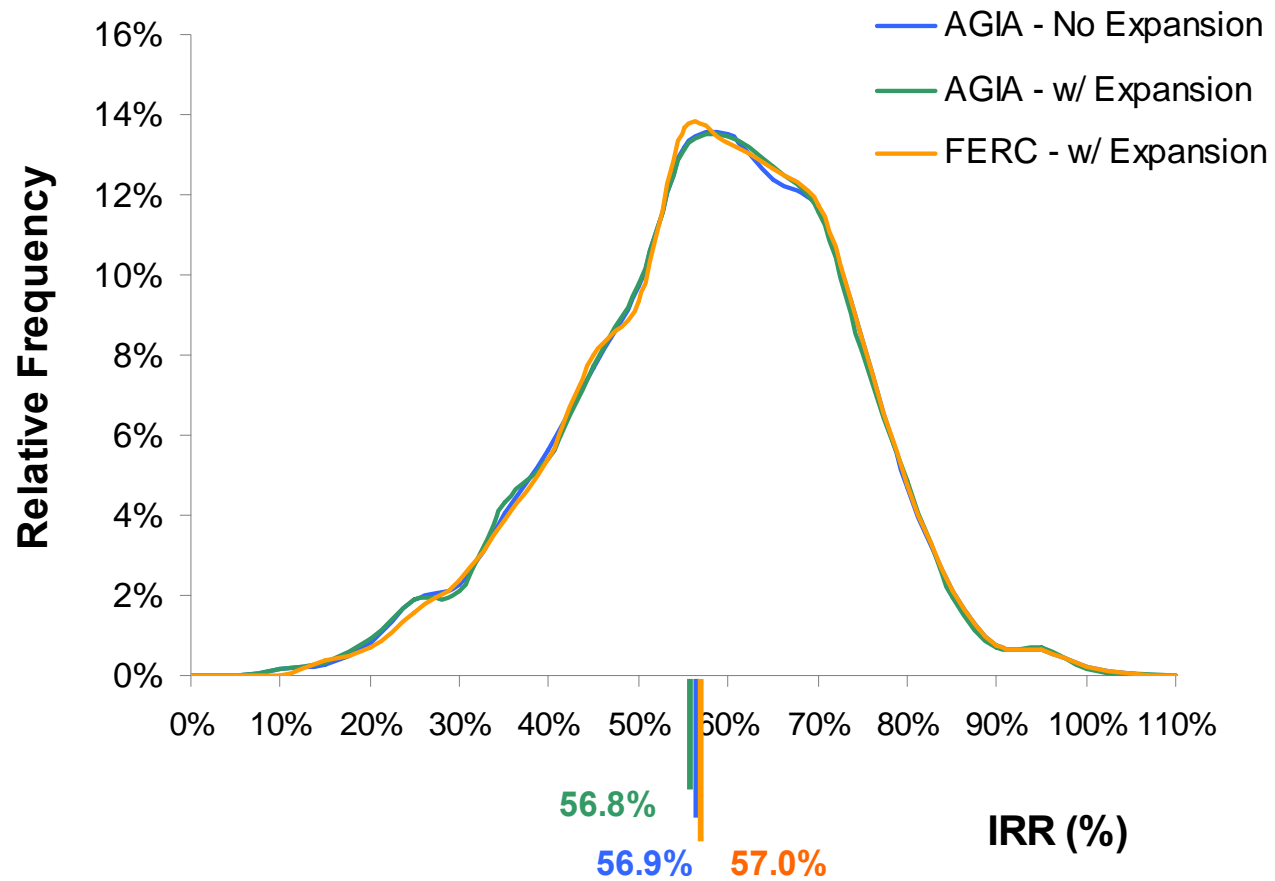
Frequency Distribution Producer Upstream NPV₁₀



Worst-Case Producer Effects of AGIA Rates - IRR



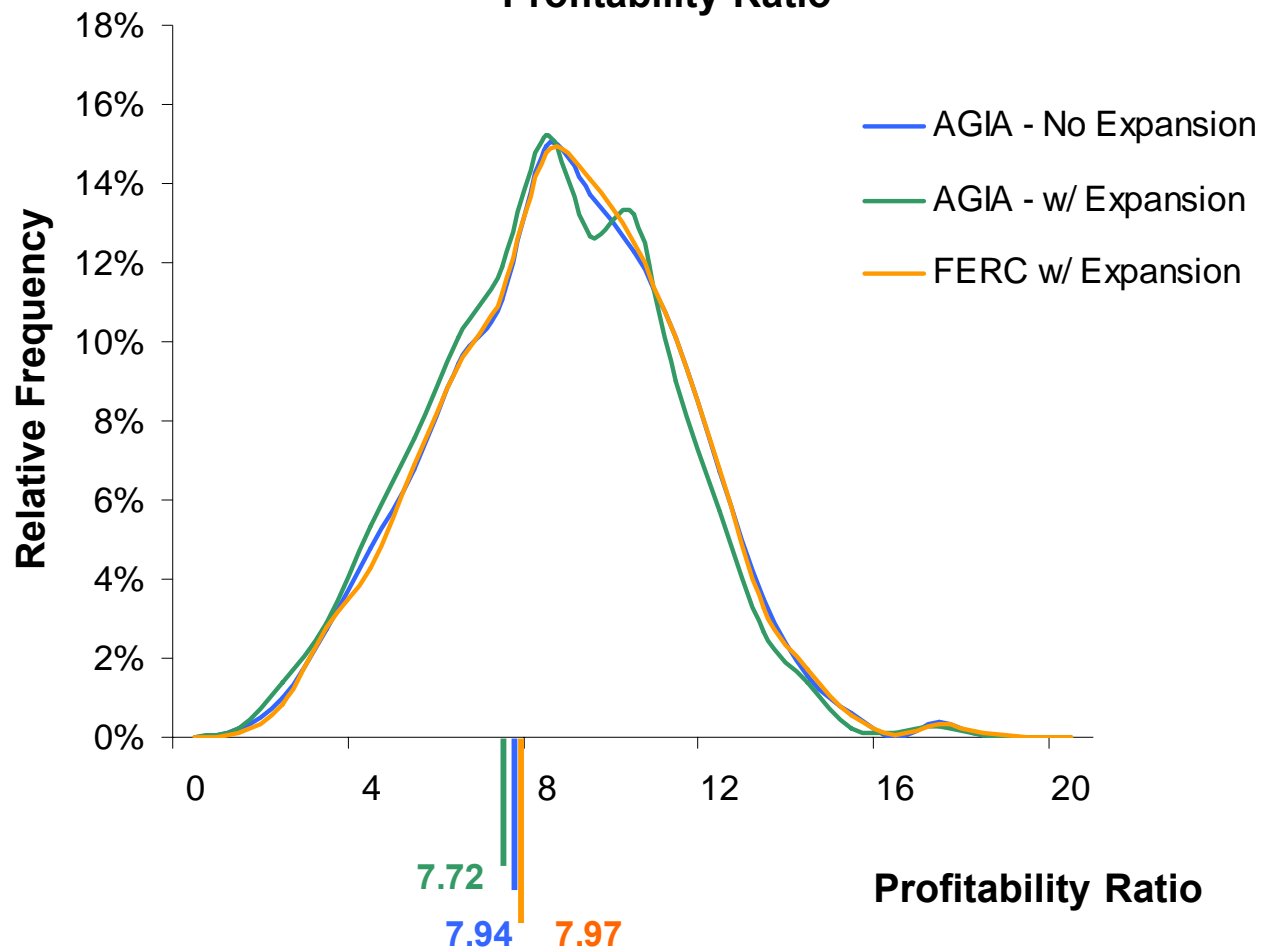
Frequency Distribution Producer Upstream IRR



Worst-Case Producer Effects of AGIA Rates – P/I



Frequency Distribution Producer UpStream Profitability Ratio



Summary



- AGIA rolled-in rates promote competition, exploration and development.
- Given uncertainties, AGIA's rolled-in rates are clearly in the state's monetary interest.
- Protests notwithstanding, the objective evidence indicates that AGIA's rolled-in provisions cost the Producers only modestly and are unlikely to affect initial investment decisions.

Appendix Methods and Assumptions for Expansion Tariffs



Expansion	CapEx (Billions)	Service Years	Shippers	Status of 1 st Expansion	Tariffs ^a					
					Stand Alone			Rolled in		
					Rate (\$/mmBtu)	Fuel Use	Combined ^b (\$/mmBtu)	Rate (\$/mmBtu)	Fuel Use	Combined ^b (\$/mmBtu)
					A	B	C	D	E	F
1 st – 2018 1 Bcf/day with In-fill Compression	\$1.2	28–31	Existing	-na-	\$1.56	2.49% ^c	\$1.56	\$1.41	2.06%	\$1.54
			Expansion		\$1.04	13.34%	\$1.70			
2 nd – 2021 1 Bcf/day with In-fill Compression	\$2.1	30	Existing	1 st exp not rolled in	\$1.56	0.00%	\$1.56	\$1.45	3.76%	\$1.69
				1 st exp rolled in	\$1.41	2.06%	\$1.54			
			Expansion	\$1.67	13.08%	\$2.49				
3 rd – 2023 1 Bcf/Day with Looping	\$3.8	28	Existing	1 st and 2 nd exp not rolled in	\$1.56	-0.45% ^d	\$1.53	\$1.65	2.93%	\$1.84 ^e
				1 st exp (only) rolled in	\$1.41	1.36%	\$1.50			
				1 st and 2 nd exp rolled in	\$1.45	2.93%	\$1.65			
			Expansion	1 st and 2 nd exp not rolled in	\$3.08	-0.45% ^d	\$3.05			
				1 st exp (only) rolled in	\$3.08	1.36%	\$3.17			
				1 st and 2 nd exp rolled in	\$3.08	2.93%	\$3.27			

Table Notes:

^a For pipeline only; tariffs do not include GTP demand charges (\$0.40 per Mcf) or cost of GTP fuel usage (2.9%).

^b Calculated assuming \$5.50 per mmBtu Chicago Citygate gas price in real 2007 dollars.

^c Base fuel usage of 2.49% for the original (base) pipeline is imbedded in \$1.56 as an in-kind gas usage. All other fuel usage depicted in columns B and E are incremental to this in-kind fuel usage.

^d A looping expansion does not increase fuel usage. Under looping, overall fuel usage is averaged (rolled in) for both stand-alone and rolled-in tariffs.

^e Does not reflect the 15% cap under AGIA, which would be lowered by approximately 4¢ per mmBtu to \$1.80 with a \$1.56 base tariff.

Appendix Methods and Assumptions for Expansion Tariffs



Assumptions:

- Prior to expansion we have a project with gas beginning to flow in 2016 consisting of a conditioning plant on the North Slope to remove impurities, and a pipeline to Alberta.
- The project costs around \$17.8 billion in 2007 dollars, or \$20.5 billion in dollars of the day to build (we assume cost inflation of only 2% going forward).
- The project delivers gas into the pipeline system at Gordondale, Alberta on a keep-whole basis (the cost and profit or loss from an NGL plant are not included).
- Fuel for the base project is assumed to be donated in-kind to the project by the shipper.
- The project has sales volume of around 4.2 bcf/day after fuel usage of about 5.5% from the conditioning plant and the pipeline. We assume gas is sold on a mmBtu basis, and that the base case gas is moderately enriched (1,080 mmBtu/mcf).
- Shippers enter into a firm transportation contract of 20 years, and the tariff is levelized on an annual nominal revenue requirement basis for this period.
- The pipeline is depreciated over 30 years.
- The tariff is determined using an imputed 70/30 debt/equity split, with a 6.5% return on debt and a 14% return on equity.
- The pipeline made use of the \$500 million state match under AGIA to lower the tariff.
- We evaluate cash flows over 30 years of project operation.

Appendix Methods and Assumptions for Expansion Tariffs



Tariff Methodology

- In calculating a tariff for the existing and expansion shippers after an expansion, we first set the tariff rule-making as either:
 - FERC existing policy in the lower 48 of rolling in expansions if doing so decreases rates for existing shippers, or
 - AGIA policy of rolling in rates until the rolled-in rate is more than 15% above the pre-expansion, pipeline start-up rate.
- In comparing rolled-in and incremental rates under the FERC and AGIA policy, we look to the rates (both demand charge and fuel charge) determined in the year of the expansion.
 - If rates are rolled-in for the demand charge, the un-depreciated capital from the existing tariffs is added to the rate base for the expansion, and then re-levelized over the life of the expansion.
 - Fuel use attributable to an expansion is translated into a \$/mmBtu tariff charge based on the then current destination price for gas.
- Fuel usage provided in the table above excludes the project fuel donated in-kind. It does not include fuel usage or the demand charge at the conditioning plant. We assumed expansion volumes were dry (1,000 Btu/mcf).

Appendix

Prospect Model Assumptions



- 12% discount rate for operator
- Land is already leased over attractive prospect
- Seismic data over prospect is already owned
- PPT credits and taxes apply to onshore gas
- 6 years from drilling to 1st gas sale, assuming no access delays

Appendix

Prospect model assumptions



- 40% = Probability 1st exploration well finds gas (geologic success)
- 60% = Probability delineation drilling program is success
- Development success cases:
 - High case = 3.6 Tcf field, 6% likelihood
 - Middle case = 1.8 Tcf field, 35% likelihood
 - Low case = 900 MMcf, 58% likelihood
 - Uneconomic case = 500 MMcf, 1% likelihood

Appendix

Prospect model assumptions



- No adjustment made for onshore vs. offshore costs
- 1st exploration well cost = \$35 million
- 3 well delineation program cost = \$45 million
- Development capital costs (success cases):
 - High case: \$382 million
 - Mid case: \$368 million
 - Low case: \$353 million
 - Uneconomic case: \$344 million

Appendix

Prospect model assumptions



- Development operating costs (success cases):
 - High case: \$341 million
 - Mid case: \$170 million
 - Low case: \$85 million
 - Uneconomic case: \$47 million
- Development property taxes (onshore only):
 - High case: \$77 million
 - Mid case: \$75 million
 - Low case: \$61 million
 - Uneconomic case: \$60 million