City of Valdez
Presentation on the In-State Gas Pipeline Bill (HB4)

Senate Finance Committee

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Problems with H.B. 4 and AGDC Concept

- Cheaper Alternatives Like LNG Import
- Unclear Whether AGIA Violated by H.B. 4
- Circumvents Existing Regulatory Structure
  - FERC open season regulations
  - RCA and not FERC regulated
  - No common carriage in-state
  - Just and reasonable rates not required
  - Expansion costs on new entrants
- Cost Estimate Not Transparent
- Wrong Project Scope
- State Loses if H.B. 4 Structure Used for Big Project

Background – H.B. 369

- **HB 369 Sec. 4.**

AS 38.34.099 to read:

"(1) 'in-state natural gas pipeline' means a pipeline for transporting natural gas that runs from the ***North Slope to tidewater*** in the state"

- **HB 369 Sec. 9.**

Amended AS 41.41.990(3)to read:

"'project' means the gas transmission pipeline, together with all related property and facilities, to extend from the North Slope of Alaska or other regions of the state to a market in the state, or be available to a market in the state, and ***to tidewater at a point on Prince William Sound or Cook Inlet***, and includes planning, design, and construction of the pipeline and facilities as described in AS 41.41.010(a)(1)-(5)."

Potential Benefits to Alaskans
from a Large Volume State-Owned Gasline/LNG Project
by
PDC Harris Group LLC (November 3, 2011)

- Natural Gas vs. Diesel Fuel Costs

  - Fairbanks **natural gas** cost = $5.29/mmbtu

    vs

  - Fairbanks **diesel fuel** cost (2021) = $27.23/mmbtu

- Represents energy cost reduction of 80%

- Total value of fuel savings of over $2.4 billion to Fairbanks residents

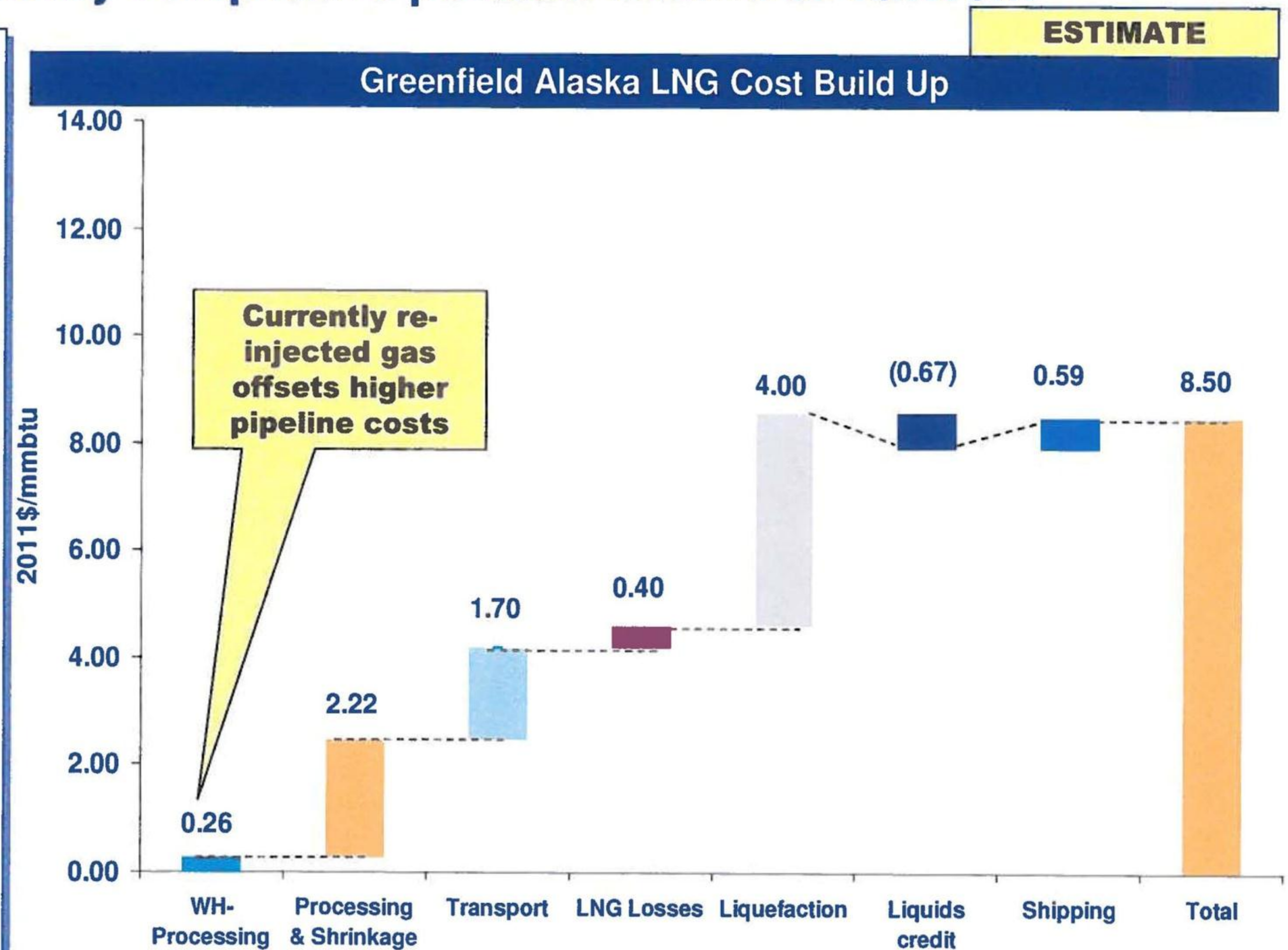
Potential Benefits to Alaskans
from a Large Volume State-Owned Gasline/LNG Project
by
PDC Harris Group LLC (November 3, 2011)

- Energy Cost Savings: Bethel and Fairbanks
- Bethel energy cost savings of up to **65%**
- Equates to potentially $886 million in fuel savings cost for Bethel residents (over 30 years)
- Fairbanks energy cost savings up to **80%**

Access to currently re-injected gas upstream puts the Alaska LNG liquefaction project in an economically competitive position relative to others…

Key Assumptions

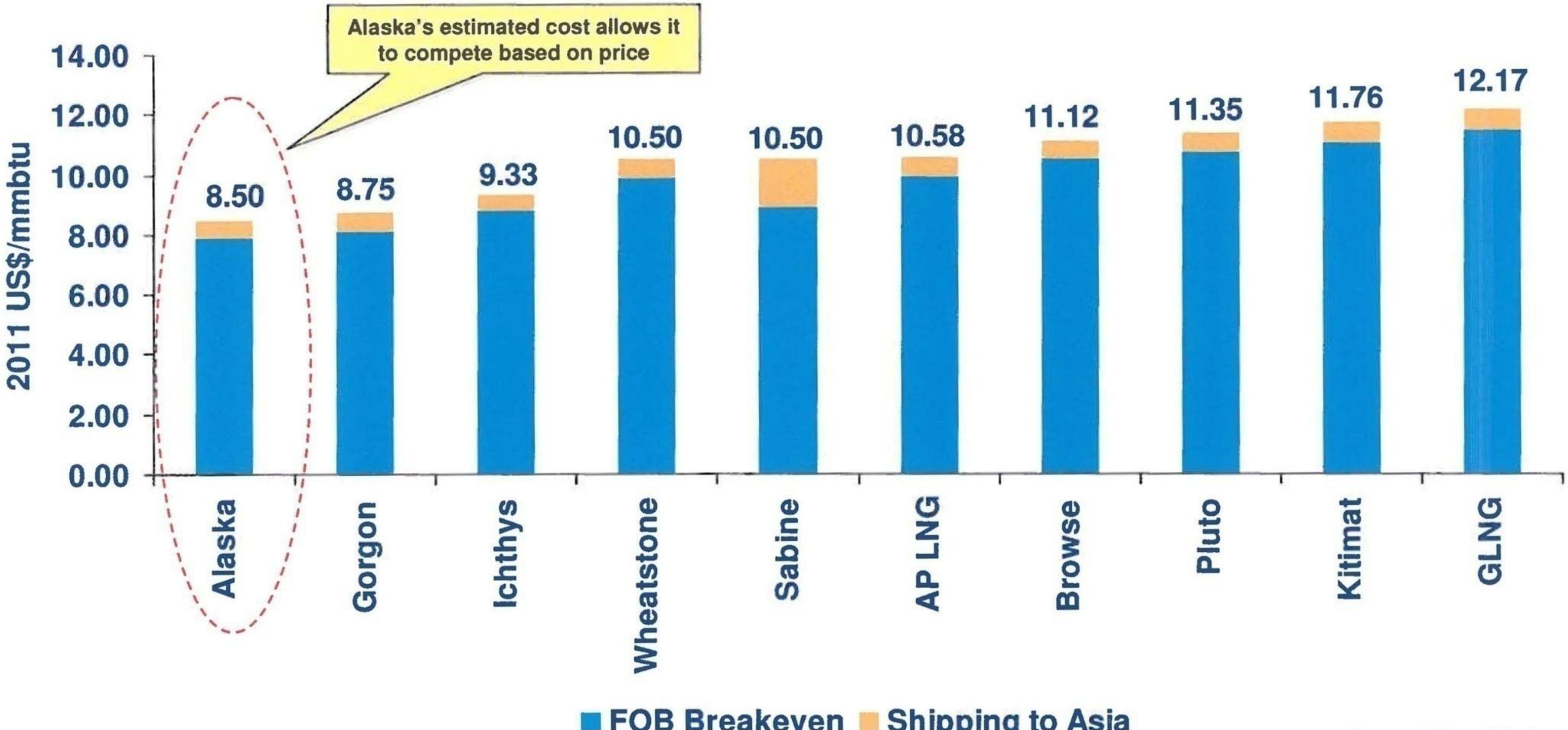
- All data from "Transcanada XOM Alaska Pipeline Project Open Season Notice, 2010, Valdez LNG Case" except below items:
- Liquefaction:
  - CapEx: $1,200/ton; est. rate covers CapEx, Opex, 12% nom. ROE.
  - Alaska LNG losses 9.65%
- Shipping Assumptions:
  - Ship: 155,000 m³
  - CapEx/ship: $200 million
  - OpEx: $15,000/day; 2.33% annual escalation
  - 8% ROE after tax
- LNG Processing Losses: estimated from AGIA NPV Report, Fig. 7.2
- Liquids credit determined using $80/bbl netback price for LPG and volumes provided by AGPA (88,000 MMBtu/d; ~20,000 bpd)



Source: Wood Mackenzie

…and it competes favorably with both proposed Australian and other North American export facilities which have yet to reach FID

DES Cost Stack Comparison



Source: Wood Mackenzie

From an economic perspective, Alaskan LNG exports are competitive, viable across scenarios, and could generate between $220 and $419 billion for Alaska*

- The numbers generally "work" for Alaskan LNG exports when the global oil price is north of $75/bbl oil and Asian firm contract pricing reflects a 13%(+) oil indexation** (indexation for firm contracts today is approximately 14.85%)
   - Alaskan LNG exports have a delivered cost structure below $10/MMBtu. Given a range of infrastructure cost scenarios, oil prices projected utilizing Woodmac's April 2011 NAGS price outlook or the NYMEX forward strip, and LNG - oil indexation pricing to Asia of 13 – 16%, Alaskan LNG could be priced DES between $18.00 - $46.00/MMBtu through 2050.
- Proposed Alaskan LNG exports have a substantial cost advantage relative to possible competing LNG supply projects
   - Alaskan LNG would use assets that are producing gas for re-injection (essentially limited to gathering, transport and processing costs)
   - Most competing Australian projects and proposed NA LNG exports yet to secure Final Investment Decision (FID) are expected to deliver LNG to Asia at costs of $10 - $12/MMBtu under current gas price assumptions
- Assuming start-up in 2021 and a project life of 30 years, royalties (12.5%) and state taxes (starting at 25% post-royalties) could yield a total of between $220 and $419 billion*
   - Royalties (12.5%) and state taxes (starting at 25% post-royalties) could yield $2.4 to $24 billion per year.
- While we do not address them, there are a number of commercial challenges associated with all liquefaction projects
   - Economics are important, but commercial issues such as the scale of value chain requirements (pipes, storage, etc.), buyer risk tolerance, financing arrangements, etc. are critical

Taking all into account – basis, shipping, capital requirements – Alaska LNG export facilities can deliver LNG to Asia less expensively than US Lower 48 or Canada and competitively vis-à-vis traditional Australian LNG sources

Wood Mackenzie

*Total undiscounted taxes and royalties values utilize nominal figures (2.4% inflation), 14.85% indexation, and avg. recourse rate of $4.18. Assuming a nominal discount rate of 5%, the NPV of taxes and royalties is between $65 and 124 billion.

**Oil indexation price example: With an oil price of $100/bbl, "oil indexation" of 14.85% yields a gas price of $14.85/MMBtu

TransCanada/Exxon
AGIA Solicitation of Interest Results
September 14, 2012

Korea, Thailand & Indonesia	Japan (REI)
KOGAS (Korea)	Japan Exploration Company, Ltd. (Japan)
POSCO (Korea)	Idemitsu Kosan Company (Japan)
GS Energy (Korea)	JX Nippon Oil & Energy Corporation (Japan)
PTT International Company, Ltd. (Thailand)	Mitsubishi Gas Chemical Company, Inc. (Japan)
PGN LNG (Indonesia)	Nippon Telephone and Telegraph (Japan)
East-West Power Company Ltd. (Korea)	
2.8 bcf/d	2.7 bcf/d
TOTAL: 5.5 bcf/d	

H.B. 4 Problems – LNG Import

- "If ASAP can't beat the cost of imported LNG then we are on a fools errand."
- 2006 ANGDA Study (*see* Exhibit 3)
  - $62.2 million to convert the existing LNG facility to receiving terminal
  - Volumes imported would match shortfall demand
- Nobody predicts a 100% shut down of Cook Inlet (*see* Exhibit 2)
- Blended price predicted lower than the 100% volume from ASAP concept
- Closure of exports from Cook Inlet will cause increase in gas availability in South Central

H.B. 4 Problems – Does it Violate AGIA?

- Legal opinion by Legislative Counsel obtained by the sponsor of H.B. 4 (February 15, 2013) (*see* Exhibit 4) raises unanswered questions
- Does a 1.6 bcf/d pipeline violate the assurance clause in AGIA?
  - If H.B. 4 is in violation of AGIA, then the fiscal note needs to be doubled or tripled
  - AGDC potential capacity above .5 bcf/d, tax exemption and state financial support "could result in liability under the assurances." Opinion at 9-11
- Is AGIA license out of compliance? If so, why are we discussing a low volume pipeline?
  - The TransCanada project was a highway project
  - On May 2, 2012 Administrated modified original project plan to allow LNG alternative (*see* Exhibit 5)
  - "A strong argument may be made that the licensee's assessment of an in-state natural gas pipeline is a different project and not a modification of the project licensed under AGIA." Opinion at 8

H.B. 4 Problems – Circumvents Existing Regulatory Framework – History of Regulatory Treatment

- LB&A Briefing Paper on FERC Open Season Regulations (November 9, 2004) (*see* Exhibit 6)
  - "Rational economic behavior suggests if the Big Three or similarly situated companies own the Alaska gas pipeline, they [will] use their vertically-integrated market dominance to limit competitor access to the pipeline, as well as extract a high tariff from those who do gain access – more income for them, higher costs for their competitors, and lower wellhead values on which royalties and taxes are payable to the State of Alaska. In fact, this is the story of the Trans Alaska oil pipeline (TAPS), except that with TAPS its status as a common carrier has thwarted any effort to use market dominance to limit access. TAPS tariffs, however, have proven to be an obstacle to competition, and have been cited by more than one company as a reason for withdrawing from efforts to commercialize Alaska's resources."
  - "The challenge for the Commission, then, is to create rules that give birth to competition, even in the face of an Alaska gas pipeline that will be a natural monopoly and may be owned by those with production interests better served by suppressing competition."
- "The Alaska Legislators conclude that, unlike the situation in the lower 48, there is no existing or foreseeable competitive environment in Alaska, where the North Slope Producers not only control the known gas reserves, but also may become the sponsors of the Alaska pipeline. Therefore, the Commission was right to not rely on market forces in Alaska to ensure the developments, routing, sizing and timing of an Alaska pipeline." FERC Order 2005-A ¶ 29 (June 1, 2005)

H.B. 4 Problems – Circumvents Existing Regulatory Framework – FERC Regulation

- In 2004 Congress required FERC to adopt open season regulations that provide access for non-Prudhoe Bay and Point Thomson gas
- In 2005 FERC adopted Alaska natural gas pipeline open season regulations (*see* Exhibit 7)
  - "[W]e are well aware of the risks to competition imposed by a project that is owned or primarily sponsored by a small group. Thus, we are imposing strict requirements on all proposals, and particularly on affiliate-owned project, with respect to public disclosure of information, to ensure that there is a level playing field. . . We will require applicants for an Alaska pipeline project to provide detailed information as to project design, how capacity is to be allocated, and proposed rates, terms and conditions. This will allow us to be in a position to monitor whether competition for capacity is fair. In addition, while we are permitting pre-subscription for 'anchor' shippers, we are requiring that contracts with such shippers be made publicly available, and that all shippers seeking the same type of capacity be offered service on the same terms and conditions." 2005 Order at ¶ 12.

H.B. 4 Problems – Circumvents Existing Regulatory Framework – RCA and not FERC Jurisdiction

- FERC has said no jurisdiction over an Alaska LNG export project that does not ship interstate. *Yukon Pacific Corporation*, 39 F.E.R.C. ¶ 61,216 (1987) (*see* Exhibit 8)
- AGDC is also a political subdivision of the State, and thus not subject to FERC jurisdiction under the Natural Gas Act. *Tennessee Gas Pipeline Co.*, 69 F.E.R.C. ¶ 61,239 (1994); *Somerset Gas Serv.*, 59 F.E.R.C. ¶ 61,012 (1992)
- Since RCA and not FERC will regulate this pipeline, it is critical the RCA be empowered to exercise maximum regulatory oversight

H.B. 4 Problems – Circumvents Existing Regulatory Framework – Common Carriage In-State

- AS 38.35.120 - Off slope gas pipeline
  - Common carrier for in-state volumes
  - Either Contract or common carrier for volumes to LNG terminal
- Common carrier pipelines ideal
  - Ensures late entry
  - Financed all the time (e.g., TAPS)
- Contract carrier status helpful to financing
  - Contract for export volumes already a compromise
  - In-state demand less than 10% of likely capacity
  - Minimum level of common carriage for in-state volumes will not substantially impact financing

AGDC Problems – Circumvents Existing Regulatory Framework – Rolled In Rates

- Expansion by rolled-in or incremental rates
  - "incremental pricing puts all of the costs associated with an expansion on the parties who caused the expansion . . . [while] rolled-in pricing spreads the costs of the expansion over all customers – existing and new" (*see* Exhibit 9 at 1)
- FERC Order 2005 ¶ 123 (*see* Exhibit 7)
  - "We conclude that there should be a rebuttable presumption in favor of rolled-in pricing for project expansions. Our existing lower-48 states policy favoring incremental rates for expansions does not apply in the case of an Alaska natural gas transportation project. There is likely to be only one Alaska pipeline, so there will be little or no opportunity for competition between pipelines. Incremental pricing of expansion could put expansion shippers at a significant rate disadvantage compared with initial shippers, and accordingly could discourage exploration, development and production of Alaska natural gas."
- Rolled-in rates an AGIA "must have" (*see* Exhibit 10)

AGDC Problems – Circumvents Existing Regulatory Framework – Rolled In Rates

- Expansion occurs in two ways (*see* Exhibit 9 at 3)
  - Low cost compression, which reduces rates
  - High cost looping, which increases rates
- H.B. 4 states rolled-in rates available if maximum rate under negotiated agreements not exceeded
  - Initial shipper (under negotiated terms) gets rate benefit of compression, but does not pay for looping?

H.B. 4 Problems – Circumvents Existing Regulatory Framework – "Just and Reasonable" Rates

- Under State royalty and tax netback regime producers have immense incentive to maximize tariffs to minimize government take
  - 1977 BP Memo explains producer "highest possible tariff" strategy *(see* Exhibit 11*)*
- History demonstrates State negotiations are no substitute for just and reasonable rates
  - 1985 TAPS Settlement Agreement resulted in $13.5 billion (1997 dollars) in tariff overcharges. 2007-2009 Gleason Decision at ¶ 76
- Independents frozen out:
  - Tariffs above "just and reasonable" rates have resulted in independents leaving the Slope
  - "It broke my heart to trade Milne Point, but we had to do it. All the values of that property was taken away from us in the pipeline tariffs. It was a valuable strategic lesson[.]" Archie Dunham, CEO Conoco (August 1996) *(see* Exhibit 12*)*

H.B. 4 Problems – Circumvents Existing Regulatory Framework –"Just and Reasonable" Rates

- AS 42.06.370(a): "All rates demanded or received by a pipeline carrier . . . shall be just and reasonable."
- "Just and reasonable" standard means FERC and RCA set under cost of service methodology
- FERC allows negotiated rates on gas pipelines so long as customers electing the recourse rate will be no worse off as a result of the use of negotiated rates
    - Negotiated rates subject to FERC review

Pre-Subscription Agreements

H.B. 4 Rules

- Confidential and filed under seal
- Individually negotiated
- Precedent agreement capacity not reduced to accommodate open season volumes
- Deemed "just and reasonable" unless unlawful/unfair dealing; affiliated owner/shippers okay if similar to one with unaffiliated party

FERC Alaska Rules

- All public within 10 days
- All shippers can chose terms of any precedent agreement
- Precedent agreement capacity reduced pro rata if open season volumes not accommodated
- Late bid provision allows shippers to obtain capacity after the expiration of the open season
- Subject to FERC negotiated rate review

H.B. 4 Problems – Project Scope – Pipe Size Not Critical Cost Driver

- Example – *see* Exhibit 13 – Alyeska 2013 cost study reported direct costs of replacing TAPS (plus owner, management and engineering costs) less marine terminal(*) at
  - 30" pipe with 440,000 bbl/d capacity **(ǂ)** ~ $8.9 billion
  - 48" pipe with 750,000 bbl/d capacity **(+)** ~ $9.7 billion

- Shared cost estimating team
  - TAPS RCN: Stantec, Michels, Micheal Baker, Price Gregory, Alyeska
  - AGDC: "Michael Baker Jr., Inc. (Baker), Price-Gregory International, Inc., Ward Whitmore & Associates, Larkspur Associates, and DoyonEmerald." (7/15/10 AGDC Project Update at 12)

- Conclusion: Cost of large diameter pipe likely not critical cost driver

(*)*AGDC reports direct costs plus owner, management and engineering costs at ~ $7.7 billion*

(ǂ) *650,000 with drag reducing agent*

(+) *1,000,000 with drag reducing agent*

H.B. 4 Problems – Project Scope – Cost of Expandable Capacity Relatively Small

- Gas conditioning, compression and liquefaction facilities can be added after initial construction

- But if thin walled, small volume pipe State trapped
    - Minimum 10 years from project start to expand pipe
    - Cost of large thick walled pipe 10-20% more???
    - Not defined given public cost estimate not transparent

H.B. 4 Problems – Project Scope

- Export Site Not Identified
  - Economies of scale require export
  - No proposal as to export location
- Proposal is Volume/Product Constrained
  - NGLs are feed stock for value added economy
  - AGDC proposes max 1.6 bcf/d and no NGLs
  - Market demand currently at 5.5 bcf/d with NGLs
- Cost of Volume/Product Expandability Relatively Small

H.B. 4 Problems – If it Becomes the Large Project, Alaska Loses

- Be wary that the State will negotiate bad agreements, or project transferred to producers without regulatory checks and balances
  - Sec. 32.25.030(e): Four board members make major decisions
- If AGDC proposal becomes the "big line," it will be without regulatory safeguards
  - No FERC jurisdiction
  - RCA disempowered
  - No in-state common carriage
  - No rolled-in rates
  - Negotiated rather than just and reasonable rates
- For all project concepts
  - Mandate RCA regulatory structure supplemented with FERC open season rules
  - Reserve to the Legislature final approval before project transferred or shipping agreements finalized