SB 138 (FILE 2)

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COMMITTEE DOCUMENTS

1

Heads of Agreement

A Presentation to the Senate Finance Committee

January 27, 2014

Department of Revenue

Angela M. Rodell
Commissioner

Department of Natural Resources

Joe Balash
Commissioner

What is a *Heads of Agreement*?

Definition:

"A non-binding document outlining the main issues relevant to a tentative partnership agreement. Heads of agreement represents the first step on the path to a full legally binding agreement or contract, and serves as a guideline for the roles and responsibilities of the parties involved in a potential partnership before any binding documents are drawn up."

www.investopedia.com

January 14, 2014

HEADS OF AGREEMENT

By and Among

THE ADMINISTRATION OF THE STATE OF ALASKA

ALASKA GASLINE DEVELOPMENT CORPORATION

TRANSCANADA ALASKA DEVELOPMENT INC.

EXXONMOBIL ALASKA PRODUCTION INC.

CONOCOPHILLIPS ALASKA, INC.

BP EXPLORATION (ALASKA) INC.

FOR THE ALASKA LNG PROJECT

The Heads of Agreement is for the Alaska LNG Project

Attachment 2

Alaska Southcentral LNG – Project Concept Description

Liquefaction Plant

- Capacity: 15 – 18 million tonnes per annum (MTA) 3 trains (5-6 MTA / train)
- Potential areas: 22 sites assessed in Cook Inlet, Prince William Sound and other Southcentral sites
- Footprint: 400 - 500 acres
- Peak Workforce: 3,500 - 5,000 people
- Required Steel: 100,000-150,000 tons

Producing Fields

- ~35 TCF discovered North Slope resource
- Additional exploration potential
- Anchored by Prudhoe Bay and Pt. Thomson with ~20 years supply available
- Use of existing and new North Slope facilities
- Confirmed range of gas blends from PBU/PTU can generate marketable LNG product
- Peak Workforce: 500 – 1,500 people

Pipeline

- Large diameter: 42"- 48" operating at >2,000 psi
- Capacity: 3 - 3.5 billion cubic feet per day
- Length: ~800 miles (similar to TAPS)
- Peak Workforce: 3,500 - 5,000 people
- Required Steel: 600,000 - 1,200,000 tons
- State off-take: ~5 points, 300-350 million cubic feet per day, based on demand

Storage / Loading

- LNG Storage Tanks, Terminal
- Dock; 1 - 2 Jetties
- Design based on 15– 20 tankers
- Peak Workforce: 1,000-1,500 people

Gas Treating

- Located at North Slope or Southcentral LNG site
- Remove CO_2 and other gases and dispose / use
- Footprint: 150 - 250 acres
- Peak Workforce: 500 - 2,000 people
- Required Steel: 250,000 - 300,000 tons
- Among largest in world

Estimated Total Cost: $45 – $65+ Billion **Peak Construction Workforce: 9,000 – 15,000 jobs**
Operations Workforce: ~1000 jobs in Alaska

Descriptions and costs are preliminary in nature and subject to change. Cost range excludes inflation.

Page 31

Source: Letter dated October 1, 2012 to Governor Parnell (Exhibit I-B of HOA)

Organization of the Heads of Agreement:

The Heads of Agreement (HOA) is broken into 16 sections that include:

- Recitals of recent events and understandings between the parties.
- 13 Articles covering guidelines for the development of the project and the roles and responsibilities of the Parties to the agreement.
- An appendix articulating access and expansion principles for the project.
- An exhibit that provides copies of the 3 letters to Governor Parnell from the Producer Parties and TransCanada.

Table of Contents

Guide to who is being referred to in the Heads of Agreement

"The Administration"

- Includes:
  - Department of Natural Resources (DNR)
  - Department of Revenue (DOR)

- *References may also be made to* "Commissioners" or the "State" *in the HOA.*

"The Parties" or "Party"

- Includes:
  - The Administration
  - The Alaska Gasline Development Corporation ("AGDC") or an AGDC Subsidiary
  - TransCanada Alaska Development Inc. ("TADI")
  - ExxonMobil Alaska Production Inc. ("EMAP")
  - ConocoPhillips Alaska, Inc. ("ConocoPhillips")
  - BP Exploration (Alaska) Inc. ("BP")

Source: Page 2 of the Heads of Agreement

Guide to who is being referred to in the Heads of Agreement

"Alaska LNG Parties"

- Includes:
  - The Alaska Gasline Development Corporation ("AGDC") or an AGDC Subsidiary
  - TransCanada Alaska Development Inc. ("TADI")
  - ExxonMobil Alaska Production Inc. ("EMAP")
  - ConocoPhillips Alaska, Inc. ("ConocoPhillips")
  - BP Exploration (Alaska) Inc. ("BP")

"Producer Parties"

- Includes:
  - ExxonMobil Alaska Production Inc. ("EMAP")
  - ConocoPhillips Alaska, Inc. ("ConocoPhillips")
  - BP Exploration (Alaska) Inc. ("BP")

Source: Page 2 of the Heads of Agreement

Recitals:

The purpose of the Recitals section, found on pages 2 through 4 of the Heads of Agreement, is to provide context for the agreement, describe recent events and articulate certain roles, goals and direction for the Alaska LNG Project and Alaska Stand Alone Pipeline ("ASAP") project currently being advanced by the Alaska Gasline Development Corporation ("AGDC").

Key Recitals

1. Recognizes changed circumstances in the Lower 48 natural gas markets led Governor Parnell to call for a change in direction, under AGIA, in the development of North Slope Gas to an LNG project.
2. Recognizes funding by the State under AGIA has supported key activities for the LNG project but that both the Administration and TransCanada believe it is appropriate to transition from the AGIA license to focus on the Alaska LNG project.
3. Recognizes that AGDC is pursuing the Alaska Stand Alone Pipeline ("ASAP") project and that the Alaska LNG project and ASAP intend to cooperate with one another.
4. The Alaska LNG Parties wish to ramp up the Pre-FEED phase of the Alaska LNG project, which is estimated to cost over $400 million.

Key Definitions

Definitions:

Article 1 of the Heads of Agreement begins on page 4 and goes through page 7 of the agreement. In Article 1 a reader can find definitions for key terms used throughout the agreement.

It is important to note that when a term is capitalized in the agreement it is referring to a specific term that is defined in Article 1.

1. "***Enabling Legislation***" describes the key components of legislation (described in more detail in Article 7) necessary to advance the project.
2. "***MOU***" refers to the agreement, referenced in Article 5.4, between TransCanada and the Administration to transition from the AGIA license to a commercial relationship.
3. "**Pre-FEED**" means the pre-front-end engineering and design work and activities for the Alaska LNG project that are sufficient to support filings for the Federal Energy Regulatory Commission (FERC).
4. "***RIK***" means *Royalty in Kind* as described in Article 8.1.1, where in lieu of receiving payments for the value of the State's royalty, the State takes a share of the gas produced.
5. "***TAG***" means "*Tax as Gas*" as described in Article 8.1.1, where in lieu of receiving payments for production tax the State would receive a share of the gas produced.

Principles and Benefits

Articles 2 and 3 of the Heads of Agreement are found on page 8 of the agreement.

Article 2 describes how the Heads of Agreement sets out the guiding principles upon which the Parties wish to progress work on the Alaska LNG Project and a roadmap for project.

Article 3 describes broadly some of the key benefits of developing the Alaska LNG Project to stakeholders.

Key Provisions

Article 2: Principles

1. Recognizes that if Enabling Legislation is passed that the Parties would negotiate contracts that would incorporate the principles in the agreement.

Article 3: Benefits of the Alaska LNG Project

1. The opportunity for competitively priced, reliable in-state gas supply;
2. Creating jobs for Alaskans in the exploration, development, production and transportation of natural gas.
3. Additional revenues to the State and Alaska LNG Parties.
4. Infrastructure to enhance opportunities for the Producer Parties and other explorers and producers.

Alaska LNG Project Work

Article 4, found on pages 8 and 9 of the Heads of Agreement, describes what work will be conducted during the Pre-FEED stage of the project.

The Pre-FEED stage is expected to take between 18 and 24 months.

The Pre-FEED stage would be followed by a review by each Party, its management and the decision to proceed to the next stage ("FEED") would be up to each individual Party.

Key Activities

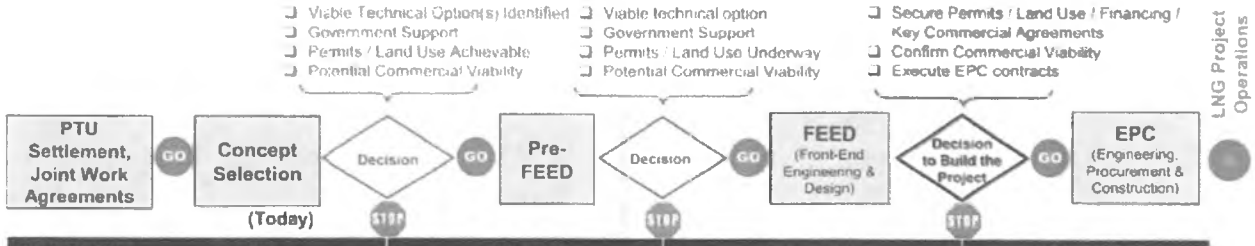
1. The development of sufficient information for evaluating the technical, cost, and schedule aspects of the Alaska LNG Project.
2. The development of key project services agreements for the State's gas with TransCanada and AGDC (or an AGDC subsidiary).
3. The Parties would work to develop mutually agreeable gas offtake and balancing agreements.
4. The State and each of the Producer Parties would initiate preliminary, individual LNG or gas sales or shipping efforts.
    1. This may also include the State (directly or through AGDC or an AGDC subsidiary) working with each Producer individually to develop agreements for the disposition of a portion of the State's LNG (Article 8.3.3).

Putting Pre-FEED in Context

Attachment 3

Southcentral Alaska LNG – Work Plans / Key Decision Points

Requirements to Take Next Step:



Peak Staffing:	~200	400 - 500	500 – 1,500	9,000 – 15,000
Cost ($):	Tens of Millions	Hundreds of Millions	Billions	Tens of Billions
Est. Engineering / Technical Duration*:		*12 - 18 Months*	*2 - 3 Years*	*5 - 6 Years*

Activities				
	Evaluate • Range of technically viable options for major project components • Business Structure • In-state gas / export LNG demand	**Progress**: • Preliminary engineering to refine concept • Business structure • Financing plan	**Complete** • Front-end engineering & design • Major contract preparation • Business structure • Financing arrangements	**Execute**: • Final engineering • Financing • Procurement • Fabricate / Logistics / Construct • Prepare for Operations
	Solicit Interest of Others		**Solicit Interest of Others**	
	Establish Government Support and Advance Regulatory Issues: • Competitive oil tax environment, predictable / durable LNG project fiscal terms; AGIA Issues • Assure ability to secure regulatory approvals / permits / land use • Environmental activities / Technical data collection • Stakeholder engagement • File DOE Export License		**Advance Gov't / Reg. Issues**: • Key permit / land use approvals • Stakeholder engagement • Secure DOE Export License	**Complete Gov't / Reg. Issues**: • Secure remaining construction / operating permits • Stakeholder engagement
		Start individual gas / LNG sales / shipping efforts	**Execute individual gas / LNG sales / shipping agreements**	**Implement business structure & agreements**
	Screen commercial viability	**Assess commercial viability**	**Confirm commercial viability**	**Commission / start-up**

* **NOTE: Duration of various phases may be extended by protracted resolution of fiscal terms, permitting and regulatory delays, legal challenges, changes in commodity market outlook, time to secure long-term LNG contracts, labor shortages, material & equipment availability, weather, etc.**

Source: Exhibit I-B: Page 32 of the Heads of Agreement

State Participation in the Project

Article 5 begins on page 9 of the Heads of Agreement and concludes on page 11 of the agreement. The Article describes broadly the reasons for State participation in the Alaska LNG Project, the Parties support for State participation and how the State would participate in the project.

Additionally, Article 5 also describes how the Administration would participate during the Pre-FEED stage and provides principles for access to information during the life of the project.

Key Provisions

1. State participation in the Alaska LNG Project could yield significant benefits to the State including:
   - A. Protecting the State's mineral interests and maximizing the value of its resources.
   - B. Improving alignment of interest between the State and the Producer Parties.
   - C. Transparency for the Administration in regards to the Alaska LNG Project.
   - D. Access and pro-expansion principles for the Alaska LNG Project.
   - E. Creating the opportunity for delivering gas to Alaskans.
   - F. An opportunity for additional State revenues.
   - G. Reducing valuation and other potential disputes between the Producer Parties and the State.
2. State will participate in the infrastructure by entering into agreements with TransCanada and a Subsidiary of AGDC to carry the State's interest in the infrastructure.
3. The State's interest should be consistent with the State's share of the gas (20%-25%).

Regulatory Framework, Access & Expansion

Article 6 begins on page 11 and continues through page 12 of the Heads of Agreement. Article 6 describes the Parties commitment, during Pre-FEED to advance the Alaska LNG Project under Section 3 of the Natural Gas Act.

The Article is designed to recognize the availability of a tailored regulatory framework under Section 3 and that the access and expansion terms developed for the project would be consistent with Appendix A of the Heads of Agreement.

Key Provisions

1. There will be **<u>at least</u>** five offtake points for the project that will provide access points for gas to Alaskans.
2. The locations of those offtake points will be developed in consultation with AGDC, who is currently pursuing the Alaska Stand Alone Pipeline ("ASAP") project. AGDC's work on ASAP will greatly benefit the State and Alaska LNG Project in developing these locations.
3. Each Party's shares in capacity would be managed on a proprietary basis; essentially creating "*projects within a project*."
4. AGDC and TransCanada's shares of capacity in the project are committed to provide access to third parties on terms developed with the State.

Appendix A: Pro-Expansion Principles

A key foundation for Article 6: *Regulatory Framework, Access and Expansion* is found in Appendix A (pages 21-23) of the Heads of Agreement.

These principles provide high level principles governing the expansion of any component of the Alaska LNG Project.

The Appendix commits the Parties to the principle that components of the Project (treatment plant, pipeline etc.) **can be expanded** and a new LNG train **can be installed**.

Appendix A
Pro-Expansion Principles

The following principles are for the Alaska LNG Project regulated under NGA Section 3. These principles apply to any component of the Alaska LNG Project.

A.1 **Alaska LNG Project Expansion.** The potential expansion of any component of the Alaska LNG Project (excluding the modification of an installed Alaska LNG Project liquefaction train, or installation of a new liquefaction train) would be addressed in the agreements to be developed during Pre-FEED, reflecting the following principles.

A.1.1 Following start-up of the Alaska LNG Project, any Alaska LNG Party may initiate the process for an expansion of any component of the Alaska LNG Project in which that Alaska LNG Party has an interest, unless that expansion would:

a. Materially and adversely affect or alter the Alaska LNG Project facilities or operations, including technical aspects, or scheduling or quality of deliveries from the Alaska LNG Project facilities;

b. Diminish service to the existing shippers or users of the Alaska LNG Project;

c. Cause the Alaska LNG Project to be in violation of any applicable environmental or safety laws or regulation; or

d. Cause a violation of the Alaska LNG Project right-of-way agreements or any other contractual obligations with respect to the Alaska LNG Project facilities.

Subject to Section A.2 regarding modification of an existing LNG Plant liquefaction train and Section A.3 regarding installation of new LNG Plant liquefaction trains, if an Alaska LNG Project expansion is proposed, all Alaska LNG Parties with an interest in the Alaska LNG Project component being expanded will have the right, but not any obligation, to participate in the proposed expansion ("Expansion Party"). Any Expansion Party may request additional volumes thereby increasing the capacity of the proposed expansion. If, however, as a result of the review of the design and cost of the proposed expansion, all the Expansion Parties determine that they wish to reduce the size of the proposed expansion, then they may do so. An Alaska LNG Party's ownership interest in the post-expansion Alaska LNG Project component would be equivalent to the proportion of its capacity to the aggregate capacity on the post-expansion Alaska LNG Project component.

Expansions can proceed if they meet the criteria in Section A.1.1 above.

A.1.2 The Expansion Parties will pay all costs related to the expansion and will have access to and share the incremental capacity developed by the expansion, provided terms related to impacts on fuel use for an expansion would be addressed during Pre-FEED by the Parties. Those Alaska LNG Parties that do not elect to participate

Enabling Legislation

Article 7 begins on page 12 and continues through page 13 of the Heads of Agreement. The article describes in broad terms the necessary component of "Enabling Legislation" that the Parties believe is necessary to advance through Pre-FEED for the AK LNG Project.

The Article describes a two stage process where:

1. General take terms and mechanisms for State participation are enacted during the 2014 Legislative session.
2. Project enabling contracts are returned to the Legislature for review in a 2015 legislative session.

The Timeline[1]

April 2014:	Legislature passes enabling legislation.
2014 – 2015:	Administration and Alaska LNG Project Parties develop project enabling contracts, including, but not limited to, agreements with TransCanada and AGDC for project services for the State Gas Share, gas offtake and balancing agreements with the Producer Parties, and preliminary LNG or gas sales contracts.
2015:	Legislature considers project enabling contracts.
2015-2016:	Parties decide to advance to FEED.

1. The timeline above assumes a success case.

Royalties and Production Taxes

Article 8 which begins on page 13 and continues through page 15 of the Heads of Agreement describes changes to the State's royalty and tax system that will facilitate progress on the Alaska LNG Project by creating a predictable State Gas Share.

The State Gas Share is the combination of royalty in kind (RIK) gas and tax as gas (TAG) received by the State for its Production Tax.

The Article also provides guidance for the range of Production Tax (~7%-13%) that the Parties believe will enable the Alaska LNG Project to advance.

Key Provisions

1. Alaska Statute AS 38.05.182(a) provides that "royalties on oil and gas shall be taken in kind unless the commissioner (DNR) determines that the taking in money would be in the best interest of the state."
2. The November 2013 "Alaska North Slope Royalty Study" performed by Black & Veatch identified potential issues related to the State taking in-kind; primarily those associated with marketing risk.
3. In Article 8.3.3 the Producer Parties commit, if asked by the State to "negotiate separately with the state in good faith to enter into an agreement with the State regarding the purchase or other disposition of a portion of the LNG that is made from the State's deliveries (RIK + TAG) of natural gas to the Alaska LNG project."

Other Project Enabling Terms & Additional State Support for the Alaska LNG Project

Articles 9 and 10, found on page 15 of the Heads of Agreement detail other terms necessary to advance the Alaska LNG Project through Pre-FEED and into FEED.

Those terms include a broad range of continued State and stakeholder support at the local, state and federal level for the project.

Key Provisions

1. The Administration, in consultation **with** local governments, will develop payments in lieu of property tax and impact payments during construction for the project.
2. Project enabling contracts negotiated between the Parties will need to be of sufficient duration to support investment decisions, permit realization of a competitive economic return, to enable necessary financing, and to support gas and LNG sales agreements; *all of which are needed by the State as well as the Alaska LNG Project Parties to advance the project.*
3. General support for the development of necessary infrastructure and other local, State and federal permitting requirements.
4. A healthy, long-term oil business.

Alaska Hire and Content

Article 11 is found on page 16 of the Heads of Agreement and provides key direction for the Alaska LNG Parties in developing the project.

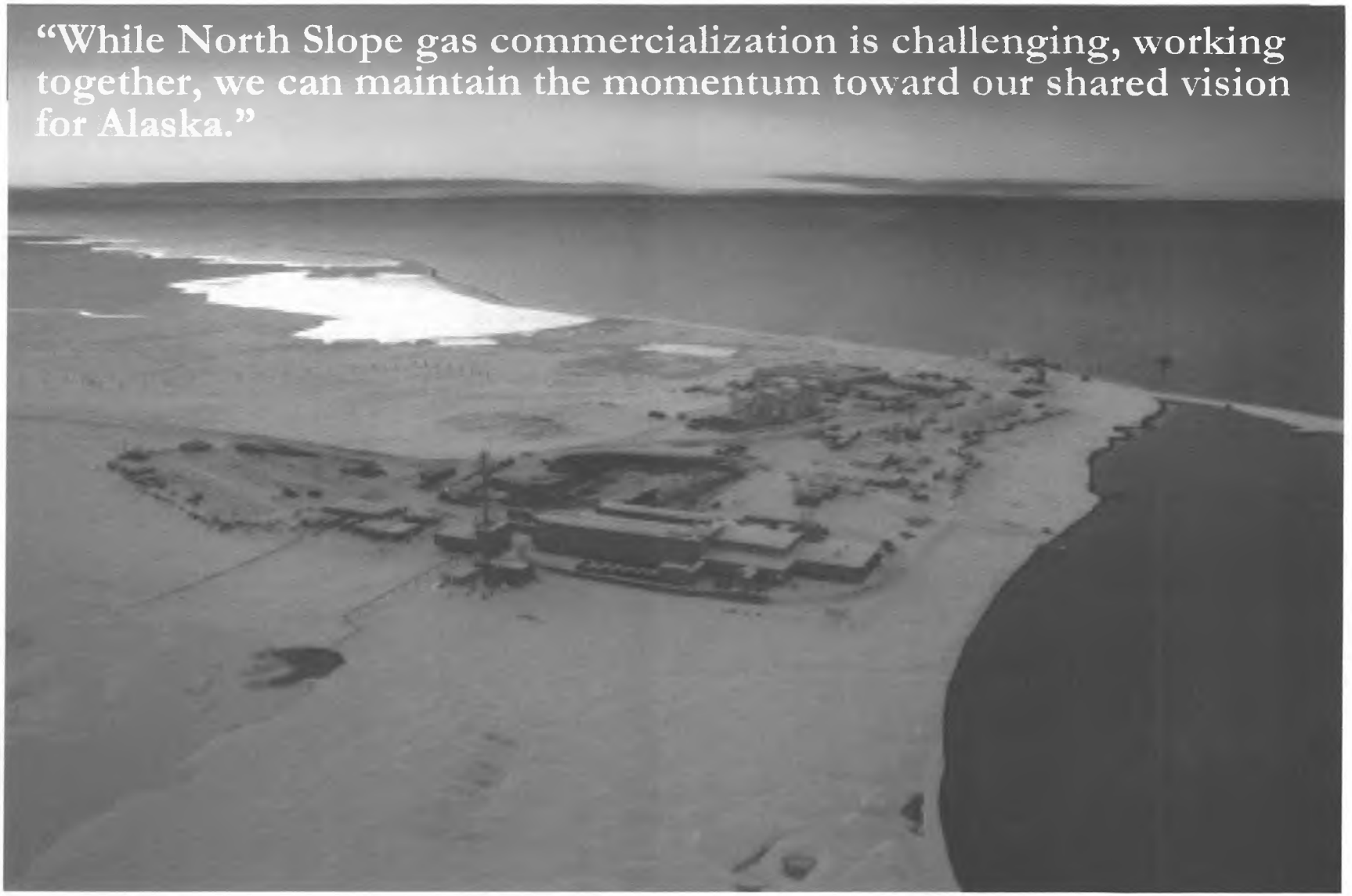
These include guidance to:

- Hire Alaska residents,
- Contract with Alaska businesses,
- Participate with the State Department of Labor and Workforce Development to update training plans and provide training, and
- Commit to negotiate in good faith project labor agreements for the Alaska LNG Project.

Key Estimates[1]

Estimated Total Cost:	$45 - $65 billion
Producing Fields:	500 – 1,500
Gas Treatment Plant:	500 – 2,000
Pipeline:	3,500 – 5,000
Liquefaction Plant:	3,500 – 5,000
Storage/Loading:	1,000 – 1,500
Peak Construction:	9,000 – 15,000
Operations:	~1,000 jobs in Alaska

1. Source: Letter dated October 1, 2012 to Governor Parnell (Exhibit I-B of HOA) and may vary with estimates by Black & Veatch.



Source: Letter dated October 1, 2012 to Governor Parnell (Exhibit I-B of HOA)

THANK YOU

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2

Testimony for Senate Finance Committee – Feb. 19, 2014

By Larry Persily, Federal Coordinator
Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects

For the record, I am Larry Persily, head of the federal Alaska gas line project office.

Thank you for the opportunity to testify today. I hope my comments are useful for your deliberations and answer some of your questions.

I'd like to explain why this time may turn out differently than all the other attempts at a North Slope gas line.

But first, I have two examples of Washington taking notice of what's happening in Alaska.

I know normally Alaskans don't like to hear that the federal government is watching our resource development — but trust me, this time it's OK.

I presented an update on the Alaska LNG project last week at the Department of Interior, speaking to the Alaska Interagency Working Group which created by presidential executive order almost three years ago to track and help coordinate the work of federal agencies for onshore and offshore energy projects in Alaska.

As I started talking about the Alaska gas line, people actually paid attention and asked good questions. They've heard about Alaska gas many times before. And their agencies have spent a lot of time on the many false starts in years past.

But they had heard and read that this time might be different — and they were eager to know what was happening.

They had heard that all of the players are working together on the same project and spending serious money to determine if Alaska's time finally has come.

Between budget cuts, retirements and other staffing reductions, however, federal resource management and regulatory agencies don't have any spare time for another false start — like they went through a few years ago with a proposed pipeline from Alaska to serve North American markets.

Though sponsors of that project tried in good faith to make it work, shale gas put an end to it — but not before federal agencies had spent a lot of time on permitting issues, rights of way, scoping meetings and reviewing draft resource reports for an environmental impact statement.

The Federal Energy Regulatory Commission, Department of Energy, Bureau of Land Management, Army Corps of Engineers and others have more than enough files on their desks without the Alaska gas line.

FERC alone has several Lower 48 LNG export terminals on its work list for environmental review.

The Department of Energy has two dozen LNG export applications waiting for review, including applications from the existing ConocoPhillips plant at Nikiski.

Federal agencies are the same as Alaskans — they don't want another false start.

But every one of those agencies is ready to work on the Alaska LNG project just as soon as an application hits their desk. They would just like to know that this time it has a real shot at making it.

I told them last week what I am going to tell you -- and this is coming from someone who is generally very cynical and skeptical.

This time very well may be different. If the markets perform as expected, if the companies and the state can keep the costs down, if the financial terms look good to all parties, you could see gas flowing in the 2020s.

The latest non-skeptic in Washington is Adam Sieminski, head of the Energy Information Administration at the Department of Energy.

"We think the economics ultimately will favor construction of an LNG facility in Alaska," Sieminksi said in an energy newsletter interview this week.

So why this time?

Global LNG demand is the strongest growth industry for energy. Between nuclear plant shutdowns in Japan and Korea; choking coal pollution in China; population and economic growth in India, China and elsewhere in Southeast Asia; high oil prices that can make LNG look affordable by comparison — they all add up to strong demand build for LNG in the Asian market.

The International Energy Agency predicts global demand for natural gas to grow more than twice as fast as oil over the next 20 years. Others predict even stronger growth rates for gas.

Most of the world's gas trade is by pipeline, but LNG is building. And building at an even faster pace than pipeline deliveries.

Many analysts talk of a 5% to 6% annual growth rate for LNG demand through 2020, then slowing down to the 2% to 3% range through 2035.

That would mean the equivalent of a new, good-sized LNG export terminal will need to start up almost every year to meet that demand growth.

And in addition to market growth, older LNG supply contracts are expiring — and some of those older export plants are running low on reserves.

Just this week Egypt, an LNG exporter since 2005, announced it will need to import LNG for the next several years as gas production has fallen short of domestic demand.

All of which means export project developers are chasing not only new demand but replacement contracts for declining reserves.

Someone is going to win that new business. It will be the lowest-cost, stable, predictable suppliers.

The potential competitors to Alaska LNG have their own strengths and weaknesses, as does Alaska.

Australia?

Seven LNG export projects are under construction and set to open over the next three years. But a majority of that gas is already sold on long-term contracts. Those projects are not Alaska's competition for deliveries to start in the 2020s.

New terminals or expansions in Australia face tough hurdles. Cost overruns on the current projects have got companies worried about repeating history.

Domestic consumers are seeing price increases for natural gas, which is being drawn from the local market to higher-priced export markets.

Dow Chemical claims it cannot get the new gas supply contracts it needs for investments in Australia.

Some local jurisdictions have imposed drilling restrictions on coal-bed gas reserves, which feed three of the export terminals under construction.

Russia?

The country has just one operating export plant, but there's talk of expanding it. Russia has another plant under construction, and thoughts of two more.

The expansion talk at Sakhalin-2, led by Gazprom with partner Shell, is dependent on sufficient gas reserves to justify the work.

Gazprom is also talking about building an LNG terminal at Vladivostok.

Yes, a good location for marketing – it's a short tanker trip from there to Japan, Korea, China or Taiwan – four of the biggest LNG buyers.

But it will take a 2,500-mile pipeline to move the gas from Russia's interior to the coast. The field development costs and pipeline are estimated at $40 billion — not counting the LNG terminal.

To really make the economics work, Russia will need to extend the pipeline and sell gas to China.

The two countries have agreed on everything but the price for the gas. You could say that about a lot of hopeful projects.

Separately, Rosneft and ExxonMobil are doing their due diligence for an LNG plant called Sakhalin-I. They have issued a contract for initial FEED work.

In Russia's distant Arctic, a terminal under construction is called Yamal LNG. It's about halfway between Iceland and Nome.

Estimated at $27 billion, the sponsors talk of making their first deliveries in three or four years.

The tricky part for Yamal is that the Northern Sea Route to Asia will be passable for LNG tankers only a few months each year, and even then only with government-funded nuclear-powered icebreakers as escorts.

The rest of the year, the plan is to ship the LNG aboard ice-class tankers to European ports, where the LNG would be transferred to less expensive standard tankers for the long voyage down the European coast, across the Mediterranean Sea, through the Suez Canal, across the Indian Ocean and into Asia.

Look at the map and you see the economic challenges Yamal faces. Plus its main sponsor, Novatek, has never built or operated an LNG terminal.

Canada?

There are multiple proposals; none have all their government authorizations or a final investment decision.

None have cleared the consultation process with every First Nation in the area and along the pipeline route.

The developers that are talking about price are emphatic that they need oil-linked LNG pricing or something comparable to cover their sizable development costs.

There is no Prudhoe Bay production facility in British Columbia's Horn River and Montney shale gas plays that would feed the LNG terminals at Kitimat and Prince Rupert. They have to build it. Gas has to pay for it.

The pipelines that would move that gas to the coast are as long as 525 miles and must go through two mountain ranges.

One possible route into Prince Rupert takes the pipeline offshore for up to 75 miles and across either an old mine tailings disposal site or mollusk bed important to First Nations people.

Meanwhile, the British Columbia government is negotiating a new LNG export tax with project sponsors. The legislation been delayed until fall, with companies saying no project decisions until they know the tax.

Tanzania and Mozambique?

An awful lot of gas but minimal infrastructure; still developing their oil and gas laws and fiscal regimes; and local poverty could become an issue for developers and political leaders.

Closer to home, the U.S. Lower 48 states?

It's a tough political battle, pitting oversupply and low prices at home vs. the free market and exports to trade partners.

The Department of Energy has approved six export licenses, totaling 8.5 bcf a day. That's equal to almost 12% of current U.S. gas production.

The unknown is if and when and under what conditions the department might start to close down or further delay its export approvals.

And regardless of what government does, the only terminals to be built will be the ones that have buyers and can get financing. Just one is under construction so far, in Louisiana.

Other issues for Lower 48 exports include cost overruns at the Panama Canal expansion, which is essential for getting tankers out of the Gulf Coast and into the Pacific.

One of the Gulf Coast project sponsors said this week that Asian buyers are putting off new long-term contracts for U.S. gas because of the delay in knowing just how much it will cost to use the expanded Panama Canal.

Local opposition over environmental and safety concerns is not very noticeable for Gulf Coast terminals but is extremely visible for terminals proposed for the Oregon and Maryland coasts.

My point is: Like Alaska, every proposed project, has its own problems, its own disadvantages, its own issues to solve.

The winners, the terminals that get built will be the ones that solve the problems, hold down costs, and convince buyers that they will start up on time with competitive prices.

The pre-FEED and FEED work — front-end engineering and design — is a key part of that effort. The more you do up front, the better the odds of avoiding surprises during construction.

And in a brief advertisement for our office's work, we issued a report today on just what are pre-FEED and FEED and why they are so important. It's available on our website arcticgas.gov.

ALASKA LNG ADVANTAGES

These are substantial and meaningful.

Shorter tanker run from Nikiski to Japan; one week vs. three weeks from the Gulf Coast

- Tanker charter rates are running $75,000 to $100,000 a day. Time is money. Big money at those rates.
- Or less capital tied up in fewer ships if owner-operated tankers.

Proven gas reserves already being produced. It's important to buyers to know that the gas they're committing to buy for 15 or 20 or 25 years actually exists.

Low production costs compared to greenfield projects in B.C., Australia, East Africa.

Oil will carry the infrastructure costs.

Almost 40 years experience producing on the North Slope.

Liquefaction compressors run much more efficiently at cold temperatures.

- Up to 15% more efficient (less gas consumed) than in warm-climate LNG sites

ALASKA LNG DISADVANTAGES

These also are substantial and meaningful.

High construction costs in Alaska.

Seasonal construction limitations (pipeline trenching during the winter only).

Summer-only sealifts of material to the North Slope.

Environmental considerations (wetlands, air quality standards, mitigation expenses).

The cost of an 800-mile pipeline to tidewater that competing LNG projects don't have.

And the need for fiscal certainty is a hard sell in the world of Alaska oil and gas politics.

The federal government is ready for the permitting work, but making the finances work is up to the project sponsors and the state.

The rewards to the state of a successful project include public revenues, the lowest cost to move gas to Alaskans, and an industry commitment to keep North Slope gas and oil flowing for decades.

The risks of state investment are cost overruns that require more cash during years of budget deficits, and the possibility that the project will not make as much money as projected or as people want.

I can't help you there, other than to say the LNG world is a competitive market. But it's not an impossible market.

3

FEBRUARY 19, 2014

OBSERVATIONS ON HEADS OF AGREEMENT

PRESENTATION TO SENATE FINANCE COMMITTEE

PREPARED FOR THE STATE OF ALASKA

BLACK & VEATCH
Building a world of difference.

BLACK & VEATCH PRESENTERS

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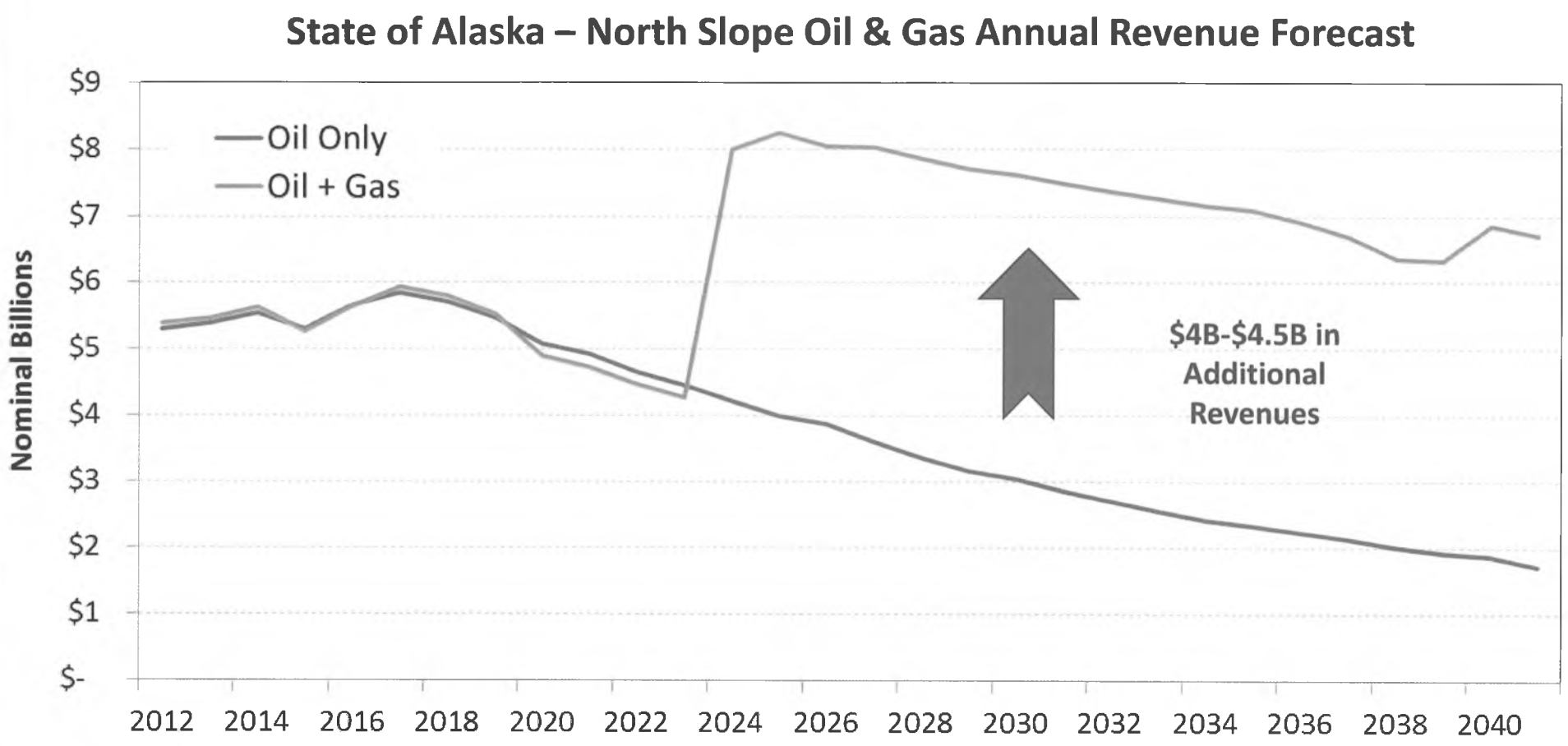
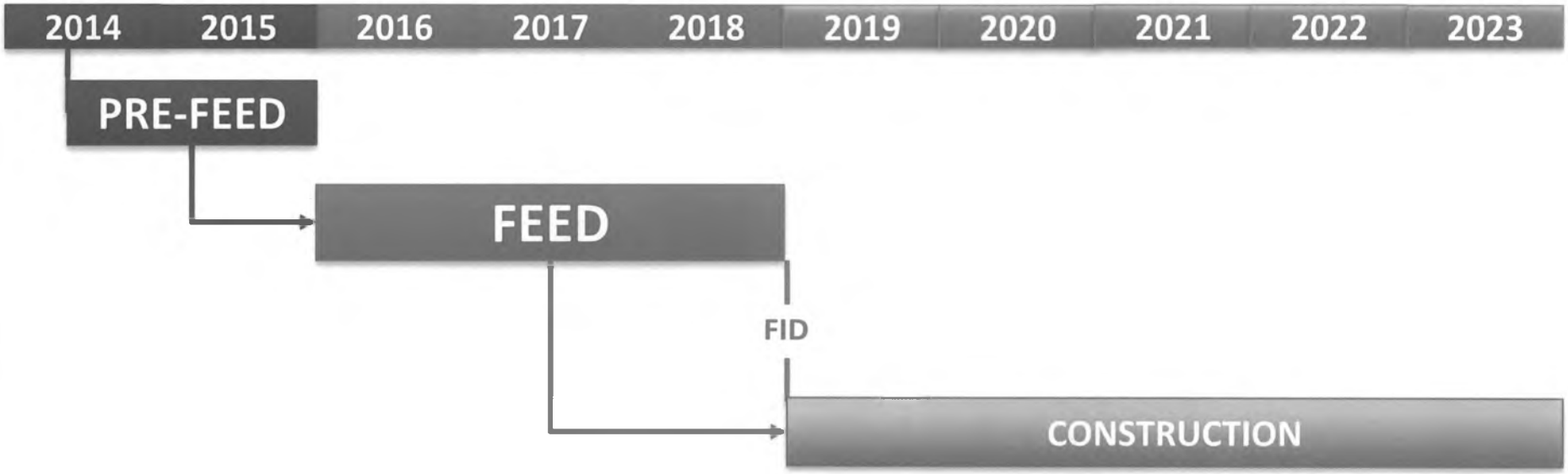
LONG-TERM NORTH SLOPE OIL & GAS REVENUES ARE DRIVEN BY AKLNG PROJECT SUCCESS



PUTTING THE HOA WITHIN THE CONTEXT OF AKLNG TIMELINE

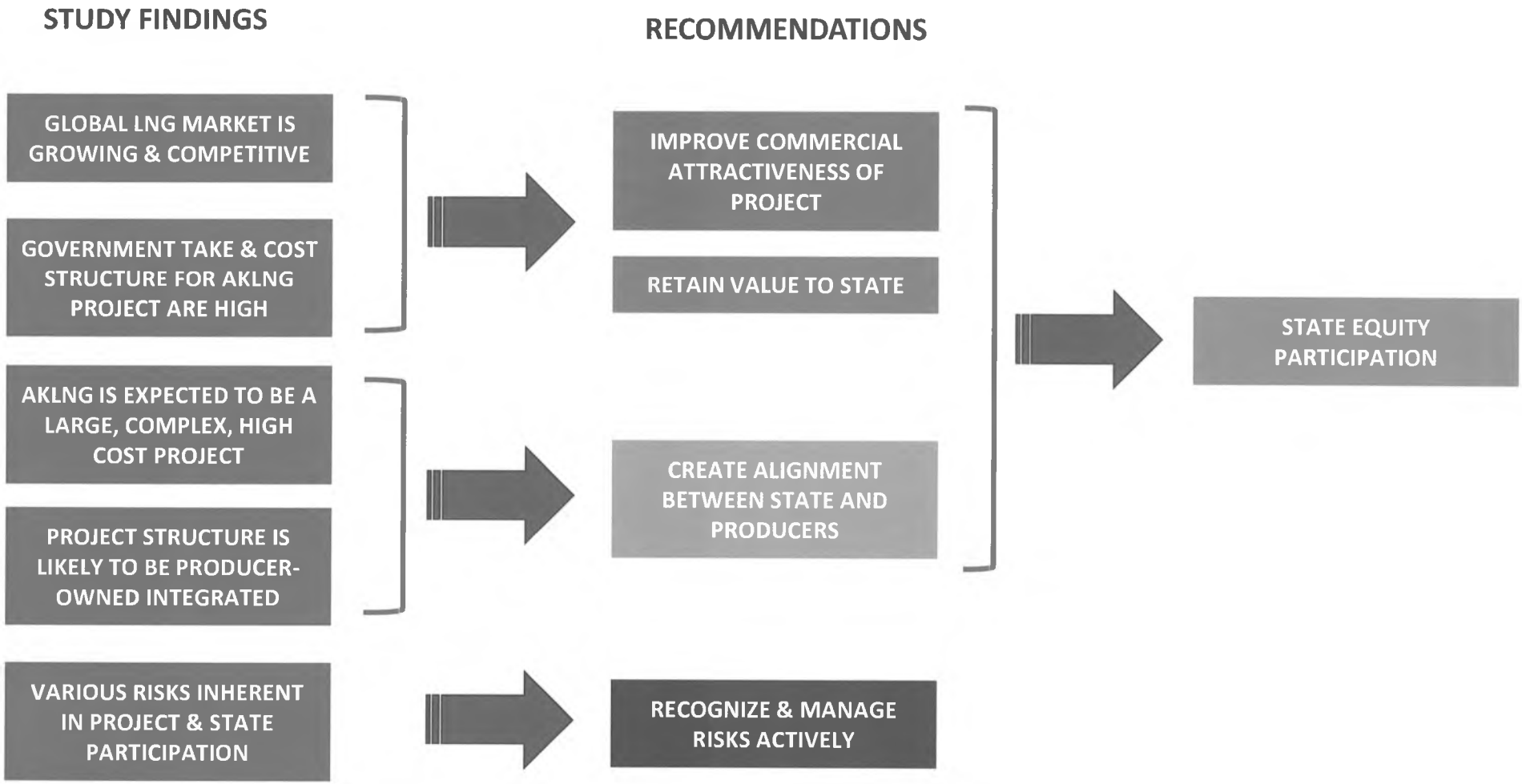


STATE INVESTMENT

$43 - $108 million or ~1% of Total Investment	$180 - $450 million or ~2%-3% of Total Investment	$7 - $13 billion or ~95%-97% of Total Investment

HOA lays out principles to advance the project to pre-FEED and enter into commercial agreements

ROYALTY STUDY HIGHLIGHTS & RECOMMENDATIONS



CRITERIA APPLIED FOR EVALUATION OF HOA TIE IN TO ROYALTY STUDY RECOMMENDATIONS

HOA – ALIGNMENT THROUGH EQUITY PARTICIPATION

Royalty Gas and Tax as Gas = State Gas Share

State Gas Share = State Equity Share

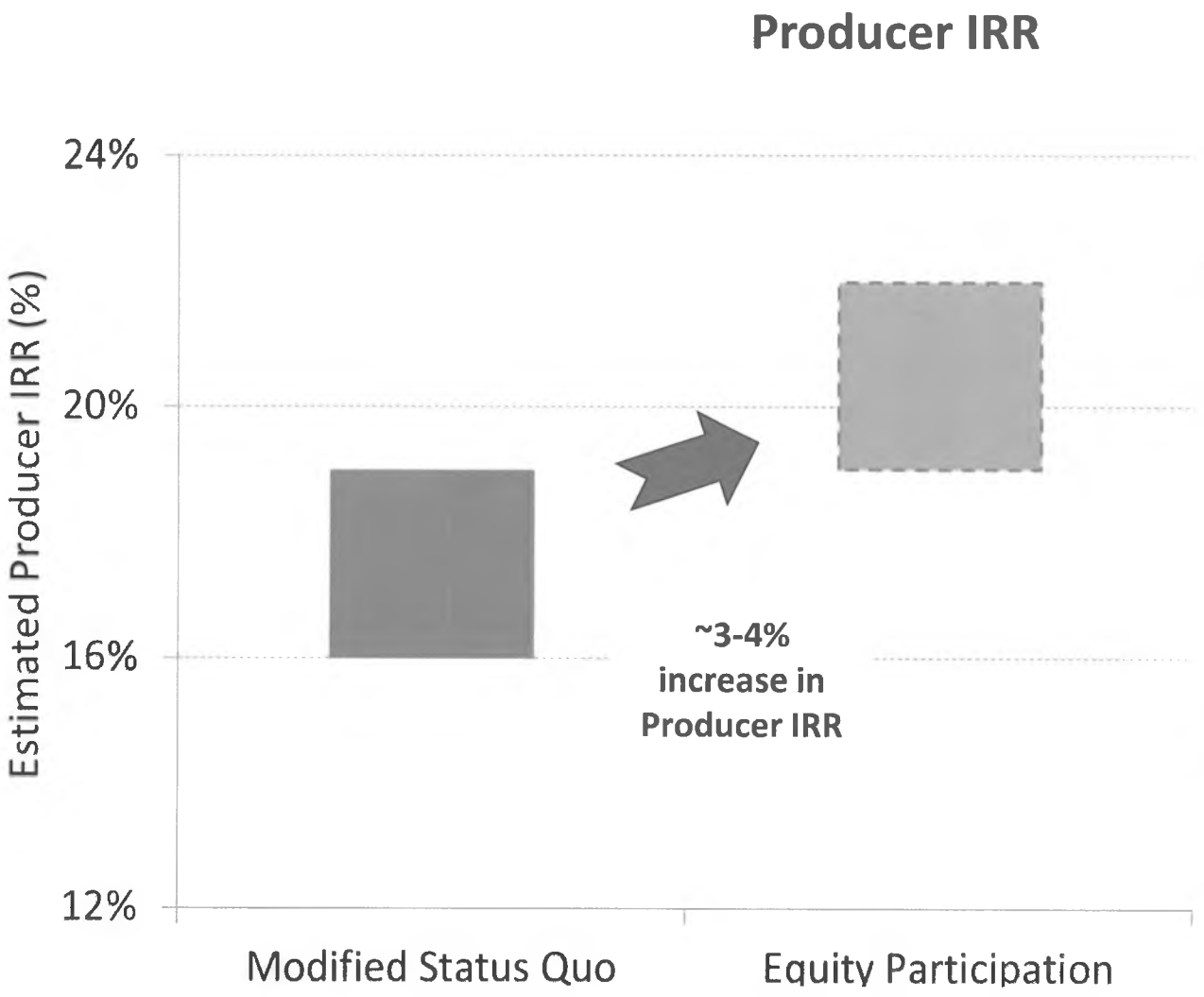
State Equity Share Impacts State Investment and State Revenues

State Holds Equity Along The Entire Supply Chain

Commitments Made In A Stage-Gated Manner

- Current decisions focused on enabling pre-FEED

IMPROVE COMMERCIAL ATTRACTIVENESS OF AKLNG PROJECT



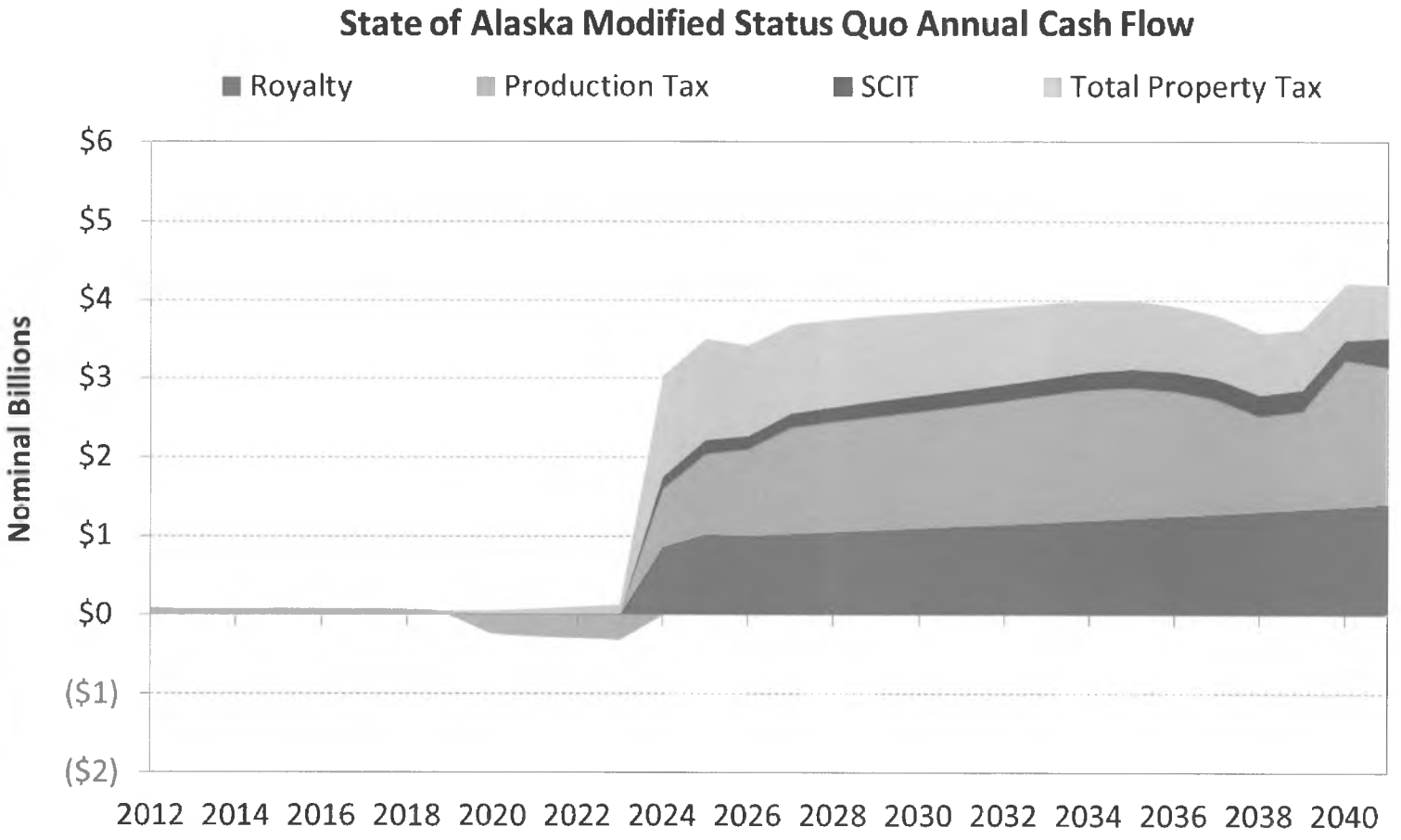
- Reduces upfront investment by Producers
- Risk is shared with the State
- Potentially reduces valuation disputes if State elects RIK

* Assumes 25% State equity participation

PRESERVE VALUE TO STATE FROM ROYALTY & TAXES

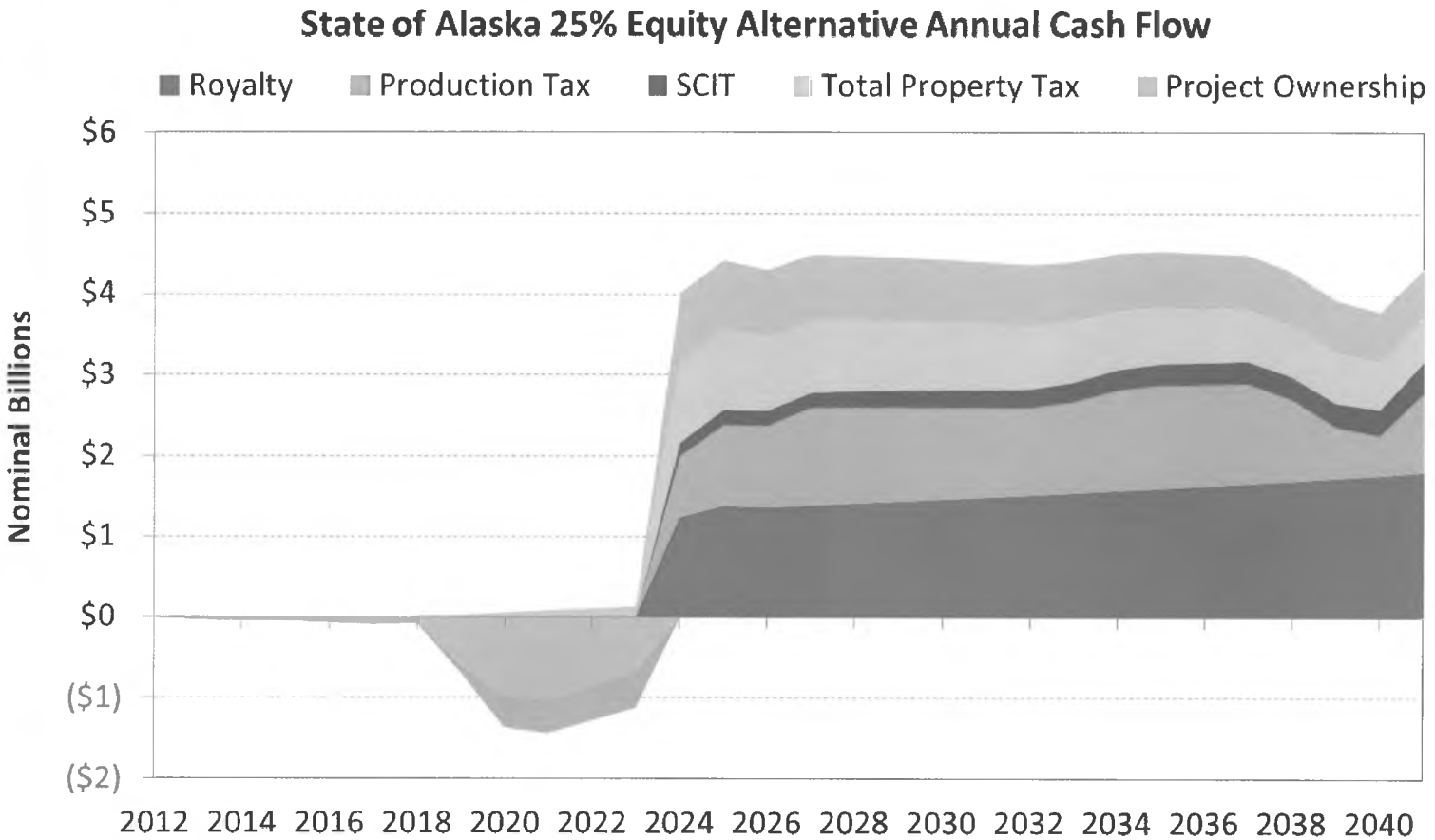
- Obtain value in return for the State's incentives to the project
- Preserve the State's expected revenues from the AKLNG Project relative to an RIV world without State equity participation

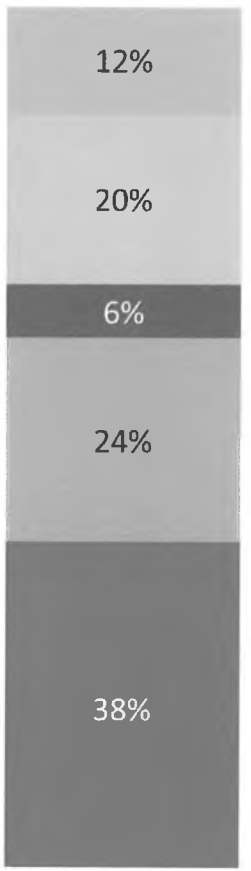
PRESERVE VALUE TO STATE FROM ROYALTY & TAXES



Total Cash Flow (Through 2041) = $68 Billion

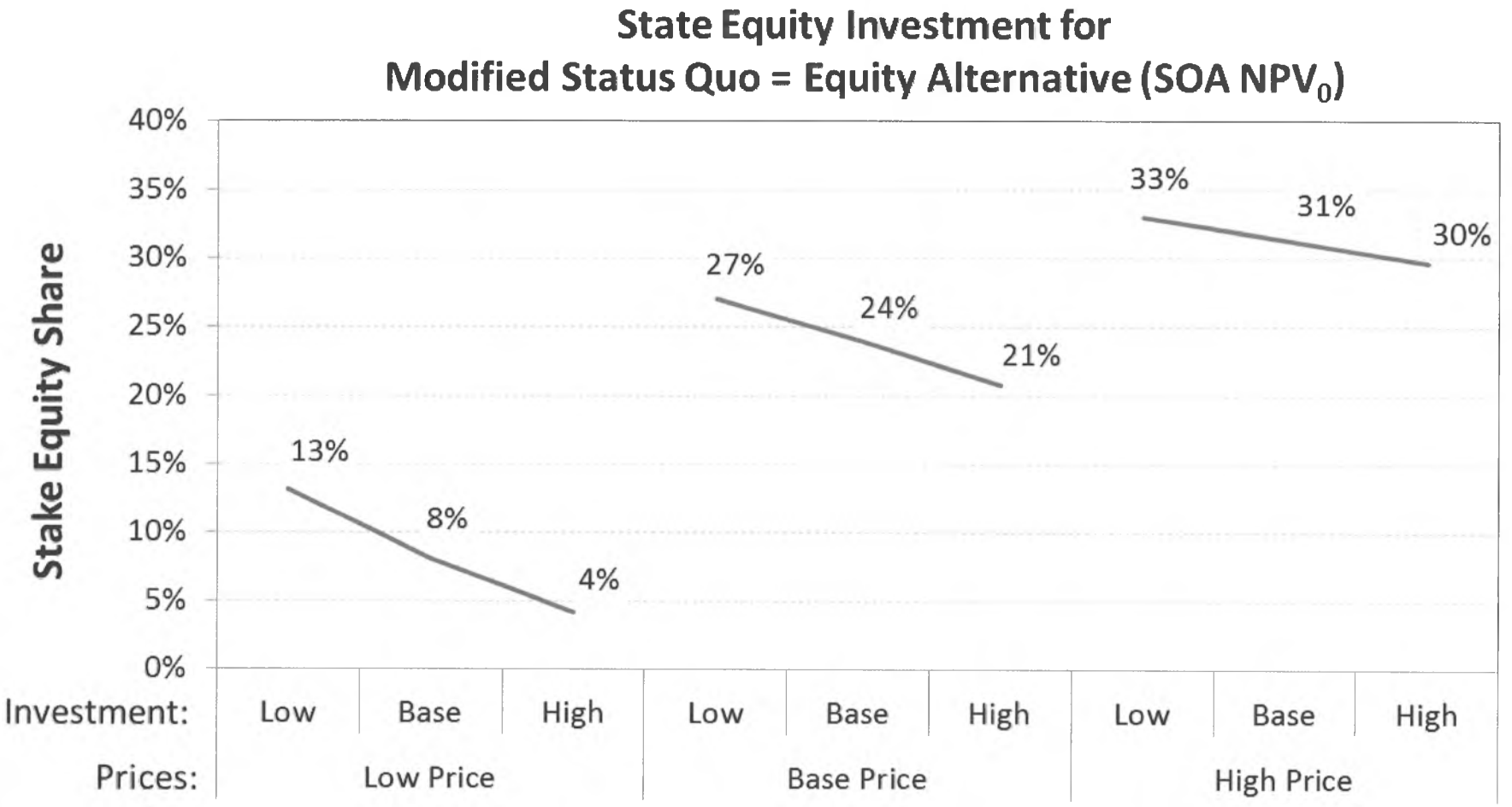
PRESERVE VALUE TO STATE FROM ROYALTY & TAXES





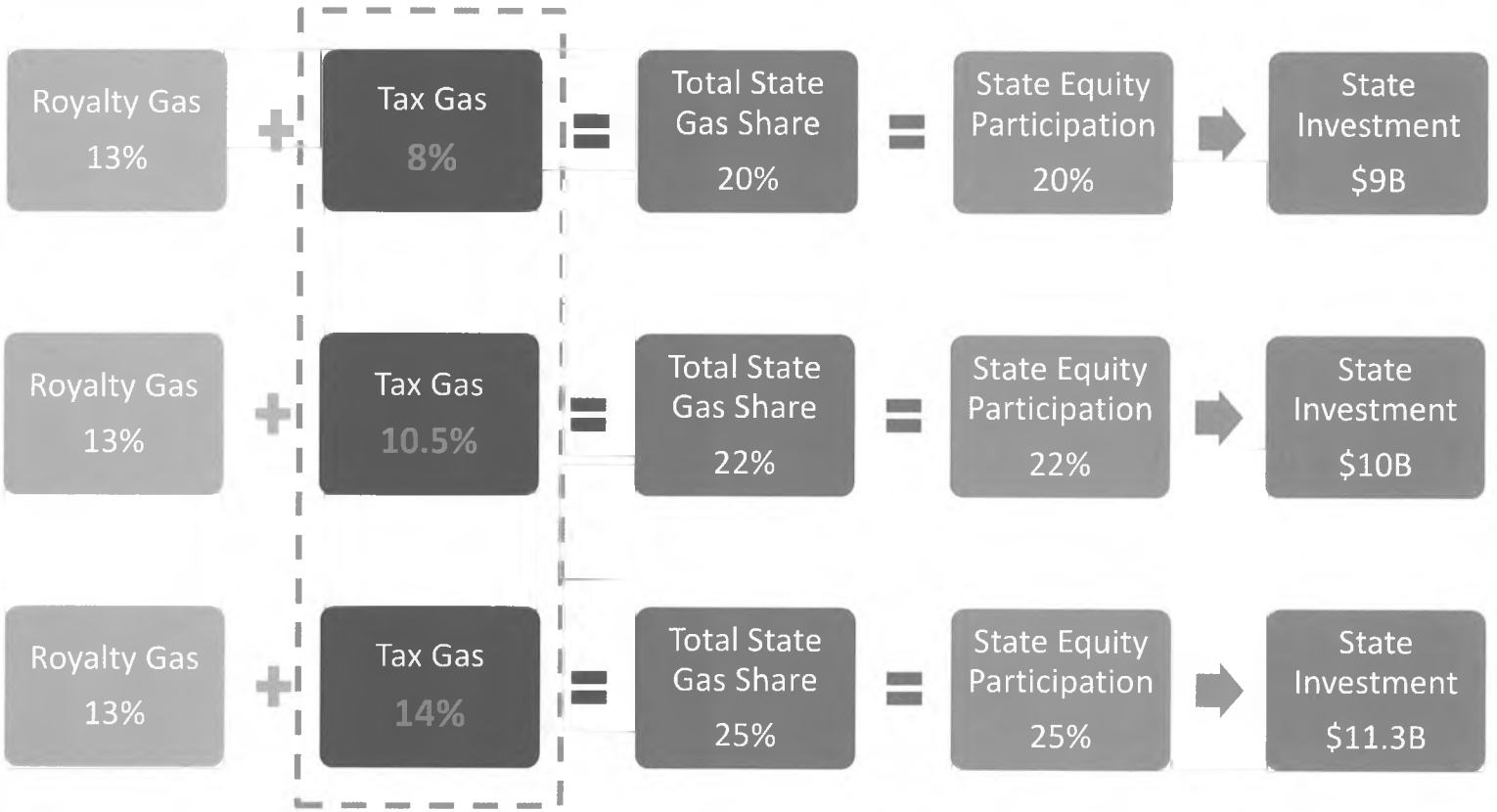
Total Cash Flow (Through 2041) = $72 Billion

PRESERVE VALUE TO STATE FROM ROYALTY & TAXES

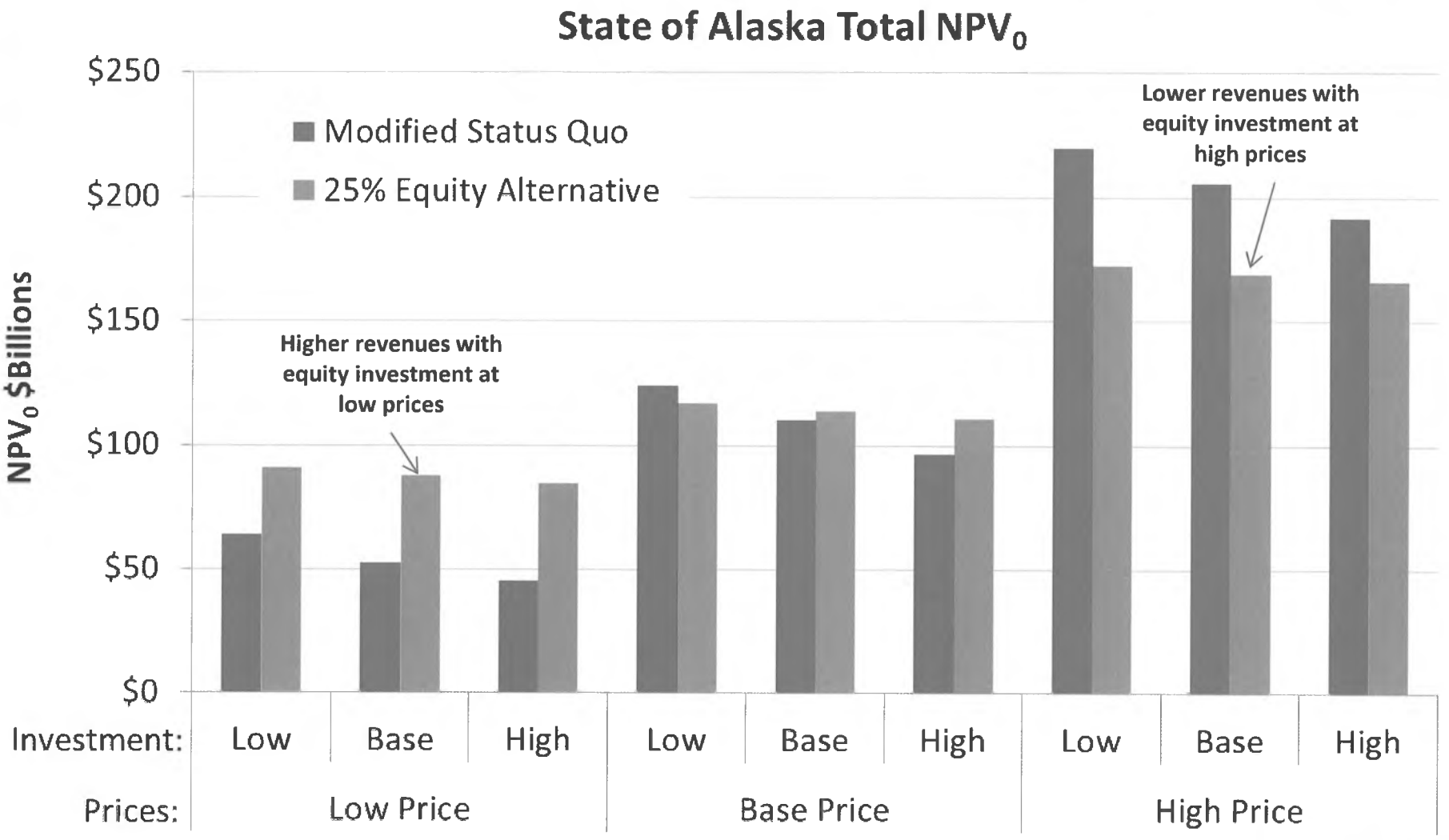


GROSS TAX RATE SETS THE TOTAL STATE GAS SHARE & EQUITY PARTICIPATION

VALUE TO SOA



MANAGE RISKS – EQUITY INVESTMENT HELPS TO HEDGE PRICE EXPOSURE

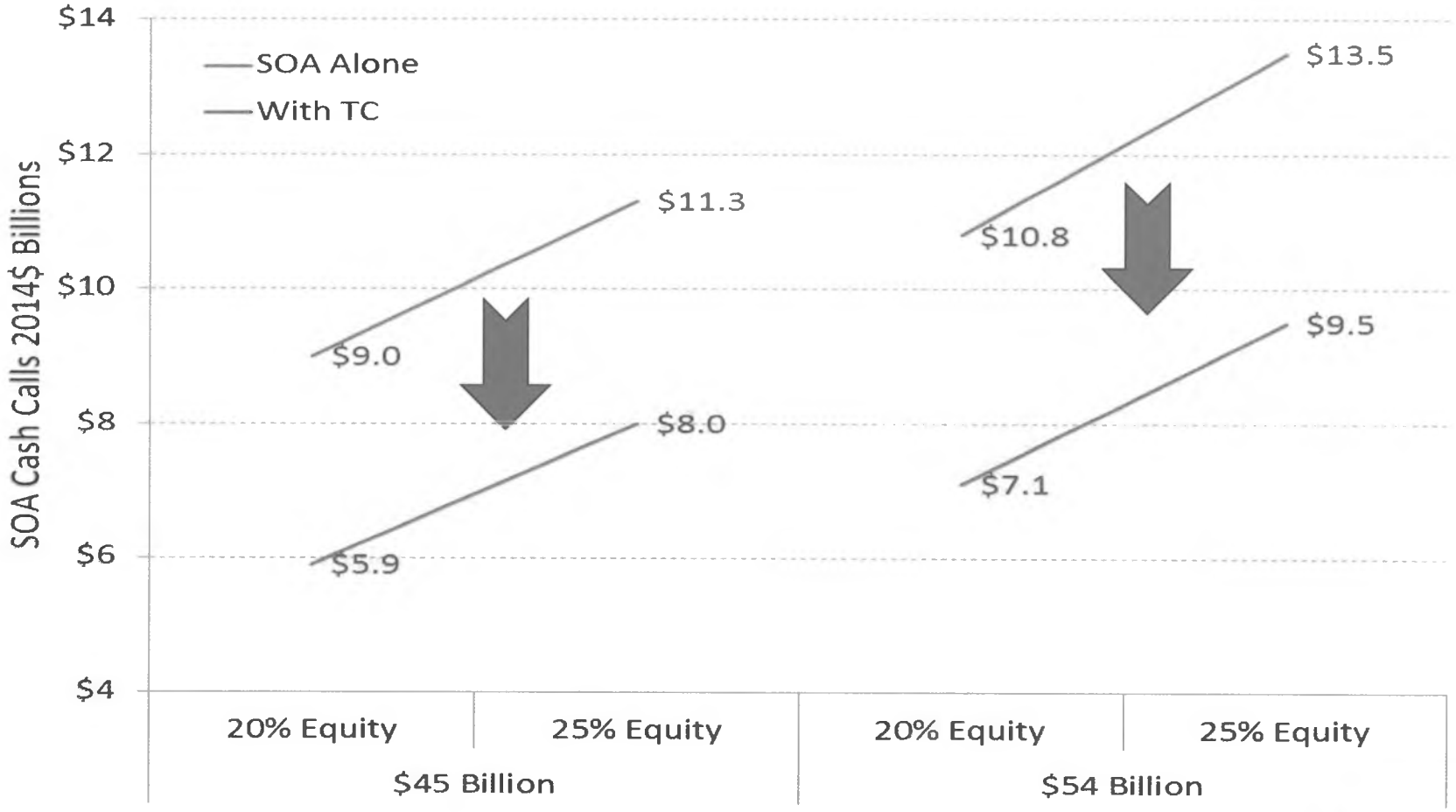


MANAGE RISKS – CAPITAL COST EXPOSURE REDUCED THROUGH TC PARTICIPATION

- Highest risk exposure is prior to project start when cash calls are not supported by project revenues
- TransCanada ("TC") participation allows State to retain 20%-25% of gas share while being responsible for only 13%-18% of the upfront costs
- This is especially important if cost overruns occur on project

MANAGE RISKS – CAPITAL COST EXPOSURE REDUCED THROUGH TC PARTICIPATION

TC Participation Reduces Upfront Cash Calls on SOA by ~40%



* Assumes State exercises 30%-40% equity buy back with TransCanada

MANAGE RISKS – REDUCE POTENTIAL LOSS OF VALUE THROUGH RIK

- **HOA includes intent of Producers to offer to negotiate separately to market State's share of gas – proportional to each Producer's share of producer capacity**
- **SOA to only obligated to elect RIK if the Producers make "satisfactory arrangements for disposition of the State's share of LNG"**
- **SOA would benefit from Producers marketing expertise rather than competing with them**
  - Could recreate marketing benefit of RIV

MANAGE RISKS – STRUCTURE OF PARTICIPATION

HOA ELEMENTS

- PROJECT WITHIN A PROJECT
- ACCESS & PRO-EXPANSION PRINCIPLES
- STAGE-GATED COMMITMENTS
- ACCESS TO INFORMATION

→ **COMMERCIAL AGREEMENTS**

HOA SCORE CARD RELATIVE TO CRITERIA

Royalty Study Recommendations	How HOA Addresses Recommendation
Alignment Through Equity	Equity Participation Along Supply Chain; Royalty and tax as share of gas
Improve Commercial Attractiveness	Increases Producer IRR Shares/Reduces Producer Risk
Preserve Value to the State	State could be Cash Flow Neutral relative to status quo depending on final equity share
Manage Risks	
Price Exposure	Equity Participation in midstream dampens exposure to prices
Capital Costs	TC participation lowers State's cash calls prior to commercial operation
RIK Marketing	HOA reflects intent of Producers to negotiate to market State's share of gas
Structure of Participation	Project within a project, Stage gated commitments, Access & pro-expansion principles, Access to information

THANK YOU

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ALASKA NATURAL GAS
TRANSPORTATION PROJECTS
OFFICE OF THE FEDERAL COORDINATOR

Early planning, design, engineering key to LNG project success

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Release Date:
February 19, 2014

Well before big money gets committed to construct a liquefied natural gas export project, sponsors typically spend years studying such questions as: Should this project get built? Does it make business sense? And, as the analysis progresses: Does this project continue to make sense? The proposed $45 billion to $65 billion Alaska LNG export project is going through that process now.

It's the up-front planning that is critical to megaproject success.
When done well, this pre-construction work can be the reason a project gets built on time and on budget, and creates the kind of cash flow the board of directors was told to expect.
The work goes by different names in different industries. For Alaska LNG, the current work is called pre-FEED — or pre-front-end engineering and design — which will be followed by a more intense FEED phase if the project continues.

During these stages, the project team selects the technology to be used in the production units. It chooses sites for facilities and does initial layouts. Utilities are plotted. Labor needs, particularly skilled-labor needs, get problem solved. Pipeline routing and the related issues — soils, vegetation, river and wetlands crossings — get documented and the best solutions determined. Needed licenses, authorizations and environmental permits are identified and many might even be secured. Markets are assessed and reassessed. A financing plan is defined.

Source: Alaska LNG Project

Part of the Alaska LNG Project gas-pipeline route. The line would feed an LNG plant and export terminal at Nikiski. (Click to enlarge.)

For Alaska, the remote location creates logistical challenges that need detailed planning: Winter-only burial of the 800-mile pipeline because that's when the tundra is frozen; summer-only delivery of massive gas treatment plant modules to the North Slope because that's when Arctic sea ice is absent.

"The definition of a project, from the formation of the core team until full-funds authorization is achieved, is what we call the FEL [front-end loading] process," wrote development guru Edward Merrow in his 2011 book "Industrial Megaprojects: Concepts, Strategies, and Practices for Success."

"FEL is the single most important predictive indicator of project success. There are very few project professionals in the process industries who do not agree with the basic principle that definition and planning drive success, and those who don't should probably be in some other line of work."

Merrow is founder and president of Independent Project Analysis Inc., a major consultancy whose client list includes some of the biggest companies in the world. IPA conducted a megaprojects seminar for Alaska lawmakers in 2011.

"Megaprojects are the most important projects in any industrial company's portfolio," Merrow said in his book.

"When they succeed, the company is strengthened for the long term. When they fail, massive amounts of shareholder wealth can be made to evaporate in a single project."

Even though good up-front planning means better project results, half of all megaprojects in his company's vast database fail to meet that standard, and their failure rate is high. LNG projects do a little better than this average "but not systematically so," he said.

For Alaska LNG, Steve Butt is the man charged with making sure the up-front planning is excellent. He's a career ExxonMobil manager and the senior project manager for this project, having worked stints with ExxonMobil on its big LNG projects in Africa and most recently in Qatar.

"Megaprojects are often defined as projects over $1 billion," Butt told an Alaska Senate Resources Committee on Feb. 3. "In today's world they're sometimes defined as projects over $10 billion. By any metric this is one of the largest megaprojects ever, and in some ways it's really five megaprojects, each one working with each other. ...

"No one has ever permitted a project this large. No one has ever permitted an 800-mile pipeline in the NEPA (environmental impact statement) era in the U.S. No one has ever done an LNG plant this big or a gas treatment plant this big. We'll have to do all three."

HUNDRED-MILLION-DOLLAR QUESTIONS

"Ignorance is the mother of research."
- Laurence J. Peter, founder of the Peter Principle

ExxonMobil owns the largest proportion of North Slope gas that would be produced for the Alaska LNG project, and it is leading the technical team among the four companies scoping the project — North Slope producers BP and ConocoPhillips as well as pipeline company TransCanada are the other three.

ExxonMobil has a reputation for tightly controlling **its LNG projects**, such as the massive Qatar plants built during the first decade of the 2000s. Its **Papua New Guinea project** is **over budget** due to unfavorable currency exchange rates, landowner protests, labor work stoppages and bad weather, but it's still on schedule to start production this year.

"Before we make the first cut with a saw, we re-measure five times instead of one," an ExxonMobil executive said in The Wall Street Journal last month of the company's megaproject planning.

Butt talked with the **Alaska Senate Resources Committee** about the challenges of the project he is overseeing, including planning a megaproject that needs labor, resources and equipment that can handle Alaska's extreme environment.

"It's so big it creates its own weather, and if we're not careful it competes with itself, because we don't want to have challenges with welders on Part A working at odds or at issues with Part B. So we have to plan this very carefully so we level-load this work, we make sure we get the resources we need for the right craft skills and we don't compete with ourselves. That's very important."

The project is "so big it creates its own weather, and if we're not careful it competes with itself. . .

so we have to plan this very carefully."
- Steve Butt, senior project manager, Alaska LNG

The team he oversees is looking at every detail, to narrow the estimated $45 billion to $65 billion price range and pin it as low in that range as possible.

"We go from really big questions — multibillion-dollar questions — and we just keep grinding it down: Hundred-million-dollar questions, ten-million-dollar questions, million-dollar questions, until we get to such a high level of certainty you move to a place where the investors are ready to make a decision," he said. "They want to know that you've resolved all those uncertainties." He cited some examples.

The steel for the 800-mile, 42-inch-diameter pipeline would be what's known as X80 — extra-strength steel that, if you extracted a plug from it and strained the plug, could withstand 80,000 pounds of pressure per square inch. Ultra high-end stuff.

"We're looking real hard at the materials," Butt said. "The type of material is really important because it defines the amount of steel in the line and the type of steel in the line, and that tells you who can make it, how many mills can you get it from and what it's going to cost. So one of things we have to study in pre-FEED is the material on that pipeline design. ... Can you go to X70? There's little questions that drive huge value, because this system is so big, any little change you make is hundreds of millions of dollars."

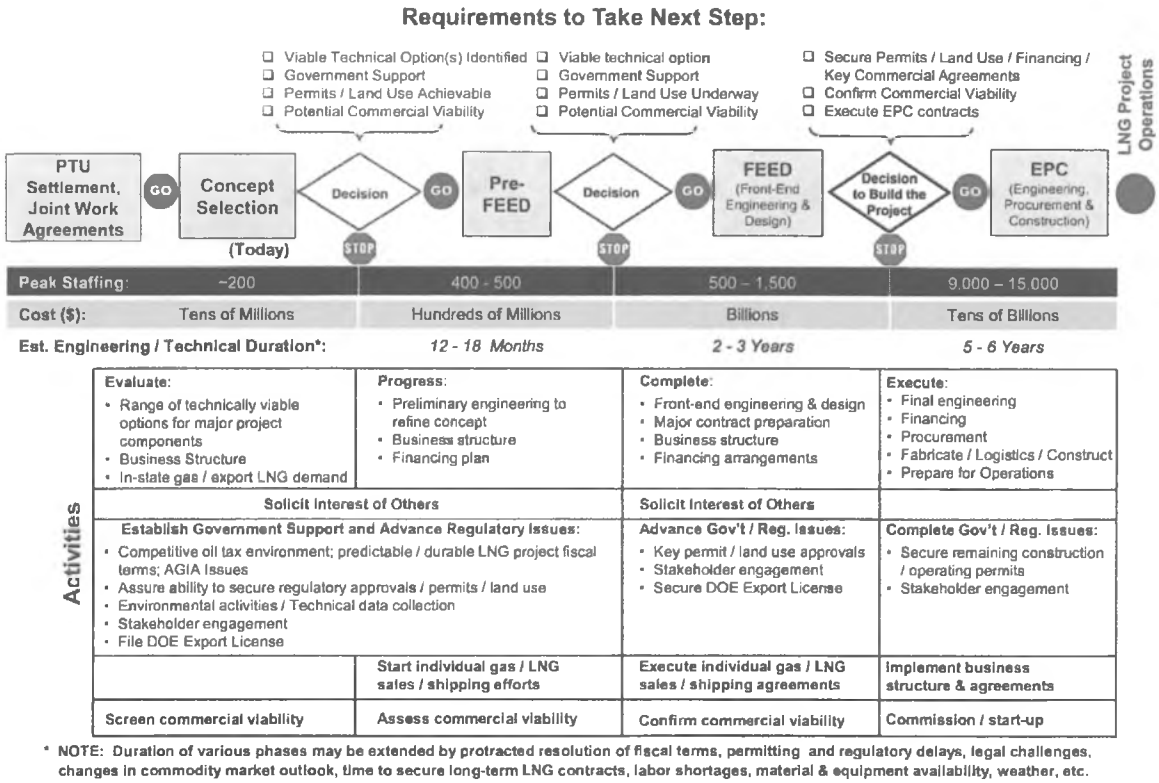
The natural gas produced at Prudhoe Bay — the main field that will feed Alaska LNG — is tainted with about 12 percent carbon dioxide. The project is planning a multibillion-dollar gas treatment plant to extract the CO_2 because it would corrode steel pipe, doesn't burn and LNG buyers don't want it in their gas. Recently Butt's team reconceived the gas treatment plant, streamlining it from an earlier design and syncing it with design of the liquefaction plant to be built 800 miles to the south.

"That's a lot of money we saved," Butt told the committee. "But more importantly, it means the system in the north — with three trains for treating — is now balanced with the system in the south — with three trains for liquefaction. For operations and maintenance over the next 35 years

it a much better balanced system. So this is a pretty big achievement for us that we've been working on over the last several months. It's a huge cost savings and risk reduction."

PRE-FEED, FEED PUSH PROJECT AHEAD

Southcentral Alaska LNG – Work Plans / Key Decision Points



Source: Alaska LNG Project

Graphic from October 2012 outlining the stages and decision points anticipated for the Alaska LNG export project. The project is in the pre-FEED stage currently. (Click to enlarge.)

Officially, people involved with Alaska LNG, including state of Alaska officials, dub the phase the project is currently in as pre-FEED, or pre-front-end engineering and design.

This phase is a precursor to a more formal — and expensive — stage called FEED, which in turn leads up to a final investment decision, or FID, on whether or not to construct the project.
One thing to know about FEED in particular is that this is a term commonly used in the LNG industry but isn't all that universal within the engineering world. Other words cover the same scope of project work — Merrow in a passage quoted above spoke of front-end loading, or FEL, a more common term.

Pre-FEED is starting to get used more widely to describe the LNG project-related activities that occur before FEED — there can be many such activities, so a term for them can be handy.
In the case of the Alaska LNG project, FEED would include:

- Enough engineering of the project so that contracts can be let for final engineering, procurement and construction (called EPC). EPC contracts are where the BIG money gets spent and the project is built.
- Crafting a plan for supplying, commissioning and starting up the Alaska LNG infrastructure — the gas treatment plant, gas pipeline, LNG plant and all related facilities.
- An estimate of the capital costs itemized in sufficient detail that corporate directors charged with making the yes-no final investment decisions are comfortable with their choice.
- A final assessment of environmental, social and health impacts.
- Action on procuring anything for the project that requires long lead times.

These are standard activities during FEED.

Pre-FEED would involve engineering, design, technical and other work needed to prepare for FEED. This includes conducting enough environmental field work and designing the project in enough detail to support applications to the Federal Energy Regulatory Commission for authority to build and operate the project. At a minimum, FERC would oversee the LNG plant construction and possibly the pipeline and gas treatment plant. The commission would produce an environment impact statement as part of its review.

At the end of the pre-FEED stage, each company sponsoring the project would decide if it wants to continue to FEED based on the information gathered so far.

"The purpose of Pre-FEED is to progress technical work that would provide each of the Alaska LNG Parties with sufficient information for evaluating the technical, cost and schedule aspects of the Alaska LNG Project," says the January 2014 **Heads of Agreement** signed by the state, the three major North Slope producers and TransCanada.

The pre-FEED, combined with other commercial, legal, economic, financial and marketing information, will help all of the parties decide whether to spend billions of dollars on FEED, the HOA says.

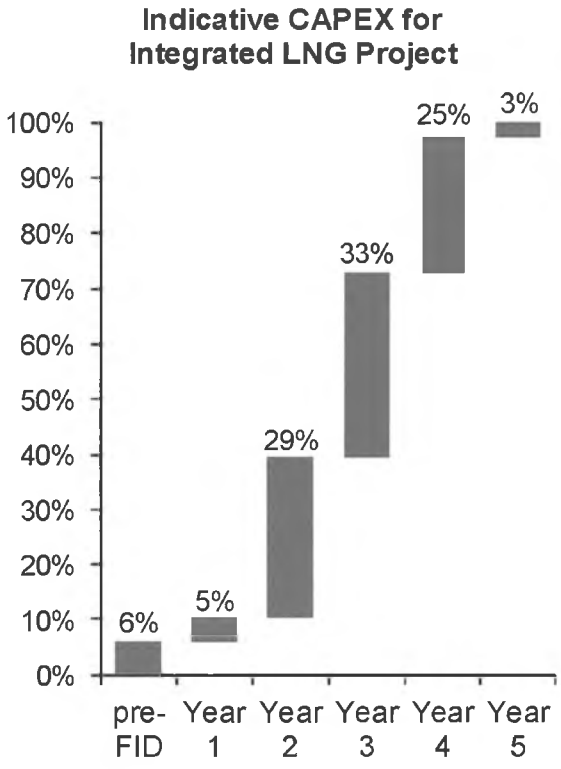
Joe Balash, Alaska commissioner of Natural Resources, and Michael Pawlowski, Alaska deputy commissioner of Revenue, told the Senate Resources Committee on Feb. 7 the pre-FEED phase should last up to 18 months and involve about $435 million in spending. Pending Alaska Legislature action before it adjourns in April, the parties committed in the HOA to ramping up pre-FEED in 2014.

The agreement says the FEED decision would occur within three years after pre-FEED ramp-up begins — that could put it at late 2016 or early 2017. Balash and Pawlowski told the Senate committee the more intense FEED stage would span two to three years and roughly estimated it would involve about $1.8 billion in spending. The HOA says FEED would cost "billions of dollars."

IS THAT BIG MONEY?

Now, $2.4 billion in pre-FEED and FEED expenditures that the state of Alaska estimates might sound like BIG money, and it is.

But for a $45 billion to $65 billion project, it's only about 5 percent of the total. It'd be like saying a 10-story building is tall — perhaps in some cities, but not in Manhattan.
Five percent CapEx spending through FEED is about normal for megaprojects, according to Merrow and others.



Source: PFC Energy

Pre-construction spending for a typical large LNG project might involve just 6 percent of the overall capital expenditures, with the other 94 percent of spending coming after the final investment decision, or FID, to build the project. (Click to enlarge.)

For LNG projects, figure 6 percent, said Nikos Tsafos of Enalytica Inc., a consultant to the Alaska Legislature on the LNG project, in November 2013. The other 94 percent gets spent after the final investment decision to build. This encompasses all the final engineering, purchase of materials and construction spending. In January, Tsafos loosened his estimate to "less than 10 percent" before FID.

"Before you get to final investment decision, you haven't spent any real money," Tsafos told the **Legislative Budget and Audit Committee** Jan. 28. "It's not 'real money' in the context of $65 billion.

"The reason this matters (the pre-FEED and FEED spending) is because by the time you get to FID, you haven't resolved but you have found an answer to most of the things you are worried about.

"So it's not the type of project where you put in $65 billion and as you're putting the money down you're thinking, 'Well, how should we do this? Who should we market it to? How should we finance it?' It doesn't work that way.

"By the time the large bulk of that investment takes place, all these things will have been sorted out. Maybe not to a 100 percent. You may not have signed every single deal with everyone. But you'll have a pretty precise idea about what each one of these things (upstream, midstream, liquefaction, shipping, marketing, finance, permitting) are going to look like," Tsafos said.

"So, yes it's a big project, it's a massive project. But the call of capital really comes only after you've had an enormous amount of time to spend to study all the permutations of the options in coming up with a schedule and a project structure that is comfortable to all the project partners."

WHAT CAN GO WRONG?

"It ain't what you don't know that gets you into trouble. It's what you know for sure that just ain't so."

- Mark Twain (some say)

One needn't look hard to find megaprojects that became big messes. Way over budget. Way behind schedule. That didn't work as planned.

Take Denver International Airport, a favorite case study in the annals of project management disasters.

It opened in 1995, 16 months behind schedule and 80 percent — $2 billion — over budget. Its much-touted automated baggage-handling system "became famous for its ability to mangle or misplace a good portion of everything that wandered into its path," as the New York Times put it. The airport scrapped it in 2005, replacing it with humans. A triumph of man over machine. The textbooks call Denver's failure a classic case of inadequate pre-FID work, of reliance on untested technologies, of "optimism bias." And, a flaw that sometimes infects big-ticket public works projects that politicians really want. It's called "strategic misrepresentation" — the cloaking of true costs from the public for fear they would rebel.

Other favorite examples: Boston's Big Dig tunnel — original budget $2.8 billion, ultimate cost $22 billion — and the Chunnel connecting England and France — 20 percent late; 80 percent more expensive than forecast.

Among LNG projects, the Chevron-led Gorgon project under way off Australia's west coast is more than 40 percent over budget as the sponsors endure a trickier environment, and costlier labor and materials than expected, as well as an unfavorable exchange rate and some acutely nasty cyclones. These are all issues that developers try to foresee and address during pre-FEED and FEED.

Angola LNG was supposed to start up in 2012. It finally shipped its first load in July 2013, more than a year behind schedule. Chevron is a partner here, too, and **the CEO said** Jan. 31, 2014,

"we have had some technical issues on the front end of that plant." Likely the plant will operate at just half capacity in 2014 and ideally will hit full capacity sometime in 2015, he said.

MONEY WELL SPENT

Source: Alaska LNG Project

An Alaska LNG field crew working in northern Alaska along the proposed gas pipeline route during the 2013 summer.

In his book, Merrow said a project with severe and continuing production problems in its initial years is a failure by definition.

After spending billions or tens of billions upfront on megaprojects, the corporate board wants its payoff, and that starts the moment the plant gets switched on. A late start or a slow start mean a lot less cash inflow than the directors were told to expect.

"The early years' production are the most valuable the project will ever have," Merrow said. When lost, they're lost for good.

Although there are no ironclad laws about these things, there are some general rules of thumbs circulating in the industry's literature about what constitutes a problem project besides start-up production problems: big cost overruns or big schedule slips — say 25 percent beyond what they should be.

"Megaproject results are frequently seriously short of the expectations of the sponsor-investors," Merrow wrote. "Their cost overruns are often so significant that the whole project becomes NPV negative."

Negative NPV — or net present value — does not mean unprofitable, it should be noted, but rather that the return on investment is below the investor's requirements.

"The real question is whether the investment you made up-front is optimal or not, or whether having put that money elsewhere would have generated a better return. So it's not really usually about losing money. It's about the optimal use of money," Tsafos explained to the Alaska Legislative Budget and Audit Committee in January 2014.

Megaprojects whose pre-FEED and FEED are well done — Merrow calls these stages FEL-1 through FEL-3 — have good track records for producing plants that operate as expected, according to his company's database.

Megaprojects are headed for trouble if the partners' interests are out of sync, if they skimp on pre-FEED and FEED staffing, if they're under such schedule pressure that corners get cut, if they short-change upfront planning because it can be expensive.

"We hear things like, 'Why should it cost so much money? I once front-end loaded a big project on a napkin over a beer.' If you are the project director, now would be a good time to post your resume," Merrow said in his book.

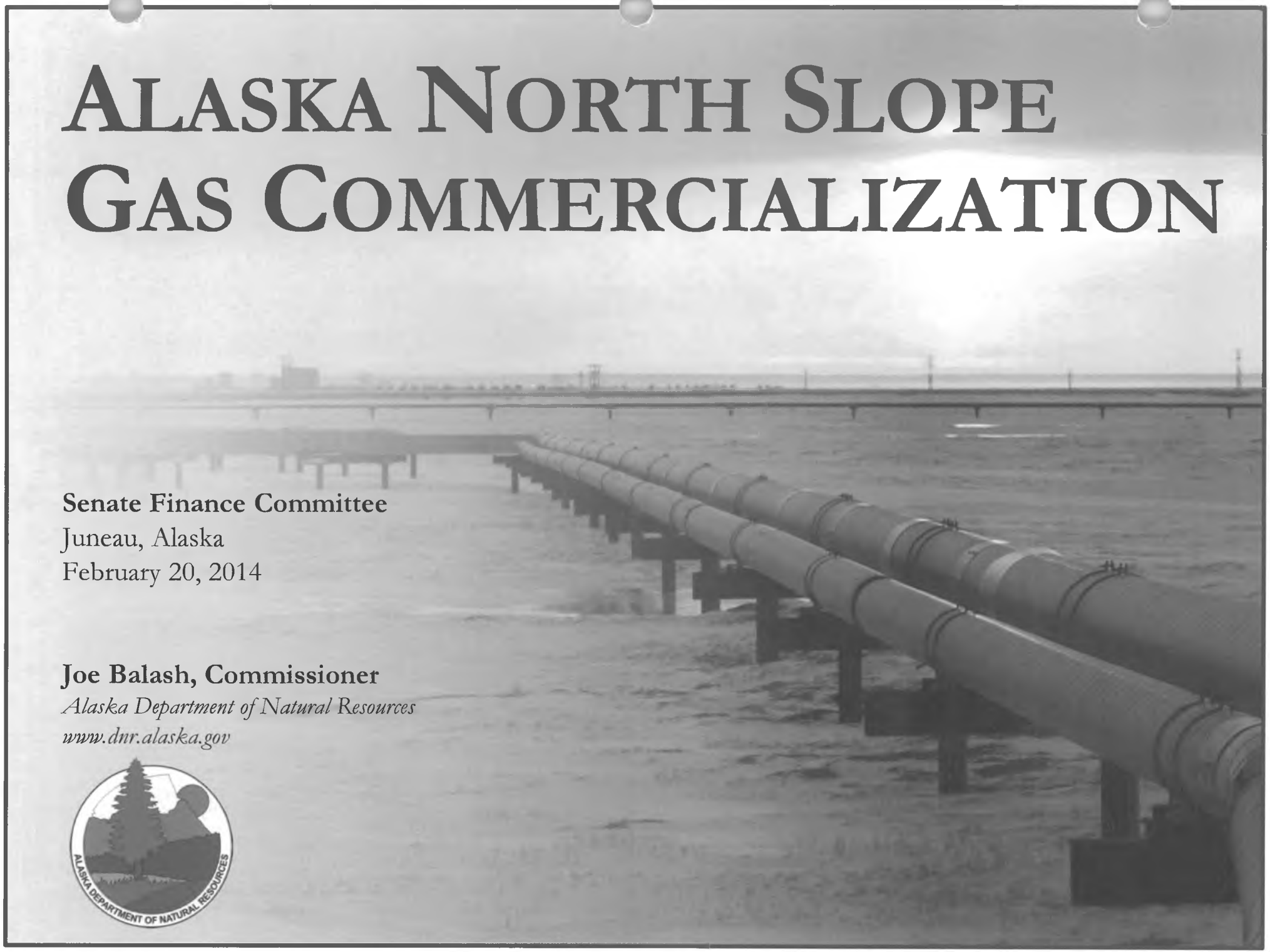
"Doing a thorough job defining and planning an industrial megaproject takes 3 to 5 percent of eventual total capital cost. Let's be clear; on a megaproject that is a lot of money. The cost, however, of not spending the money is much, much more."

-By Bill White, Researcher/Writer for the OFC. bwhite@arcticgas.gov

http://www.arcticgas.gov/early-planning-design-engineering-key-lng-project-success

5

Alaska North Slope Gas Commercialization



Senate Finance Committee
Juneau, Alaska
February 20, 2014

Joe Balash, Commissioner
Alaska Department of Natural Resources
www.dnr.alaska.gov

Alaska North Slope Gas Commercialization

Commercializing Alaska North Slope Gas:

- Where we have been
- Where we are
- Where we hope to be

Key principles for any project

- Gas to address Alaska's in-state needs for abundant supplies of low-cost energy and economic growth
- Gas that will maximize the value of the state's massive resource base through high-volume and export markets
- A project that incentivizes exploration and investment in continued oil and gas development

North Slope Gas Commercialization

- Benefits to the State -

- In-State Gas: opportunity for competitively priced, reliable in-state gas supply
- Commercialization of Alaska North Slope gas resources through sale of large quantities of natural gas beyond in-state needs

Photo: Getty Images courtesy of WSJ

- Additional revenues to the State
- Creates jobs for Alaskans in the exploration, development, production, and transportation of natural gas
- Increased opportunities for Alaskan based contractors and businesses
- Infrastructure for development of additional gas resources to enhance further oil and gas exploration/production opportunities

North Slope Gas Commercialization
- State Interests -

North Slope Resource Estimates

U.S. Geological Survey (USGS) estimates that Alaska's North Slope and Arctic Outer Continental Shelf have over 200 trillion cubic feet (TCF) of conventional natural gas.

- Prudhoe Bay: ~ 24.8 TCF
- Point Thomson & other undeveloped fields: ~ 8 TCF

Region and Assessment Segment		Gas, BCF (billion cubic feet) Probabilty Distribution F95	Mean	F05
North Slope Onshore & State Waters[2]				
Central North Slope	*Oil & Associated gas*	2,681	4,198	6,092
	NGL & Non-associated gas	23,939	33,318	44,873
Nat'l Petrol Reserve Alaska	*Oil & Associated gas*	--	--	--
	NGL & Non-associated gas	--	52,839	--
ANWR coastal plain[2]	*Oil & Associated gas*	--	4,764	--
	NGL & Non-associated gas	0	3,841	10,852
total - North Slope Onshore		--[3]	98,960	--[3]
Arctic Alaska Outer Continental Shelf (OCS)				
Chukchi Shelf	*Oil & all gas*	10,320	76,770	209,530
Beaufort Shelf	*Oil & all gas*	650	27,640	72,180
Hope Basin	*Oil & all gas*	0	3,770	14,980
total - Arctic OCS (offshore)		--[3]	108,180	--[3]
TOTAL - Arctic Alaska		--[3]	***207,140***	--[3]

Table compiled from multiple USGS and BOEM assessments; pld, Division of Oil & Gas

State interested in lowest reasonable tariffs, favorable expansion policy

Alaska has world-class unconventional resources, including tens of billions of barrels of heavy oil, shale oil, and viscous oil, and hundreds of trillions of cubic feet of shale gas, tight gas, and gas hydrates.

- The mean estimated onshore gas hydrate resource is 590 TCF of gas-in-place, with a mean of 85.4 TCF potentially recoverable with current technology (USGS, 2008).

Photo Courtesy of DOE

North Slope Gas Commercialization
- AGIA Background, Purpose, and Terms -

- Alaska Gasline Inducement Act (AGIA) resulted from the aftermath of the failed Stranded Gas Development Act (SGDA)
- Relied on private sector project sponsor
  - Utilized reimbursement to de-risk development costs
  - Also secured an option to purchase information/assets if project did not advance
- Established terms designed to maximize state benefits
  - Low tariffs – through high debt/equity capital structure
  - Favorable expansion policy
- Expectation was long lead time on development could proceed in parallel with commercial/fiscal negotiations

North Slope Gas Commercialization
- History & Timelines -

2007:

- AGIA process set out in statute
- Applications received December 1, 2007

2008:

- April: Denali announced by BP and COP
- July: Enstar-ANGDA Plan announced
- August: AGIA license approved by Legislature

2009:

- February: In-State Project Manager is named
  - Built on work started by Enstar and Anadarko
- June: ExxonMobil aligns with TC to form the Alaska Pipeline Project (APP)

North Slope Gas Commercialization
- History & Timelines -

2010:

- April: Legislature passes HB 369
- July: Open Season held for APP – conditioned bids received
- October: Open Season held for Denali – conditioned bids received

Shift to LNG in 2011:

- May: BP and Conoco abandon Denali
- July: AGDC/ASAP project plan released
- October: Governor Parnell calls on parties to move forward on large-diameter pipeline to tidewater in Alaska in an AGIA framework

North Slope Gas Commercialization
- 2012 State of the State and Benchmarks -

January 2012: Three CEOs meet with the Governor

> *"Currently, Alaska is pursuing parallel tracks to get a gasline. The State financially supports two different projects—one under the Alaska Gasline Inducement Act, and the other under the Alaska Gasline Development Corporation. While both are making progress, neither can finish the job alone."*
>
> - Gov. Sean Parnell, 2012 State of the State

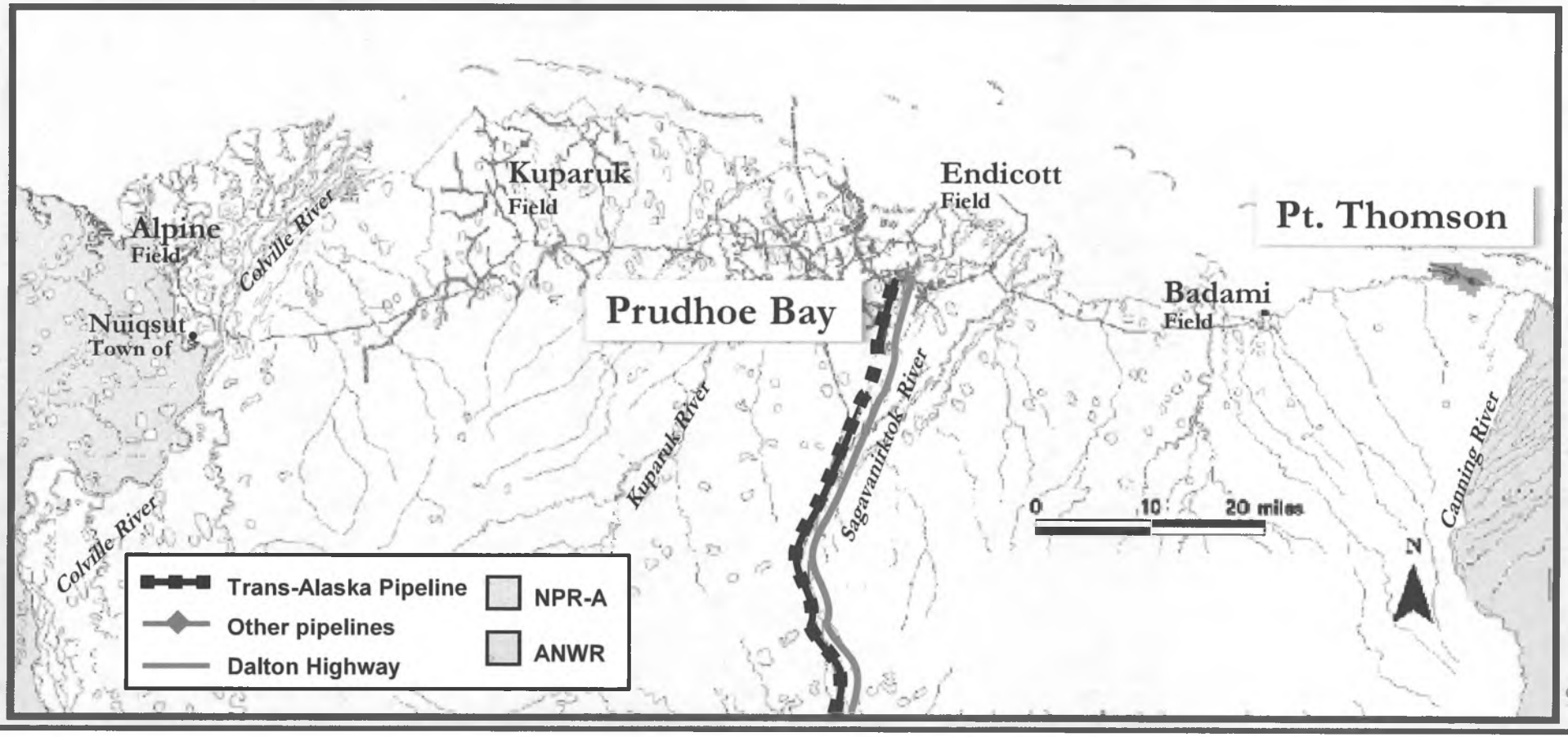
Governor's Roadmap to Gasline

1. Resolve Point Thomson
2. Align during the first quarter of 2012 under an AGIA framework on a large diameter gasline to tidewater
3. Two projects—under AGIA and AGDC—complete discussions by third quarter of 2012 determining what potential exists to consolidate projects
4. Harden numbers on an Alaska LNG project by the third quarter of 2012, and identify a pipeline project and associated work schedule
5. If milestones are met, the 2013 Legislature can take up gas tax legislation designed to move the project forward

North Slope Gas Commercialization
- Point Thomson Settlement -

March 30, 2012: Point Thomson Settlement Agreement filed with the Alaska Supreme Court

- Premised on requirement to perform work, start production
- Working Interest Owners must earn the acreage
- Sanction of Major Gas Sale pipeline project (in 2016 or 2019) secures entire unit



North Slope Gas Commercialization
- 2013 Milestones: Governor's State of the State -

Strengthen AGDC

"We need to boost AGDC's ability to build an All-Alaska gasline, or to participate with others in building one. Representative Hawker and the Speaker have filed legislation to add horsepower to AGDC's engine.

Without sacrificing accountability, we can unite around that legislation, and accelerate AGDC's work. We can accelerate a merger between the State's two parallel paths, and help avoid redundant costs between the projects.

Together, in the committee process, we will ensure that AGDC can commercialize Alaska's gas for the maximum benefit of all Alaskans."

APP 2013 Milestones

1. **By February 15, private parties involved in APP must select a concept on an all-Alaska project; they must describe and detail the project and pipeline specifications. To include:**
   - the size of the pipe and the daily volume of gas
   - the location of the gas treatment plant and detailing the number of compressor stations to move the gas along
   - the size and scope of the liquefaction plant and LNG storage tanks
   - the number of off-take points to ensure that Alaskans can utilize our gas for our needs
2. **Spring 2013: Companies finalize an agreement to advance to Pre-FEED** (front-end engineering design)
   - Pre-Feed – hundreds of millions of private-sector dollars
3. **Producers ensure a full summer field season** (Summer 2013)

North Slope Gas Commercialization
- 2013 Milestones -

April:

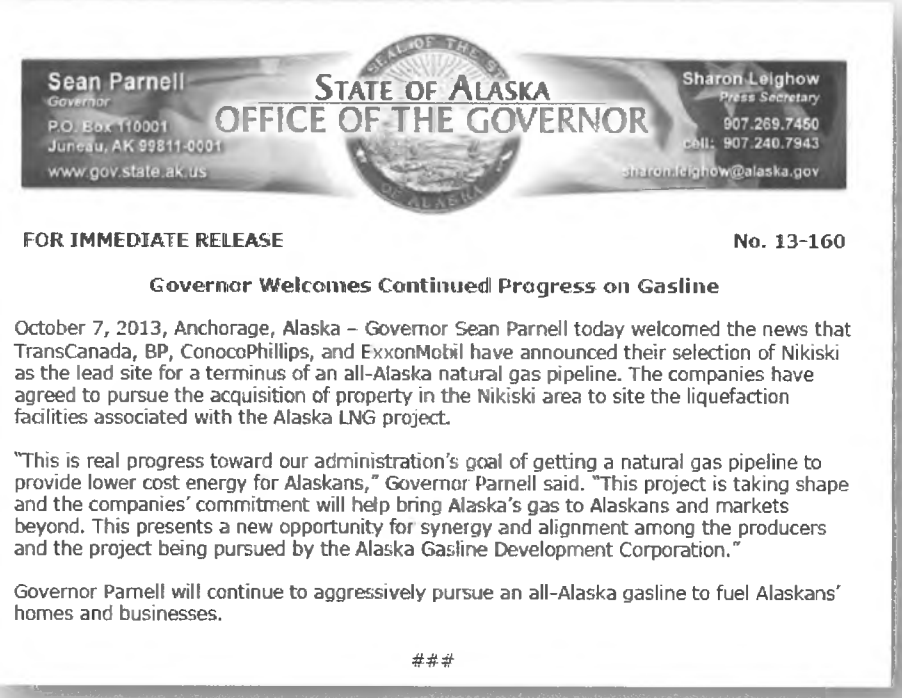
- HB 4 and More Alaska Production Act (MAPA/SB21) passed by Legislature

June:

- Last milestone of 2013 not met – no special session on gas tax legislation

October:

- Nikiski named as preferred location for pipeline terminus



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FOR IMMEDIATE RELEASE **No. 13-160**

Governor Welcomes Continued Progress on Gasline

October 7, 2013, Anchorage, Alaska – Governor Sean Parnell today welcomed the news that TransCanada, BP, ConocoPhillips, and ExxonMobil have announced their selection of Nikiski as the lead site for a terminus of an all-Alaska natural gas pipeline. The companies have agreed to pursue the acquisition of property in the Nikiski area to site the liquefaction facilities associated with the Alaska LNG project.

"This is real progress toward our administration's goal of getting a natural gas pipeline to provide lower cost energy for Alaskans," Governor Parnell said. "This project is taking shape and the companies' commitment will help bring Alaska's gas to Alaskans and markets beyond. This presents a new opportunity for synergy and alignment among the producers and the project being pursued by the Alaska Gasline Development Corporation."

Governor Parnell will continue to aggressively pursue an all-Alaska gasline to fuel Alaskans' homes and businesses.

###

North Slope Gas Commercialization
- Fiscal Discussions -

Early Breakthrough on Take vs. Stability

- Set take terms now, provide stability later
- Commensurate commitments by parties as project moves forward

Fundamental differences between SOA and Producers – stemming from our misalignment of interests

- State interests driven by lowest transportation charges/highest netback
- Lack of regulation at LNG plant/terminal (ownership of pipeline only does not solve the problem)
- Integrated companies are not driven by the capital structure/netback

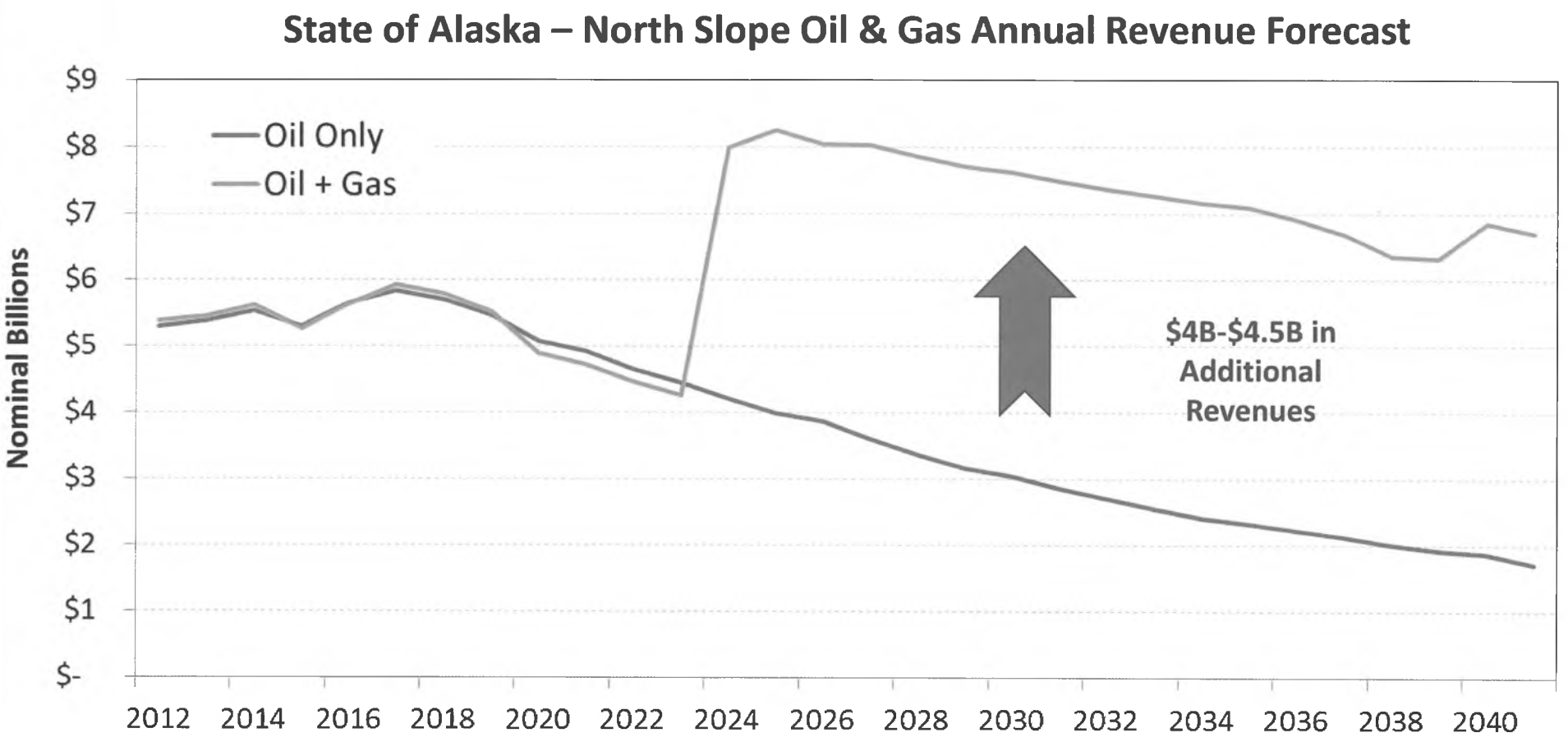
Key to Resolution: equity participation by SOA (project in a project)

- Allows each party to structure their financing as they see fit
- Enables any party to initiate an expansion on a sole-risk/keep-whole basis

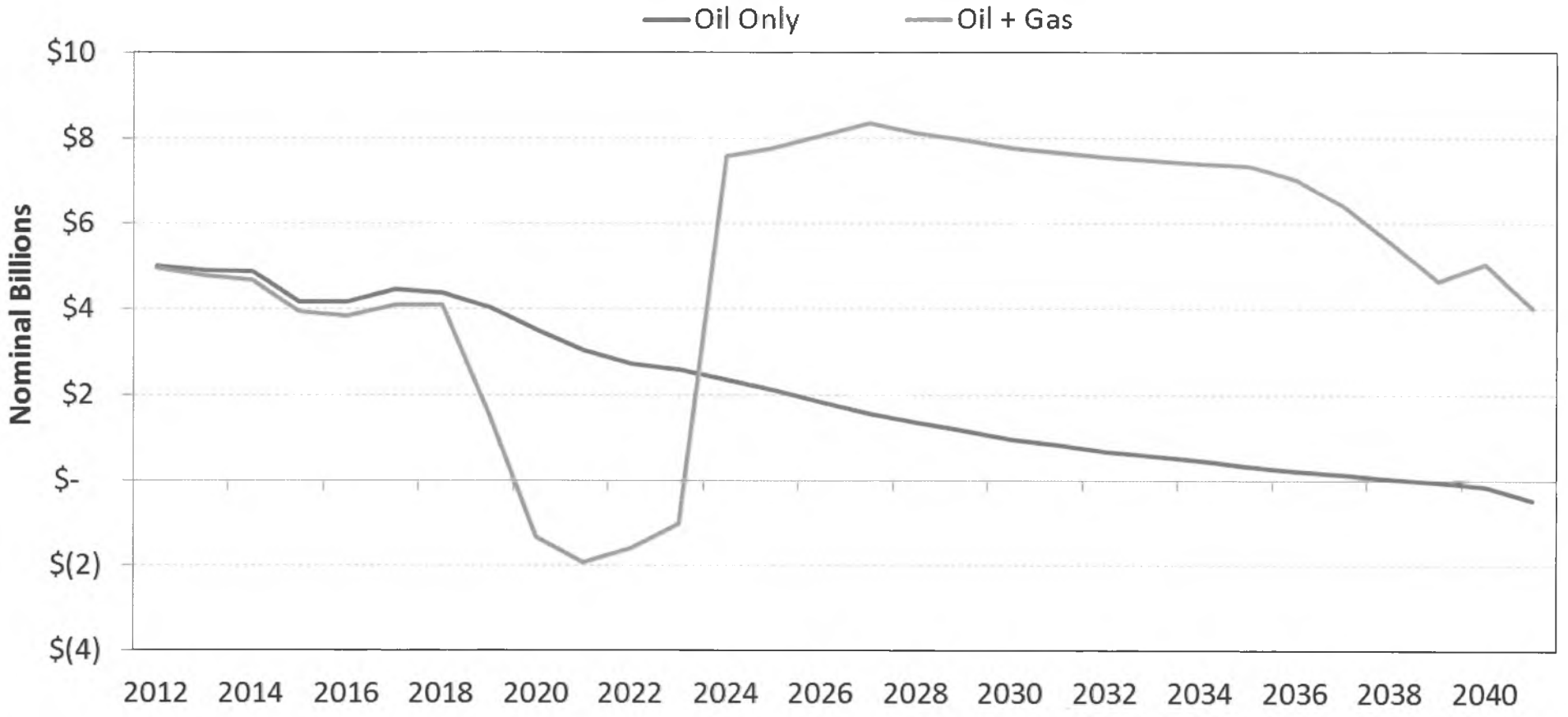
North Slope Gas Commercialization
- What's Different this Time? -

- Pt. Thomson resolved
- All the necessary parties have aligned to make an Alaska gasline project go – three producers, a pre-eminent pipeline builder, and AGDC
- Commercial issues being resolved by parties
- Gas-oil ratio (GOR) reaching a tipping point in 2020s
- Clear articulation of all parties' commitments
- Agencies asking the Legislature to provide term sheet-level approach
- Papering of Definitive Agreements only occurs after Legislature grants authority
- Definitive Agreements not binding unless/until Legislature ratifies – at next stage of commitment by Producers

LONG-TERM NORTH SLOPE OIL & GAS REVENUES ARE DRIVEN BY AKLNG PROJECT SUCCESS



Producer (Upstream + Midstream) Status Quo Annual Cash Flows



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Meet Alaska Conference

Governor Sean Parnell
January 10, 2014
(as prepared)

Thanks again to the Alliance for helping us build a healthy oil industry for our state. Your work on SB-21 – phenomenal. Your work to keep the gains we have – priceless.

Over the holidays, our family had the opportunity to watch again the blockbuster movie, "Lincoln." How many of you have seen it? The movie recounts the story of the 13th Amendment to the Constitution.

During the film, Secretary of State Seward scolds President Lincoln about letting two seemingly incompatible paths march forward. Lincoln responds: "Time is a great thickener of things."

Time is a great thickener of things.

The Fort Knox Gold Mine was originally staked in 1913, but no mining took place for many decades. The land remained undeveloped until it was re-staked in 1980. Again, nothing happened until new owners purchased the property. Finally, first gold was poured in 1996.

The geology stayed the same over those 80 years, but time thickened the technology, transportation, and investment climate — it all changed! To this day, Alaskans benefit from Fort Knox.

In 1957, oil and gas exploration in Alaska, particularly on the Kenai, was promising, but challenged. Development on the Kenai Peninsula was estimated to cost two to four times that of wells developed in California.

In 1959, the president of Standard Oil said, "The risks likely to be encountered in Alaska oil development are not for the faint-hearted or the speculator with a shallow purse … What we see is a picture clouded by present problems and past failures, but illuminated by cautious hopes."

Only two years later, those "cautious hopes" for Cook Inlet oil turned into a major refinery investment, thousands of jobs in oil and gas across decades, and cheaper energy for Southcentral Alaska.

For Cook Inlet oil and gas development, time has, indeed, been a great thickener of things.

And so it is with North Slope gas, a dream of Alaskans since 1968, when the announcement of Prudhoe Bay oil included an estimated 26 trillion cubic feet of natural gas.

As Alaskans, we own our gas and lease rights to our gas. Consequently, every Alaska gasline effort has dealt not only with the economics of gas, but also with the challenge of merging private and public resource ownership interests.

In the 1990s, Governor Knowles' administration privately negotiated a North Star royalty reduction with BP. The administration presented the royalty contract for legislative approval in what was seen as a "take it or leave it" deal.

The Legislature reacted strongly and negatively.

Lawmakers of the late 90s were concerned — after North Star — that an administration might negotiate all of the commercial terms of a gasline deal, without legislative input or public scrutiny.

Legislators agreed with the Knowles administration assertion that it was not in the State's interest to have companies negotiate with 60 individual legislators. Legislators, however, also wanted a real shot at protecting Alaskans' interests. The Legislature codified these interests in the original Stranded Gas Development Act, and Governor Knowles signed it into law.

The Stranded Gas Act gave the administration authority to negotiate fiscal terms for a gasline, but legislators put sideboards on the administration's authority, including requiring legislative approval of any contract negotiated.

Under the terms of the Stranded Gas Act, Governor Murkowski's administration negotiated fiscal terms with producers between 2003 and 2005. But when Governor Murkowski sought legislative approval, lawmakers rejected the contract. Neither legislators nor the public trusted the lengthy, private negotiation process, nor the contract terms produced.

As the Stranded Gas Act was a predictable progression from the tussle over North Star, so in 2007, passage of Governor Palin's AGIA legislation was a logical progression from the Stranded Gas Act experience.

Back then, Alaskans' trust in state government had vaporized. Gasline negotiations had gone badly, and public trust was very low.

On the gasline, Alaskans, legislators, the administration, all in 2007, were locked in a way of doing things that assumed in order to get a gasline we had to negotiate all the terms for a gasline at once.

Governor Palin and legislators sought to restore public trust and protect the public interest by enshrining a set of "must haves" in statute for Alaskans in exchange for State participation in a gasline project.

And, time, once again, became a thickener.

When AGIA passed, no parties were moving cooperatively forward toward a gasline. AGIA changed that.

TransCanada was selected by the State as the AGIA licensee.

Exxon joined TransCanada and the two began working cooperatively with the State.

BP and ConocoPhillips joined together in a competing project known as Denali.

AGIA's original focus was to induce construction of a gasline through Alaska and Canada to the Lower 48.

The producers, the AGIA licensee, Alaska's state government – virtually everyone was focused on a pipe to the Lower 48. That's because most thought the U.S. was facing a sharp decline in domestic gas production.

But the same year AGIA was passed, something unique was shifting the market. Gas volumes in the Lower 48 were increasing dramatically. Shale gas transformed the US natural gas market, and made its impact felt globally.

Some claim today that they always knew an overland pipe to the Lower 48 would never work, but I'd say to them that not even major companies, like BP or ConocoPhillips, were willing to publicly admit that until 2011, when they shuttered the Denali project.

Indeed, as late as September 2011, Sen. Mark Begich sent a letter to my office urging that I create a state loan guarantee to back a pipeline through Canada to the Lower 48.

By then, however, it was clear that Alaska gas was unlikely to flow overland to the Lower 48 in the near term, because of the growing volume of shale gas.

At the same time, the Pacific Rim market demand was strengthening.

I set Alaska on a different course. I challenged North Slope producers and TransCanada to get behind one project, an all-Alaska LNG project to supply gas to Alaskans, and be marketed as LNG to world markets.

I set a steady, logical plan to get us there using lessons learned firsthand with the history I described today.

First, we needed gas.

We need gas from both Prudhoe and Pt. Thomson to anchor any large-diameter gasline.

Pt. Thomson, with trillions of cubic feet of gas and lots of liquids, was in litigation when I became governor. No development had occurred there in more than 40 years. The State's lands had been under lease, yet little work had been completed east of Prudhoe.

We fought for Alaskans' interests all the way through the Alaska Supreme Court. Thanks to the hard work of many people, including then-Natural Resources Commissioner Dan Sullivan, ExxonMobil's Rich Krueger, BP Alaska's former head, John Minge, and ConocoPhillips-Alaska's Trond-Erik Johansen, we resolved the litigation and put lots of Alaskans to work.

Today, more than a thousand people have jobs because of Pt. Thomson. And you heard earlier from Gina Dickerson from Exxon - $1.8 billion of spending, so far, and total projected investment at $4 billion.

In resolving Pt. Thomson, we negotiated an agreement that grows opportunity with performance and results.

At Pt. Thomson we built trust and reward through incremental, verifiable performance.

We brought a related principle into gasline discussions with the producers and TransCanada: The principle of commensurate, proportionate commitments.

In other words, you take a step, we take a step, you make a commitment, we make a commitment. Along the way, we each verify our commitments and progress.

When it comes to the gasline, the State will verify progress and make new commitments through the legislative process at multiple points, and the companies via their board room decisions at multiple points.

With Pt. Thomson gas now in the gasline equation, we next needed a project concept selected.

It is in the State's interest to negotiate commercial terms with a single project, not individual partners. If the State gets caught up trying to satisfy individual partners, rather than negotiating with one entity, the State loses far more value.

The State has but one geographic resource base from which to maximize value for Alaskans. The companies across the table have global resources from which to work around issues arising between them. Accordingly, we want to deal with a project's unified position, which they can arrive at using their many resources. The State does not want to get tangled up in individual company concerns.

To get a project, in 2012 I called on the producers and TransCanada to harden their numbers, and identify a pipeline project and work schedule. They met that benchmark! And, this last fall, the companies picked Nikiski as the termination point for the project.

Then, yesterday, AGDC's Board of Directors voted to create a subsidiary with the intent to participate in the Alaska LNG project with the producers, TransCanada, and Alaska's Departments of Natural Resources and Revenue.

For the first time in Alaska's history, all the necessary parties have aligned to make an Alaska gasline project go – three producers, a pre-eminent pipeline builder, AGDC – an entity that can

carry whatever State interest is required of it, and State agencies responsible for the people's royalties and taxes.

With gas, a project, and alignment of parties, the next question is what role should the State play? How can we best own our destiny and maximize gas resources for our people?

Because an LNG project is much more complex and expensive than a traditional natural gas overland pipe, we hired some of the world's most qualified experts to examine Alaska's cost, tax, and royalty structures. We asked them to look for ways we could be competitive in world markets. And, we've analyzed ways to do this without necessarily reducing State royalties or taxes.

Alaska can best control her own destiny if we become a partner in the Alaska LNG project. Here's why:

Ownership or participation allows the State to receive a share in the profits over the entirety of the project. When companies build LNG projects, they often take profits at all points in the value chain. Gas processors take profit, pipelines take profit, the liquefaction facility takes profit, and ship owners take profit.

Without ownership or participation, the State would, in essence, pay for others profits that reduce the State's revenue from taxes and royalties.

With Alaska as a partner, Alaskans stand to gain more.

Ownership ensures we either pay ourselves for project services or, at the very least, understand, negotiate and ensure the lowest possible costs.

This structure is also attractive to the North Slope producers. From their perspective, their capital costs are reduced by an amount proportional to the percentage of State take from royalty and taxes.

Think of it like a hunting trip, where the costs are borne between the participants. Three guys go out hunting and the costs are prorated between them. But if a fourth joins the hunting party, the costs per person go down.

State participation can make Alaska gas more competitively priced in world markets in the next decade, while retaining our State tax and royalty revenues.

So let's take stock of where we are:

- We have the gas, both from Prudhoe and Pt. Thomson.
- We have an all-Alaska LNG project selected from the North Slope to Nikiski.
- We have all the right parties aligned and working together.

To pursue this path, however, requires a transition from AGIA to a new structure. It's another natural progression where time has been not only a thickener of things, but a great teacher.

AGIA was designed for a sole developer of a singular pipeline project moving natural gas. The complexity and scope of the Alaska LNG project is different — with a gas treatment plant, pipeline, liquefaction — a broad consortium of owners that must work together.

While AGIA may not have induced actual construction of a gasline, that statutory framework played a substantial role in inducing alignment for an LNG project.

Our way forward will be on Alaska's terms and in Alaskans' interests.

AGIA contained timeless principles and benefits for Alaska, and we will retain them: Gas for Alaskans on reasonable tariff terms, exploration of Alaska's gas acreage, gasline expansion potential, and local hire, to name a few. The way we get there is by working with a party or parties who will meet Alaska's terms.

We have agreed to amicably terminate our involvement with TransCanada under AGIA, but sign up with TransCanada in a more traditional, commercial arrangement along with the producers and AGDC. The reasons for signing up under a traditional commercial agreement with TransCanada start with TransCanada's willingness to meet Alaska on Alaskans' terms.

First, TransCanada agreed to a debt equity structure that guarantees Alaska's interests are protected. Second, TransCanada is the pre-eminent pipeline builder/operator in North America. Third, they know this project well, having worked on it for years. Fourth, AGDC and the producers are willing to move forward as a group with TransCanada to commercialize Alaska's gas. And fifth, TransCanada's participation reduces the State's cash commitment and increases state return.

We plan to seek legislative approval for the State entities to align with TransCanada and the producers in a more traditional commercial arrangement.

Very soon, I expect a commercial agreement with a transparent set of terms and road map for Alaskans to consider. That commercial agreement is known as a Heads of Agreement for the Alaska LNG project.

I expect that document to be signed shortly by Exxon, BP, ConocoPhillips, TransCanada, the AGDC, and by our commissioners of the Departments of Revenue and Natural Resources.

The Heads of Agreement will be subject to public review by the Legislature this session.

Additionally, I will ask legislators to take up legislation addressing how the State will manage its gas resource. Our proposed legislation would authorize DNR to modify certain leases, and allow the State to enter into shipping agreements to move and sell Alaska's gas.

The legislation will also ask lawmakers to switch from a variable net tax to a flat gross tax, for North Slope gas. It would allow certain leases to pay production taxes with gas, and enable the Departments of Revenue and Natural Resources to work together to manage the State's gas revenues.

The bottom line: We'll have an investment-quality project when this is complete.

Finally, this session I will ask the Legislature to review changes made to AGDC in House Bill 4 and support revisions needed to carry the State's interests in a project—for example, AGDC could be authorized to carry an interest in liquefaction.

To summarize what I expect in the next four months: Public review of project guidance documents, including a signed Heads of Agreement for the Alaska LNG project, and passage of authorizing legislation.

With a Heads of Agreement and legislation passed, the parties will formally cross into Pre-FEED -- the Pre-Front End Engineering and Design phase.

Pre-FEED is a half-billion dollar step in gasline development. Costs will be shared among the parties. Pre-FEED further refines the cost and engineering challenges the project faces – challenges that must be addressed before the parties commit the billions of dollars necessary to complete the project.

Over the course of about 18 months of pre-FEED, the parties will finish fieldwork, begin detailed design, regulatory filings, and testing of world markets.

Unlike previous efforts to commercialize North Slope gas, the public and Legislature will have the basic ingredients of a deal in front of them as they consider legislation moving the project forward.

The guidance documents we will submit to legislators form the basic agreements that will keep the project moving forward and provide guidance to the deeply technical and complicated negotiations to follow.

The guidance documents set out general agreement on essential issues dealing with factors such as State ownership, project costs, project expansion policy, workforce development, in-state hire, and the marketing of gas.

They define the State's and other parties' interests in broad terms and commit the parties to negotiate the details in good faith – details that will ultimately be addressed in contracts that come back to the Legislature for approval.

Over the decades, we've seen efforts to develop a large gas project falter for various reasons. That's why we'll maintain our backup plan to get Alaskans' gas to Alaskans. The Legislature wisely addressed this in creating AGDC.

AGDC is uniquely positioned to be our ace in the hole. We can still get gas to Alaskans first via AGDC's smaller volume ASAP project, if work falters on the Alaska LNG project. AGDC will remain on track for an open season for early 2015.

The good news today:

- We have a gasline project in sight;
- We have parties aligned who can move a project forward;
- We have protected Alaskans' interests through commensurate proportionate steps that can be publicly scrutinized.
- And, we have a back-up plan to build a gasline that's proceeding to open season.

Alaska's foundation is strong and our future is bright. We're moving forward on the promise of Alaska's natural gas. Thank you.

7

FEBRUARY 21, 2014

TRANSCANADA PARTICIPATION IN AKLNG PROJECT

PRESENTATION TO SENATE FINANCE COMMITTEE

PREPARED FOR THE STATE OF ALASKA

BLACK & VEATCH
Building a world of difference.®

BLACK & VEATCH PRESENTERS

Deepa Poduval is a Principal in Black & Veatch's Management Consulting Division and is responsible for business strategy and project management. Ms. Poduval focuses on strategic analytical services supporting energy asset valuation and optimization, marketing and business strategy development. She has been involved in providing analysis and commercial support related to Alaska North Slope gas monetization for eight years. Ms. Poduval holds an M.E.M. from Dartmouth College and a M.Sc. Economics and B.E., Mechanical Engineering from BITS, Pilani, India.

Jason De Stigter is a Senior Consultant with Black & Veatch's Management Consulting Division and is responsible for business analysis and project management. Mr. De Stigter's client engagements center on economic, financial, market, and risk analysis of large capital projects. He has extensive experience in developing complex and innovative economic and risk analysis models. Mr. De Stigter holds a B.E., Mechanical Engineering and a B.A. Business Administration from Dordt College and is a Professional Engineer.

MEMORANDUM OF UNDERSTANDING – HIGHLIGHTS OF THE DEAL ON THE TABLE

TC Holds the State's Equity Share in GTP+Pipe

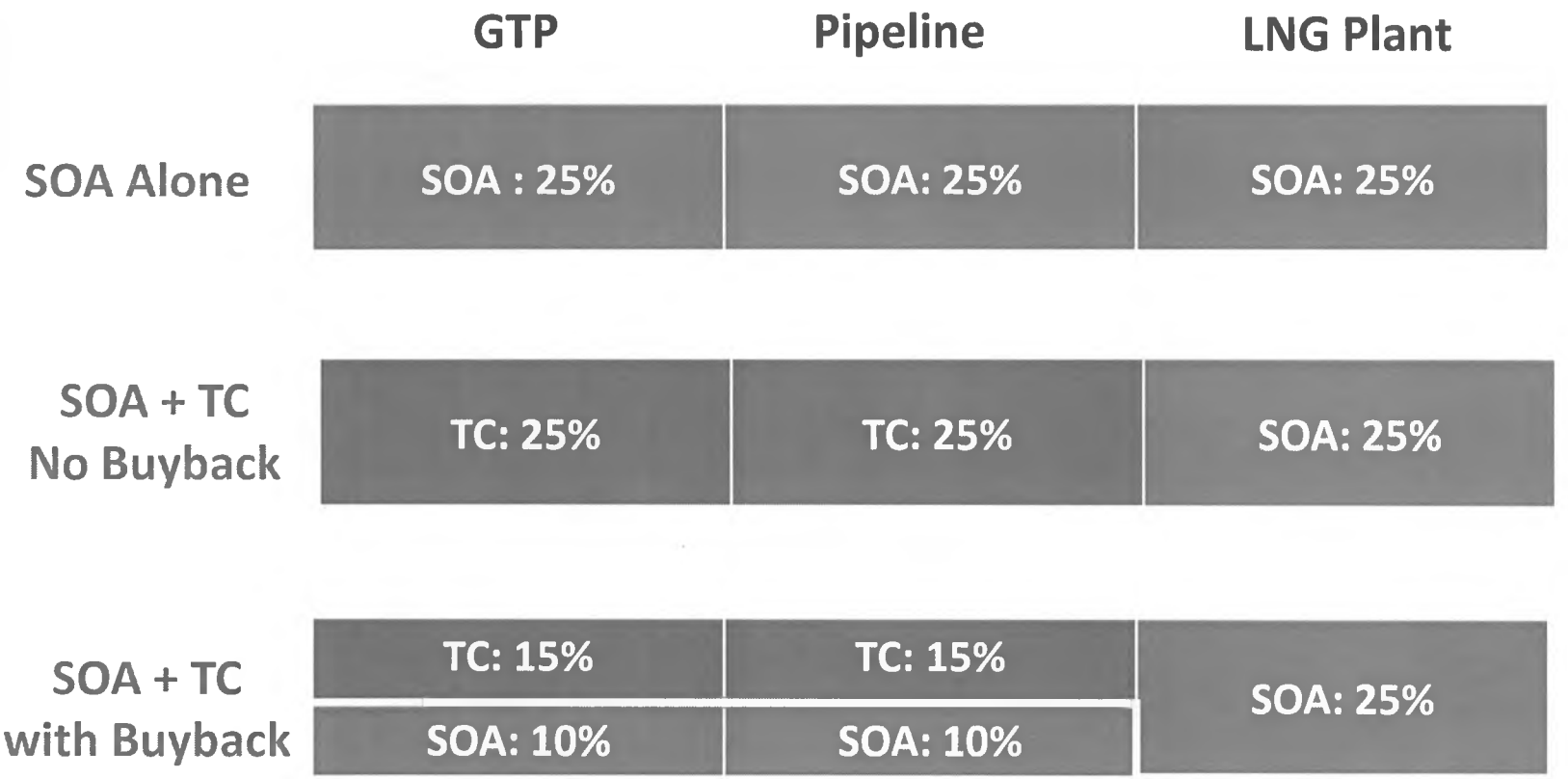
SOA Option to Buy Back 40% of TC's Share at FEED

State Commits to 25 Year Transportation Agreement with TC

Agreement Commits TC to a WACC of 6.75%

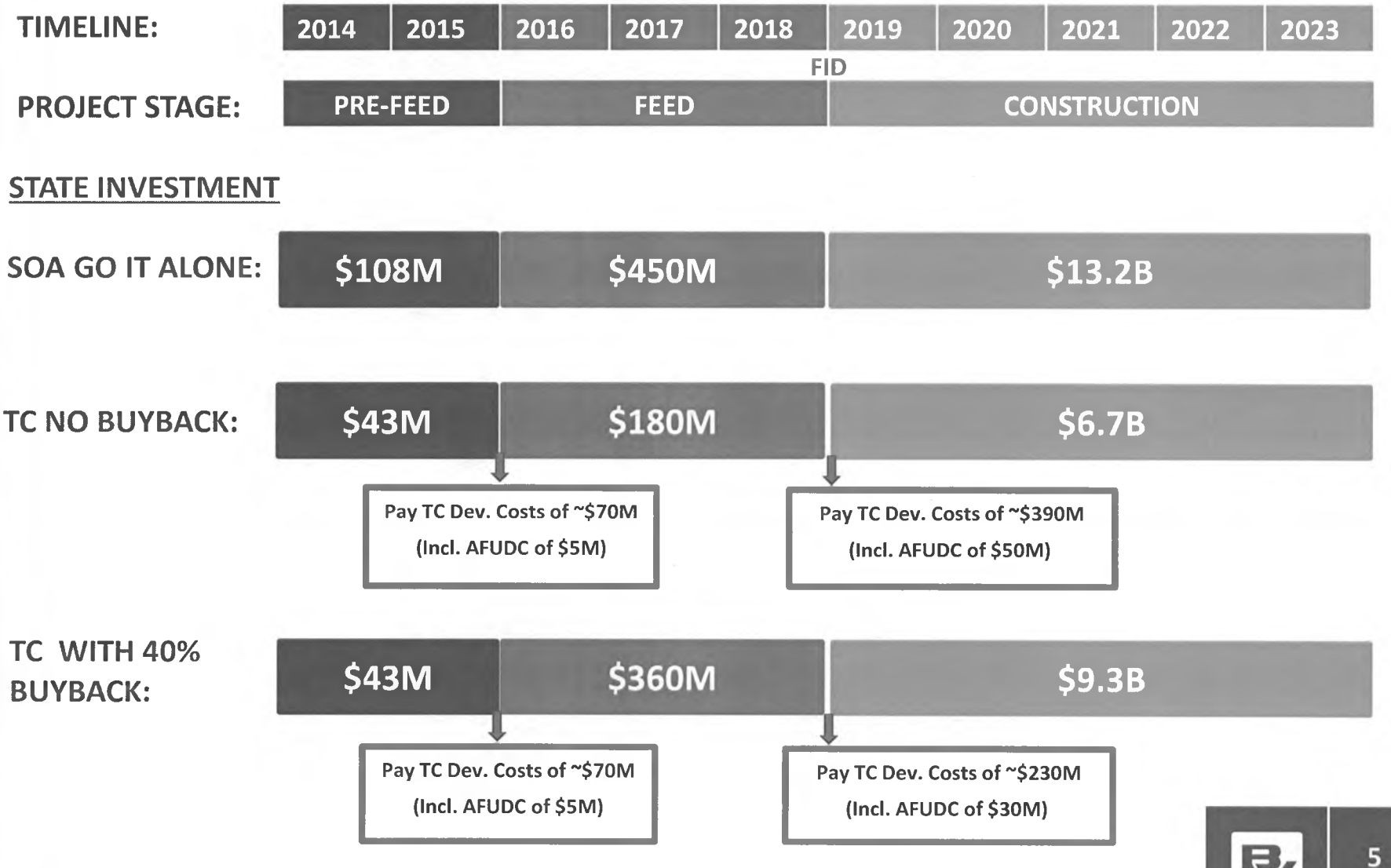
Various Milestones & Off Ramps for SOA and TC

OPTIONS IDENTIFIED BY STATE FOR EQUITY PARTICIPATION



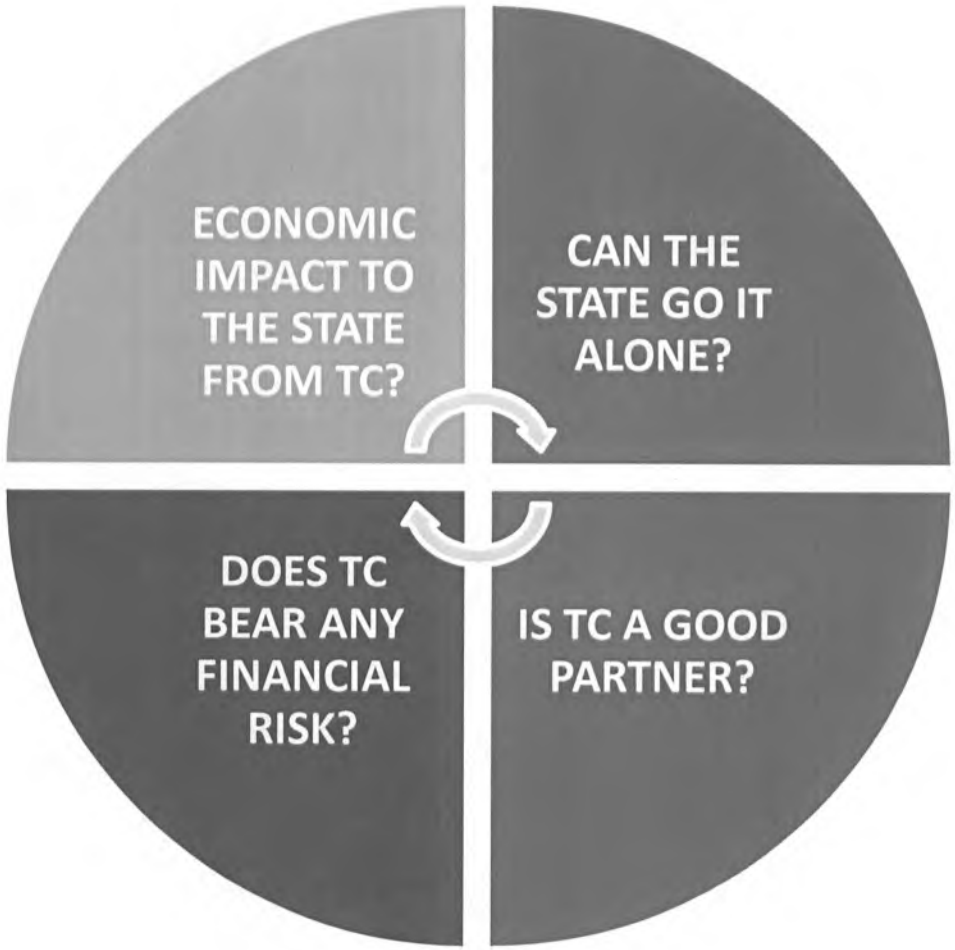
* Assumes 25% State equity participation

IMPLICATIONS OF OPTIONS AND POTENTIAL OFF RAMPS



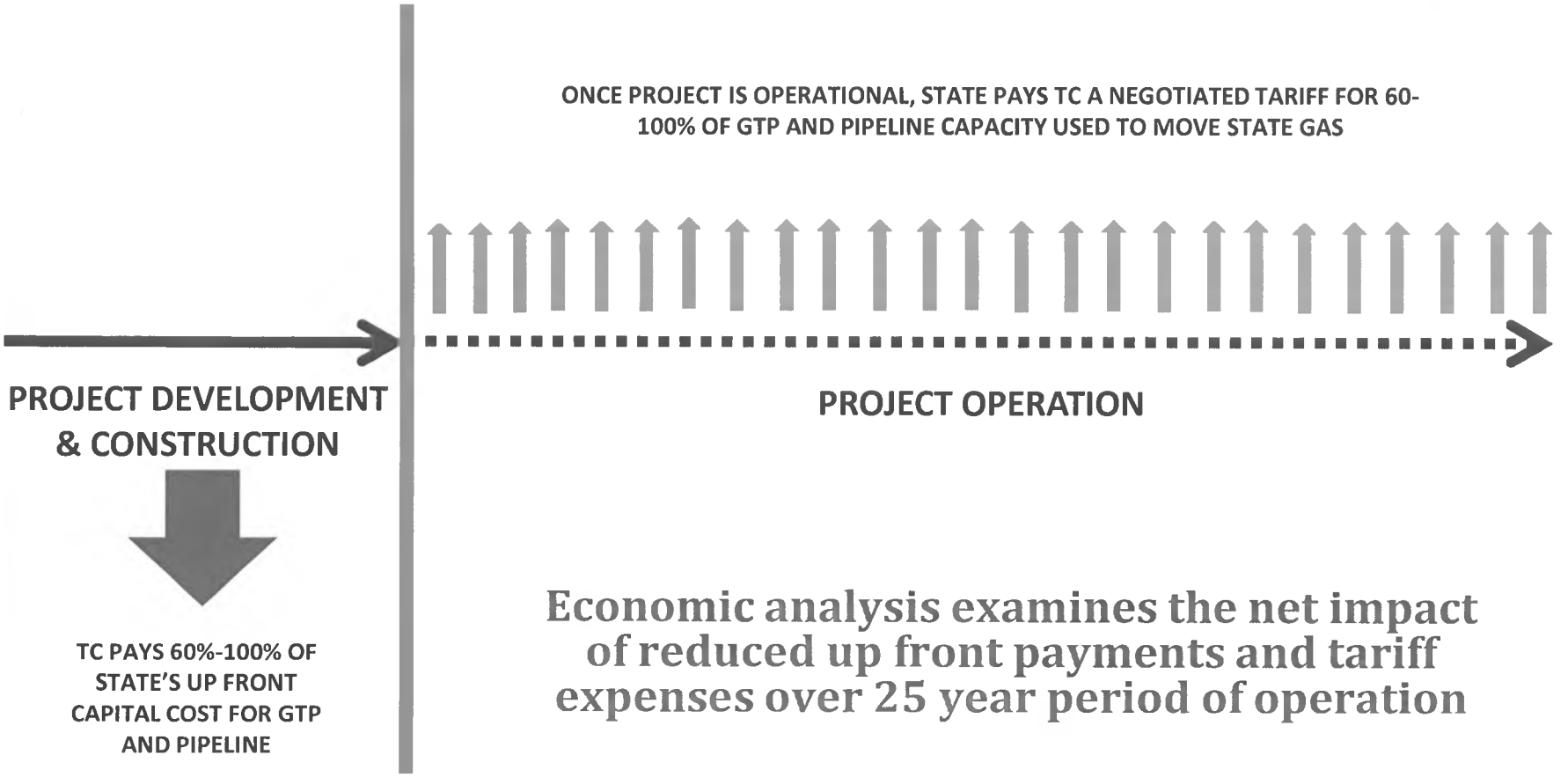
* Assumes 25% State equity participation

KEY QUESTIONS IN LOOKING AT VALUE OF TRANSCANADA'S PARTICIPATION



WHAT IS THE ECONOMIC IMPACT TO STATE FROM TRANSCANADA'S PARTICIPATION?

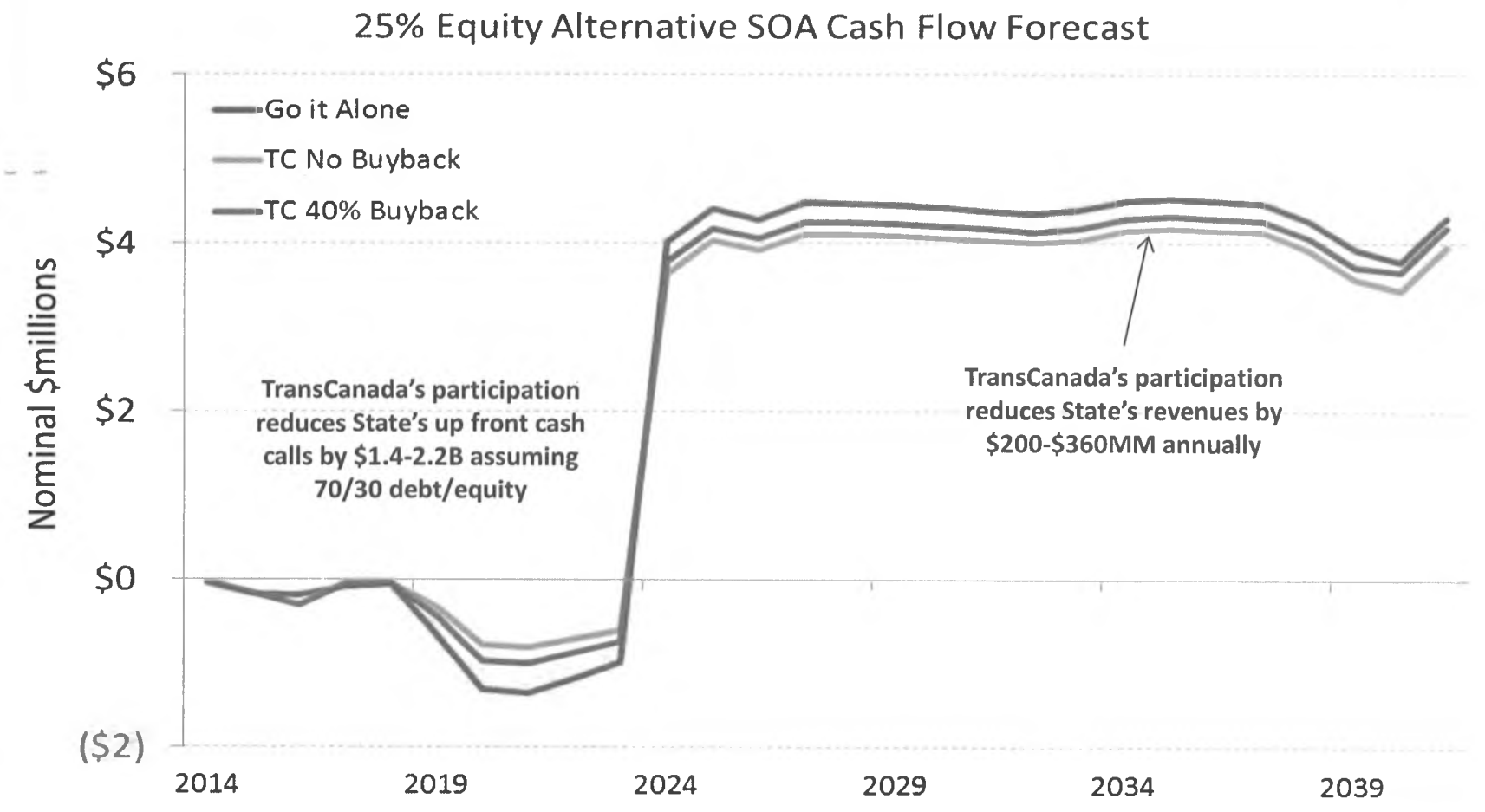
SOA IMPACT



Economic analysis examines the net impact of reduced up front payments and tariff expenses over 25 year period of operation

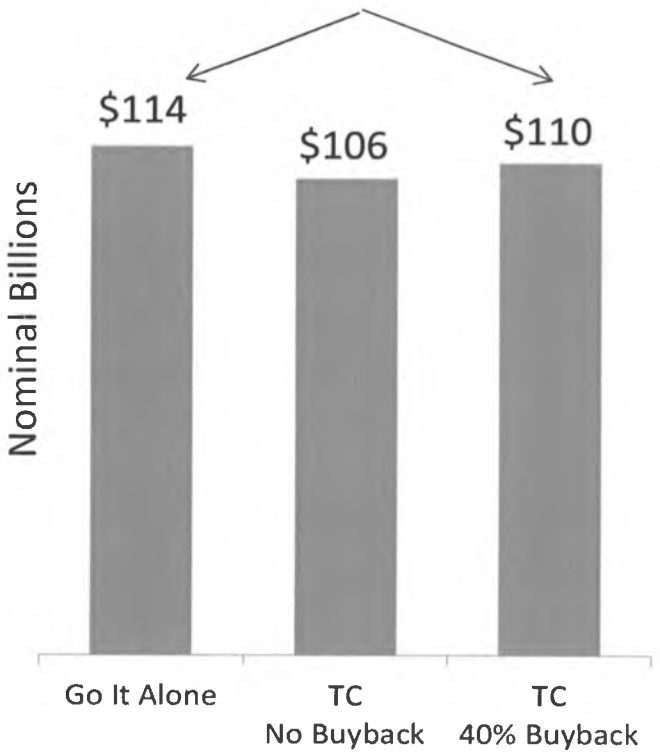
TRANSCANADA'S PARTICIPATION IMPACTS SOA UP FRONT CASH CALLS AND REVENUES FROM PROJECT

SOA IMPACT



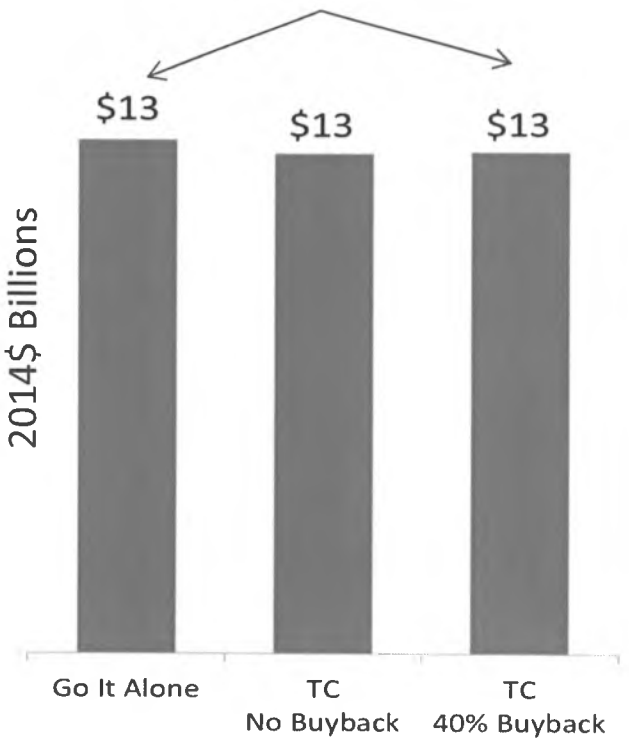
WHAT IS THE ECONOMIC IMPACT TO STATE FROM TRANSCANADA'S PARTICIPATION?

TransCanada participation reduces the State's total cash flows with buy back option



STATE OF ALASKA CASH FLOWS

Minimal impact on the State on an NPV basis with TransCanada participation.



STATE OF ALASKA NPV_{10}

TransCanada's NPV is expected to be $150-$200MM over the initial 25 year period

* Assumes 25% State equity participation

CAN THE STATE GO IT ALONE?

- What are the capital cost and investment implications of going it alone
- What are the debt implications of going it alone?

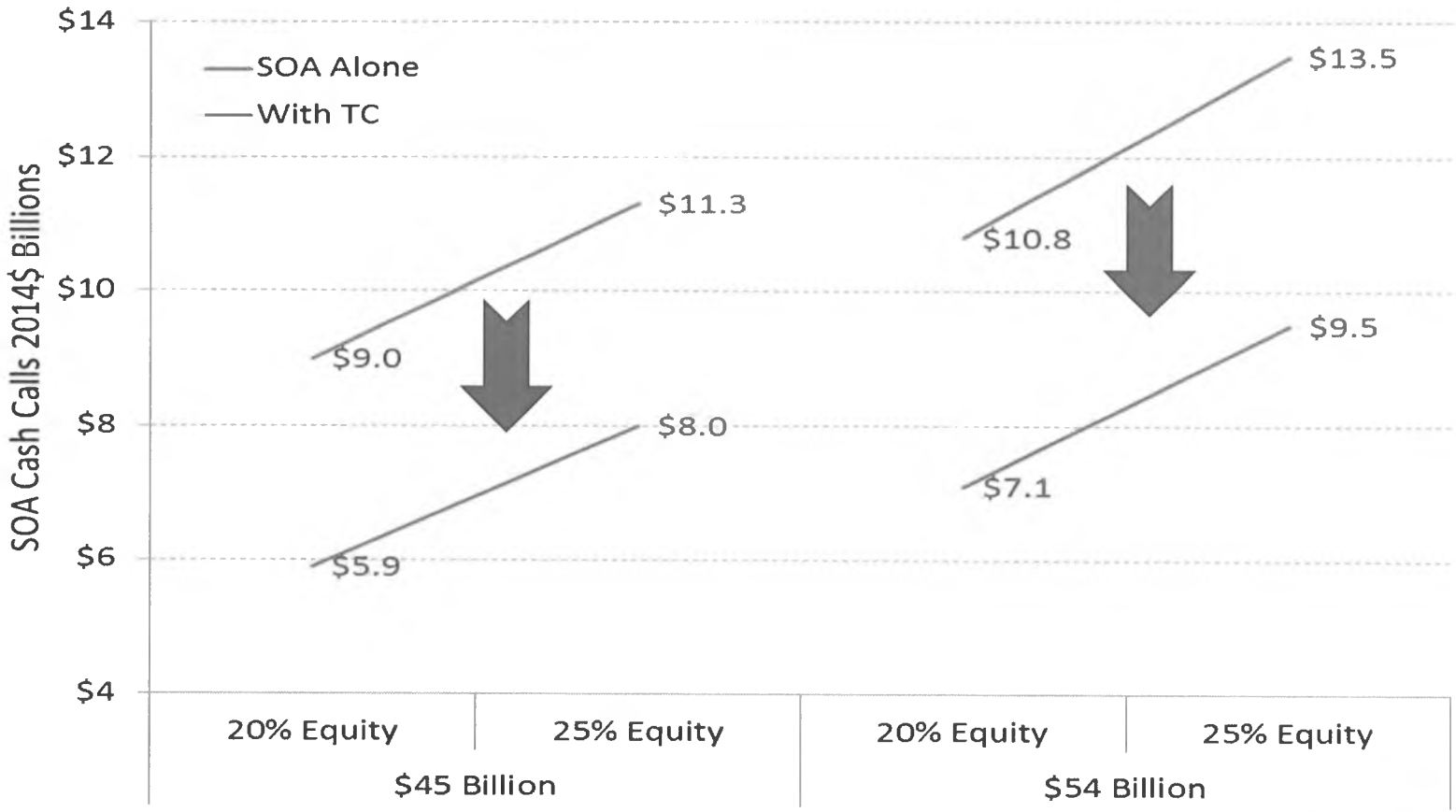
SOA UP FRONT CAPITAL COST EXPOSURE IS REDUCED THROUGH TC PARTICIPATION

- Highest risk exposure is prior to project start when cash calls are not supported by project revenues
- TransCanada ("TC") participation allows State to retain 20%-25% of gas share while being responsible for only 13%-18% of the upfront costs
- This is especially important if cost overruns occur on project

SOA UPFRONT CAPITAL COST EXPOSURE IS REDUCED THROUGH TC PARTICIPATION

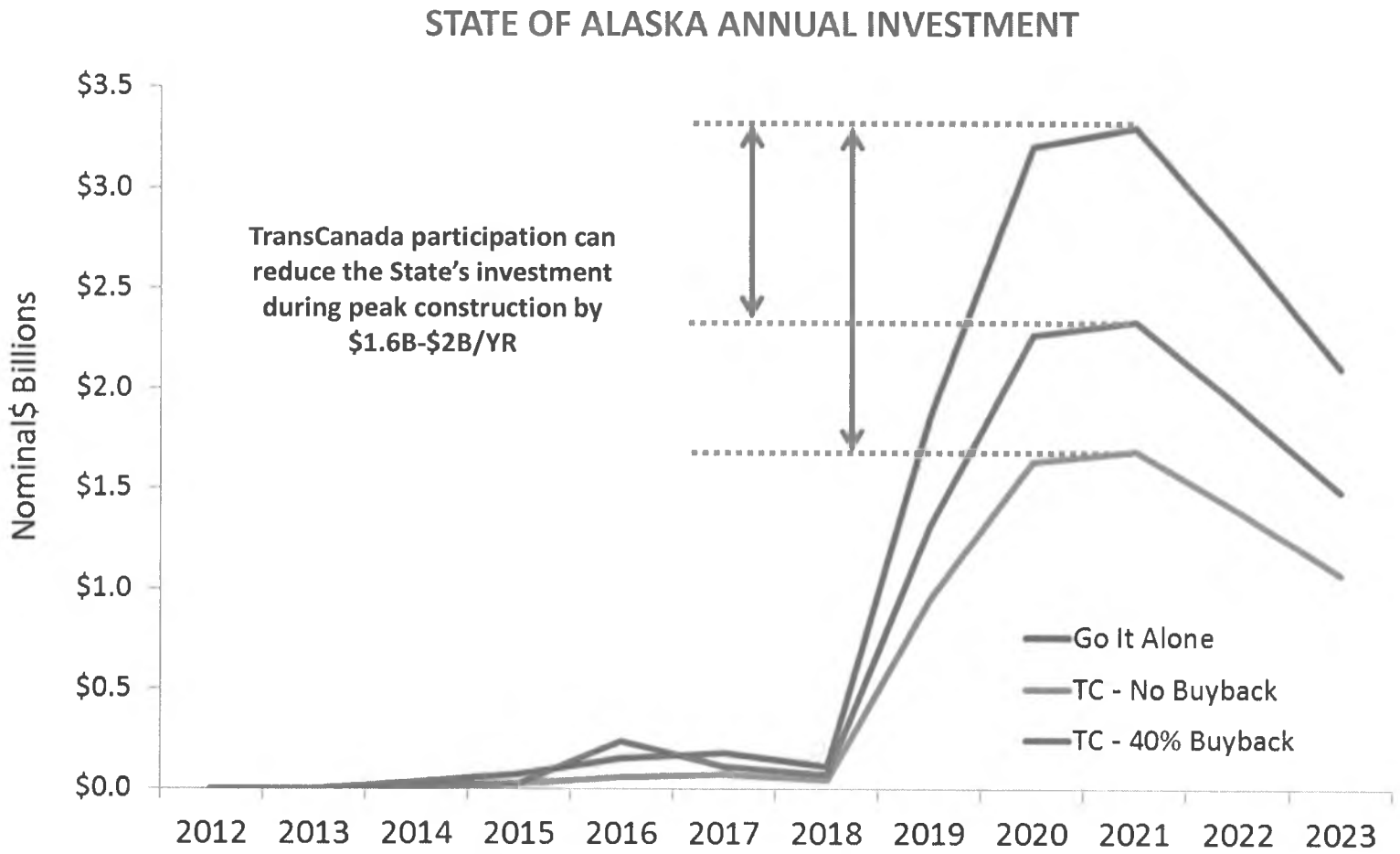
SOA ALONE?

TC Participation Reduces Total Upfront Investment by SOA by ~40%



* Assumes State exercises 30%-40% equity buy back with TransCanada

SOA UPFRONT CAPITAL COST EXPOSURE IS REDUCED THROUGH TC PARTICIPATION



* Assumes 25% State equity participation

CAN THE STATE GO IT ALONE? - STATE'S DEBT CAPACITY

- **Financing the State's share of the AKLNG Project on the State's balance sheet – key issues:**
  - At what cost of debt?
  - Debt servicing as what % of general fund unrestricted revenue?

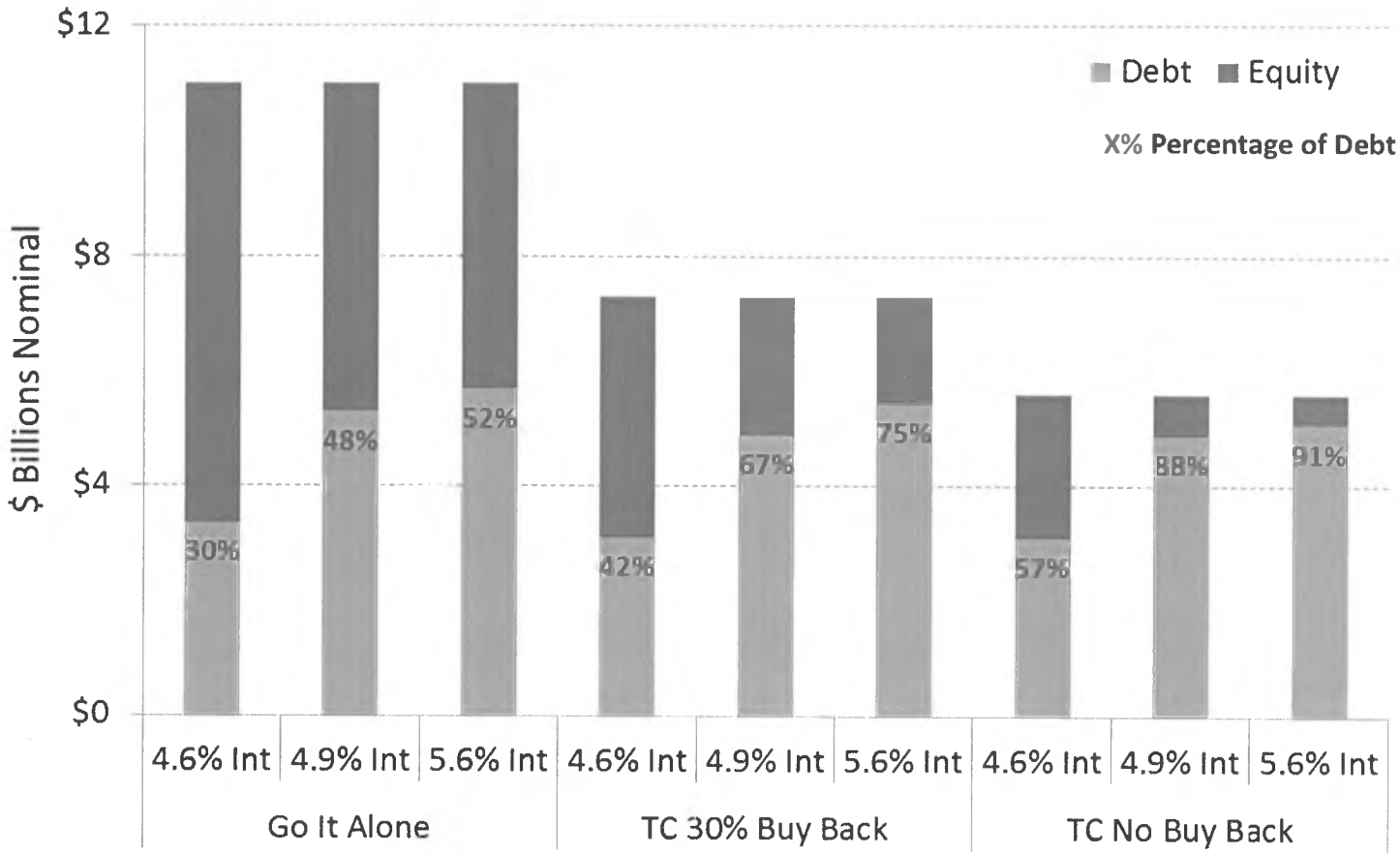
Scenario 1 (lower interest)	• SOA Debt at 4.6% • Debt Service limited to 3% of GFUR
Scenario 2	• SOA Debt at 4.9% • Debt Service limited to 5% of GFUR
Scenario 3 (higher interest)	• SOA Debt at 5.6% • Debt Service limited to 6% of GFUR

*** High-level, indicative assumptions based on input from Department of Revenue**

THE AMOUNT OF CHEAP DEBT AVAILABLE TO THE STATE COULD BE LIMITED

SOA ALONE?

Indicative Levels of Debt for State to Finance 20% Equity Stake in AKLNG Project



*** Analysis based on high-level, indicative assumptions based on input from Department of Revenue. Financing arrangements for the AKLNG project will become clearer further into the development process.**

IS TRANSCANADA A GOOD PARTNER FOR THE STATE OF ALASKA IN THE AKLNG PROJECT?

Extensive experience in building, owning and operating northern pipelines

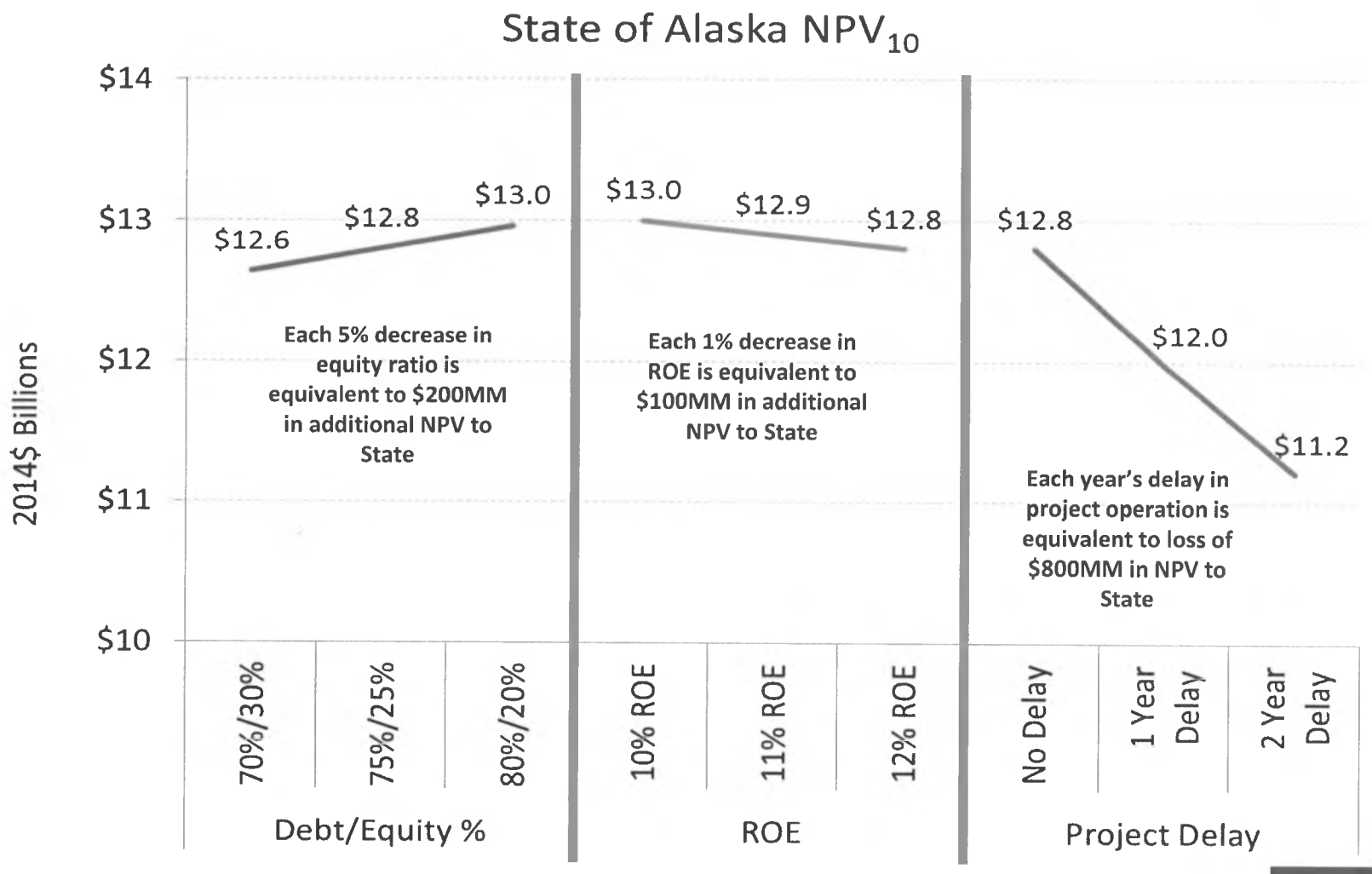
Long history of interest in Alaska Pipeline

Retains momentum in the project

Facilitates expansion

RETAINING MOMENTUM ON PROJECT COULD BE MORE VALUABLE THAN SECURING BETTER COMMERCIAL TERMS

TC AS PARTNER



DOES TRANSCANADA BEAR ANY FINANCIAL RISK?

TransCanada has committed to the following terms for providing treating and transportation services to the State

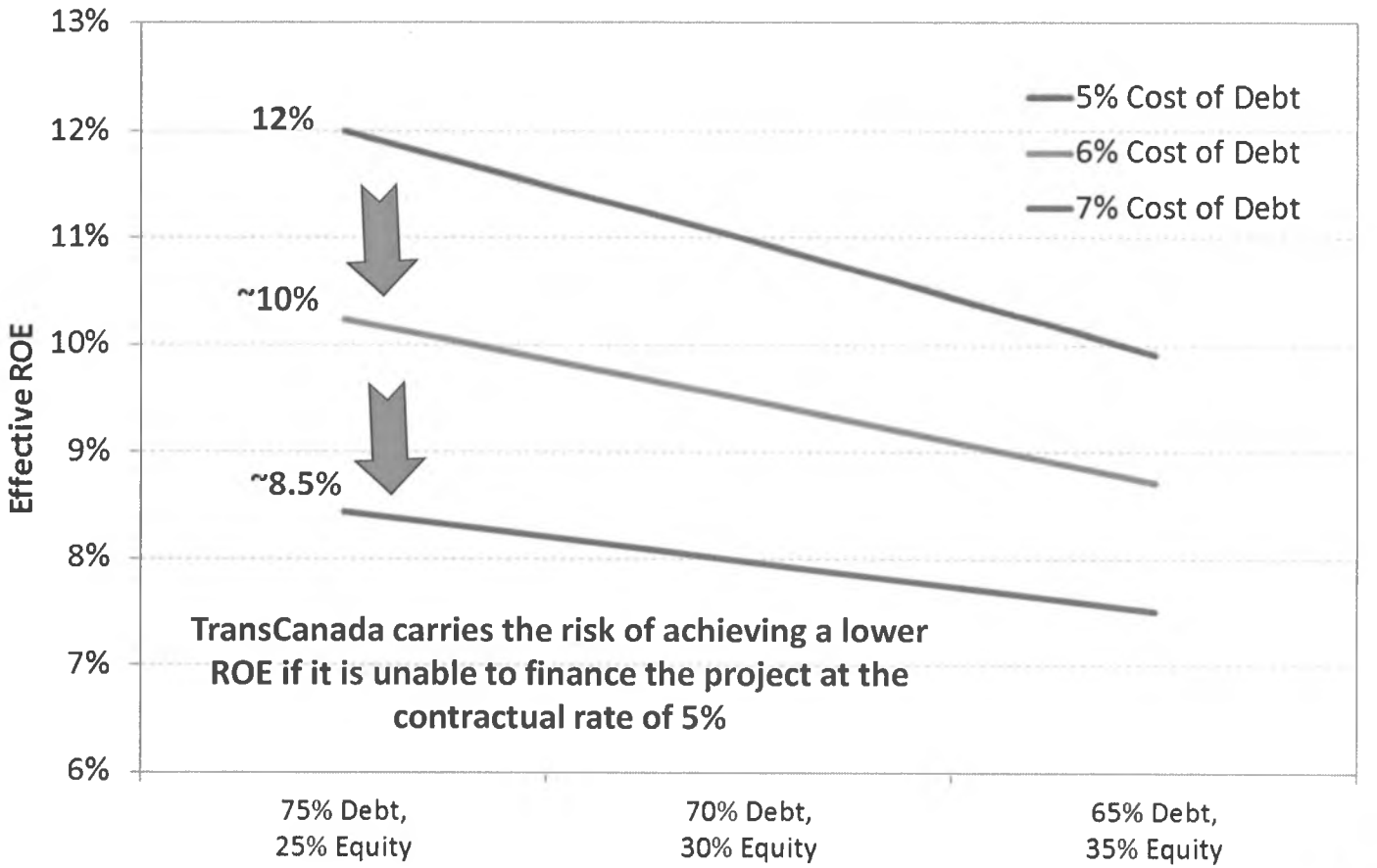
- D/E split of 75%/25%
- Return on equity of 12%; Cost of debt of 5%

Locking in this capital structure before actual financing arrangements have been made for the project places a risk on TransCanada of under-earning its expected return on equity and eroding its expected NPV from the project

Given the scale of this project and the uncertainties associated with it, financing remains a significant risk

DOES TRANSCANADA BEAR ANY FINANCIAL RISK?

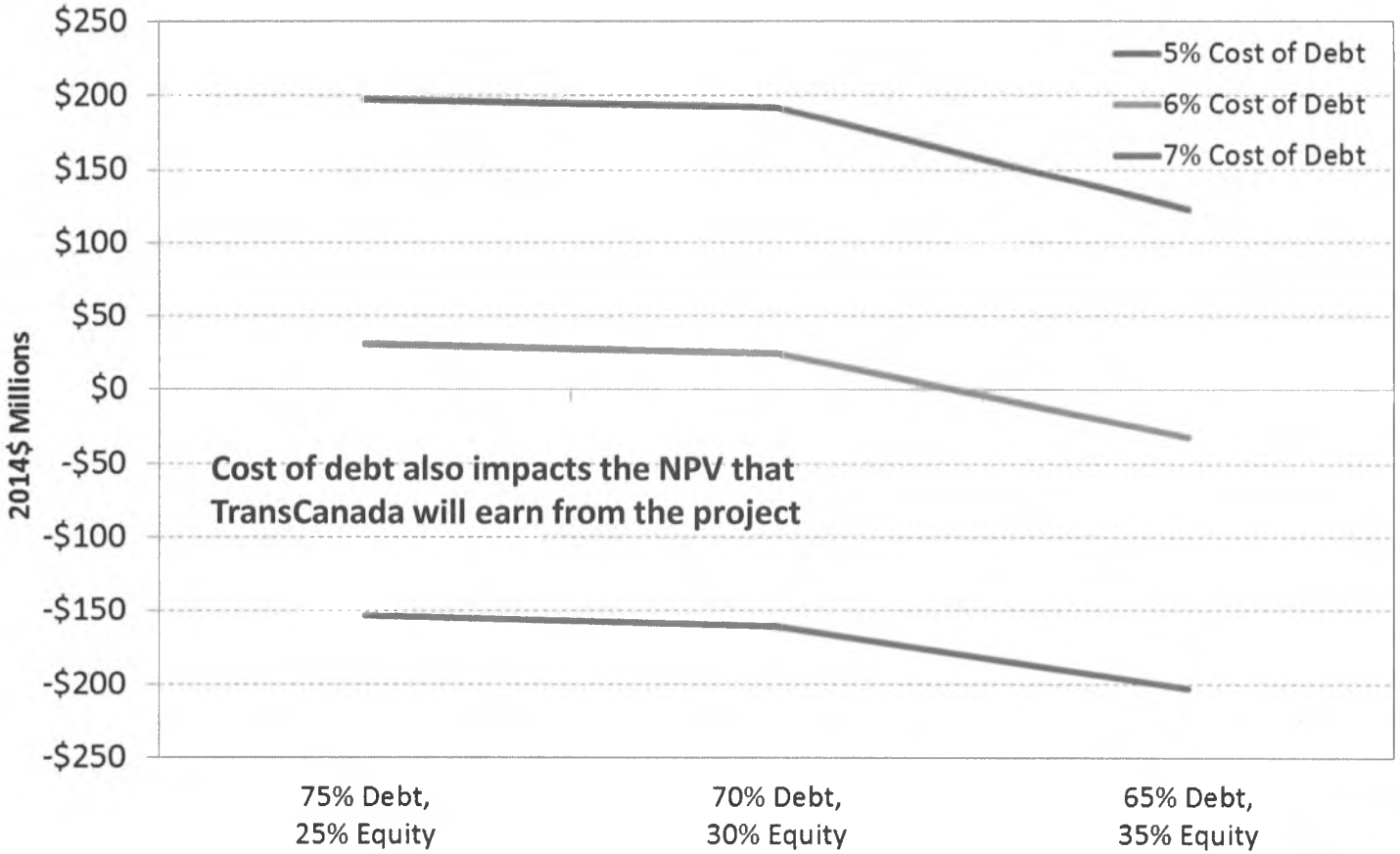
TRANSCANADA EFFECTIVE ROE UNDER DIFFERENT FINANCING ARRANGEMENTS



* Assumes 25% State equity participation without State exercising buy back option

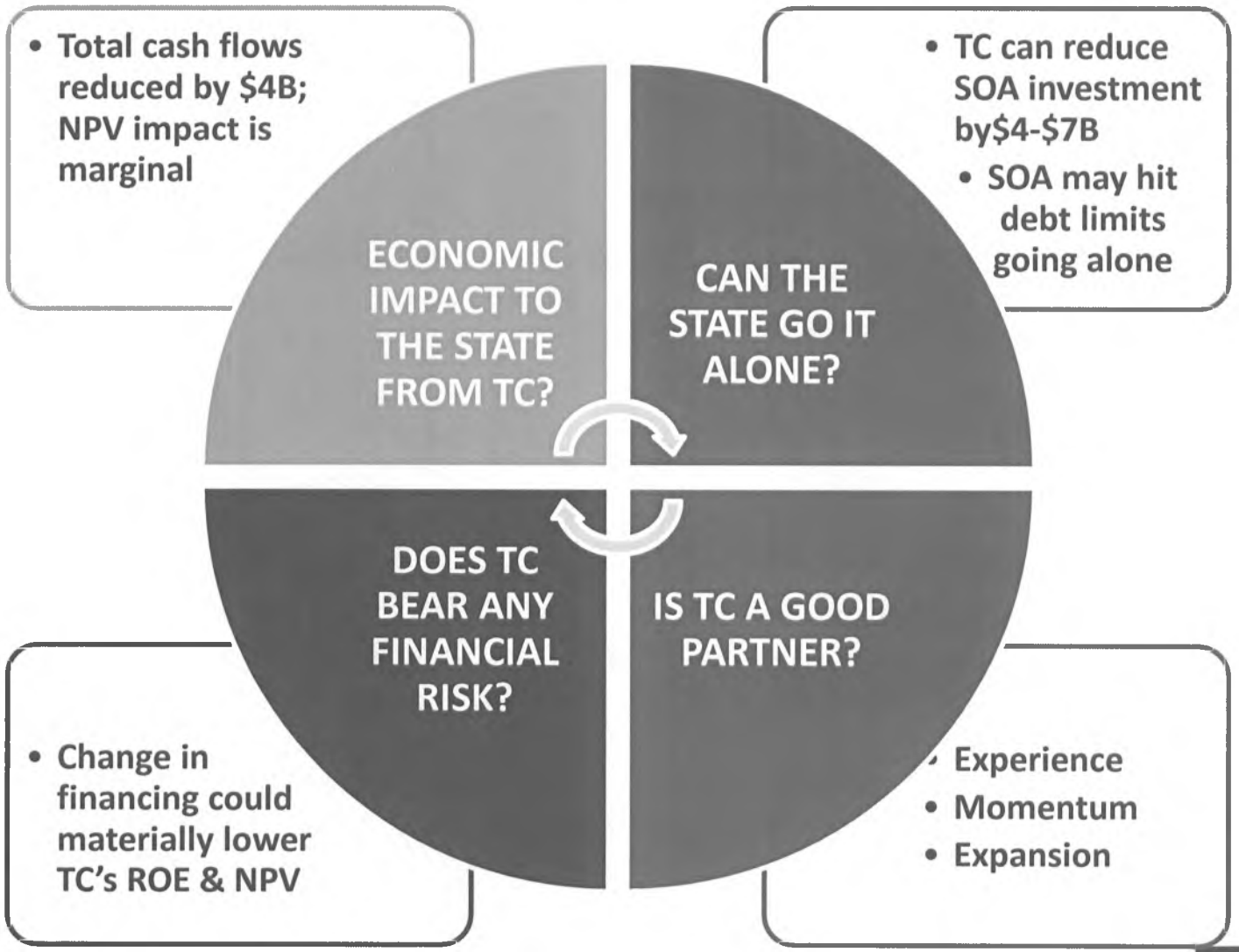
DOES TC BEAR ANY FINANCIAL RISK?

NPV_{10} TO TRANSCANADA FROM AKLNG PROJECT



* Assumes 25% State equity participation without State exercising buy back option

SUMMARY ON 4 KEY QUESTIONS



THANK YOU

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8

COMPETITIVENESS, PROJECT PATHWAY & ALIGNMENT

Prepared for Senate Finance Committee
Juneau, Alaska › February 21, 2014

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Before co-founding *en*alytica, Janak led the Upstream Analytics team at PFC Energy, focusing on fiscal terms analysis and project economic and financial evaluation, data management and data visualization.

Janak has modeled upstream fiscal terms in all of the world's major hydrocarbon regions, and has built economic and financial models to value prospective acquisition targets and develop strategic portfolio options for a wide range of international and national oil company clients. He has advised Alaska State Legislature for multiple years on reform of oil and gas taxation, providing many hours of expert testimony to Alaska's Senate and House Finance and Resources Committees.

Prior to his work as an energy consultant, Janak advised major minerals industry clients on a range of controversial environmental and social risk issues, from uranium mining through to human rights and climate change. He has advised bankers at Citigroup and policy-makers at the US Treasury Department on the management and mitigation of environmental and social impacts in major projects around the world, and has undertaken macroeconomic research with senior development economists at the World Bank and the Peterson Institute for International Economics.

Janak holds an MA with distinction in international relations and economics from from the Johns Hopkins School of Advanced International Studies (SAIS), and a BA with first-class honors from the University of Adelaide, Australia.

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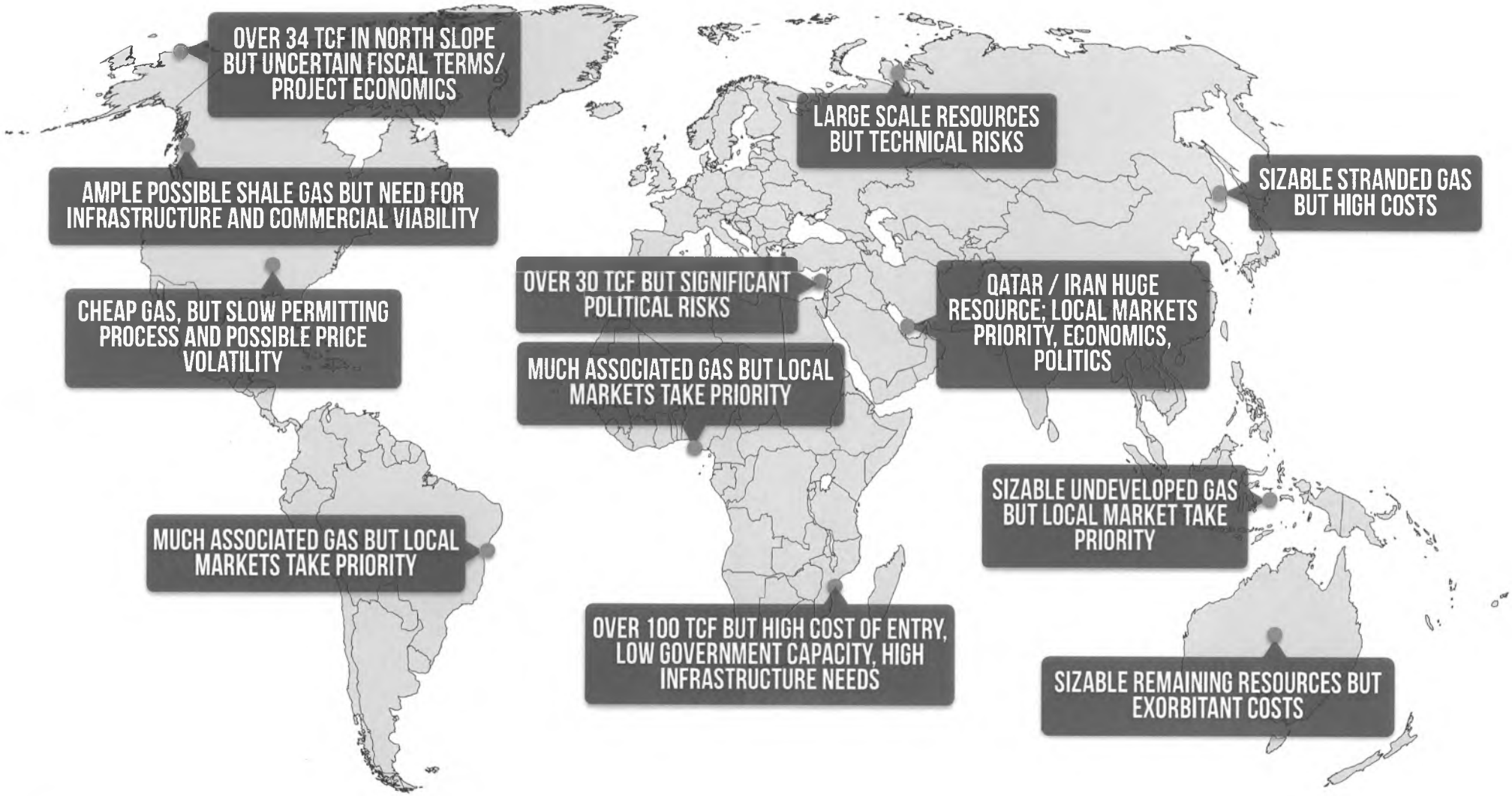
Nikos Tsafos has a diverse background in the private, public and non-profit sectors. He is currently a founding partner at *en*alytica. In his 7 ½ years with PFC Energy, Nikos advised the world's largest oil and gas companies on some of their most complex and challenging projects; he also played a pivotal role in turning the firm into one of the top natural gas consultancies in the world, with responsibilities that included product design, business development, consulting oversight and research direction.

Prior to PFC Energy, Nikos was at the Center for Strategic and International Studies (CSIS) in Washington, DC where he covered political, economic, and military issues in the Gulf, focused on oil wealth, regime stability and foreign affairs. Before CSIS, he was in the Greek Air Force, and prior to his military service, Nikos worked on channeling investment from Greek ship-owners to Chinese shipyards.

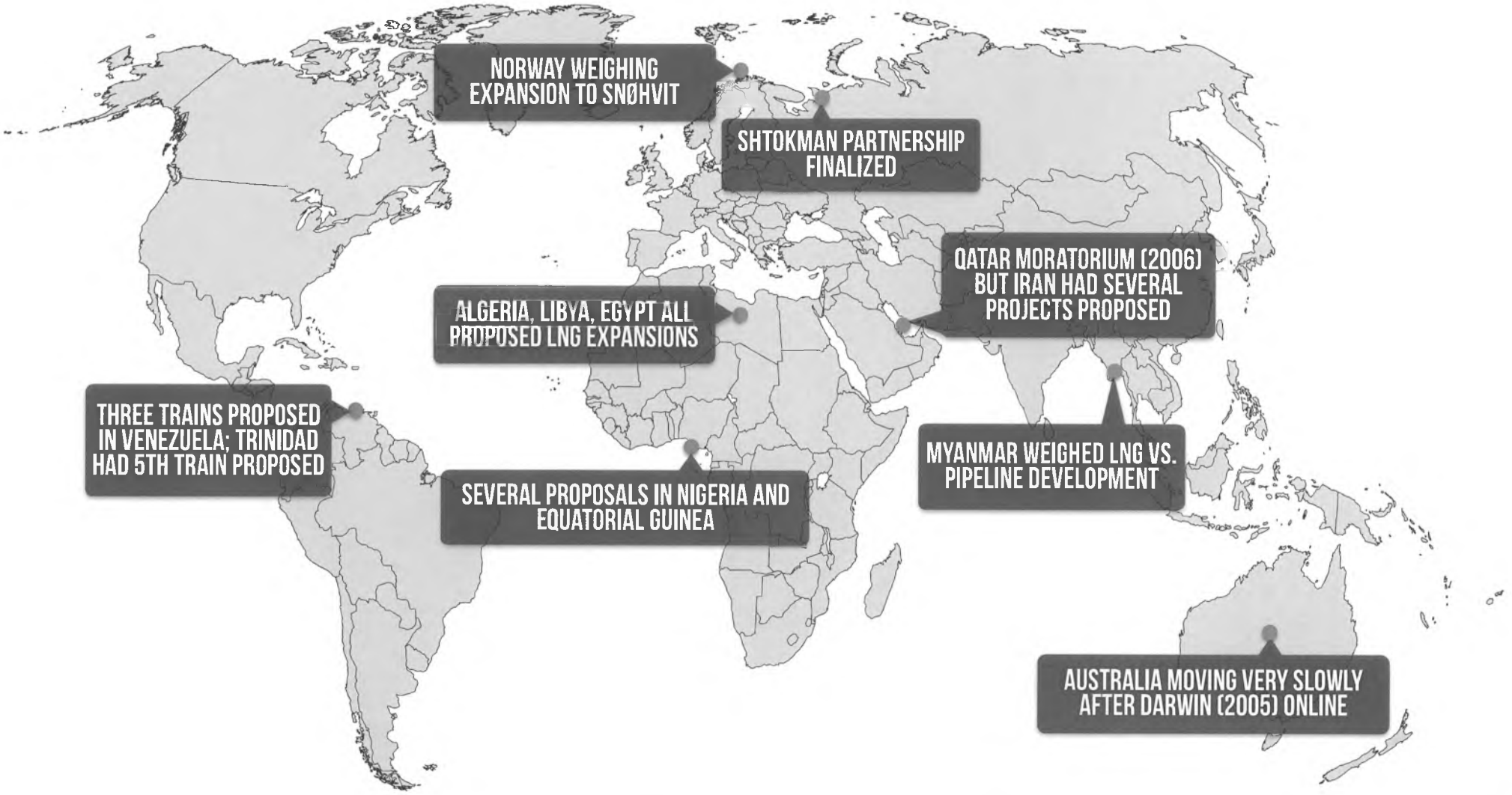
Nikos has also written extensively on the domestic and international dimensions of the Greek debt crisis. His blog (Greek Default Watch) was listed as one of "Europe's Top Economic Blogs" by the Social Europe Journal, and his book "Beyond Debt: The Greek Crisis in Context" was published in March 2013.

Nikos holds a BA with distinction in international relations and economics from Boston University and an MA with distinction in international relations from the Johns Hopkins School of Advanced International Studies (SAIS).

AK LNG IS COMPETING IN A WORLD WITH MANY CHOICES



BUT WE'VE BEEN HERE BEFORE IN THE MID/LATE 2000S



LNG PROJECTS EVOLVE: QC LNG (AUSTRALIA) CASE STUDY

	FEED (JULY 2008)	FID (OCTOBER 2010)	JANUARY 2014
Size	One train: 3-4 mmtpa Expandable to 12 mmtpa	Two trains 8.5 mmtpa	Two trains 8.5 mmtpa
Upstream	BG owned 9.9% of QGC and 20% of QGC's coal-bed methane in Surat Basin	All BG except CNOOC 5% and Tokyo Gas 1.25% in parts of Surat Basin	Gas from AP LNG; Same as FID plus CNOOC 25% in Surat and Bowen Basin
Liquefaction	T1: BG 70%, QGC 30%	T1: BG 90%, CNOOC 10% T2: BG 97.5%, Tokyo Gas 2.5%	T1: BG 50%, CNOOC 50% T2: BG 97.5%, Tokyo Gas 2.5% T3: CNOOC option for 25%
Off-take*	BG Group: 100%	CNOOC: 3.6 mmtpa* Tokyo Gas: 1.2 mmtpa* BG Group: balance	CNOOC: 8.6 mmtpa* Tokyo Gas: 1.2 mmtpa* Chubu Electric: ~0.6 mmtpa*
External Financing			JBIC: 175 mn to Tokyo Gas US EX-IM: $1.8 billion

** Off-take is supplemented by BG's global portfolio—not all LNG will come from Australia*

SOURCE: BG GROUP DATABOOK 2008—2013 EDITIONS, INDUSTRY PRESS

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Project Stage	Pre-FEED			FEED				Construction				Online	
Project Milestones	Move to FEED			FID								Debottleneck / expansion	
Marketing	MOU/HOA SOA Plan			HOA/SPAs SOA Plan				SPAs for any unsold LNG					
Financing	Initial talks			Defining terms / singing loans				Possible additional financing				Refinance	
Project Structure & Ownership	Define initial structure			New partners / redefine ownership				New partners / redefine ownership				New partners possible	
Investment (Project)	$400–$500 mm			$1,500–$2,000 mm (Equity)				$45–65 billion (Debt and equity)				O&M Met from cash flow	
Investment (SOA)	$50–$125 mm			$200–$500 mm (Equity)				$6–$15 billion (Debt and equity)				O&M Met from cash flow	

	System	SOA ownership percent			SOA share of CAPEX & OPEX			SOA cash commitments	
	Value / Kind	Upstream	GTP & Pipe	LNG	Upstream	GTP & Pipe	LNG	Debt	Tariffs
Status Quo	in value	0%	0%	0%	Indirect (taxes)	0%	0%	No debt	Tariff matters for valuation
HOA	in kind	0%	25%	25%	Indirect (taxes)	25%	25%	Principal and interest	Tariff only notional
MOU Option 1	in kind	0%	10% (40% x 25%)	25%	Indirect (taxes)	10% (40% x 25%)	25%	Principal and interest	Tariff payable to T/C
MOU Option 2	in kind	0%	0%	25%	Indirect (taxes)	0%	25%	Principal and interest	Tariff payable to T/C

FY 2015 PRODUCTION TAX ESTIMATE USING INCOME STATEMENT FORMAT

	Price	Barrels (Thousands)	Value ($ million)
Avg ANS Oil Price ($/bbl) & Daily Production	$105.06	498	$52.4
Annual Production			
Total		181,912	$19,111.7
Royalty, Federal & other barrels		(23,301)	($2,448.0)
Taxable bbls from companies w/ tax liability		158,611	$16,663.7
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transporation	($3.46)		
TAPS Tariff	($6.18)		
Other	($0.40)		
Total Transportation Costs	($10.03)	158,611	($1,591.0)
Deductable Lease Expenditures			
Deductible Operating Expenditures	($17.91)		($2,840.3)
Deductible Capital Expenditures	($28.08)		($4,453.4)
Total Lease Expenditures	($45.99)	158,611	($7,293.7)
Production Tax			
Gross Value Reduction			($63.8)
Production Tax Value (PTV)	$48.64		$7,715.2
Base Tax (35%*PTV)			$2,700.3
Total Tax before credits			$2,700.3

SOURCE: DEPARTMENT OF REVENUE, REVENUE SOURCES BOOK, FALL 2013, P. 106

OIL VALUE CHAIN

Oil ~$105/bbl

Midstream costs ~$10/bbl

Lease expenditures $46/bbl

Production tax on ~$49/bbl netback

FY 2015 PRODUCTION TAX ESTIMATE USING INCOME STATEMENT FORMAT

	Price	Barrels (Thousands)	Value ($ million)
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SOURCE: DEPARTMENT OF REVENUE, REVENUE SOURCES BOOK, FALL 2013, P. 106

PRICE FOR ALASKAN GAS WILL BE:

Less transparent

no readily available published price like ANS WC

Less consistent by destination

contract-by-contract differences can be large

Likely link to Japan Crude Oil Cocktail, JCC

in 2004-2013, JCC traded at $0.22/bbl discount to ANS

Lower value vs. oil (thermal equivalency)

e.g. $100/bbl ≠ $100/boe of LNG

$100/bbl = $78–$90/boe (13%–15% "slope")

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Production Tax			
Gross Value Reduction			($63.8)
Production Tax Value (PTV)	$48.64		$7,715.2
Base Tax (35%*PTV)			$2,700.3
Total Tax before credits			$2,700.3

SOURCE: DEPARTMENT OF REVENUE, REVENUE SOURCES BOOK, FALL 2013, P. 106

MIDSTREAM COSTS WILL BE:

Order of magnitude higher

Gas is significantly more expensive to transport

Tariff not regulated by FERC

FERC will regulate permitting, not rate-setting

Tariff highly sensitive to capital structure

return on equity and /or assumed debt/equity ratio

INDICATIVE TAX BEFORE CREDITS FOR ALASKA LNG PROJECT @ ANS

	Price	Barrels (Thousands)	Value ($ million)
Avg LNG Price ($/boe) & Daily Production	$81.00	384	$31.1
Annual Production			
Total		140,306	$11,364.8
Royalty, Federal & other barrels		(19,643)	($1,591.1)
Taxable bbls from companies w/ tax liability		120,664	$9,773.8
Downstream (Transportation) Costs ($/boe)			
Marine Transporation	($6.00)		($724.0)
Pipeline & GTP Tariff	($24.18)		($2,917.6)
Liquefaction Tariff	($36.00)		($4,343.9)
Total Transportation Costs	($66.18)	120,664	($7,985.5)
Deductable Lease Expenditures			
Deductible Operating Expenditures	($3.00)		($362.0)
Deductible Capital Expenditures	($3.00)		($362.0)
Total Lease Expenditures	($6.00)	120,664	($724.0)
Production Tax			
Gross Value Reduction			$0.0
Production Tax Value (PTV)	$8.82		$1,064.3
Base Tax (35%*PTV)			$372.5
Total Tax before credits			$372.5

SOURCE: ENALYTICA ANAL OF REVENUE, REVENUE SOURCES BOOK, FALL 2013, P. 106

INDICATIVE LNG CHAIN: $100/BBL

At $100/bbl, LNG price ~$81/boe (13.5%)

Midstream ~$66/boe

Upstream ~$6/boe

Limited netback to tax (less than $9/boe)

INDICATIVE TAX BEFORE CREDITS FOR ALASKA LNG PROJECT @ ANS

	Price	Barrels (Thousands)	Value ($ million)
Avg LNG Price ($/boe) & Daily Production	$72.18	384	$27.7
Annual Production			
Total		140,306	$10,127.3
Royalty, Federal & other barrels		(19,643)	($1,417.8)
Taxable bbls from companies w/ tax liability		120,664	$8,709.5
Downstream (Transportation) Costs ($/boe)			
Marine Transporation	($6.00)		($724.0)
Pipeline & GTP Tariff	($24.18)		($2,917.6)
Liquefaction Tariff	($36.00)		($4,343.9)
Total Transportation Costs	($66.18)	120,664	($7,985.5)
Deductable Lease Expenditures			
Deductible Operating Expenditures	($3.00)		($362.0)
Deductible Capital Expenditures	($3.00)		($362.0)
Total Lease Expenditures	($6.00)	120,664	($724.0)
Production Tax			
Gross Value Reduction			$0.0
Production Tax Value (PTV)	$0.00		$0.0
Base Tax (35%*PTV)			$0.0
Total Tax before credits			$0.0

INDICATIVE LNG CHAIN: $89/BBL ANS

A drop to $89/bbl ANS ...

... wipes out any production tax value

INDICATIVE TAX BEFORE CREDITS FOR ALASKA LNG PROJECT @ ANS

	Price	Barrels (Thousands)	Value ($ million)
Avg LNG Price ($/boe) & Daily Production	$81.00	384	$31.1
Annual Production			
Total		140,306	$11,364.8
Royalty, Federal & other barrels		(19,643)	($1,591.1)
Taxable bbls from companies w/ tax liability		120,664	$9,773.8
Downstream (Transportation) Costs ($/boe)			
Marine Transporation	($6.73)		($812.4)
Pipeline & GTP Tariff	($27.13)		($3,274.2)
Liquefaction Tariff	($40.40)		($4,874.7)
Total Transportation Costs	($74.27)	120,664	($8,961.3)
Deductable Lease Expenditures			
Deductible Operating Expenditures	($3.37)		($406.2)
Deductible Capital Expenditures	($3.37)		($406.2)
Total Lease Expenditures	($6.73)	120,664	($812.4)
Production Tax			
Gross Value Reduction			$0.0
Production Tax Value (PTV)	$0.00		$0.0
Base Tax (35%*PTV)			$0.0
Total Tax before credits			$0.0

INDICATIVE LNG CHAIN: HIGHER COSTS

A 12.2% hike in costs / tariffs

... wipes out any production tax value

INDICATIVE TAX BEFORE CREDITS FOR ALASKA LNG PROJECT @ ANS

	Price	Barrels (Thousands)	Value ($ million)
Avg LNG Price ($/boe) & Daily Production	$81.00	384	$31.1
Annual Production			
Total		140,306	$11,364.8
Royalty, Federal & other barrels		(19,643)	($1,591.1)
Taxable bbls from companies w/ tax liability		120,664	$9,773.8
Downstream (Transportation) Costs ($/boe)			
Marine Transporation	($6.00)		($724.0)
Pipeline & GTP Tariff	($24.18)		($2,917.6)
Liquefaction Tariff	($36.00)		($4,343.9)
Total Transportation Costs	($66.18)	120,664	($7,985.5)
Deductable Lease Expenditures			
Deductible Operating Expenditures	($3.00)		($362.0)
Deductible Capital Expenditures	($3.00)		($362.0)
Total Lease Expenditures	($6.00)	120,664	($724.0)
Production Tax			
Gross Value Reduction			$0.0
Production Tax Value (PTV)	$8.82		$1,064.3
Base Tax (35%*PTV)			$372.5
Total Tax before credits			$372.5

IMPLICATIONS FOR STATE OF ALASKA

Fair market price critical for top line

Midstream, midstream, midstream

Upstream secondary to midstream

Wellhead insufficient to drive state take

http://enalytica.info

*en*alytica

Data. Analytics. Solutions. in Energy

9

The Heads of Agreement and Memorandum of Understanding: *Risks and Benefits*

A Presentation to the Senate Finance Committee

February 24, 2014

Department of Natural Resources

Joe Balash
Commissioner

Department of Revenue

Angela Rodell
Commissioner

Michael Pawlowski
Deputy Commissioner

Guidance Documents & SB 138

Heads of Agreement (HOA)

- Describes roadmap to advance project through phased process.
- Describes understanding and consensus on key terms.

Memorandum of Understanding (MOU)

- Describes agreement to transition from AGIA License to a more traditional commercial relationship.
- Describes key commercial terms for that relationship.

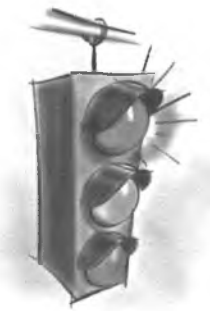
HOA and MOU Describe **how** SB 138 would be used.

Senate Bill 138

Participation *in the AKLNG Project.*

Percentage *of State Gas Share and Participation in the AKLNG Project.*

Process *for development of Project Enabling Contracts and* ***Legislative oversight*** *and* ***approval*** *of future contracts.*



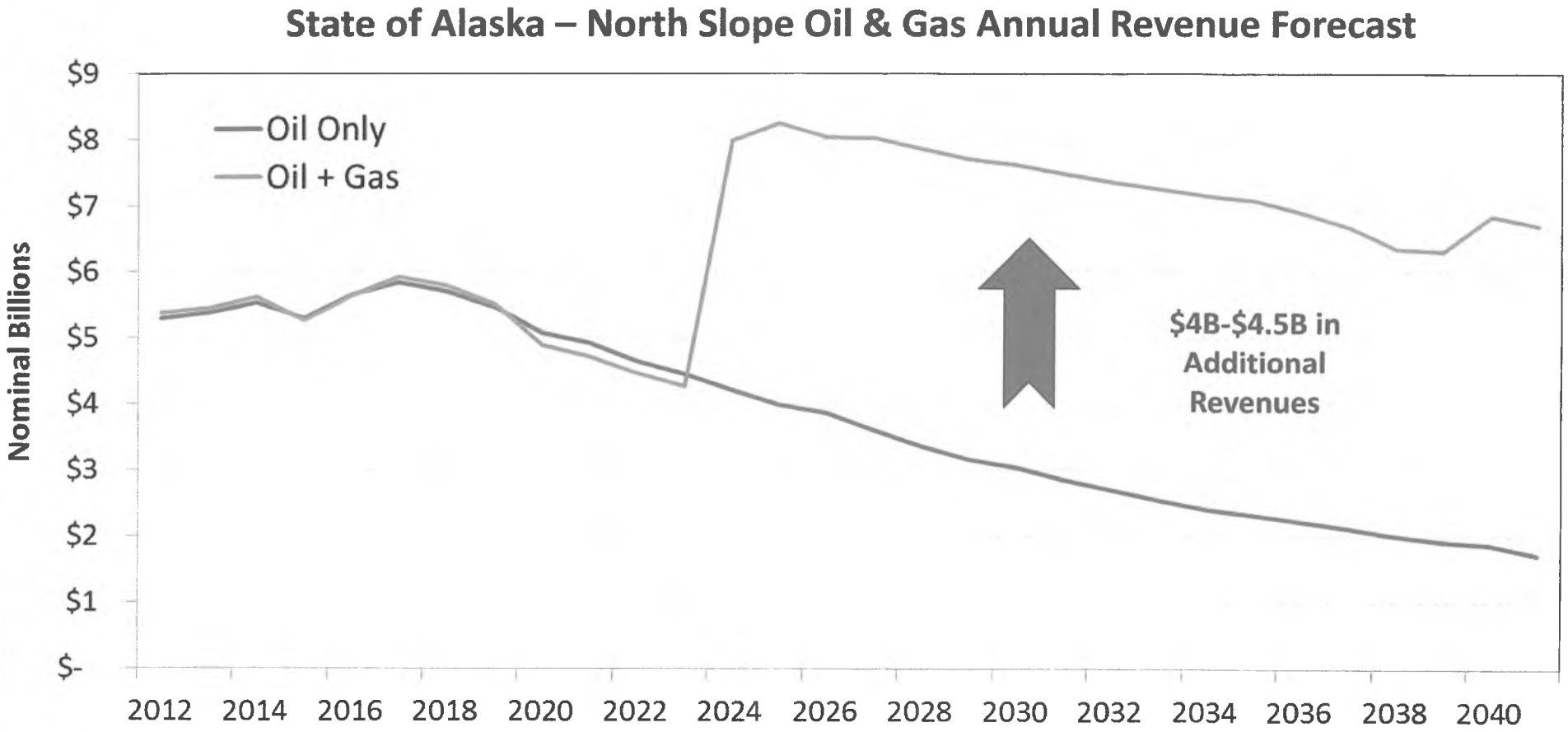
Legislature decides whether to advance or not.

Introduction

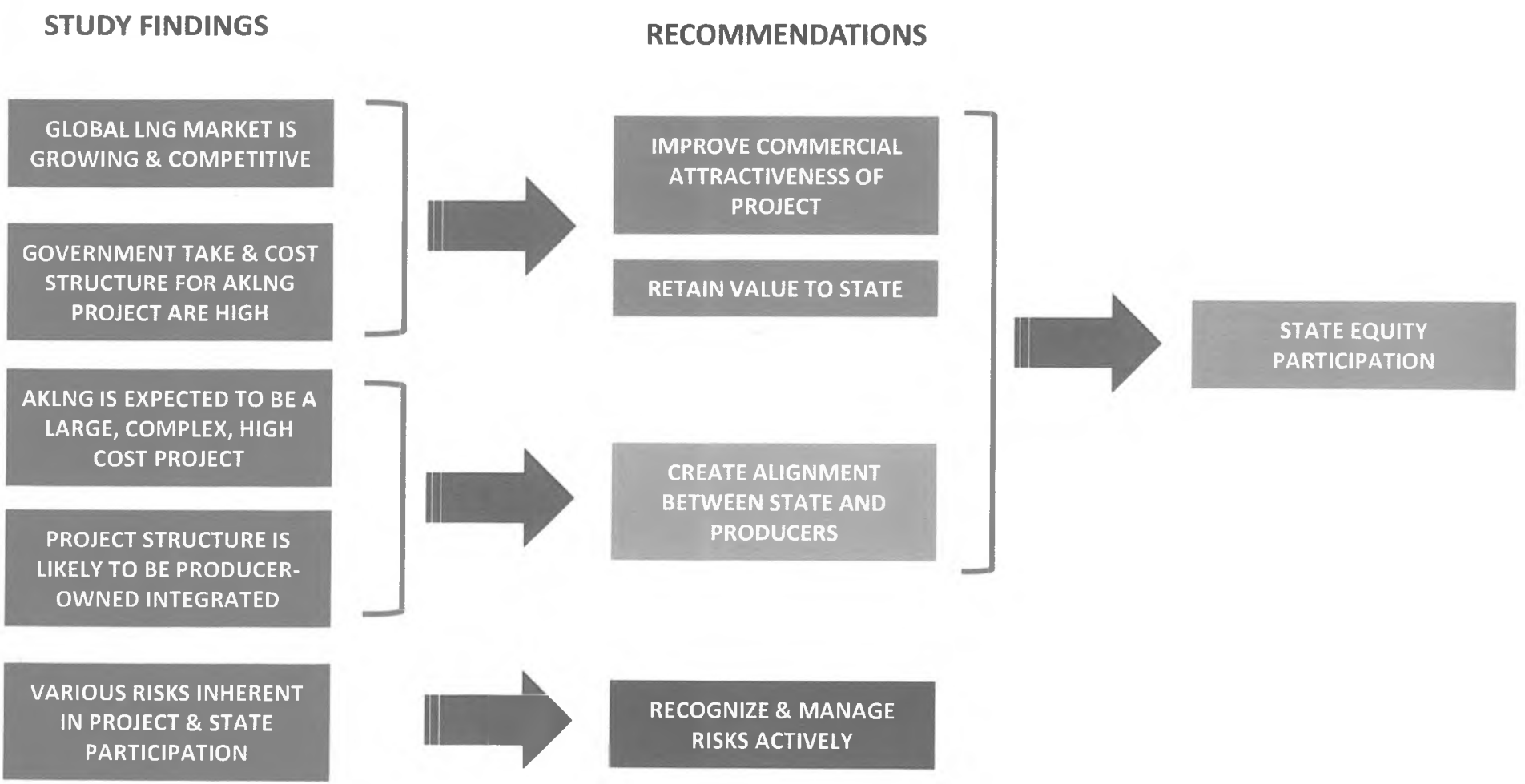
- **Should the State participate in the AK LNG project?**
  - What are some of the benefits?
  - What are some of the risks?
  - Can the risks be mitigated?

- **Should the State partner with TransCanada?**
  - Does partnering with TransCanada advance State interests?
  - What are the risks and benefits of partnering with TransCanada?

LONG-TERM NORTH SLOPE OIL & GAS REVENUES ARE DRIVEN BY AKLNG PROJECT SUCCESS



ROYALTY STUDY HIGHLIGHTS & RECOMMENDATIONS



The HOA:
A Step Toward Mitigating Risks

The Heads of Agreement begins the process of mitigating risks identified in the royalty study by committing the Parties to a phased approach to the project.

Key State concerns are recognized and Parties commit to developing agreements during Pre-FEED and FEED.

- Marketing Risk
- Expansion Principles
- Regulatory Framework and 3rd Parties

January 14, 2014

HEADS OF AGREEMENT

By and Among

THE ADMINISTRATION OF THE STATE OF ALASKA

ALASKA GASLINE DEVELOPMENT CORPORATION

TRANSCANADA ALASKA DEVELOPMENT INC.

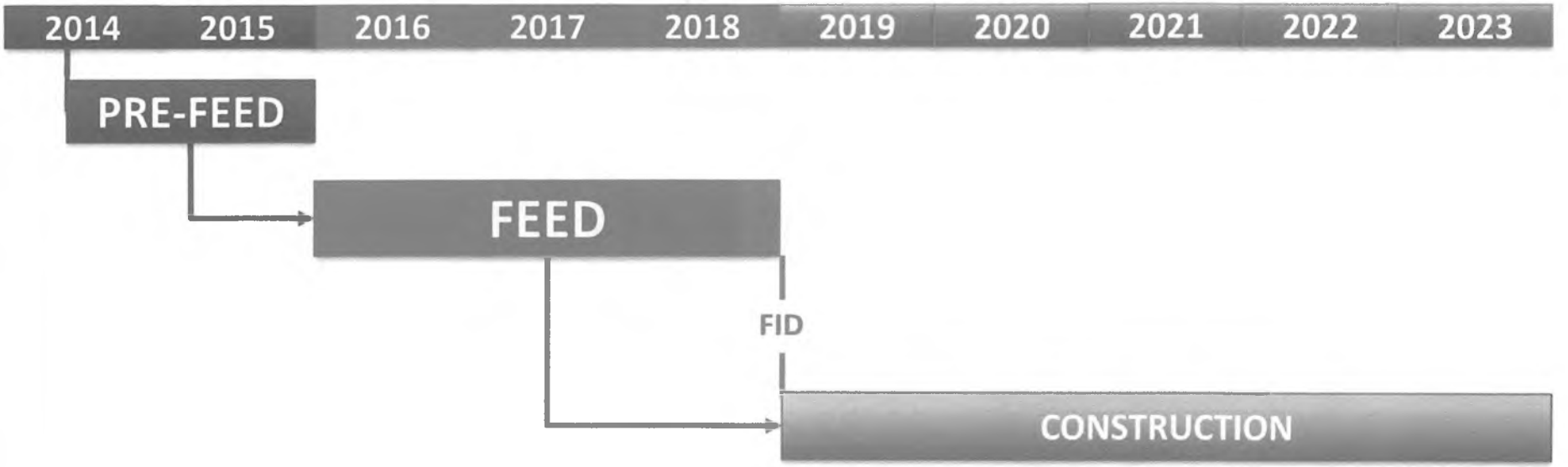
EXXONMOBIL ALASKA PRODUCTION INC.

CONOCOPHILLIPS ALASKA, INC.

BP EXPLORATION (ALASKA) INC.

FOR THE ALASKA LNG PROJECT

PUTTING THE HOA WITHIN THE CONTEXT OF AKLNG TIMELINE



STATE INVESTMENT

$43 - $108 million or ~1% of Total Investment	**$180 - $450 million or ~2%-3% of Total Investment**	**$7 - $13 billion or ~95%-97% of Total Investment**

HOA lays out principles to advance the project to pre-FEED and enter into commercial agreements

HOA: AKLNG Infrastructure Components

In order to understand the context of the proposal, we need to return to the Heads of Agreement (HOA) and State participation in the project as outlined in Articles 5 and 6 of the HOA.

The HOA describes how the Parties intend to cooperate in the joint pursuit of the Alaska LNG project – which is comprised of the PBU and PTU transmission lines, gas treatment plant (GTP), Pipeline, and LNG Plant.

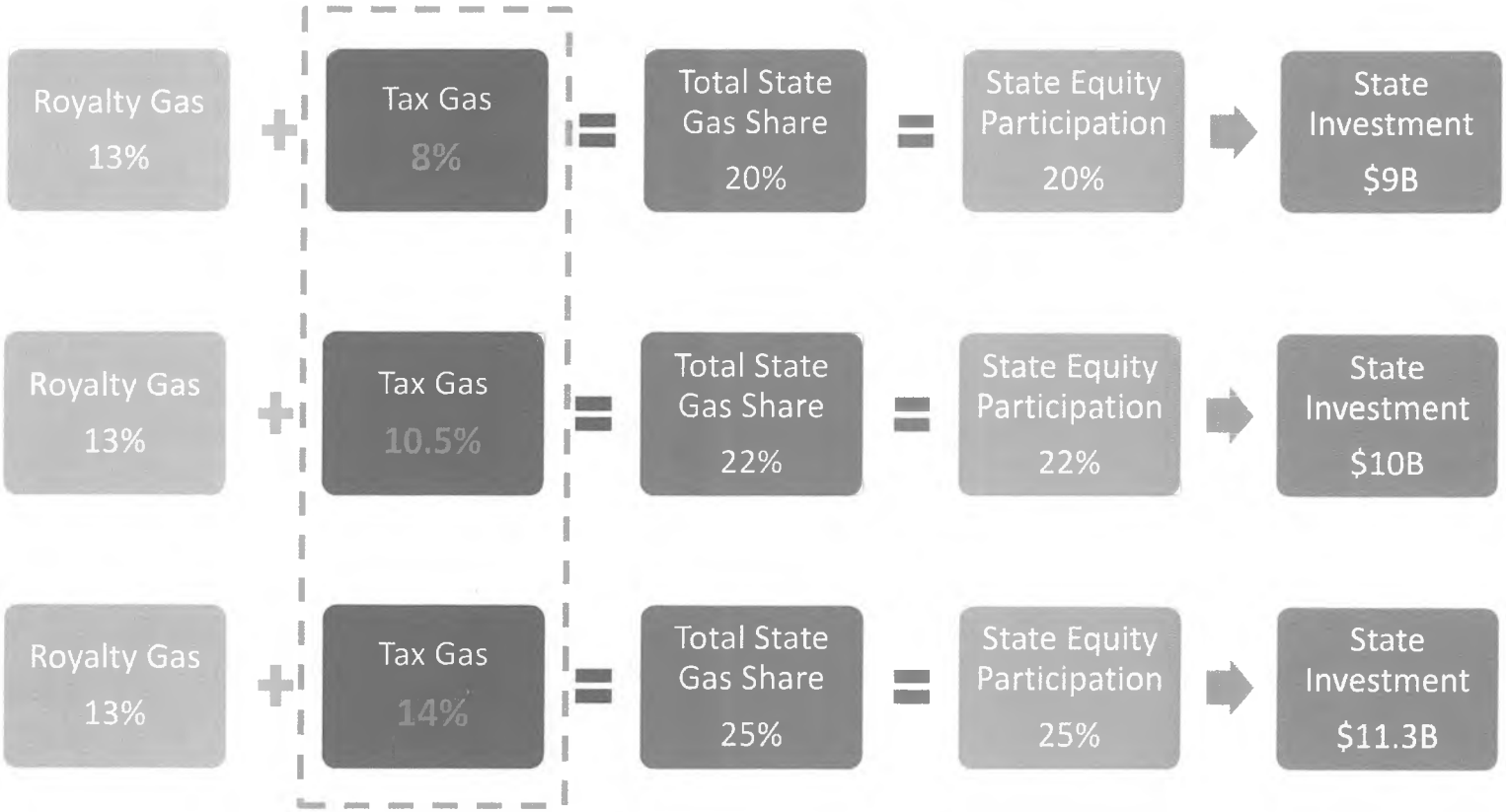
GTP
& Transmission Lines

PIPELINE

LNG Plant

GROSS TAX RATE SETS THE TOTAL STATE GAS SHARE & EQUITY PARTICIPATION

VALUE TO SOA

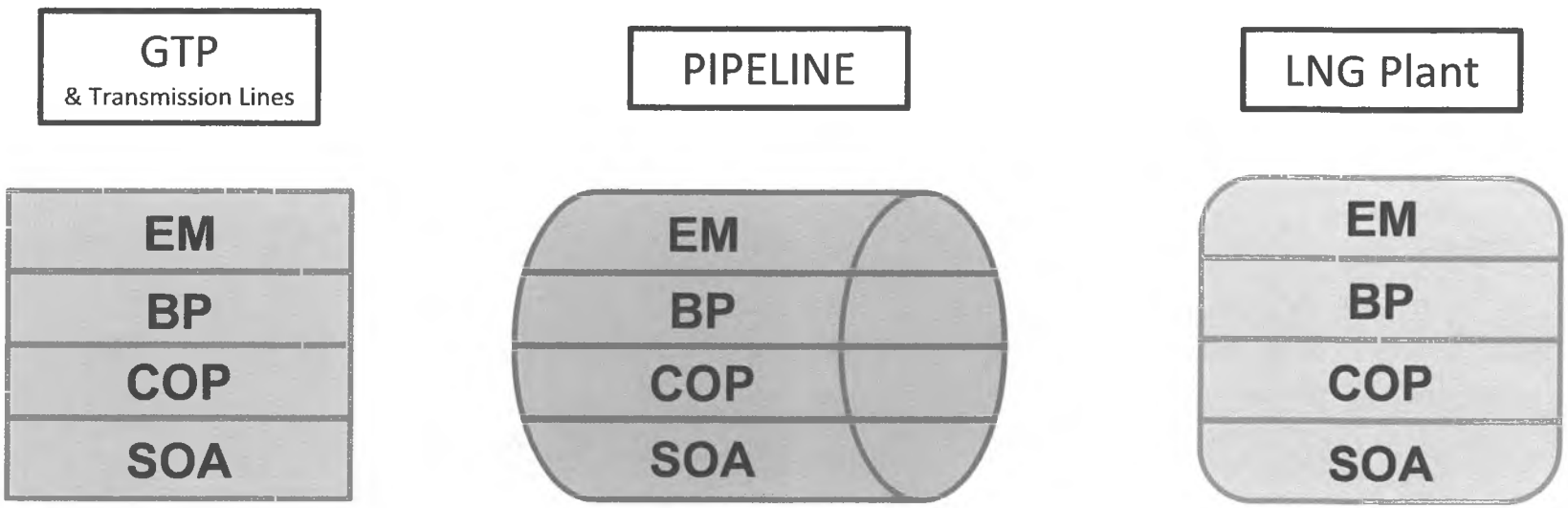


The Heads of Agreement describes this concept.

HOA: Equity Interest in Infrastructure

The overall structure of the HOA contemplates an alignment of the State's tax and royalty interests in the gas with an equity interest in each component of the infrastructure.

Each of the Parties will be responsible for their own financing and set the terms for access to their share of the project.



HOA SCORE CARD RELATIVE TO CRITERIA

Royalty Study Recommendations	How HOA Addresses Recommendation
Alignment Through Equity	Equity Participation Along Supply Chain; Royalty and tax as share of gas
Improve Commercial Attractiveness	Increases Producer IRR Reduces government take through reducing Feds share
Preserve Value to the State	State is NPV and Cash Flow Neutral relative to Status quo
Manage Risks	
Price Exposure	Equity Participation in midstream dampens exposure to prices
Capital Costs	TC participation lowers State's cash calls prior to commercial operation
RIK Marketing	HOA reflects intent of Producers to negotiate to market State's share of gas
Structure of Participation	Project within a project, Stage gated commitments, Access & pro-expansion principles, Access to information

Key Takeaways: Heads of Agreement

- LNG is a significant opportunity for Alaska and Alaskans.
- Phased process with commensurate steps.
- Off-ramps for all Parties.
- Maintains AGDC momentum on Alaska Stand-Alone Pipeline (ASAP).
- Creates opportunities to mitigate State risks identified in royalty study.
- Major risk is **cost** of State participation.

The Memorandum of Understanding

The MOU with TransCanada provides a roadmap for a transition from the AGIA license to a more traditional commercial relationship with TransCanada.

The MOU describes how the State will:

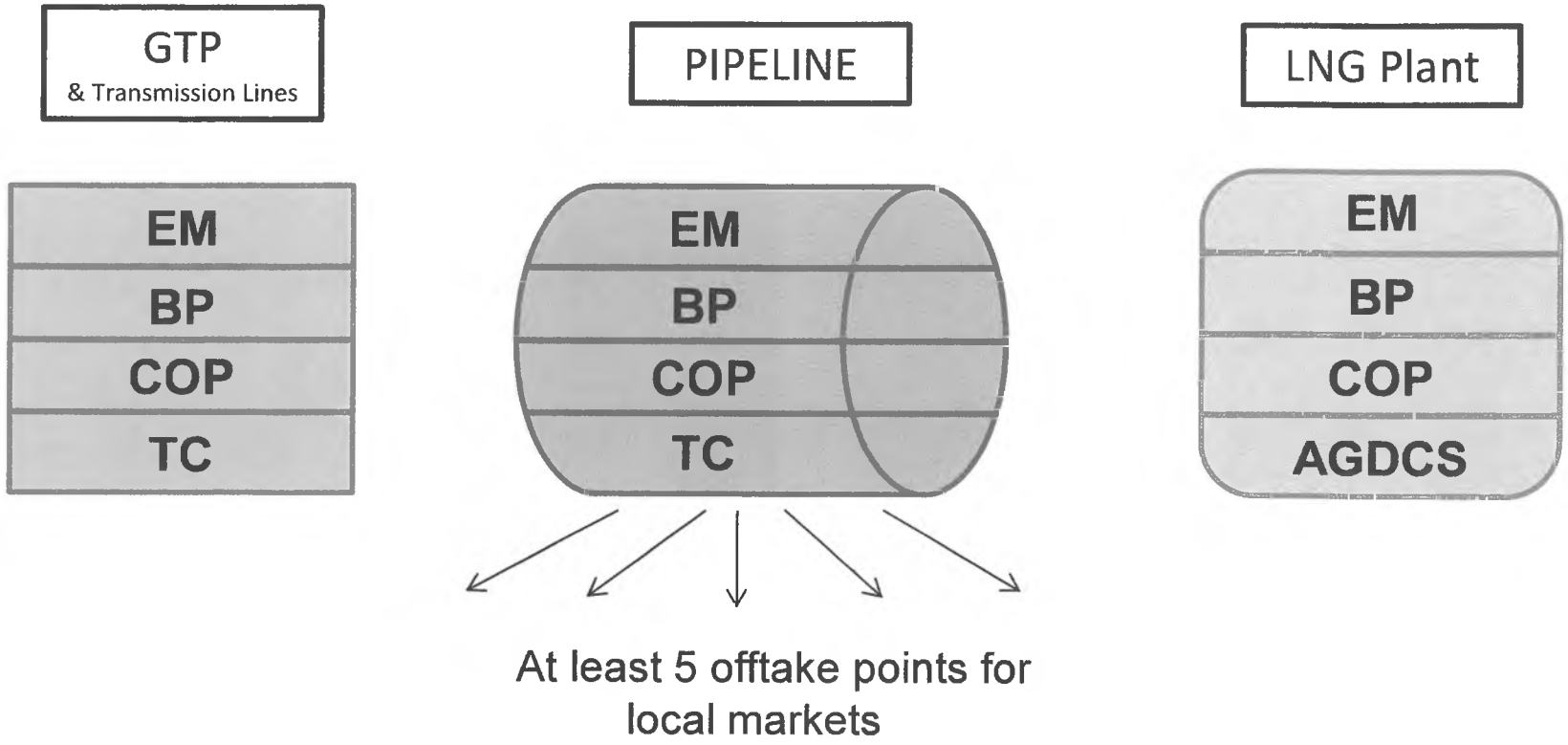
1. Abandon the AGIA license.
2. Partner with TransCanada in the midstream (Transmission lines, GTP and Pipeline) of the AKLNG project.
3. Provide for active interest in expansions.

Key Terms of MOU:

1. Favorable Debt to Equity Ratio
   - 75/25 ratio for rate-making purposes reduces the State's tariff.
   - Lower tariffs improve the State's overall cash flows.
2. Cash Contributions by TransCanada
   - TransCanada as project developer reduces the State's exposure to cash calls and obligations until the pipeline is in service.
3. Improved Value to the Treasury
   - When you consider the opportunity cost of utilizing the State's capital (which earns 6% in the treasury), our NPV is improved overall.
4. Expansions
   - TransCanada committed to 70/30 capital structure for expansions.
5. Gas to Alaskans
   - At least 5 offtake points
   - Distance sensitive rates with three zones for delivery

MOU: Transporting Alaska's Gas:

The MOU details TransCanada's terms of service for transporting Alaska's State Gas Share via the GTP and Pipeline. It is further contemplated that a subsidiary corporation of AGDC will be established to carry the State's interest in the LNG plant.



TransCanada will create an affiliate, TransCanada Alaska Development Inc. ("TADI"), for the AKLNG project

Exhibit B of the MOU:

Contains a term sheet for the State to exercise an equity option up to 40%* of the partnership established by TransCanada for the relevant portion of the midstream.

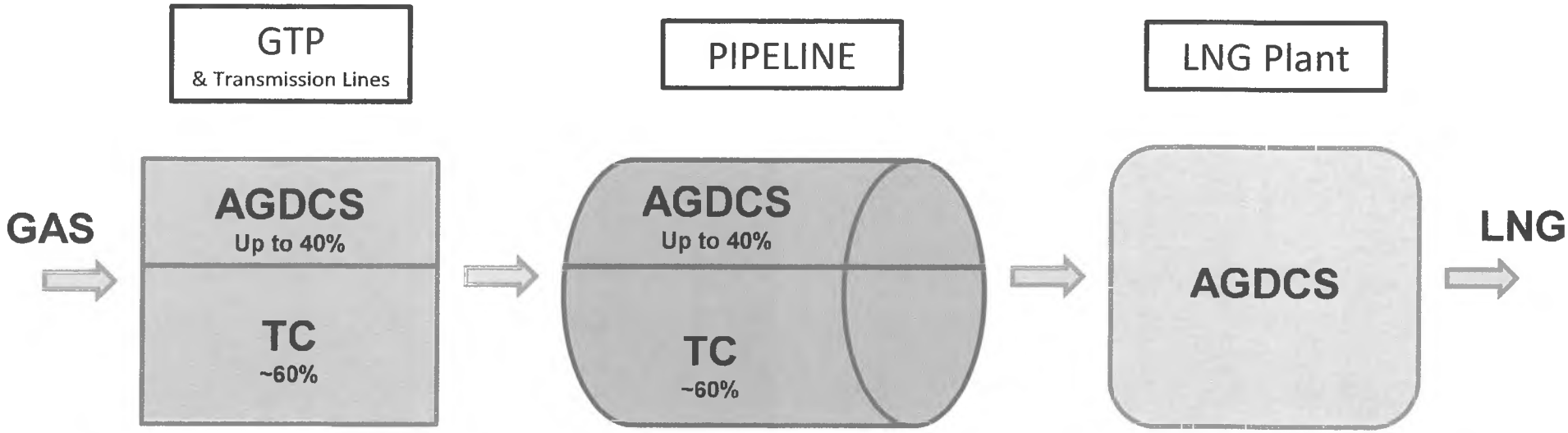
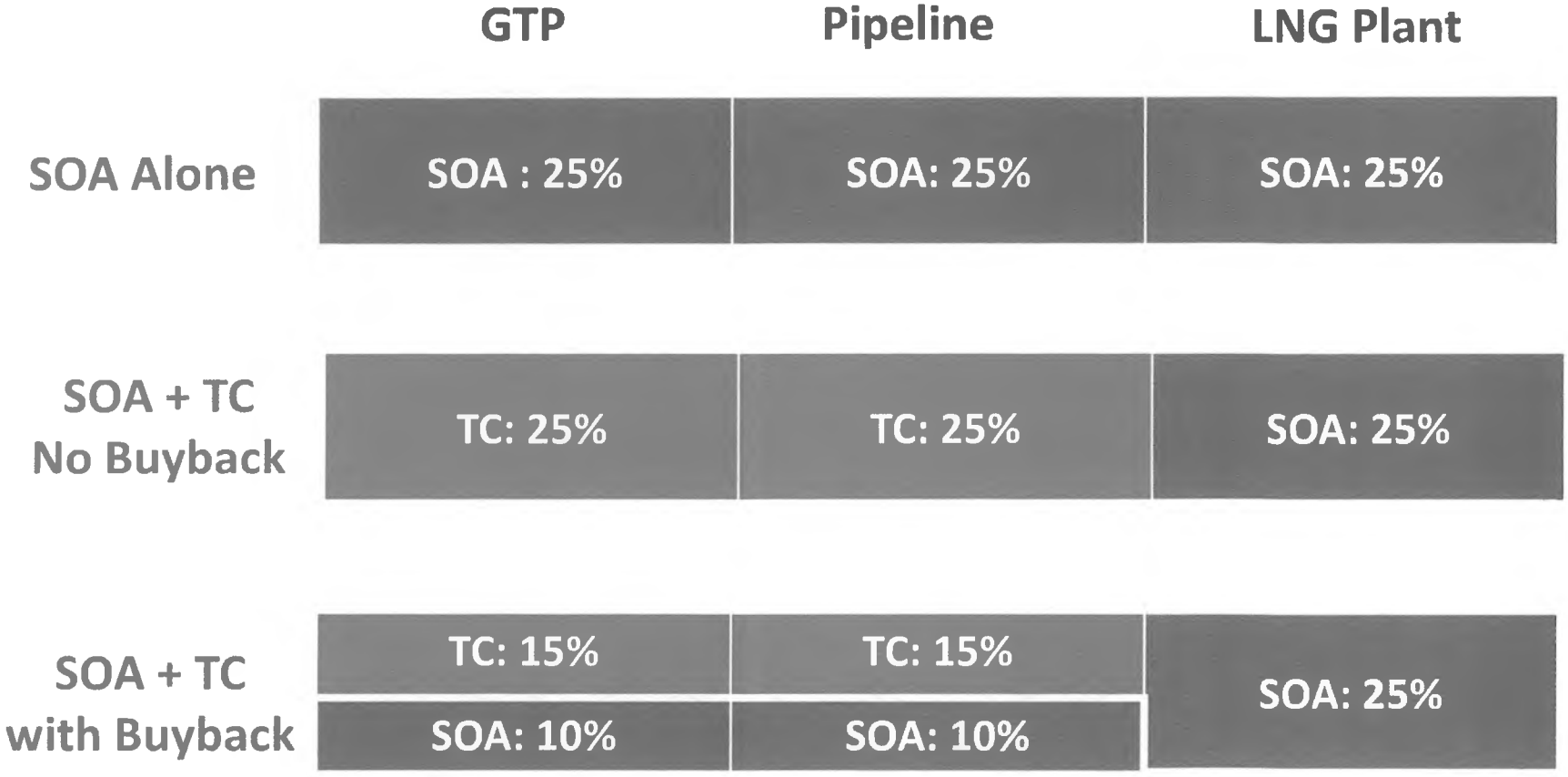


*Exhibit B specifies TransCanada's interest in the midstream components will not be less than 14% of the total (Exhibit B, Page 1).

MOU: Describes how the State will share the responsibility for its share of the project with TransCanada

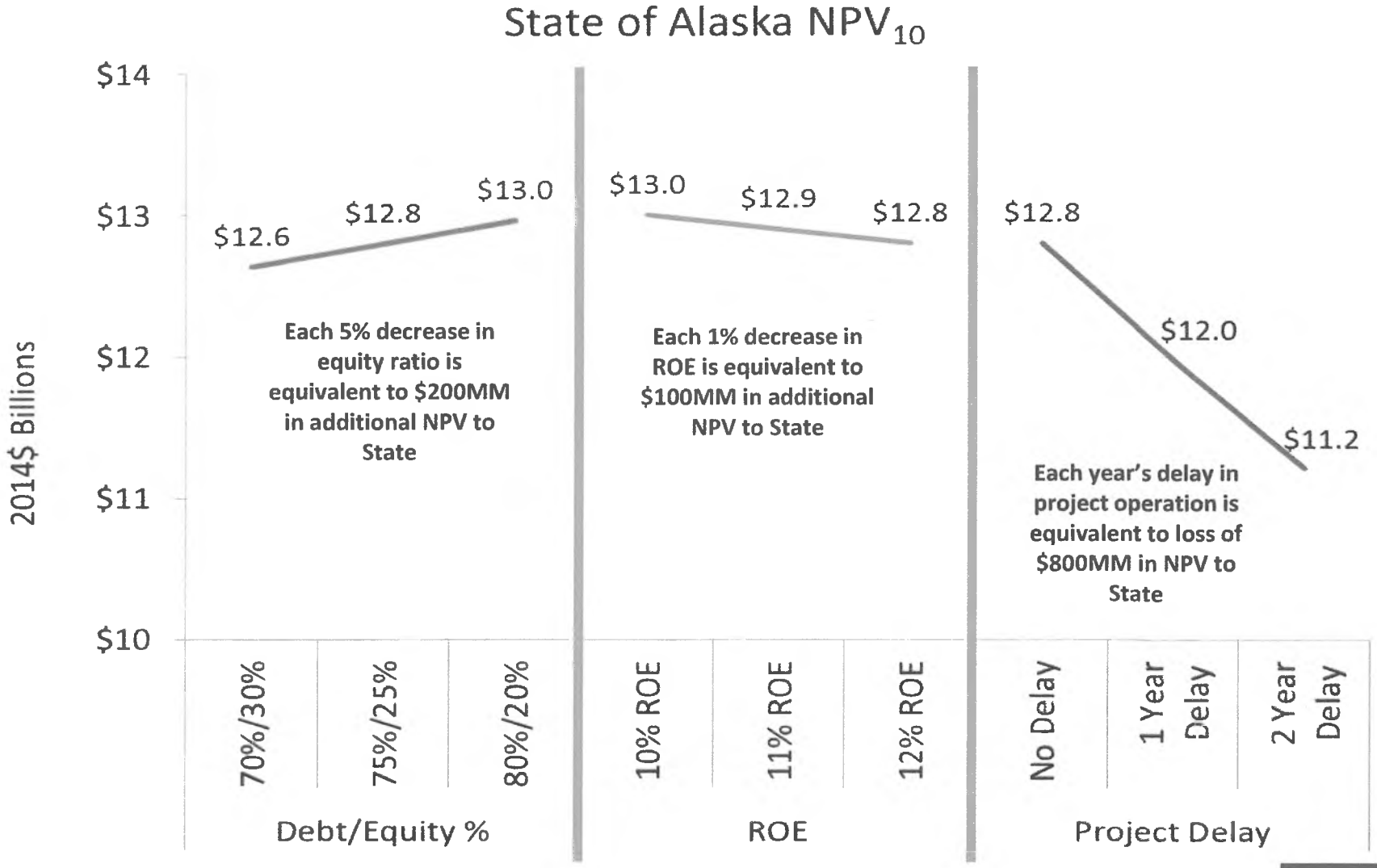


* Assumes 25% State equity participation

Source: Graphics provided by Black & Veatch

RETAINING MOMENTUM ON PROJECT COULD BE MORE VALUABLE THAN SECURING BETTER COMMERCIAL TERMS

TC AS PARTNER

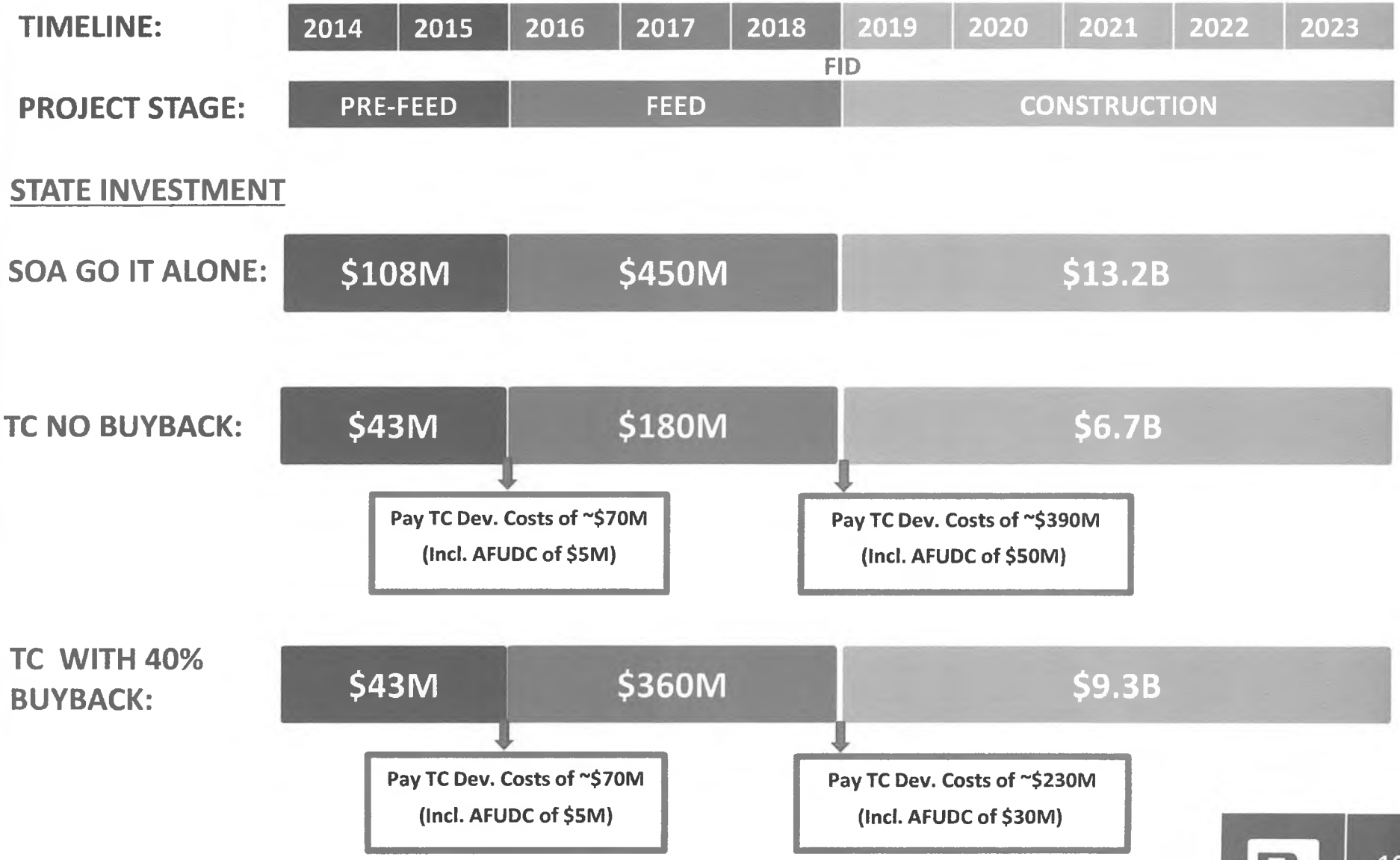


Comparing the Commercial Terms
FERC Certificate Orders
Examples of Approved Capital Structure and Return on Equity ("ROE") for Major New/Expansion Projects (Initial Rates)

Pipeline	Project Description[1]	Capital Structure (Debt/Equity)	ROE
***Bison Pipeline LLC*, 131 FERC ¶ 61,013 (2010)**	Proposal to construct a new 302-mile, 30-inch diameter system from near Gillette, WY to interconnect with Northern Border	50/50	14.00%
***ETC Tiger Pipeline*, LLC, 131 FERC ¶ 61,010 (2010)**	Proposal to construct a new 175-mile, 42-inch diameter system from near Carthage, TX to near Delhi, LA	50/50	14.00%
***Fayetteville Express Pipeline LLC*, 129 FERC ¶ 61,235 (2009)**	Proposal to construct a new 64.3 miles of 42-inch diameter pipeline from Conway County, AR to Panola County, MS	50/50	14.00%
***Florida Gas Transmission Company, LLC*, 129 FERC ¶ 61,150 (2009)**	Proposal to construct 483.2 miles of pipeline expansion facilities and the addition of 213,600 additional compressor HP	60/40	13.00%
***Ruby Pipeline L.L.C*, 128 FERC ¶ 61,224 (2009)**	Proposal to construct new pipeline from the Opal Hub in Lincoln County, Wyoming to an interconnection with PG&E's system at the Oregon/California border (Malin, Oregon)	60/40	14.00%
***Mid-Atlantic Express, L.L.C.*, 126 FERC ¶ 61,019 (2009)**	Proposal to construct new pipeline from the proposed Sparrows Point LNG terminal (Baltimore, MD) to an interconnection with three existing interstate pipelines in Eagle, PA	70/30	14.00%

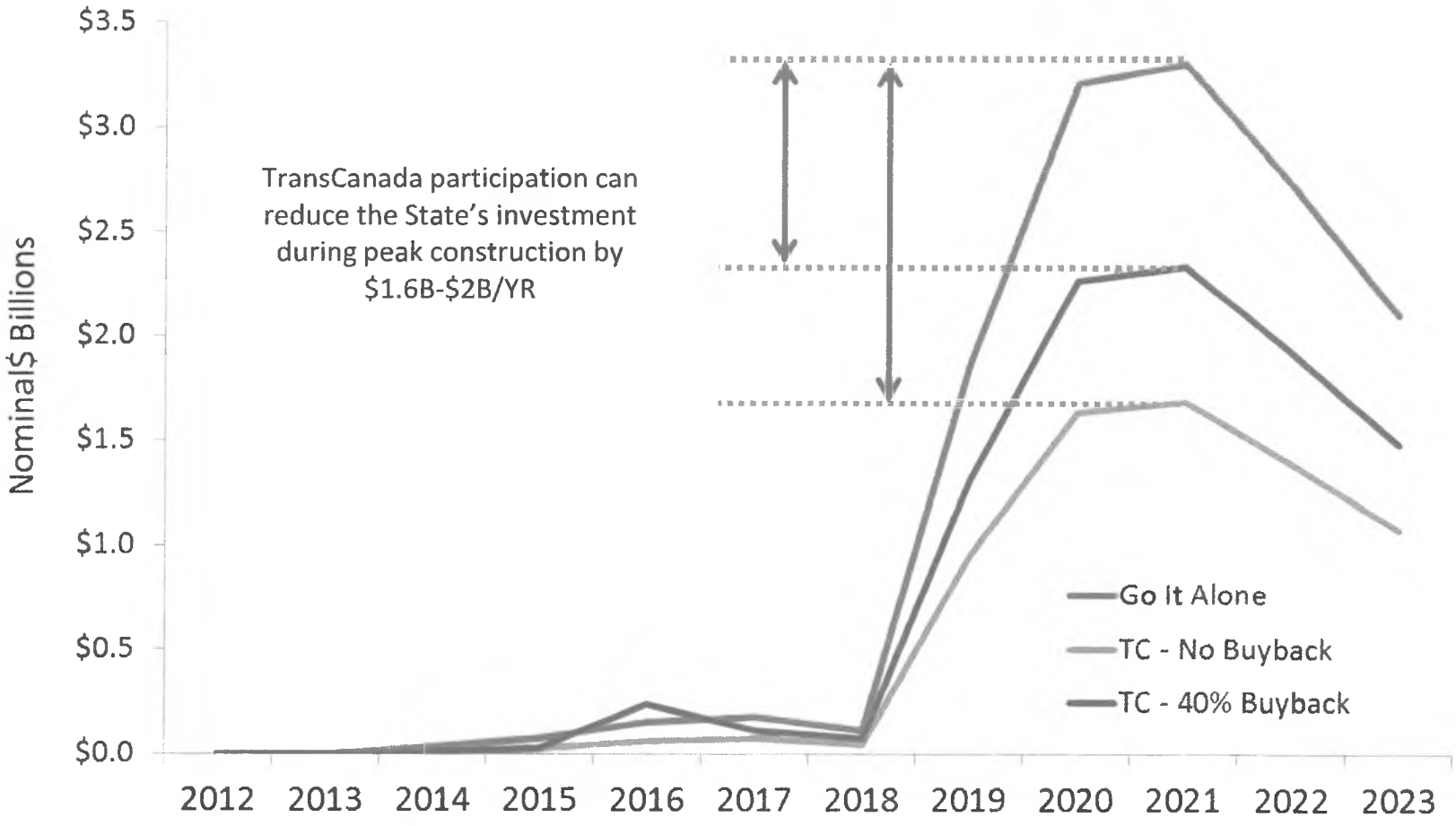
[1] All of the information contained in this chart was derived from the orders cited in the "Pipeline" column.

IMPLICATIONS OF OPTIONS AND POTENTIAL OFF RAMPS



* Assumes 25% State equity participation

The "MOU" Memorandum of Understanding with TransCanada; Partnering to Share Risk



The MOU enables the State to partner with TC to advance key State interests like expansion policy and third party access during Pre-FEED and FEED while sharing risks in the construction phase of the project.

Source: Graphics provided by Black & Veatch

CAN THE STATE GO IT ALONE? - STATE'S DEBT CAPACITY

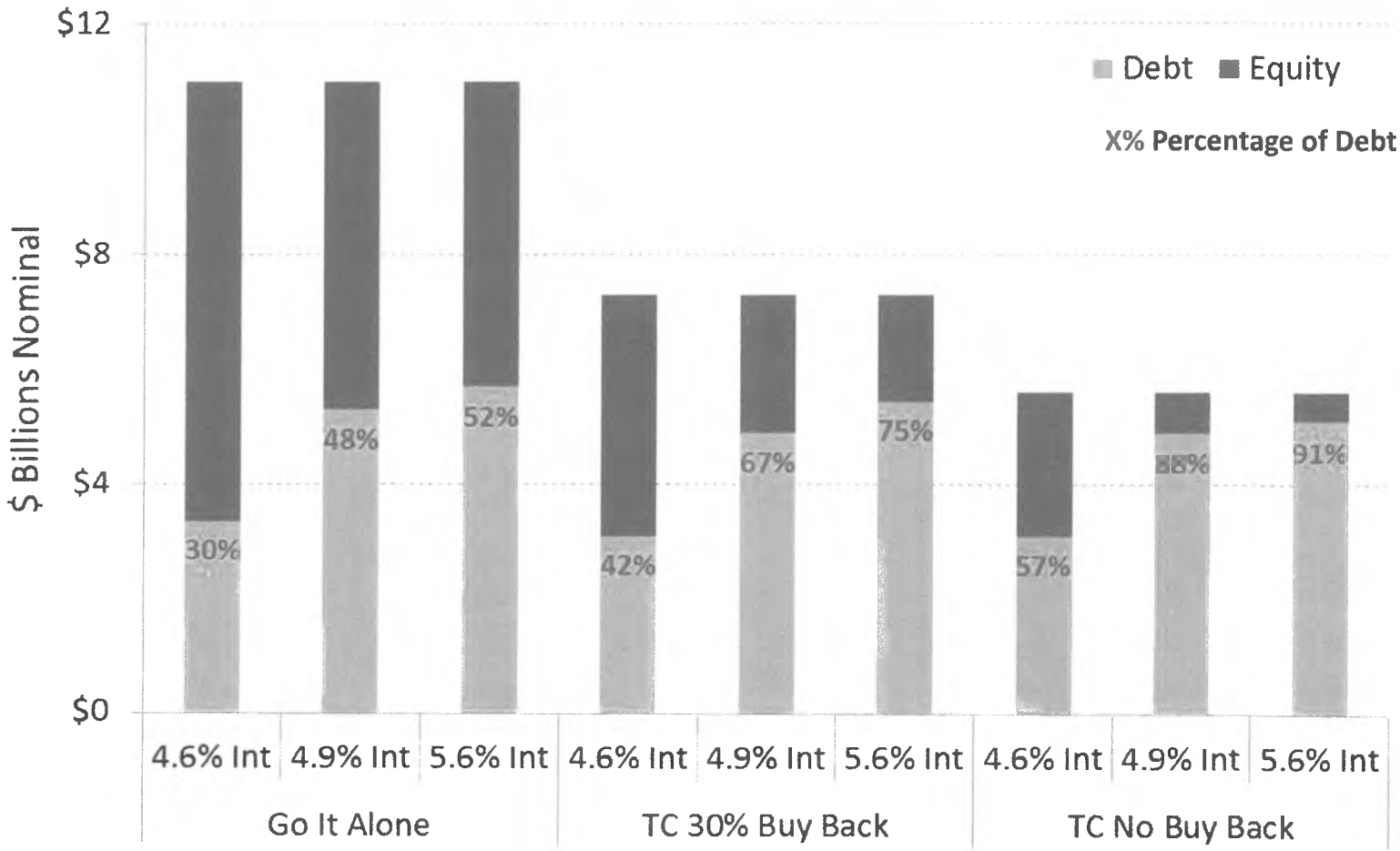
- **Financing the State's share of the AKLNG Project on the State's balance sheet – key issues:**
  - At what cost of debt?
  - Debt servicing as what % of general fund unrestricted revenue?

Scenario 1 (lower interest)	• SOA Debt at 4.6% • Debt Service limited to 3% of GFUR
Scenario 2	• SOA Debt at 4.9% • Debt Service limited to 5% of GFUR
Scenario 3 (higher interest)	• SOA Debt at 5.6% • Debt Service limited to 6% of GFUR

*** High-level, indicative assumptions based on input from Department of Revenue**

THE AMOUNT OF CHEAP DEBT AVAILABLE TO THE STATE COULD BE LIMITED

Indicative Levels of Debt for State to Finance 20% Equity Stake in AKLNG Project



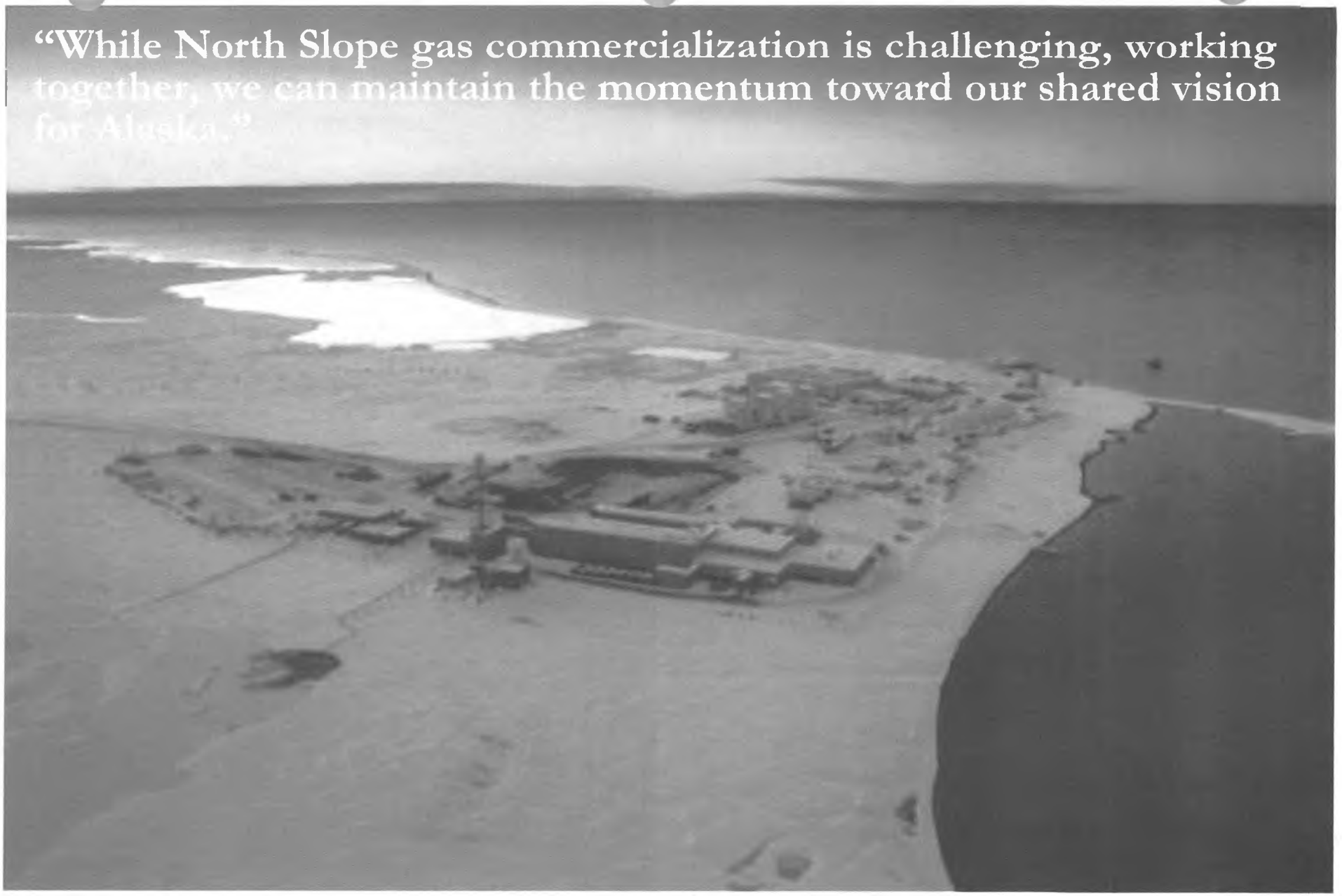
*** Analysis based on high-level, indicative assumptions based on input from Department of Revenue. Financing arrangements for the AKLNG project will become clearer further into the development process.**

Key Takeaways: MOU

- Delays in momentum will generally outweigh gains in commercial terms.
- Partnering with TransCanada:
  - Advances key State interests (expansion & access) during Pre-FEED and FEED.
  - Supports larger State Gas Share by sharing risk in construction.
- Provides transition out of AGIA with passage of enabling legislation.
- Off-ramps exist with TransCanada in MOU.

Summary

- **State participation in the AK LNG project:**
  - Maximizes the value of the State's resources.
  - Improves competitiveness of AK LNG project.
  - Puts State in a position to mitigate risks.
- **Partnering with TransCanada:**
  - Advances key State interests (expansion & access) during Pre-FEED and FEED.
  - Supports larger State Gas Share by sharing risk in construction.
- **Phased process allows all Parties to mitigate risks.**



Source: Letter dated October 1, 2012 to Governor Parnell (Exhibit I-B of HOA)

THANK YOU

Please find our contact information below:

Michael Pawlowski
Deputy Commissioner
Department of Revenue
Michael.Pawlowski@alaska.gov

Joe Balash
Commissioner
Department of Natural Resources
Joe.Balash@alaska.gov

Resources

http://dor.alaska.gov/AKGasDocs.aspx

www.dnr.alaska.gov/AKgas.htm

10

THE STATE of ALASKA
GOVERNOR SEAN PARNELL

Department of Natural Resources
Joe Balash, Commissioner
Department of Revenue
Angela M. Rodell, Commissioner

March 10, 2014

The Honorable Pete Kelly, Co-Chair
The Honorable Kevin Meyer, Co-Chair
Senate Finance Committee
Alaska State Capitol, Room 532
Juneau, AK 99801

Dear Senators Kelly and Meyer:

Please find the following responses to questions, which were asked by committee members during the February 27th hearing on SB 138. Please see questions in italics and our responses immediately below the questions.

Question from Senator Meyer: *What federal taxes would apply to the producers from the gas project and at what rates? What would the total federal take be?*

Federal corporate income tax of 35% would apply to the producers from the AKLNG project. The total federal take is expected to be around 25% under baseline assumptions.

Question from Senator Fairclough: *Sen Fairclough had specific questions on Section 13 of the bill relating to AS 38.05.180(i). Can we confirm that no one had taken advantage of these credits recently? What is the maximum amount of credits obtainable under this particular provision?*

AS 38.05.180(i) established the authority for the DNR commissioner to provide for an exploration incentive credit (EIC) based on footage drilled or geophysical work in certain regions that was in effect from the early 1980s until 1994. The AS 38.05.180(i) statute and the relevant regulations linked the EIC program to specific lease sales, and when the next EIC program under AS 41.09.010 was implemented, the older AS 38.05.180(i) provisions were no longer offered as terms of the lease sales. Some 22 wells qualified for the AS 38.05.180(i) EIC, all between 1983 and 1994. The maximum eligible costs were 50% of the drilling or geophysical costs. The statute is still available, but the Commissioner of Natural Resources would have to reinstitute it as a program tied to specific lease sales. Attached is a list of approved credits.

Question from Senator Fairclough: *What is the maximum amount of credits that can be taken against oil and gas revenues?*

Each of the different tax credits available against the production tax has its own limitations and provisions, which include various limits on the value of the credits. There is no single limit that applies to all credits, and some credits can exceed a company's tax liability and issued as a tax credit certificate which may be eligible for a refund from the oil and gas tax credit fund, AS 43.55 028. Please find below an explanation of tax credits available to producers of oil and gas in 2024 with the passage of SB 138. Also attached is a summary of the available production tax credits and their specific provisions.

Production Tax credits that may be available to producer of oil and gas in 2024 with the passage of SB 138.

With the passage of SB 138 the following production tax credits may be available to a producer or explorer of oil and gas, north of 68 degrees North latitude.

AS 43.55.019 Oil and gas producer education credit

A producer of oil and gas is allowed a credit against a production tax liability resulting from cash contributions for educational, research, intercollegiate sporting events and certain cultural activities. The amount of the credit is 1) 50% of cash contributions up to $100,000, 2)100% of the next $200,000 of contributions; and 3) 50% of the amount of contributions that exceed $300,000. The credit may not reduce a person's tax liability below zero for any tax year. A credit or portion of a credit not used under this section may **not** be sold, traded, transferred, or applied in a subsequent year.

AS 43.55.023(b) Carried forward annual loss credit

A producer or explorer may take a tax credit in the amount of 35% of a carried forward annual loss. A carried forward annual loss occurs when the producer's or explorer's annual adjusted lease expenditures exceed the gross revenue at the point of production of oil or gas produced or if the lease expenditures were incurred without any revenue. The earliest that a production tax credit resulting from a carried forward annual loss can be applied against a production tax liability or converted to a transferable tax credit certificate and sold to the state for cash, if the producer or explorer qualifies under AS 43.55.028, is the year following the tax year that the loss was incurred. The credit does not expire and unused portions of the credit amounts can be used to reduce production tax liabilities in subsequent tax years.

AS 43.55.024(c) – Small Producer Credit

If the producer did not have commercial production from a lease or property before April 1, 2006, and first has commercial production in 2015 or 2016 (before May 1), the producer may take a tax credit of up to $12 million per year, if the producer's daily average production does not exceed 100,000 BTU equivalent barrels per day. (In this scenario, 2024 would fall within the nine calendar years after the calendar year during which the producer first had commercial oil and gas production). The credit is prorated from $12 million to zero between 50,000 to 100,000 BTU equivalent barrels per day. The credit can only be used against a producer's production tax liability and may **not** :

1) reduce the production tax liability below zero,
2) be carried forward for use in a succeeding year, or
3) be converted to a transferable tax credit certificate and sold to the state under AS 43.55.028.

AS 43.55.024(i) Per barrel credit for oil production qualifying for a gross revenue exclusion under AS 43.55.160(f) and (g).

A producer may apply against a production tax liability under AS 43.55.011(e) a tax credit of $5 for each barrel of oil taxable under AS 43.55.011(e) that meets on of the criteria of AS 43.55.160(f) or (g), gross revenue exclusion. A tax credit under this section may **not**:

1) reduce the production tax liability below zero,
2) be carried forward for use in a succeeding year, or
3) be converted to a transferable tax credit certificate and sold to the state under AS 43.55.028.

AS 43.55.024(j) Sliding Scale per barrel credit for oil production not qualifying for a gross revenue exclusion under AS 43.55.160(f) and (g).

A producer may apply against a production tax liability under AS 43.55.011(e) a tax credit for each barrel of oil taxable under AS 43.55.011(e) that does not meets on of the criteria of AS 43.55.160(f) or (g), gross revenue exclusion. The amount of the per barrel credit ranges from $8.00 per barrel to $0 per barrel based on the average gross value at the point of production per barrel. The credit is a sliding scale which amounts to $8 per barrel when the average gross value per barrel is less that $80 and decreases by a dollar increment for each $10 increase in the average gross value at the point of production. The per barrel credit reaches zero when the average gross values at the point of production per barrel equals or exceeds $150 per barrel. A tax credit under this section may **not**:

1) reduce the production tax liability below the amount calculated under AS 43.55.011(f) (the minimum tax),
2) be carried forward for use in a succeeding year, or
3) be converted to a transferable tax credit certificate and sold to the state under AS 43.55.028.

Question from Senator Fairclough: *What is the case for allowing TC to partner with the State on the Midstream?*

The State is preparing a white paper to supplement the testimony that has been provided in committee.

We hope the Senate Finance Committee finds this information to be useful. Please do not hesitate to contact either of us if you have further questions.

Sincerely,

Joe Balash, Commissioner
Department of Natural Resources

Angela M. Rodell, Commissioner
Department of Revenue

Attachments

Exploration Incentive Credits

AS 38.05.180(i)

ADL	WELL	COMPANY	CERTIFICATION DATE	TOTAL AMOUNT
343109	G-2 Well	Exxon Company USA	10/05/83	$6,197,625.00
		Sohio Alaska Petro.	12/27/83	4,152,408.75
		BP Alaska Exploration	10/05/83	2,045,216.25
344010	Leffingwell	ARCO Alaska Inc.	10/02/84	$3,706,000.00
		Unocal	10/02/84	3,706,000.00
344033	J-1 Well	Exxon Company USA	10/31/84	$5,119,500.00
355005	Long Island Well	Exxon Company USA	11/14/84	$1,367,738.00
		Sohio Alaska Petroleum	11/14/84	1,378,076.00
345130	Totek Hills	ARCO Alaska Inc.	08/02/85	$715,530.81
355037	Colville Delta #1	Texaco Inc.	07/09/86	$952,179.00
		Amerada Hess	07/08/86	888,594.00
		Diamond Shamrock (Maxus)	07/08/86	100,128.00
		Rosewood Resources	07/08/86	12,662.00
		Hunt Petroleum Co.	07/08/86 (1)	8,866.36
		BP Alaska Exploration	02/31/87	475,631.00
		Mobil	02/05/87	432,511.00
364478 (2)	Colville Delta Area AHC 25-13-6 #1 Well	Amerada Hess	10/12/87 (3)	$140,071.13
		Texaco Inc.	10/12/87 (4)	771,743.46
		Maxus Exploration	10/12/87 (5)	100,297.41
		Rosewood Resources	10/12/87 (6)	4,111.82
355038 (2)	Colville Delta #2	Amerada Hess	10/28/87	$757,731.46
		Texaco Inc.	10/28/87	898,563.40
		BP Alaska Exploration	10/28/88	423,982.26
355039 (2)	Colville Delta #3	Amerada Hess	10/28/87 (7)	$ 0.00
		Texaco Inc.	10/28/87 (8)	0.00
		BP Alaska Exploration	10/28/87 (9)	63,228.39
		Union Texas Petroleum	10/28/87 (10)	14,097.50
344176	Gyr #1	ARCO Alaska, Inc.	11/15/90 (11)	$699,302.43
		Amerada Hess	11/15/90 (11)	732,804.63
		Conoco	11/15/90 (12)	732,804.62
355021	NW Milne #1	Conoco	07/10/92 (13)	$1,371,691.42
		Conoco	02/09/93	660,321.00
375044	Sequoia #1	Conoco	07/10/92 (13)	$275,521.32
		Petrofina	07/10/92 (14)	227,594.08
		Conoco	02/09/93	16,333.56
		Petrofina	02/09/93	19,963.24

Exploration Incentive Credits (continued)

ADL	WELL	COMPANY	CERTIFICATION DATE	TOTAL AMOUNT
375076	Cirque #2	ARCO Alaska, Inc.	02/09/93 (15)	$845,018.43
375108	Tarn #1	ARCO Alaska, Inc.	02/09/93 (16)	$727,939.95
355036	Kalubik #1	ARCO Alaska, Inc.	02/09/93 (17)	$2,599,602.13
		ARCO Alaska Inc. (UTP)	03/04/93	250,822.50
		ARCO Alaska Inc. (UTP)	04/22/93	11,779.91
372104	Fiord #1	ARCO Alaska Inc. (UTP)	02/09/93 (18)	$1,811,218.84
		ARCO Alaska Inc.	03/04/93	191,018.62
372006	Tulaga #1	ARCO Alaska Inc.	03/25/93 (19)	$1,241,177.00
355011	Jones Island #1	ARCO Alaska Inc.	07/12/93	$2,160,000.00
		ARCO Alaska Inc. (UTP)	07/20/93 (20)	1,910,175.00
375133	Cascade Well #1	BP Exploration (AK) Inc	04/04/94 (21)	$893,245.73
375061	Yukon Gold #1	BP Exploration (AK) Inc	08/08/94 (22)(23)	$2,394,546.77
		Union Oil Co. of Cal (H)	08/23/94 (24)	487.240.46
TOTAL EICs GRANTED TO-DATE:				$54,692,614.64

(1) Hunt's EIC balance reduced through a commissioner's decision dated March 18, 1998. Hunt made a subsequent payment in April 1998.
(2) Colville Delta wells were settled through the Colville Delta EIC settlement agreement dated 12/31/98.
(3) Amerada Hess EIC balance reduced through an EIC settlement agreement and subsequent payment on 1/29/99.
(4) Texaco's EIC balance reduced through an EIC settlement agreement and subsequent payment on 1/28/99.
(5) Maxus' EIC balance reduced through an EIC settlement agreement and subsequent payment on 1/26/99.
(6) Rosewood's EIC balance reduced through an EIC settlement agreement and subsequent payment on 1/7/99.
(7) Amerada Hess EIC balance reduced through an EIC settlement agreement and subsequent payment on 1/29/99.
(8) Texaco's EIC balance reduced through an EIC settlement agreement and subsequent payment on 1/28/99.
(9) BP's EIC balance reduced through an EIC settlement agreement and subsequent payment on 12/31/98.
(10) Union Texas' EIC balance reduced through an EIC settlement agreement and subsequent payment on 1/29/99.
(11) ARCO and Amerada's EIC balances reduced through an EIC audit and subsequent payment in February 1997.
(12) Conoco's EIC balance reduced through an EIC audit and subsequent payment in March 1997.
(13) Conoco's EIC balance reduced through an EIC audit and subsequent payment in July 1997.
(14) $125,190.33 of EIC expired for Petrofina on March 31, 1996.
(15) ARCO's EIC balance reduced through an EIC audit and subsequent payment in December 1997.
(16) ARCO's EIC balance reduced through an EIC audit and subsequent payment in December 1997.
(17) ARCO's EIC balance reduced through an EIC audit and subsequent payment in December 1997.
(18) ARCO's EIC balance increased through an EIC audit and subsequent payment in December 1997.
(19) Union Texas (ARCO) EIC balance reduced through an EIC audit and subsequent payment on 8/18/98.
(20) Union Texas (ARCO) EIC balance reduced through an EIC audit and subsequent payment on 8/18/98.
(21) BP's EIC balance reduced through an EIC audit and subsequent payment in December 1997.
(22) BP's EIC balance reduced through an EIC audit and subsequent payment in December 1997.
(23) BP's EIC balance reduced through an EIC audit and subsequent payment on 12/31/98.
(24) Union's EIC balance reduced through an EIC audit and subsequent payment in July 1998.

Source: Alaska Department of Natural Resources, Division of Oil and Gas

Summary of Tax Credits under AS 43.55 – The Alaska Oil and Gas Production Tax

Disclaimer:

This summary is intended as an informational guide only. The State of Alaska makes no warranty, expressed or implied, as to the accuracy of this summary. To be certain of the current statutes and regulations, refer to the official printed version of the statutes and regulations. This information only relates to tax credits in effect on and after January 1, 2014.

The Alaska Department of Revenue Tax Division (Division) offers many different production tax credits under AS 43.55. Below is a brief summary of the tax credits that the Division administers. Please note: there are other credits that the Department of Natural Resources or other sections of the Tax Division may offer that may be applied against royalty or rental payments, the production tax liability levied by AS 43.55, or the corporate income tax under AS 43.20 that are not included in this summary; please see the relevant Department or section for more information on those credits.

Education Tax Credit under AS 43.55.019

The education credit is a tiered credit based on cash contributions made to qualified educational and vocational entities or programs[1] outlined under AS 43.55.019(a). The credit is allowed for oil and gas producers against the tax due under this chapter for cash contributions to qualifying programs or entities. The credit was increased in 2010 for the period January 1, 2011 – December 31, 2013 and in 2011 the increase was extended through December 31, 2020.

Effective 1/1/2011 – 12/31/2020[2], the credit is limited to 50 percent of contributions of not more than $100,000; 100 percent of the next $200,000 of contributions; and 50 percent of the amount of contributions that exceed $300,000.[3] A contribution claimed as a credit under this section may not be the basis for a credit claimed under another provision of this title; and when combined with contributions that are the basis for credits taken during the taxpayer's tax year under AS 21.96.070, 21.96.075, AS 43.20.014, AS 43.56.018, AS 43.65.018, AS 43.75.018, or AS 43.77.045, may not result in the total amount of credits exceeding $5,000,000 in a single calendar year for an affiliated group.[4]

Effective 1/1/2021, the credit is limited to 50 percent of contributions of not more than $100,000; and 100 percent of the next $100,000 of contributions. A contribution claimed as a credit under this section may not be the basis for a credit claimed under another provision of this title; and when combined with contributions that are the basis for credits taken during the taxpayer's tax year under AS 21.96.070, 21.96.075, AS 43.20.014, AS 43.56.018, AS 43.65.018, AS 43.75.018, or AS 43.77.045, may not result in the total amount of credits exceeding $150,000.[5]

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[1] Effective July 1, 2011, cash contributions for qualified athletic tournaments, Alaska Native culture programs, or coastal ecosystem learning centers also qualify. SB 84, (ch. 7, SLA 2010)

[2] Original change took place in 2010 with the passing of SB 236 (ch. 29, SLA 2010) and the sunset provision was extended for the increased credit amount through 12/31/2020 through the passage of SB 84.

[3] AS 43.55.019(b)

[4] AS 43.55.019(d)(2)

[5] These are delayed amendments per SB 236

Summary of Tax Credits under AS 43.55 – The Alaska Oil and Gas Production Tax

Uses of Credit

This credit may be applied against any tax levied by 43.55. The credit is NOT transferable, is NOT available to be issued as a certificate, and may not reduce a person's tax liability below zero for any tax year. An unused credit or portion of a credit not used under this section for a tax year may not be sold, traded, transferred, or applied in a subsequent tax year.[6]

Pertinent Statutes and Regulations

AS 43.55.019; no regulations at this time

Qualified Capital Expenditures (QCE) Credit under AS 43.55.023(a)

The QCE credit is a 20% credit based on Qualified Capital Expenditures, as defined by AS 43.55.023(o).[7] The QCEs must also be allowable Lease Expenditures under AS 43.55.165. If the expenditures are incurred in connection with geological or geophysical exploration or an exploration well under AS 43.55.023(a)(2), then there are also certain data requirements[8] that must be met with the Department of Natural Resources (DNR). NOTE: After December 31, 2013, there is no longer a QCE credit for the North Slope[9], as amended by SB 21.[10]

Uses of Credit

The full credit may be applied[11] directly against a producer's tax liability in the year it was incurred by taking the total credit allowed for the year and applying it equally against the liability for each month of the year.[12] This credit may also be requested as a tax credit certificate[13], but no more frequently than once per calendar quarter[14]. To receive a credit certificate, an application[15] must be submitted to the Department of Revenue (DOR) with all relevant backup required under regulation[16] after the expenditures have been incurred.[17] The DOR has until the later of 120 days from the date that the application is received by the Department, the date that the annual return is filed, or from March 31st of the calendar year following the calendar year in which the expenditures were incurred[18] to grant or deny the application. All credits may be issued as one certificate available in the year it was issued.[19] If the credit is issued as a certificate, the credit certificate may

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[6] AS 43.55.019(e)

[7] Definition of a QCE was re-lettered as a revisers edit to AS 43.55.023(o) after HB 280 passed in 2010

[8] The data requirements are outlined in AS 43.55.025(f)(2)

[9] North of 68 degrees North latitude

[10] Section 14 of the bill added AS 43.55.023(a)(3). SB 21 was enacted as ch. 10, SLA 2013.

[11] AS 43.55.023(a)(1) is amended by section 14 of SB 21 and effective for expenditures incurred on or after January 1, 2013, to allow the full credit

[12] Per AS 43.55.020(a)(1)

[13] Under AS 43.55.023(d)

[14] Per 15 AAC 55.320(a)(1)

[15] Form 0405-330 located on the tax division website at http://www.tax.alaska.gov//programs/programs/forms/index.aspx?60650

[16] See 15 AAC 55.320 and 345 for filing requirements

[17] See regulation for "When cost is incurred" under 15 AAC 55.290

[18] Per AS 43.55.023(d)

[19] AS 43.55.023(d) is amended by section 16 of SB 21

then be sold or transferred to another company, applied to tax liability under AS 43.55.011(e),[20] or if all requirements are met under AS 43.55.028, redeemed for cash from the State by the original applicant. The credit may not be used to reduce a person's tax liability below zero for any tax year.[21]

Pertinent Statutes and Regulations

AS 43.55.023; AS 43.55.165-170; 15 AAC 55.250-290; 15 AAC 55.305-381; 15 AAC 55.900

Carried-Forward Annual Loss Credit under AS 43.55.023(b)

The carried-forward annual loss credit is based on a producer or explorer's adjusted lease expenditures[22] that were not deductible in calculating production tax values for that calendar year under AS 43.55.160. The credit is 25% for non-North Slope expenditures and North Slope expenditures incurred before January 1, 2014. The credit for North Slope expenditures is 45% between January 1, 2014 and December 31, 2015, and 35% for expenditures on or after January 1, 2016[23]. This credit may also be requested as a tax credit certificate,[24] but not earlier than January 1st of the calendar year following the calendar year in which the loss was incurred.[25]

Uses of Credit

This credit may be applied directly against a producer's tax liability in the year following the year it was incurred by taking the total credit allowed for the year and applying it equally against the liability for each month of the year.[26] This credit may also be requested as a tax credit certificate[27]. To receive a credit certificate, an application[28] must be submitted to the Department of Revenue (DOR) with all relevant backup required under regulation[29] after the expenditures have been incurred.[30] The DOR has until the later of 120 days from the date that the application is received by the Department, the date that the annual return is filed, or from March 31st of the calendar year following the calendar year in which the expenditures were incurred[31] to grant or deny the

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to allow all certificates to be issued in full (no longer split into two) and is effective for expenditures incurred on or after January 1, 2013

[20] 15 AAC 55.381(b) allows for the credit certificate under this section to be applied against a single monthly installment payment

[21] No credit or portion of credit may be used to reduce a person's tax liability under AS 43.55.011(e) for any calendar year below zero. See; 43.55.023(c); 43.55.025(f) and (g); and 43.55.025(i)

[22] Under AS 43.55.165 and 170

[23] Section 15 of SB 21

[24] Under AS 43.55.023(d)

[25] Per 15 AAC 55.320(a)(2)

[26] Per AS 43.55.020(a)(1)

[27] Under AS 43.55.023(d)

[28] Form 0405-330 located on the tax division website at http://www.tax.alaska.gov//programs/programs/forms/index.aspx?60650

[29] See 15 AAC 55.320 and 345 for filing requirements

[30] See regulation for "When cost is incurred" under 15 AAC 55.290

[31] Per AS 43.55.023(d)

application. All credits may be issued as one certificate available in the year it was issued.[32] If the credit is issued as a certificate, the credit certificate may then be sold or transferred to another company, applied to tax liability under AS 43.55.011(e),[33] or if all requirements are met under AS 43.55.028, redeemed for cash from the State by the original applicant. The credit may not be used to reduce a person's tax liability below zero for any tax year.[34]

Pertinent Statutes and Regulations

AS 43.55.023; AS 43.55.165-170; 15 AAC 55.250-290; 15 AAC 55.305-381; 15 AAC 55.900

Transitional Investment Expenditure ("TIE") Credit under AS43.55.023(i) – repealed[35]

The TIE credit is a 20% credit for qualified capital expenditures incurred between April 1, 2001, and March 31, 2006. The credit may not exceed 1/10 of the AS 43.55.023(a) QCE credit taken from the period April 1, 2006, through December 31, 2007, and may only be taken by a company that did not have commercial production before January 1, 2008.

Uses of Credit

This credit may be applied against a tax levied by AS 43.55.011(e), but not for any calendar year after 2013.[36] The credit is NOT transferable, is NOT available to be issued as a certificate, and may not be used to reduce a person's tax liability below zero for any tax year. An application form[37] must be submitted with the annual return for the year that the credit is applied with all applicable backup.

Well Lease Expenditure Credit under AS 43.55.023(*l*)

The Well Lease Expenditure credit is a 40% credit based on Well Lease Expenditures incurred south of 68 degrees North latitude, which includes "middle earth" and Cook Inlet, after June 30, 2010. The Well Lease Expenditures must also be allowable lease expenditures under AS 43.55.165, qualified capital expenditures under AS 43.55.023(o), and intangible drilling and development costs[38] authorized under 26 U.S.C. (Internal Revenue Code). If the expenditures are incurred in connection with geological or geophysical exploration or an exploration well under AS

[32] AS 43.55.023(d) is amended by section 16 of SB 21 to allow all certificates to be issued in full (no longer split into two) and is effective for expenditures incurred on or after January 1, 2013

[33] 15 AAC 55.381(b) allows for the credit certificate under this section to be applied against a single monthly installment payment

[34] No credit or portion of credit may be used to reduce a person's tax liability under AS 43.55.011(e) for any calendar year below zero. See; 43.55.023(c); 43.55.025(f) and (g); and 43.55.025(i)

[35] This credit is repealed by section 33 of SB 21 effective January 1, 2014

[36] AS 43.55.023(i)(3)(A)

[37] Form 0405-330

[38] AS 43.55.023(n)

43.55.023(*l*)(2), then there are also certain data requirements[39] that must be met with the Department of Natural Resources (DNR).

Uses of Credit

This credit may be applied directly against a tax levied by AS 43.55.011(e) in the year it was incurred by taking the total credit allowed for the year and applying it equally against the liability for each month of the year[40]. This credit may also be requested as a tax credit certificate[41], but no more frequently than once per calendar quarter.[42] To receive a credit certificate, an application[43] must be submitted to the Department of Revenue (DOR) with all relevant backup required under regulation[44] after the expenditures have been incurred.[45] The DOR has until the later of 120 days from the date that the application is received by the Department or 120 days from March 31st of the calendar year following the calendar year in which the expenditures were incurred[46] to grant or deny the application. This credit is issued as one certificate available in the year it was issued[47]. If the credit is issued as a certificate, the credit certificate may then be transferred to another company, applied to a tax levied by AS 43.55.011(e)[48], or redeemed for cash from the State by the original applicant if all requirements are met under AS 43.55.028.

Pertinent Statutes and Regulations

AS 43.55.023; AS 43.55.165-170; 15 AAC 55.250-290; 15 AAC 55.305-381; 15 AAC 55.900

Additional Nontransferable Tax Credits under AS 43.55.024(a) & (c)[49] (aka the "Middle Earth Credit" & "Small Producer Credit")

Under AS 43.55.024(a), a prorated credit up to $6,000,000 may be applied against a producer's tax liability levied by AS 43.55.011(e) for a calendar year for oil and gas produced outside of Cook Inlet and south of 68 degrees North latitude[50] aka "middle earth"[51]. This credit may not be taken after the later of 2016 or after the 9th calendar year after the calendar year in which the producer first had commercial production before May 1, 2016[52] from at least one lease or property in "middle earth".

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[39] The data requirements are outlined in AS 43.55.025(f)(2)
[40] Per AS 43.55.020(a)(1)
[41] Under AS 43.55.023(d) or (m)
[42] Per 15 AAC 55.320(a)(1)
[43] Form 0405-330 located on the tax division website at http://www.tax.alaska.gov//programs/programs/forms/index.aspx?60650
[44] See 15 AAC 55.320 and 345 for filing requirements
[45] See regulation for "When cost is incurred" under 15 AAC 55.290
[46] Per AS 43.55.023(d)
[47] AS 43.55.023(m)
[48] 15 AAC 55.381(b) allows for the credit certificate under this section to be applied against a single monthly installment payment.
[49] SB 21 added new credits under AS 43.55.024(i) and (j) that are not in effect until January 1, 2014
[50] AS 43.55.024(a)
[51] "Middle Earth" is phrase commonly used to describe the land south of 68 degrees North latitude and outside of Cook Inlet
[52] AS 43.55.024(b)

Tax credits under AS 43.55.024(c), also known as the "small producer credit", may be applied for a calendar year in which the producer's tax liability exceeds zero against a producer's tax levied by AS 43.55.011(e) for a producer whose average amount of oil and gas produced a day and taxable under AS 43.55.011(e) is less than 100,000 BTU equivalent barrels a day. If a producer's average taxable production is more than 50,000 and less than 100,000 BTU equivalent barrels per day, a producer may apply a prorated portion of the $12,000,000 credit for the calendar year.[53] A producer may not take a tax credit under (c) of this section after the later of 2016; or if the producer did not have commercial oil or gas production from a lease or property in the state before April 1, 2006, the ninth calendar year after the calendar year during which the producer first has commercial oil or gas production before May 1, 2016, from at least one lease or property in the state.[54]

Uses of Credit

These credits may be applied against a tax levied by AS 43.55.011(e). The credits are NOT transferable and are NOT available to be issued as a certificate. An unused tax credit or portion of a tax credit under this section may not be carried forward for use in a later calendar year.[55] The credit may not be used to reduce a tax liability for any calendar year below zero.[56] For a calendar year during which two or more producers that qualify under AS 43.55.024(e) are succeeded through merger, acquisition, or a similar transaction by a single producer that qualifies under AS 43.55.024(e), they are each only allowed a portion of the credit.[57]

Additional Nontransferable Tax Credits under AS 43.55.024(i) & (j)[58]

Under AS 43.55.024(i), a five dollar per barrel credit is allowed for each barrel of taxable oil produced on the North Slope that qualifies for the Gross Value Reduction (GVR) under AS 43.55.160(f) and (g). Under AS 43.55.024(j), a sliding scale credit of one to eight dollars per barrel is based on the gross value of oil, when prices are below $150 per barrel, that does not qualify for the Gross Value Reduction (GVR) under AS 43.55.160(f) and (g).

Uses of Credit

These credits may be applied against a tax levied by AS 43.55.011(e). The credits are NOT transferable and are NOT available to be issued as a certificate. An unused tax credit or portion of a tax credit under this section may not be carried forward for use in a later calendar year.[59] The credit may not be used to reduce a tax liability for any calendar year below zero.[60]

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[53] As 43.55.024(c)(2)
[54] AS 43.55.024(d)
[55] AS 43.55.024(h)
[56] AS 43.55.024(g)
[57] 15 AAC 55.335(b)
[58] SB 21 added new credits under AS 43.55.024(i) and (j) effective for oil and gas produced after January 1, 2014
[59] AS 43.55.024(h)
[60] AS 43.55.024(g)

Alternative Tax Credit for Oil and Gas Exploration under AS43.55.025(a)(1)-(4)

Depending on the type of exploration (seismic vs. exploration well) and the location of the project a company may receive a 30% or 40% credit under AS 43.55.025. For a qualifying exploration well that is bottom holed more than 3 miles from a preexisting well, other than in Cook Inlet, and pre-approved by the commissioner of natural resources before the project commences[61] a company may receive a 30% credit.[62] For a qualifying exploration well that is more than 25 miles outside an existing unit, or 10 miles outside of a unit in Cook Inlet, a company may receive a 30% credit.[63] For a qualifying exploration well that is both more than 3 miles from a preexisting well and 25 miles from a unit, other than in Cook Inlet, a company may receive a 40% credit.[64] For a qualifying seismic project outside a unit, a company may receive a 40% credit.[65] To qualify for any credits under this section the company must submit required data sets to the Department of Natural Resources. A credit application[66] must be completed and received by the Department of Revenue within six months of the completion of the exploration activity.[67] The application must be either submitted by a single applicant that holds a 100% interest in the project and incurred 100% of the expenditures or submitted by a designated joint applicant on behalf of and signed by all partners.[68] All credit requests under this section are audited before a certificate is issued and a tax credit certificate is always issued. These credits are only for work performed before July 1, 2016, for North Slope and Cook Inlet. The credits are for work performed before January 1, 2022, for "Middle Earth".[69]

A five percent credit for exploration expenditures performed before July 1, 2003 is available for seismic exploration performed outside the boundaries of an existing production unit if the Commissioner of the Department of Natural Resources determines public distribution of the seismic information is in the best interest of the State.[70]

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[61] AS 43.55.025(c)(2)
[62] AS 43.55.025(a)(1) and (c)
[63] AS 43.55.025(a)(2) and (d)
[64] AS 43.55.025(a)(3), (c), and (d)
[65] AS 43.55.025(a)(4) and (e)
[66] Form 0405-310
[67] The completion date of an exploration well is defined under 15 AAC 55.900(b)(10) and the completion date of a seismic project is generally the date that the initial processing of the seismic data has been completed.
[68] 15 AAC 55.355(a) and 15 AAC 55.356
[69] "Middle Earth" is phrase commonly used to describe the land south of 68 degrees North latitude (North Slope) and outside of Cook Inlet
[70] AS 43.55.025(k)

Uses of Credit

The credit itself may be applied against a producer's tax liability in the year in which it was incurred and also before the tax credit certificate is issued.[71] The credit certificate may be transferred, applied to tax liability,[72] or cashed out with the State under AS 43.55.028 by the original applicant.

Pertinent Statutes and Regulations

AS 43.55.025; 15 AAC 55.305-381

Alternative Tax Credit for Oil and Gas Exploration under AS43.55.025(a)(5) – aka the "Jack-up Rig Credit"

Signed into effect May 20, 2010[73], AS 43.55.025(a)(5) and (*l*) were added to AS 43.55.025 to provide tax credits for a jack-up rig in Cook Inlet applicable to work performed after March 31, 2010. These sections added credits of 100% of qualifying exploration expenditures up to $25 million for the first well, 90% of qualifying exploration expenditures up to $22.5 million for the second well, and 80% of qualifying exploration expenditures up to $20 million for the third well incurred for exploratory drilling with a jack-up rig in Cook Inlet. The three wells must be drilled by unaffiliated parties, use the same jack-up rig, and penetrate and evaluate a prospect in the pre-Tertiary zone. The latter determination is made by the Commissioner of the Department of Natural Resources.

Uses of Credit

The credit itself may be applied against a producer's tax liability in the year in which it was incurred and also before the certificate is issued.[74] The credit certificate may be transferred, applied to tax liability,[75] or cashed out with the State under AS 43.55.028 by the original applicant.

Pertinent Statutes and Regulations

AS 43.55.025; 15 AAC 305-381

Alternative Tax Credit for Oil and Gas Exploration under AS43.55.025(a)(6)&(7) – aka the "Frontier Basin Credits"

Effective January 1, 2013[76], AS 43.55.025(a)(6), (a)(7), (n) and (o) were added to the statute to provide tax credits for exploration wells and seismic projects performed after June 30, 2012 and

[71] 15 AAC 55.370(c)
[72] 15 AAC 55.381(b) allows for the credit certificate under this section to be applied against a single monthly installment payment
[73] Senate Bill 309, (Ch. 15 SLA 2010)
[74] 15 AAC 55.370(c)
[75] 15 AAC 55.381(b) allows for the credit certificate under this section to be applied against a single monthly installment payment
[76] Section 46 of SB 23

before July 1, 2016, in certain "Frontier Basins" described in AS 43.55.025(p). These sections added credits of 80% of qualifying exploration expenditures up to $25 million for the first two wells in any single basin and 75% of qualifying seismic exploration expenditures up to $7.5 million for the first seismic project in each basin. Many requirements must be met with the Department of Natural Resources to qualify for the credits, including pre-qualifications.

Uses of Credit

The credit itself may be applied against a producer's tax liability in the year in which it was incurred and also before the certificate is issued.[77] The credit certificate may be transferred, applied to tax liability,[78] or cashed out with the State under AS 43.55.028 by the original applicant.

Pertinent Statutes and Regulations

AS 43.55.025; 15 AAC 305-381

Assigning Tax Credit Certificates

Effective June 26, 2013,[79] all certificates under AS 43.55.023 and 43.55.025 are assignable within 30 days of the certificate request. The Department has created a form[80] that may be completed to assign the certificate and meet the specified criteria listed in the statute. A specific dollar amount up to 90% of the certificate request or a percentage up to 100% of the certificate request may be assigned. Once the Department receives the assignment form, the assignment can only be canceled with written permission from the assignee.

Pertinent Statutes and Regulations

AS 43.55.029

Contact Information

For additional information about the Department of Revenue Tax Credits and how to apply, please contact Destin Greeley at (907) 269-6642. For additional information regarding the data required to be submitted to the Department of Natural Resources for credits relating to exploration expenditures, please contact Heather Ann Heusser at (907) 269-0137.

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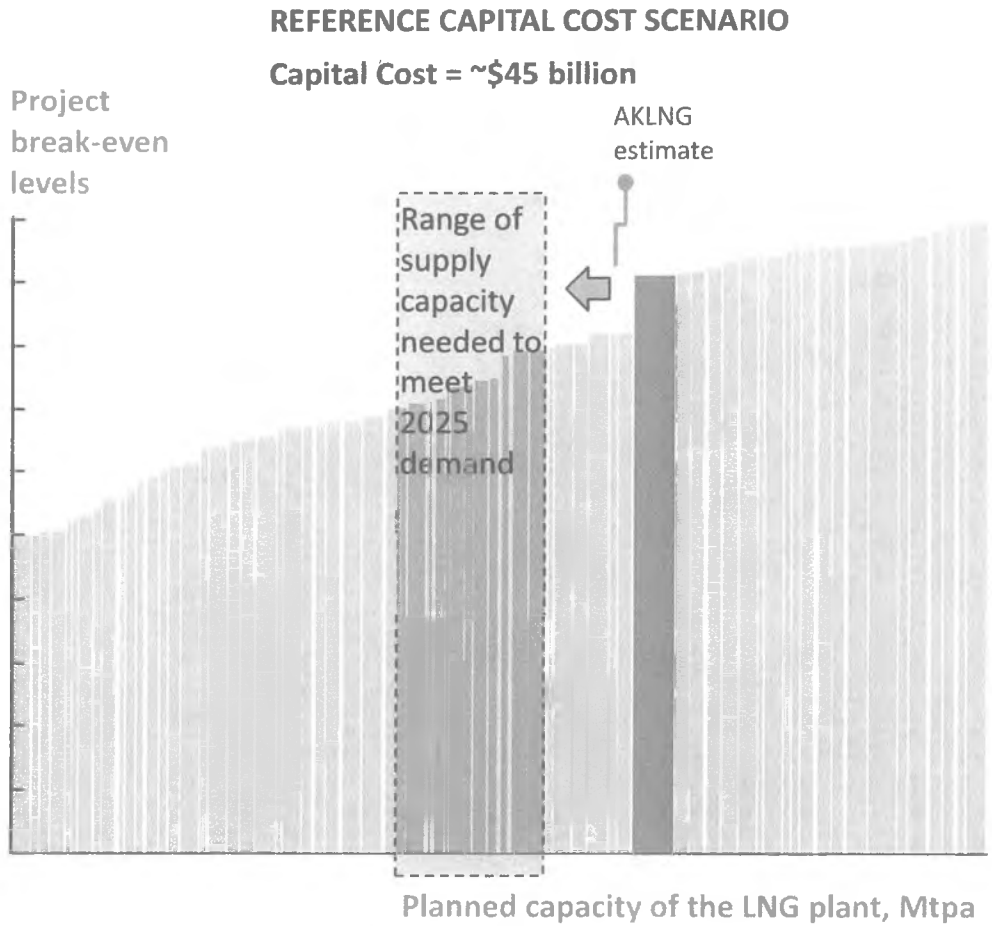
[77] 15 AAC 55.370(c)

[78] 15 AAC 55.381(b) allows for the credit certificate under this section to be applied against a single monthly installment payment

[79] Section 4 of SB 83 takes effect immediately on June 26, 2013, when the governor signed the bill

[80] Form 0405-335 is located on the Tax Division's website at http://www.tax.alaska.gov/programs/programs/forms/index.aspx?60650.

ON THE GLOBAL SUPPLY CURVE, AKLNG APPEARS TO CURRENTLY BE OUT OF THE MONEY, MODIFICATIONS REQUIRED FOR COMPETIVENESS



ILLUSTRATIVE CHART, ANALYSIS DONE FOR ALL PROJECTS WITH STARTUP AFTER 2013

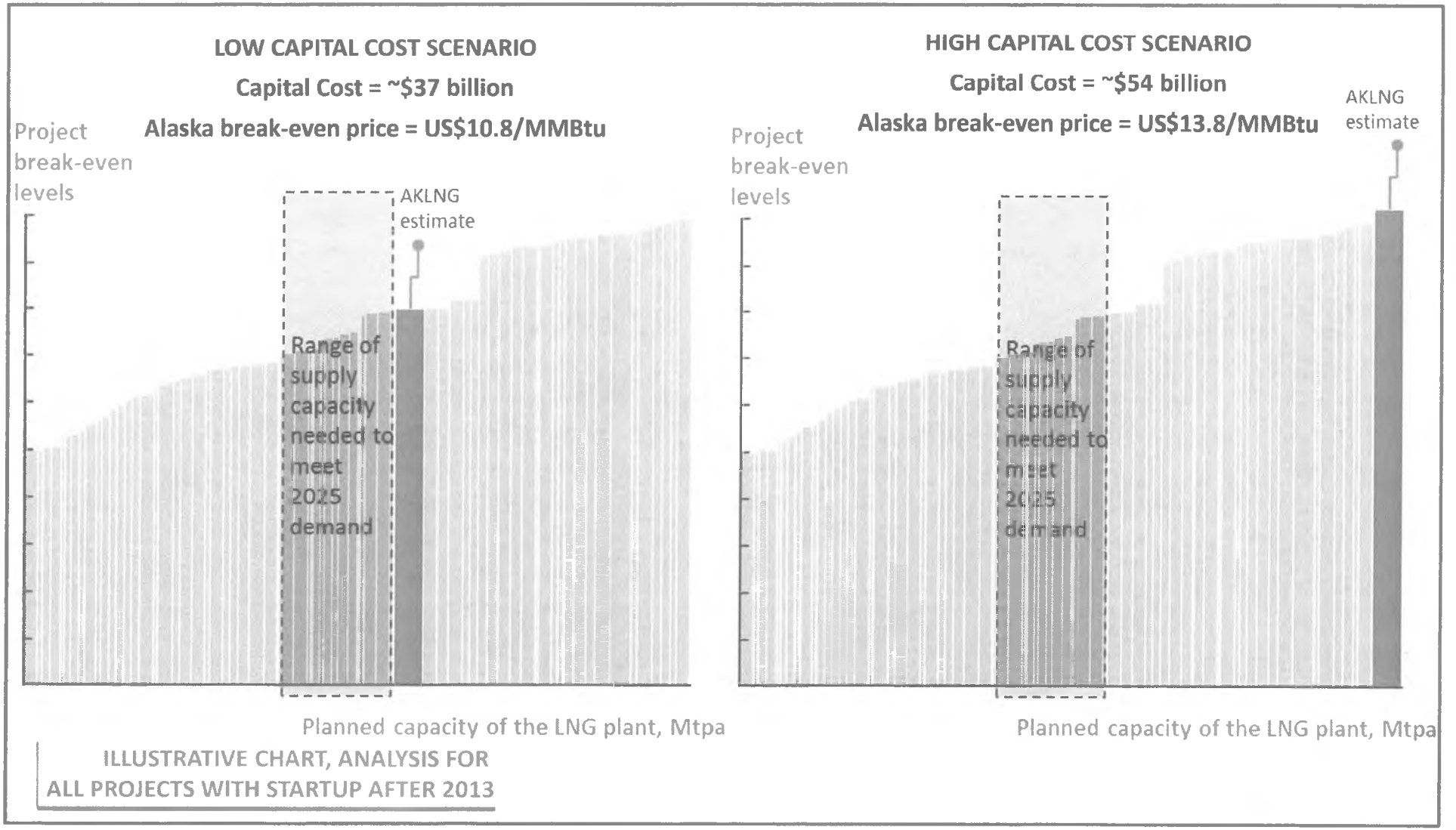
IMPLICATIONS:

1. **AKLNG is currently out of the money:**
   - **Alaska break-even price is US$12.3/MMBtu**
   - **Projects more economic than Alaska can provide ~340 MTPA new supply, more than required to meet global LNG demand (~250 – 300 MTPA)**
2. **AKLNG faces significant competition**
   - **There are several projects to the right in supply stack which will compete with AKLNG**
3. **However, the risk levels of competing LNG projects also needs to be considered**
   - **Due to political, resource and other risks, some in the money projects may be delayed/cancelled, leading to range of needed capacity**

[1] NPV=0 @ discounted at Weighted Average Cost of Capital

SOURCE: Team Analysis

AKLNG POSITION IN GLOBAL SUPPLY CURVE – SENSITIVITY TO CAPITAL COST



[1] NPV=0 @ discounted at Weighted Average Cost of Capital

SOURCE: Team Analysis

IN KIND VS. IN VALUE, RISKS & MIDSTREAM OPTIONS

Prepared for Senate Finance Committee
Juneau, Alaska › February 27, 2014

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Before co-founding *en*alytica, Janak led the Upstream Analytics team at PFC Energy, focusing on fiscal terms analysis and project economic and financial evaluation, data management and data visualization.

Janak has modeled upstream fiscal terms in all of the world's major hydrocarbon regions, and has built economic and financial models to value prospective acquisition targets and develop strategic portfolio options for a wide range of international and national oil company clients. He has advised Alaska State Legislature for multiple years on reform of oil and gas taxation, providing many hours of expert testimony to Alaska's Senate and House Finance and Resources Committees.

Prior to his work as an energy consultant, Janak advised major minerals industry clients on a range of controversial environmental and social risk issues, from uranium mining through to human rights and climate change. He has advised bankers at Citigroup and policy-makers at the US Treasury Department on the management and mitigation of environmental and social impacts in major projects around the world, and has undertaken macroeconomic research with senior development economists at the World Bank and the Peterson Institute for International Economics.

Janak holds an MA with distinction in international relations and economics from from the Johns Hopkins School of Advanced International Studies (SAIS), and a BA with first-class honors from the University of Adelaide, Australia.

NIKOS TSAFOS
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Nikos Tsafos has a diverse background in the private, public and non-profit sectors. He is currently a founding partner at *en*alytica. In his 7 ½ years with PFC Energy, Nikos advised the world's largest oil and gas companies on some of their most complex and challenging projects; he also played a pivotal role in turning the firm into one of the top natural gas consultancies in the world, with responsibilities that included product design, business development, consulting oversight and research direction.

Prior to PFC Energy, Nikos was at the Center for Strategic and International Studies (CSIS) in Washington, DC where he covered political, economic, and military issues in the Gulf, focused on oil wealth, regime stability and foreign affairs. Before CSIS, he was in the Greek Air Force, and prior to his military service, Nikos worked on channeling investment from Greek ship-owners to Chinese shipyards.

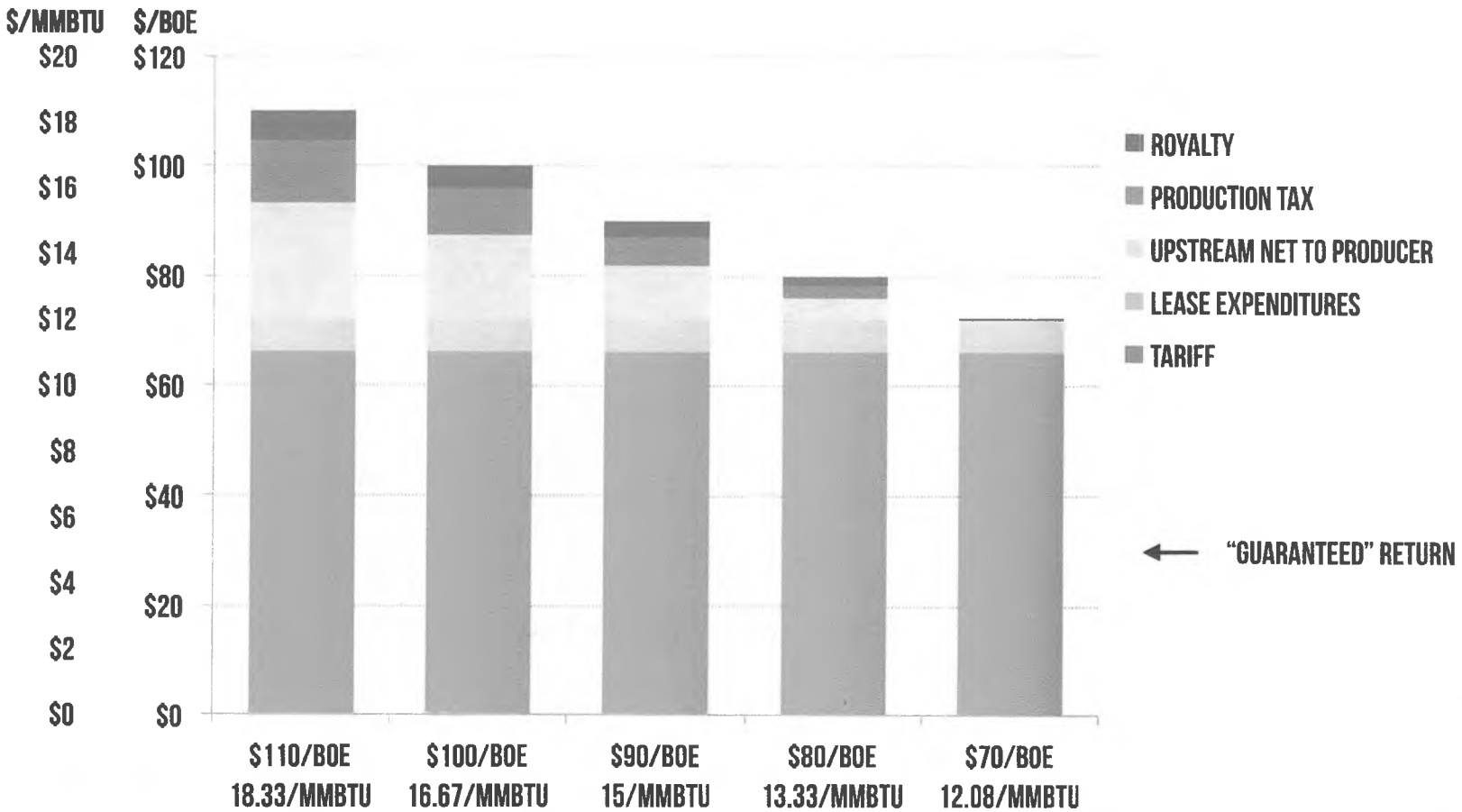
Nikos has also written extensively on the domestic and international dimensions of the Greek debt crisis. His blog (Greek Default Watch) was listed as one of "Europe's Top Economic Blogs" by the Social Europe Journal, and his book "Beyond Debt: The Greek Crisis in Context" was published in March 2013.

Nikos holds a BA with distinction in international relations and economics from Boston University and an MA with distinction in international relations from the Johns Hopkins School of Advanced International Studies (SAIS).

	System	SOA ownership percent			SOA share of CAPEX & OPEX			SOA cash commitments	
	Value / Kind	Upstream	GTP & Pipe	LNG	Upstream	GTP & Pipe	LNG	Debt	Tariffs
Status Quo	in value	0%	0%	0%	Indirect (taxes)	0%	0%	No debt	Tariff matters for valuation
HOA	in kind	0%	25%	25%	Indirect (taxes)	25%	25%	Principal and interest	Tariff only notional
MOU Option 1	in kind	0%	10% (40% x 25%)	25%	Indirect (taxes)	10% (40% x 25%)	25%	Principal and interest	Tariff payable to T/C
MOU Option 2	in kind	0%	0%	25%	Indirect (taxes)	0%	25%	Principal and interest	Tariff payable to T/C

RIV: UPSTREAM ABSORBS ALL THE PRICE RISK

Fixed nature of tariff in 'in value' alternative amplifies impact of price movement on state returns

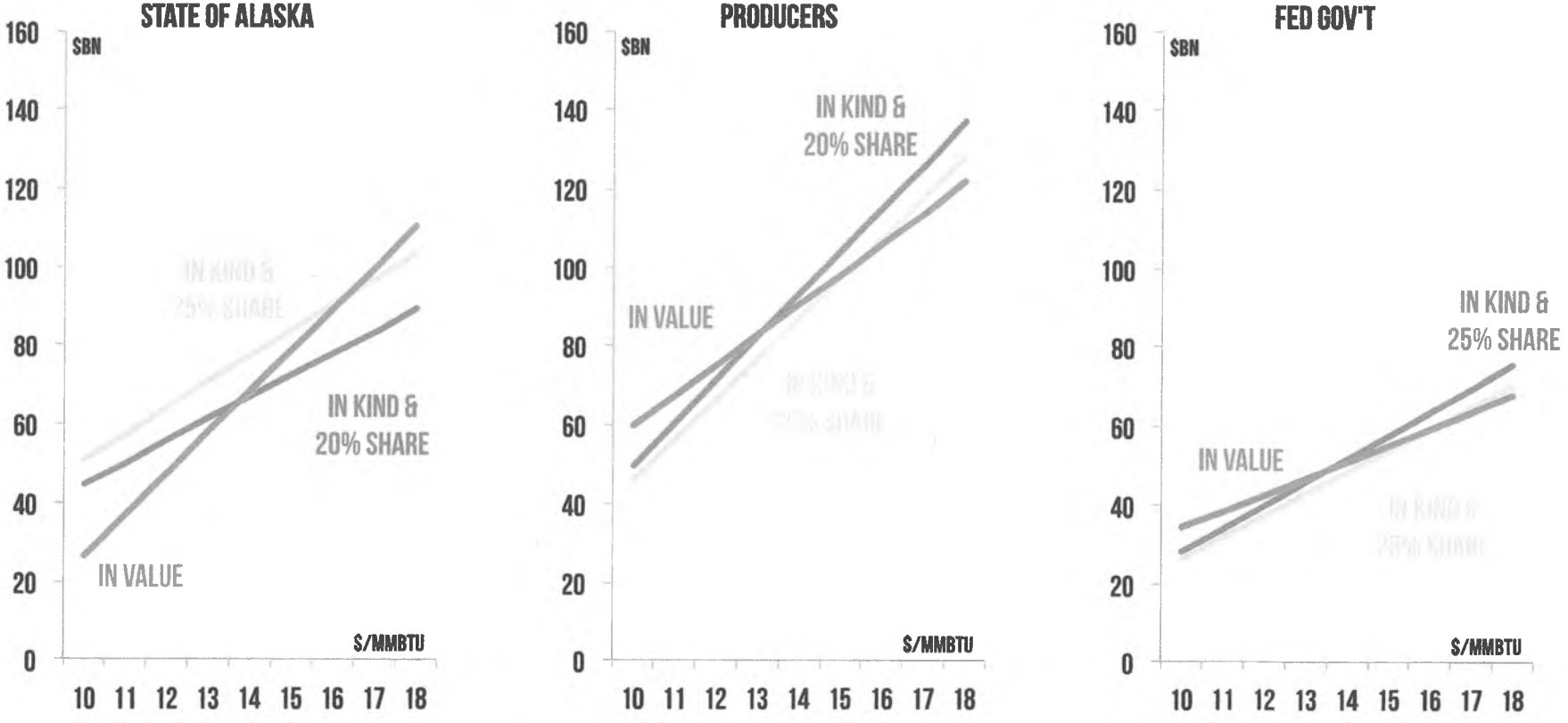


'IN KIND' W/ EQUITY OFFERS MORE DOWNSIDE PROTECTION

'In value' structure protects producers, not state, in low price environment because of tariff component

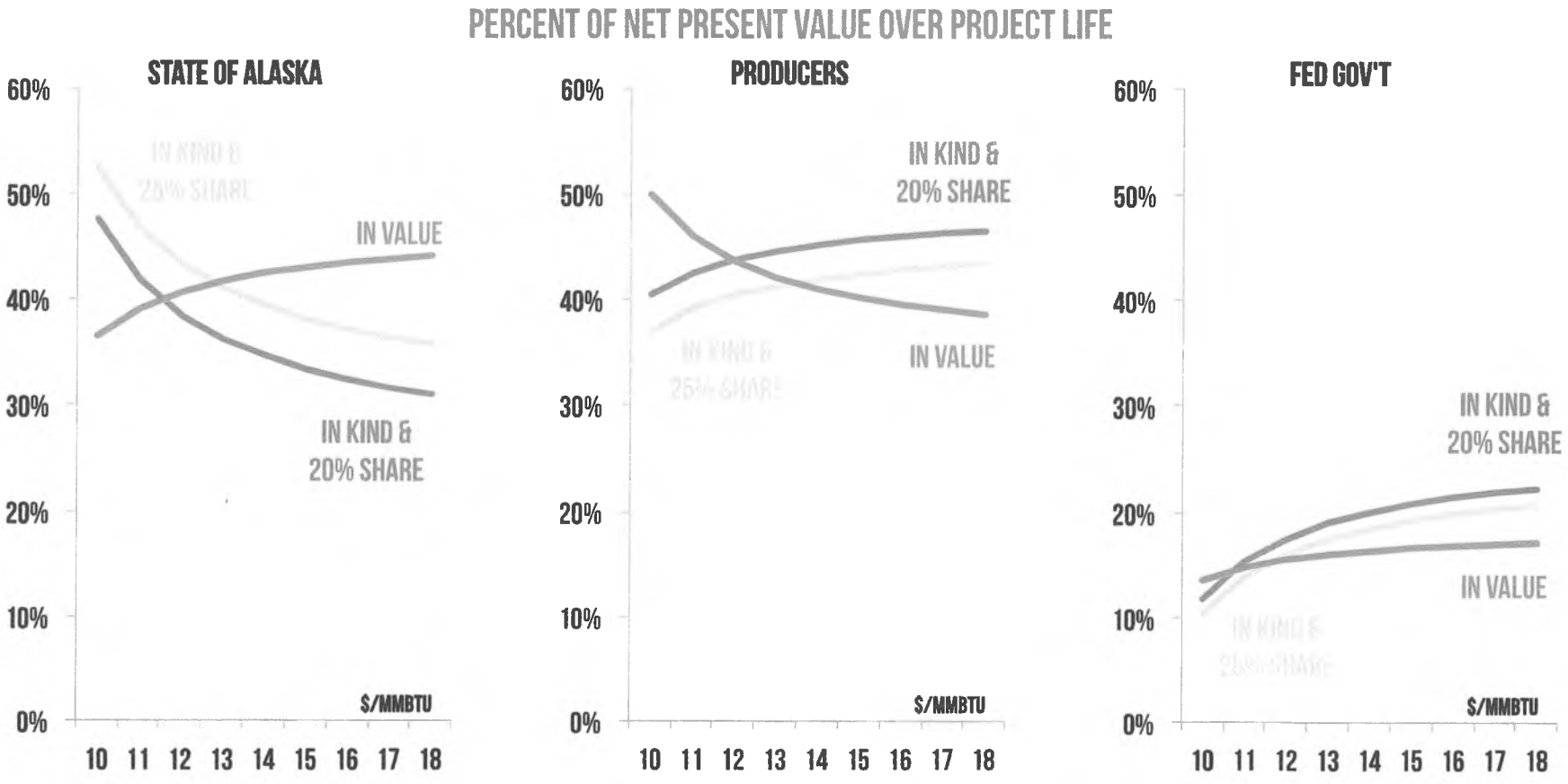
Higher SOA equity pushes up the price at which 'in value' is better than equity

CUMULATIVE CASH FLOWS OVER PROJECT LIFE



SOA SHARE OF VALUE HIGHER THAN EQUITY SHARE

SOA participation in midstream means fixed tariff for producers no longer "guaranteed"

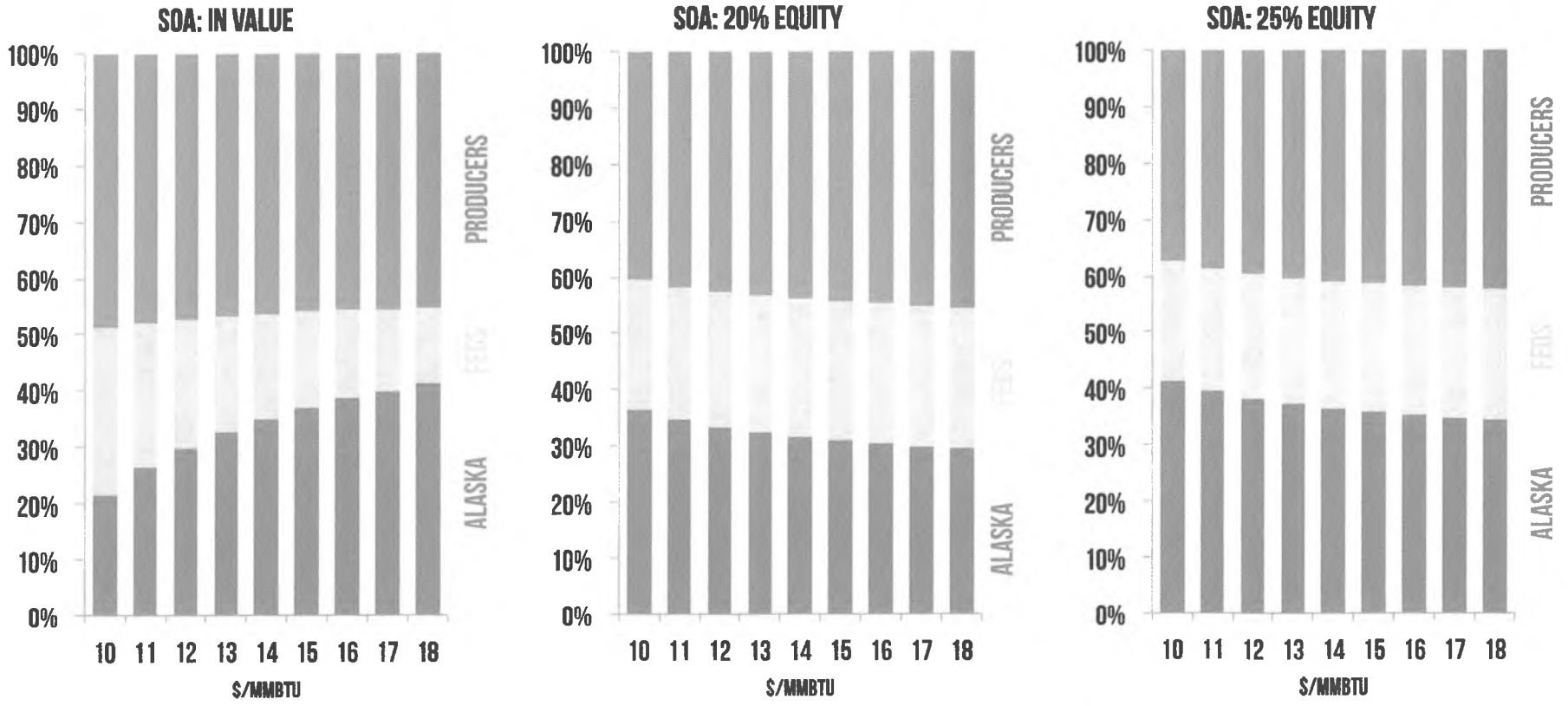


SOA EQUITY LEADS TO HIGHER GOV'T TAKE ON AVERAGE

'In value' entails lowest government take, especially in low prices as cash goes to producers

Split between Fed vs. SOA split depends on both 'in value' vs. 'in kind' as well as SOA equity share

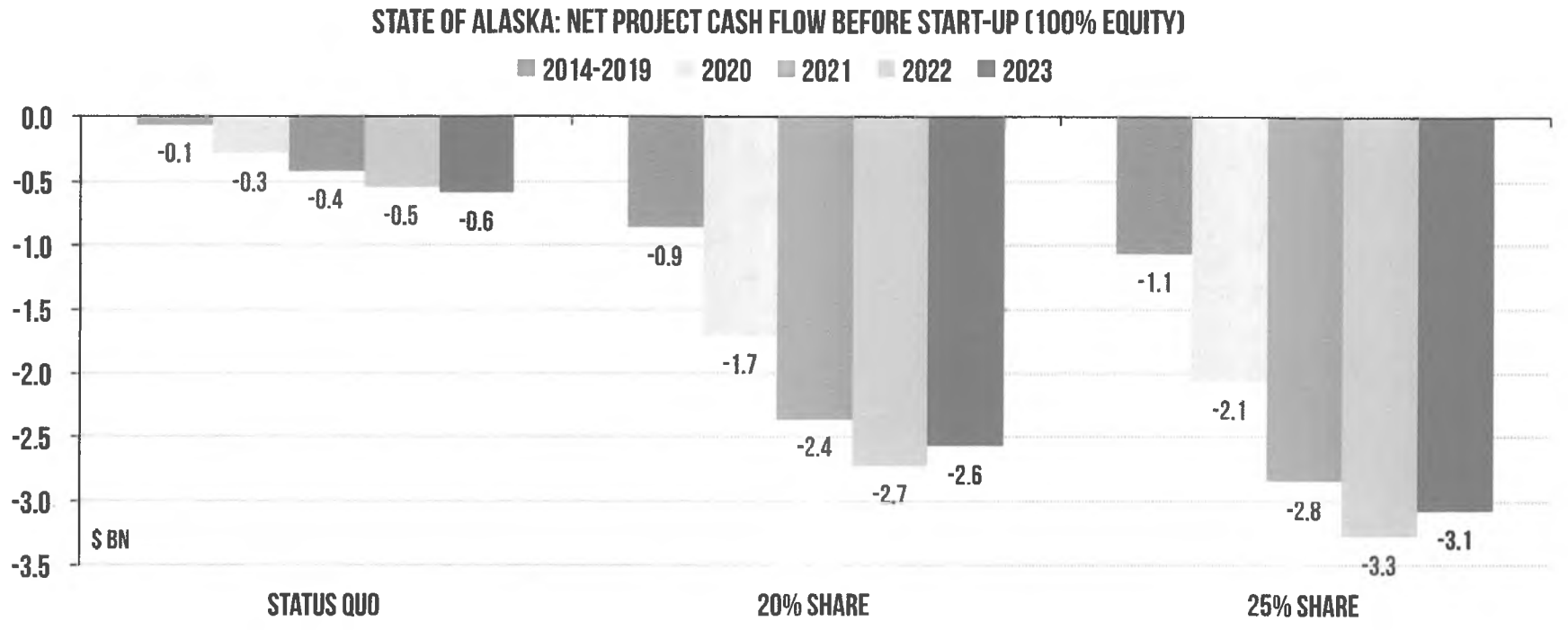
PERCENT OF CUMULATIVE CASH FLOWS OVER PROJECT LIFE



EQUITY BOOSTS SOA OUTLAYS TO $10.2-$12.3 BN

Annual outlays could peak at $2.7 (20% equity) to $3.3 bn (25% equity), assuming no debt

Even in status quo ('in value'), state has outlays through the tax system



Total:	$1.90 bn	$10.2 bn	$12.3 bn

PROJECT	SANCTIONED	TARGET DATE	ACTUAL DATE	DELAY	BUDGET BN	COST BN	% OVERRUN
Snøhvit (Norway)	Mar-02	2006	Sep-07	1.5 years	NOK39.50	NOK48.00	21.5%
Egyptian LNG T1	Sep-02	Aug-05	May-05	3 months early	$1.1	on budget	0%
Sakhalin-2 (Russia)	May-03	2007	Mar-09	2 years	$10.0	$22.0	120.0%
Atlantic LNG T4 (Trinidad)	Jun-03	2005	Dec-05	on time	$1.2	on budget	0%
Egyptian LNG T2	Jul-03	Jun-06	Sep-05	9 months early	$0.6	on budget	0%
Equatorial Guinea	Jun-04	Late 2007	May-07	6 months early	$1.5	on budget	0%
North West Shelf (Australia)	Jun-05	2008	Sep-08	on time	AUS$2	AUS$2.6	30.0%
Yemen	Aug-05	Dec-08	Nov-09	1 year	$3.7	$4.5	21.6%
Peru	Jan-07	mid 2010	Jun-10	on time	$3.8	$3.9	2.6%
Pluto	Jun-07	Early 2011	May-12	1.5 years	AUS$11.2	AUS$14.9	33.0%
Skikda LNG (Algeria)	Jun-07	2011	Mar-13	2 years	$2.8	?	?
Angola	Dec-07	Early 2012	Jun-13	1.5-2 years	?	$10.0	?
Gorgon (Australia)	Sep-09	2014	n/a	n/a	$37.0	$54.0	45.9%
Papua New Guinea	Dec-09	2014	n/a	n/a	$15.0	$19.0	26.7%
Queensland Curtis (Australia)	Nov-10	2014	n/a	n/a	$15.0	$20.5	36.7%
Gladstone LNG (Autralia)	Jan-12	2015	n/a	n/a	$16.0	$18.5	15.6%

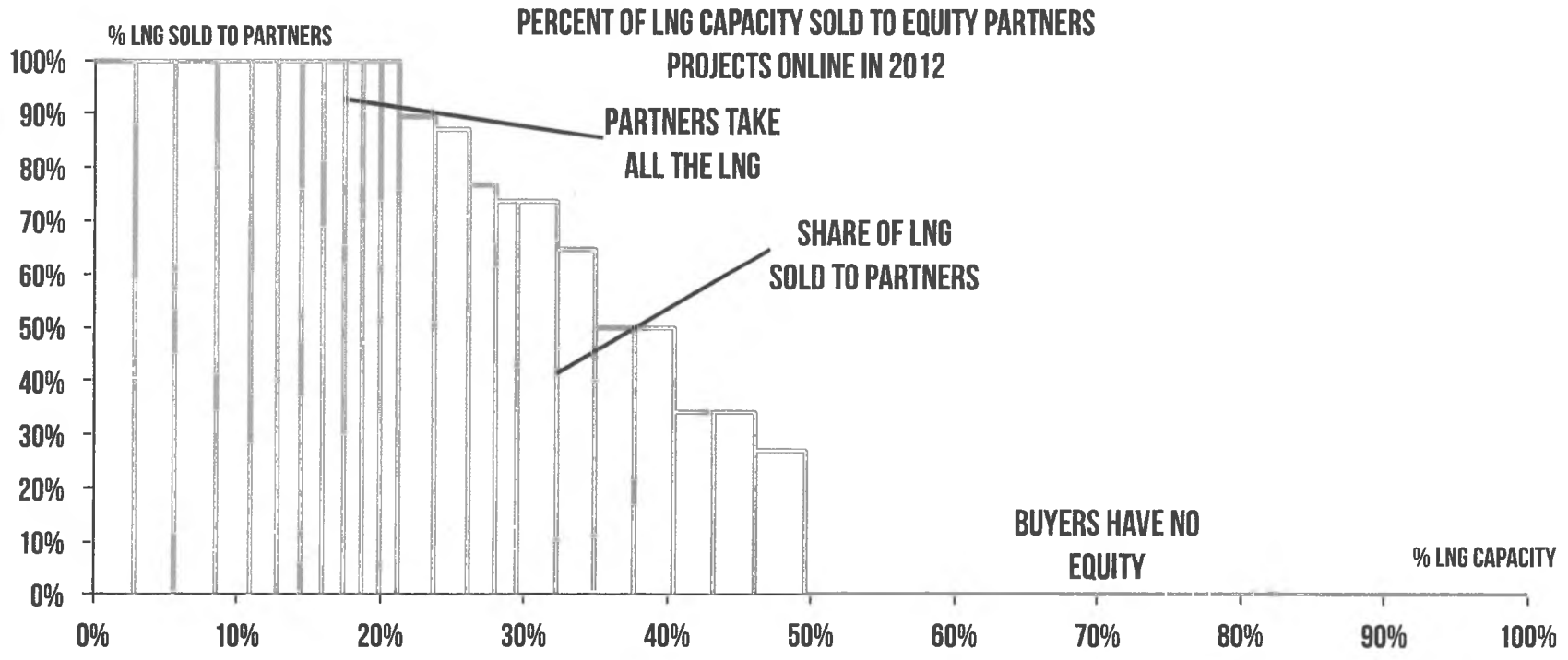
SOURCE: ENALYTICA BASED ON COMPANY PRESS RELEASES AND INDUSTRY PRESS

BUYERS OFTEN TAKE EQUITY IN LNG PROJECTS

In half of the world's LNG capacity, a share of the LNG is sold to equity partners

Such deals can mitigate risk by aligning supplier-buyer interests (e.g. output shortfall)

Buyers get sense of supply security, and these deals often open up the project to third-party financing



SOURCE: BASED ON GIIGNL, THE LNG INDUSTRY IN 2012, HTTP://WWW.GIIGNL.ORG/SITES/DEFAULT/FILES/PUBLICATION/GIIGNL_THE_LNG_INDUSTRY_2012.PDF

PROJECT FINANCE WELL ESTABLISHED IN LNG

IHS estimates that LNG projects raised over $97 billion in third-party financing since 2000

Financing from project sponsors, export credit agencies, multilateral banks and commercial banks

Commercial loans can also secure sovereign guarantees as insurance

The Japan Bank of International Cooperation (JBIC) is the largest single provider of funds

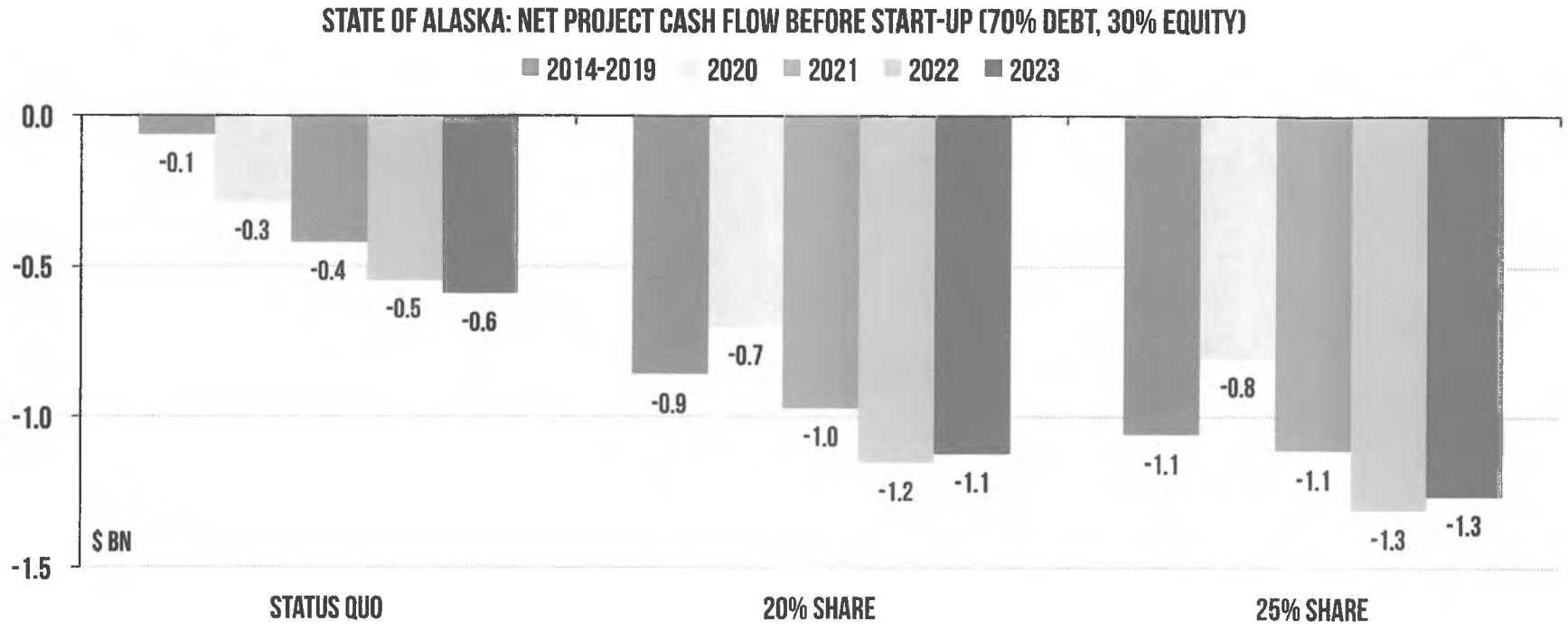
Examples

AP LNG	$5.8 billion	US EXIM, China EXIM, banks
Ichthys	$20 billion	JBIC, Korea and Australia EXIM, banks, sponsors ($4 bn)
Papua New Guinea	$14 billion	Six ECAs and 17 banks, ExxonMobil
Peru	$2.25 billion	IADB, US EXIM, Korea EXIM, IFC, others
Sakhalin-2	$6.4 billion	JBIC, NEXI, banks
Tangguh	$3.5 billion	JBIC, ADB, banks

SOURCES: IHS IN LEDESMA, ET. AL, "THE COMMERCIAL AND FINANCING CHALLENGES OF AN INCREASINGLY COMPLEX LNG CHAIN," LNG 17 (APRIL 2013); INDUSTRY PRESS

SOA CASH CALL $4.8-$5.5BN WITH 70/30 DEBT/EQUITY

Peak outlays shrink to $1.2 to $1.3 bn depending on equity level (20% or 25%)



	STATUS QUO	20% SHARE	25% SHARE
Total:	$1.90 bn	$4.8 bn	$5.5 bn

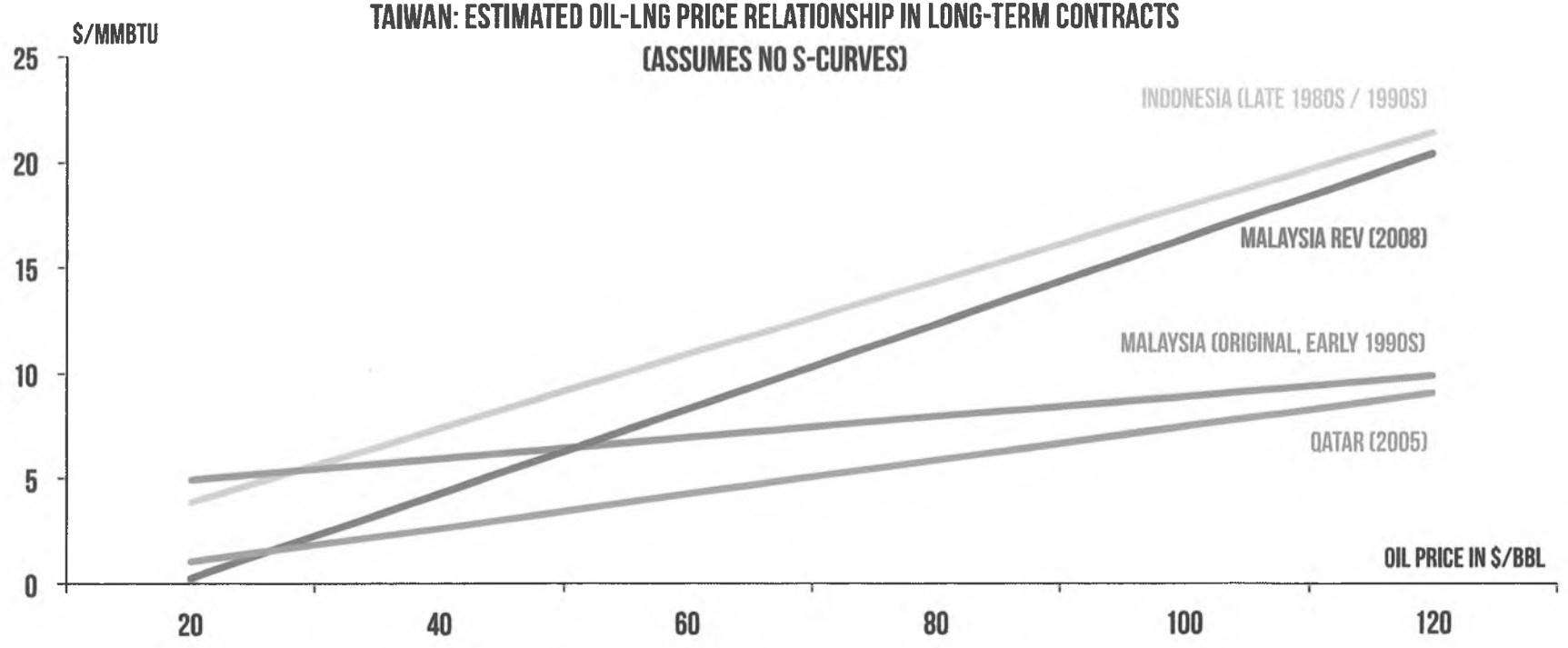
PRICE EXPOSURE DEFINED AT CONTRACT SIGNING

Oil linkage does not mean identical **linkage to oil (e.g. Taiwan, below); bargaining power defines linkage**

New contracts do not impact **existing deals (e.g. new Henry Hub-based LNG vs. existing oil-linked SPAs)**

But if price is seriously out of sync with fundamentals, parties can trigger a review clause

TAIWAN: ESTIMATED OIL-LNG PRICE RELATIONSHIP IN LONG-TERM CONTRACTS
(ASSUMES NO S-CURVES)



SOURCE: ENALYTICA BASED ON DATA FROM TAIWAN'S CUSTOMS ADMINISTRATION, MINISTRY OF FINANCE (HTTP://WWW.CUSTOMS.GOV.TW/STATISTICSWEBEN/IESEARCH.ASPX)

EXPENSIVE PROJECTS CAN HEDGE AGAINST VOLATILITY

"S-curves" are clauses that change the relationship between oil and gas above or below thresholds

Instead of a linear link, gas prices do not rise/fall as much if oil prices rise/fall above certain thresholds

They reduce downside risk by forgoing some upside—they can even provide a floor/ceiling on prices

	System	SOA ownership percent			SOA share of CAPEX & OPEX			SOA cash commitments	
	Value / Kind	Upstream	GTP & Pipe	LNG	Upstream	GTP & Pipe	LNG	Debt	Tariffs
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HOW COULD ALASKA STRUCTURE THE MIDSTREAM?

MIDSTREAM
- PRODUCERS
- PRODUCERS + STATE OF ALASKA
- PRODUCERS + STATE OF ALASKA + 3RD PARTY
  - LEVERAGE AGIA (TRANSCANADA)
  - TERMINATE AGIA & LAUNCH BID

PATH OF THE MEMORANDUM OF UNDERSTANDING (MOU)

MIDSTREAM
- PRODUCERS
- PRODUCERS + STATE OF ALASKA
- PRODUCERS + STATE OF ALASKA + 3RD PARTY
  - LEVERAGE AGIA (TRANSCANADA)
  - TERMINATE AGIA & LAUNCH BID

PRODUCER-SOA ALIGNMENT	Minimize disputes over where value is allocated Tariffs reflect value maximization across the entire chain
THIRD-PARTY EXPANSION	Midstream becomes an enabler for further exploration and development Expansion principles favor development of additional transportation capacity
IN-STATE DELIVERIES	Alaskan consumers receive cost at the lowest cost possible (given adequate returns on investment)
EXECUTION	Pipeline is delivered on time and at the lowest possible cost
CONTINUITY & MOMENTUM	Project maintains and accelerates current investment interest Project leverages work to date and is not delayed by possible litigation

PRODUCER ONLY: ALIGNMENT / EXPANSION WEAK POINTS

MIDSTREAM

- PRODUCERS
- PRODUCERS + STATE OF ALASKA
- PRODUCERS + STATE OF ALASKA + 3RD PARTY
  - LEVERAGE AGIA (TRANSCANADA)
  - TERMINATE AGIA & LAUNCH BID

✗	PRODUCER-SOA ALIGNMENT	Significant potential for disputes over allocation of value, and optimal level for midstream tariff
✗	THIRD-PARTY EXPANSION	Focus on commercializing producers' resources over gas belonging to third parties
✗	IN-STATE DELIVERIES	Uncertain tariff for in-state deliveries (of SOA's gas)
✓	EXECUTION	Strong and proven ability to execute, but midstream becoming less of a core focus for majors
?	CONTINUITY & MOMENTUM	Uncertainty about possibility of litigation and loss of work done to date

SOA EQUITY: MORE EXPANSION BIAS BUT BURDEN ON SOA

MIDSTREAM

- PRODUCERS
- PRODUCERS + STATE OF ALASKA
- PRODUCERS + STATE OF ALASKA + 3RD PARTY
  - LEVERAGE AGIA (TRANSCANADA)
  - TERMINATE AGIA & LAUNCH BID

✓	PRODUCER-SOA ALIGNMENT	Strong alignment between producers and SOA
?	THIRD-PARTY EXPANSION	Relies on SOA to drive expansions, seeking new entrants and / or new partners; SOA may not be best placed to fill this role
✓	IN-STATE DELIVERIES	SOA can use its equity-entitled capacity to carry gas to local markets at lower cost
✓/?	EXECUTION	Strong and proven ability to execute for initial investment; expansion will depend on securing capabilities and/or another party
?	CONTINUITY & MOMENTUM	Uncertainty about possibility of litigation and loss of work done to date

MOU: EXPANSION BIAS & MOMENTUM; BUT BEST DEAL?

MIDSTREAM

- PRODUCERS
- PRODUCERS + STATE OF ALASKA
- PRODUCERS + STATE OF ALASKA + 3RD PARTY
  - LEVERAGE AGIA (TRANSCANADA)
  - TERMINATE AGIA & LAUNCH BID

✓	PRODUCER-SOA ALIGNMENT	Strong alignment between producers and SOA; capital structure for rate-setting purposes appears within norm, but unclear if new bidding could have produced lower tariff
✓✓	THIRD-PARTY EXPANSION	TransCanada will be advocate for a project structure that encourages expansion and will have incentive to drive expansion of the infrastructure based on market interest
✓✓	IN-STATE DELIVERIES	SOA can use its equity-entitled capacity to carry gas to local markets at lower cost; pro-expansion bias further incentivizes possible in-state deliveries
✓	EXECUTION	TransCanada brings execution knowhow and expertise, while producers reinforce cost discipline (to ensure lowest possible tariff)
✓	CONTINUITY & MOMENTUM	Project maintains and accelerates investment interest and leverages work done to date

BID: WILL REWARD COMPENSATE FOR COST IN TIME AND $?

MIDSTREAM

- PRODUCERS
- PRODUCERS + STATE OF ALASKA
- PRODUCERS + STATE OF ALASKA + 3RD PARTY
  - LEVERAGE AGIA (TRANSCANADA)
  - TERMINATE AGIA & LAUNCH BID

✓/?	PRODUCER-SOA ALIGNMENT	Strong alignment between producers and SOA; new bid could lead to a lower tariff, but it could also lead to a higher one; low investor interest could also slow down entire process
✓	THIRD-PARTY EXPANSION	Third party will have incentive to drive expansion of the infrastructure based on market interest, but would likely have less influence over current negotiations
✓✓	IN-STATE DELIVERIES	SOA can use its equity-entitled capacity to carry gas to local markets at lower cost; pro-expansion bias further incentivizes possible in-state deliveries
✓	EXECUTION	Third party would presumably bring execution knowhow and expertise, while producers would reinforce cost discipline (to ensure lowest possible tariff)
✗	CONTINUITY & MOMENTUM	Uncertainty about possibility of litigation and loss of work done to date; HOA negotiations could slow down in anticipation of new bidding process and license award

SOA NEEDS TO CAREFULLY WEIGH KEY QUESTIONS

What compensation might the SOA have to pay and what intellectual property will Alaska LNG retain?

Will the HOA process slow down if the midstream is tied in litigation?

What are the odds that a new selection process will deliver better terms than those available today?

To what extent was the AGIA process representative of the industry's interest in an Alaskan pipeline?

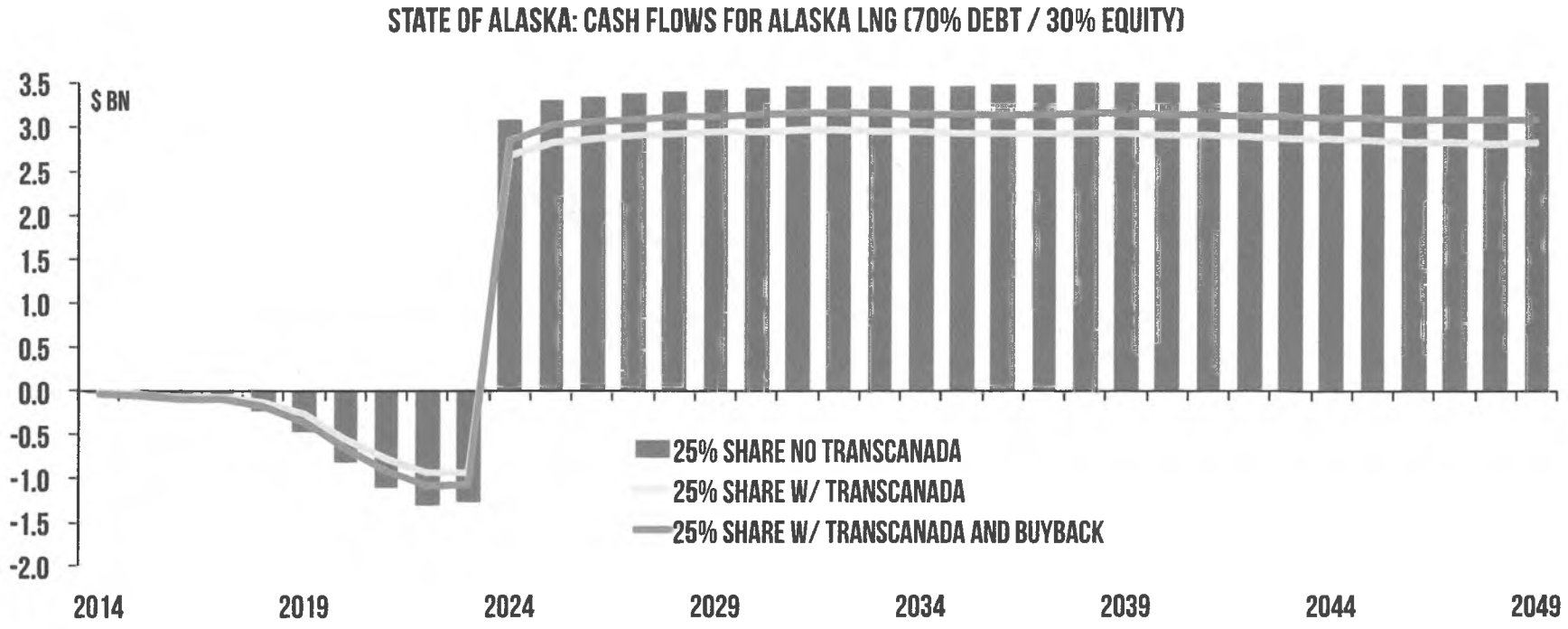
Would a new tariff offset absence from negotiating table; reduced momentum; cost to dissolve AGIA?

	PRODUCERS	PRODUCERS + STATE OF ALASKA	PRODUCERS + STATE OF ALASKA + TRANSCANADA	PRODUCERS + STATE OF ALASKA + 3RD PARTY
PRODUCER-SOA ALIGNMENT	✗	✓	✓	✓/?
THIRD-PARTY EXPANSION	✗	?	✓✓	✓
IN-STATE DELIVERIES	✗	✓	✓✓	✓✓
EXECUTION	✓	✓/?	✓	✓
CONTINUITY & MOMENTUM	?	?	✓	✗

FINANCIALLY, TRANSCANADA DEAL IS AKIN TO A LOAN

TransCanada shoulders a share of SOA's capital commitments and Alaska repays over time with tariff

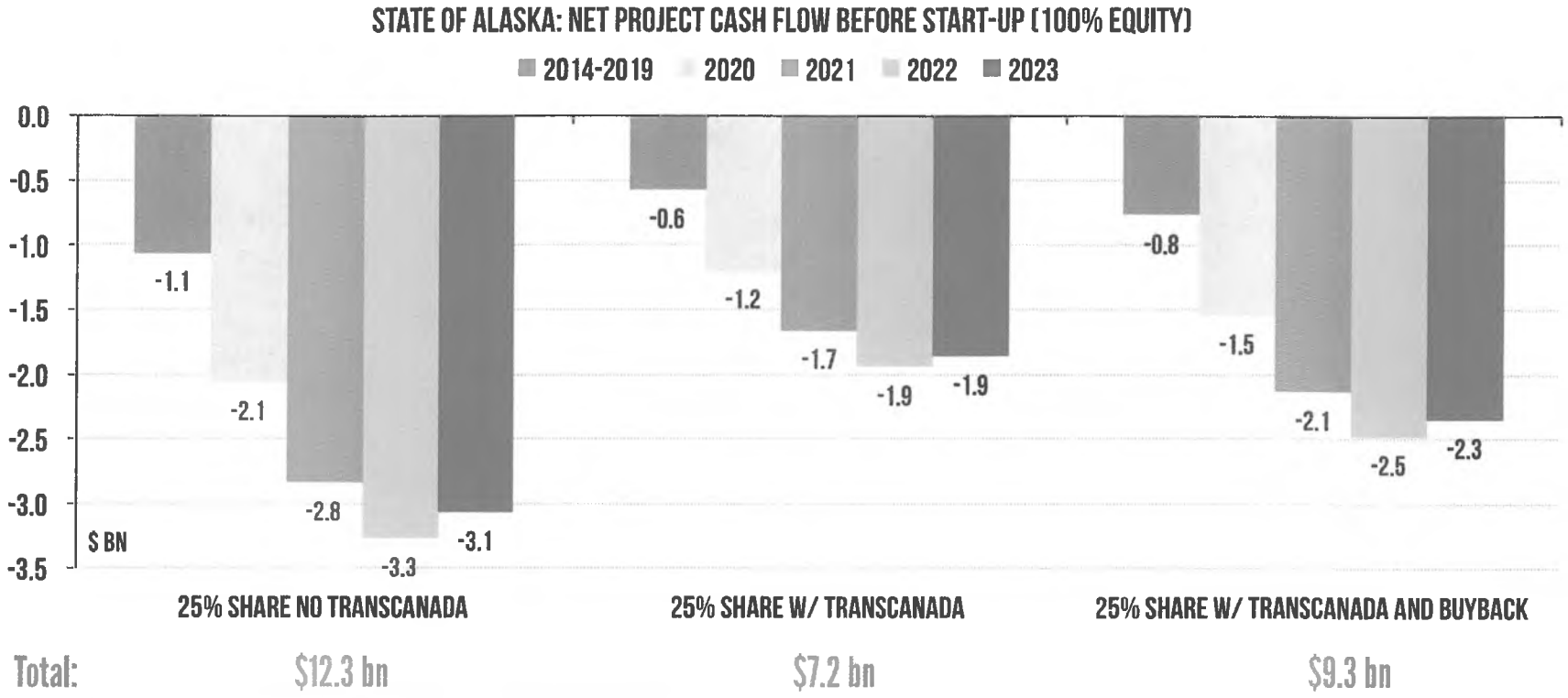
SOA outlays fall by $1,700 mm (no buyback) to $1 bn (buyback) during development period

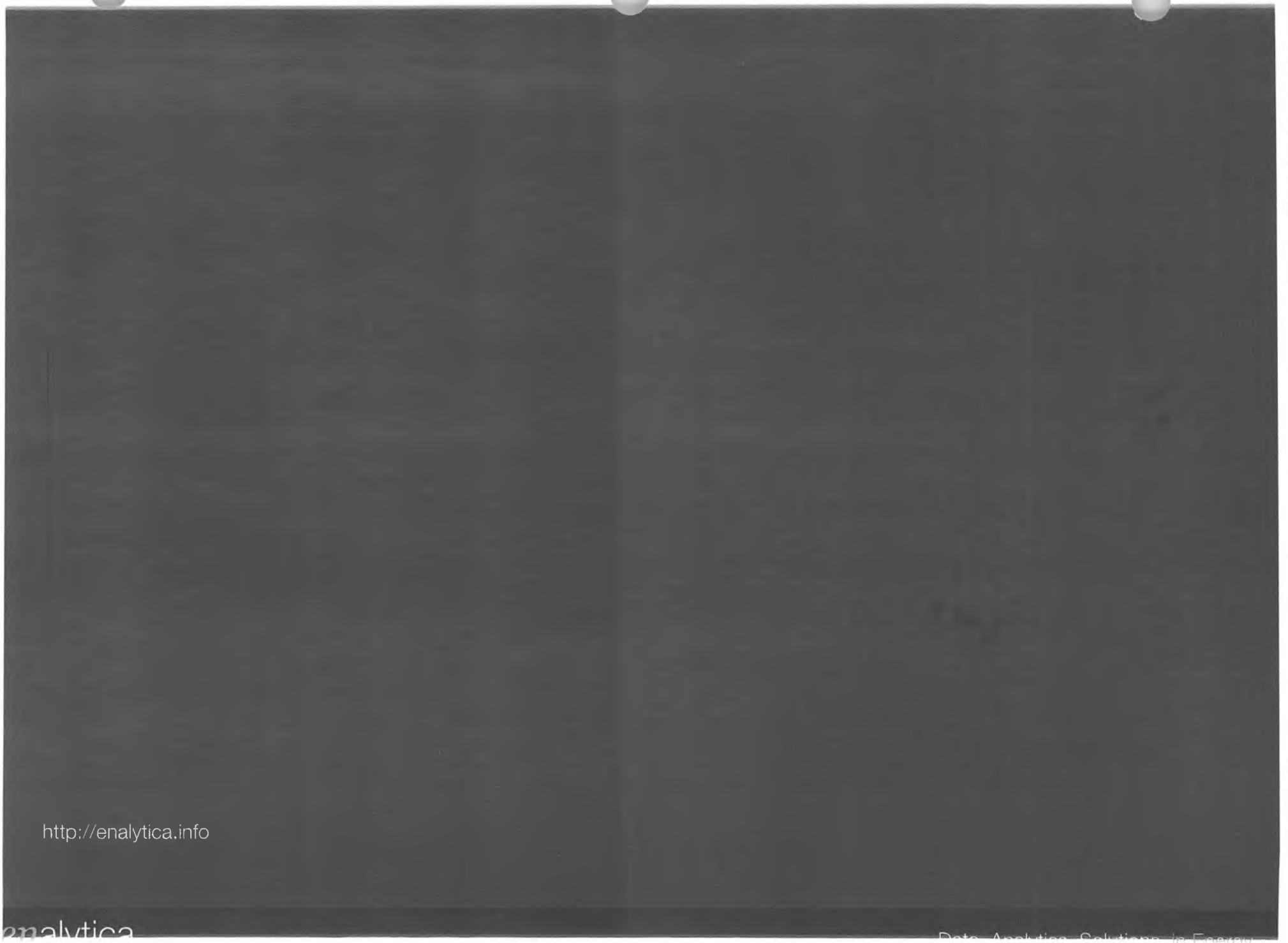


TRANSCANADA LOWERS SOA OUTLAYS BY $3-5 BN

TransCanada's participation would lower SOA peak outlays by $0.8 bn to $1.4

Buyback option also lowers outlays before FID (pre-2019)

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11

From: Larry Persily [mailto:lpersily@arcticgas.gov]
Sent: Wednesday, February 26, 2014 11:05 AM
To: Sen. Anna Fairclough
Cc: Laura Pierre; Bruce Campbell
Subject: Today's questions

Senate,

I wanted to answer your questions from Senate Finance this morning:

The federal loan guarantees and federal tax incentives in the Alaska Natural Gas Pipeline Act of 2004 apply only and exclusively to a project that serves North American (Lower 48) markets. It would require congressional action to amend the law to apply those benefits to an export project and, honestly, I have not heard or seen any interest whatsoever in such a change in Congress or the administration. I think the politics would be near impossible.

As for the Department of Energy export license, yes, a project developer would want to have that in hand before FID. And, in a related piece of information, an export project applicant needs to pre-FILE with FERC before the Department of Energy will put them on the priority list for review.

Let me know if you need any additional information. I am in Anchorage this week and next and certainly available if needed.

Larry

12

State Financial Participation in an Alaska Natural Gas Pipeline

- **The History**
- **The Project**
- **The Options**
- **The Costs**
- **The Risks of State Participation**

Prepared by the Alaska Department of Revenue
January 31, 2002

PETRIE PARKMAN & CO.

CH2M HILL

Executive Summary

The purpose of this report is to examine whether the State of Alaska should financially participate in a pipeline to transport natural gas from Alaska's North Slope to domestic or foreign markets.

The legal and fiscal issues today are not much different than the gas pipeline concerns Alaskans have grappled with over the past 30 years. During that time, the state and private groups commissioned several reports both favoring and dissuading state financial participation. Although the issues have not changed much, certainly the legal, regulatory, market and fiscal situation today is much different than that of decades ago.

Today, proponents of state involvement cite three main reasons for the state to participate in ownership or financing of an Alaska Gas Pipeline project:

- It would be a good investment with a healthy rate of return and minimal risk.
- Alaska should control its own financial destiny and development of its resources.
- State involvement would enhance the project's feasibility—that is, the pipeline would stand a better chance of getting built sooner if the state was a financial partner.

The answers, however, are much less clear than the questions.

A Good Investment

The state is in a precarious financial position as it starts 2002. Its ability to provide essential services will be tested as the Constitutional Budget Reserve Fund runs out of money. The Department of Revenue projects that the reserve fund, which has helped cover state spending for all but two years since 1991, will hit empty by Labor Day 2004. Alaska may be resource rich but we are cash poor—unless you count the Permanent Fund. Other than taking money out of the Permanent Fund to invest in a gasline, the state is in no position to write a check for any significant investment in a gas pipeline project, regardless how good the investment.

The Alaska Permanent Fund

There are several options for using the Permanent Fund for state investment in the project:

- Spend money from the Earnings Reserve Account to buy in as a gasline partner. This means going into the business of owning and operating a natural gas pipeline. This could be done by a legislative appropriation to another state agency or new state corporation to make an equity investment in the pipeline. However, withdrawing too much from the Earnings Reserve Account could jeopardize its future ability to pay for inflation proofing of the fund's principal and dividends.
- The legislature could change state law to authorize a direct investment by the Permanent Fund in the gasline business. A statute change would be required because the Permanent Fund's investment authority does not cover going into the gasline business.
- Or the Permanent Fund, as part of its regular asset allocation and investment mix, could decide to buy shares in a public traded corporation or buy bonds issued by the corporation or corporations that own the pipeline. These investments, however, would give the state no more control over the project than any other minority shareholder, and any return would depend on the corporation's performance and stock or bond value. Any such investment would—by constraint of the Prudent Expert Rule for Permanent Fund investments—be limited to a small percentage of a pipeline corporation's stock or debt.

Taking on State Debt

The state and its municipalities are looking at how to pay for several billion dollars of school construction and repairs, and deferred maintenance to public facilities. The state, which has not issued any general obligation bonds in nearly 20 years, will go to market in the next year if legislators agree with the governor's proposal for school bonds. Taking on new debt for schools and other needs most likely will consume all of the state's available debt capacity, unless Permanent Fund earnings are diverted from the dividend program to pay debt service.

Any over-ambitious reliance on debt to finance a state investment in the gasline could jeopardize Alaska's credit rating, which could have a domino effect as it raises the cost of borrowing for the state and municipalities.

Rate of Return

The Federal Energy Regulatory Commission in the United States and the National Energy Board in Canada would regulate the rate of return on any interstate pipeline, and we expect that return would not differ significantly from what the state—or the Permanent Fund—could earn in other investments with similar risks.

Risks to the State

State investment as a partner in the project could put the state at financial risk if there are construction overruns, delays in completion of the project, unbudgeted calls for additional capital, or volatile natural gas market conditions. Unlike large corporations, the state does not maintain reserves for such risks, and it would be a difficult policy call to tell the public that key government services might be cut back to make money available for gasline expenses.

State Control

Proponents who advocate state financial participation in the project for reasons of control raise two points: (1) Alaska should take a stronger hand in managing its resource development, and (2) a belief that North Slope oil producers took advantage of the state by inflating tariffs on the Trans-Alaska Pipeline System, thereby reducing their oil tax and royalty payments to the state.

Both are emotional issues, and both require an unemotional review.

First, whether the state should take an active role in managing the development and marketing of its oil and gas resources is a public policy call. If people believe that is the overriding issue in this project, then it might justify the financial risks to the state. However, advocates of this position should carefully weigh the risks against the potential benefits. Could state participation in the gasline make it happen any sooner? Would state participation dissuade corporations from putting up their own billions—private money that Alaska needs. And is it the role of government to build and operate for-profit ventures? We believe the state could best control the development of its resources by regulating their extraction and use, and

could best profit from its resources by levying reasonable taxes on the companies that profit from their development.

Second, whether the state received less revenue because of the oil pipeline tariff structure—as some have alleged over the years—is immaterial to the gasline. The Federal Energy Regulatory Commission would regulate the gasline tariffs, and the state would have full access to those proceedings—regardless whether it had a so-called "seat at the table" as an active partner in the business. The state would not gain any more control over the gasline tariff as a business partner than simply participating in the federal regulatory proceedings as the State of Alaska.

And, assuming the state was not the sole owner or majority owner of the gasline, its seat at the table would most certainly be a minority seat with little or no ability to influence any major corporate decisions. The state would have more authority with its own statutes and regulations to influence project management decisions than as a minority business partner.

It is also important to note that even if the state had a seat at the table as a partner operating the gasline, the state could not use any information from the table in tax or regulatory proceedings on the project, nor could it use any of the proprietary information to compete with its other partners for natural gas sales. Confidential information set out on the table would have to remain at the table.

Helping the Project

The two biggest hurdles to building a project to carry natural gas from Alaska's North Slope to market are: (1) the risk of construction cost overruns, and 2) the risk that in periods of low market prices either the pipeline operators or the shippers would suffer a loss. State participation as a business partner would do nothing to lessen either risk and, in fact, some might argue that state involvement in building and operating the line could add to the cost.

Although people talk more and more about running government like a business, the truth is government is not a business. It has rules and regulations and procedures and public access laws that could present formidable problems should government sign on as a partner with a private business venture. Nor surprisingly, none of the oil and gas and pipeline industry

representatives interviewed for this report saw much, if any, benefit to having the state sit on the board of directors of a gasline venture. Many listed such state laws as open meetings, public records and procurement codes—not to mention the entire process of public policy decisions—as key reasons not to take on the state as a partner. Speed and decisiveness are essential to running a multibillion-dollar construction job and company, and, unfortunately, it's highly possible that state involvement would detract, not add, to the operation.

But the largest risk to any partner in the gasline venture is that there could be periods when the market price for gas is not high enough to cover the cost of moving the gas to market and still leave an economic wellhead value for the producers. There is no guarantee that year in and year out, over the entire life of the project, the market will be such that profits will flow to everyone involved in the gasline. Someone—the gas producers or the pipeline owners, if they are different than the producers—would have to take the risk that some of the gas sometimes could move to market at a loss.

If the producers build and operate the line to move their own gas, they would take the risk. If pipeline companies build the line, they and the producers could negotiate which of them shares how much of the risk. Either way, state participation in the project would do nothing to eliminate that risk.

For example, the gas flow at 4 billion cubic feet per day would be worth $14 million a day at $3.50 per million Btu. Perhaps two-thirds or more of that $3.50 would go toward the tariff—the cost of moving the gas to market. If the market price were to drop below that cost, the financial loss could be significant to anyone sharing in the risk. A market price just 10 cents below the cost of moving 4 Bcf per day to market would add up to a $400,000-a-day loss for whoever is contractually bound to the price risk.

Finally, the oil and gas and pipeline companies on the list of potential sponsors simply do not need the state's money to build the project. Their own finances are strong enough that they could either just write a check or raise the money they need from commercial financing sources or by issuing corporate bonds.

It appears state financial participation would do nothing to move along the project, unless the state could find a way under federal law to issue tax-exempt debt to own and/or finance the

project. The lower cost of tax-exempt debt could help tip the project toward economic feasibility, and that could be a proper role for the state to take in assisting in the development of its natural resources. Even with the lower interest rate on tax-exempt debt, however, it is still possible that the companies might choose to issue their own taxable debt in order to take advantage of the federal tax benefits of owning and depreciating the line.

As it says in the cover letter to this report, there are no easy answers.

13

SENATE FINANCE COMMITTEE

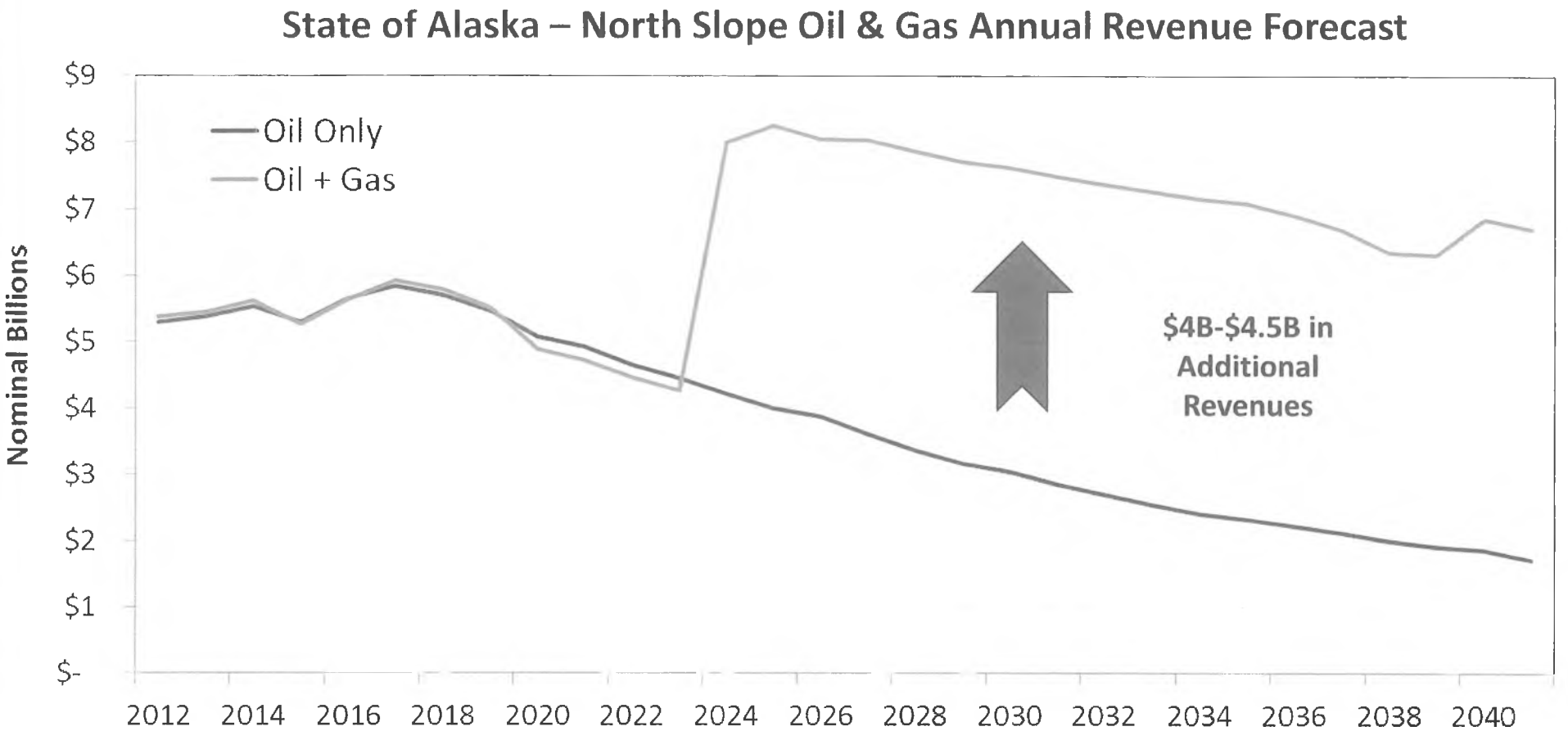
CLARIFICATIONS ON PREVIOUS PRESENTATIONS

PREPARED FOR THE STATE OF ALASKA

MARCH 5, 2014

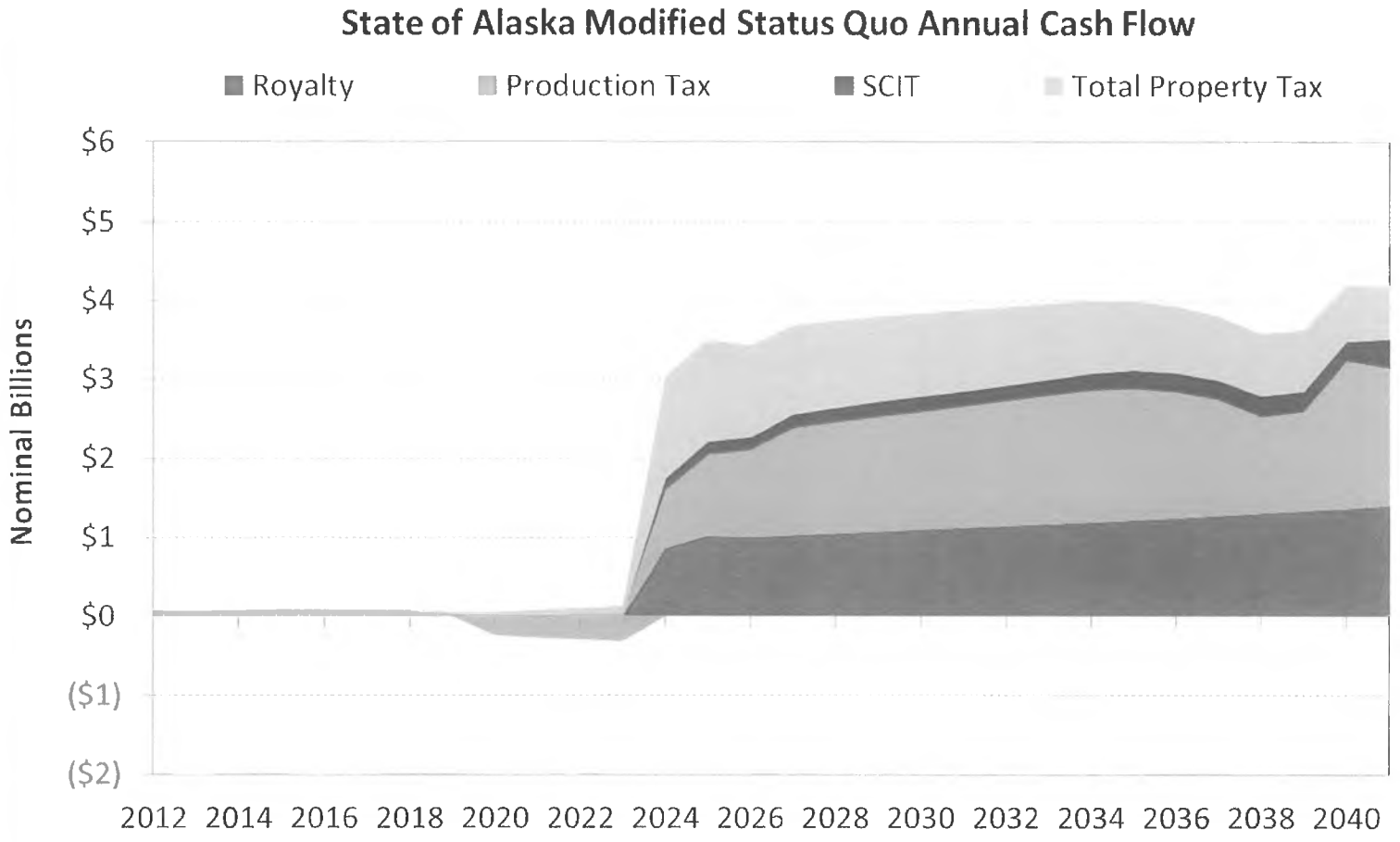
BLACK & VEATCH
Building a world of difference.

LONG-TERM NORTH SLOPE OIL & GAS REVENUES ARE DRIVEN BY AKLNG PROJECT SUCCESS



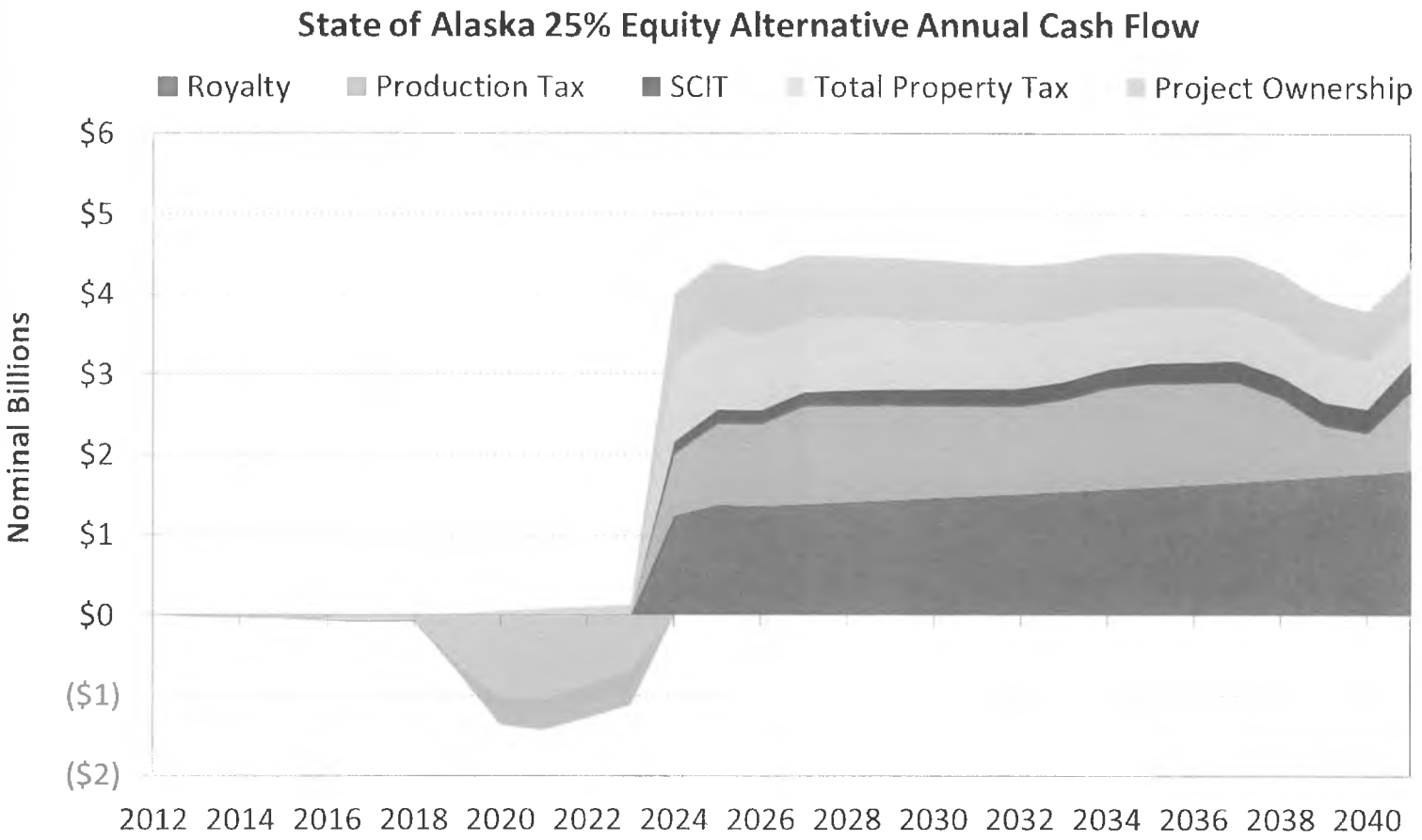
PRESERVE VALUE TO STATE FROM ROYALTY & TAXES

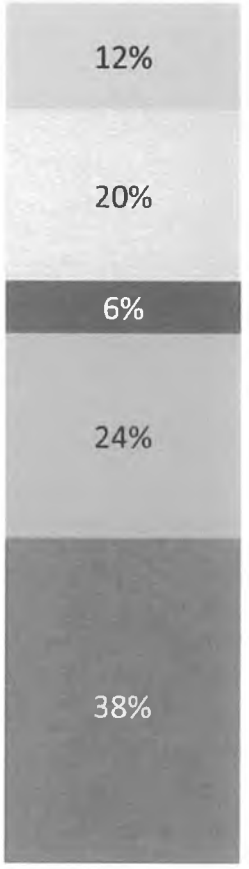
VALUE TO SOA



Total Cash Flow (Through 2041) = $68 Billion

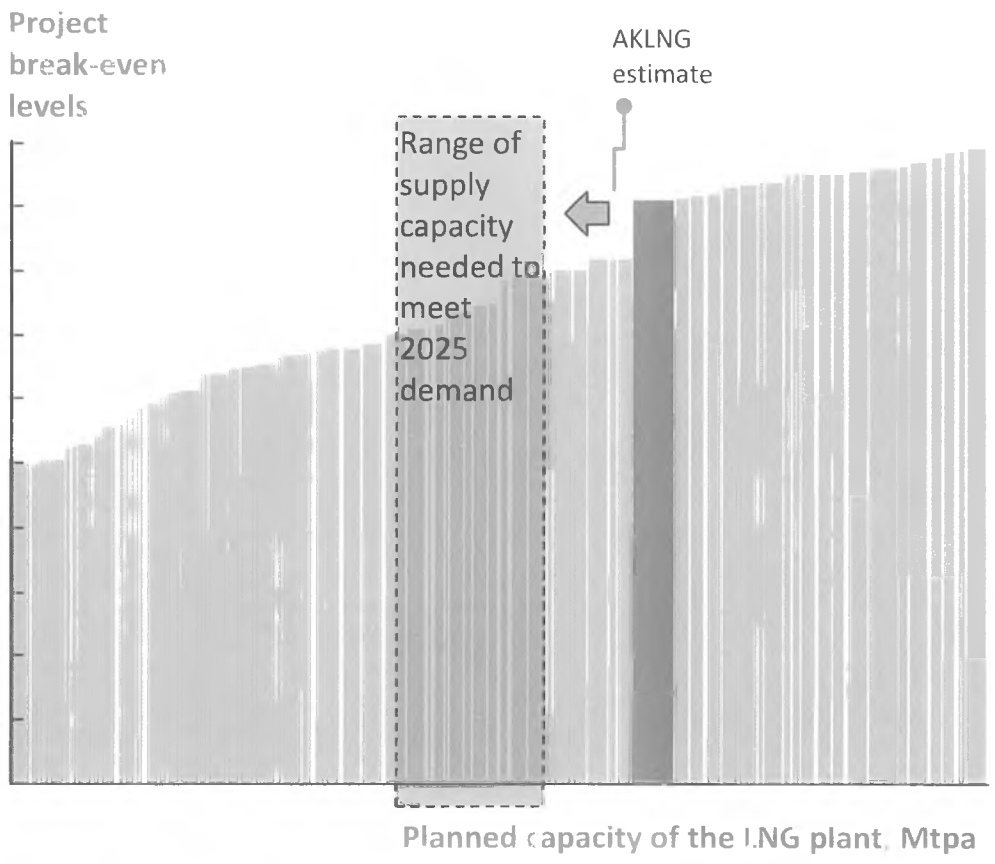
PRESERVE VALUE TO STATE FROM ROYALTY & TAXES





Total Cash Flow (Through 2041) = $72 Billion

ON THE GLOBAL SUPPLY CURVE, AKLNG APPEARS TO CURRENTLY BE OUT OF THE MONEY, MODIFICATIONS REQUIRED FOR COMPETIVENESS



ILLUSTRATIVE CHART, ANALYSIS DONE FOR ALL PROJECTS WITH STARTUP AFTER 2013

IMPLICATIONS:

1. **AKLNG is currently out of the money:**
   - **Alaska break-even price is US$12.3/MMBtu**
   - **Projects more economic than Alaska can provide ~340 MTPA new supply, more than required to meet global LNG demand (~250 – 300 MTPA)**
2. **AKLNG faces significant competition**
   - **There are several projects to the right in supply stack which will compete with AKLNG**
3. **However, the risk levels of competing LNG projects also needs to be considered**
   - **Due to political, resource and other risks, some in the money projects may be delayed/cancelled, leading to range of needed capacity**

[1] NPV=0 @ discounted at Weighted Average Cost of Capital

SOURCE: Team Analysis

BLACK & VEATCH STATEMENT

This presentation was prepared for the State of Alaska ("Client") by Black & Veatch Corporation ("Black & Veatch") and is based in part on information not within the control of Black & Veatch.

In conducting our analysis, Black & Veatch has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies we utilize in performing the analysis and making these projections follow generally accepted industry practices. While we believe that such assumptions and methodologies as summarized in this report are reasonable and appropriate for the purpose for which they are used; depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those projected.

Readers of this presentation are advised that any projected or forecast price levels and price impacts reflect the reasonable judgment of Black & Veatch at the time of the preparation of such information and are based on a number of factors and circumstances beyond our control. Accordingly, Black & Veatch makes no assurances that the projections or forecasts will be consistent with actual results or performance. To better reflect more current trends and reduce the chance of forecast error, we recommend that periodic updates of the forecasts contained in this presentation be conducted so recent historical trends can be recognized and taken into account.

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14

CASH CALLS, CASH FLOWS & IMPACT ON OIL REVENUES

Prepared for Senate Finance Committee
Juneau, Alaska › March 5, 2014

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JANAK MAYER
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Before co-founding *en*alytica, Janak led the Upstream Analytics team at PFC Energy, focusing on fiscal terms analysis and project economic and financial evaluation, data management and data visualization.

Janak has modeled upstream fiscal terms in all of the world's major hydrocarbon regions, and has built economic and financial models to value prospective acquisition targets and develop strategic portfolio options for a wide range of international and national oil company clients. He has advised Alaska State Legislature for multiple years on reform of oil and gas taxation, providing many hours of expert testimony to Alaska's Senate and House Finance and Resources Committees.

Prior to his work as an energy consultant, Janak advised major minerals industry clients on a range of controversial environmental and social risk issues, from uranium mining through to human rights and climate change. He has advised bankers at Citigroup and policy-makers at the US Treasury Department on the management and mitigation of environmental and social impacts in major projects around the world, and has undertaken macroeconomic research with senior development economists at the World Bank and the Peterson Institute for International Economics.

Janak holds an MA with distinction in international relations and economics from from the Johns Hopkins School of Advanced International Studies (SAIS), and a BA with first-class honors from the University of Adelaide, Australia.

NIKOS TSAFOS
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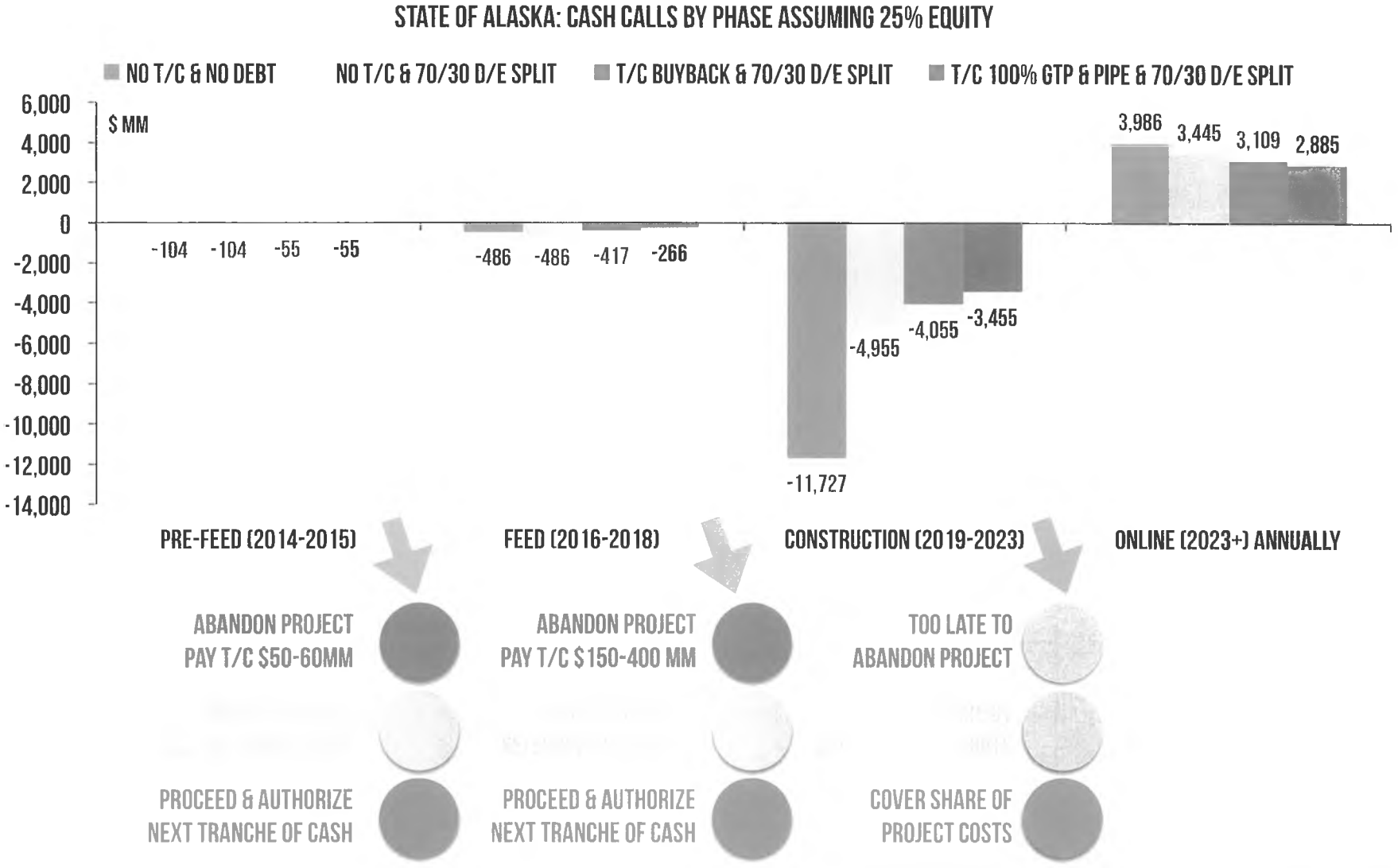
Nikos Tsafos has a diverse background in the private, public and non-profit sectors. He is currently a founding partner at *en*alytica. In his 7 ½ years with PFC Energy, Nikos advised the world's largest oil and gas companies on some of their most complex and challenging projects; he also played a pivotal role in turning the firm into one of the top natural gas consultancies in the world, with responsibilities that included product design, business development, consulting oversight and research direction.

Prior to PFC Energy, Nikos was at the Center for Strategic and International Studies (CSIS) in Washington, DC where he covered political, economic, and military issues in the Gulf, focused on oil wealth, regime stability and foreign affairs. Before CSIS, he was in the Greek Air Force, and prior to his military service, Nikos worked on channeling investment from Greek ship-owners to Chinese shipyards.

Nikos has also written extensively on the domestic and international dimensions of the Greek debt crisis. His blog (Greek Default Watch) was listed as one of "Europe's Top Economic Blogs" by the Social Europe Journal, and his book "Beyond Debt: The Greek Crisis in Context" was published in March 2013.

Nikos holds a BA with distinction in international relations and economics from Boston University and an MA with distinction in international relations from the Johns Hopkins School of Advanced International Studies (SAIS).

SOA'S CASH CALLS AND OFF-RAMPS

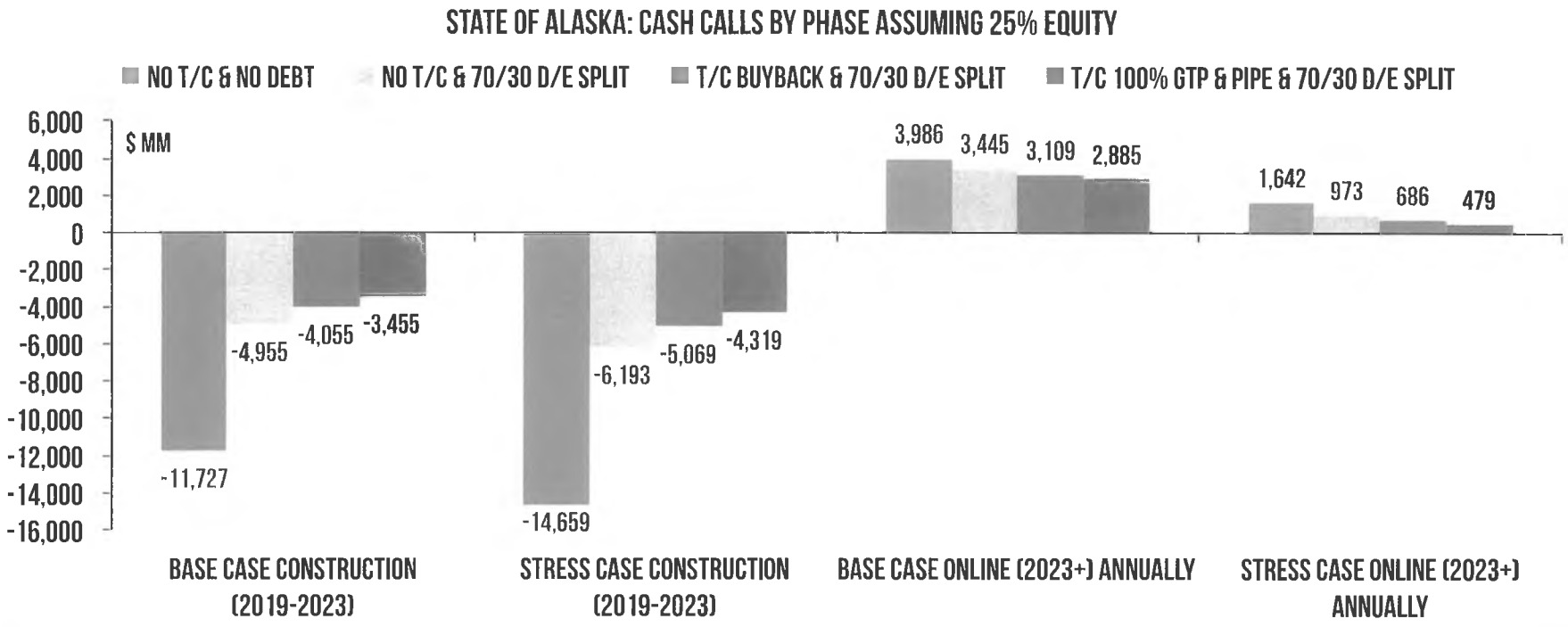


STRESS TESTING SOA'S CASH CALLS AND REVENUES

Stress Test Project CAPEX is 25% higher

+ Sales price is $7/mmbtu vs. $15/mmbtu in base case

+ Average utilization is 80% vs. 100% in base case

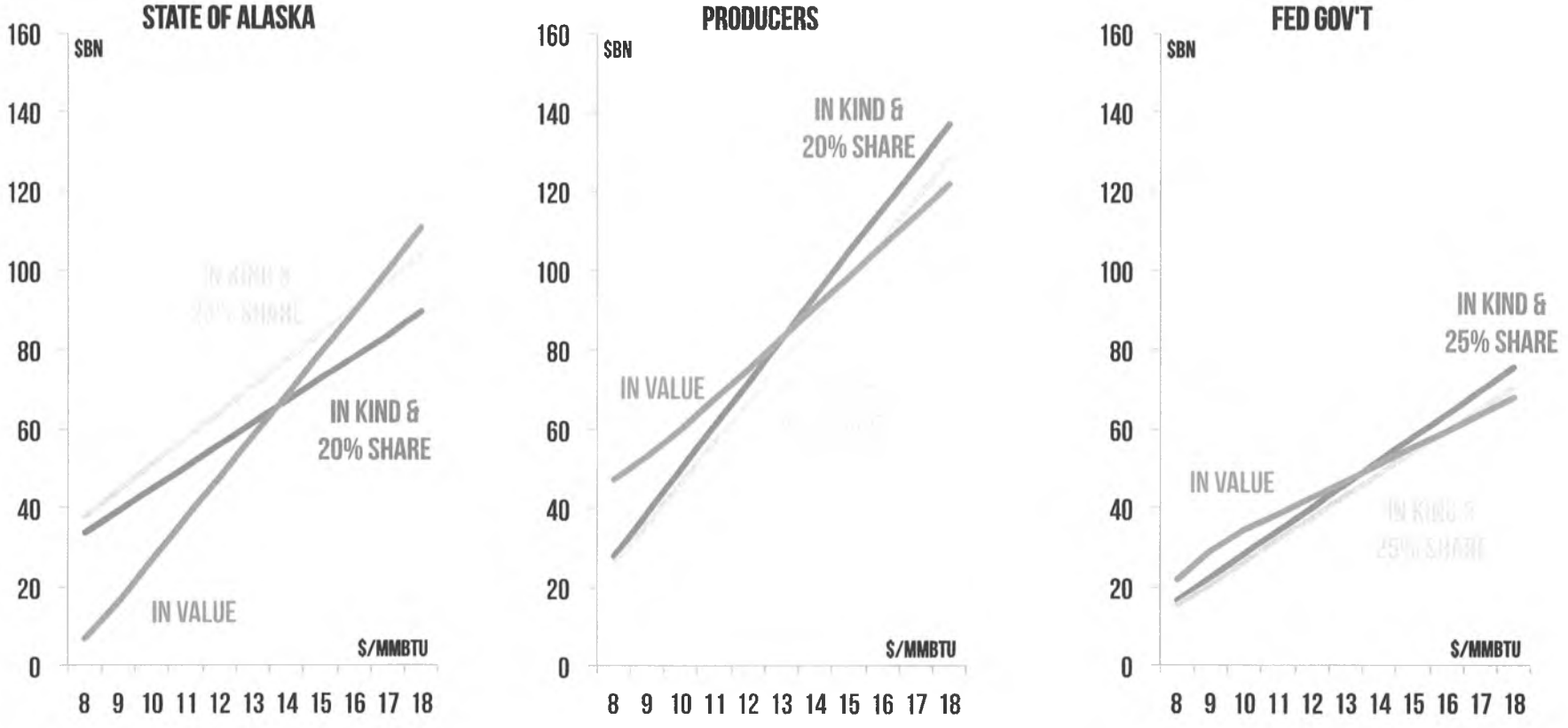


'IN KIND' W/ EQUITY OFFERS MORE DOWNSIDE PROTECTION

'In value' structure protects producers, not state, in low price environment because of tariff component

Higher SOA equity pushes up the price at which 'in value' is better than equity

CUMULATIVE CASH FLOWS OVER PROJECT LIFE



SOA EQUITY LEADS TO HIGHER GOV'T TAKE ON AVERAGE

'In value' entails lowest government take, especially in low prices as cash goes to producers

Split between Fed vs. SOA split depends on both 'in value' vs. 'in kind' as well as SOA equity share

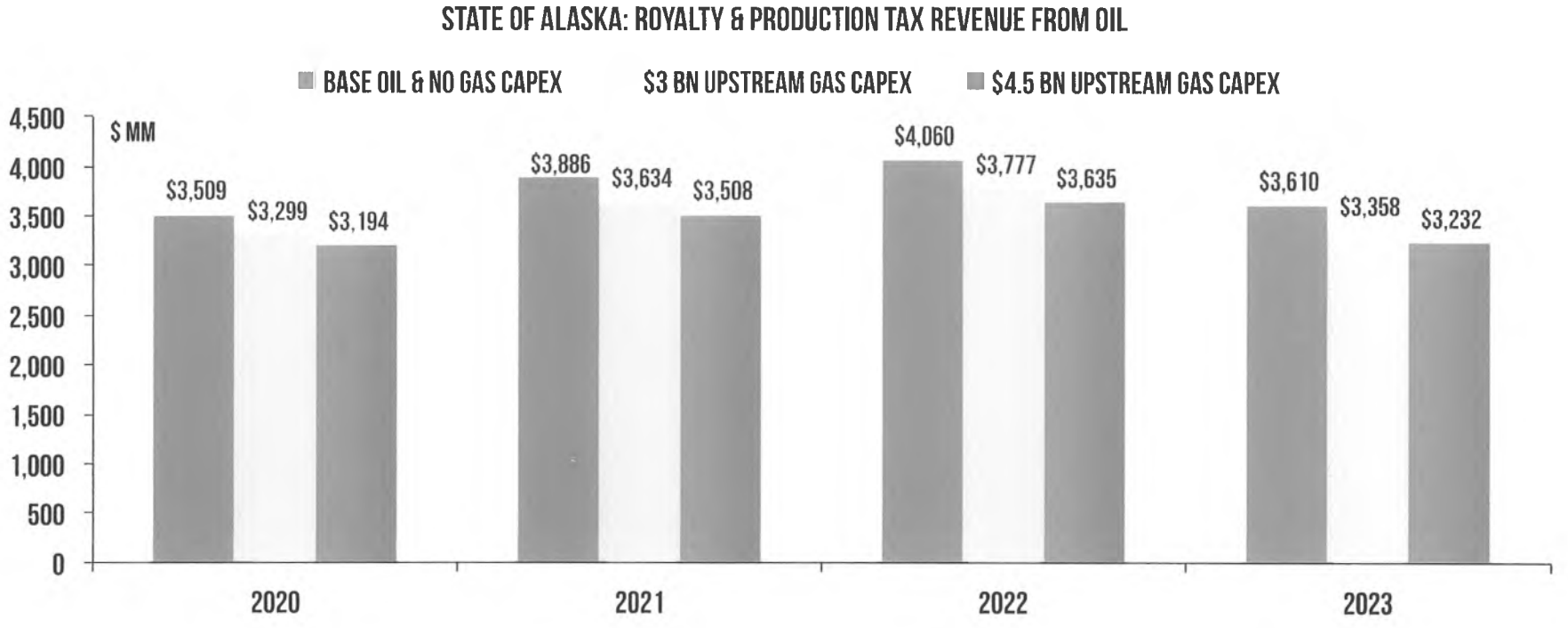
PERCENT OF CUMULATIVE CASH FLOWS OVER PROJECT LIFE

IMPACT OF GAS CAPEX ON OIL REVENUES

Lease expenditures for gas are deductible for calculating production value tax for oil

Relative to a no-gas scenario, oil revenues (royalty and production tax) will fall by $250 mm annually

If upstream costs end up 50% higher, oil revenues would fall by $374 mm annually vs. no-gas case



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15

Alaska gas pipeline project

What's different this time?

Larry Persily, Federal Coordinator for Alaska Gas Line Projects

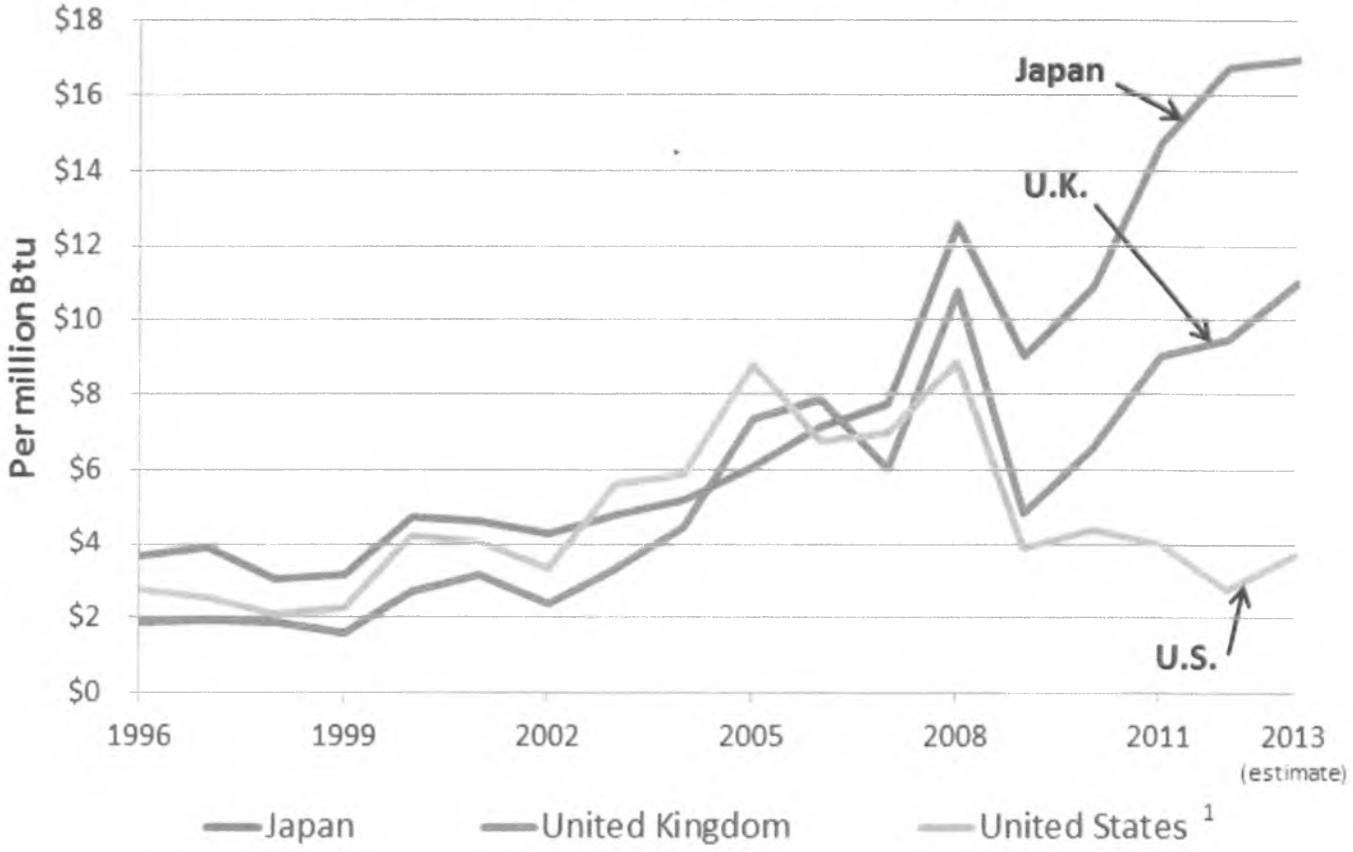
Senate Finance Committee – March 10, 2014

ALASKA NATURAL GAS
TRANSPORTATION PROJECTS
OFFICE OF THE FEDERAL COORDINATOR

The world changed, not us

- Global LNG trade has quadrupled since 1995
- Asian LNG demand alone could double by 2025
- China demand growing double-digit annual rate
- Europe looking for alternatives to Russian gas
- Worldwide concerns over coal, nuclear plants
- Alaska LNG could be the victor of circumstances

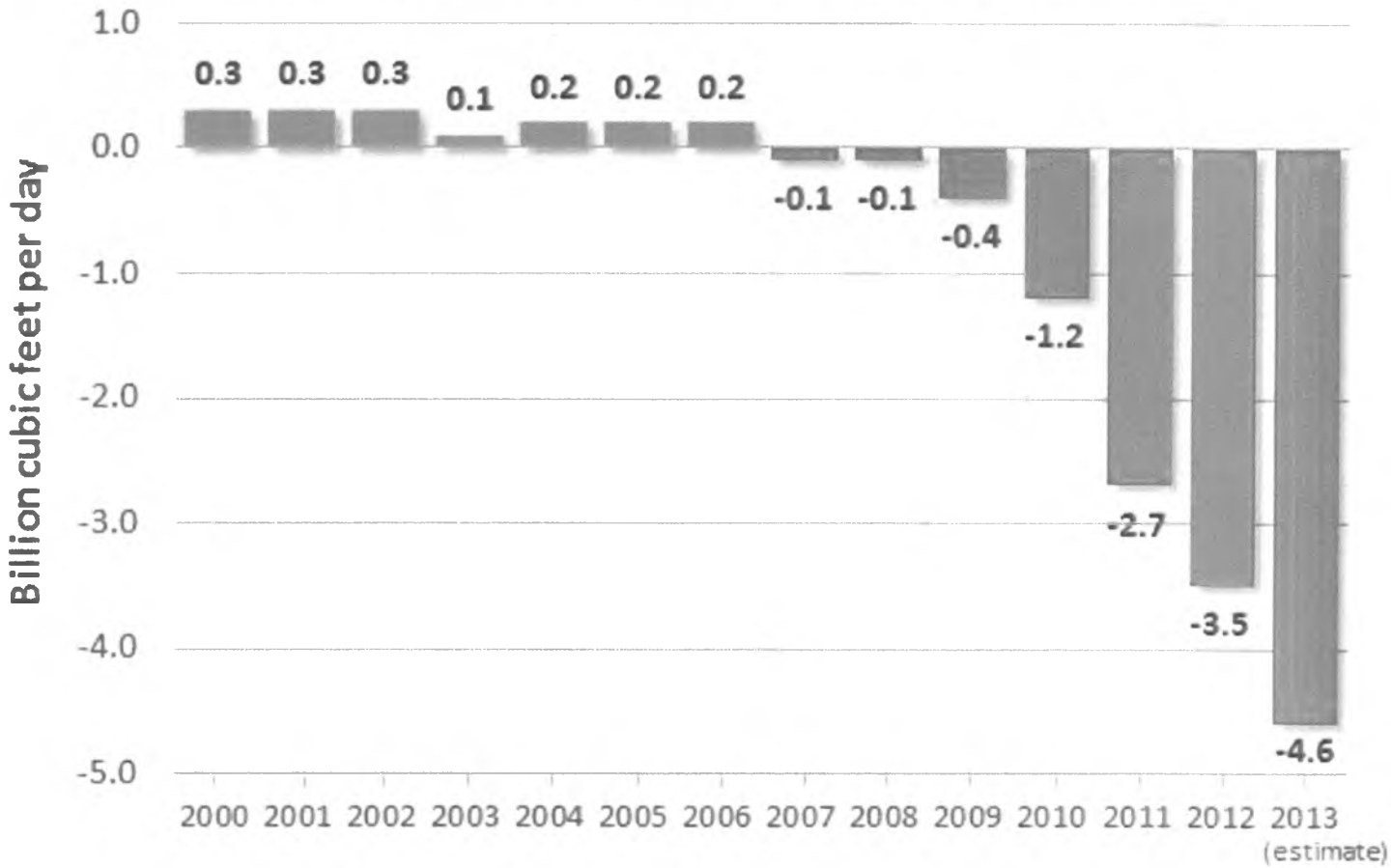
Global gas prices diverge



[1] Henry Hub price

Source: BP Statistical Review of World Energy

China's domestic gas supply deficit



Sources: BP, National Bureau of Statistics China, China SignPost

Price is everything

- Japan paid $70-plus billion for LNG in 2013
- Energy a big reason for $112 billion trade gap
- Third year in a row of trade deficit in Japan after more than 30 years of a trade surplus
- Japan leading the charge for new suppliers, more competition and lower LNG pricing regime
- Alaska could be price competitive in the market

No project has it easy

- BG Group says 525-mile natural gas pipeline to Prince Rupert could cost up to $10 billion
- LNG tax debate under way in British Columbia
- Dredging, harbor, berthing costs estimated at $1.5 billion for Australia's Wheatstone LNG
- Russian politics out ahead of project economics
- Buyers hold back, wait to see LNG pricing trend

Alaska has changed, too

- Prudhoe Bay growing older, economics look better as an oil and gas play rather than oil only
- Point Thomson under development and would supply 25 percent of the gas for the LNG project
- Major North Slope producers willing to spend significant money to advance the gas project
- Alaskans appear willing to consider investing significant state money into the LNG project

Patience is a virtue

- Patience is a must for state LNG investment
- Long wait for the first check — but long payback
- Norway invested billions in oil and gas and then waited years for any return; it took a decade before real investment payback started to roll in
- If it wants to act like an oil and gas business, Alaska must think like one — and think long term

What's changed since 2002

- DOR 2002 report looked at pipeline, not LNG
- Different markets, sales, risks and regulations
- State is in a better cash position today ($17 billion in savings) than 2002 ($2 billion)
- State equity investment in 2002 might have needed assistance from the Permanent Fund
- 100% state ownership was on the table in 2002

Some things haven't changed

- DOR 2002 report recommended the state match pipeline capacity with its share of the gas
- Report said conflicts as an owner and regulator are real, but state-owned corporation could provide a partial barrier to minimize the conflicts
- Minority ownership doesn't give state control
- Report warned: Keep politics out of the business

For more information

Office of the Federal Coordinator
for Alaska Natural Gas Transportation Projects

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www.arcticgas.gov

ALASKA NATURAL GAS
TRANSPORTATION PROJECTS
OFFICE OF THE FEDERAL COORDINATOR

16

THE STATE
of ALASKA
GOVERNOR SEAN PARNELL

Department of Natural Resources
Joe Balash, Commissioner
Department of Revenue
Angela M. Rodell, Commissioner

March 11, 2014

The Honorable Donald Olson
Alaska State Senator
State Capitol, Room 508
Juneau, AK 99801

Dear Senator Olson:

Please find the following response to your question from yesterday, March 10, 2014. You asked about the approach for establishing a framework for the settlement of property taxes, and if it is based on the agreement of the pipeline? In addition, you asked whether or not a large diameter gas line as contemplated under SB 138 would be exempt from municipal taxation if the state is an equity owner.

Reflecting that the Heads of Agreement (HOA) framework is a proposal to initiate consultation by the administration with local governments, nothing in the bill currently before the legislature makes any changes to the municipal property tax statutes in AS 29.45 or the state property tax statutes in AS 43.56. Under current law, an LNG plant is subject to local property taxes under AS 29.45 but not state property taxes under AS 43.56. The GTP and gas pipeline would be subject to state property taxes under current law. However, if under SB 138 AGDC acquires an equity interest in the LNG plant, and an equity interest in the GTP and pipeline by exercising an option to acquire part of TC's interest for example, the entire LNG plant, GTP and pipeline – not just AGDC's share – would be exempt from property taxes until the commencement of commercial operations of the project. See AS 43.56.020(d) (part of HB 4 passed in 2013). After commercial operations begin only AGDC's share of the LNG plant, GTP and pipeline would be exempt from taxes. See AS 31.25.260 (part of HB 4).

However, the HOA (reflected in the proposed legislative findings in SB 138 for property taxes relating to a North Slope natural gas pipeline project) provides that the state administration would consult with local governments to determine an appropriate series of impact payments during construction as well as property tax structure for the project. See HOA Article 9.3.1. The HOA parties proposed a starting framework that they believed would fairly compensate local governments while seeking to avoid contentious valuation disputes in the future. The HOA proposal for taxes once the project is operating, to be considered in future legislation, and in the contract negotiations, would be to base the payments on the volume of gas moving through the pipeline or other facilities (e.g., cents per MCF), called payments in lieu of taxes or "PILT," instead of being based on property value and millage subject to AS 29.45 or AS 43.56. The HOA also proposes to establish serial impact payments to be paid by the developers of a North Slope natural gas pipeline project to help offset increased services and other costs borne by state and local governments during construction.

All communities benefit from property taxes on oil and gas properties, either directly or indirectly through state revenue sharing with municipalities. Based on that consultation, the state would propose legislation in a later legislative session to amend the state and municipal property tax statutes for the GTP, pipeline and LNG plant. The legislation would provide a property tax and impact payment framework and enable the administration to negotiate contracts with the project owners concerning a property tax payment method for determining the appropriate revenues to the state and local governments from the North Slope natural gas project developers.

Sincerely,

Joe Balash, Commissioner
Department of Natural Resources

Angela M. Rodell, Commissioner
Department of Revenue

CC: Senator Pete Kelly, Co-Chair, Senate Finance Committee
Senator Kevin Meyer, Co-Chair, Senate Finance Committee
Members of the Senate Finance Committee
Heather Brakes, Legislative Director

AK LNG:
Potential State Revenues and Debt Capacity

Supplemental Slides for the Senate Finance Committee

March 10, 2014

Corrected

Angela Rodell
Commissioner
Alaska Department of Revenue

Fiscal Impacts - Overview

This presentation aims to tie together several different sources of analysis, to provide a comprehensive overview of AKLNG project fiscal impacts to the state.

Fiscal Impact Analysis

Fall 2013 Revenue Forecast + AK LNG

Alaska Department of Revenue, Tax Division

Black and Veatch

AK LNG Debt Capacity

Alaska Department of Revenue, Treasury Division

Black and Veatch

A note on uncertainty….

- Goal: To give a **reasonable** view of how the AKLNG project could impact Alaska's financial position both over the:
  - short term (next few years),
  - mid term (next decade), and
  - long term (to 2040 and beyond)

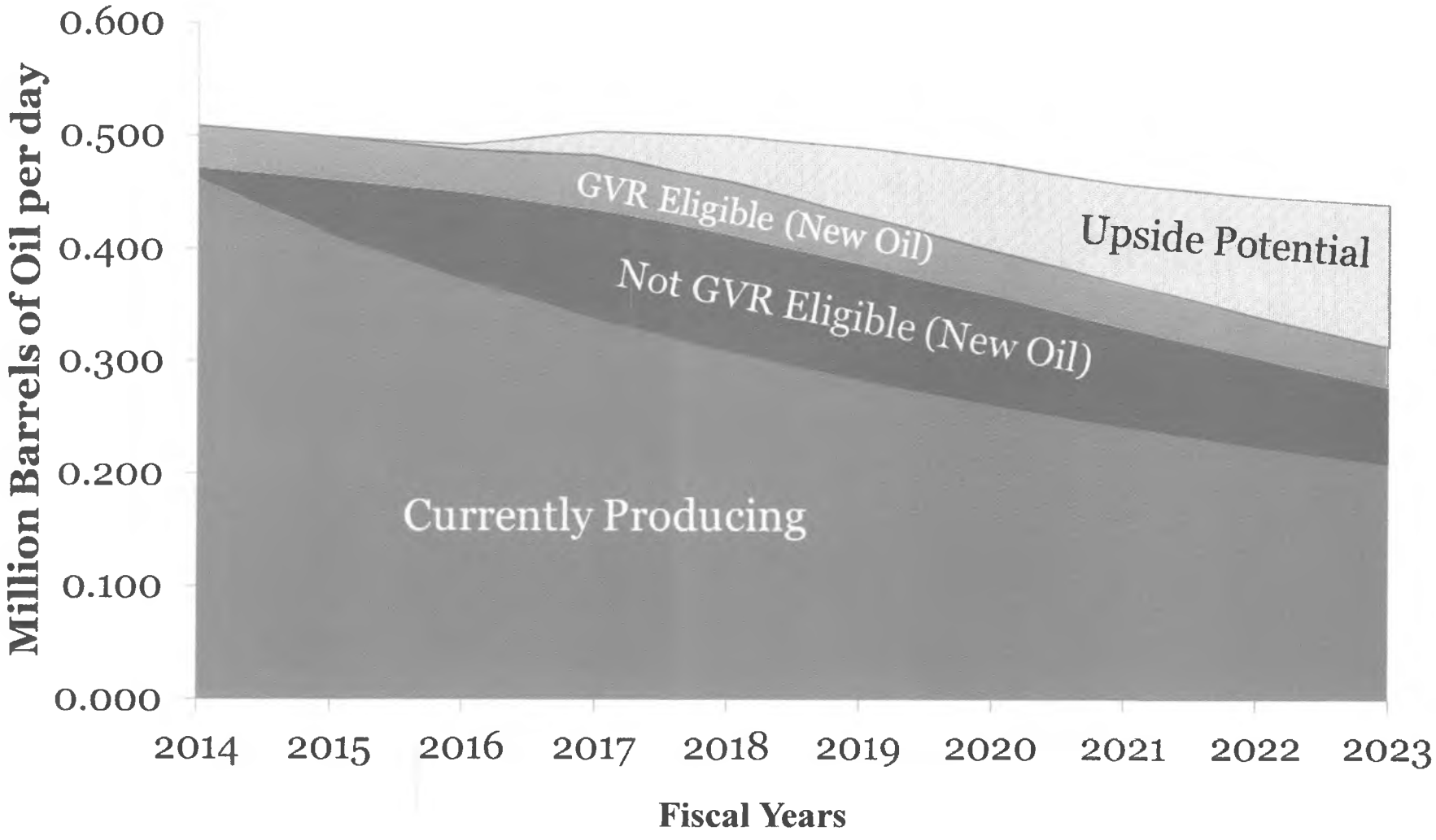
- Analysis presented represent a set of scenarios taken from a range of possible outcomes
- Different assumptions may produce significantly different results.

- Department of Revenue and consultants are in the process of refining this analysis. As a result, future analysis could have different results.

AKLNG – Long term potential: Assumptions

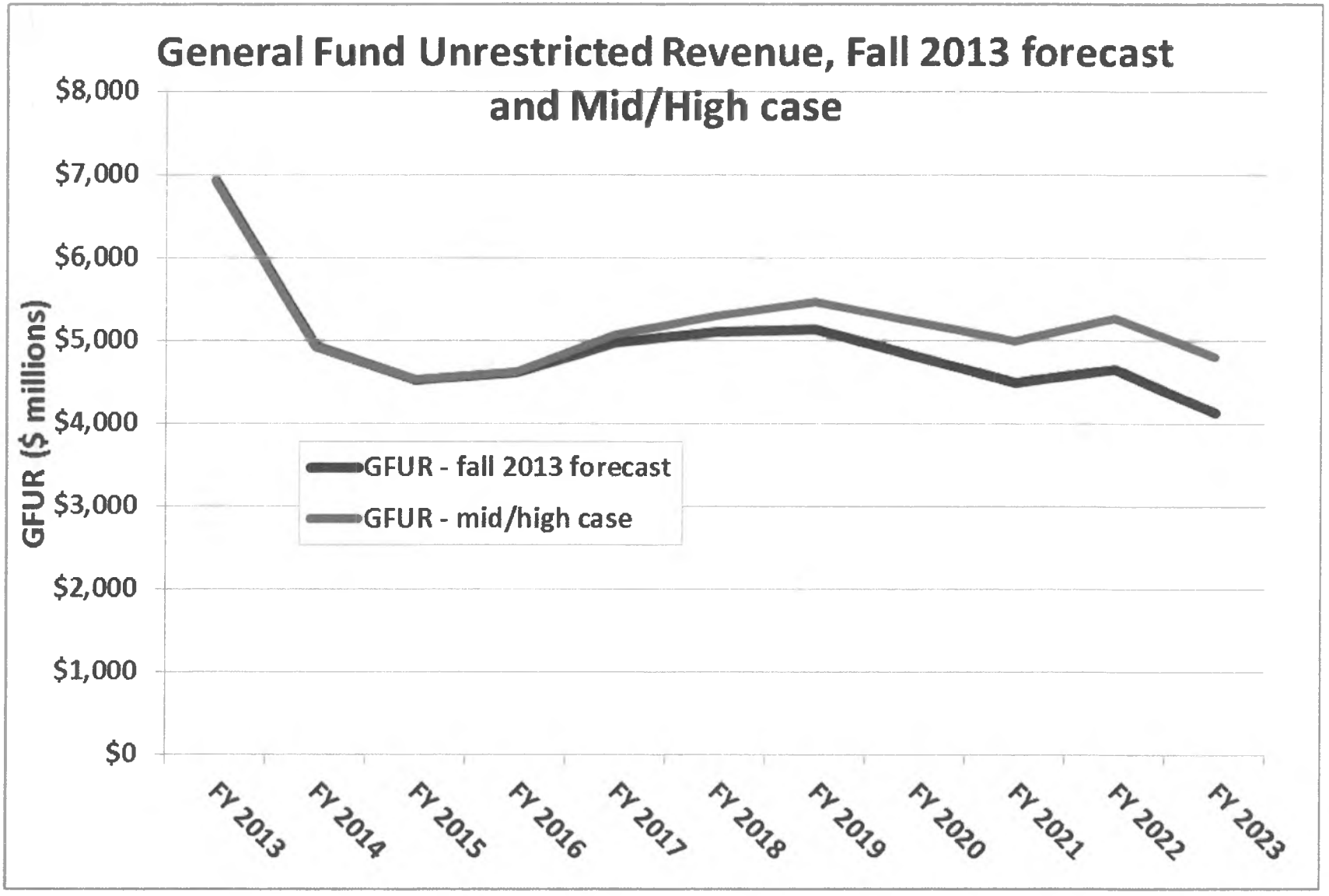
- Incremental analysis: Gas revenues forecasted independent of oil
- Long-term forecast assumes the following trends for oil and gas related revenues
  - Oil revenues – GFUR mid/high case through 2024, then trend from 2020-2024 projected forward (decline of ~2%/yr)
  - Gas revenues – AKLNG Project revenues assumed to begin in 2024
- Assumptions underlying gas revenues
  - AKLNG project comes online in 2024
  - Capital cost of AKLNG Project (GTP, Pipeline and LNG Plant) = $55 billion in nominal dollars.
  - Export volume of 2.5 Bcf/d and in-state volume of 0.25 Bcf/d
  - Oil price = $90/bbl in 2013$ growing at 2.5% a year; LNG Price ($/MMBtu) = 13.5%*Oil Price + $1
  - GFUR is assumed to include 75% of royalties, 25% of property tax, 100% of state corporate income tax, production tax and return on equity on AKLNG project investment
- Three different scenarios for State equity participation:
  - Go it alone – State holds 20%-25% equity stake in GTP, Pipeline and LNG Plant
  - TC with no buy back – TC holds 20%-25% equity stake in GTP and Pipeline, State holds 20-25%% equity stake in LNG Plant
  - TC with buy back – initially, TC holds 20%-25% equity stake in GTP and Pipeline, State holds 20%-25% equity stake in LNG Plant. State buys back 30%-40% of TC's stake at beginning of FEED

North Slope Production Forecast



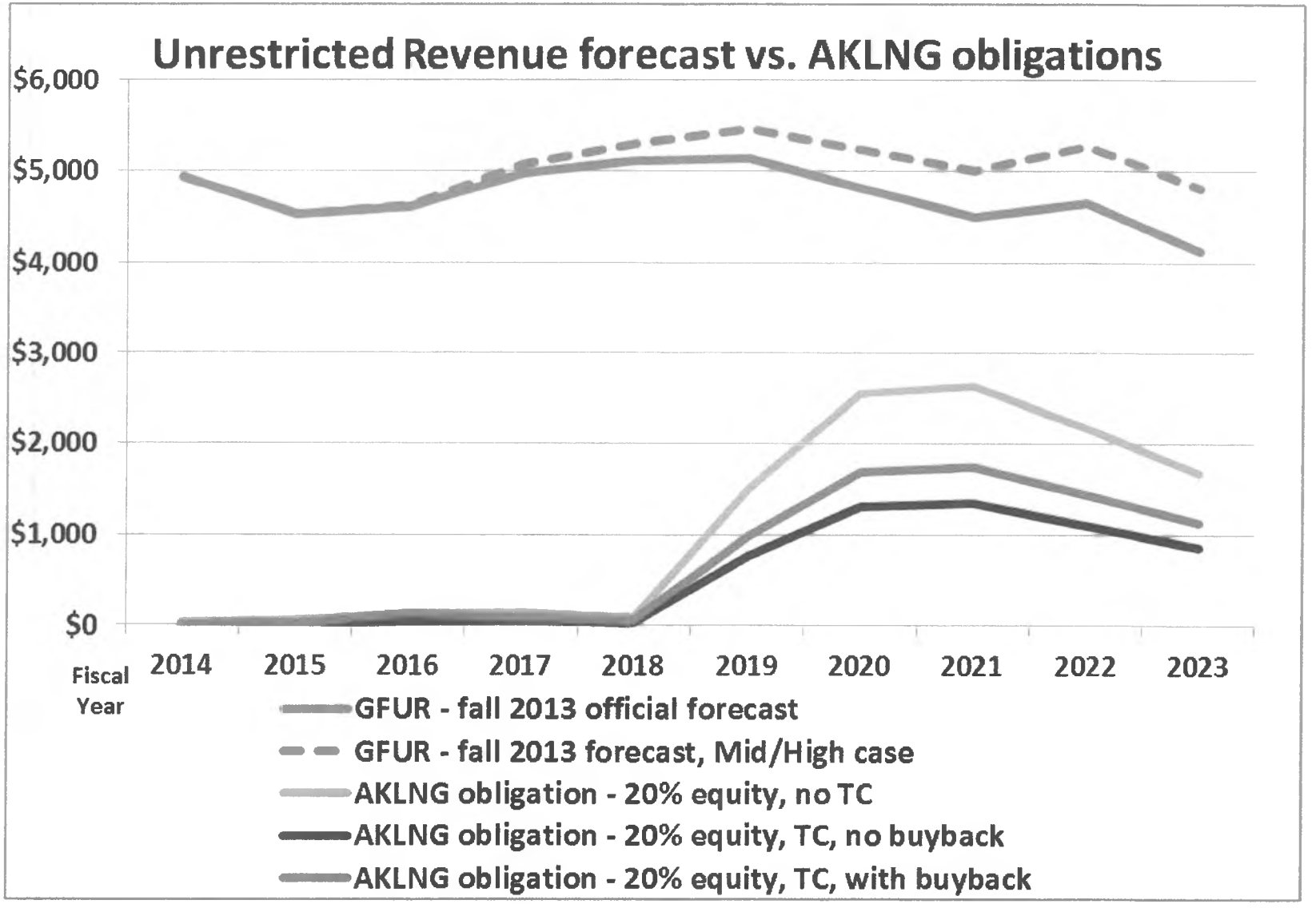
Source: Department of Revenue - Revenue Sources Book Fall 2013

Revenue Forecast – Official, and Mid/High Case



Source: Department of Revenue. Official forecast from Revenue Sources Book Fall 2013. Mid/high case uses a production assumption midway between the fall 2013 official "risked" forecast, and an unrisked, independent technical assessment provided to the Department.

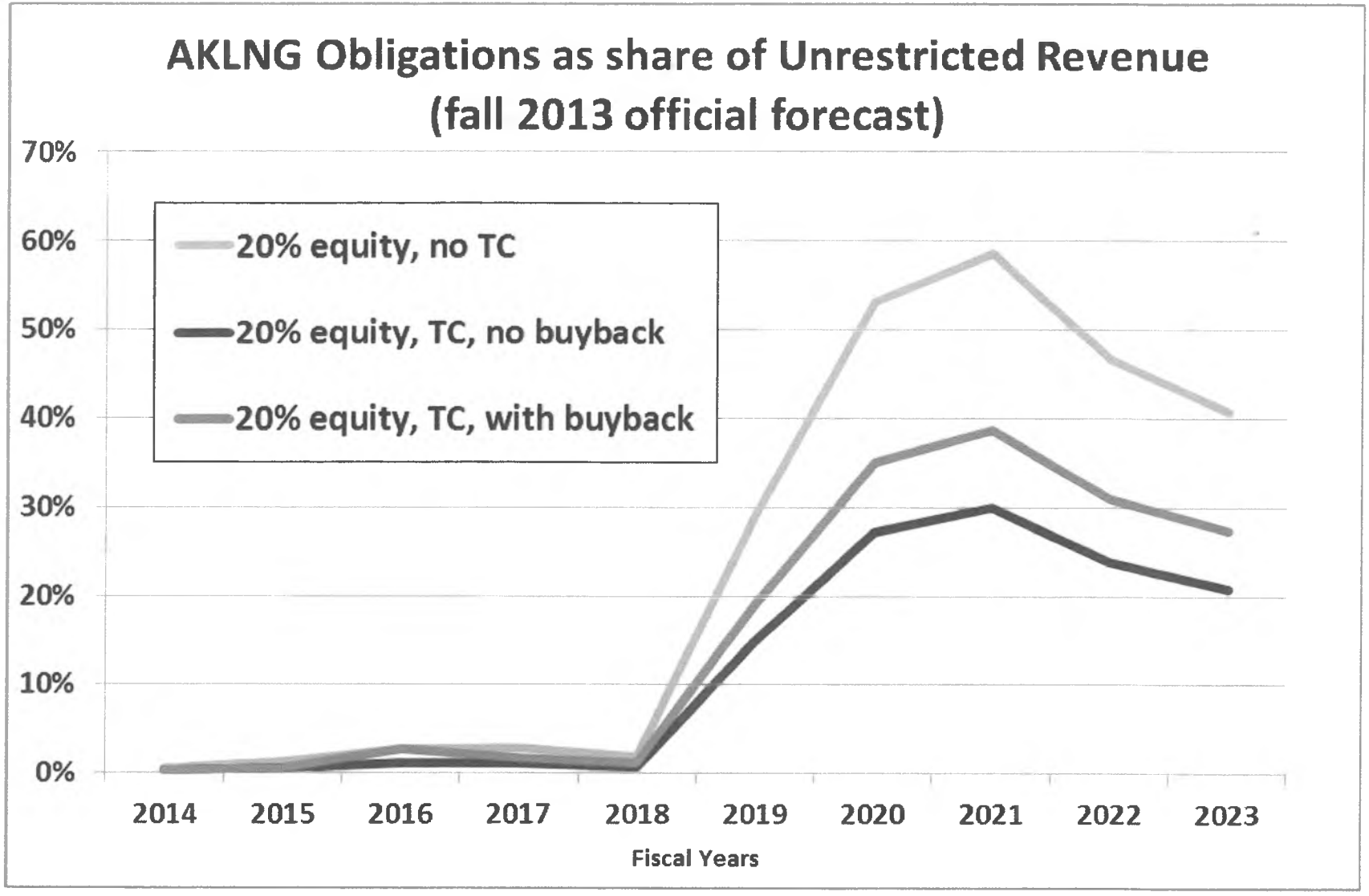
Revenue Forecast vs AKLNG Obligations @ 20% state ownership in millions of dollars



Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG Obligations vs. GFUR Forecast @ 20% state ownership



Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG Obligations vs. GFUR Forecast @ 20% State Ownership in Millions of Dollars.

Inrestricted Revenue Forecast vs. AKLNG Obligations

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023
GFUR - fall 2013 official forecast $ millions	$ 4,930	$ 4,532	$ 4,609	$ 4,981	$ 5,105	$ 5,135	$ 4,810	$ 4,503	$ 4,654	$ 4,129
GFUR - fall 2013 forecast, Mid/High case $millions	$ 4,930	$ 4,532	$ 4,620	$ 5,070	$ 5,300	$ 5,470	$ 5,230	$ 5,000	$ 5,270	$ 4,810
AKLNG obligation - 20% equity, no TC $millions	$ 28	$ 58	$ 123	$ 144	$ 93	$ 1,493	$ 2,563	$ 2,640	$ 2,175	$ 1,680
AKLNG obligation - 20% equity, TC, no buyback $millions	$ 11	$ 23	$ 49	$ 58	$ 37	$ 763	$ 1,310	$ 1,349	$ 1,112	$ 859
AKLNG obligation - 20% equity, TC, with buyback $millions	$ 11	$ 23	$ 145	$ 90	$ 58	$ 1,037	$ 1,782	$ 1,842	$ 1,530	$ 1,200
Obligation % of GFUR - 20% equity, no TC	1%	1%	3%	3%	2%	29%	53%	59%	47%	41%
Obligation % of GFUR -20% equity, TC, no buyback	0%	1%	1%	1%	1%	15%	27%	30%	24%	21%
Obligation % of GFUR -20% equity, TC, with buyback	0%	1%	3%	2%	1%	20%	37%	41%	33%	29%

Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG Obligations vs. GFUR Forecast @ 20% state ownership in Billions of dollars.

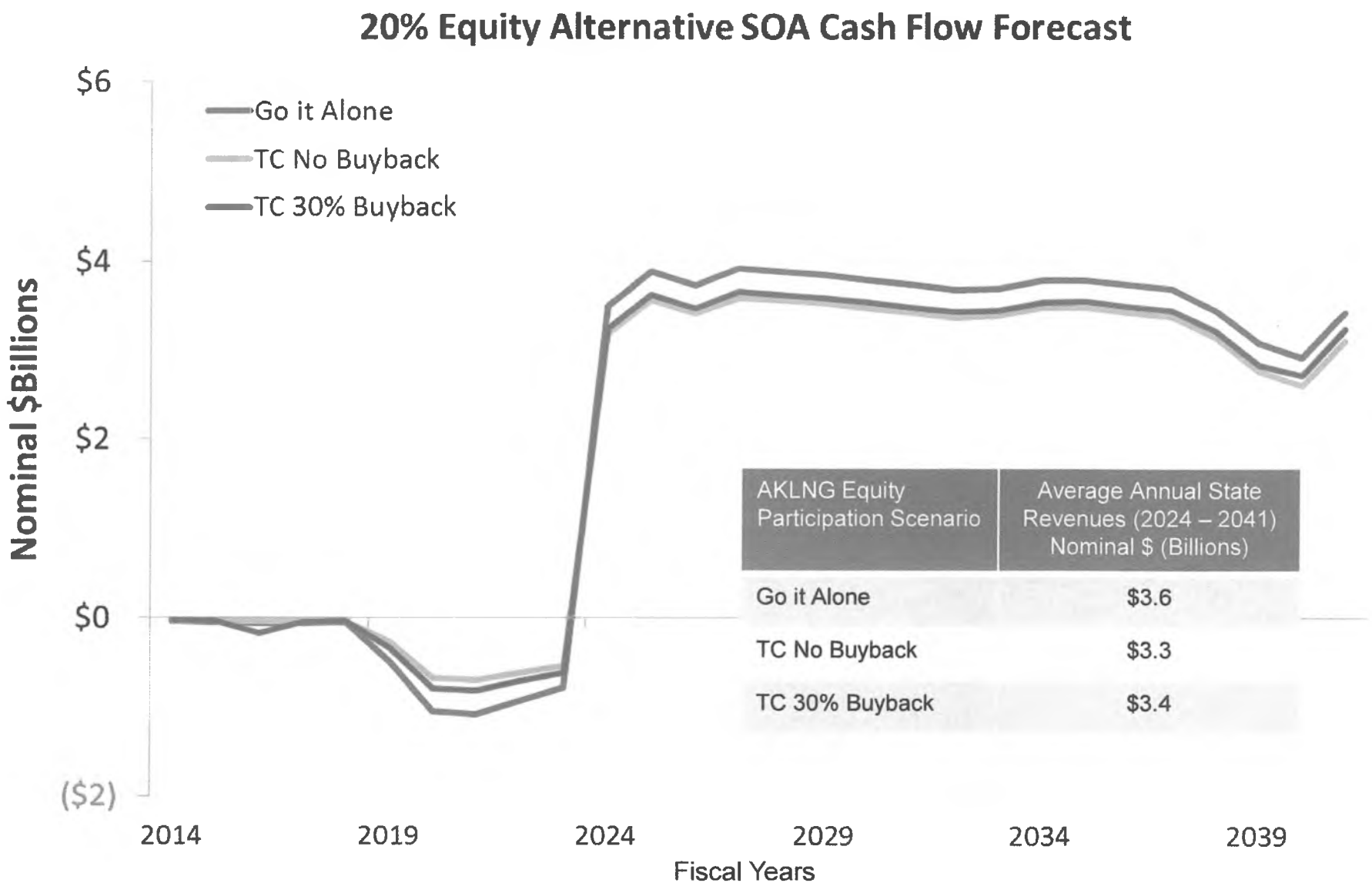
Unrestricted Revenue Forecast vs. AKLNG Obligations

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023
GFUR - fall 2013 official forecast $billions	$ 4.9	$ 4.5	$ 4.6	$ 5.0	$ 5.1	$ 5.1	$ 4.8	$ 4.5	$ 4.7	$ 4.1
GFUR - fall 2013 forecast, Mid/High case $billions	$ 4.9	$ 4.5	$ 4.6	$ 5.1	$ 5.3	$ 5.5	$ 5.2	$ 5.0	$ 5.3	$ 4.8
AKLNG obligation - 20% equity, no TC $billions	$ 0.0	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 1.5	$ 2.6	$ 2.6	$ 2.2	$ 1.7
AKLNG obligation - 20% equity, TC, no buyback $billions	$ 0.0	$ 0.0	$ 0.0	$ 0.1	$ 0.0	$ 0.8	$ 1.3	$ 1.3	$ 1.1	$ 0.9
AKLNG obligation - 20% equity, TC, with buyback $billions	$ 0.0	$ 0.0	$ 0.1	$ 0.1	$ 0.1	$ 1.0	$ 1.8	$ 1.8	$ 1.5	$ 1.2
Obligation % of GFUR - 20% equity, no TC	1%	1%	3%	3%	2%	29%	53%	59%	47%	41%
Obligation % of GFUR -20% equity, TC, no buyback	0%	1%	1%	1%	1%	15%	27%	30%	24%	21%
Obligation % of GFUR -20% equity, TC, with buyback	0%	1%	3%	2%	1%	20%	37%	41%	33%	29%

Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG – Long term potential



AKLNG Equity Participation Scenario	Average Annual State Revenues (2024 – 2041) Nominal $ (Billions)
Go it Alone	$3.6
TC No Buyback	$3.3
TC 30% Buyback	$3.4

Source: Black and Veatch. Based on assumed 70%/30% financing split for debt/equity.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG – Long term potential – 20% equity

in *Millions of Dollars*

Equity Alternative 20% - State Go It Alone		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Royalty	[mm$/yr]	$1,230	$1,380	$1,360	$1,380	$1,410	$1,440	$1,460	$1,490	$1,510	$1,540	$1,570	$1,590	$1,620	$1,650	$1,690	$1,720	$1,760	$1,800
Production Tax	[mm$/yr]	$330	$550	$540	$710	$670	$630	$570	$520	$470	$500	$590	$600	$550	$500	$240	($160)	($320)	$120
SCIT	[mm$/yr]	$170	$190	$190	$200	$210	$230	$230	$240	$250	$260	$270	$280	$290	$290	$300	$320	$340	$420
Total Property Tax	[mm$/yr]	$1,060	$1,070	$960	$940	$930	$900	$880	$860	$830	$800	$770	$730	$700	$680	$670	$660	$620	$580
Project Ownership	[mm$/yr]	$700	$690	$680	$670	$660	$650	$640	$630	$620	$610	$600	$590	$580	$570	$550	$540	$530	$520
Total SOA Net Cash Flow	**[mm$/yr]**	**$3,490**	**$3,880**	**$3,730**	**$3,900**	**$3,880**	**$3,850**	**$3,780**	**$3,740**	**$3,680**	**$3,710**	**$3,800**	**$3,790**	**$3,740**	**$3,690**	**$3,450**	**$3,080**	**$2,930**	**$3,440**

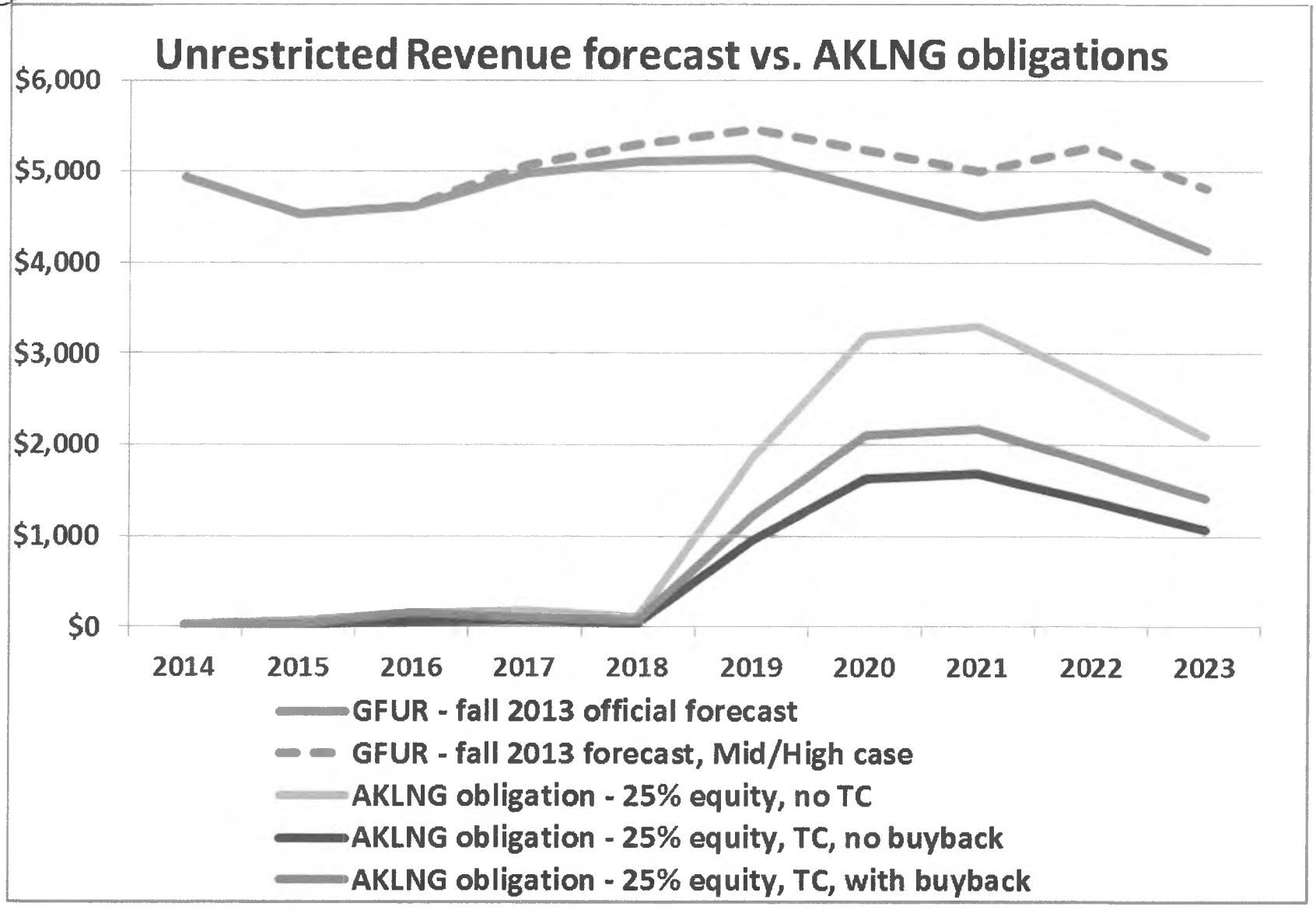
Equity Alternative 20% - TC No Buy Back		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Royalty	[mm$/yr]	$1,170	$1,320	$1,300	$1,330	$1,350	$1,380	$1,400	$1,430	$1,450	$1,480	$1,510	$1,540	$1,560	$1,600	$1,630	$1,660	$1,700	$1,740
Production Tax	[mm$/yr]	$300	$520	$510	$680	$640	$600	$540	$490	$440	$460	$560	$570	$510	$470	$210	($190)	($360)	$90
SCIT	[mm$/yr]	$170	$190	$190	$200	$210	$230	$230	$240	$250	$260	$270	$280	$290	$290	$300	$320	$340	$420
Total Property Tax	[mm$/yr]	$1,160	$1,170	$1,060	$1,040	$1,020	$990	$970	$940	$910	$880	$840	$810	$770	$750	$730	$720	$670	$620
Project Ownership	[mm$/yr]	$360	$360	$350	$350	$340	$340	$330	$320	$320	$310	$300	$300	$290	$280	$270	$260	$260	$250
Total SOA Net Cash Flow	**[mm$/yr]**	**$3,160**	**$3,560**	**$3,410**	**$3,600**	**$3,560**	**$3,540**	**$3,470**	**$3,420**	**$3,370**	**$3,390**	**$3,480**	**$3,500**	**$3,420**	**$3,390**	**$3,140**	**$2,770**	**$2,610**	**$3,120**

Equity Alternative 20% - TC with Buy Back		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Royalty	[mm$/yr]	$1,170	$1,320	$1,300	$1,330	$1,350	$1,380	$1,400	$1,430	$1,450	$1,480	$1,510	$1,540	$1,560	$1,600	$1,630	$1,660	$1,700	$1,740
Production Tax	[mm$/yr]	$300	$520	$510	$680	$640	$600	$540	$490	$440	$460	$560	$570	$510	$470	$210	($190)	($360)	$90
SCIT	[mm$/yr]	$170	$190	$190	$200	$210	$230	$230	$240	$250	$260	$270	$280	$290	$290	$300	$320	$340	$420
Total Property Tax	[mm$/yr]	$1,160	$1,170	$1,060	$1,040	$1,020	$990	$970	$940	$910	$880	$840	$810	$770	$750	$730	$720	$670	$620
Project Ownership	[mm$/yr]	$460	$450	$450	$440	$430	$430	$420	$410	$410	$400	$390	$380	$380	$370	$360	$350	$390	$390
Total SOA Net Cash Flow	**[mm$/yr]**	**$3,260**	**$3,650**	**$3,510**	**$3,690**	**$3,650**	**$3,630**	**$3,560**	**$3,510**	**$3,460**	**$3,480**	**$3,570**	**$3,580**	**$3,510**	**$3,480**	**$3,230**	**$2,860**	**$2,740**	**$3,260**

Source: Black and Veatch. Based on assumed 70%/30% financing split for debt/equity.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

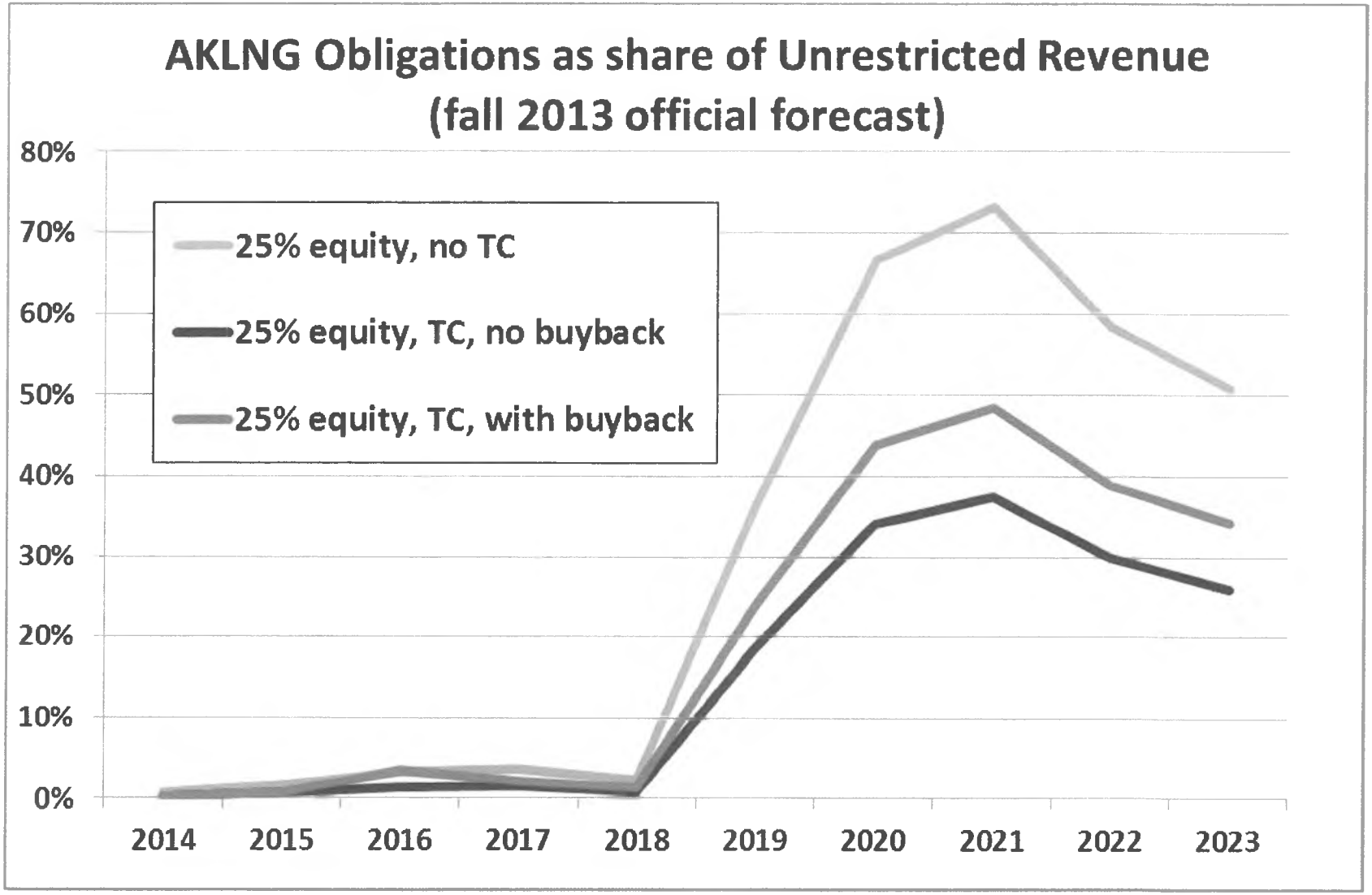
Revenue Forecast vs AKLNG Obligations @ 25% State Ownership in Millions of Dollars



Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG Obligations vs. GFUR Forecast @ 25% State Ownership



Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG Obligations vs. GFUR Forecast @ 25% State Ownership In Millions of Dollars.

Unrestricted Revenue Forecast vs. AKLNG Obligations

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023
GFUR - fall 2013 official forecast $millions	$ 4,930	$ 4,532	$ 4,609	$ 4,981	$ 5,105	$ 5,135	$ 4,810	$ 4,503	$ 4,654	$ 4,129
GFUR - fall 2013 forecast, Mid/High case $millions	$ 4,930	$ 4,532	$ 4,620	$ 5,070	$ 5,300	$ 5,470	$ 5,230	$ 5,000	$ 5,270	$ 4,810
AKLNG obligation - 25% equity, no TC $millions	$ 35	$ 73	$ 153	$ 180	$ 116	$ 1,866	$ 3,203	$ 3,300	$ 2,719	$ 2,100
AKLNG obligation - 25% equity, TC, no buyback $millions	$ 14	$ 29	$ 61	$ 72	$ 46	$ 954	$ 1,637	$ 1,686	$ 1,390	$ 1,073
AKLNG obligation - 25% equity, TC, with buyback $millions	$ 14	$ 29	$ 158	$ 105	$ 67	$ 1,227	$ 2,109	$ 2,179	$ 1,808	$ 1,415
Obligation % of GFUR - 25% equity, no TC	1%	2%	3%	4%	2%	36%	67%	73%	58%	51%
Obligation % of GFUR - 25% equity, TC, no buyback	0%	1%	1%	1%	1%	19%	34%	37%	30%	26%
Obligation % of GFUR - 25% equity, TC, with buyback	0%	1%	3%	2%	1%	24%	44%	48%	39%	34%

Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG Obligations vs. GFUR Forecast @ 25% state ownership in billions of dollars.

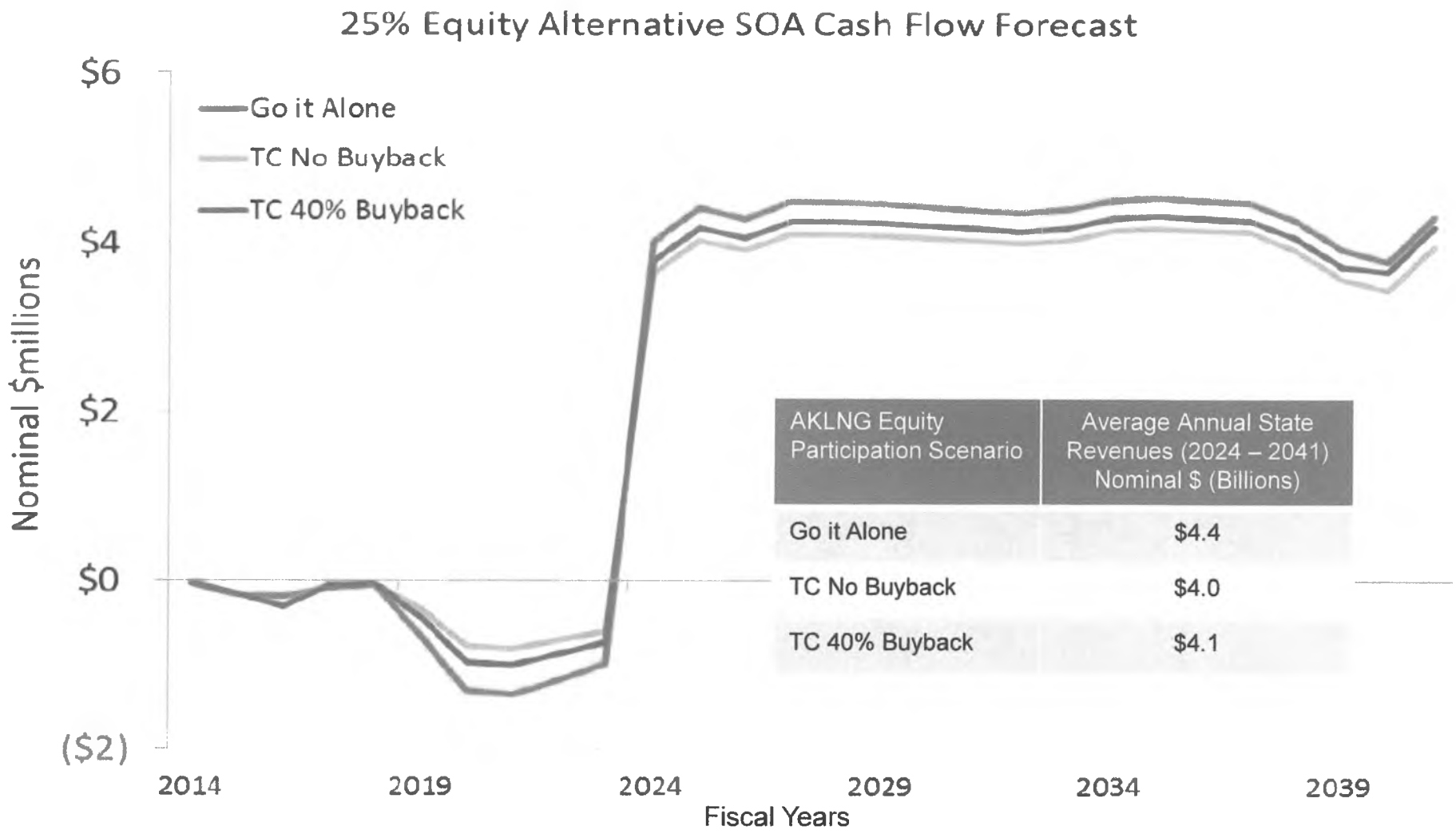
Unrestricted Revenue Forecast vs. AKLNG Obligations

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023
GFUR - fall 2013 official forecast $billions	$ 4.9	$ 4.5	$ 4.6	$ 5.0	$ 5.1	$ 5.1	$ 4.8	$ 4.5	$ 4.7	$ 4.1
GFUR - fall 2013 forecast, Mid/High case $billions	$ 4.9	$ 4.5	$ 4.6	$ 5.1	$ 5.3	$ 5.5	$ 5.2	$ 5.0	$ 5.3	$ 4.8
AKLNG obligation - 25% equity, no TC $billions	$ 0.0	$ 0.1	$ 0.2	$ 0.2	$ 0.1	$ 1.9	$ 3.2	$ 3.3	$ 2.7	$ 2.1
AKLNG obligation - 25% equity, TC, no buyback $billions	$ 0.0	$ 0.0	$ 0.1	$ 0.1	$ 0.0	$ 1.0	$ 1.6	$ 1.7	$ 1.4	$ 1.1
AKLNG obligation - 25% equity, TC, with buyback $billions	$ 0.0	$ 0.0	$ 0.2	$ 0.1	$ 0.1	$ 1.2	$ 2.1	$ 2.2	$ 1.8	$ 1.4
Obligation % of GFUR - 25% equity, no TC	1%	2%	3%	4%	2%	36%	67%	73%	58%	51%
Obligation % of GFUR -25% equity, TC, no buyback	0%	1%	1%	1%	1%	19%	34%	37%	30%	26%
Obligation % of GFUR -25% equity, TC, with buyback	0%	1%	3%	2%	1%	24%	44%	48%	39%	34%

Source: Department of Revenue - Revenue Sources Book Fall 2013; Black and Veatch.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG – Long term potential



AKLNG Equity Participation Scenario	Average Annual State Revenues (2024 – 2041) Nominal $ (Billions)
Go it Alone	$4.4
TC No Buyback	$4.0
TC 40% Buyback	$4.1

Source: Black and Veatch. Based on assumed 70%/30% financing split for debt/equity.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

AKLNG – Long term potential – 25% equity

in *Millions of Dollars*

Equity Alternative 25% - State Go It Alone		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Royalty	[mm$/yr]	$1,230	$1,380	$1,360	$1,380	$1,410	$1,440	$1,460	$1,490	$1,510	$1,540	$1,570	$1,590	$1,620	$1,650	$1,690	$1,720	$1,760	$1,800
Production Tax	[mm$/yr]	$750	$990	$1,000	$1,200	$1,180	$1,160	$1,130	$1,100	$1,070	$1,120	$1,240	$1,280	$1,250	$1,230	$1,000	$630	$490	$970
SCIT	[mm$/yr]	$160	$180	$180	$190	$200	$210	$220	$230	$230	$240	$250	$260	$270	$270	$280	$290	$310	$390
Total Property Tax	[mm$/yr]	$1,000	$1,010	$910	$900	$880	$860	$840	$810	$790	$760	$730	$690	$670	$640	$640	$630	$590	$550
Project Ownership	[mm$/yr]	$880	$860	$850	$840	$830	$820	$800	$790	$780	$760	$750	$740	$720	$710	$690	$680	$660	$650
Total SOA Net Cash Flow	**[mm$/yr]**	**$4,020**	**$4,420**	**$4,300**	**$4,510**	**$4,500**	**$4,490**	**$4,450**	**$4,420**	**$4,380**	**$4,420**	**$4,540**	**$4,560**	**$4,530**	**$4,500**	**$4,300**	**$3,950**	**$3,810**	**$4,360**

Equity Alternative 25% - TC No Buy Back		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Royalty	[mm$/yr]	$1,170	$1,320	$1,300	$1,330	$1,350	$1,380	$1,400	$1,430	$1,450	$1,480	$1,510	$1,540	$1,560	$1,600	$1,630	$1,660	$1,700	$1,740
Production Tax	[mm$/yr]	$700	$940	$950	$1,140	$1,120	$1,100	$1,070	$1,040	$1,020	$1,070	$1,190	$1,220	$1,200	$1,180	$940	$570	$440	$920
SCIT	[mm$/yr]	$160	$180	$180	$190	$200	$210	$220	$230	$230	$240	$250	$260	$270	$270	$280	$290	$310	$390
Total Property Tax	[mm$/yr]	$1,130	$1,140	$1,030	$1,010	$990	$970	$950	$920	$890	$860	$820	$790	$750	$730	$720	$710	$660	$610
Project Ownership	[mm$/yr]	$460	$450	$440	$440	$430	$420	$410	$410	$400	$390	$380	$370	$360	$350	$340	$330	$320	$310
Total SOA Net Cash Flow	**[mm$/yr]**	**$3,620**	**$4,030**	**$3,900**	**$4,110**	**$4,090**	**$4,080**	**$4,050**	**$4,030**	**$3,990**	**$4,040**	**$4,150**	**$4,180**	**$4,140**	**$4,130**	**$3,910**	**$3,560**	**$3,430**	**$3,970**

Equity Alternative 25% - TC with Buy Back		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Royalty	[mm$/yr]	$1,170	$1,320	$1,300	$1,330	$1,350	$1,380	$1,400	$1,430	$1,450	$1,480	$1,510	$1,540	$1,560	$1,600	$1,630	$1,660	$1,700	$1,740
Production Tax	[mm$/yr]	$700	$940	$950	$1,140	$1,120	$1,100	$1,070	$1,040	$1,020	$1,070	$1,190	$1,220	$1,200	$1,180	$940	$570	$440	$920
SCIT	[mm$/yr]	$160	$180	$180	$190	$200	$210	$220	$230	$230	$240	$250	$260	$270	$270	$280	$290	$310	$390
Total Property Tax	[mm$/yr]	$1,130	$1,140	$1,030	$1,010	$990	$970	$950	$920	$890	$860	$820	$790	$750	$730	$720	$710	$660	$610
Project Ownership	[mm$/yr]	$610	$600	$600	$590	$580	$570	$560	$550	$540	$530	$530	$520	$510	$500	$490	$480	$550	$540
Total SOA Net Cash Flow	**[mm$/yr]**	**$3,770**	**$4,180**	**$4,060**	**$4,260**	**$4,240**	**$4,230**	**$4,200**	**$4,170**	**$4,130**	**$4,180**	**$4,300**	**$4,330**	**$4,290**	**$4,280**	**$4,060**	**$3,710**	**$3,660**	**$4,200**

Source: Black and Veatch. Based on assumed 70%/30% financing split for debt/equity.

Assumes obligation is due in the corresponding fiscal year; i.e. CY 2019 obligation in FY 2019, etc.

Current Debt Servicing & Capacity

Debt capacity: Current debt outstanding

$6.6 to $8.1 Billion in Outstanding State Debt 1999-2014 Summarized by category in millions

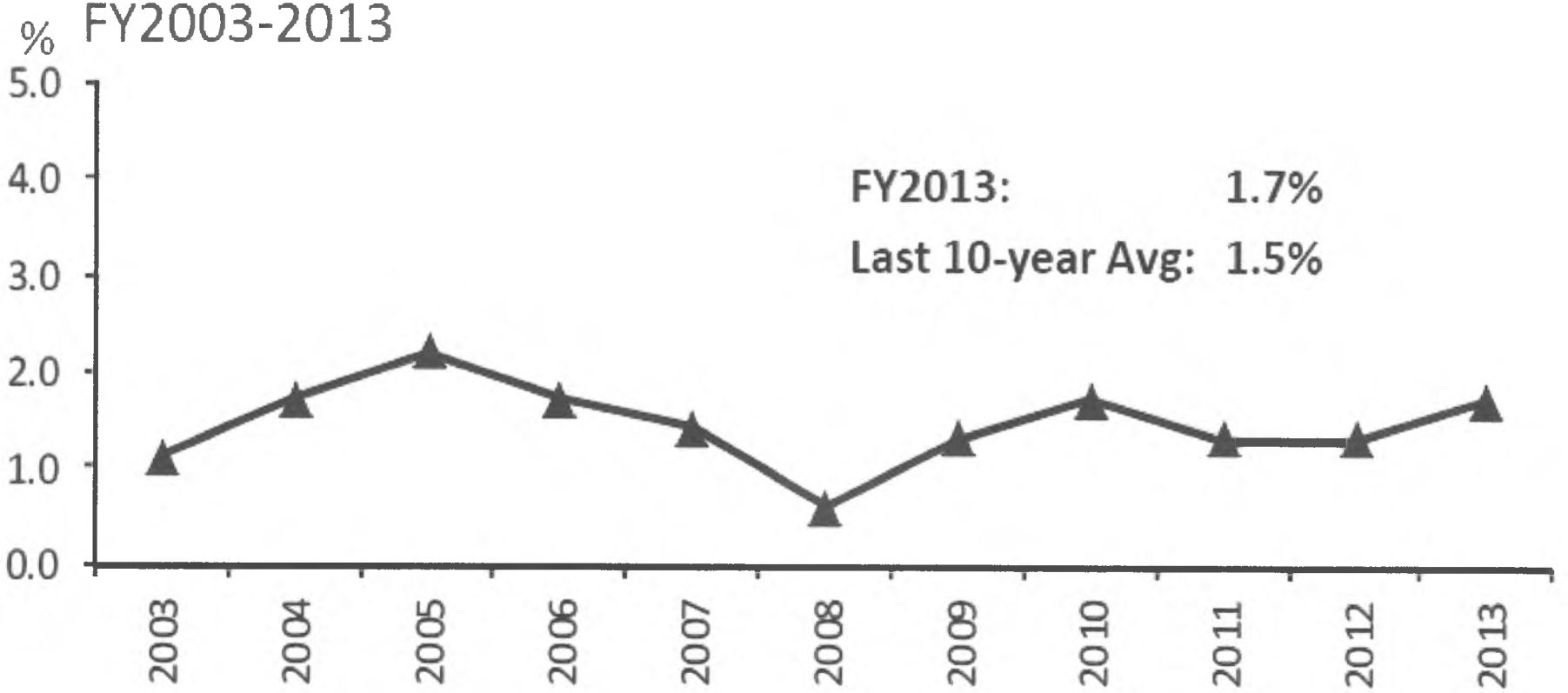
	1999	2014	
• General Obligation	2.4	840.2	(additional $303 million authorized but unissued)
• State Supported (leases & school debt reimbursement)	459.1	1,195.0	
• State Guaranteed (Veteran's Mortgage Program)	391.0	102.1	(additional $695 million authorized but unissued)
• State Moral Obligation (AMBBA, AEA, ASLC)	763.1	1,200.7	
• State Revenue (AIAS & Sport Fishing Hatcheries)	210.4	595.7	
• University	85.7	190.5	
• State Agency (AHFC, AMBBA, ARR, NTSC)	767.5	543.3	
• State Agency Collateralized (AHFC, AIDEA)	1,983.8	2,312.2	
• Municipal	2,303.4	3,150.6*	

Source: Alaska Public Debt Book, Table 1.1

*$2.0 billion of Municipal Debt is also included primarily in the State Supported, and State Moral Obligation categories

Debt capacity: Historically, debt service has been low relative to revenue

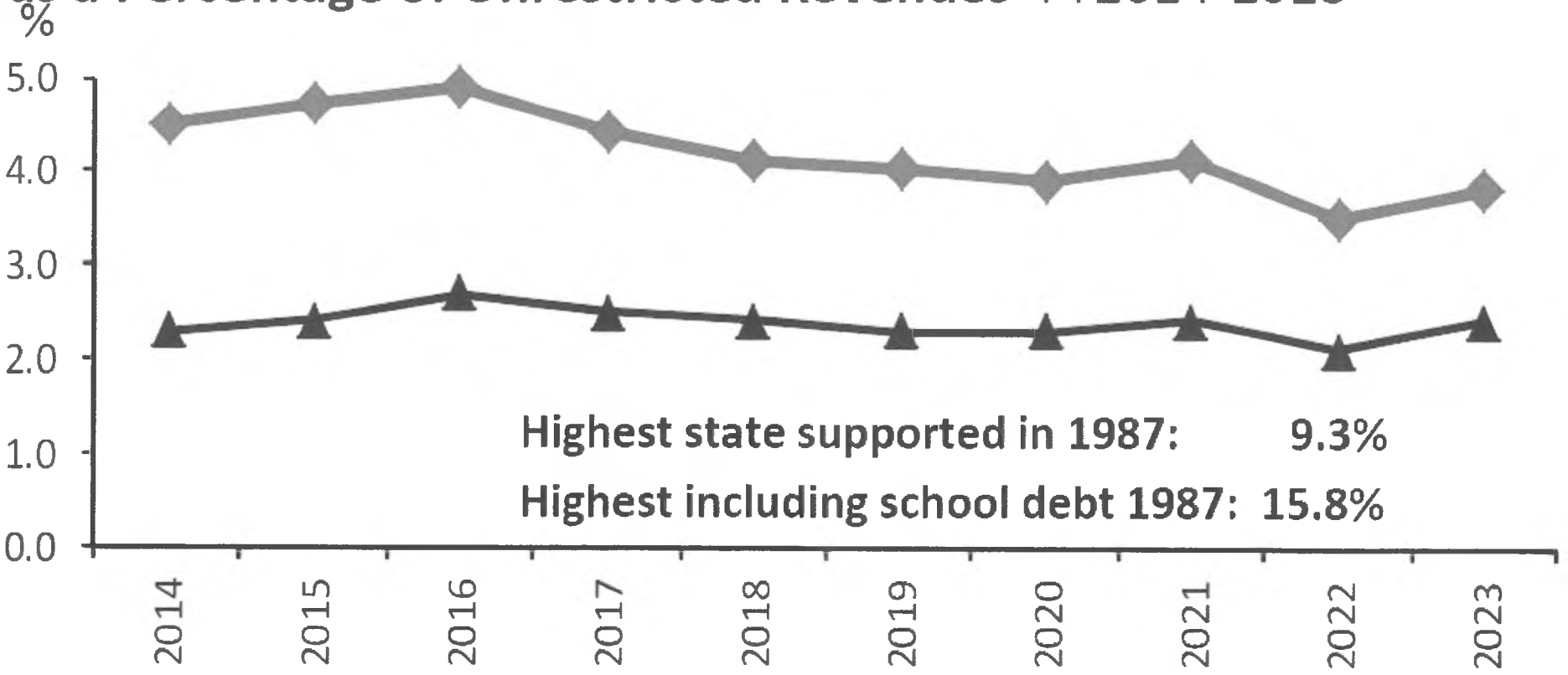
Historical Total State Debt Service (G.O. and State Supported) as a Percentage of Unrestricted Revenues[1]



Source: 2/13/2014 presentation to Senate Finance committee

Debt capacity: Projected debt service

Projected State Debt Service (G.O. Plus State Supported compared to G.O., State Supported, & School Debt Reimbursement) as a Percentage of Unrestricted Revenues[1] FY2014-2023



Source: 2/13/2014 presentation to Senate Finance committee

Financial Management and Debt Metrics

The State has a long track record of conservative debt practices

- G.O. bonds carry pledge of full faith, credit and resources of the State
  - State policy limits debt service to less than 8% of General Fund unrestricted revenue
  - Debt service as a percentage of unrestricted General Fund revenues has remained low for 15 years
    - 10-year average 1.5%; FY2013 was 1.7% (3.3% including school debt reimbursements)
- Use of executive power to control expenses
- Historical Preference for utilizing pay-as-you-go funding versus debt
- Current and Future borrowing:
  - 2012 G.O. Authorization for State transportation projects (up to $453 million)
    - Issued $149.6 million Bond Anticipation Note in March 2013
    - Anticipate issuing up to $230 million Bond Anticipation Note in March 2014 and $35 million Certificate of Participation in April 2014
- State financial support has been discussed for a number of strategic capital initiatives

Source: 2/13/2014 presentation to Senate Finance committee

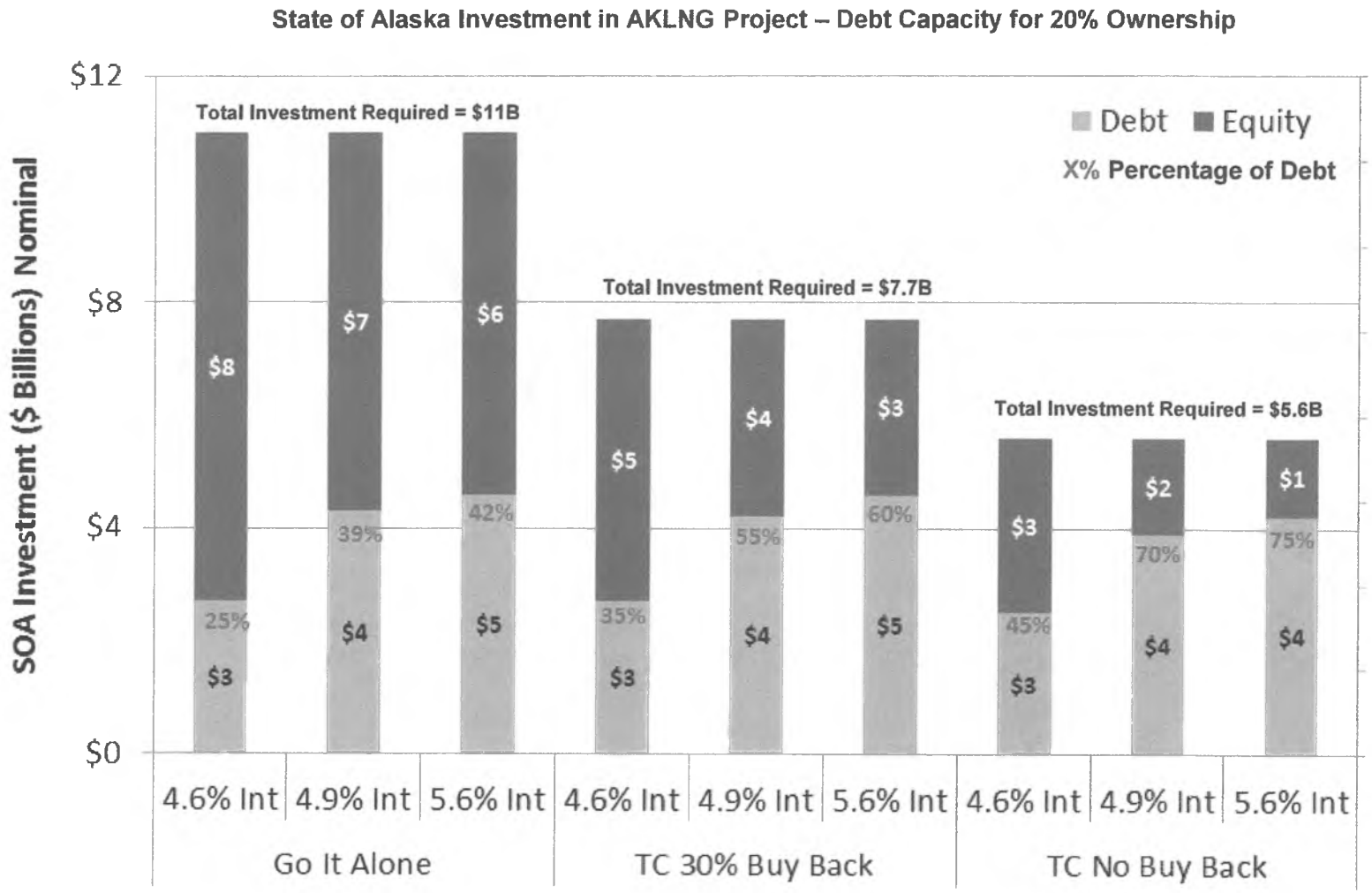
CAN THE STATE GO IT ALONE? - STATE'S DEBT CAPACITY

- **Financing the State's share of the AKLNG Project on the State's balance sheet – key issues:**
  - At what cost of debt?
  - Debt servicing as what % of general fund unrestricted revenue?

Scenario 1 (lower interest)	• SOA Debt at 4.6% • Debt Service limited to 3% of GFUR
Scenario 2	• SOA Debt at 4.9% • Debt Service limited to 5% of GFUR
Scenario 3 (higher interest)	• SOA Debt at 5.6% • Debt Service limited to 6% of GFUR

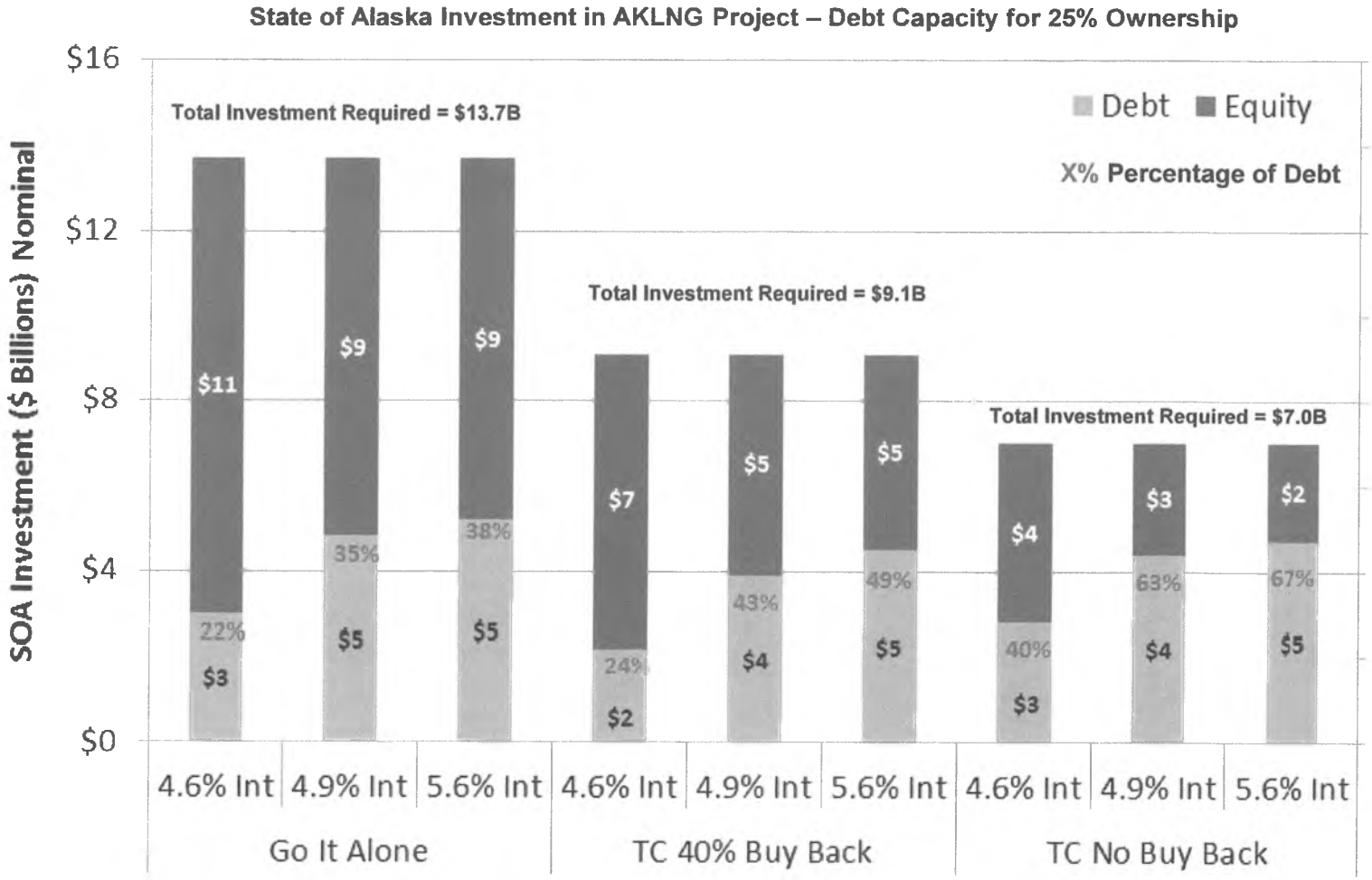
- **High-level, indicative assumptions based on input from Department of Revenue**
- **Based on market conditions as of February 20, 2014**

CAN THE STATE GO IT ALONE? - STATE'S DEBT CAPACITY @ 20% OWNERSHIP



- **High-level, indicative assumptions based on input from Department of Revenue**
- **Based on market conditions as of February 20, 2014**
- **Assumes $55 billion in nominal dollars for total project costs**

CAN THE STATE GO IT ALONE?
- STATE'S DEBT CAPACITY @ 25% OWNERSHIP



- **High-level, indicative assumptions based on input from Department of Revenue**
- **Based on market conditions as of February 20, 2014**
- **Assumes $55 billion in nominal dollars for total project costs**

THANK YOU

Please find our contact information below:

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17

18

LNG OVERVIEW

3

Liquified Natural Gas: Alaska's Once and Future Export?

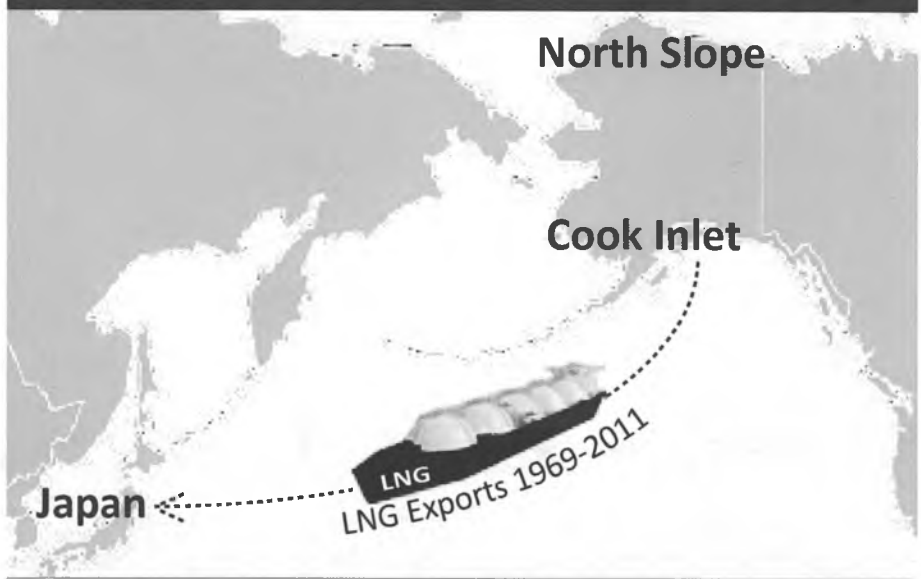
Natural gas is an abundant resource within Alaska.

Compared to oil production, natural gas production in Alaska is several orders of magnitude smaller, including the amount of tax revenue it generates for the State of Alaska. Nevertheless, natural gas production has played a significant role in Alaska's economy.

Alaska's natural gas production primarily comes from two regions: the Cook Inlet and the North Slope. The first major commercial gas discovery came in Cook Inlet in 1959, the year Alaska became a state. Natural gas was later found along with oil at Prudhoe Bay (central North Slope) in 1968.

The export of natural gas in a liquefied state to Japan was one of Alaska's first major world-class development projects. Cook Inlet natural gas has been produced for export to Japan and for in-state use for over a half-century. Overall, since 1959, Cook Inlet has produced over 7.75 trillion cubic feet of gas[1]; of this about 2.5 trillion cubic feet has been exported.[2]

Figure 3-A: Geographic Overview



Source: Background Image "Pacific Centric SVG World Map". http://commons.wikimedia.org/wiki/File:Blank_Map_Pacific_World.svg. Accessed 13 November 2013.

Figure 3-B shows natural gas exports for Cook Inlet from 1989 to 2011. Regular exports to Japan ceased by 2011.

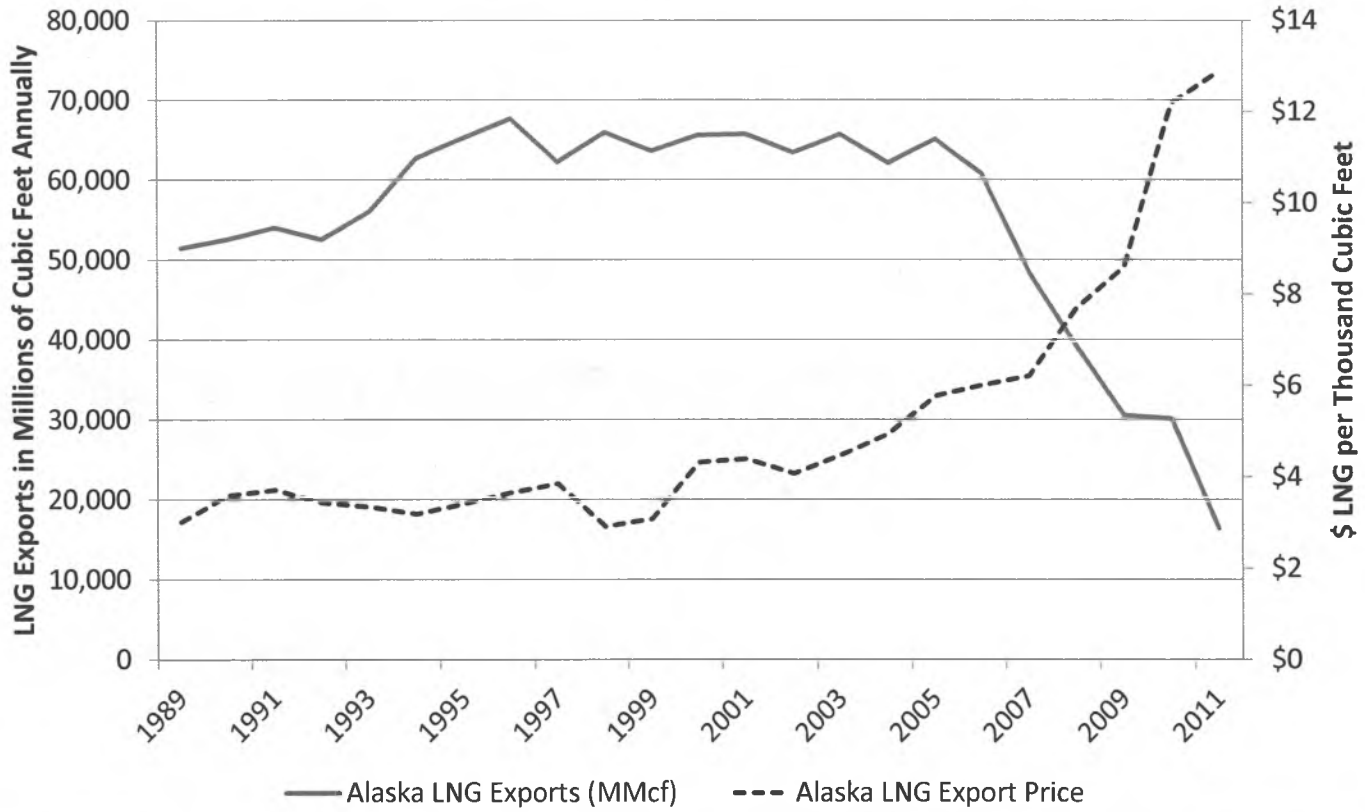
Locally, by the 1980s, natural gas became the primary fuel for generating electricity and for heating Alaska's largest city, Anchorage, and the "Railbelt" area tied into the electrical grid. Earlier, in the area of Barrow (western North Slope), the US Navy discovered natural gas as early as 1949. This field remains a source of energy for Barrow, one of the few settlements in the Arctic to be almost completely powered and heated by natural gas. The village of Nuiqsut (central North Slope) is also powered and heated by natural gas.

The export of LNG (liquefied

[1] This chapter will predominantly use the English conventions for measuring natural gas used in the United States, rather than the International System of Units (metric system).

[2] Oil and Gas Division of the Department of Natural Resources

Figure 3-B: Alaska LNG Volumes and Price



Source: US Energy Information Agency

natural gas) was one of the major drivers of Alaska's economy and helped establish Alaska as an energy exporter. The export of LNG from Cook Inlet also set the stage in how the State would interact with the development of the North Slope – primarily in understanding that the act of exporting a resource outside of Alaska can be an engine of economic growth.

The possibility of a large-scale project that can export the immense North Slope natural gas resources to North American or global markets has been tantalizing and frustrating Alaskans for almost half a century. Economic and commercial conditions for a North Slope natural gas project have not coalesced in the last forty years. Discussion about the potential of such exports is often a major issue within Alaska, and began about the same time major oil discoveries were made on the North Slope.

Natural Gas Basics

Natural gas is a mixture of hydrocarbons, at least 70% methane (CH4) by volume, that, at ambient temperatures, is in gaseous form. The gas can be burned to release energy in the form of heat for electricity generation and steam generators, as well as residential, commercial, and industrial heating and cooling. The heating value of natural gas within the US is defined as giving off between 950 and 1,100 British Thermal Units (BTU)[1] per standard cubic foot (scf), under standard atmospheric conditions. A barrel of oil, by comparison, gives off about as much energy as six thousand cubic feet (mcf) of natural gas. A common rule of thumb is to divide gas volumes in thousands of cubic feet by six to approximate the "barrel of oil equivalent" of gas production and consumption. The exact conversion factor varies.

[1] One BTU is the amount of energy needed to heat or cool one pound of water one degree.

Natural gas is more abundant and cleaner burning than other hydrocarbons, but is more difficult to transport and store. Like oil, natural gas can be transported over long distances in pipelines. However, unlike oil, which is liquid at ambient temperature, natural gas is difficult to ship by sea. Natural gas can be chilled to extremely cold temperatures (-259° F) to become a liquid. In its chilled state, natural gas is 600 times denser than the original gas at ambient temperatures. Liquified natural gas can be easily transported on very large marine vessels to markets, where it is re-gasified and used as conventional natural gas. However, liquifaction is a costly process. One way to export natural gas from Alaska is to deliver gas by pipeline to a tidewater liquefaction plant, convert the gas to LNG and then ship it from a marine terminal to the destination market.

Alaska, an early global leader in LNG exports

Alaska was one of the earliest pioneers in the global trade of LNG. A LNG plant on the Kenai Peninsula, in Nikiski, Alaska, operated between 1969 and 2011 and shipped gas to Japanese electrical utilities. This LNG plant was a globally significant project, since it was the world's second-ever intercontinental LNG project, after an export project between Algeria and Italy. In addition to monetizing a world-class natural gas source at tidewater, this project created the initial destination infrastructure that allowed Japan to become a major user of LNG from global sources. For the exporter, because of US maritime laws, primarily the Jones Act, the LNG could be moved from Alaska overseas to Japan on low-cost, foreign-owned, foreign-built and foreign-operated tankers. This would not have been the case if LNG was delivered to the US, which would have required higher cost vessels and operating conditions related to the Jones Act.

For many years, Cook Inlet gas was considered relatively inexpensive, and was so plentiful relative to what was exported to Japan and what was locally used that the natural gas was also converted to a relatively low valued commodity, urea (ammonia) fertilizer, at a plant in Kenai, Alaska. The fertilizer was also exported. The plant was a major employer, with over 250 people employed, in the Kenai area from 1969 until 2007. Before it closed, it was the second largest producer of urea in the US.

Since the early 2000s, local demand for natural gas expanded with the growth of Alaska's population in the south-central area. At the same time, gas production declined, primarily because additional reserves were not developed within Cook Inlet. In 2011, according to the US Energy Information Administration, Alaska consumers used over 85 bcf of natural gas, which accounted for 63% of power generation in the State and 53% of heating fuel. See Figure 3-C for Alaska consumption trends from 2004-2011.

As natural gas prices in North America rose to all-time highs and the prices became higher relative to prices for LNG shipped to Asian markets, and since there was no regasification terminal to accept Alaska LNG on the US West Coast, the deposits in Cook Inlet were not of great interest to the industry.

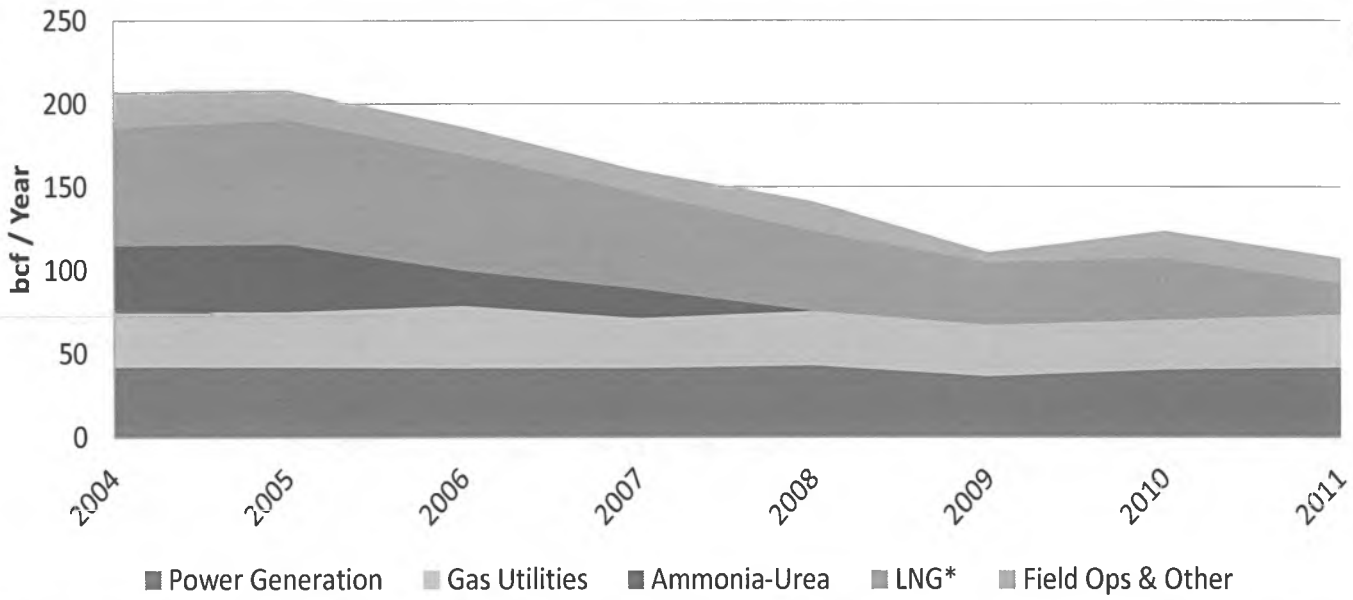
The fertilizer plant closed in 2007 and the LNG plant in 2011, as higher value use competed for diminishing gas production, and because proved gas reserves were not sufficient to meet anticipated Anchorage demand. For the same reason, lack of available gas forced the Nikiski LNG plant to close. Consistent LNG exports to Japan ceased in 2011. Figure 3-D show Cook Inlet contributions to production tax and royalty for 1991-2012.

Local Use of Natural Gas

Resolving gas supply for Anchorage issue became an important issue for the Municipality of Anchorage and the State. In 2012, a gas storage facility was constructed, which allows extra gas produced in summer to be saved for use in the winter for peak demand, at times when demand outpaces production.

Several different proposals to resolve Anchorage's gas requirements included bringing natural gas from the North Slope by pipeline (small or large diameter); exploring and discovering additional reserves in the Cook Inlet and/or nearby; or, bringing in LNG into the Anchorage market. In the short-term, while production has declined and demand in south-central Alaska has increased, the overall rise in price as well as a fiscal policy that includes significant credits for exploration and development resulted in increased exploration. Increased exploration has, in turn, discovered new supply for natural gas, and the Anchorage market now has sufficient supply through 2018, according to the

Figure 3-C: Cook Inlet Gas Consumption and Sum of Heating Degree Days Annually



Source: Alaska Department of Natural Resources Oil and Gas Division

Department of Natural Resources.

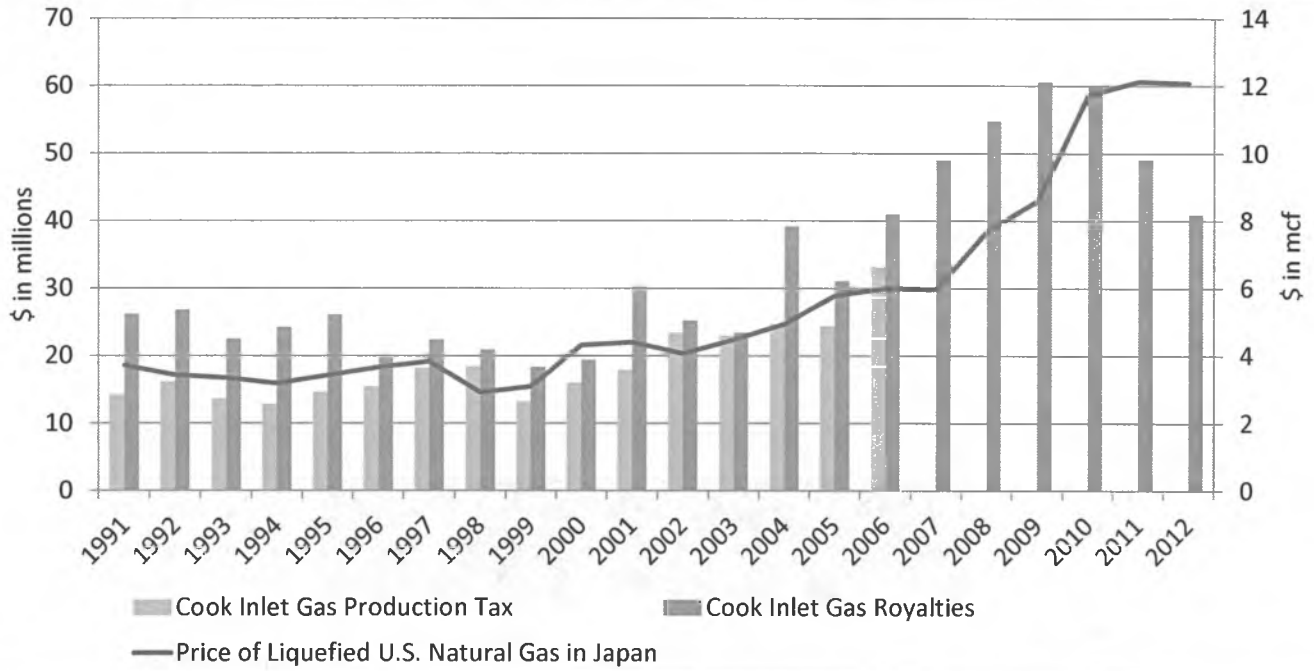
A small amount of Cook Inlet gas is trucked to Fairbanks for heat and power. Currently, 1,100 households in the Fairbanks area use natural gas. For the most part, however, Fairbanks and most outlying areas of the State do not use natural gas for electricity generation, and face significantly higher utility costs than south-central Alaska. Fairbanks faces an energy crisis because of high prices for electricity and heating. The heating issue is exacerbated by the fact that many people are heating or supplementing their ordinary heating systems with firewood, which has created a significant problem with air quality in the area. Current limits of the facility in Big Lake (where the Cook Inlet gas is loaded on trucks) have created demand for a new supply source from the North Slope. Access to increased supply of gas for Fairbanks could reduce the costs of both space heating and electrical generation for the Interior. Without a pipeline to supply the gas to Fairbanks, trucking gas from the North Slope has been proposed as a fast, flexible and efficient way to serve the Interior and resolve the gas supply issue for Fairbanks in the short-term. The trucking project has been discussed for several years, and may materialize in the near-term.

An expanded use for natural gas is a part of the discussion about the energy use mix within the State, especially in terms of electricity generation. Should North Slope gas be delivered to south-central Alaska or Cook Inlet production increase, at a competitive price, at sufficient volumes, new uses are proposed for natural gas within the State. For example, several mining projects have proposed using natural gas to power their operations. The developer of the Donlin Creek gold mine, a major prospect located near Bethel in Southwest Alaska, proposed constructing a 312-mile-long pipeline to the mine to generate power. Pebble Partnership proposes using natural gas in its concept plan to power mine operations. This is also coupled with the thought that such a gas supply could provide a cleaner and cheaper fuel to generate electricity for the larger region, which currently relies mainly on fuel oil that is barged in. Also, any electrical energy generated in Anchorage can enter the Railbelt regional grid benefiting even the Fairbanks area population. LNG imports have even been considered should a regional source of natural gas be unavailable.

Past Plans for Alaska Natural Gas Export

The Prudhoe Bay oil discovery in 1968 that led to the construction of the Trans-Alaska Pipeline System

Figure 3-D: Production Tax and Royalty Collections on Cook Inlet Natural Gas and Japan Natural Gas Price



Source: Alaska Department of Natural Resources

(TAPS) also included an estimated 26 trillion cubic feet of natural gas, which has been revised to over 35 trillion cubic feet of gas. Efforts to commercialize natural gas began soon after the completion of TAPS, and over forty years there have been numerous and even competing proposals to move North Slope gas to markets. However, to date, Alaska does not export North Slope gas, although natural gas is used for enhanced oil recovery and for electricity generation on the North Slope.

The use of natural gas on the North Slope is not insignificant. Producers are prohibited by law from flaring natural gas on the North Slope. Instead, they use it for power generation to support oil production. Since oil production began in 1977, 6 trillion cubic feet of gas has been used for power. Some natural gas is produced as liquids that can be shipped through the TAPS along with oil. Since the completion of the Central Gas Facility in 1986, over 600 million barrels of gas liquids have been produced. Some of the gas is turned into a "miscible injectant" that helps increase oil production. The remaining gas is re-injected into the Prudhoe Bay reservoir to maintain pressure and help increase oil production.

In 1976, Congress passed the Alaska Natural Gas Transportation Act, which provided for expedited development of a pipeline. The following year, the United States and Canadian governments approved the construction and ownership of a pipeline along a route that followed the Alaska Highway through Canada to reach Continental US customers. A competing project at the time included the El Paso Natural Gas project to export LNG to California, also called the "All-Alaska" route (a name used later by other Alaska projects that follow a similar route), to a marine terminal near the oil terminal in Valdez, Alaska that was rejected under the same federal certification process that approved the Alaska Highway route. Even an "over-the-top" offshore route in the Arctic Ocean to Canada and ultimately to US East Coast markets was proposed at the time.

Deregulation of the US domestic natural gas industry led to a supply increase and a price drop for the destination markets in the Lower-48 and the Alaska Highway project never materialized. In the end, none of the projects were able to answer the ultimate question to investors and project organizers: did the margin between the delivered cost and the expected price per unit of

gas result in sufficient net returns to justify the risk? In 1983, these costs needed to beat about $3.00 per thousand cubic feet of gas in real 1983 prices, while annual average wellhead prices hovered above $2.50 per thousand cubic feet. By 1986 were less than $2 per thousand cubic feet. Only the southern leg of the planned Alaska Highway route was constructed, allowing gas from the Province of Alberta to help meet Continental US demand. Natural gas wellhead prices only passed the nominal $3 per thousand cubic feet threshold in 2000.

Table 3-1: North Slope Gas Potential

Exploration Area	Mean Technically Recoverable Gas (trillion cubic feet)
Prudhoe Bay	23
Point Thompson	8
ANWR	9
Beaufort Sea OSC	32
Chukchi Sea OCS	77
Colville-Canning Area & adjacent state waters	38
NPR-A	53
Total	240

Sources: U.S. Department of Energy, August 2007; BOEM, *2011 National Assessment.* Energy Information Administration, *2009 Annual Energy Outlook.*

Studies done in the 1980s revived a proposal to establish an LNG export operation for North Slope gas to Asia, but prices failed to support the commencement of such a project. Interest in a gas pipeline picked up again around the turn of the millennium due to rising prices and demand in the Continental US, primarily in using gas in electricity generation. In 1998, the Alaska Legislature passed the Alaska Stranded Gas Act Development Act, which allowed the State to negotiate special fiscal, tax and royalty terms, and regulatory terms with the North Slope oil producers, for an LNG project that exported "stranded gas," defined as gas that, "… is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the Department of Revenue commissioner for a particular project." The act was reauthorized in 2003 and extended to any North Slope gas pipeline project.

In 2004, Congress passed the Alaska Natural Gas Pipeline Act, which established a federal project coordinator, provided for loan guarantees, and offered tax and regulatory incentives for a pipeline project. These laws led to negotiations between the State administration and the producers that culminated in a contract in 2006 that was rejected by the State Legislature. At this time, annual average nominal wellhead prices in North America exceeded $6 per thousand cubic feet.

In 2007, the State Legislature passed the Alaska Gasline Inducement Act (AGIA), which provided for partial reimbursement for a developer's expenses, up to $500 million, in exchange for agreeing to terms including following the State's timeline. TransCanada, a Canadian pipeline company, was awarded the license on the project, and ExxonMobil later agreed to work with them on the project. Meanwhile, BP and ConocoPhillips launched a competing proposal, called Denali – The Alaska Gas Pipeline. The plans in their various incarnations called for a pipeline to Canada to link into mid-American markets that were similar to the Alaska Highway proposals of the 1970s.

Falling natural gas prices in the Continental US due to the explosion of shale gas production drastically increased the North American supply within a period of a few years. In 2012, the three main North Slope oil producers, and owners of North Slope natural gas resources, joined together to propose a pipeline to a south-central Alaska LNG facility that would export gas to Asian markets, rather than a pipeline to North American markets. Work continues on this plan, and a preliminary concept was selected in early 2013. The current proposed project is reported to have an estimated cost of between $45 and $65 billion for a gas treatment plant, a 42-inch pipeline, and an LNG export facility (three trains delivering 15-18 million tons of LNG) in Nikiski on the Kenai Peninsula.

Two other LNG proposals include a recent proposal from Japanese company Resources Energy Inc. (REI) and an older proposal, by the Alaska Gasline Port Authority (AGPA), a joint venture organized in 1999 between the Fairbanks North Star Borough, Valdez, and, at one time, the North Slope Borough. The

port authority project applied for an export license, but the proposal was rejected in 2013 by the Department of Energy.

Parallel to these efforts to construct a large-diameter pipeline is an effort to construct a smaller pipeline to transport North Slope natural gas, to serve the local needs of Alaska consumers in the south-central area. In 2002, Alaska voters approved a ballot measure that created the Alaska Natural Gas Development Authority (ANGDA), which was vested with the authority to act as a shipper and obtain financing for a project. In 2010, the Legislature created the Alaska Gasline Development Corporation (AGDC), as a subsidiary of the Alaska Housing Finance Corporation. AGDC was tasked with moving forward with the Alaska Stand Alone Pipeline (ASAP) project to build a line. In 2013, the Legislature made AGDC an independent corporation and folded ANGDA's operations into it. The AGDC project itself reports a cost estimate of $7.7 billion for a 36-inch pipeline to Anchorage and a gas conditioning facility on the North Slope $4.9 and $2.8 billion, respectively.

Natural Gas Markets

The physical requirements needed to transport natural gas dictate the manner in which it is marketed and used. Countries or regions that have deposits of natural gas and have well-developed natural gas pipeline networks are able to move the gas to where it is needed. Countries or regions without natural gas or use more natural gas than they produce, must import gas either by pipeline or must import LNG at a marine terminal. An example of the former is Germany's use of Russian natural gas that is delivered by large-diameter pipeline, and an example of the latter is Italy's import of Algerian gas by sea. South Korea, which has little domestic gas, but has a well-developed national gas pipeline network, is able to import natural gas through three injection points and distribute it relatively efficiently throughout the country. In contrast, Japan has a very rudimentary national pipeline network, and relies on over 20 marine terminals to accept natural gas. The electrical utilities own most of the LNG import terminals and the natural gas is used to generate electricity, which is then distributed throughout the country. Rigid right-of-way laws have made the establishment of a gas pipeline network problematic.

Globally, the major distinction, therefore, is between natural gas that can be delivered by pipeline overland and natural gas that is sold as LNG by sea. Historically, Alaska's natural gas, produced at tidewater in Cook Inlet, was a natural candidate as an LNG export project.

However, projects to export Alaska's North Slope gas are always faced by various options, including moving natural gas by pipeline to North American markets via a route to the closest major Canadian hub located in Alberta, known as the Alberta Energy Company (AECO) hub. Other options include moving the gas to a marine liquefaction plant for export to Japan or other markets in Asia, or, even to North American West Coast markets, which require the additional cost of constructing an import terminal at the destination. There have been other options considered as well. There is the so-called "over-the-top" option, with a pipeline going due east along the Arctic National Wildlife Refuge, into Canada. This option would pick up Canadian arctic gas deposits, and be delivered to the previously high-priced markets of the US Northeast. This option is typically rejected because of difficult environmental permitting issues related to the federal refuge, and because the pipeline has a relatively short length within Alaska and the United States and has been couched as benefiting Canada disproportionately. In fact, there is a state resolution (HJR 44, 2002) and a federal law (Alaska Natural Gas Pipeline Act, 2004) that prohibits the "over-the-top option." There is the option of a shorter pipeline to the Bering Sea, or taking gas directly out of the Arctic on LNG vessels, but these options have significant technical challenges.

Either option requires significant lead time and large capital costs, and the construction of an overland pipeline either to Canada or to south-central Alaska. However, one option ties Alaska natural gas directly into North American markets and the extensive pipeline network, while the other, would have Alaska continue as a player in the marine LNG trade. For the export of Alaska North Slope gas, the price differentials at various times would have one option seem advantageous over the other. However, over a thirty year period, the price differential between the two destinations has been large and small, and has reversed several times.

Globally, population centers and energy basins exist in different locations. Nowhere is this more pronounced than with the Asian

economies of Japan, Republic of Korea and Taiwan. Japan, as mentioned before, is unique since its gas supply comes into many different terminals associated with an electrical utility and the national pipeline network is non-existent. These three industrialized countries are the premium markets for LNG. In addition, China, India, South America, the Middle East, India and European countries represent new and growing markets for LNG. These new LNG demand centers have more energy options than Japan and Korea, resulting in weaker premium LNG prices in these locations. Yet, these regions are reliant on external LNG sources.

Basins located in Russia, Qatar, Australia, and others are the main suppliers to the global LNG market. Suppliers to the LNG market are set to rapidly expand. Up to 25 countries have proposed plans to build export LNG terminals or add additional capacity over the next decade. These additional exporters have little or no current capacity. Ironically, with LNG prices at unprecedented highs, Alaska, one of the first suppliers of LNG in the world, has ceased to produce and export LNG from Cook Inlet.

Natural Gas Prices

To show how these markets interact and to get a picture of the current conditions of the global market for natural gas that are relevant to Alaska, we compare major natural gas pricing points – the US Gulf Coast Henry Hub (HH), the UK's European National Balancing Point (NBP), and the Japan-Korea Marker (JKM).

Henry Hub, in Louisiana, is the price hub that defines the market for North American pipeline gas in mid-America. Pipeline infrastructure defines natural gas markets in North America. Henry Hub natural gas prices are the most often quoted natural gas prices in North America. Natural gas pricing in North America is lucid, despite a large geographical area the infrastructure covers. With accessible infrastructure, large reserves, cutting edge production technology, stable governments, large numbers of suppliers and consumers, financial markets and other factors, have created an unparalleled distribution system. Extensive infrastructure coupled with a massive amount of associated gas produced along with the relatively new "shale oil revolution" in North America, the US currently has some of the lowest natural gas prices in the world. Only five years ago, this was not the case. Annual average prices were almost triple what they are today at the wellhead.

The National Balancing Point (NBP) is a virtual trading location and is a price point for British gas. Unlike Henry Hub, it is not a physical location. It includes North Sea gas into the UK and has both a pipeline and LNG natural gas market component. It is also the price and delivery point for the Intercontinental Exchange (ICE) for natural gas futures contracts.

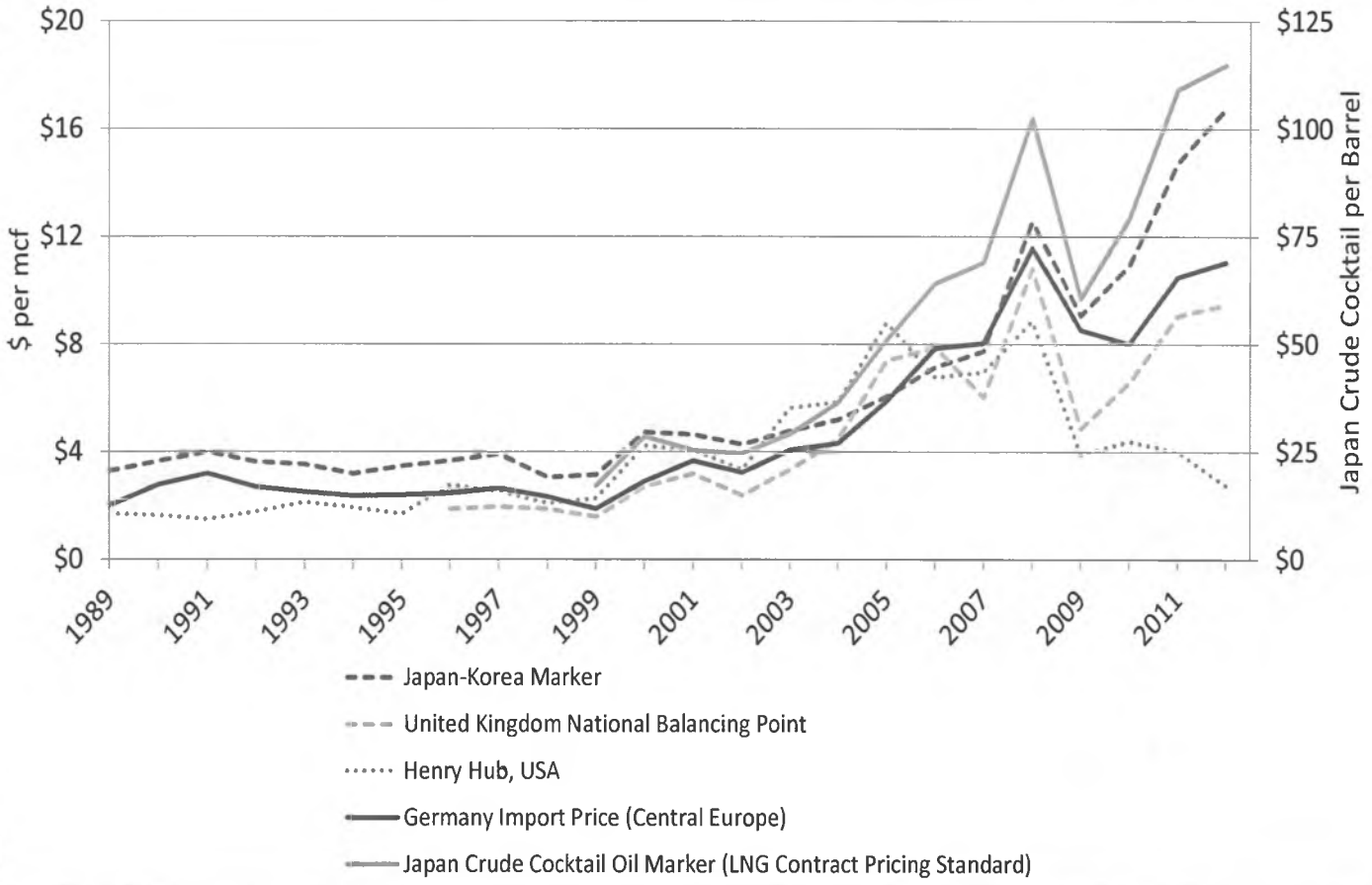
The Japan-Korea Marker is Northeast Asia's pricing point that consists of an LNG import market connected to South Korea's national pipeline system, and the large number of marine terminals in Japan where the natural gas is directly converted into electricity. Japan LNG also supplies a relatively inefficient city gas market.

Figure 3-E illustrates natural gas prices globally, including a comparison with oil, on an equivalent thermal basis.

While the global gas price hubs continue to follow oil prices, Henry Hub notably does not. In general, the major price hubs have experienced significant divergence in price. Until 2007, these markets normally traded within $2-$3 of each other. Currently, the pipeline market and the LNG market differentials have never been greater, consistently exceeding $10. The current divergence between Henry Hub and the Japan-Korea market differs by more than five times.

In the 1990s, natural gas prices in North America were relatively low and stable, and natural gas became extremely popular in electricity generation because it was a cheaper and cleaner burning fuel, relative to coal and oil. On the demand side, the US deregulation and restructuring of the natural gas industry expanded the use of natural gas in the US energy mix. On the supply side, prior to 2007, natural gas production was mainly tied to discoveries linked to oil, creating a structural relationship that existed between oil and natural gas. Oil prices started to rise in 2003 due to loss of spare capacity in the oil market, strong global growth and underinvestment by petroleum companies accustomed to a low oil price environment. Further, US supplies were constrained primarily to domestic supplies, since LNG import terminals were relatively insignificant as a source of supply.

Figure 3-E: Global Natural Gas Prices



Sources: BP's 2013 Statistical Review of World Energy, Bloomberg, and Reuters

As demand grew and supply was constrained, the result was a sharp increase in natural gas price in US markets.

Incidentally, the 1990s coincided with proposed plans to bring Alaska LNG into the California markets. One problem was the difficulty of permitting an LNG import terminal in the Continental US. Another problem was that shipping Alaska LNG would require vessels constructed and operated under Jones Act requirements, considerably more costly, considering delivery to higher priced Japanese LNG markets could be delivered in foreign vessels, with foreign crews.

After 2007, the oil and gas industry in North America increased investments in developing new resources of natural gas from shale. Prices in North America collapsed, further exacerbated by a lucrative market in stripping natural gas liquids (a high price commodity relative to gas), leaving behind a large supply of relatively low price natural gas. See Henry Hub prices in Figure 3-G. At the same time, in addition to Henry Hub prices diverging from other prices, the Japan-Korea Marker and National Balancing Point pricing diverged due to the way LNG contracts link to oil price markets. National Balancing Point price increases have been muted when compared to Japan-Korea Marker prices, which are heavily influenced

[1] NBP has both LNG and pipeline gas supplies resulting in gas on gas competition. Europe also has a wide variety of sources to obtain supplies, which include North Africa, Middle East, European sources and Russia, in other words Europe is a marginal consumer of LNG. Pipeline gas prices from Russia to Germany and central Europe did not fall as far. Gazprom, the Russian national gas supply company, was able to maintain prices due to its dominance in the European market. Gazprom is now facing an anti-trust case launched by the European Commission.

by oil linked contracts.[1]

Natural gas prices in Alberta have always been important to Alaska, since this would be the likely destination for any Alaska gas overland pipeline project that delivers gas to the Continental US. The differential between Louisiana and Alberta prices is the cost of transportation between natural gas coming from Alberta to Louisiana. This is a sign of a mature market with ample infrastructure. All other natural gas hubs in the US and Canada are based upon either of these hubs, plus a differential to reflect regional dynamics. Prices for natural gas vary in different regions, determined by local factors such as the number of competitors selling gas, regulatory bodies, pipeline capacity, industry, abundance, substitute energy sources, etc. Currently, the processes within the US that have reduced natural gas prices are also at work in Canada.

Figure 3-F: Geographic View of Price Differentials

Source: BP's 2013 Statistical Review of World Energy

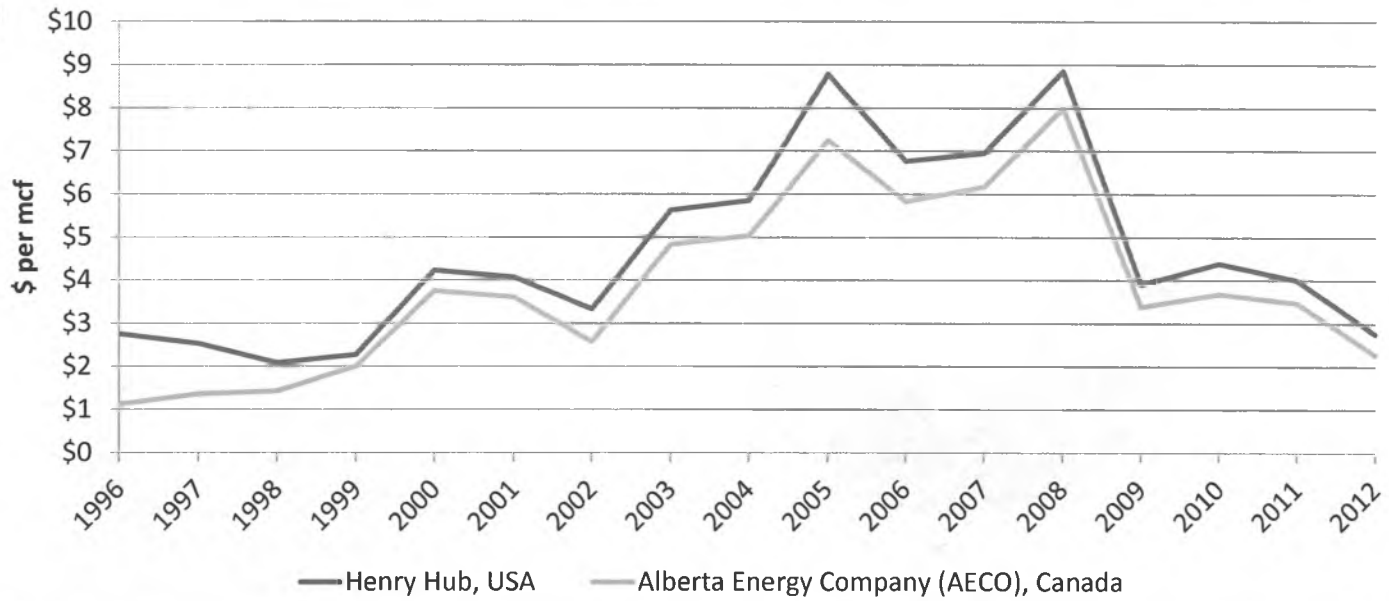
For Alaska, price volatility (especially from the 1990s through today) has greatly affected project economics of a North American gas pipeline. In the ten years it takes to complete an Alaska project, natural gas prices could change dramatically. See Figure 3-F a geographic view of price differentials. Reduction of pricing risk is critical to the success of a pipeline from the North Slope. Regional price dynamics play a critical role in determining the final destination of the gas. Ideally, gas would be delivered to a population center isolated from large supplies of natural gas and that has ample demand. The location of where the gas is delivered is important as it relates to the two major pricing hubs in North America and the route the gas takes to get there.

The relatively cheap natural gas price in North America has now made it a major fuel in electricity generation. In fact, cheap natural gas burns cleaner than coal, producing 70% lower carbon emissions. This advantage has allowed natural gas to capture more of the electricity market in the US. As Figure 3-H illustrates, between 2000 and 2011 the market share of coal has decreased and natural gas market share has increased. This trend is set to continue as America's oldest electricity plants that run on coal are being retired, and are replaced by natural gas plants.

LNG Demand

Global LNG demand has grown 7.6% per year since 2000, compared to global natural gas demand growth of 2.7% over the same time period. Asia has been the single largest contributor to this rise in demand for LNG. The Fukushima reactor meltdown has anchored LNG growth in the short- to mid-term as Japan has moved away from nuclear energy for current and planned incremental electricity generation. LNG demand seems to be set to continue expanding as nations seek energy diversification and flexibility in their energy sources. There is also a growth in infrastructure within Northeast Asia and India that allows LNG used, and there is a regional concern for hydrocarbon emission and the desire to replace coal with the cleaner burning gas. Finally, there is a surge of supply as new basins are brought online to serve

Figure 3-G: Major North American Hub Prices



Source: BP's 2013 Statistical Review of World Energy

the LNG demand in Asia. Europe, which has spent years developing a de-carbonization strategy, with Germany's rejection of electricity generation by nuclear energy, also a reaction to the Fukushima disaster, has not had subsequent increase of use of natural gas in electricity generation. This is primarily because Germany is one of Europe's main energy consumers and Germany's main supply of gas, by pipeline from Russia, faced the monopolistic pricing policy of Russia's state-owned gas production giant, Gazprom. Ironically, coal use in Europe has increased to compensate for the shut-in nuclear capacity.

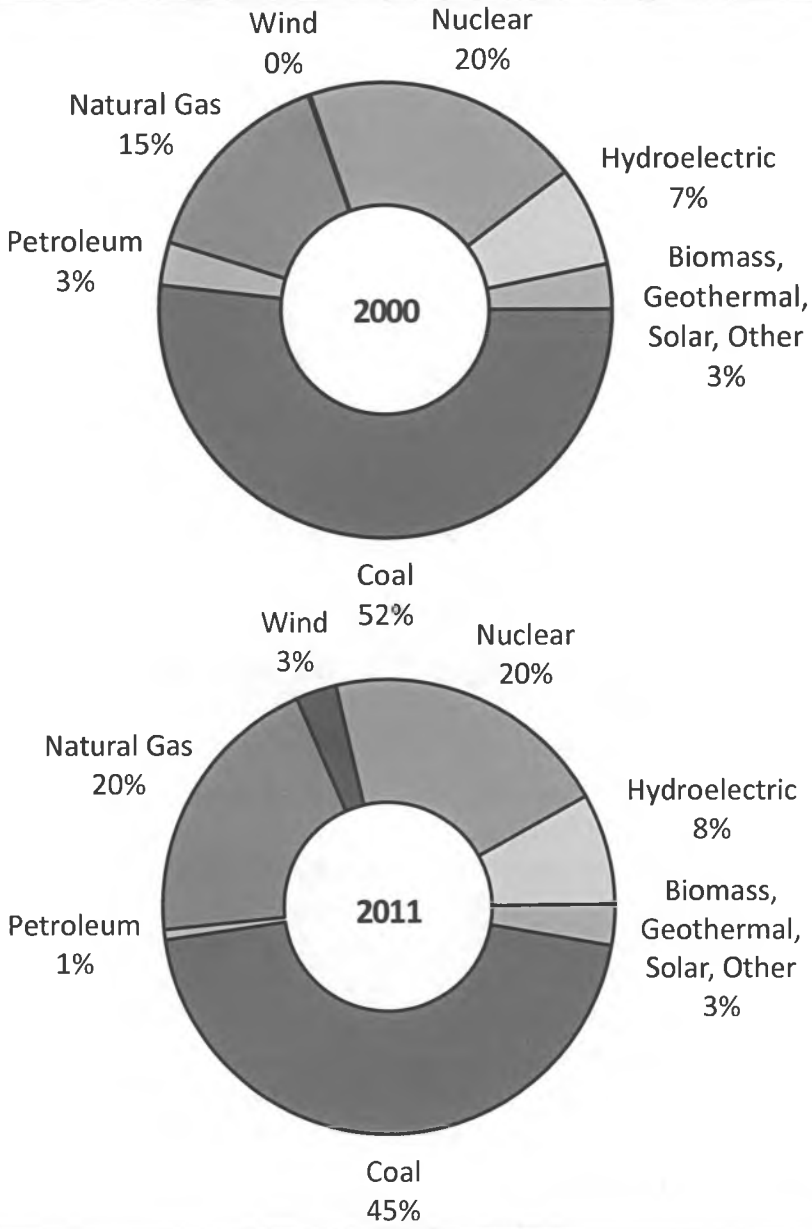
The International Energy Agency (IEA) predicts strong global growth of natural gas usage. IEA's forecast for natural gas in 2035 is 25% of energy consumption, up from 21% in 2010. Global natural gas demand is projected to grow 1.6% per year, whereas oil growth is projected to rise at 0.8% annually over the same time frame. Estimated LNG demand in 2030 is 24,000 bcf, double 2012 demand of 12,000 bcf. LNG demand is forecast as particularly strong through 2020, with a broad range of analysts and observers projecting 5%-6% growth per year.

Currently, half of LNG market demand comes from Japan, Republic of Korea (South Korea) and Taiwan. These countries are classified as being heavily industrialized with limited domestic energy resources and are expected to remain the major drivers of LNG demand in the future.

New LNG demand is led by China and India. China's latest five year plan doubles the amount of LNG used from 4% when the plan came out to 8% in 2015 and 10% by 2020. In order for China to meet the goals of its "five year plan," coal consumption must decline, likely to be replaced by LNG. Currently, China's coal consumption is seven times larger than the global LNG trade. In contrast, US coal consumption for electricity generation decreased by 26% between 2007 and 2012, according to the EIA. China does have natural gas opportunities to develop, including shale gas and pipeline gas expansions, and it has pursued these opportunities aggressively. If China's natural gas demand continues to grow, pipeline and shale gas production volumes will need to be supplemented by increased LNG imports. With multiple supply options, China should be well-supplied by domestic sources, pipeline gas and LNG contracts. Figure 3-I illustrates China's projected LNG imports.

Other countries have planned new construction or to add additional capacity to import LNG. Many

Figure 3-H: U.S. Electricity Fuel Sources 2000 and 2011



Source: Energy Information Administration

of these countries will be new importers. Currently, there are 25 countries that import LNG with a regasification capacity of 28.8 trillion cubic feet per year; and, by 2020, 38.4 trillion cubic feet per year of regasification capacity could exist, an increase of 9.6 trillion cubic feet, or 33% over current capacity.

LNG Supply Risks

Uncertainty is the key term the LNG supply chain faces. Challenges exist in multiple forms on a global scale, from competition to unwieldy expensive large projects, and local to global economics. Since 2009, global economic growth has been slow to emerge. Many economies within the Organisation for Economic Co-operation and Development (OECD)[1] have yet to recover fully, with non-OECD countries growth being restricted because of this. LNG projects are handicapped with this uncertainty, even though current economic trends suggest that the global economy has stabilized and economic growth has returned.

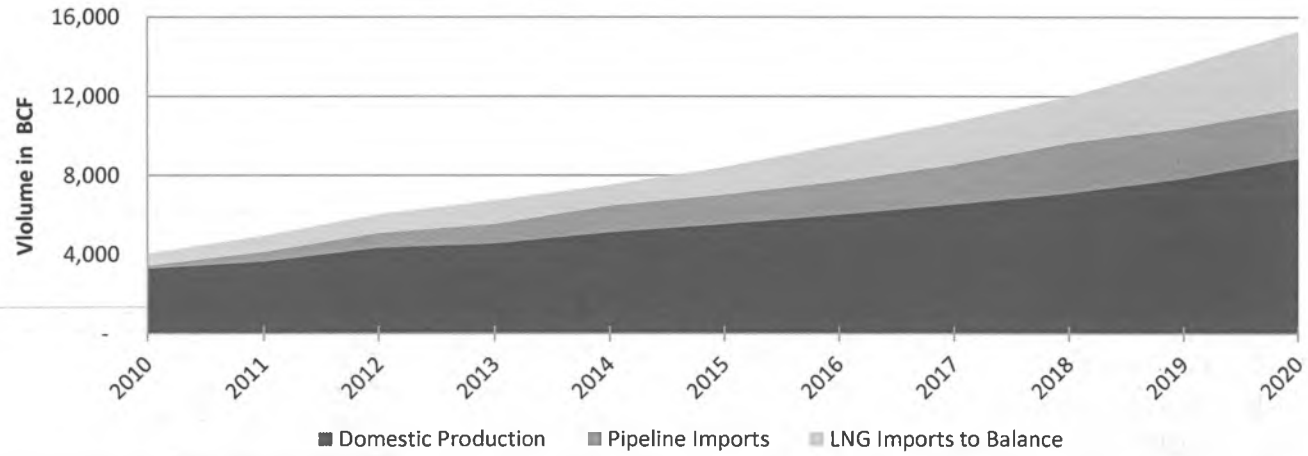
New supplies from unconventional resources such as shale gas, coal bed methane, tight gas and methane hydrates could capture potential future LNG market share. These unconventional sources also exist on the North Slope of Alaska. Ten years ago, the estimated natural gas resource base worldwide was for 50 to 60 years' worth of supplies. Now the natural gas resource base is projected to have expanded to a 200 year supply. The IEA estimates there are 752 tcm of technically recoverable natural gas world-wide.

LNG Supply - Capacity

Global LNG capacity has developed in stages. In addition to Alaska's Cook Inlet, early LNG exporters included Algeria, Indonesia, and Malaysia, followed more recently by Australia and Qatar. The early LNG exporters still control about 60% of the global LNG supply, with Australia and Qatar providing 20% of the market. This market structure is expected to shift dramatically by 2020. Algeria, Indonesia, and

[1] The OECD economies are the world's industrialized economies.

Figure 3-I: Chinese Natural Gas Supply Sources



Source: Ernst & Young Global LNG "Will new demand and new supply mean new pricing?" 2013

Malaysia market share will drop to about 20% on a global basis by 2020. While Australia and Qatar are expected to expand their markets share to about 50% globally.

Australia in particular has a number of LNG projects under development representing a third global wave of projects. These green field projects will have the capacity to produce 2.8 trillion cubic feet annually.

LNG Supply – New Entrants

Any Alaskan LNG project must evaluate future competing LNG projects worldwide. LNG projects under construction and those projects currently supplying the LNG market are not Alaska's competitors. Those LNG projects have clients, the development costs have been partially or fully funded and risks have been resolved or negated to an acceptable level. Longer term, suppliers to the LNG market will expand as new entrants enter the market. There are up to 25 new countries who currently could become entrants to the global LNG market. Possible new entrants include Canada, United States, Tanzania, Mozambique, Israel, Iran, and Venezuela. Some countries like Iran and Venezuela are less likely to develop their reserves due to geopolitical events and financial constraints. Other countries like the US and Canada are in much better position to begin exports.

Future LNG projects all face unique risks. Israel's natural gas reserves are subject to national security matters. Tanzania and Mozambique proposed LNG projects have no supporting infrastructure, contain security risks and are located far offshore. Canadian LNG terminals face an uphill battle due to multiple projects competing for the same market, environmental opposition, and resource constraints if multiple LNG plants are all constructed at once.

Under current conditions an Alaska project also faces significant risk, some of which would have to be mitigated to have an LNG project move forward. This may be a strategy to provide a win-win situation, where producers have an economically viable project, Alaska's economy is more diversified, and state revenues are diversified and increased.

LNG Supply – US, Canada and East Africa

The Department of Energy (DOE) must issue an export license to any US LNG export terminal according to US law. As of January 2013, there are 20 companies who have applied for an export license from DOE. Licensing for LNG exports falls into two categories, countries with whom the US has free trade agreements (FTA) and non-FTA countries. Sixteen projects have received approval to export to FTA countries and one project has non-FTA country approval. South Korea and Singapore are the only FTA countries with significant LNG demand.

Nine US LNG export facilities have infrastructure already in place. These facilities were originally designed for LNG imports. They were planned just before the advent of widespread shale gas, as a way to alleviate North

American supply constraints in the 2000s. These "white elephant" import facilities are being converted to export facilities. Conversion of this existing infrastructure into export facilities represents cost savings in comparison to new LNG facilities and creates revenue opportunities from otherwise money-losing infrastructure.

The proposed export projects represent 10.2 trillion cubic feet of LNG export capacity. It is very unlikely all this capacity will be built, as global demand was 12.0 trillion cubic feet in 2012.

Cheniere's Sabine Pass LNG export terminal in the Gulf of Mexico is the only project near export production and its gas is all under contract. Originally, it was constructed as a LNG import terminal. Sabine Pass has export capacity of 864 bcf annually. The project has four anchor buyers and there is some gas reserved for spot sales. Contracts for buyers are structured on Henry Hub gas prices, a 15% uplift/shrinkage charge, and a fixed liquefaction charge. It is these Henry Hub structured contracts that are of great interest in the Asian markets and are of great interest in relation to the traditional oil-denominated contracts.

There is intense interest in exporting LNG from Western Canada. There are four projects planned, representing 2,400 bcf of annual capacity. These projects are based on large natural gas resources located in Western Canada, supportive government policies and openness to foreign investment. These projects are expensive, costing tens of billions of dollars. Each project is a greenfield development, from the wellhead to the LNG export terminal, meaning everything has to be built from the ground up. Developers of the projects will own every aspect of the LNG project, requiring extremely large capital investments upfront. The basins these potential projects will access include the Montney, Horn River, and Liard. Pipeline investments alone are expected to add $200 million to project costs.

Individual projects are worth noting for their strengths and weaknesses. There are two projects are located in Kitimat, British Columbia. The largest project is the Shell led consortium, with a planned LNG export facility of 1,150 bcf annually. Shell's partners include national oil companies (NOC) Petrochina, and Kogoas, along with Japanese conglomerate Mitsubishi. The competing, Apache's consortium, that also includes Chevron, is planned with a capacity to produce 480 bcf annually. Chevron brings extensive LNG experience, financing, and a clientele of existing customers. Chevron has publically stated oil linked prices are necessary for the project to be successful, while LNG importers are likely to challenge this stance.

Offshore of East Africa, there have been a number of extremely large natural gas fields found in a lightly explored area. Most of the confirmed natural gas finds have occurred in Mozambique, with more recent finds in nearby Tanzania. There is an estimated 110 trillion cubic feet of natural gas in Mozambique alone. Project economics are dependent upon clustering of infrastructure to reduce costs, requiring cooperation between the ENI led consortium and the Anadarko led consortium. LNG export capacity from this area is unknown at this time since no project plan has been developed. Other considerations for the companies at this point are securing LNG export licenses, funding, clients, fiscal terms and cooperation between the different stakeholders.

LNG Economics

LNG projects are expensive, and often financing is sought for the entire LNG chain from wellhead to shipping. Suppliers of future LNG look toward clarity in pricing to justify the economics of these projects. Early LNG projects before 2003 cost less than $4 million/bcf annually. The second wave of projects cost between $10 to $25 million/bcf annually. Now projects under consideration are in the $54 million/bcf annually range according to Deutsche Bank.[1]

Analysts at Credit Suisse expect several proposed LNG export projects to be built in North America and Africa.[2] Economics of these projects compare favorably to the Australian projects being developed. The US and African projects have an estimated cost of $96 thousand per bcf per year, versus $144 thousand per bcf per year for Australian projects. Australia's economics did not look to be at

[1] Deutsche Bank. *Oil and Gas for Beginners Industry Update*, 25 January 2013.

[2] Credit Suisse. Global Equity Research, Global LNG Sector Update, 7 June 2012.

such a disadvantage when the decisions were made to develop the LNG projects. Currency risk has hit Australian projects hard, as the Australian dollar has appreciated more than 60% against the US dollar since 2009, as has the shortage of specialized labor.

In order to offset these very high risk and extremely capital intensive projects, suppliers want iron clad LNG contracts linked to oil prices. Traditionally, LNG contracts were linked to oil prices, with Japan, Korea, and Taiwan willing to accept these contracts for imported LNG in order to diversify their energy sources. However, there may be less willingness to accept this standard going forward. LNG is developing a market as a separate commodity from oil and some analysts suggest that the LNG market will continue being more competitive in the future, although this view is far from universal. The LNG market views oil as becoming scarcer and higher priced and LNG becoming more plentiful making the linkage between the two undesirable, especially in the long-term. A response to this is the shift from oil-indexed contracts to Henry Hub based indexing, which is now growing popular in Asia.

The LNG market is following a classic trajectory toward market equilibrium. Suppliers looking at developing expensive projects need high prices to justify their development. At the same time, more price sensitive buyers are unwilling to commit to expensive long term contracts. The result has been buyers signing shorter-term contracts and strict oil indexation is faltering. Again, an example of this is the preference in Asia for Henry Hub based contracts over traditional oil indexing.

Longer term market prices and oil based LNG prices should migrate away from each other, as suppliers of LNG will be forced to compete on price in order to remain competitive. However, the relationship between the two will likely not collapse. In order to guarantee supply, importers of LNG will pay a higher price. The same relationship holds true in the oil market. Excess capacity exists, but there is a premium built into price to ensure adequate future supplies.

The development of a more active spot market pricing for LNG would be a major next step for pricing. The development of a trading hub where supplies can be physically delivered and picked up, will increase liquidity and support the development of an active financial market. An active spot market will provide price clarity to all market participants. Singapore is the leading contender in Asia for the actively traded physical and financial market to be located. The terminal in Singapore will have both import and export capacity, enabling it to fulfill this role. Currently, weak pricing signals exist in the LNG market as pricing transparency is hindered by contracts and their terms are obfuscated.

A contrary argument is that the considerable investment for each project makes it untenable for financing should the market not remain with a predominance of long-term contracts. A sign of a mature market is when risk based premiums for commodities weaken. Instead global LNG players emerge with a portfolio of places LNG is sourced from and this is sold to a portfolio of buyers. Major energy companies like BP and Chevron are already participants in this market development. These portfolio players will be able to sign contracts where greater flexibility will exist for a cargo's timing and delivery location. When this happens regional prices for LNG should start to converge on global price, due to arbitrage.

Even a well-developed spot market will not spell the end for LNG risk premiums. Spot markets for Henry Hub prices have had tremendous price movements. Volatility in LNG prices will force LNG suppliers to have higher rates of return in order to justify new projects.

Financing Large Natural Gas Projects

Large project financing follows a straightforward formula. A project is identified, passes the project partners internal hurdles for investment, and project partners set up a separate entity to reduce risks to them. The newly created entity is funded with an equity contribution from each partner and debt issued by the new entity. Capital raised is used exclusively to fund the project through project completion. Cash flows from the project are the only means of repayment of debt and any excess capital is returned to the project partners, if the project is successful.

Risks

Benefits of establishing a separate entity for a large natural gas project are centered on risk management. Project risks are considerable. Risk mitigation strategies include debt default protection, clear project funding sources, separate accounting,

limiting environmental liabilities, political risk, transportation risk, counterparty risk, supply risk, commodity risk, technology risk, inventory risk, taxation risk and other risks the project would encounter. These risks can be independent, dependent or interdependent on other risks the project faces.

A key question becomes how projects can reduce risk exposure. One way is through the assistance of government.

Government Incentives

Large projects often require the cooperation of both industry and government. These projects can carry benefits for both industry and government. Governments can assist in making projects more attractive for financing in many different ways (as shown in Figure 3-J).

Figure 3-J: Government Incentive Programs for Major LNG Projects

	Financial	Policy Assistance
Direct	Grants Subsidies Capital Investments Development Cost Funding Loans	Dedication of governmental natural resources Guaranteed off-take Expedited permitting Use of state property Condemnation power
Indirect	Income Tax Incentives Loan Guaranties Reduction in Fiscal Take Tax Credits Waivers of Property, Use, Sales, Franchise, and VAT taxes Use of governmental bond authority	R&D support Portfolio standards Demand incentives Fuel preference programs Consumer financial incentives Labor initiatives Building/zoning codes Interconnection planning Permitting standards

Governments have worked collaboratively on several important projects around the world. Included here is a discussion of planned projects in Russia, British Columbia, Australia, and Norway.

Russia

The Yamal Peninsula on the Arctic Ocean contains Russia's largest natural gas reserves, estimated at 55 tcm of natural gas. Russia's Novatek and France's Total looked to develop a green field LNG export project from the region. However, arctic conditions, high costs, long distances from customers and tax issues made the project questionable for development.

Russia is heavily dependent upon its natural resources for revenue and has substantial interests in the energy industry, including protectionist legislation and a mostly state-owned industry. Nevertheless, currently Russia has made the decision to cut taxes, approve LNG exporters other than Gazprom (the state-owned Russian gas company) and has provided other promises of assistance to ensure the export of Yamal gas. In 2011, the Russian government exempted LNG from the 30% minerals extraction tax. Other assistance from the Russian government will come in the form of financing of a port, an airport, gas pipelines, icebreakers, and dredging work. This assistance has an estimated price tag of $9 billion. Regional governments are also assisting with the development, property tax exemption, and a lower Corporate Income Tax. These lower tax rates will expire once 8.8 trillion cubic feet of gas or 180 million barrels of condensate are extracted. Recently, foreign capital investment in the project included China National Petroleum Corporation acquisition of a 20% stake from Novatek. A final development decision is expected in 2014.

British Columbia

Lack of infrastructure hinders the development of British Columbia's large natural resource base. Oil and gas deposits are located in remote areas, with challenging geography, and require large capital investments, and high degrees of uncertainty for any project success. Hopes for an LNG export industry are based on these greenfield oil and gas projects being developed. There are currently no LNG marine export terminals, although several are planned on the Pacific Coast.

Government supported incentives for development of these greenfield projects mainly revolve around royalty credits. These credits are for roads, pipelines and LNG export terminals. It is the intention of

British Columbia's government to generate more in royalties, than it spends in credits.

The framework for the credit program is based upon the original cost of the project submitted to the government before the project is started. Upon completion of the project the project can receive up to 50% of project costs as credits against royalties owed to the government. If a project cost $1 billion, the developers would be able to take up to $500 million in royalty credits.

As of June 2013, a total of $1.7 billion was made in capital investments, including 1,243 new miles of road, representing 78 new resource roads, and 1,304 miles of new pipeline.

Norway

Norway, like Alaska, is a mature petroleum production area with tremendous petroleum resources. The Snohvit gas field is currently considered as a source for LNG export. First discovered in 1984, the field took 23 years to develop. Located in the Arctic Ocean 90 miles from land, in 1,000 feet of water, the project had to confront some major obstacles and a new way of thinking about offshore development.

In order to develop the challenged Snohvit gas field, Norway reduced the tax burden on the project. Norway has a corporate income tax rate of 50% on profits generated by offshore production, plus 28% base rate paid by all corporations in the country. In order to enhance Snohvit's economics the 50% offshore tax was waived. This was done by allocating the profits from the offshore project to the onshore LNG terminal. Another important taxation issue to consider, Norway allows for a six year depreciation schedule. A six year depreciation schedule enables capital cost recovery in a shorter time period, than in Alaska or at the US federal level.

Development of Snohvit required production equipment to be located on the sea floor with the gas piped onshore. Development costs totaled $10 billion, well above the projected cost estimate of $6 billion made in 2002. Snohvit has the capacity to liquefy 750 million cubic feet of natural gas per day.

State Tax and Natural Gas

In Alaska, the production tax for natural gas is calculated in the same way that the tax is calculated on oil, with regional differences. The three oil and gas producing areas are 1) North Slope, 2) Cook Inlet, and 3) the rest of Alaska (collectively known as "Middle Earth").

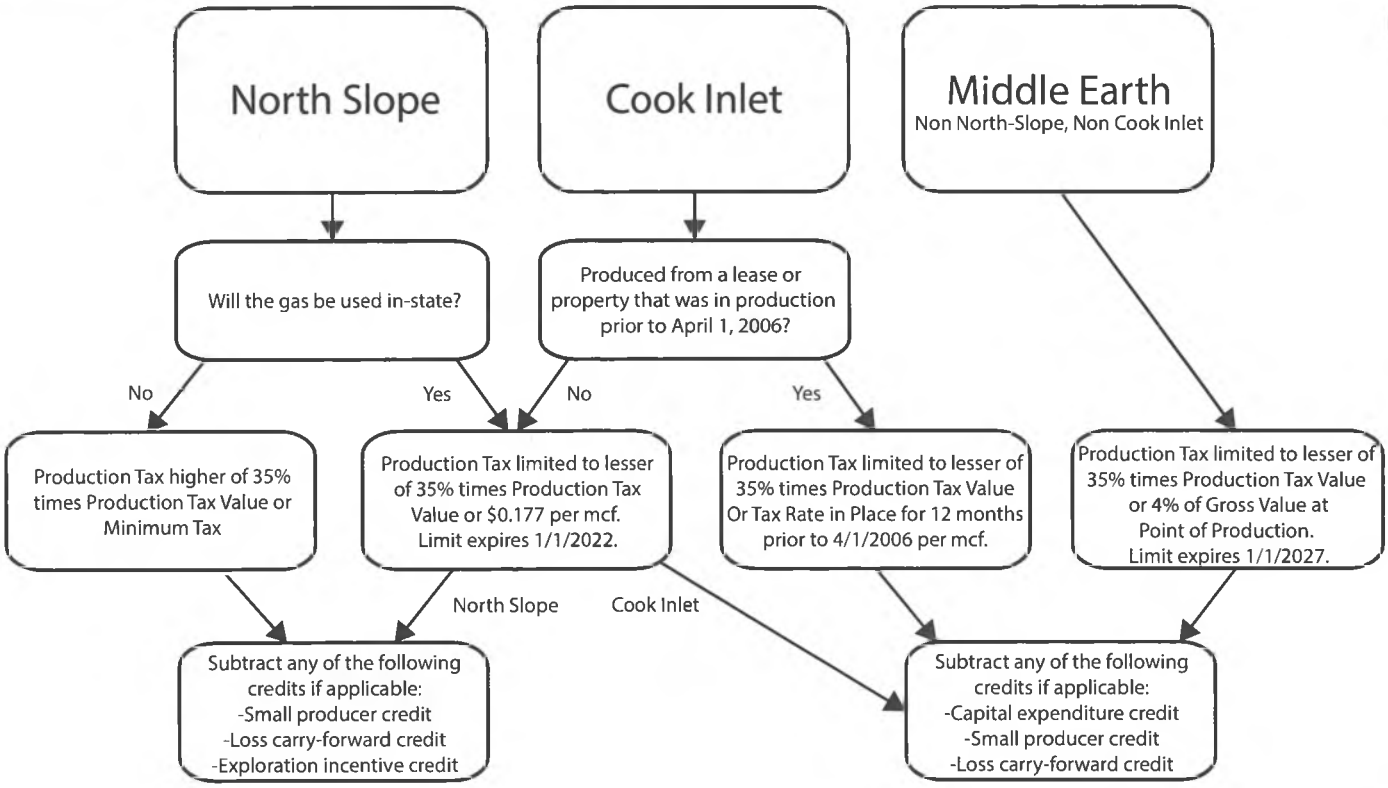
The production tax levied on natural gas under AS 43.55.011(e) may be limited by statute and the limit is set to a certain derived price per thousand cubic feet based. Figure 3-K is a graphic that shows how the production tax is calculated for the three regions and highlights some of the similarities and differences. The distinction on the North Slope is that the tax is calculated is based on destination, whether the gas is used in-state or leaves the State. "Gas used in state" is defined per AS 43.55.900(24) as gas "delivered for consumption as fuel in state, including as fuel consumed to generate electricity." Not all gas used in state will qualify. For example, gas used in manufacturing may not qualify. In Cook Inlet, the distinction for taxation is whether the gas is produced from a lease or property that was in production prior to April 1, 2006. Areas outside the North Slope and Cook Inlet have a maximum tax of 4% of gross value at the point of production regardless of destination, governed by AS 43.55.011(p).

For taxation purposes, natural gas volume is measured according to the average value per "barrel of oil equivalent" (BOE), a measure that equalizes the thermal value. Under the ACES tax regime, prior to January 1, 2014, including lower value gas in the same tax calculation as higher value oil reduced the progressive tax rate on oil ("progressivity"). By taxing oil and gas together, gas production reduces oil taxes even though oil operations are unaffected. This has been called the "flip the switch" problem. Under ACES, if major gas sales began, State tax revenue could have dropped significantly under certain price scenarios, including current prices. However, under the provisions of the More Alaska Production Act (MAPA), effective January 1, 2014, although oil and gas are still included in the same tax calculation, adding gas will not impact the tax rate on oil, since the legislation imposes a flat tax rate of 35%.

Conclusions

Alaska's history of exporting LNG to Japan, producing fertilizer, and utilizing natural gas for local electricity generation and heating, provides the region with a long-term familiarization with the natural gas industry, including the LNG export trade. Even the analysis and discussion of several major

Figure 3-K: Natural Gas Production Tax Calculation Diagram



unfinanced and unconstructed natural gas export project plans over the years have provided Alaska with experts and policy makers with a better understanding of natural gas markets.

Natural gas remains an abundant resource within Alaska. LNG is natural gas that is in a form that can get to distant markets by marine transport. In deciding where Alaska North Slope natural gas should be sold, given the choice to go by land in a pipeline or by sea as LNG, the discussion should revolve around the destination price minus the costs of delivering a unit of gas over the lifetime of the project. The discussion also has revolved around the importance of profit made at the point of production, since this is where the current tax regime provides revenue to the State. Other tax considerations include that the new tax regime has taken a step in dealing with the issue of "decoupling" oil and gas tax revenues to avoid diluting oil revenues with lower value natural gas barrels of oil equivalent.

Natural gas markets have changed dramatically within the last five years with North American natural gas prices falling and global LNG prices, especially in Asia, rising, resulting in a historic differential in prices in the market. At this time, the current price differential indicates a preference for exporting Alaska gas as LNG. However, new supply entrants are also planning to put their projects in the queue, as competing LNG projects take advantage of the current high price and supply shortfall. In some cases, the new entrants are supported with government involvement and support.

The window opened by current market conditions of natural gas and LNG might provide the necessary potential for new revenue, but up to now elusive, economic and commercial conditions for a North Slope natural gas project. Understanding the past and present conditions may give some insight for the future of Alaska's natural gas resources.