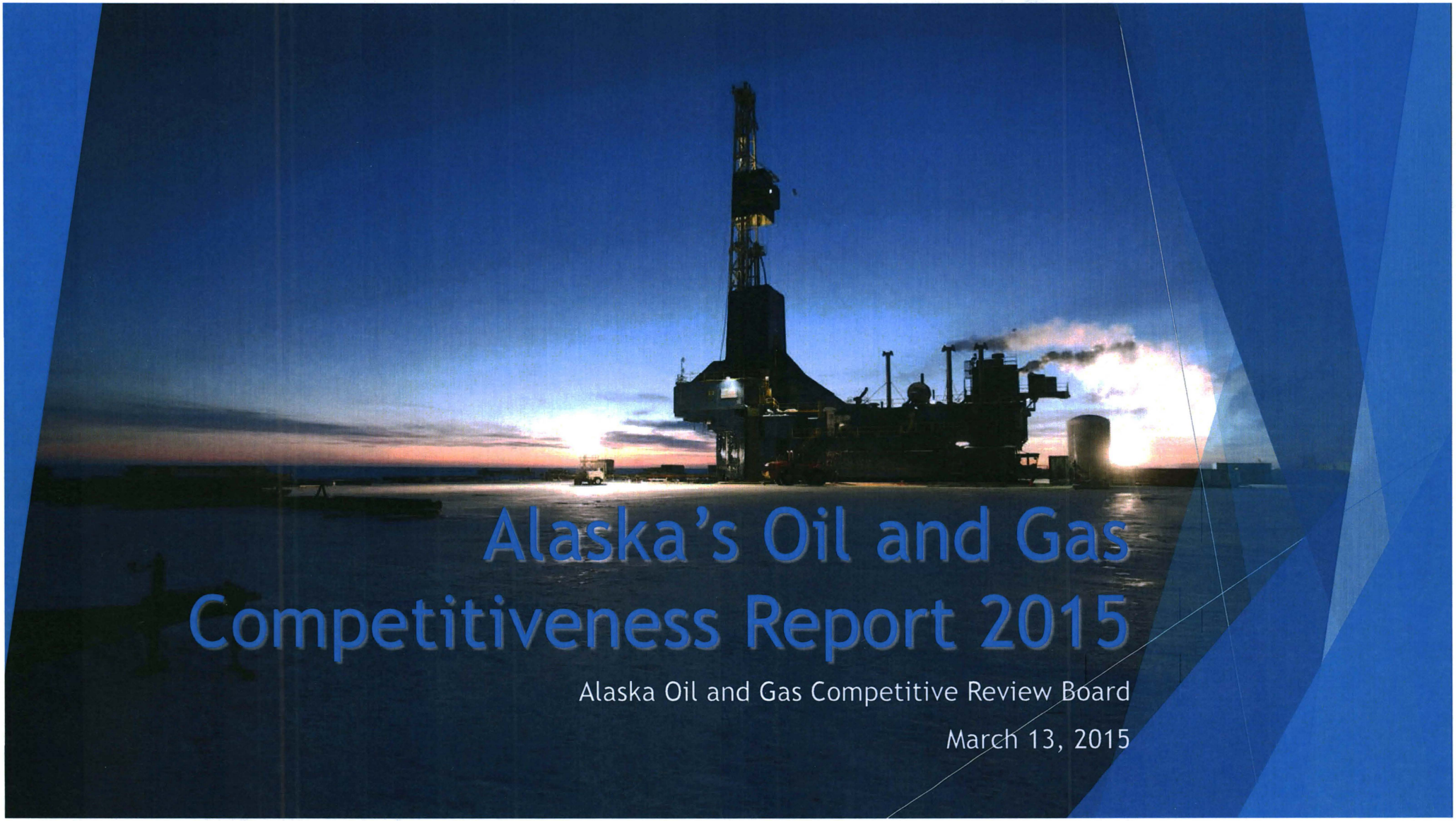
03-13-15 PRESENTATION: OIL AND GAS COMPETATIVENESS REVIEW BOARD UPDATE

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Alaska's Oil and Gas Competitiveness Report 2015

Alaska Oil and Gas Competitive Review Board

March 13, 2015

Overview

- History and Goals of the Oil & Gas Competitiveness Review Board (OGCRB)
- Alaska's vast natural resources
- Lands and lease sales
- Exploration and Development Activity
- Infrastructure
- Labor and Employment
- Regulatory and Permitting Structure
- Alaska Oil and Gas Fiscal System
  - Elements of Alaska's system
  - Comparison to other areas
- Goals and Future Work of OGCRB

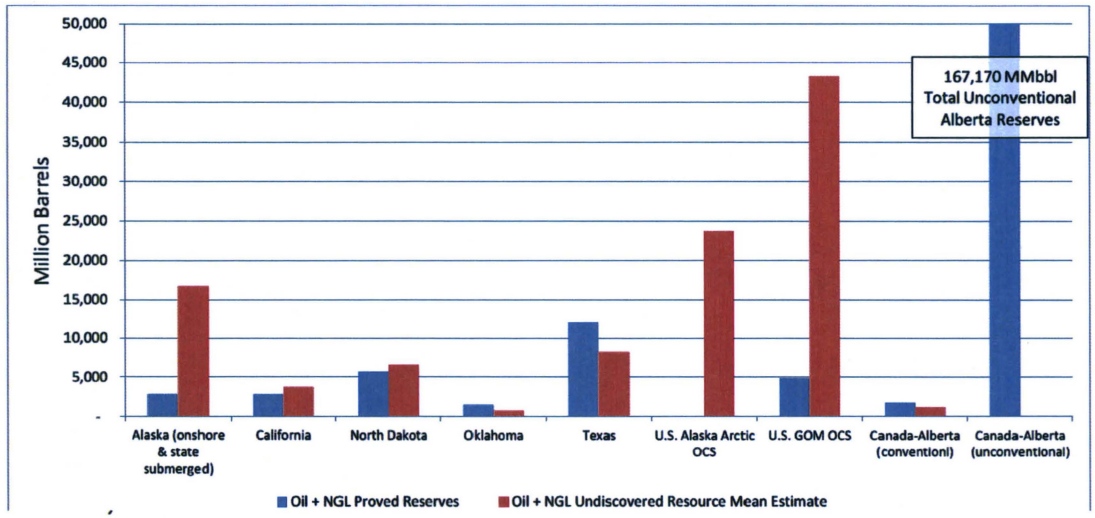
Oil and Gas Competitive Review Board

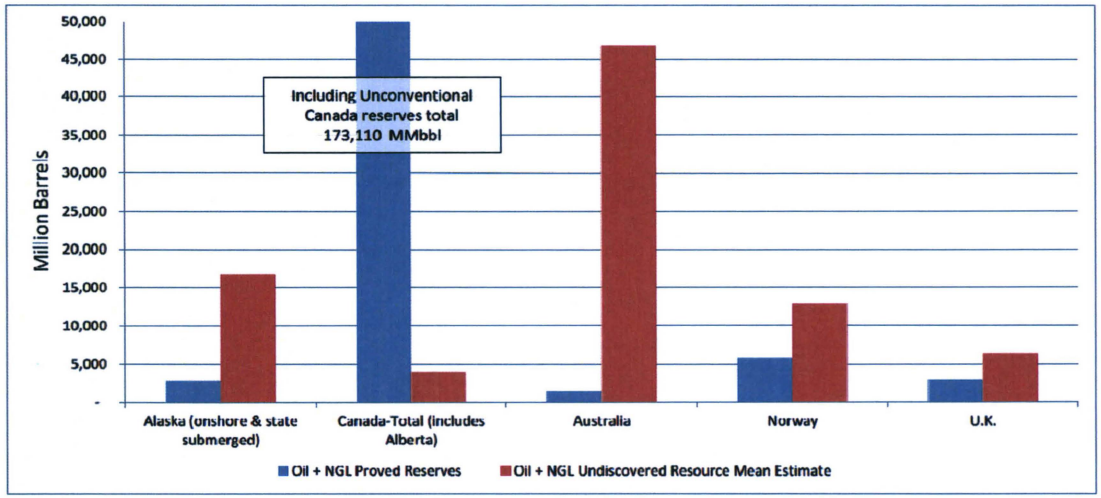
- Formed as part of SB 21
- Created to
  - Establish and maintain salient data regarding oil and gas exploration, development, and production
  - Advise the Alaska Legislature on the state's fiscal system, labor pool, and regulatory competitiveness
- Comprised of:
  - 2 public members
  - 3 administration department heads
  - 1 commissioner from the Alaska Oil and Gas Conservation Commission
  - 3 oil and gas subject matter experts
  - 2 industry trade group representatives
- **Initial goal- to produce a report to the legislature in early 2015 comparing Alaska's competitiveness to oil and gas producing peers around the world**

Alaska's Peer Groups

Jurisdiction	Type	North America	Europe	Pacific	Arctic
Alaska	State	X		X	X
California	State	X		X	
North Dakota	State	X			
Oklahoma	State	X			
Texas	State	X			
US GOM OCS	Federal	X			
US AK OCS	Federal	X			X
Alberta	Province	X			
Canada- Northwest Territories	Federal	X			X
Canada- Beaufort Sea	Federal	X			X
Australia	Federal			X	
Norway	Federal		X		X
United Kingdom	Federal		X		

Alaska's Vast Reserves/Resources





Land and Lease Sales

Federal (61%)

- Onshore leases in Cook Inlet region and North Slope
  - Managed by Bureau of Land Management
- Offshore leases in OCS- 3-200 nautical miles from shore
  - Managed by Bureau of Ocean Energy Management

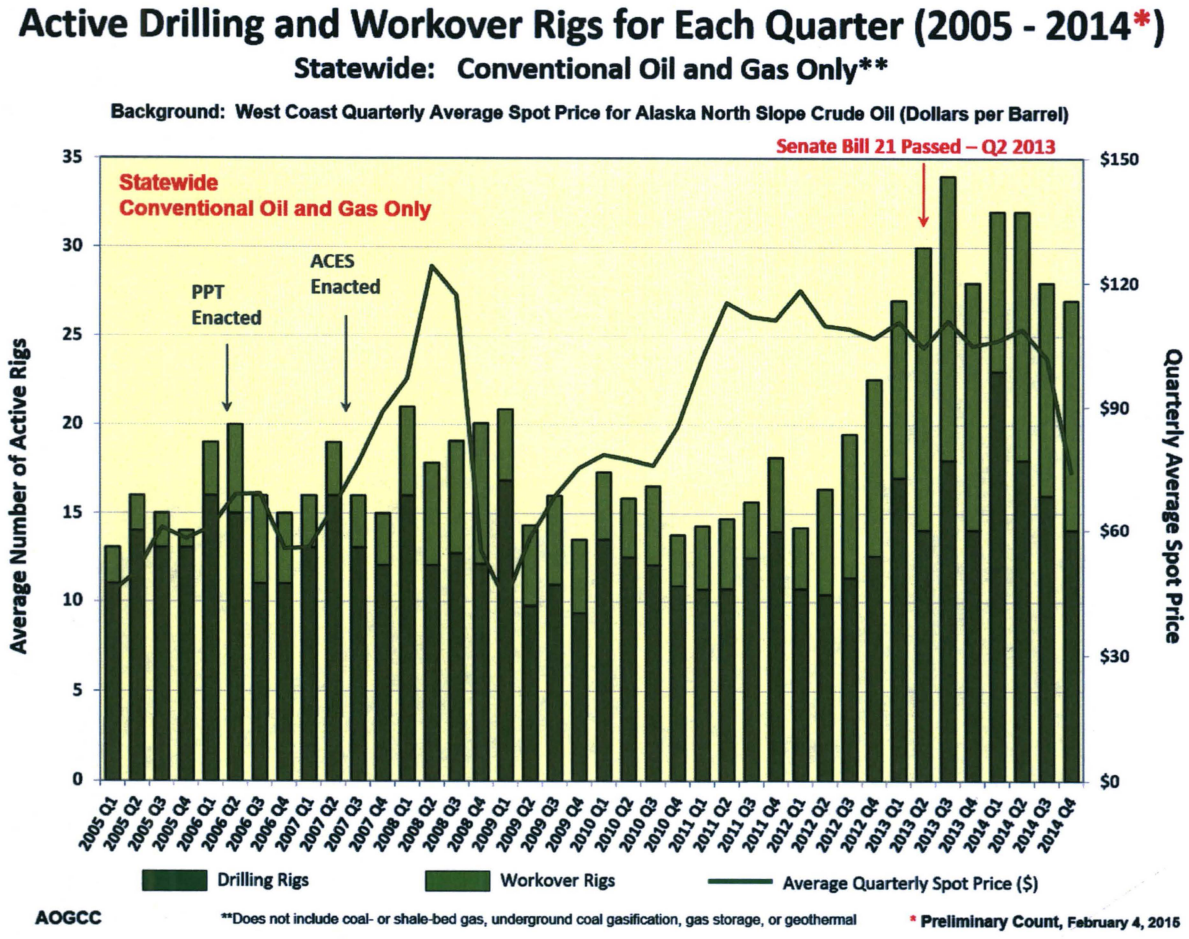
Private Lands (12%)

- University of Alaska- 3 oil and gas leases on Kenai Peninsula
  - Combination lease structure that supports University Scholars Program and research programs
- Alaska Mental Health Trust Authority
  - Land in Southcentral and Interior Alaska
- Alaska Native Corporations
  - Owners of surface and subsurface oil and gas estates on North Slope and Cook Inlet, and lands proximal to frontier basins

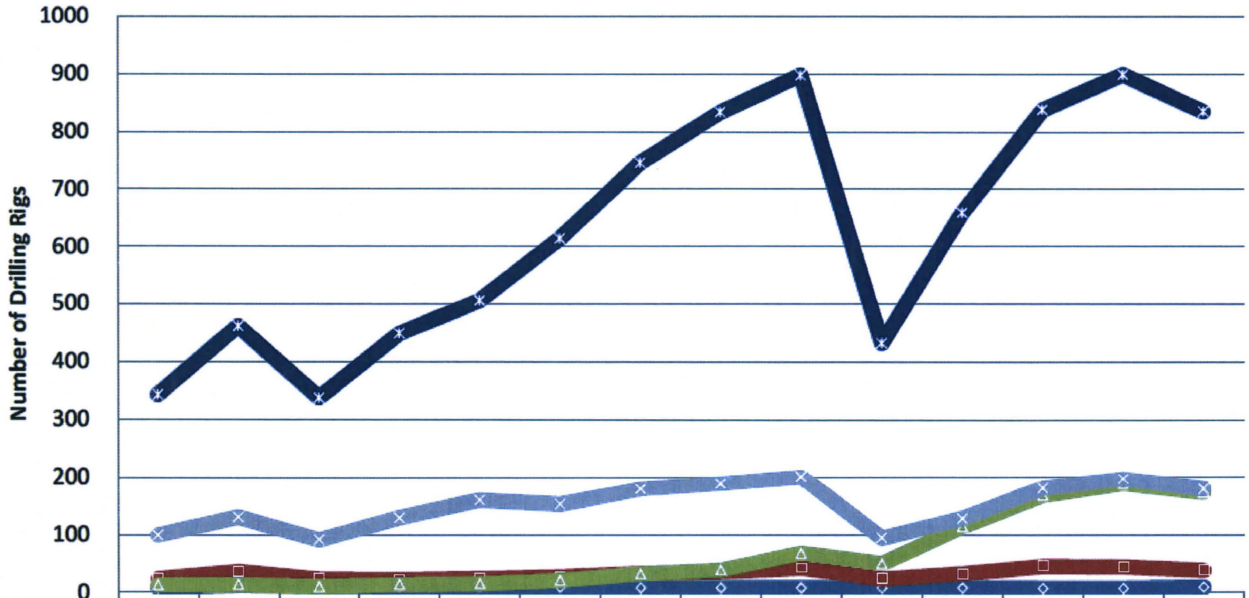
State of Alaska (27%)

- Managed by the Department of Natural Resources in 5 year leasing programs
- Conventional oil and gas leases
  - Moderate to high potential for development
  - Annual area-wide leasing
  - More efficient exploration and earlier development and production decisions
- Exploration licenses
  - Encourages exploration outside known areas
  - Competitive leasing, must commit to direct expenditures for exploration
  - Exclusive rights to explore for 10 years
  - State is provided most geological and geophysical information

Drilling Activity in Alaska



Drill Rigs - State Comparison



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Alaska	8	13	11	10	10	9	8	8	8	8	8	7	7	9
California	24	36	23	22	24	27	33	35	42	23	32	45	44	38
North Dakota	13	14	10	14	15	21	32	39	68	50	114	168	188	173
Oklahoma	99	130	91	129	159	152	179	188	200	94	128	180	196	179
Texas	343	462	338	449	506	614	746	834	898	432	659	838	899	835

Source: Baker Hughes.

Current North Slope Infrastructure and Challenges





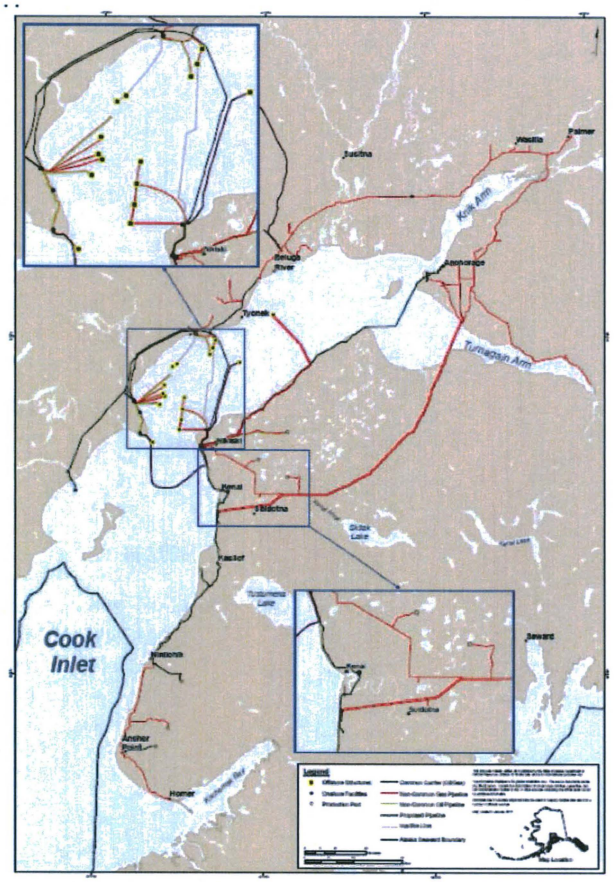
Current North Slope Infrastructure

- TAPS
- State owns and maintains Dalton Highway and Deadhorse Airport
- Oil and gas related infrastructure predominately owned and operated by industry
  - Pads and wells
  - Processing facilities and pipelines
  - Transmission and utility corridors
  - Roads, air strips and fields, and coastal landings
  - Bridges and culverts
  - Borrow sites and mine sites
- Ice roads and ice pads

Current North Slope Challenges

- Incident response
- Increased water handling capability
- TAPS oil flow contingencies

Cook Inlet and Frontier Basins Infrastructure



Cook Inlet

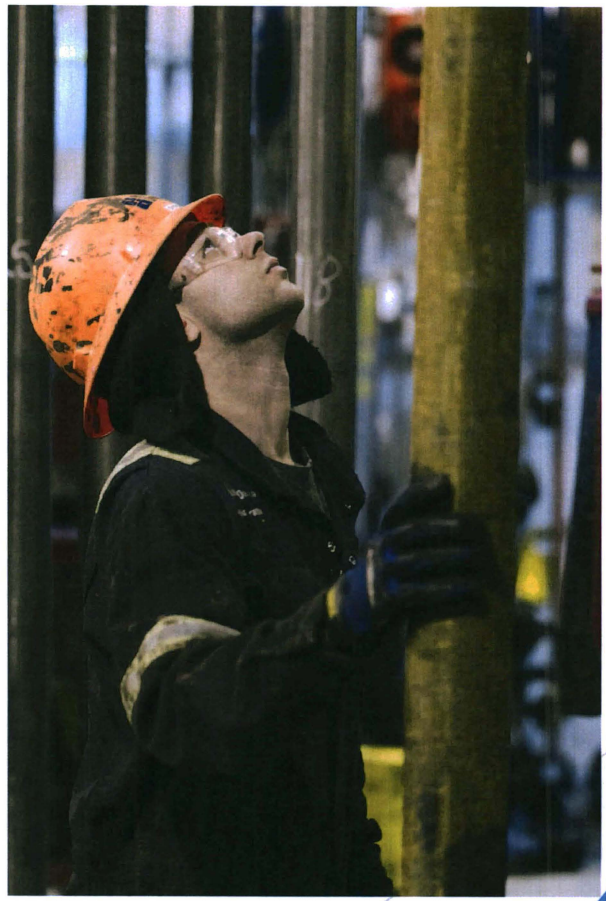
- 34 units/fields- all connected to infrastructure to bring oil or gas to processing facilities
- Oil pipelines, dockage, gas storage facilities

Frontier basins

- 6 frontier basins for exploration
- Generally lack infrastructure
- Regulations will involve multiple agencies

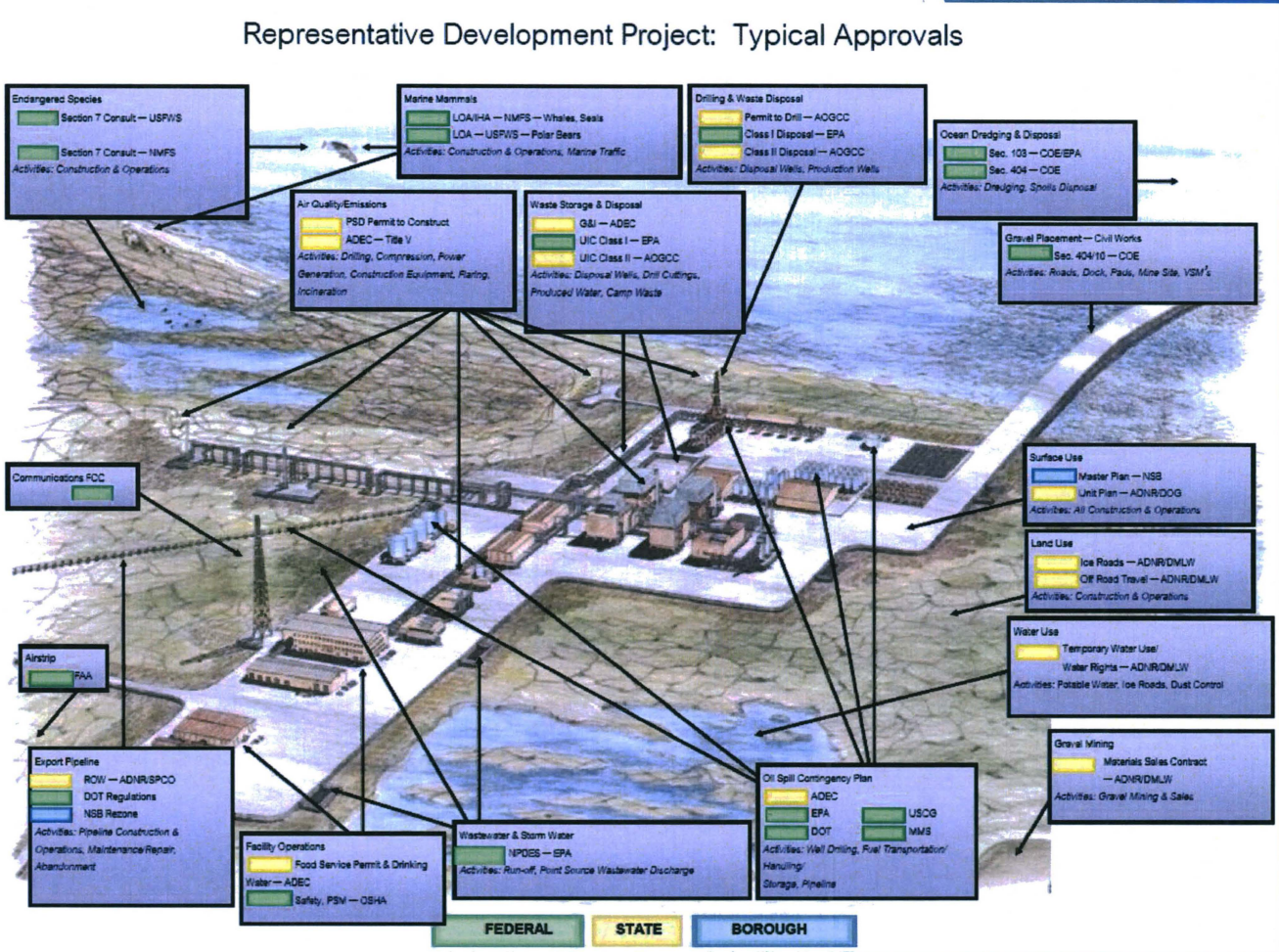
Labor and Employment

- Oil Industry-related direct and indirect jobs: 45,000 workers
  Wages: $2.65 billion
- Oil and gas industry jobs at an all time high for Alaska and on North Slope
- Alaska Department of Labor and Workforce Development
  - Apprenticeship programs
  - Fairbanks Pipeline Training Center
  - Construction Academy
  - Alaska Oil and Gas Industry Workforce Development Plan 2014- 2018



Regulatory and Permitting Structure

- Aim to minimize the impact of oil and gas activities on the environment- air and water quality, habitat, fish and wildlife, and the placement and preparedness for the storage and spillage of fuel or hazardous substances
- Multiple agencies administer and manage various permits, engage at multiple levels through the project to monitor, and conduct on-site inspections



Typical Permitting Requirements

Onshore Exploration: State Lands

Federal
- Camp wastewater discharge permit*
- Polar bear Letter of Authorization

State
- Land use permit (ice road, off-road travel)
- Fish habitat permit
- Water use permit (ice road, drilling, camp)
- Lease/Unit Operations approval
- Air Quality Permit – drill rig and camp
- Oil Discharge Prevention and Contingency Plan / C-Plan
- Drilling waste storage
- Permit to Drill

NSB
- Development Permit (or admin approval)

Offshore Exploration: OCS

Federal
- BSEE Exploration Plan
- Permit to Drill
- Oil Spill response plan
- Wastewater discharge
- Endangered species consultation
- Polar bear Letter of Authorization
- Seal / whale Incidental Harassment Authorization
- Air Quality Permit – drill rig and camp

State
- Land use permit (ice road, off-road travel)
- Water use permit (ice road, drilling, camp)

NSB
- Development Permit

Onshore Development: State Lands

same requirements as exploration permits **plus:**

Federal
- Environmental Impact Statement or Assessment
- Endangered species consultation
- Section 404/10 permit for gravel fill
- Injection well authorization

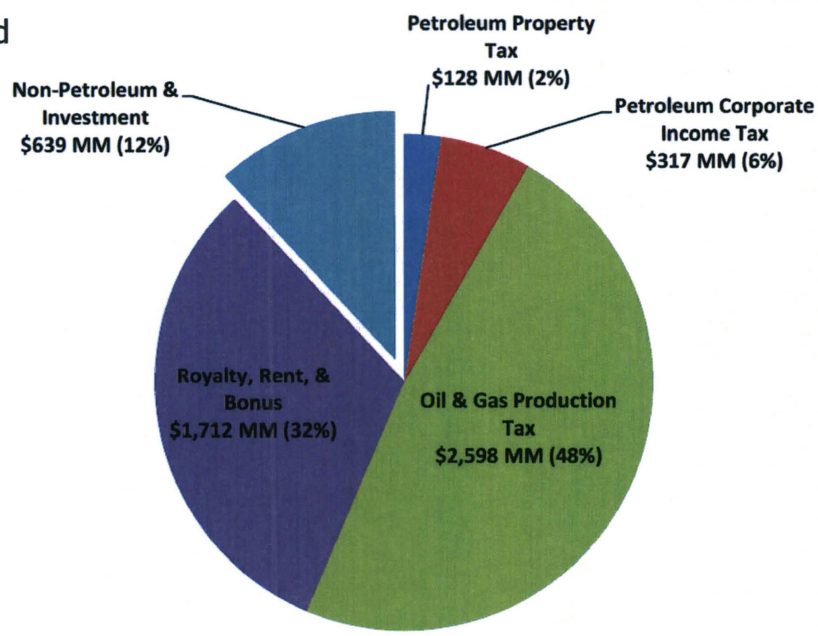
State
- Gravel materials sales contract Lease/Unit Operations approval
- Waste management facility / wastewater disposal
- Pipeline right-of-way
- Wastewater and stormwater discharge permit*

NSB
- Rezoning

Alaska's Oil and Gas Fiscal System

Four major components that generate State revenue in FY 14:

- Royalties
  - On state land, 12.5 - 16.67 percent
  - Royalties account for more than 30% of unrestricted revenue paid to the state
- Property tax
  - Assessed by DOR, tax rate 20 mills
  - Important component to local governments- up to $400m/year split among 10 local governments
- State corporate income tax
  - Administered by DOR using modified apportionment method
  - Progressively graduated to top tax rate 9.4 percent
- Production (severance) tax
  - Largest revenue generating components of Alaska's fiscal system
  - SB 21- taxes net profits of production after opex and capex
  - Credits for taxable barrels produced, exploration, and companies producing less than 100,000 barrels per day



Petroleum fiscal regime peer group highlights:

Jurisdiction	Royalty (% of Gross Production)	Rental Fees ($ per Acre)	Property /Ad Val. Tax	Federal Corp. Income Tax Rate	State/ Province Corp. Income Tax Rate	Net Tax / Profit Share (net of costs)	Gross / Severance Tax	Indirect Sales / VAT Tax Rate	Partici-pation
U.S./States									
Alaska	State: 12½% - 16⅔% Federal: 12½%	State: $1 - $3 Federal: $1.50 - $2	Yes	35%	9.4%	North Slope: 35% and up	Gross minimum tax may apply	none	-
California	Federal: 12½% Private: 16⅔% - 25%	Federal: $1.50 - $2 Private: $5 - $30	Yes	35%	8.84%	-	$0.1063/bbl. $0.1063/MCF	7%	-
North Dakota	State: 16⅔% Private: 12½% - 25%	State: $0 - $1 Private: $1	None	35%	6.4%	-	5% - 11.5%	5%	-
Oklahoma	Private: 12½% - 20%	Private: $1	Yes	35%	6%	-	7.2% (reduced at low prices)	4.5%	-
Texas	Private: 12½% - 30%	Private: $3.50	Yes	35%	1% of Net Taxable	-	$0.0063/bbl. $0.0667/MCF plus 0 - 4.6% oil and liquids and 7.5% gas value	6%	-
U.S. GOM OCS	Federal: 18¾%	Federal: $7 - $16	None	35%	-	-	-	none	-
U.S. Alaska OCS	Federal: 12½%	Federal: $2.50 - $20	None	35%	-	-	-	none	-
Canada/Provinces									
Alberta	Province: 0% - 40%	Province: $1.35	None	16.5%	10%	-	-	5%	-
Northwest Territories	Province: 1% - 5%	work commitment, no rental	None	16.5%	11.5%	-	-	5%	-
Canada - Beaufort Sea	Federal: 1% - 5%	work commitment, no rental	None	26.5%	-	-	-	5%	-
International									
Australia - Deepwater	none	Federal: $0 - $1	None	30%	-	40%	-	10%	-
Norway	none	Federal: $20 - $80	None	28%	-	50%	-	25%	20%
U.K.	none	Federal: $0.1 - $30	None	30%	-	32%	-	20%	-

Not meant to be a comparison.
There is no perfect fiscal system.

Goals and Future Work

- Broad- range survey of companies to better understand Alaska's perceived strengths and weaknesses with global peers
- Need Appropriation for RPF to fund survey
- Create a dashboard of critical measurements- track past, current, and projected future statistics/trends/progress



Future Deliverables

- Next deliverable due January 15, 2017: Provide written findings and recommendations regarding:
  - The state's tax structure and rates on oil and gas produced south of 68 degrees North latitude;
  - A tax structure that takes into account the unique economic circumstances for each oil and gas producing area south of 68 degrees North latitude;
  - A reduction in the gross value at the point of production for oil and gas produced south of 68 degrees North latitude that is similar to the reduction in gross value at the point of production in AS 43.55.160(f) and (g); and
  - Other incentives for oil and gas production south of 68 degrees North latitude.
- Final statutorily required deliverable due January 31, 2021: Provide written findings and recommendations regarding:
  - Changes to the state's fiscal regime that would be conducive to increased and ongoing long-term investment in and development of the state's oil and gas resources;
  - Alternative means for increasing the state's ability to attract and maintain investment in and development of the state's oil and gas resources; and
  - A review of the current effectiveness and future value of any provisions of the state's oil and gas tax laws that are expiring in the next five years.

STATE OF ALASKA
Department of Revenue
Commissioner's Office
333 Willoughby Avenue, 11th Floor
Juneau, AK 99801

Request For Proposals

2015-0400-xxxx
Date of Issue: March 23, 2015

Title and Purpose of RFP: Alaska Oil & Gas Economic Competitiveness Survey

The Department of Revenue, Commissioner's Office, on behalf of the Oil & Gas Competitiveness Review Board, is soliciting proposals from qualified firms to conduct a comprehensive survey of oil and gas companies aimed at assessing Alaska's economic competitiveness as it relates to both current and future industry investment. The information obtained by the survey will be subsequently aggregated and made available to the public. Ultimately, the Oil & Gas Competitiveness Review Board will review and analyze the aggregated survey results to better inform future projects and strategies.

Offerors Are Not Required To Return This Form.

Important Notice: If you received this solicitation from the State of Alaska's "Online Public Notice" web site, you must register with the procurement officer listed in this document to receive subsequent amendments. Failure to contact the procurement officer may result in the rejection of your offer.

Dorie Choquette
Procurement Office
Department of Revenue

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DRAFT

SECTION ONE
INTRODUCTION AND INSTRUCTIONS

1.01 Return Mailing Address, Contact Person, Telephone, Fax Numbers and Deadline for Receipt of Proposals

Offerors must submit one (1) original signed proposal and one copy in Adobe Acrobat.pdf format on a CD or a Thumb drive to the procurement officer in a sealed package. The cost proposal included with the package must be sealed separately from the rest of the proposal and must be clearly identified. The sealed proposal package(s) must be addressed as follows:

Department of Revenue
Commissioner's Office
Attention: Dorie Choquette
Request for Proposal (RFP) Number: 2015-0400-xxxx
Project name: Alaska Oil & Gas Economic Competitiveness Survey
333 Willoughby Avenue, 11th Floor
Juneau, AK 99801

Proposals must be received no later than 1:30 P.M., Alaska Time on Monday, April 13, 2015. Emailed proposals are acceptable. Oral or faxed proposals are not acceptable.

If submitting a proposal via email, the technical proposal and cost proposal must be saved as separate PDF documents and emailed to **dorie.choquette@alaska.gov** as separate, clearly labeled attachments, such as "Vendor A – Technical Proposal.pdf" and "Vendor A – Cost Proposal.pdf" (Vendor A is the name of the offeror). The email must contain the RFP number in the subject line.

The **maximum** size of a single email (including all text and attachments) that can be received by the state is **20mb (megabytes)**. If the email containing the proposal exceeds this size, the proposal must be sent in multiple emails that are each less than 20 megabytes and each email must comply with the requirements described above. It is the offeror's responsibility to contact the issuing agency at **907-465-2313** to confirm that the proposal has been received. The state is not responsible for unreadable, corrupt, or missing attachments.

An offeror's failure to submit its proposal prior to the deadline will cause the proposal to be disqualified. Late proposals or amendments will not be opened or accepted for evaluation.

Important Note: There is **no** overnight express delivery to Juneau, AK. **All expedited mail and courier services take at least two nights.**

PROCUREMENT OFFICER: ***Dorie Choquette*** – PHONE **907-*465-2313*** - FAX ***907-465-2037***

1.02 Contract Term and Work Schedule

The contract term and work schedule set out herein represents the State of Alaska's best estimate of the schedule that will be followed. If a component of this schedule, such as the deadline for receipt of proposals, is delayed, the rest of the schedule will be shifted by the same number of days.

The length of the contract will be from the date of award, approximately May 1, 2015, through July 1st of 2015.

Unless otherwise provided in this RFP, the State and the successful offeror/contractor agree: (1) that any holding over of the contract excluding any exercised renewal options, will be considered as a month-to-month extension, and all other terms and conditions shall remain in full force and effect and (2) to provide written notice to the other party of the intent to cancel such month-to-month extension at least 30-days before the desired date of cancellation.

The approximate contract schedule is as follows:

- Issue RFP ***March 23, 2015*** (Minimum 21-days circulation period between issue and deadline for receipt of proposals dates and requires posting on the State of Alaska Online Public Notice web site)
- Pre-proposal telephonic conference will be held at ***10:00 am***, Alaska Time, on ***Thursday, April 2, 2015***
- Deadline for Receipt of Proposals ***April 13, 2015***,
- Proposal Evaluation Committee complete evaluation by ***April 17, 2015***,
- State of Alaska issues Notice of Intent to Award a Contract ***April 20, 2015***,

(Minimum period between issuing Notice of Intent and issuing contract is 10 days - to allow time for protests.)

- State of Alaska issues contract ***April 30, 2015***
- Contract start ***May 4th, 2015***
- Contractor work period ***May 4th, 2015 through July 1st, 2015.***

1.03 Purpose of the RFP

On April 14th, 2013 the Legislature passed and the Governor signed on June 24th, 2014 Senate Bill 21 which contained a provision (Section 31) creating the Oil and Gas Competitiveness Review Board (the Board) under AS 43.98.040. The Board is charged under its duties (outlined in AS 43.98.050) to establish and maintain a collection of salient information that assesses the State of Alaska's competitiveness relative to other regions around the world that possess oil and gas resources. One of the key elements to meeting the Board's duties is to obtain an accurate perception of the State of Alaska's competitiveness by the oil and gas industry in four categories: the permitting and regulatory structure and environment; the status of the labor pool and workforce development efforts by the State of Alaska; the status and deficiencies of the State of Alaska's oil and gas related infrastructure; and the State of Alaska's fiscal oil and gas regime.

Because assessment of jurisdictions is based on proprietary information, the Board determined it was critical to obtain the support of a neutral third party surveyor. The survey would be a baseline assessment in moving forward with the Board's duties to compare the State of Alaska's progress in terms of improving its competitive standing for attracting investment in oil and gas development.

1.04 Budget

Department of Revenue, Commissioner's Office, estimates a budget up to ***$300,000*** dollars for completion of this project.

1.05 Location of Work

Work may be performed in any location. However, the contractor must be able to attend meetings in person as requested by the Oil & Gas Competitiveness Review Board. Travel expenses related to any meetings shall be paid by the contractor. Two in person meetings are anticipated. These meetings would be held in Anchorage.

1.06 Human Trafficking

By signature on their proposal, the offeror certifies that the offeror is not established and headquartered or incorporated and headquartered in a country recognized as Tier 3 in the most recent United States Department of State's Trafficking in Persons Report.

The most recent United States Department of State's Trafficking in Persons Report can be found at the following website: http://www.state.gov/j/tip/

Failure to comply with this requirement will cause the state to reject the proposal as non-responsive, or cancel the contract.

1.07 Assistance to Offerors with a Disability

Offerors with a disability may receive accommodation regarding the means of communicating this RFP or participating in the procurement process. For more information, contact the procurement officer no later than ten days prior to the deadline for receipt of proposals.

1.08 Required Review

Offerors should carefully review this solicitation for defects and questionable or objectionable material. Comments concerning defects and objectionable material must be made in writing and received by the procurement officer at least ten days before the deadline for receipt of proposals. This will allow time for the issuance of any necessary amendments. It will also help prevent the opening of a defective solicitation and exposure of offeror's proposals upon which award could not be made. Protests based on any omission or error, or on the content of the solicitation, will be disallowed if these faults have not been brought to the attention of the procurement officer, in writing, at least ten days before the deadline for receipt of proposals.

1.09 Questions Received Prior to Deadline for Receipt of Proposals

All questions must be in writing and directed to the issuing office, addressed to the procurement officer. The interested party must confirm telephone conversations in writing.

Two types of questions generally arise. One may be answered by directing the questioner to a specific section of the RFP. These questions may be answered over the telephone. Other questions may be more complex and may require a written amendment to the RFP. The procurement officer will make that decision.

1.10 Amendments

If an amendment is issued, it will be provided to all who were mailed a copy of the RFP and to those who have registered with the procurement officer after receiving the RFP from the State of Alaska Online Public Notice web site.

1.11 Alternate Proposals

Offerors may only submit one proposal for evaluation.

In accordance with 2 AAC 12.830 alternate proposals (proposals that offer something different than what is asked for) will be rejected.

1.12 Right of Rejection

Offerors must comply with all of the terms of the RFP, the State Procurement Code (AS 36.30), and all applicable local, state, and federal laws, codes, and regulations. The procurement officer may reject any proposal that does not comply with all of the material and substantial terms, conditions, and performance requirements of the RFP.

Offerors may not qualify the proposal nor restrict the rights of the state. If an offeror does so, the procurement officer may determine the proposal to be a non-responsive counter-offer and the proposal may be rejected.

Minor informalities that:

- do not affect responsiveness;
- are merely a matter of form or format;
- do not change the relative standing or otherwise prejudice other offers;
- do not change the meaning or scope of the RFP;
- are trivial, negligible, or immaterial in nature;
- do not reflect a material change in the work; or
- do not constitute a substantial reservation against a requirement or provision;

may be waived by the procurement officer.

The state reserves the right to refrain from making an award if it determines that to be in its best interest.
A proposal from a debarred or suspended offeror shall be rejected.

1.13 State Not Responsible for Preparation Costs

The state will not pay any cost associated with the preparation, submittal, presentation, or evaluation of any proposal.

1.14 Disclosure of Proposal Contents

All proposals and other material submitted become the property of the State of Alaska and may be returned only at the state's option. AS 40.25.110 requires public records to be open to reasonable inspection. All proposal information, including detailed price and cost information, will be held in confidence during the evaluation process and prior to the time a Notice of Intent to Award is issued. Thereafter, proposals will become public information.

Trade secrets and other proprietary data contained in proposals may be held confidential if the offeror requests, in writing, that the procurement officer does so, and if the procurement officer agrees, in writing, to do so. The offeror's request must be included with the proposal, must clearly identify the information they wish to be held confidential, and include a statement that sets out the reasons for confidentiality.Unless the procurement officer agrees in writing to hold the requested information confidential, that information will also become public after the Notice of Intent to Award is issued.

1.15 Subcontractors

Subcontractors may be used to perform work under this contract. If an offeror intends to use subcontractors, the offeror must identify in the proposal the names of the subcontractors and the portions of the work the subcontractors will perform.

If a proposal with subcontractors is selected, the offeror must provide the following information concerning each prospective subcontractor within five working days from the date of the state's request:

(a) complete name of the subcontractor;

(b) complete address of the subcontractor;

(c) type of work the subcontractor will be performing;

(d) percentage of work the subcontractor will be providing;

(e) evidence that the subcontractor holds a valid Alaska business license; and

(f) a written statement, signed by each proposed subcontractor that clearly verifies that the subcontractor is committed to render the services required by the contract.

An offeror's failure to provide this information, within the time set, may cause the state to consider their proposal non-responsive and reject it. The substitution of one subcontractor for another may be made only at the discretion and prior written approval of the project director.

1.16 Joint Ventures

Joint ventures are not acceptable.

1.17 Offeror's Certification

By signature on the proposal, offerors certify that they comply with the following:

(a) the laws of the State of Alaska;

(b) the applicable portion of the Federal Civil Rights Act of 1964;

(c) the Equal Employment Opportunity Act and the regulations issued thereunder by the federal government;

(d) the Americans with Disabilities Act of 1990 and the regulations issued thereunder by the federal government;

(e) all terms and conditions set out in this RFP;

(f) a condition that the proposal submitted was independently arrived at, without collusion, under penalty of perjury;

(g) that the offers will remain open and valid for at least 90 days; and

(h) that programs, services, and activities provided to the general public under the resulting contract conform with the Americans with Disabilities Act of 1990, and the regulations issued thereunder by the federal government.

If any offeror fails to comply with [a] through [h] of this paragraph, the state reserves the right to disregard the proposal, terminate the contract, or consider the contractor in default.

1.18 Conflict of Interest

Each proposal shall include a statement indicating whether or not the firm or any individuals working on the contract has a possible conflict of interest (e.g., currently employed by the State of Alaska or formerly employed by the State of Alaska within the past two years) and, if so, the nature of that conflict. The Commissioner of the Department of Revenue reserves the right to **consider a proposal non-responsive and reject it or** cancel the award if any interest disclosed from any source could either give the appearance of a conflict or cause speculation as to the objectivity of the program to be developed by the offeror. The Commissioner's determination regarding any questions of conflict of interest shall be final.

1.19 Right to Inspect Place of Business

At reasonable times, the state may inspect those areas of the contractor's place of business that are related to the performance of a contract. If the state makes such an inspection, the contractor must provide reasonable assistance.

1.20 Solicitation Advertising

Public notice has been provided in accordance with 2 AAC 12.220.

1.21 News Releases

News releases related to this RFP will not be made without prior approval of the project director.

1.22 Assignment

Per 2 AAC 12.480, the contractor may not transfer or assign any portion of the contract without prior written approval from the procurement officer.

1.23 Disputes

A contract resulting from this RFP is governed by the laws of the State of Alaska. If the contractor has a claim arising in connection with the agreement that it cannot resolve with the state by mutual agreement, it shall pursue the claim, if at all, in accordance with the provisions of AS 36.30.620 – AS 36.30.632. To the extent not otherwise

governed by the preceding, the claim shall be brought only in the Superior Court of the State of Alaska and not elsewhere.

1.24 Severability

If any provision of the contract or agreement is declared by a court to be illegal or in conflict with any law, the validity of the remaining terms and provisions will not be affected; and, the rights and obligations of the parties will be construed and enforced as if the contract did not contain the particular provision held to be invalid.

1.25 Federal Requirements

The offeror must identify all known federal requirements that apply to the proposal, the evaluation, or the contract.

SECTION TWO
STANDARD PROPOSAL INFORMATION

2.01 Authorized Signature

All proposals must be signed by an individual authorized to bind the offeror to the provisions of the RFP. Proposals must remain open and valid for at least 90-days from the date set as the deadline for receipt of proposals.

2.02 Pre-proposal Conference

A pre-proposal telephonic conference will be held at **10:00 am**, Alaska Time, on **Thursday, April 2, 2015.** The purpose of the conference is to discuss the work to be performed with the prospective offerors and allow them to ask questions concerning the RFP. Questions and answers will be transcribed and sent to prospective offerors as soon as possible after the meeting.

Offerors with a disability needing accommodation should contact the procurement officer prior to the date set for the pre-proposal conference so that reasonable accommodation can be made.

2.03 Site Inspection

The state may conduct on-site visits to evaluate the offeror's capacity to perform the contract. An offeror must agree, at risk of being found non-responsive and having its proposal rejected, to provide the state reasonable access to relevant portions of its work sites. Individuals designated by the procurement officer at the state's expense will make site inspection.

2.04 Amendments to Proposals

Amendments to or withdrawals of proposals will only be allowed if acceptable requests are received prior to the deadline that is set for receipt of proposals. No amendments or withdrawals will be accepted after the deadline unless they are in response to the state's request in accordance with 2 AAC 12.290.

2.05 Supplemental Terms and Conditions

Proposals must comply with Section **1.12 Right of Rejection**. However, if the state fails to identify or detect supplemental terms or conditions that conflict with those contained in this RFP or that diminish the state's rights under any contract resulting from the RFP, the term(s) or condition(s) will be considered null and void. After award of contract:

a) if conflict arises between a supplemental term or condition included in the proposal and a term or condition of the RFP, the term or condition of the RFP will prevail; and
b) if the state's rights would be diminished as a result of application of a supplemental term or condition included in the proposal, the supplemental term or condition will be considered null and void.

2.06 Clarification of Offers

In order to determine if a proposal is reasonably susceptible for award, communications by the procurement officer or the proposal evaluation committee (PEC) are permitted with an offeror to clarify uncertainties or eliminate confusion concerning the contents of a proposal. Clarifications may not result in a material or substantive change to the proposal. The evaluation by the procurement officer or the PEC may be adjusted as a result of a clarification under this section.

2.07 Discussions with Offerors

The state may conduct discussions with offerors in accordance with AS 36.30.240 and 2 AAC 12.290. The purpose of these discussions will be to ensure full understanding of the requirements of the RFP and proposal. Discussions will be limited to specific sections of the RFP or proposal identified by the procurement officer. Discussions will only be held with offerors who have submitted a proposal deemed reasonably susceptible for award by the procurement officer. Discussions, if held, will be after initial evaluation of proposals by the procurement officer or the PEC. If modifications are made as a result of these discussions they will be put in writing. Following discussions, the procurement officer may set a time for best and final proposal submissions from those offerors with whom discussions were held. Proposals may be reevaluated after receipt of best and final proposal submissions.

If an offeror does not submit a best and final proposal or a notice of withdrawal, the offeror's immediate previous proposal is considered the offeror's best and final proposal.

Offerors with a disability needing accommodation should contact the procurement officer prior to the date set for discussions so that reasonable accommodation can be made. Any oral modification of a proposal must be reduced to writing by the offeror.

2.08 Prior Experience

In order for proposals to be considered responsive offerors must meet these minimum prior experience requirements. **Extensive experience working with the oil and gas industry, both domestically and internationally, is an essential requirement. Offerers must demonstrate experience in developing and executing extensive, confidential surveys that assessed the perception of jurisdictions by the oil and gas industry.**

- At least twenty (10) years of experience working with clients in the oil and gas industry, both nationally and internationally.

- At least twenty (10) years of experience assessing the fiscal, permitting, and resource competitiveness of energy producing jurisdictions, both nationally and internationally.
- At least fifteen (10) years of experience working with public sector clients.
- Preparation and execution of at least three (3) surveys of a similar nature regarding jurisdictional competitiveness. A synopsis of the surveys will need to be included in the proposal.

An offeror's failure to meet these minimum prior experience requirements will cause their proposal to be considered non-responsive and their proposal will be rejected.

2.09 Evaluation of Proposals

The procurement officer, or an evaluation committee made up of at least three state employees or public officials, will evaluate proposals. The evaluation will be based solely on the evaluation factors set out in Section SEVEN of this RFP.

After receipt of proposals, if there is a need for any substantial clarification or material change in the RFP, an amendment will be issued. The amendment will incorporate the clarification or change, and a new date and time established for new or amended proposals. Evaluations may be adjusted as a result of receiving new or amended proposals.

2.10 Vendor Tax ID

A valid Vendor Tax ID must be submitted to the issuing office with the proposal or within five days of the state's request.

2.11 Alaska Business License and Other Required Licenses

Prior to the award of a contract, an offeror must hold a valid Alaska business license. However, in order to receive the Alaska Bidder Preference and other related preferences, such as the Alaska Veteran and Alaska Offeror Preference, an offeror must hold a valid Alaska business license prior to the deadline for receipt of proposals. Offerors should contact the Department of Commerce, Community and Economic Development, Division of Corporations, Business, and Professional Licensing, P. O. Box 110806, Juneau, Alaska 99811-0806, for information on these licenses. Acceptable evidence that the offeror possesses a valid Alaska business license may consist of any one of the following:

(a) copy of an Alaska business license;

(b) certification on the proposal that the offeror has a valid Alaska business license and has included the license number in the proposal;

(c) a canceled check for the Alaska business license fee;

(d) a copy of the Alaska business license application with a receipt stamp from the state's occupational licensing office; or

(e) a sworn and notarized affidavit that the offeror has applied and paid for the Alaska business license.

You are not required to hold a valid Alaska business license at the time proposals are opened if you possess one of the following licenses and are offering services or supplies under that specific line of business:

- fisheries business licenses issued by Alaska Department of Revenue or Alaska Department of Fish and Game,
- liquor licenses issued by Alaska Department of Revenue for alcohol sales only,
- insurance licenses issued by Alaska Department of Commerce, Community and Economic Development, Division of Insurance, or
- Mining licenses issued by Alaska Department of Revenue.

Prior the deadline for receipt of proposals, all offerors must hold any other necessary applicable professional licenses required by Alaska Statute.

2.12 Application of Preferences

Certain preferences apply to all contracts for professional services, regardless of their dollar value. The Alaska Bidder, Alaska Veteran, and Alaska Offeror preferences are the most common preferences involved in the RFP process. Additional preferences that may apply to this procurement are listed below. Guides that contain excerpts from the relevant statutes and codes, explain when the preferences apply and provide examples of how to calculate the preferences are available at the Department of Administration, Division of General Service's web site:

http://doa.alaska.gov/dgs/policy.html

Alaska Products Preference - AS 36.30.332
Recycled Products Preference - AS 36.30.337
Local Agriculture and Fisheries Products Preference - AS 36.15.050
Employment Program Preference - AS 36.30.321(b)
Alaskans with Disabilities Preference - AS 36.30.321(d)
Alaska Veteran's Preference - AS 36.30.321(f)

The Division of Vocational Rehabilitation in the Department of Labor and Workforce Development keeps a list of qualified employment programs and individuals who qualify as persons with a disability. As evidence of a business' or an individual's right to the Employment Program or Alaskans with Disabilities preferences, the Division of Vocational Rehabilitation will issue a certification letter. To take advantage of these preferences, a business or individual must be on the appropriate Division of Vocational Rehabilitation prior to the time designated for receipt of proposals. Offerors must attach a copy of their certification letter to the proposal. An offeror's failure to provide this certification letter with their proposal will cause the state to disallow the preference.

2.13 5 Percent Alaska Bidder Preference AS 36.30.321(a), AS 36.30.990(2), & 2 AAC 12.260

An Alaska Bidder Preference of five percent will be applied to the price in the proposal. The preference will be given to an offeror who:

(1) holds a current Alaska business license prior to the deadline for receipt of proposals;

(2) submits a proposal for goods or services under the name appearing on the offeror's current Alaska business license;

(3) has maintained a place of business within the state staffed by the offeror, or an employee of the offeror, for a period of six months immediately preceding the date of the proposal;

(4) is incorporated or qualified to do business under the laws of the state, is a sole proprietorship and the proprietor is a resident of the state, is a limited liability company (LLC) organized under AS 10.50 and all members are residents of the state, or is a partnership under AS 32.06 or AS 32.11 and all partners are residents of the state; and

(5) if a joint venture, is composed entirely of ventures that qualify under (1)-(4) of this subsection.

Alaska Bidder Preference Affidavit
In order to receive the Alaska Bidder Preference, the proposal must include a statement certifying that the offeror is eligible to receive the Alaska Bidder Preference.

If the offeror is a LLC or partnership as identified in (4) of this subsection, the affidavit must also identify each member or partner and include a statement certifying that all members or partners are residents of the state.

If the offeror is a joint venture which includes a LLC or partnership as identified in (4) of this subsection, the affidavit must also identify each member or partner of each LLC or partnership that is included in the joint venture and include a statement certifying that all of those members or partners are residents of the state.

2.14 5 Percent Alaska Veteran Preference AS 36.30.321(f)

An Alaska Veteran Preference of five percent, not to exceed $5,000, will be applied to the price in the proposal. The preference will be given to an offeror who qualifies under AS 36.30.990(2) as an Alaska bidder and is a:

(a) sole proprietorship owned by an Alaska veteran;

(b) partnership under AS 32.06 or AS 32.11 if a majority of the partners are Alaska veterans;

(c) limited liability company organized under AS 10.50 if a majority of the members are Alaska veterans; or

(d) corporation that is wholly owned by individuals, and a majority of the individuals are Alaska veterans.

Alaska Veteran Preference Affidavit
In order to receive the Alaska Veteran Preference, the proposal must include a statement certifying that the offeror is eligible to receive the Alaska Veteran Preference.

2.15 Formula Used to Convert Cost to Points AS 36.30.250 & 2 AAC 12.260

The distribution of points based on cost will be determined as set out in 2 AAC 12.260(c). The lowest cost proposal will receive the maximum number of points allocated to cost. The point allocations for cost on the other proposals will be determined through the method set out below. In the generic example below, cost is weighted as 40% of the overall total score. The weighting of cost may be different in your particular RFP. See section SEVEN to determine the value, or weight of cost for this RFP.

EXAMPLE

Formula Used to Convert Cost to Points

[STEP 1]

List all proposal prices, adjusted where appropriate by the application of all applicable preferences.

Offeror #1 -	Non-Alaskan Offeror	$40,000
Offeror #2 -	Alaskan Offeror	$42,750
Offeror #3 -	Alaskan Offeror	$47,500

[STEP 2]

Convert cost to points using this formula.

$$\frac{[(\text{Price of Lowest Cost Proposal}) \times (\text{Maximum Points for Cost})]}{(\text{Cost of Each Higher Priced Proposal})} = \text{POINTS}$$

The RFP allotted 40% (40 points) of the total of 100 points for cost.

Offeror #1 receives 40 points.

The reason they receive that amount is because the lowest cost proposal, in this case $40,000, receives the maximum number of points allocated to cost, 40 points.

Offeror #2 receives 37.4 points.

$40,000 Lowest Cost	x	40 Max Points	=	1,600,000	÷	$42,750 Offeror #2 Adjusted By The Application Of All Applicable Preferences	=	37.4 Points

Offeror #3 receives 33.7 points.

$40,000 Lowest Cost	x	40 Max Points	=	1,600,000	÷	$47,500 Offeror #3 Adjusted By The Application Of All Applicable Preferences	=	33.7 Points

2.16 Alaska Offeror Preference AS 36.30.321 & 2 AAC 12.260

2 AAC 12.260(e) provides Alaska offerors a 10 percent overall evaluation point preference. Alaska bidders, as defined in AS 36.30.990(2), are eligible for the preference. An Alaska offeror will receive 10 percent of the total available points added to their overall evaluation score as a preference.

EXAMPLE

Alaska Offeror Preference

[STEP 1]

Determine the number of points available to Alaskan offerors under the preference.

Total number of points available - 100 Points

100 Total Points Available	**x**	**10%** Alaskan Offerors Percentage Preference	**=**	**10** Number of Points Given to Alaskan Offerors Under the Preference

[STEP 2]

Add the preference points to the Alaskan offers. There are three offerors: Offeror #1, Offeror #2, and Offeror #3. Offeror #2 and Offeror #3 are eligible for the Alaska Offeror Preference. For the purpose of this example presume that all of the proposals have been completely evaluated based on the evaluation criteria in the RFP. Their scores at this point are:

Offeror #1 - 89 points
Offeror #2 - 80 points
Offeror #3 - 88 points

Offeror #2 and Offeror #3 each receive 10 additional points. The final scores for all of the offers are:

*Offeror #1 - **89 points***
*Offeror #2 - **90 points***
*Offeror #3 - **98 points***

Offeror #3 is awarded the contract.

2.17 Contract Negotiation

2 AAC 12.315 CONTRACT NEGOTIATIONS After final evaluation, the procurement officer may negotiate with the offeror of the highest-ranked proposal. Negotiations, if held, shall be within the scope of the request for proposals and limited to those items which would not have an effect on the ranking of proposals. If the highest-ranked offeror fails to provide necessary information for negotiations in a timely manner, or fails to negotiate in good faith, the state may terminate negotiations and negotiate with the offeror of the next highest-ranked proposal. If contract negotiations are commenced, they may be held in the Commissioner's conference room on the 11th floor of the State Office Building in Juneau, Alaska.

If the contract negotiations take place in Juneau, Alaska, the offeror will be responsible for their travel and per diem expenses.

2.18 Failure to Negotiate

If the selected offeror

- fails to provide the information required to begin negotiations in a timely manner; or
- fails to negotiate in good faith; or
- indicates they cannot perform the contract within the budgeted funds available for the project; or
- if the offeror and the state, after a good faith effort, simply cannot come to terms,

the state may terminate negotiations with the offeror initially selected and commence negotiations with the next highest ranked offeror.

2.19 Notice of Intent to Award (NIA) — Offeror Notification of Selection

After the completion of contract negotiation the procurement officer will issue a written Notice of Intent to Award (NIA) and send copies to all offerors. The NIA will set out the names of all offerors and identify the proposal selected for award.

2.20 Protest

AS 36.30.560 provides that an interested party may protest the content of the RFP.

An interested party is defined in 2 AAC 12.990(a) (7) as "an actual or prospective bidder or offeror whose economic interest might be affected substantially and directly by the issuance of a contract solicitation, the award of a contract, or the failure to award a contract."

If an interested party wishes to protest the content of a solicitation, the protest must be received, in writing, by the procurement officer at least ten days prior to the deadline for receipt of proposals.

AS 36.30.560 also provides that an interested party may protest the award of a contract or the proposed award of a contract.

If an offeror wishes to protest the award of a contract or the proposed award of a contract, the protest must be received, in writing, by the procurement officer within ten days after the date the Notice of Intent to Award the contract is issued.

A protester must have submitted a proposal in order to have sufficient standing to protest the proposed award of a contract. Protests must include the following information:

a. the name, address, and telephone number of the protester;

b. the signature of the protester or the protester's representative;

c. identification of the contracting agency and the solicitation or contract at issue;

d. a detailed statement of the legal and factual grounds of the protest including copies of relevant documents; and the form of relief requested.

Protests filed by telex or telegram are not acceptable because they do not contain a signature. Fax copies containing a signature are acceptable.

The procurement officer will issue a written response to the protest. The response will set out the procurement officer's decision and contain the basis of the decision within the statutory time limit in AS 36.30.580. A copy of the decision will be furnished to the protester by certified mail, fax or another method that provides evidence of receipt.

All offerors will be notified of any protest. The review of protests, decisions of the procurement officer, appeals, and hearings, will be conducted in accordance with the State Procurement Code (AS 36.30), Article 8 "Legal and Contractual Remedies."

SECTION THREE
STANDARD CONTRACT INFORMATION

3.01 Contract Type

This contract is a firm fixed price contract.

3.02 Contract Approval

This RFP does not, by itself, obligate the state. The state's obligation will commence when the contract is approved by the Commissioner of the Department of Revenue, or the Commissioner's designee. Upon written notice to the contractor, the state may set a different starting date for the contract. The state will not be responsible for any work done by the contractor, even work done in good faith, if it occurs prior to the contract start date set by the state.

3.03 Standard Contract Provisions

The contractor will be required to sign and submit the attached State's Standard Agreement Form for Professional Services Contracts (form 02-093/Appendix A). The contractor must comply with the contract provisions set out in this attachment. No alteration of these provisions will be permitted without prior written approval from the Department of Law. Objections to any of the provisions in Appendix A must be set out in the offeror's proposal.

3.04 Proposal as a Part of the Contract

Part or all of this RFP and the successful proposal may be incorporated into the contract.

3.05 Additional Terms and Conditions

The state reserves the right to add terms and conditions during contract negotiations. These terms and conditions will be within the scope of the RFP and will not affect the proposal evaluations.

3.06 Insurance Requirements

The successful offeror must provide proof of workers' compensation insurance prior to contract approval.

The successful offeror must secure the insurance coverage required by the state. The coverage must be satisfactory to the Department of Administration Division of Risk Management. An offeror's failure to provide evidence of such insurance coverage is a material breach and grounds for withdrawal of the award or termination of the contract.

Offerors must review form APPENDIX B1, attached, for details on required coverage. No alteration of these requirements will be permitted without prior written approval from the Department of Administration, Division of Risk Management. Objections to any of the requirements in APPENDIX B1 must be set out in the offeror's proposal.

3.07 Contract Funding

Payment for the contract is subject to funds already appropriated and identified.

3.08 Proposed Payment Procedures

The state will make payments based on a negotiated payment schedule. Each billing must consist of an invoice and progress report. No payment will be made until the progress report and invoice has been approved by the project director.

3.09 Contract Payment

No payment will be made until the contract is approved by the Commissioner of the Department of Revenue or the Commissioner's designee. Under no conditions will the state be liable for the payment of any interest charges associated with the cost of the contract.

The state is not responsible for and will not pay local, state, or federal taxes. All costs associated with the contract must be stated in U.S. currency.

3.10 Informal Debriefing

When the contract is completed, an informal debriefing may be performed at the discretion of the project director. If performed, the scope of the debriefing will be limited to the work performed by the contractor.

3.11 Contract Personnel

Any change of the project team members or subcontractors named in the proposal must be approved, in advance and in writing, by the project director. Personnel changes that are not approved by the state may be grounds for the state to terminate the contract.

3.12 Inspection & Modification - Reimbursement for Unacceptable Deliverables

The contractor is responsible for the completion of all work set out in the contract. All work is subject to inspection, evaluation, and approval by the project director. The state may employ all reasonable means to ensure that the work is progressing and being performed in compliance with the contract. The project director may instruct the contractor to make corrections or modifications if needed in order to accomplish the contract's intent. The contractor will not unreasonably withhold such changes.

Substantial failure of the contractor to perform the contract may cause the state to terminate the contract. In this event, the state may require the contractor to reimburse monies paid (based on the identified portion of unacceptable work received) and may seek associated damages.

3.13 Termination for Default

If the project director determines that the contractor has refused to perform the work or has failed to perform the work with such diligence as to ensure its timely and accurate completion, the state may, by providing written notice to the contractor, terminate the contractor's right to proceed with part or all of the remaining work.

This clause does not restrict the state's termination rights under the contract provisions of Appendix A, attached.

3.14 Contract Changes - Unanticipated Amendments

DRAFT

During the course of this contract, the contractor may be required to perform additional work. That work will be within the general scope of the initial contract. When additional work is required, the project director will provide the contractor a written description of the additional work and request the contractor to submit a firm time schedule for accomplishing the additional work and a firm price for the additional work. Cost and pricing data must be provided to justify the cost of such amendments per AS 36.30.400.

The contractor will not commence additional work until the project director has secured any required state approvals necessary for the amendment and issued a written contract amendment, approved by the Commissioner of the Department of Revenue or the Commissioner's designee.

3.15 Contract Invalidation

If any provision of this contract is found to be invalid, such invalidation will not be construed to invalidate the entire contract.

3.16 Nondisclosure and Confidentiality

Contractor will be required to agree that all "Confidential Information" shall be used only for purposes of providing the deliverables and performing the services specified herein and shall not disseminate or allow dissemination of confidential information except as provided for in this section. The contractor shall hold as confidential and will use reasonable care (including both facility physical security and electronic security) to prevent unauthorized access by, storage, disclosure, publication, dissemination to and/or use by third parties of, the confidential information. "Reasonable care" means compliance by the contractor with all applicable federal and state law, including the Social Security Act and HIPAA. The contractor must promptly notify the state in writing if it becomes aware of any storage, disclosure, loss, unauthorized access to or use of the confidential information.

"Confidential Information" for the purpose of this contract, means any data, files, software, information or materials (whether prepared by the state or its agents or advisors) in oral, electronic, tangible or intangible form and however stored, compiled or memorialized that is classified as confidential by the State of Alaska's Classification and Categorization guidelines which will be provided by the state to the contractor or otherwise made available to the contractor. Examples of confidential information include, but are not limited to: technology infrastructure, architecture, financial data, trade secrets, equipment specifications, user lists, passwords, research data, and technology data (infrastructure, architecture, operating systems, security tools, IP addresses, etc).

Additional information that the contractor shall hold as "Confidential Information" during the performance of services under this contract include information provided to contractor by the Department of Revenue, the Department of Natural Resources or the Alaska Gasline Development Corporation that is confidential under state or federal law.

If "Confidential Information" is requested to be disclosed by the contractor pursuant to a request received by a third party and such disclosure of the "Confidential Information" is required under applicable state or federal law, regulation, governmental or regulatory authority, the contractor may disclose the "Confidential Information" after providing the state with written notice of the requested disclosure (to the extent such notice to the state is permitted by applicable law) and giving the state opportunity to review the request. If the contractor receives no objection from the state, it may release the "Confidential Information" within 30 days. Notice of the requested disclosure of "Confidential Information" by the contractor must be provided to the state within a reasonable time after the contractor's receipt of notice of the requested disclosure and, upon request of the state, shall seek to obtain legal protection from the release of the "Confidential Information".

The following information shall not be considered "Confidential Information": information previously known to be public information when received from the other party; information freely available to the general public; information which now is or hereafter becomes publicly known by other than a breach of confidentiality hereof; or information which is disclosed by a party pursuant to subpoena or other legal process and which as a result becomes lawfully obtainable by the general public.

SECTION FOUR
BACKGROUND INFORMATION

4.01 Background Information

Senate Bill 21, or the More Alaska Production Act (MAPA) was passed by the Alaska Legislature on April 14th, 2013. Section 31 of MAPA created the Oil and Gas Competitiveness Review Board under AS 43.98.040. The board's duties were established under AS 43.98.050. Those duties included consolidating salient information regarding Alaska's competitiveness in contrast to other jurisdictions that have oil and gas resources on four main topics, and making that information readily available to the public. Those topics were the state's permitting and regulatory system, the state's labor pool and efforts by the state to develop its workforce, the status of the state's oil and gas related infrastructure and any deficiencies, and the state's fiscal oil and tax regime.

The Oil & Gas Competitiveness Review Board **is to make its first written findings and recommendations to the Alaska State Legislature before January 31, 2015,** or as soon thereafter as possible in relation to these four areas:

1) Changes to the state's regulatory environment and permitting structure that would be conducive to encouraging increased investment while protecting the interests of the people of the state and the environment.

2) Status of the oil and gas labor pool in the state and the effectiveness of workforce development efforts by the state.

3) Status of the oil and gas related infrastructure of the state, including a description of infrastructure deficiencies.

4) Competitiveness of the state's fiscal oil and gas tax regime when compared to other regions of the world.

The documents for the Oil & Gas Competitiveness Review Board can be found on the following website:
http://dor.alaska.gov/OilGasCompetitivenessReviewBoard.aspx

SECTION FIVE
SCOPE OF WORK

5.01 Scope of Work

In order to complete this initial report and maintain a salient collection of information relevant to the assessment of Alaska's competitiveness, the Oil & Gas Competitiveness Review Board is obtaining information from a variety of sources and stakeholders, including the following: various state agencies such as the Department of Labor & Workforce Development, the Department of Revenue, the Department of Environmental Conservation, the

Department of Natural Resources, previously conducted studies, other workforce development interests, etc. The Oil & Gas Competitiveness Review Board recognizes that obtaining a complete collection of information requires cooperation and significant input from oil and gas companies.

To obtain accurate data from relevant companies, the Oil & Gas Competitiveness Review Board solicits proposals for a third party contractor to conduct a confidential survey of oil and gas companies to obtain pertinent data regarding the four aforementioned areas. The confidential survey will allow companies anonymity as well as the ability to share proprietary information and insight into respective investment strategies. Comparable surveys are routinely conducted across the industry, both domestically and internationally. This survey would be tailored specifically for the needs of Alaska's Oil & Gas Competitiveness Review Board.

In order to construct an effective and appropriate survey, the contractor will coordinate and consult with the Oil & Gas Competitiveness Review Board and approved Department of Revenue staff. Although the Oil & Gas Competitiveness Review Board will be privy to the survey and the results, it will not have access to individual company responses, which will remain confidential.

5.02 Deliverables

1. The contractor shall provide a written report with the results of its survey. This report should, without compromising the confidentiality of respondents, be able to demonstrate the extensiveness and depth of the product.
2. The contractor shall assist, when requested by the State, in presentations or provide requested information when necessary. Plan on 2 – 2 day trips to Juneau and 2 – 2 day trips to Anchorage in your cost proposal as well as a per hour cost for presentation preparation.

SECTION SIX
PROPOSAL FORMAT AND CONTENT

6.01 Proposal Format and Content

The state discourages overly lengthy and costly proposals, however, in order for the state to evaluate proposals fairly and completely, offerors must follow the format set out in this RFP and provide all information requested.

Proposals shall be limited to ten (10) pages. This does not include a synopsis of exampled surveys under the minimum qualifications set in 2.08.

6.02 Introduction

Proposals must include the complete name and address of offeror's firm and the name, mailing address, and telephone number of the person the state should contact regarding the proposal.

Proposals must confirm that the offeror will comply with all provisions in this RFP; and, if applicable, provide notice that the firm qualifies as an Alaskan bidder. Proposals must be signed by a company officer empowered to bind the company. An offeror's failure to include these items in the proposals may cause the proposal to be determined to be non-responsive and the proposal may be rejected.

A brief introduction shall be provided that demonstrates familiarity of oil and gas competitiveness factors as described in the scope of work.

6.03 Management Plan for the Project

Offerors must provide comprehensive narrative statements that set out the management plan they intend to follow and illustrate how the plan will serve to accomplish the work and meet the state's project goals and legislative deadlines.

6.04 Experience and Qualifications

Demonstrate familiarity of oil and gas competitiveness factors as described in the scope of work.
Outline, in detail, prior experience with conducting similar surveys of the oil and gas industry.

To be considered for this project, the Consultant/contractor must demonstrate experience and familiarity with the appropriate information required for this project. Experience with oil and gas companies is essential. Please include biographies of those principles that will be involved in the project.

6.05 Cost Proposal

The compensation for the contract shall be proposed in the following form:

A flat rate, including travel and expenses. Include a separate line item for two 2 day trips to Anchorage and two 2 day trips to Juneau.

This rate should include Management, Development of Survey & Identifying Companies to respond, Conducting Survey, Data Review & Compilation and Reporting findings.

A separate per hour cost for presentation preparation if required.

6.06 Evaluation Criteria

All proposals will be reviewed to determine if they are responsive. They will then be evaluated using the criterion that is set out in Section SEVEN.

An evaluation may not be based on discrimination due to the race, religion, color, national origin, sex, age, marital status, pregnancy, parenthood, disability, or political affiliation of the offeror.

A proposal shall be evaluated to determine whether the offeror responds to the provisions, including goals and financial incentives, established in the request for proposals in order to eliminate and prevent discrimination in state contracting because of race, religion, color, national origin, sex, age, marital status, pregnancy, parenthood, or disability.

SECTION SEVEN
EVALUATION CRITERIA AND CONTRACTOR SELECTION

**THE TOTAL NUMBER OF POINTS USED
TO SCORE THIS PROPOSAL IS 100**

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7.01 Management Plan for the Project (30 Percent)

Proposals will be evaluated against the questions set out below:

[a] How well does the management plan support all of the project requirements and logically lead to the deliverables required in the RFP?

[b] How well is accountability completely and clearly defined?

[c] Is the organization of the project team clear?

[d] How well does the management plan illustrate the lines of authority and communication?

[e] To what extent does the offeror already have the hardware, software, equipment, and licenses necessary to perform the contract?

[f] To what extent has the offeror identified potential problems?

7.02 Experience and Qualifications (20 Percent)

Proposals will be evaluated against the questions set out below:

Questions regarding the personnel:

[a] Do the individuals assigned to the project have experience on similar projects?

[b] Are resumes complete and do they demonstrate backgrounds that would be desirable for individuals engaged in the work the project requires?

[c] How extensive is the applicable education and experience of the personnel designated to work on the project?

Questions regarding the firm:

[d] How well has the firm demonstrated experience in completing similar projects on time and within budget?

[e] How successful is the general history of the firm regarding timely and successful completion of projects?

[f] Has the firm provided letters of reference from previous clients?

[g] If a subcontractor will perform work on the contract, how well do they measure up to the evaluation used for the offeror?

7.03 Contract Cost (40 Percent)

Overall, a minimum of **40** of the total evaluation points will be assigned to cost. The cost amount used for evaluation may be affected by one or more of the preferences referenced under Section 2.13.

Converting Cost to Points

The lowest cost proposal will receive the maximum number of points allocated to cost. The point allocations for cost on the other proposals will be determined through the method set out in Section 2.16.

7.04 Alaska Offeror Preference (10 Percent)

If an offeror qualifies for the Alaska Bidder Preference, the offeror will receive an Alaska Offeror Preference. The preference will be 10 percent of the total available points. This amount will be added to the overall evaluation score of each Alaskan offeror.

SECTION EIGHT
ATTACHMENTS

8.01 Attachments

Attachments

1. Proposal Evaluation Form
2. Standard Agreement Form - Appendix A
3. Appendix B1
4. Notice of Intent to Award

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PROPOSAL EVALUATION FORM

All proposals will be reviewed for responsiveness and then evaluated using the criteria set out herein.

Person or Firm Name _____

Name of Proposal Evaluation (PEC) Member _____

Date of Review _____

RFP Number _____

EVALUATION CRITERIA AND SCORING

THE TOTAL NUMBER OF POINTS USED TO SCORE THIS PROPOSAL IS 100 _____

7.01 Management Plan for the Project—30 Percent

Maximum Point Value for this Section - 30 Points
100 Points x 30 Percent = 30 Points

Proposals will be evaluated against the questions set out below.

[a] How well does the management plan support all of the project requirements and logically lead to the deliverables required in the RFP?

EVALUATOR'S NOTES _____

_____

[b] How well is accountability completely and clearly defined?

EVALUATOR'S NOTES _____

_____

[c] Is the organization of the project team clear?

EVALUATOR'S NOTES _____

_____

[d] How well does the management plan illustrate the lines of authority and communication?

EVALUATOR'S NOTES _____

_____

[e] To what extent does the offeror already have the hardware, software, equipment, and licenses necessary to perform the contract?

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EVALUATOR'S NOTES _____

_____

[f] To what extent has the offeror identified potential problems?

EVALUATOR'S NOTES _____

_____

EVALUATOR'S POINT TOTAL FOR 7.03 _____

7.04 Experience and Qualifications—20 Percent

Maximum Point Value for this Section - 20 Points
100 Points x 20 Percent = 20 Points

Proposals will be evaluated against the questions set out below.

Questions regarding the personnel.

[a] Do the individuals assigned to the project have experience on similar projects?

EVALUATOR'S NOTES _____

_____

[b] Are resumes complete and do they demonstrate backgrounds that would be desirable for individuals engaged in the work the RFP requires?

EVALUATOR'S NOTES _____

_____

[c] How extensive is the applicable education and experience of the personnel designated to work on the project?

EVALUATOR'S NOTES _____

_____

Questions regarding the firm.

[d] Has the firm demonstrated experience in completing similar projects on time and within budget?

EVALUATOR'S NOTES _____

_____

[e] How successful is the general history of the firm regarding timely and successful completion of projects?

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EVALUATOR'S NOTES _____

_____

[f] Has the firm provided letters of reference from previous clients?

EVALUATOR'S NOTES _____

_____

[g] If a subcontractor will perform work on the project, how well do they measure up to the evaluation used for the offeror?

EVALUATOR'S NOTES _____

_____

EVALUATOR'S POINT TOTAL FOR 7.04 _____

7.05 Contract Cost — 40 Percent

Maximum Point Value for this Section - 40 Points
100 Points x 40 Percent = 40 Points

Overall, a minimum of 20 percent of the total evaluation points will be assigned to cost. The cost amount used for evaluation may be affected by one or more of the preferences referenced under Section 2.13.

Converting Cost to Points

The lowest cost proposal will receive the maximum number of points allocated to cost. The point allocations for cost on the other proposals will be determined through the method set out in Section 2.16.

EVALUATOR'S POINT TOTAL FOR 7.05 _____

7.06 Alaska Offeror Preference — 10 Percent

Alaska bidders receive a 10 percent overall evaluation point preference.
Point value for Alaska bidders in this section -- 10 Points
100 Points x 10 Percent = 10 Points

If an offeror qualifies for the Alaska Bidder Preference, the offeror will receive an Alaska Offeror Preference. The preference will be 10 percent of the total available points. This amount will be added to the overall evaluation score of each Alaskan offeror.

EVALUATOR'S POINT TOTAL FOR 7.06 (either 0 or 10) _____

EVALUATOR'S COMBINED POINT TOTAL FOR ALL SECTIONS _____

DRAFT

ALASKA'S OIL AND GAS COMPETITIVENESS REPORT 2015

Alaska Oil and Gas Competitiveness Review Board

FEBRUARY 28, 2015

This report is available exclusively online and can be downloaded at the Board's website provided by the Department of Revenue:

http://dor.alaska.gov/OilGasCompetitivenessReviewBoard

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Executive Summary

The Oil and Gas Competitiveness Review Board (Board) is tasked with the important job of identifying critical criteria, collecting and analyzing historical, current and forecast data, and providing written findings regarding the competitive position of Alaska for oil and gas exploration and development.

The Board embarked on a series of meetings to address the statutory requirements that it was tasked with. Acknowledging the relatively short period of time allowed for research and analysis of a subject as complex as Alaska's oil and gas competitiveness, the critical importance of oil and gas to the State's revenue stream obligated the board to making sure the report was delivered on the schedule identified in statute. Testimony and input was invited from a number of experts within the administration on the topics enumerated above. This document is the initial report from the Board to fulfill its statutory obligations.

Alaska's crude oil production is down by more than 50 percent from its peak in 1989, it's proved reserves have also declined over a similar time frame, but estimated undiscovered oil and gas resources are much greater than any other state in the U.S. Thus, it seems that Alaska's resource potential is great compared to the Lower-48, but not our current production performance. Similarly, our production performance, as well as our resource potential, compared to international oil and gas resource-rich jurisdictions is ranked below many OPEC countries, but is still respectably ranked.

When looking at Alaska's competitiveness, it is important to consider a variety of criteria in comparison to other resource-rich jurisdictions. As we just touched on, proved reserves, as well as estimated undiscovered resources, are important pieces of information. Historic drilling rates and rig activity are reasonable leading indicators of the near-term trend of production growth and proved reserves additions. These data sets are those that tend to have more comprehensive coverage worldwide. This makes quantitative comparisons more appropriate.

Other competitiveness criteria are less easy to quantify for comparison. This includes assessment of Alaska's regulatory environment, permitting structure, industry labor resources, and the status of oil-and-gas-related infrastructure. To varying degrees, these data sets tend to have significant less consistency in character between jurisdictions. Even within Alaska there are significant differences between the North Slope and Cook Inlet in our ability to quantify and characterize these competitiveness criteria.

After our initial review of a variety of comparison criteria, a group of relevant peer jurisdictions were selected that appear to be most closely comparable to Alaska over many of those criteria. The jurisdictions that seem to most closely compare to Alaska for many of the important criteria, and are selected here to comprise the relevant peer group for Alaska, include four U.S. states, two provinces of Canada, two regions of the U.S. outer continental shelf and four foreign countries.

After peer group selection and analysis, another priority of the Board is to poll a broad range of oil and gas exploration and development companies to better understand Alaska's perceived relative strengths and weaknesses with our global peers. We plan to survey a representative group of large to small companies, including existing producers and lease owners, as well as other companies, such as service companies, that would represent companies not active in Alaska. This undertaking will take funding. We have prepared a draft RFP for the survey effort, with a budget for up to $300,000, to be considered by DOR and the Alaska Legislature. An effective survey of this type could take up to nine months, just to collect the survey data. Then additional time will be required to compile and analyze the collected data. It is paramount to be able to compare our strengths and weaknesses against other peer jurisdictions to insure that we are getting the greatest benefit from Alaska's resources while continuing to attract investment to the state.

As we review our competitiveness we need to consider the items that the State of Alaska has control of, or can influence, such as permitting, infrastructure, labor, lease costs, taxation, royalties and access to resources. We need to be able to do a grounded comparative analysis of our fiscal structure versus our peers. One of our thoughts moving ahead is to build a dashboard of critical measurements for Alaskans to easily review using principally, but not limited to items that are currently being measured by various state and federal agencies that can be compiled and provided on a single website. Our goal is to track past, current and projected future statistics and projections for a group of key diagnostic criteria that will help interested parties view specific progress or trends related to the oil and gas industry in Alaska compared to peer jurisdictions. These measures could be items like number of wells being drilled, production, resource pricing, permitting and other pertinent trending data. This will be maintained on a recurrent basis so interested parties have a baseline to current view of the industry.

To prepare for future statutorily required deliverables, significant additional work by the state and the Board remains to be done in the area of collecting the necessary data and performing meaningful analysis of the data to better understand the competitive relationships between Alaska and other resource-rich jurisdictions. Additionally, the Board is tasked with providing a better understanding of the competitive comparisons of different areas within Alaska, as well.

The next required deliverable from the Board is a report to the Alaska State Legislature due on or before January 15, 2017. For the January 2017 Competitiveness Report the Board is asked to provide written findings and recommendations regarding:

1. the state's tax structure and rates on oil and gas produced south of 68 degrees North latitude;

2. a tax structure that takes into account the unique economic circumstances for each oil and gas producing area south of 68 degrees North latitude;

3. a reduction in the gross value at the point of production for oil and gas produced south of 68 degrees North latitude that is similar to the reduction in gross value at the point of production in AS 43.55.160(f) and (g); and

4. other incentives for oil and gas production south of 68 degrees North latitude.

The Board's final statutorily required deliverable is a report to the Alaska State Legislature due on or before January 31, 2021. For the January 2021 Competitiveness Report the Board is asked to provide written findings and recommendations regarding:

1. changes to the state's fiscal regime that would be conducive to increased and ongoing long-term investment in and development of the state's oil and gas resources;

2. alternative means for increasing the state's ability to attract and maintain investment in and development of the state's oil and gas resources; and

3. a review of the current effectiveness and future value of any provisions of the state's oil and gas tax laws that are expiring in the next five years.

1. Introduction

Oil and Gas Competitiveness Review Board history and goals

The concept of the Alaska Oil and Gas Competitiveness Review Board (Board) originated with SB 21, the More Alaska Production (MAP) Act, passed by the Alaska legislature in 2013. The intent of the MAP Act was to reform Alaska's oil and gas production tax to improve Alaska's competitiveness against other oil and gas producing jurisdictions around the globe. Along with production tax reform, the legislature created the Board to establish and maintain salient data regarding oil and gas exploration, development, and production and advise the Alaska legislature on the state's oil and gas fiscal system, labor pool, and regulatory competitiveness.

The Board is made up of two public members, three administration department heads, a commissioner from the Alaska Oil and Gas Conservation Commission, three oil and gas subject matter experts, and two industry trade group representatives. The idea for Alaska's Board was, at least in part, modeled after a similarly tasked board in Alberta, Canada.

The Board met for the first time on October 15, 2014 and was tasked with presenting this report in early 2015. The limited time statutorily allowed this group to research and write this report has constrained this report to establishing a framework within which, over time we hope to refine and possibly expand the criteria, methodology and analysis of Alaska's competitiveness within a reasonable peer group.

This report is the product of the Board and the Alaska Department of Revenue (DOR). It was written and provided to the Alaska Legislature to satisfy the statutory report obligation found in AS 43.98.050(6)(A).

To be a good steward of its resources, Alaska should define policies that encourage responsible exploration and development and manage the impacts of those policies to maximize the benefits of oil and gas production for all Alaskans. In fact, this is a constitutional mandate.

In this report Alaska's fiscal system and other competitiveness criteria will be compared to similar oil and gas producing jurisdictions around the world. While much attention in Alaska is focused on fiscal systems, they are not the only criteria oil and gas producers use to make investment decisions. Factors such as resource volumes and potential, capital and operating costs, economic and political stability, access to infrastructure, availability of labor, efficiency of permitting, and access to lands for exploration all play important roles.

Alaska's position in the global marketplace is unlikely to stay static with time; rather, it will evolve with changes in oil and gas prices, perceived geologic potential, anticipated cost structure, and outside competition. This publication is the first in a series of mandated reports by the Board that attempts to establish a set of important criteria that are used by investors when comparing Alaska to other oil and gas producing areas of the world and select a group of reasonable peers for future analysis and comparison. It was extremely challenging to research and analyze these important factors in sufficient depth in a single report in the short period of time that was available. As a result, it is the goal of the Board to continue to refine the list of important competitiveness criteria and factors and discuss and analyze them in more depth in future reports. Additionally, because of further research and analysis and changes in our understanding of resource potential and economics, the group of peers may evolve and change in future reports.

Alaska peer group selection

Alaska has been a North America leader in oil production since production began on the North Slope in the 1970s. However, new technologies and new discoveries have provided oil and gas companies with a long list of opportunities around the globe when deciding where to invest capital

and resources. Fiscal structure is one of the significant factors that explorers and producers consider for their project portfolio when making investment decisions. In order to stay competitive with other jurisdictions where investors may consider investing private capital in oil and gas projects, it is critical that Alaska consider both domestic and international competition when selecting a peer group to benchmark its competitiveness.

In most jurisdictions, the sovereign right to explore for and produce hydrocarbons and other minerals belongs to the national or local government. This is true on federal and state lands in the United States, although outside of Alaska, the majority of land and mineral interests are privately owned. Whether lands are publicly or privately owned, oil and gas companies have historically shared a variety of attributes that make it beneficial for mineral owners to offer them significant rights and a share of the profits from exploration and production. The benefits offered by oil and gas companies include:

1. A willingness to take large risks and expose significant private capital searching for hydrocarbons.
2. Technical expertise in exploration, development, and production including technology and resources that is not otherwise easily available.
3. Massive capital investment that is often required to develop oil and gas fields and a willingness to invest those funds years in advance of revenue and cash flow.
4. Highly trained and experienced people capable of managing major projects associated with oil and gas development.
5. Access to refineries and distribution systems to refine, upgrade and market produced oil and gas.

Simply turning over rights to a for-profit international oil company (IOC) in return for cash (and in some cases, a minor share of the revenue being generated) is usually not an arrangement that is beneficial to the economic health of the jurisdiction that owns the resource. Under early agreements between IOCs and regional jurisdictions, local workers did not receive training or meaningful experience leading to advancement, and the immediate export of oil and gas meant there was no benefit to local industry or governments. Beginning in the 1950s, governments began working to develop fiscal schemes that offered more long-term benefit, with issues of control, involvement of citizens beyond low-level roles and development of local industry and infrastructure beginning to change significantly in the 1960s and continuing to evolve through the present day.

One goal of this report is to select a reasonable peer group of jurisdictions that will allow a representative comparison of Alaska's position in the world with respect to oil and gas exploration and development. At first glance this may seem like a relatively straight-forward task, but comparing broadly different areas of the world on the basis of many widely different criteria rapidly becomes quite complex. For example the similarities may seem stretched when comparing Alaska to Texas, North Dakota or any of the other Lower-48 states on exploration and development costs, infrastructure, environmental challenges, or "upside" resource potential. A peer group that is diverse and representative of the competition is critical to a meaningful comparison. To gain the most benefit from a peer group comparison, the peers need to share a core group of similarities to the competitive markets that Alaska faces. It is reasonable to expect the peer group list to evolve and change over time as world oil and gas exploration and production, global markets, the industry, and our understanding of all of the above evolve and change. We believe the criteria discussed in this report can provide a logical framework to show the value of using a peer group comparison and specifically this set of peers at this time.

Figure 1-1 lists the Alaska peer group selected for this report and some of their basic geographic characteristics. We narrowed the list in part by focusing primarily on concession-type (tax and

royalty) fiscal arrangements, generally similar to Alaska's fiscal regime. We also preferred a geographic affinity: a location in the Arctic, in North America or Europe, or in the Pacific region.

Other preferable similarities included jurisdictions with similar size reserves and undiscovered resource potential and favored jurisdictions with a history of significant hydrocarbon production. Throughout this report we will compare Alaska to all or portions of this peer group and present data to show the logic of using this comparison group. While, in the past, all of the jurisdictions mentioned in this list have been used as peers in comparing Alaska's oil and gas resources and fiscal system, it is wise to regularly review the peer group and each individual jurisdiction in the group, as well as previously excluded jurisdictions, for relevance based on current information, especially now with the enactment of SB 21 tax legislation in 2014. The Board acknowledges the possibility that the peer group selected for future reports may be different than the group selected for this report as the Board's analyses and understanding evolves.

Figure 1-1. Peer group jurisdiction and fiscal regime type and geographic affinities.

Jurisdiction	Jurisdiction Type	Type of Fiscal Regime	North America	Europe	Pacific	Arctic
Alaska	State	Concession	X		X	X
California	State	Concession	X		X	
North Dakota	State	Concession	X			
Oklahoma	State	Concession	X			
Texas	State	Concession	X			
U.S. GOM[1] OCS[2]	Federal	Concession	X			
U.S. Alaska OCS	Federal	Concession	X			
Alberta	Province	Concession	X			
Canada-Northwest Territories	Federal	Concession	X			X
Canada-Beaufort Sea	Federal	Concession	X			X
Australia	Federal	Concession			X	
Norway	Federal	Concession		X		X
United Kingdom	Federal	Concession		X		

[1]Gulf of Mexico (GOM)

[2]Outer Continental Shelf (OCS)

2. Hydrocarbon endowment

A region's production history and future production potential are important elements to consider when establishing or reviewing a petroleum fiscal system. It seems logical that Alaska's oil and gas peer group should include jurisdictions that have a similar resource base and production volumes, referred to in this report as the hydrocarbon endowment. Beyond historic production, proved reserves and undiscovered resource volumes considered for this report, it may be important to broaden the discussion into related areas of study. Further refinement around this issue could involve discussion of economic field size distributions, basin maturity, exploration success ratios, and whether recent additions to proved reserves and undiscovered resource are conventional or unconventional.

This section of the report focuses on the comparison of Alaska's hydrocarbon endowment for conventional oil and does not address other energy resource types, such as natural gas and viscous or "heavy" oil. While these resource types will possibly be important contributors if Alaska's overall production is to increase, there is no available source from which to draw meaningful comparisons of worldwide unconventional resources.

In considering hydrocarbon endowment and Alaska's peer group, it is important to recognize the physical differences of each region, the location of the resources with regards to infrastructure, and the level of investment required for exploration, development, production, and transportation. In each case, the geology, geography, size of the resource, and proximity to market are factors that make comparison of limited shelf life. For example, Alaska has proved conventional oil reserves that led the nation's production in the 1980's and 1990's. Development of unconventional oil sources along with continued decline in North Slope production has changed Alaska's position during the past decade. However, without transport via the Trans-Alaska Pipeline System (TAPS), the proved reserves would have remained as contingent resources, like the vast quantities of stranded North Slope natural gas are. Similarly, without existing surface infrastructure and advances in hydraulic fracturing and horizontal drilling the vast reserves of unconventional resources in the lower 48 states would not have been realized. These points are important to consider in evaluating the competitiveness of each peer to the other.

Production volumes

The Energy Information Agency (EIA), an agency of the U.S. Department of Energy, is used throughout this report as our primary source for oil and gas production and proved reserves for both North America and the rest of the world (Figures 2-1 and 2-2). In the case of Canadian provinces, data were gathered from Canada's National Energy Board (NEB). The EIA provides annual estimates of the United States' proved reserves of crude oil and natural gas based on filed responses to Form EIA-23, Annual Survey of Domestic Oil and Gas Reserves, which includes data from about 1,200 domestic operators. The purpose of this portion of the report is to provide these numbers as a basis for discussion, not to attempt to explain or offer an opinion on the causes of these production trends.

Figure 2-1. Annual oil production history for Alaska and its peer group jurisdictions. Complete annual data are only available through 2013.

Jurisdiction	Annual Oil Production					
	2008	2009	2010	2011	2012	2013
Units	[Mbbl/d]	[Mbbl/d]	[Mbbl/d]	[Mbbl/d]	[Mbbl/d]	[Mbbl/d]
United States[1]						
Alaska[2]	729	703	652	610	590	544
California	649	664	686	686	686	686
North Dakota	172	218	310	419	666	860
Oklahoma	184	183	189	209	254	319
Texas	1,109	1,094	1,169	1,449	1,979	2,543
U.S. Alaska OCS[2]	0.00	0.00	0.00	0.00	0.00	0.00
U.S. GOM OCS	1,157	1,562	1,552	1,317	1,267	1,254
Canada[3]						
Canada-Alberta	2,292	2,461	2,477	2,657	2,870	3,093
Canada-total (includes Alberta)	3,195	3,275	3,306	3,493	3,692	3,965
Rest-of-the-World[4]						
Australia	586	592	604	531	519	445
Norway	2,464	2,353	2,135	2,007	1,902	1,826
U.K.	1,584	1,510	1,406	1,167	1,009	916

[1]Data source for Alaska crude oil production is the Alaska Department of Revenue "Revenue Sources Book" for consistency with other DOR work. Data source for all other U.S. state crude oil production outside Alaska is the Departement of Energy, Energy Information Agency (EIA) at http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm.

[2]The only oil production allocated to the Alaska Outer Continental Shelf (OCS) is a small fraction of the production from Northstar field. This production is insignificant when compared to the rest of Alaska and its peer group and is not broken out in EIA reports. Because of the units precision used in this table, Alaska OCS production appears as zeros, but the actual production was positive but less than 0.005 MMbbl/d.

[3]Data source for Canada production is Canadian Association of Petroleum Producers (CAPP) Statistical Handbook available at http://www.capp.ca/library/statistics/handbook/Pages/default.aspx. Data series includes natural gas liquids.

[4]Data source for Rest-of-the-World production is the Departement of Energy, Energy Information Agency (EIA) at http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm.

Figure 2-2. Annual natural gas production history for Alaska and its peer group jurisdictions. Complete annual data are only available through 2013.

Jurisdiction	Annual Natural Gas Production					
	2008	2009	2010	2011	2012	2013
Units	[MMcf/d]	[MMcf/d]	[MMcf/d]	[MMcf/d]	[MMcf/d]	[MMcf/d]
United States[1]						
Alaska	1,022	1,025	968	917	901	866
California	772	720	750	652	640	NA
North Dakota	122	135	193	227	418	NA
Oklahoma	4,869	4,900	4,676	4,808	5,145	NA
Texas	17,921	17,520	17,210	18,169	18,840	NA
U.S. Alaska OCS	0.0	0.0	0.0	0.0	0.0	0.0
U.S. GOM OCS	6,323	6,655	6,151	4,965	3,889	NA
Canada[2]						
Canada-Alberta	5,265	4,866	4,644	4,346	4,247	4,159
Canada-total (includes Alberta)	6,931	6,452	6,261	6,148	5,987	6,012
Rest-of-the-World[1]						
Australia	4,329	4,570	4,364			
Norway	9,597	10,011	10,290			
U.K.	6,764	5,718	5,447			

[1]Data source for Alaska crude oil production is the Alaska Department of Revenue "Revenue Sources Book" for consistency with other DOR work. Data source for all other U.S. state crude oil production outside Alaska is the Departement of Energy, Energy Information Agency (EIA) at http://www.eia.gov/.

[2]Data source for Canada production is Canadian Association of Petroleum Producers (CAPP) Statistical Handbook available at http://www.capp.ca/library/statistics/handbook/Pages/default.aspx.

Alaska's oil production in comparison with its North American peers for the last six years is presented in Figure 2-3. This group of North American producers includes all the largest-volume oil-producing jurisdictions in North America. In general, Alaska holds a place in the low to midlevel, and in each of the last six years, Alaska's oil production has declined. Meanwhile, Alberta, Oklahoma, North Dakota, and Texas have all seen significant production increases in the last six years, with production in Texas and North Dakota up sharply due to expanded development of unconventional oil resources, including shale oils and tight sand structures. The U.S. Gulf of Mexico oil production saw an early increase and recent decline over the same time period, California's production has held relatively constant.

When we compare Alaska with the international peer group (Figure 2-4) the most striking thing to note is that unlike the peer group of states, Alaska, along with Australia, is at the bottom of the oil production history graph. In addition Alaska, Australia, Norway and the United Kingdom (U.K.) have all experienced continuous production declines over the last six years, possibly reflecting the maturity of the basins where production occurs in those countries.

Natural gas production for the North American peer group over the last six years (Figure 2-5) shows significantly different trends than oil production, primary of which is that Alaska is very close to the bottom of the production volume graph. Alaska and California have experienced a slight decline in natural gas production in recent years. Oklahoma, Texas, and North Dakota have seen increases in natural gas production due to the ramp-up in production of shale and unconventional resources. Over the same period, the U.S. Gulf of Mexico has seen a significant decline in production, a drop of almost 40 percent. Only North Dakota has a significant production increase in the recent few years, even though their production is still low compared to others in the selected peer group.

When comparing Alaska's natural gas production to international peers (Figure 2-6), Alaska is by far the lowest producing jurisdiction of the group. Australia and, to some degree Norway, have upward production trends in the time period. Canada and the U.K. have declining trends.

Figure 2-3. Oil production history for Alaska and its North American peers. (Note that figures 2-3 and 2-4 have different vertical scales.)

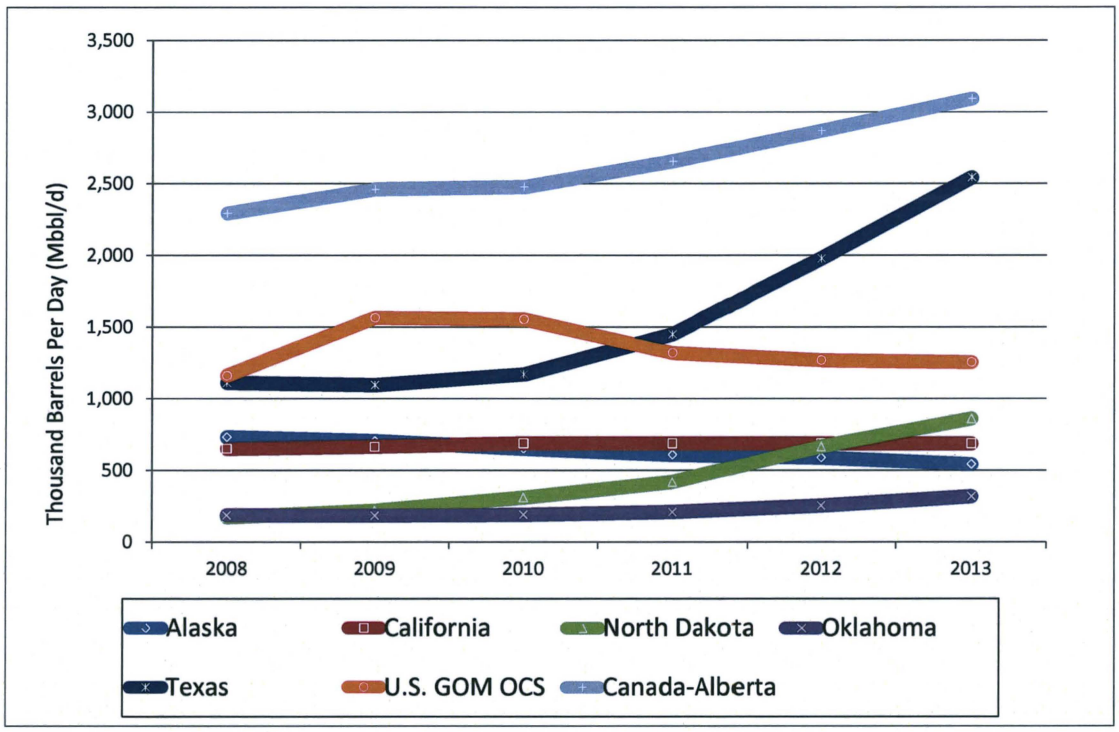


Figure 2-4. Oil production history for Alaska and its international peers. (Note that figures 2-3 and 2-4 have different vertical scales.)

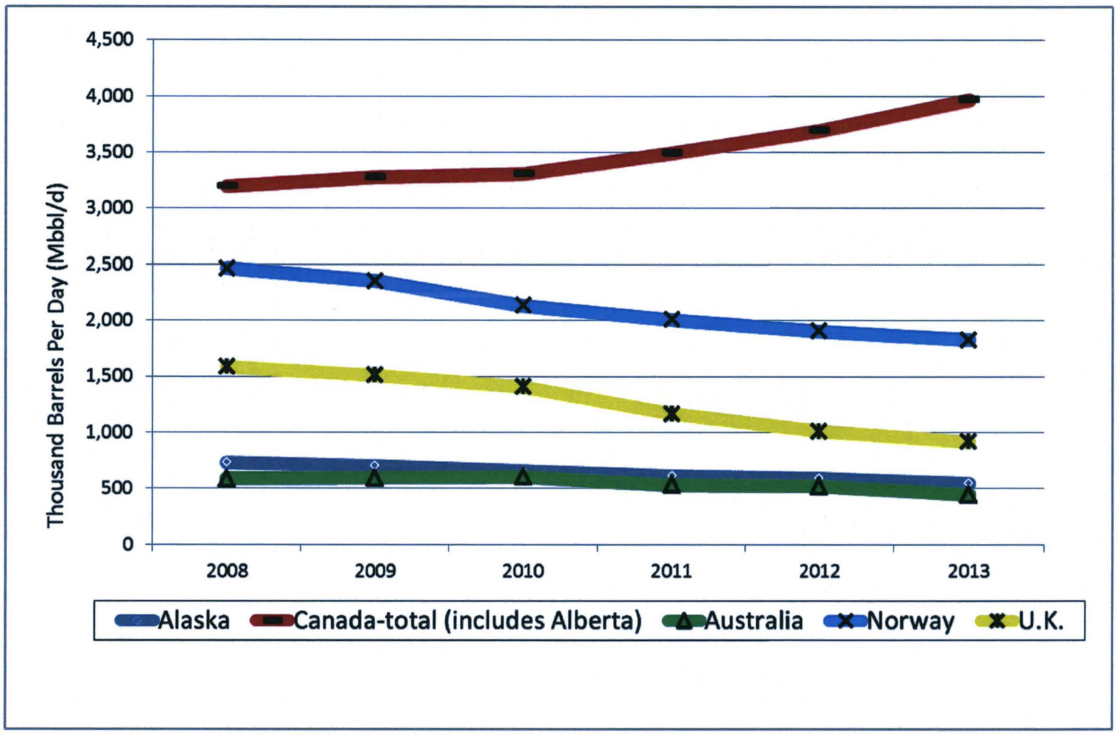


Figure 2-5. Natural gas production history for Alaska and its North American peers. (Note that figures 2-5 and 2-6 have different vertical scales.)

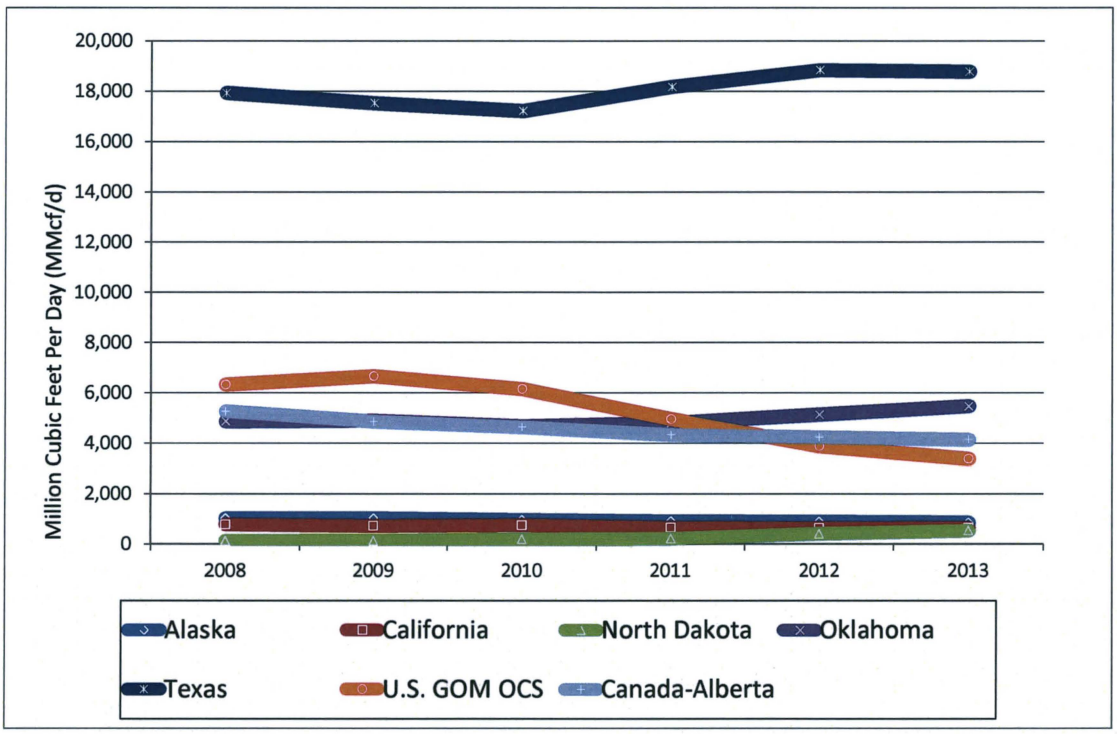
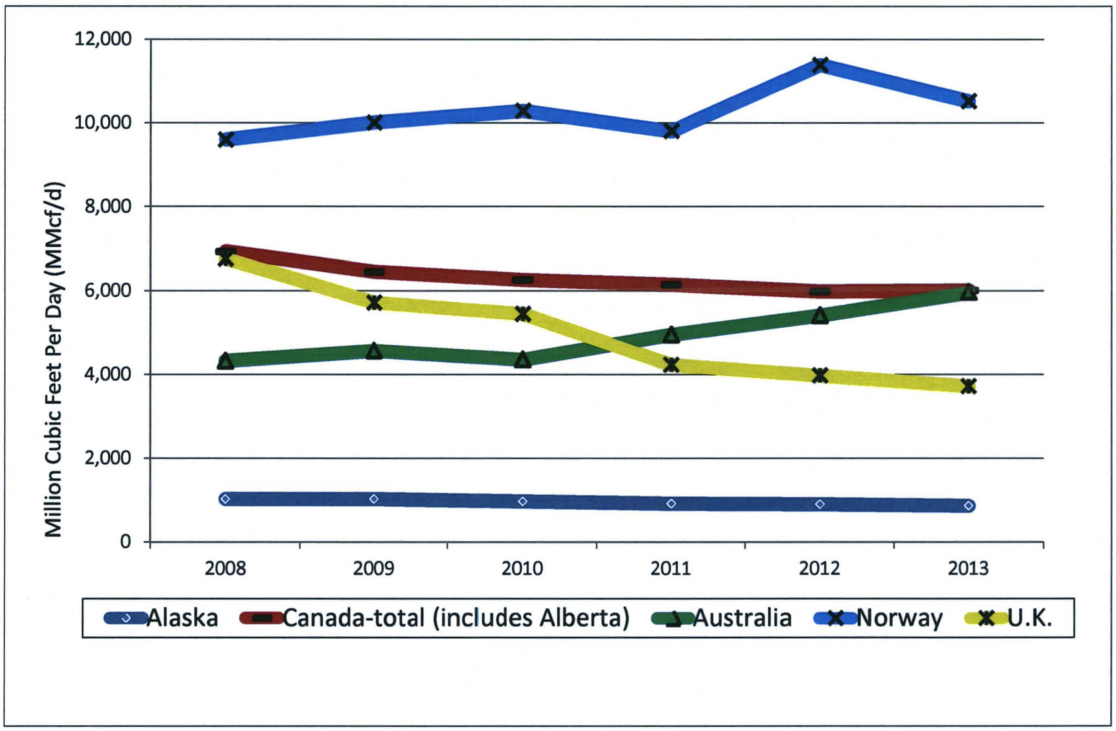


Figure 2-6. Natural gas production history for Alaska and its international peers. (Note that figures 2-5 and 2-6 have different vertical scales.)



Proved reserves

EIA defines "proved reserves" as "those volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions." Reserves estimates change from year to year as new discoveries are made, existing reserves are produced, technologies change, companies modify development schedules for undeveloped reserves and prices change. Discoveries include new fields, identification of new reservoirs in old fields, and extensions of existing reservoirs. Extensions are reserve additions that result from additional drilling and exploration in previously discovered reservoirs. Extensions typically account for a large percentage of "discoveries" within a given year. While actual discoveries of new fields and reservoirs are important indicators of new resources, they usually account for a small percentage of reserve additions in a given year. Revisions occur primarily when operators change their estimates of what they will be able to profitably produce from the properties they operate using existing technology and prices.

While several factors influence proved reserves, crude oil and natural gas prices are particularly important. Higher prices typically increase estimates (positive revisions) as operators consider a broader portion of the resource base economically producible, or proved. Lower prices generally reduce estimates (negative revisions) as the economically producible base contracts.

Scheduling changes can also result in some undeveloped reserves being removed and others added. When an undeveloped resource development project is more than five years from achieving production, it is outside the limit, based on SEC rules, to be considered "proved reserves." When a project moves into the five-year window its reserves are added to "proved reserves."

Proved reserves: Alaska and its peers

EIA maintains an annual assessment of the U.S. crude oil and lease condensate proved reserves and the U.S. total natural gas proved reserves for the period 1983-2013. Figures 2-7 and 2-8 are a graphical comparison of Alaska with U.S. onshore, offshore and total reserves for liquid hydrocarbons (oil and condensate) and natural gas over a thirty year period, from 1983 through 2013. Figure 2-9 is a tabular comparison of Alaska and its North American peer group for proved reserves and undiscovered resource estimates of oil and natural gas. This table also provides the historical trends changing reserves estimates.

Compared to top producing U.S states, Alaska's proved oil reserves are only greater than Oklahoma. They are roughly equivalent to California and are less than North Dakota and Texas (Figure 2-11). Continuing improvements in technology and changing economics of producing unconventional oil from the Williston Basin only recently increased North Dakota's reserves to a level that exceed Alaska's. Texas and Canada have also experienced dramatic increases in proved reserves because of improved economics of unconventional oil and gas production. If unconventional oil resource development was ever to become economic on the North Slope, Alaska's proved reserves also would increase dramatically.

It is worthwhile keeping in mind the importance of commodity price in determining how oil and gas may move into and out of the "proved reserves" classification. Recent price declines may disproportionately affect states with large volumes of relatively expensive to produce oil reserves, such as that from shale oil. Low prices may result in the reclassification of large volumes of proved reserves to potential reserves, reversing the reserve increases some states recently experienced as a result of greater than $100 per barrel oil prices.

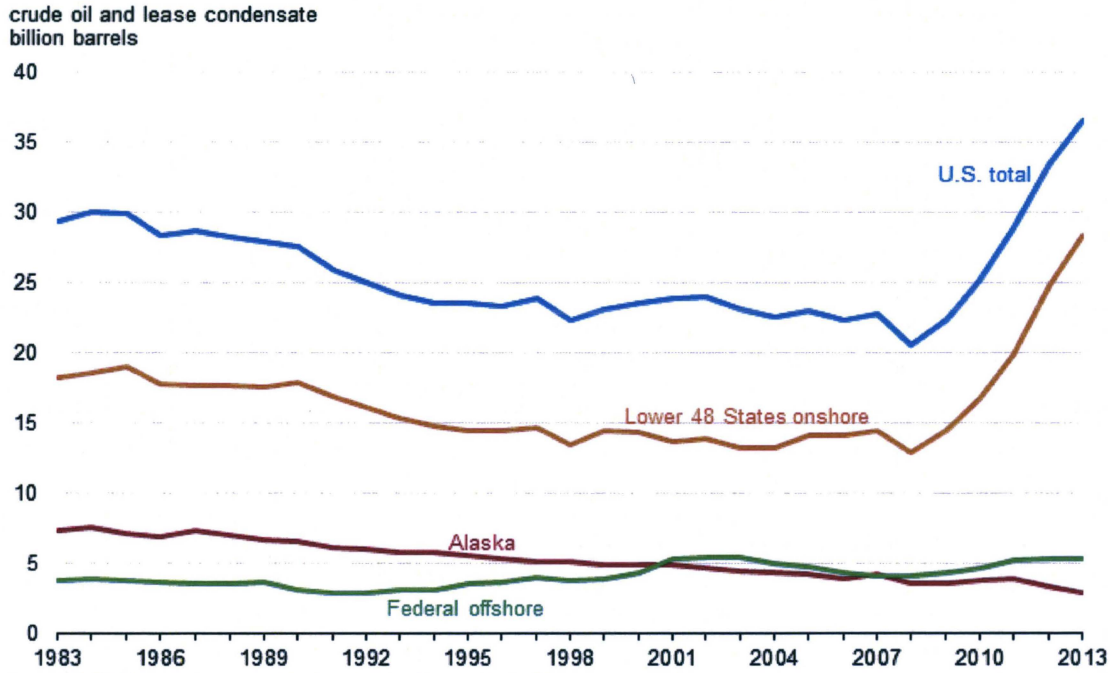
Within the international peers, proved oil reserves in Norway are much greater than Alaska's, but are still within a range that does not preclude them from consideration for an Alaska peer group. Australia's oil reserves are similar in size, and the U.K.'s oil reserves are only slightly lower.

Proved reserves in both Norway and the U.K. have declined in recent years. However, significant new discoveries in Norwegian waters of the North Sea that were announced in the past few years may reflect a change in fortune for the basin.

Alaska's proved reserves of natural gas are constrained by the definition of "proved reserves." Given the contingent resources of natural gas on the North Slope, estimated in excess of 35 TCF. This stranded natural gas resource is an area of significant economic interest. The Alaska LNG project is working on feasibility studies to bring the North Slope gas to tidewater. Based on the findings of these studies and if successfully constructed, the transport of this contingent resource would meet the definition of proved reserves and change Alaska's position to second in the nation. It is also important to note that the North Slope natural gas, and most of the gas attributed to our international peer group, is a conventional natural gas source versus a combination of conventional and unconventional sources that constitute proved reserves in the Lower-48 peer group.

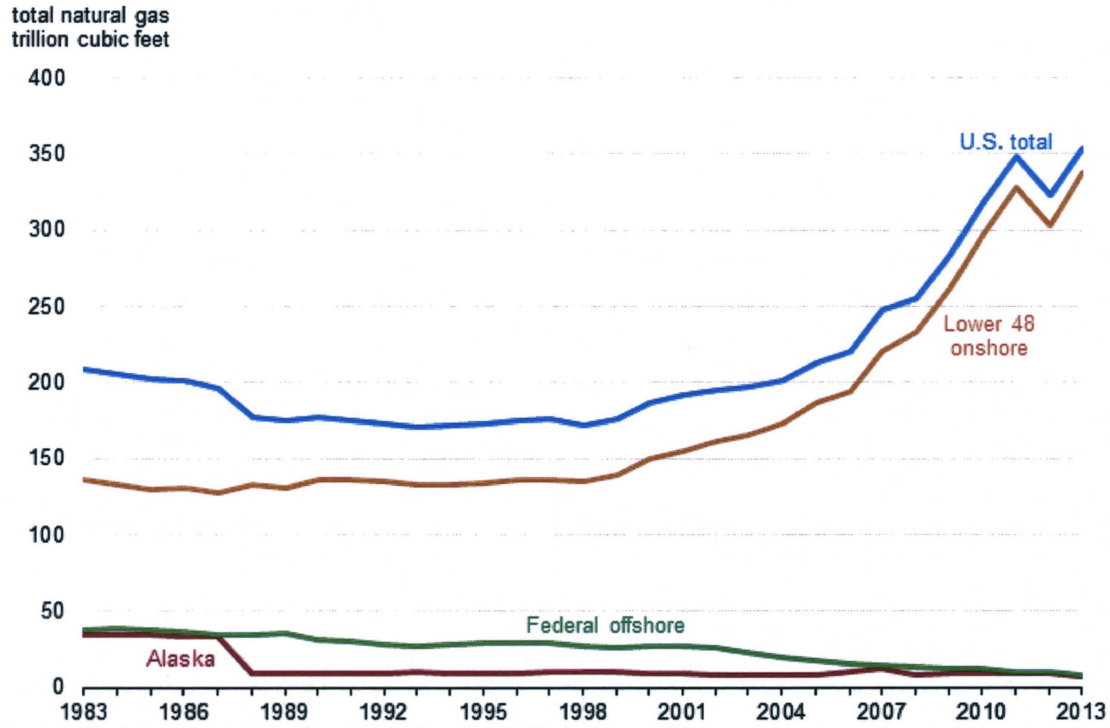
Another key factor in analyzing Alaska's North Slope reserves is that they are currently located almost exclusively on state and Native corporation lands and do not include federal lands in National Petroleum Reserve-Alaska (NPR-A) or the 1002 area of Arctic National Wildlife Refuge (ANWR)+.

Figure 2-7. EIA estimate of U.S. crude oil and lease condensate proved reserves 1983-2013.



Source: http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf.

Figure 2-8. EIA estimate of U.S. total natural gas proved reserves, 1983-2013. (Note: Alaska's proved reserves do not include the vast estimates of the North Slope as they are not "recoverable under existing economic and operating conditions."



Source: http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf.

Figure 2-9. Estimates of proved reserves and undiscovered resources in Alaska and peers.

Jurisdiction	Oil + NGL Proved Reserves	Natural Gas Proved Reserves	Oil + NGL Undiscovered Resource Mean Estimate	Natural Gas Undiscovered Resource Mean Estimate
[Units]	[MMbbl]	[BCF]	[MMbbl]	[BCF]
United States[1,2,3,4]				
Alaska (onshore & state submerged)	2,898	7,383	16,750	123,826
California	2,878	2,023	3,748	7,349
North Dakota	5,683	6,081	6,536	1,464
Oklahoma	1,469	28,900	790	10,244
Texas	12,004	97,921	8,174	55,468
U.S. Alaska Arctic OCS	-	-	23,750[3]	108,180[3]
U.S. GOM OCS	4,950	16,535	43,310	169,160
Canada[5,6]				
Canada-Alberta (conventionl)	1,781	31,900	1,196	15,916
Canada-Alberta (unconventional)	167,170	-	-	-
Canada-Total (includes Alberta)	173,110	68,170	4,043	42,990
Rest-of-the-World[6]				
Australia	1,433	43,037	46,746	114,000
Norway	5,825	73,806	12,881	183,000
U.K.	2,979	8,616	6,329	23,377

[1]Data source for U.S. reserves is the Departement of Energy, Energy Information Agency (EIA) at *http://www.eia.gov/dnav/pet/pet_crd_cplc_a_EPCCOND_R01_MMbbl_a.htm* and *http://www.eia.gov/dnav/ng/ng_enr_sum_a_EPG0_R11_BCF_a.htm.*

[2]Data source for U.S. undiscovered resource estimates is the U.S. Geological Survey (USGS) at *http://pubs.usgs.gov/dds/dds-030/.*

[3]Alaska current mean undiscovered resource estimates from the U.S. Geological Survey and Bureau of Ocean Energy Managment were compiled by the Alaska Department of Natural Resources, Division of Oil and Gas. The USGS estimates undiscovered resource by assessment areas (generally conforming to sedimentary basin outlines), but does not estimate resources by state. For this publication the Department of Revenue performed a rough allocation of the U.S.G.S. resource estimates to individual states for use in this table.

[4]Data source for U.S. Gulf of Mexico Outer Continental Shelf undiscovered resource is "Assessment of Undiscovered Recoverable Oil and Gas...", 2011; at *http://www.boem.gov/2011-National-Assessment-Factsheet/.*

[5]Data source for Alberta reserves at *http://www.aer.ca/data-and-publications/statistical-reports/st98*

[6]Data source for Canada (total) and Rest-of-the-World undiscovered resource estimates is the U.S. Geological Survey (USGS) at *http://pubs.usgs.gov/dds/dds-030/*

Undiscovered oil resource estimates

The U.S. Geological Survey (USGS) is used throughout this report as our source for undiscovered resource estimates for both North America and the rest-of-the-world.[1,2] The USGS assesses the recoverability of undiscovered conventional oil and gas resources, as shown in Figure 2-9.[3] Figures 2-12, 2-13, 2-14, and 2-15 graphically compare the current estimates of

[1] http://energy.usgs.gov/OilGas/AssessmentsData/NationalOilGasAssessment.aspx

[2] http://energy.usgs.gov/OilGas/AssessmentsData/WorldPetroleumAssessment.aspx

[3] The USGS also conducts unconventional resource assessments for resource types not included in this report, including coalbed methane, source rock oil and gas (shale oil and gas), continuous tight sands, and gas hydrates.

Alaska's liquid hydrocarbon and natural gas undiscovered conventional resources and proved reserves with its North American and international peer groups. Several conclusions can be drawn from these graphs. These data show that Alaska's reserves are significantly less than undiscovered resource potential, unlike the U.S. states in the peer group, but similar to the Gulf of Mexico and Australia. Most of the U.S. states have roughly equal reserves and undiscovered resources, implying a higher overall level of exploration and development maturity than Alaska. A second observation is that the overall level of undiscovered conventional oil resource is much greater than any of the U.S. states and some of its international peers. It is, however, less than the Gulf of Mexico and Australia. A third observation is that Alaska's natural gas potential, as defined by undiscovered resource, is outranked in the peer group only by the Gulf of Mexico and Norway. Gas resource estimates for U.S. states are all far below Alaska.

The USGS analysis estimates how much undiscovered conventional oil and gas is technically recoverable and the difference between what is proved reserves and technically recoverable. For the onshore United States, the "assessment units" defined in the USGS analysis does not conform to any state or political jurisdictional boundary. Instead, the "assessment units" are based more on geologic divisions, such as the Permian Basin (Texas and New Mexico) and Williston Basin (North Dakota, South Dakota, Montana, Manitoba and Saskatchewan). In this way the USGS avoids dividing otherwise single coherent continuous plays between two or more assessment units. The international undiscovered resource assessment more closely adheres to national boundaries to define the "assessment units" or the geographic limits of the area analyzed. Understanding how much undiscovered technically recoverable resource might be present serves as a basis for calculating how much might be ultimately economically developed.

Technically recoverable resources are those that could be potentially produced using current technology and industry practices. Economically recoverable resources are those that can be sold at a price that covers the costs of discovery, development, production and transportation to the market. Figure 2-9 shows the significant differences in undiscovered resources between Alaska and the Lower-48 states and many of its international peers.

USGS assessments are meant to provide a means to estimate quantities of undiscovered conventional oil, gas and natural gas liquids that have the potential to be added to reserves (proved and otherwise) in some specified future time span. These estimated petroleum volumes reside in fields whose sizes exceed a minimum cutoff value that the USGS establishes for each assessment unit. The term "undiscovered conventional resource" as used in this report is understood to mean short approximations of this objective. Note that the USGS assessment of undiscovered resource has no stated or implied estimate of timing of development or volumes produced.

The USGS defines both heavy oil and shale oil as unconventional and considers those resources separately from its conventional resource estimates. While the USGS provides undiscovered resource estimates for nations in a relatively straightforward manner, its use of assessment units that do not adhere to state boundaries presented a barrier to clear comparisons for this study. To circumvent this barrier, we approximated undiscovered resources by state by visually estimating the areas of the assessment units contained within the state boundaries and prorating the total based on the estimated area allocations.

The USGS assessment effort ranks Alaska's undiscovered resource potential in a relatively high position compared to other parts of the world. Alaska's onshore undiscovered conventional petroleum resource is estimated to be approximately 17 billion barrels of oil. When the estimate for offshore undiscovered petroleum resource is added in, Alaska's total undiscovered resources top 40 billion barrels of oil. The USGS characterizes these estimates as representing a "significant potential for energy and mineral resource that is unmatched by any other onshore region of the U.S."

Figure 2-10. Estimates of proved oil reserves for Alaska and North American peers.

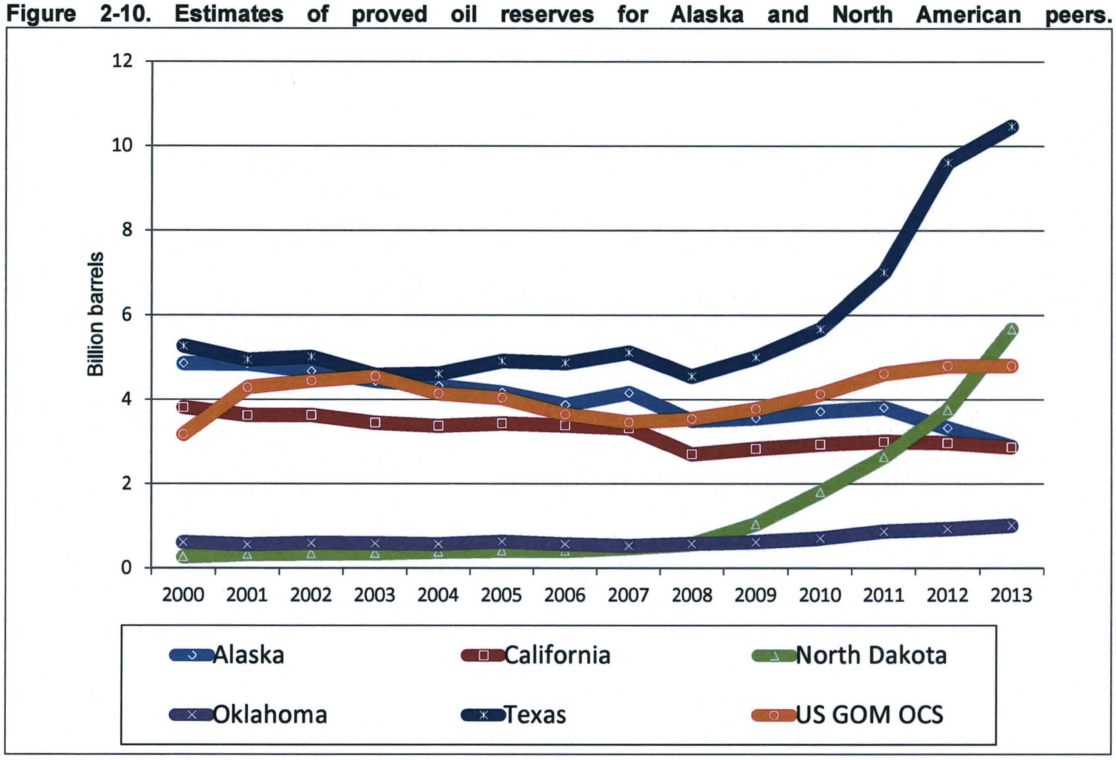


Figure 2-11. Estimates of proved oil reserves for Alaska and international peers.

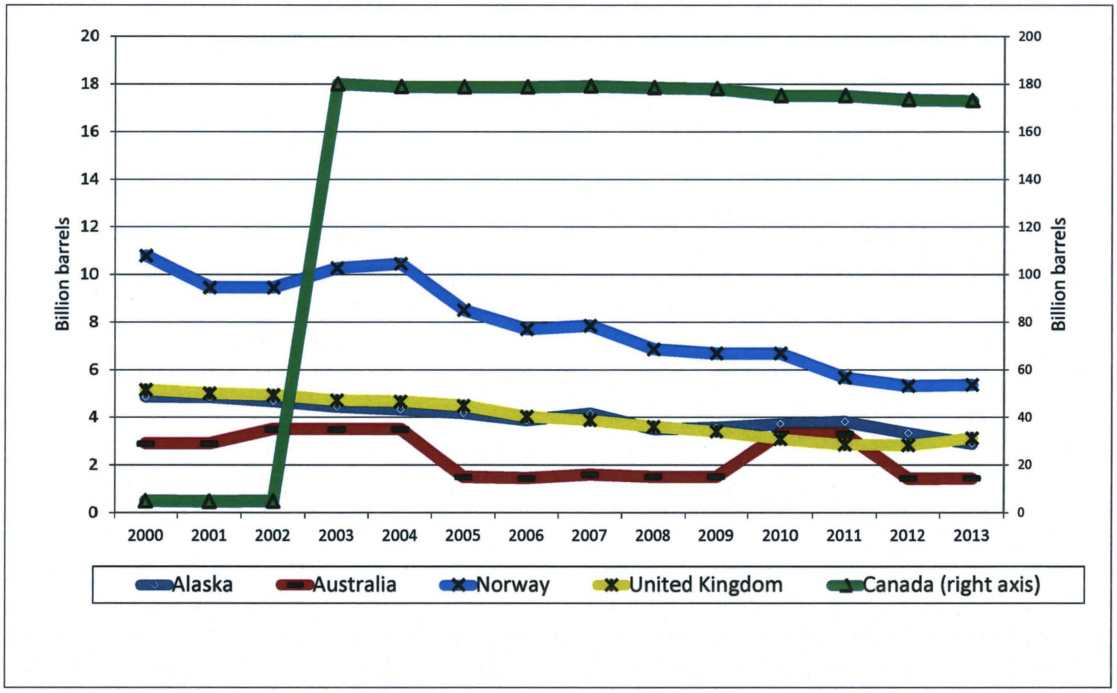


Figure 2-12. Comparison of proved reserves and undiscovered liquid hydrocarbon resource between Alaska and North American peers. (Note that for scaling purposes, the bar representing Canada's reserves is truncated.)

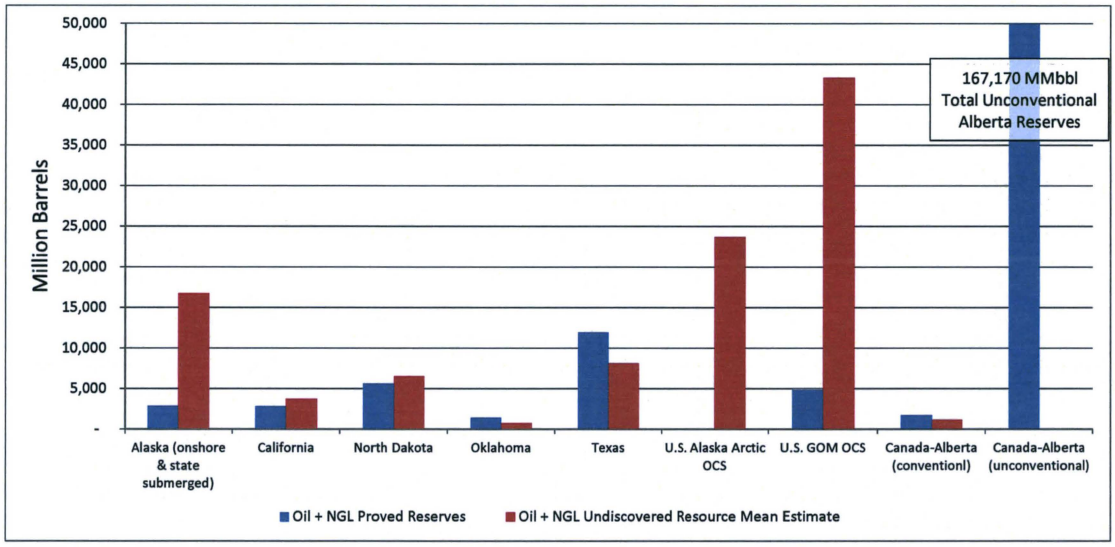


Figure 2-13. Comparison of proved reserves and undiscovered liquid hydrocarbon resource between Alaska and international peers. (Note that for scaling purposes, the bar representing Canada's reserves is truncated.)

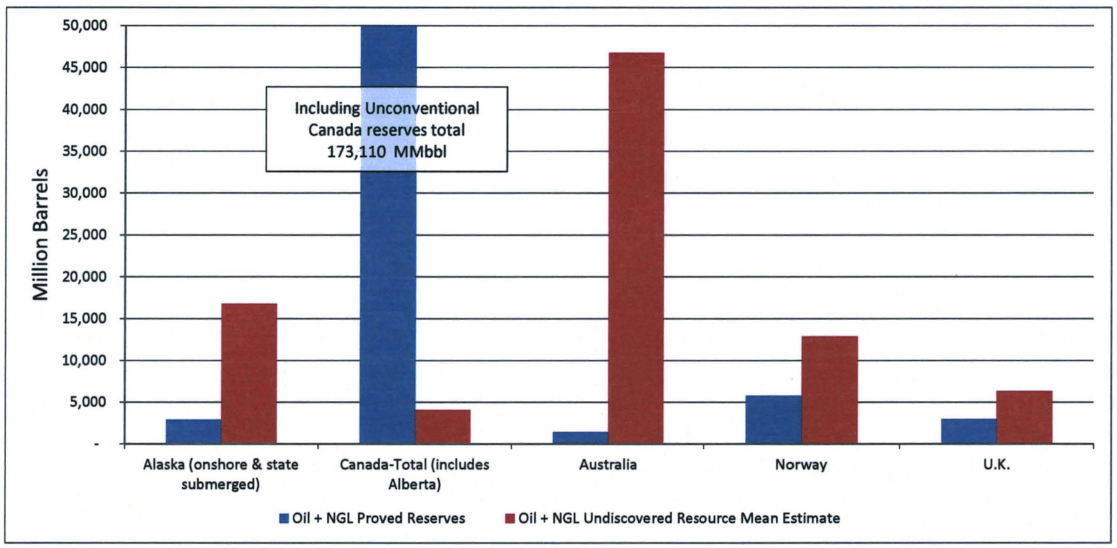


Figure 2-14. Comparison of proved reserves and undiscovered natural gas resource between Alaska and North American peers.

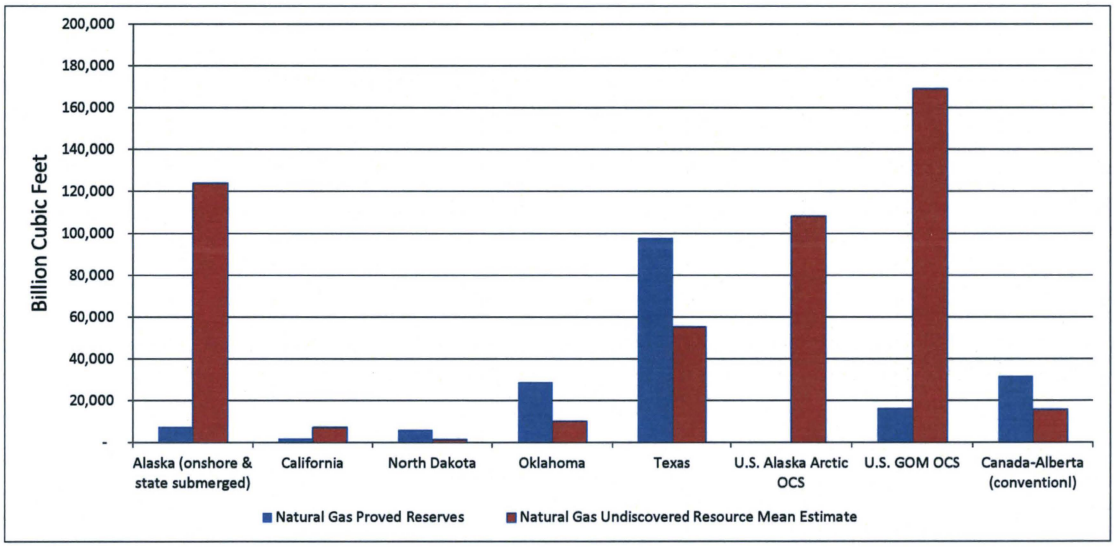
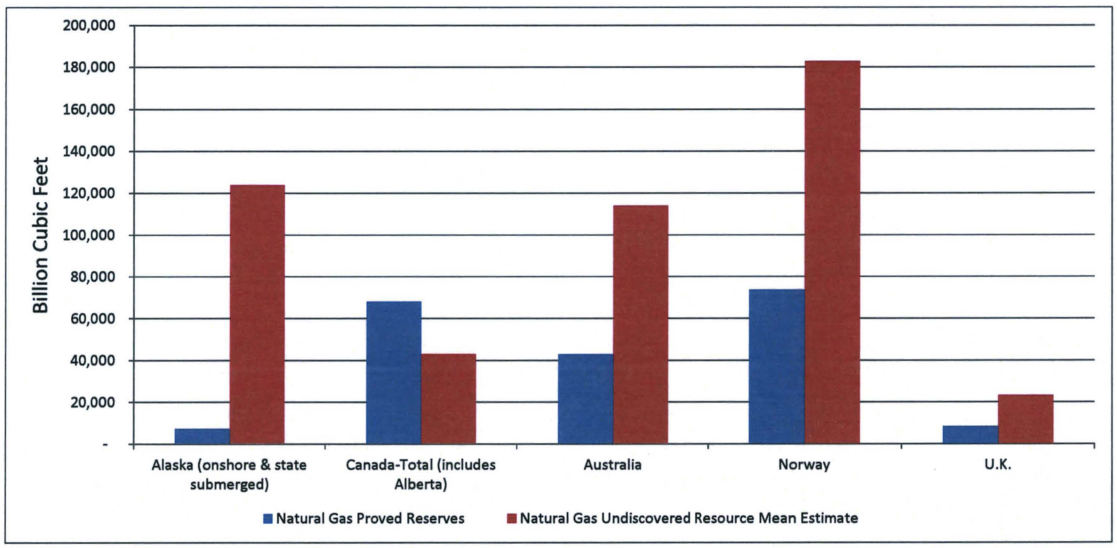


Figure 2-15. Comparison of proved reserves and undiscovered natural gas resource between Alaska and international peers.



Natural gas, viscous oil and other unconventional resources

As stated earlier, the focus of this publication is on Alaska's conventional oil and the fiscal systems the state has put in place to capture revenue from it. However, Alaska also has other significant hydrocarbon resources, including large quantities of natural gas, viscous oil, shale oil, shale gas, coalbed methane, and gas hydrates. While Alaska currently does not receive significant revenue from these hydrocarbon sources, the potential is significant, so a brief summary of these potential resources is warranted.

Natural gas

Alaska has a huge resource base of discovered and undiscovered natural gas (217.91 trillion cubic feet). Much of northern Alaska's conventional natural gas remains unexploited awaiting construction of an economically viable export option, such as an export pipeline or liquid natural gas (LNG) via tankers. Any capital spending to identify new natural gas reserves will only be made by companies expecting long periods of time before payback on investment. All of the options to construct infrastructure to exploit northern Alaska gas will likely be expensive and technically challenging and sensitive to market prices. Two possible scenarios for export of northern Alaska's natural gas have been considered in recent years. The two scenarios are a gas pipeline down existing highways from Prudhoe Bay to Alberta, Canada, or shipping liquefied natural gas (LNG) from tidewater. Recent attention has focused on the LNG option.

Viscous oil

Alaska has a large discovered and delineated potential for the production of viscous oil, sometimes referred to as "heavy oil." Viscous oil delineation and test production has been occurring for decades. Schrader Bluff (including West Sak) and Ugnu reservoirs in the Kuparuk River, Milne Point, and Prudhoe Bay units have recently been estimated to contain a total of 23 to 36 billion barrels of viscous oil in place.[4] This compares to a previous estimate of 18 to 40 billion barrels in place in the loosely described "Kuparuk River area."[5] Additional in-place volumes in the Schrader Bluff reservoir at Eni's Nikaitchuq Unit are estimated at 800 to 930 million barrels (AOGCC Conservation Order 639).[6]

Current production of viscous oil flows from six Participating Area (PA) developments in four North Slope units: Kuparuk River, Milne Point, Nikaitchuq and Prudhoe Bay. The combined in-place resources under active development total 5.5 to 7.4 billion barrels. These developments are expected to recover 1.0 to 1.2 billion barrels, with overall recovery factors of 15 to 20 percent.[7]

Coalbed methane

Coalbed methane is a form of natural gas extracted from coal beds. In recent decades it has become an important source of energy in the United States, Canada, and other countries. Coalbed methane is distinct from natural gas produced from a typical sandstone or conventional gas reservoirs because the methane is stored within the coal by a process called adsorption. The methane is in a near-liquid state, lining the inside of pores within the coal (called the matrix). The open fractures in the coal (called "cleats") can also contain free gas or be saturated with water. The adsorbed gas is extracted along with fluid from a well completed in the coal seam (300 to 5,000 feet below ground). Adsorbed gas is released when sustained fluid production reduces the pressure within the coal seam. As formation water is produced from the coalbed, both gas and "produced water" come to the surface through tubing. Alaska currently has no production and receives no revenue from this type of unconventional hydrocarbon.

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[4] Hartz, J., Decker, P., Houle, J., and Swenson, R., 2007, The historical resource and recovery growth in developed fields on the Arctic Slope of Alaska (abs), American Association of Petroleum Geologists Annual Convention and Exhibition Hedberg Conference Proceedings, April 1-7, Long Beach, California, 4 p.

[5] Werner, M.R., 1987, West Sak and Ugnu sands; Low-gravity oil zones of the Kuparuk River area, Alaskan North Slope, in Tailleur, I., and Weimer, P., eds., Alaskan North Slope Geology, v. 1: Bakersfield, California, Pacific Section, Society of Economic Paleontologists and Mineralogists and Alaska Geological Society, p. 109-118.

[6] Alaska Oil and Gas Conservation Commission, Conservation Order 639 and production records.

[7] Hartz, J., Decker, P., Houle, J., and Swenson, R., 2007, The historical resource and recovery growth in developed fields on the Arctic Slope of Alaska (abs), American Association of Petroleum Geologists Annual Convention and Exhibition Hedberg Conference Proceedings, April 1-7, Long Beach, California, 4 p.

Methane hydrates

Another unconventional resource, methane hydrates, is a huge potential hydrocarbon resource in Alaska, as well as in many locations throughout the world. In 2008, the USGS completed the first assessment of the undiscovered technically recoverable gas hydrate resources on the North Slope of Alaska. Using a geology-based assessment methodology, the USGS estimates that there are about 85 TCF of undiscovered, technically recoverable natural gas resources within gas hydrates in northern Alaska.[8] This untapped resource is a significant addition to Alaska's resource base and will possibly prove to be an important component to gas production in the future. Alaska currently has no production and receives no revenue from this type of unconventional hydrocarbon.

Shale oil

Some explorers in Alaska have begun considering development of unconventional shale oil and gas resources. Lease acquisitions and test well drilling has begun in northern Alaska and has brought considerable attention to the possibility of producing oil and gas from shale in Alaska. The technology necessary to produce oil and gas from shale in the Lower-48 has evolved in the past decade and is now accepted as relatively mainstream. Many oil and gas exploration and production companies of all sizes are participating in the rush to exploit this newly emergent resource. Alaska is now receiving attention as a possible new frontier in this resource play. It remains unclear whether Alaska's shale resource plays can prove productive, much less if they are economically viable or if the technology applications and methods used to produce shale oil in the Lower-48 will translate reasonably well to an Arctic environment, especially considering Alaska's limited infrastructure outside the conventional oil and gas field areas. Alaska currently has no production and receives no revenue from this type of unconventional hydrocarbon.

[8] USGS, 2008, Assessment of Gas Hydrate Resources on the North Slope, Alaska, 2008, USGS FS08-3073, 2 pp.

3. Lease sales

Federal

Onshore

Oil and gas leasing on Alaska's federal onshore lands is concentrated in both the Cook Inlet Region (on both sides of the Inlet) and in the NPR-A which is a 22.8-million acre area on Alaska's North Slope. The U.S. Bureau of Land Management (BLM) conducts annual oil and gas lease sales for onshore federal land. Additional information on federal onshore lease sales in Alaska can be found at the BLM online.[9]

Offshore

The Bureau of Ocean Energy and Management (BOEM) conducts federal lease sales for the Outer Continental Shelf (OCS), which are the submerged lands, subsoil, and seabed, lying between the seaward extent of the States' jurisdiction and the seaward limit of Federal jurisdiction, currently known as the Exclusive Economic Zone. The State of Alaska's seaward limits are extended 3 nautical miles seaward of the baseline from which the breadth of the territorial sea is measured. Federal jurisdiction is established as the 200 nautical mile limit, as defined under treaty and accepted principles of international law. For BOEM OCS leasing information please review their Leasing 101.[10]

University, Mental Health Trust, Native corporation, and private lands

In general, University of Alaska (University) property is available for oil and gas leasing. University property is located throughout the state and currently the University has three oil and gas leases on the Kenai Peninsula, one of which is actively producing. The University's oil and gas leases are awarded on a competitive basis or through direct negotiation. All proposed leases are Public Noticed in local area newspapers, listed on UA's website, with notices sent to the University Board of Regents and legislators. The University's terms and conditions for oil and gas leases are driven by current market economics, and as such, each lease is somewhat unique to the lessee. Additionally, the framework of the lease is a combination of the Alaska Division of Oil and Gas lease structure and the Alaska Mental Health Trust Land Office lease structure; which are detailed later in this report. The University's leasing program actively seeks development and production of oil and gas on its property in an effort to continue support of the University Scholars Program and research programs. Information is available through the University Land Management website.[11]

The Trust Land Office (TLO) manages approximately 1 million acres of land and other natural resources owned by the Alaska Mental Health Trust Authority (Trust). The TLO generates revenue through land leases and sales. The Trust's oil and gas resources are principally located in Southcentral and interior Alaska. The TLO regularly offers Trust land for oil and gas leasing and encourages active development of leased lands. Information is available from the TLO website[12] and their Resource Management Strategy.[13]

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[9] BLM information on federal onshore lease sales in Alaska
http://www.blm.gov/ak/st/en/prog/energy/oil_gas/leasing.html

[10] BOEM OCS Leasing 101
http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/5BOEMRE_Leasing101.pdf

[11] University of Alaska Land Management http://www.ualand.com/

[12] Trust Land Office http://mhtrustland.org/

Alaska Native corporations are private land owners of surface and subsurface oil and gas estates, including lands in the Cook Inlet and the North Slope, as well as lands proximal to state identified frontier basins for which there may be available exploration tax credits. For detailed information on specific privately held Alaska Native corporation lands, please see individual corporations' websites. A list of Alaska Native corporations and links to their individual websites is available online.[14]

In many cases private individual Alaskans own surface, mineral and oil and gas estates in a variety of combinations. These individuals may lease their land for oil and gas and associated development.

These privately structured leases (University, Mental Health Trust, Native corporation, and private individuals) have a variety of different leasing mechanisms, contracts and rules in place and they vary from owner to owner and from lessee to lessee. Agreements between the lessee and the land owner are often held in confidence. Negotiable terms may include a monetary bonus, variations in rental or royalty rates, the primary term and work commitments, among others.

State of Alaska Conventional oil and gas leases

The State of Alaska offers its oil and gas mineral estate for exploration and development primarily under two programs: conventional oil and gas leases (AS 38.05.180) and exploration licenses (AS 38.05.131 – 134). The Alaska Department of Natural Resources (DNR) is charged with preparing and scheduling a five-year proposed oil and gas leasing program. A detailed description of the state's leasing programs and schedule, including location information for lease sales that will be held in the next five years, is updated annually and is available to view or download from the DNR Division of Oil and Gas website.[15]

In 1998, DNR changed the way it offered state lands for competitive bid oil and gas leasing for the North Slope, North Slope Foothills, Beaufort Sea and Cook Inlet areas. These are the areas designated by the state as having moderate to high potential for oil and gas development. So-called "areawide leasing" became the standard for lease sales so that the state could provide stability and predictability in the lease sale program. In 2004, the Alaska Peninsula was added to the list of areas offered by the state under the areawide leasing program. Under areawide leasing, the state offers all available state-owned land within these five areas for lease by competitive bidding at annually scheduled lease sales. Prior to adoption of areawide lease sales, DNR used a nomination process and wrote best interest findings for each sale.

Conducting annual areawide sales is more cost-effective because it allows companies to plan for and develop their exploration strategies and budgets years in advance and to bid on any available acreage within an entire region. A regular schedule of areawide lease sales allows for quicker turnaround of expired or terminated leases, or leases contracted out of units, for reoffer in the next annual sale. The result is more efficient exploration leading to earlier development and production decisions. It also allows smaller companies and individuals the opportunity to acquire leases in areas of lesser interest to the major oil companies.

Leasing methods

Alaska has several leasing method options designed to encourage oil and gas exploration and maximize state revenue, as described in AS 38.05.180(f). These methods include combinations of fixed and variable bonus bids, royalty shares, and net profit shares. Minimum bids for state leases are generally $5 or $10 per acre. Fixed royalty rates are generally 12.5 percent or 16 and

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[13] Trust Land Office Resource Management Strategy http://mhtrustland.org/wp-content/uploads/2014/05/Resource-Management-Strategy.pdf

[14] Alaska Native Corporations and links http://www.ncai.org/tribal-directory/alaska-native-corporations

[15] "Five-Year Program of Proposed Oil and Gas Lease Sales," January 2014: http://dog.dnr.alaska.gov/

two-thirds percent, although some have been as high as 20 percent. A sliding scale royalty has also been used on occasion. Lease terms are set at 5, 7, or 10 years, depending on geographical location.

Several months before a scheduled sale, a geologic and economic evaluation of the sale area is prepared to determine the general bidding method, leasing method and the lease terms for the sale. Public notice of the sale is sent out to an extensive mailing list maintained by the Division of Oil and Gas. Leases in areawide sale areas must be offered by competitive bidding. Leases are issued to the highest responsible qualified bidder.

Historical lease sale data

The state has conducted 68 areawide sales since 1998 in the five areas mentioned above.[16] Reviews of sale results, summarized by year, indicate the levels of participation and interest from bidders for leasing in Alaska over the past decade. Figure 3-1 includes data for leases sold, acres sold, bonus bids received, and participation by bidder class for the period 2000 through 2014. During that time, over 2,700 tracts totaling 9.3 million acres of state land have been awarded, resulting in a cumulative total of $237.6 million in bonus bids received (Figure 3-2).

Figure 3-3 shows participation levels by bidder class as a percent of total tracts leased in State of Alaska competitive oil and gas lease sales from 2000 through 2014. For example, in 2000 the major oil companies bidding alone acquired 13 percent of all tracts sold by the Alaska DNR in all of the competitive oil and gas lease sales, major and/or active independent companies bidding together as a consortium acquired 44 percent, active independent oil companies bidding alone acquired 26 percent, and very small companies and/or individuals bidding alone or together as bidder consortiums acquired 17 percent of tracts sold. In general, recent lease sales have seen active independent oil and gas companies acquiring the greatest share of leases in DNR lease sales.

Exploration licenses

Exploration licensing supplements the state's oil and gas leasing program and encourages oil and gas exploration on DNR administered lands outside of the known oil and gas provinces in the North Slope, Beaufort Sea, Cook Inlet, Alaska Peninsula, and North Slope Foothills areawide sale areas. The DNR is currently administering five existing and two proposed exploration licenses (Figure 3-4). The holder of an oil and gas exploration license has the exclusive right to explore an area between 10,000 acres and 500,000 acres in size for a term of up to 10 years. Rather than an up-front bonus payment to the state, as is done in competitive leasing, a licensee must commit direct expenditures for exploration. Because a license has no annual rental payments, the only money guaranteed the state is a one-time $1 per acre licensing fee, which is paid upon acceptance. However, the state is provided most of the geological and geophysical information acquired by the licensee, and so it can gain a better understanding of an area's resource potential.

Each application for an exploration license must go through a public notice and written finding process to determine whether issuance of a license is in the state's best interest. DNR first issues a notice of intent to evaluate the exploration license proposal and solicits any competing proposals for the area. The department then requests public comment on the proposal(s) and goes through a best interest finding process similar to that for oil and gas leasing to determine whether issuing a license for the area is in the best interest of the state. If competing proposals are submitted for an area, the applicants must submit sealed bids. If DNR finds that an exploration lease is in the State's best interests, the successful bidder is determined by the highest bid in terms of the minimum work commitment dollar amount. Exploration license bidders must all be qualified by DNR for their bid to be accepted.

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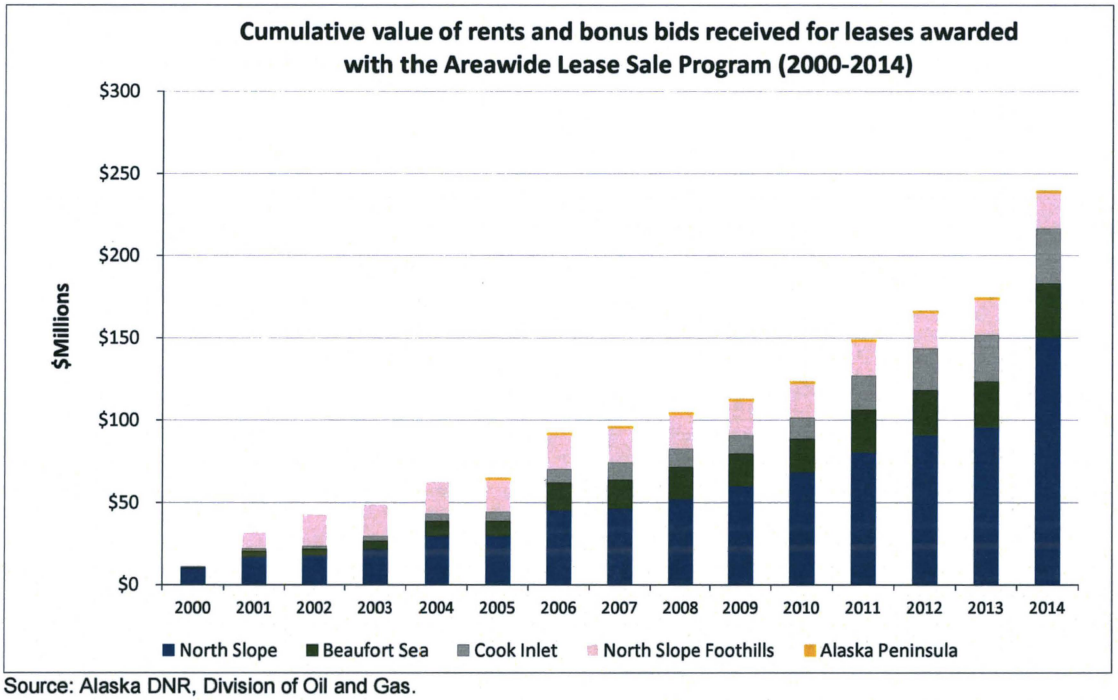
[16] 1998 to 2014 areawide sales: 16 were in the North Slope, 17 in Cook Inlet (added in 1999), 14 in Beaufort Sea (added in 2000), 13 in North Slope Foothills (added in 2001), and eight in Alaska Peninsula (added in 2005).

Figure 3-1. Alaska DNR competitive oil and gas lease sale results summary with all lease sales summed together by year.

Year	Total Tracts Sold	Total Acres Sold	Total High Bonus Bids Received [$ MM]	Average Winning Bid Per Acre	Number of Lease Sales Held	Major Oil Company Tracts Acquired	Major &/or Independent Consortium Tracts Acquired	Active Independent Tracts Acquired	Small Co. & Individual Investor Tracts Acquired
	Annual Totals, All Sales					Annual Total, Tracts Acquired by Bidder Classification			
2000	183	753,252	$ 11.066	$ 14.69	3	24	80	47	31
2001	322	1,432,604	$ 21.087	$ 14.72	4	30	68	145	81
2002	87	329,737	$ 4.398	$ 13.34	4	4	32	40	16
2003	123	326,630	$ 5.671	$ 17.36	4	5	-	87	31
2004	162	558,757	$ 13.564	$ 24.28	4	11	4	126	21
2005	104	420,660	$ 2.514	$ 5.98	3	33	-	38	33
2006	363	1,320,022	$ 30.160	$ 22.85	6	42	29	140	152
2007	85	247,256	$ 3.748	$ 15.16	5	15	-	8	62
2008	115	348,135	$ 8.383	$ 24.08	5	1	1	81	32
2009	85	314,838	$ 8.150	$ 25.89	4	-	-	76	9
2010	197	767,858	$ 11.346	$ 14.78	6	1	-	9	199
2011	342	981,694	$ 25.898	$ 26.38	5	72	-	209	65
2012	160	406,541	$ 17.837	$ 43.87	5	77	3	103	24
2013	115	260,583	$ 8.251	$ 31.66	5	-	-	117	2
2014[1]	335	759,701	$ 64.968	$ 85.52	5	-	2	319	14
Totals	2,778	9,228,267	$ 237.038		68	315	219	1,545	772

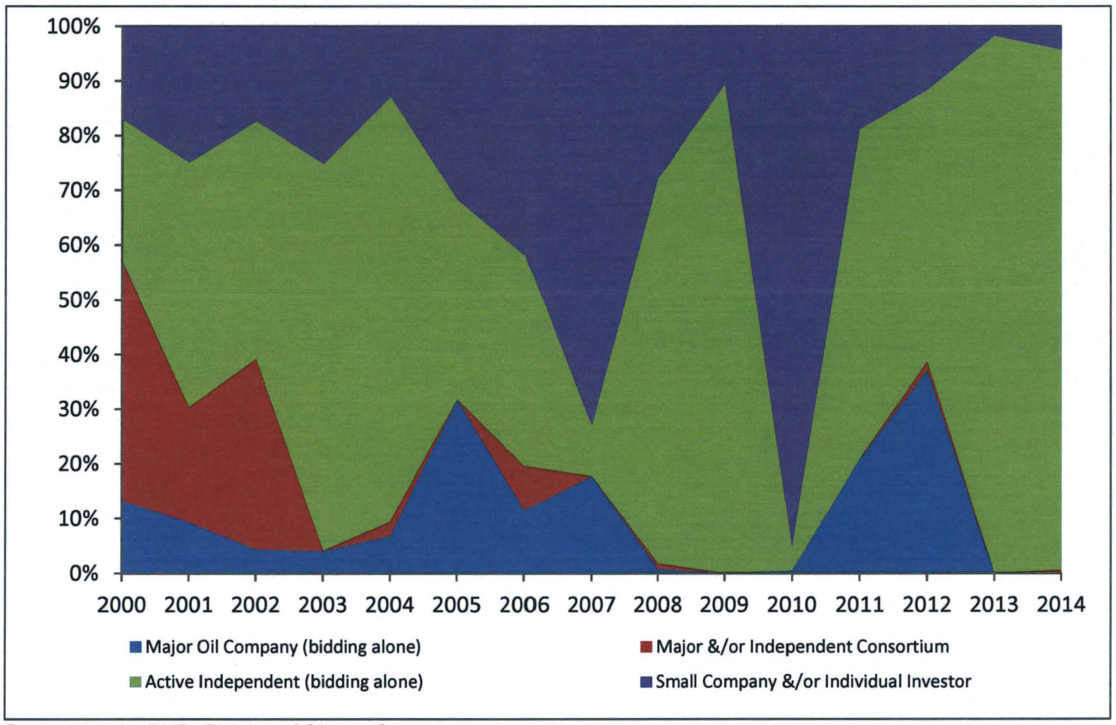
[1]Data based in-part on preliminary sale results, values will likely change when final results are available.
Source: Alaska DNR, Division of Oil and Gas.

Figure 3-2. Cumulative value of rents and bonus bids received for oil and gas leases administered by DNR.



Source: Alaska DNR, Division of Oil and Gas.

Figure 3-3. Participation levels by bidder class as percent of total tracts sold in Alaska DNR competitive oil and gas lease sales.



Source: Alaska DNR, Division of Oil and Gas.

Figure 3-4. Existing and proposed oil and gas exploration licenses administered by the Alaska DNR in January 2015.

Location	ADL[1]	Status	Licensee	Acres	Work Commitment	Effective Date	Term
Healy Basin	390606	Active	Usibelli Coal Mine Inc.	204,883	$500,000	1/1/2011	10 Yrs
Susitna Basin IV	391628	Active	Cook Inlet Energy LLC	62,909	$2,250,000	4/1/2011	10 Yrs
Susitna Basin V	391794	Active	Cook Inlet Energy LLC	45,764	$250,000	4/1/2012	5 Yrs
Tolsona	392209	Active	Ahtna, Inc.	43,492	$415,000	12/1/2013	5 Yrs
Southwest Cook Inlet	392536	Active	Cook Inlet Energy LLC	168,581	$1,501,000	10/1/2014	4 Yrs
Houston-Willow Basin	391282	Application	LAPP Resources Inc.	21,080	$500,000	Proposed	10 Yrs
North Nenana	392535	Application	Rocky Riley	25,600	$500,000	Proposed	5 Yrs

[1]ADL is the Alaska Division of Lands case number (lease) prefix or identifier.
Source: Alaska DNR, Division of Oil and Gas.

4. Exploration and development activity

The oil and gas industry worldwide, like many resource extraction industries, is known for its "boom and bust" cycles. There are many different causes of booms and busts. Booms could be brought on by sudden demand for a resource, high sales prices, technology breakthroughs that make the resource extraction more attractive economically, or an easing of regulations on the resource to be extracted. Busts are often caused by the exact opposite of what created the boom in the first place, or they could signal a depletion of the resource in a particular locality.

It is not difficult to identify a booming industry. In the case of oil and gas production, common indicators include the number of active drilling rigs, the number of persons employed, and the number of wells drilled. A booming oil or gas development will attract other companies, increasing competition for leases, drilling rigs, support services and equipment, and housing and office space may be in short supply.

Drilling activity in Alaska

Drilling activity, including the number and type of wells drilled, is an indicator of oil and gas industry activity. The Alaska Oil and Gas Conservation Commission (AOGCC) authorizes and monitors permits to drill for oil and gas and other oil and gas related subsurface activities in Alaska. The AOGCC web site[17] provides detail on the number and types of oil and gas wells drilled in Alaska from 2000 to 2014. We have reproduced below several of the charts that the AOGCC included in their online presentation.

Exploratory wells

Figure 4-1 shows the number of exploratory wells and wellbores that were completed, suspended or abandoned in the years 2000 through 2014. The numbers on each column indicate the number of companies that contributed to the number of wells shown. Figure 4-1 shows a significant amount of exploration well activity in 2001 through 2004, a substantial drop in activity began in 2008 and lasted through 2011and then an increase of exploration activity occurred, back to higher historic levels. It is worthy of note that drilling of exploration wells in Alaska is at a much lower level than our entire selected peer group.

Development and service wells

Figure 4-2 shows the number of development and service wells and wellbores that were completed, suspended or abandoned in the years 2000 through 2014. Like the previous figure, the period from 2000 through 2004 shows a steady, relatively high rate of well development, with a drop in activity beginning in 2005 and continuing through 2011. Development drilling remained low through 2013 and then saw a substantial increase in 2014. As with exploration drilling, drilling of development and service wells in Alaska is at a much lower level than our entire selected peer group, especially in the Llower-48 states.

Drilling rig counts

The number of drilling rigs in an oil and gas jurisdiction is also an indicator of petroleum-related activity. The AOGCC tracks drilling and workover rig activity within Alaska. Figures from the 2011 presentation, shown as Figure 4-3 and Figure 4-4, indicate that well workover activity has been healthy throughout the years shown in the graphs but again, at a much lower level than any jurisdiction within our selected peer group.

[17] The AOGCC web site is found at http://doa.alaska.gov/ogc/

Figure 4-1. Exploratory wells and wellbores in Alaska (statewide). Includes all exploration wells that were completed, suspended or abandoned between 1999 and 2013. Background graphic shows West Coast spot price for Alaska North Slope crude oil (dollars per barrel).

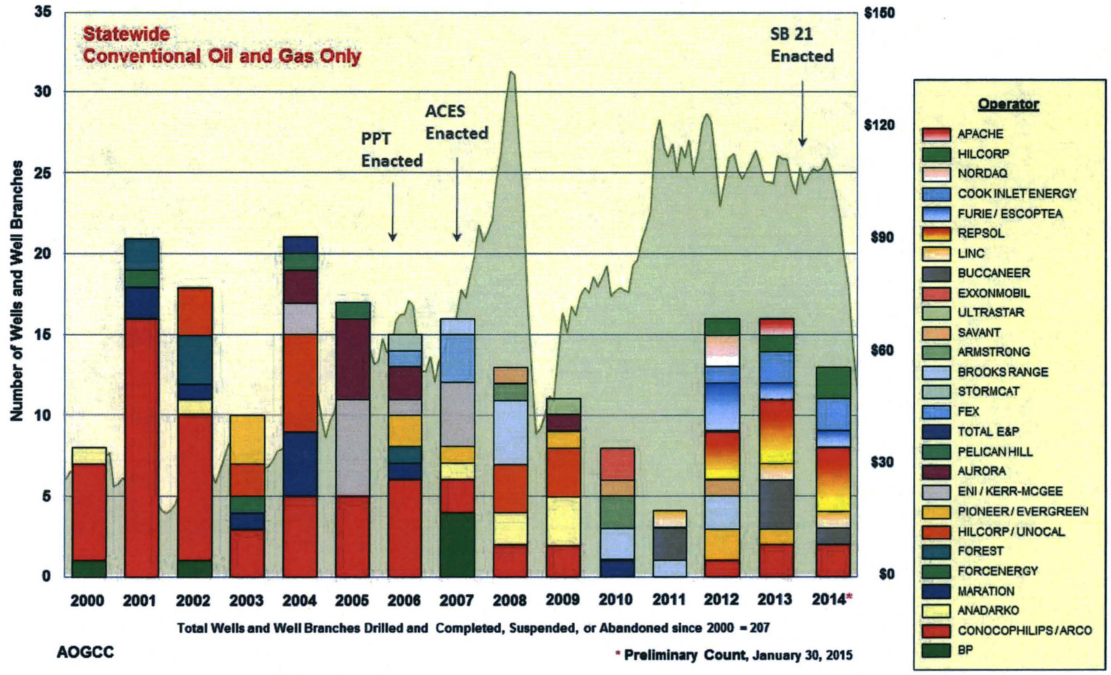


Figure 4-2. Development and service-class wells and wellbores in Alaska (statewide). Includes all development and service wells that were completed, suspended or abandoned between 2000 and 2014. Background graphic shows West Coast spot price for Alaska North Slope crude oil (dollars per barrel).

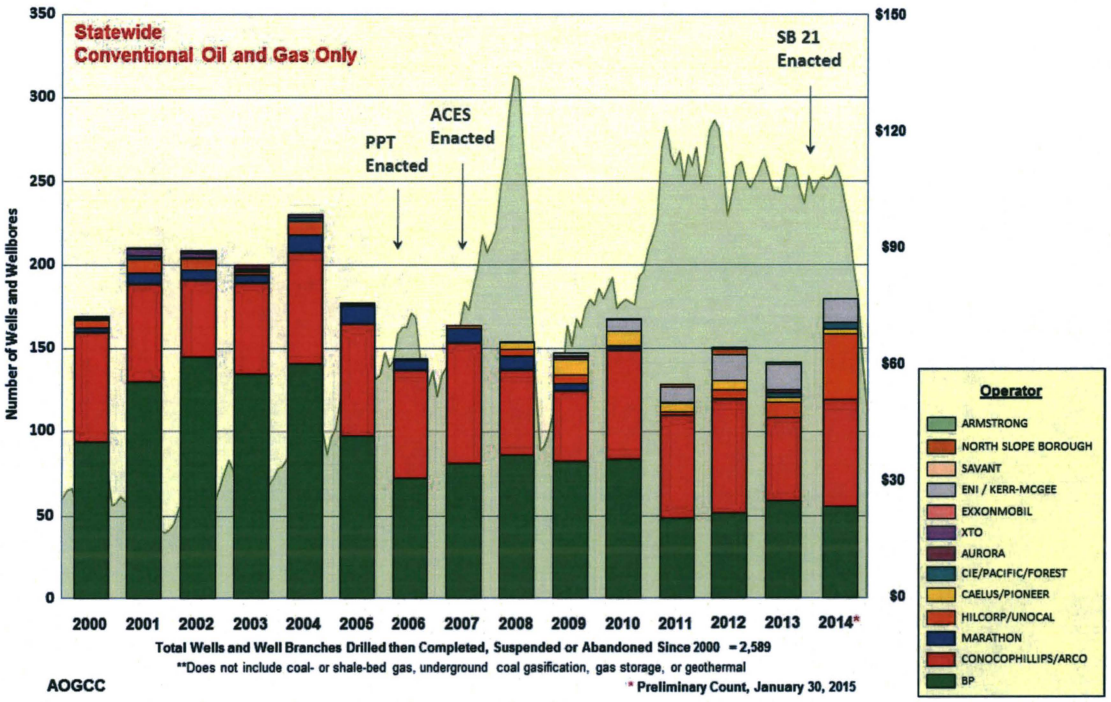


Figure 4-3. Alaska's combined active drilling rigs and workover rigs for each quarter from 2005 through 2014.

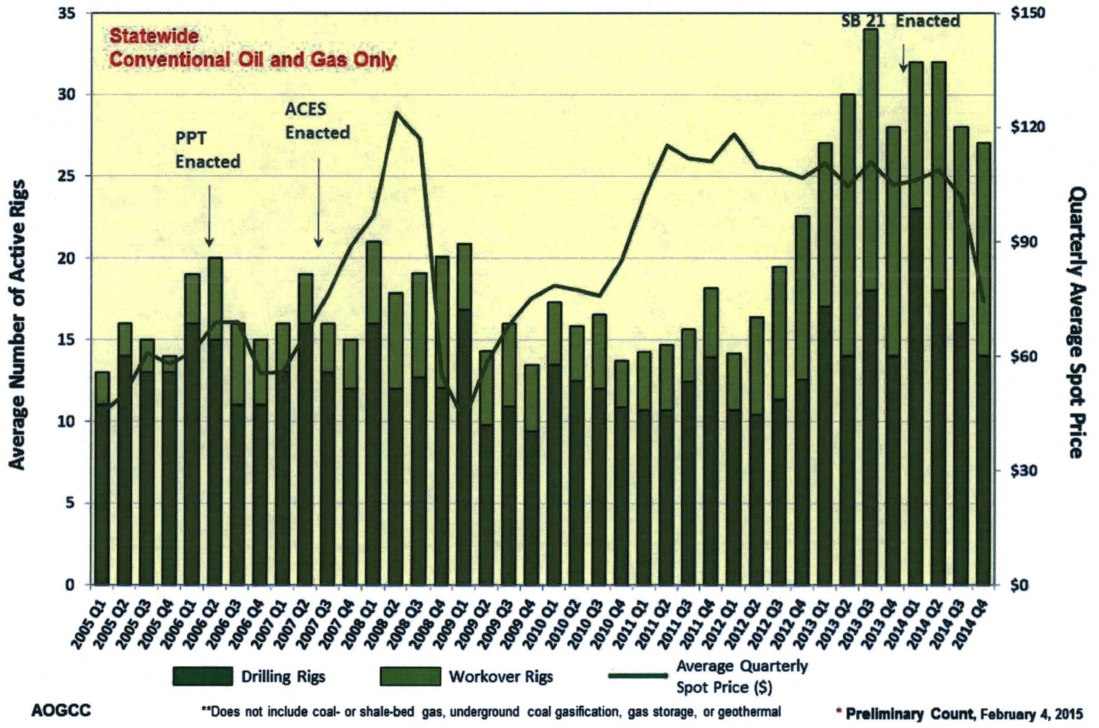
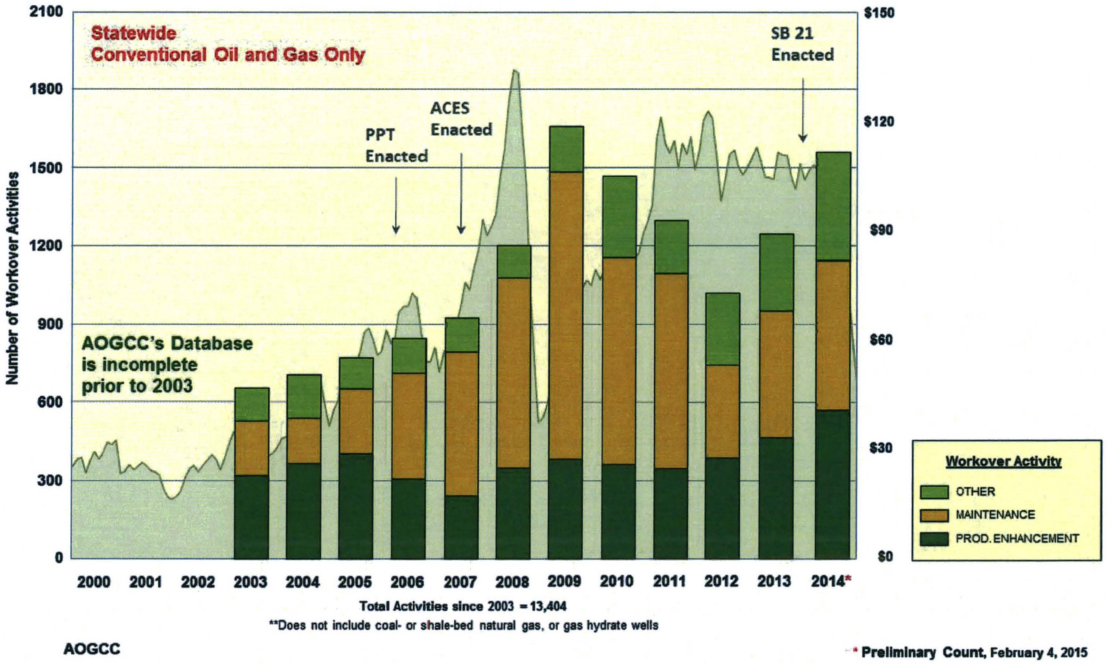
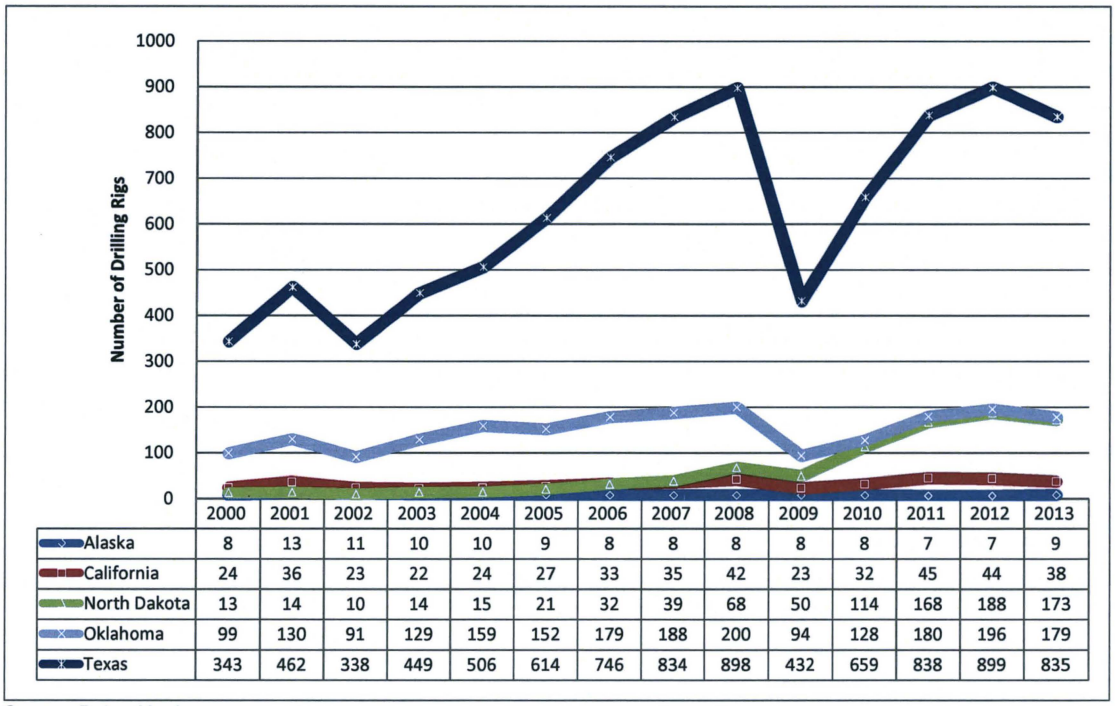


Figure 4-4. Number of Alaska's well workover activities by calendar year, from 2003 through 2014.* Solid line represents West Coast spot price for Alaska North Slope crude oil (dollars per barrel).



Baker Hughes, an oilfield service company that operates in 80 countries, has been providing counts of rotary rigs for the petroleum industry for over 65 years. Although not as detailed as the information provided by the AOGCC, the rig counts provided by Baker Hughes can be viewed relative to other oil and gas provinces over a given time period. Figure 4-5 shows a comparison of annual average rotary rig counts in Alaska and four other oil and gas-producing states from 2000 through 2013. We note that the data show a dip in rig counts in all states except Alaska in 2009, followed by an increase in rig counts in all states except Alaska in 2010. According to Baker Hughes, the annual average rig count for Alaska has remained flat since 2006. In the other four states, rig counts increased at least 28 percent between 2009 and 2010, and in North Dakota, the number of rotary rigs more than doubled.

Figure 4-5. Number of drilling rigs by state.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Alaska	8	13	11	10	10	9	8	8	8	8	8	7	7	9
California	24	36	23	22	24	27	33	35	42	23	32	45	44	38
North Dakota	13	14	10	14	15	21	32	39	68	50	114	168	188	173
Oklahoma	99	130	91	129	159	152	179	188	200	94	128	180	196	179
Texas	343	462	338	449	506	614	746	834	898	432	659	838	899	835

Source: Baker Hughes.

Investment in North Slope oil and gas

Investment in the oil and gas industry since exploration began in Alaska has been substantial. Exploration, development and production costs have been high throughout the state since oil was first produced at Katalla in 1902. The North Slope of Alaska is remote, and prior to oil and gas development had no roads or facilities close to where the development would be. To date, the area has only one road connecting it with the rest of the state, which is itself remote from the other states in the U.S. The amount of investment that had to occur in order to explore for and develop the North Slope's oil and gas resources, and to transport oil to markets, was an order of magnitude higher than the amount of investment required to produce and transport oil in much of the Lower-48 states. Although Alaska does not have any official records, estimates for the initial development of the major North Slope fields are in the tens of billions of dollars.

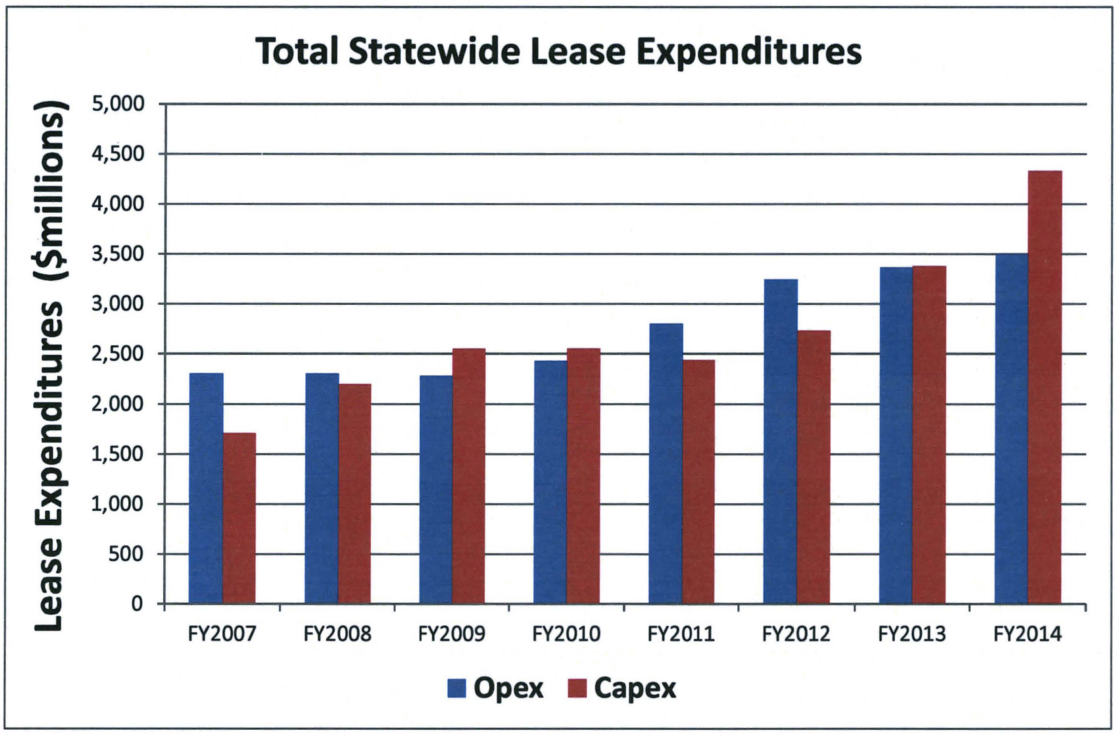
Since that time, over 17 billion barrels of oil have been produced and sent through facilities that were constructed in the 1960s and 1970s. In recent years, the aging infrastructure has begun to show signs of the years of wear. Shortly after major pipeline leaks in 2006, BP Exploration (Alaska) Inc. undertook several large-scale projects to improve the integrity of the pipelines, flow-

lines, and associated facilities. The project cost hundreds of millions of dollars and required a significant increase in the labor force.

Investment can be broken down into capital expenditures and operating expenditures, both of which are deductible under the ACES production tax. Capital expenditures are the type of expenditures most often associated with property development and improvements. With the passage of a production tax on net profits, the State of Alaska began to receive information about the amount of investment in North Slope oil and gas operations. Although much of this information has yet to be audited, it provides some estimates with which to assess investment in oil and gas in Alaska.

Company reported operating and capital expenditures (opex and capex) from 2007 through 2014 is shown in Figure 4-6 and shows that statewide both opex and capex show a long-term trend of increases with noticeable increases in capex in 2013 and 2014.

Figure 4-6. Statewide operating expenditures (opex) and capital expenditures (capex).



Figures 4-7 and 4-8 splits opex and capex spending into two categories, with Figure 4-7 showing spending on the North Slope and Figure 4-8 showing spending in Cook Inlet and non-North Slope areas. North Slope spending reflects the statewide spending seen in the previous figure, because the magnitude of the spending on the North Slope is dramatically higher than spending in Cook Inlet and non-North Slope areas. Spending in the rest of the state when extracted from the statewide data shows much greater variability than the North Slope, but here, too, significant increases in spending have occurred in recent years.

Figure 4-7. North Slope opex and capex.

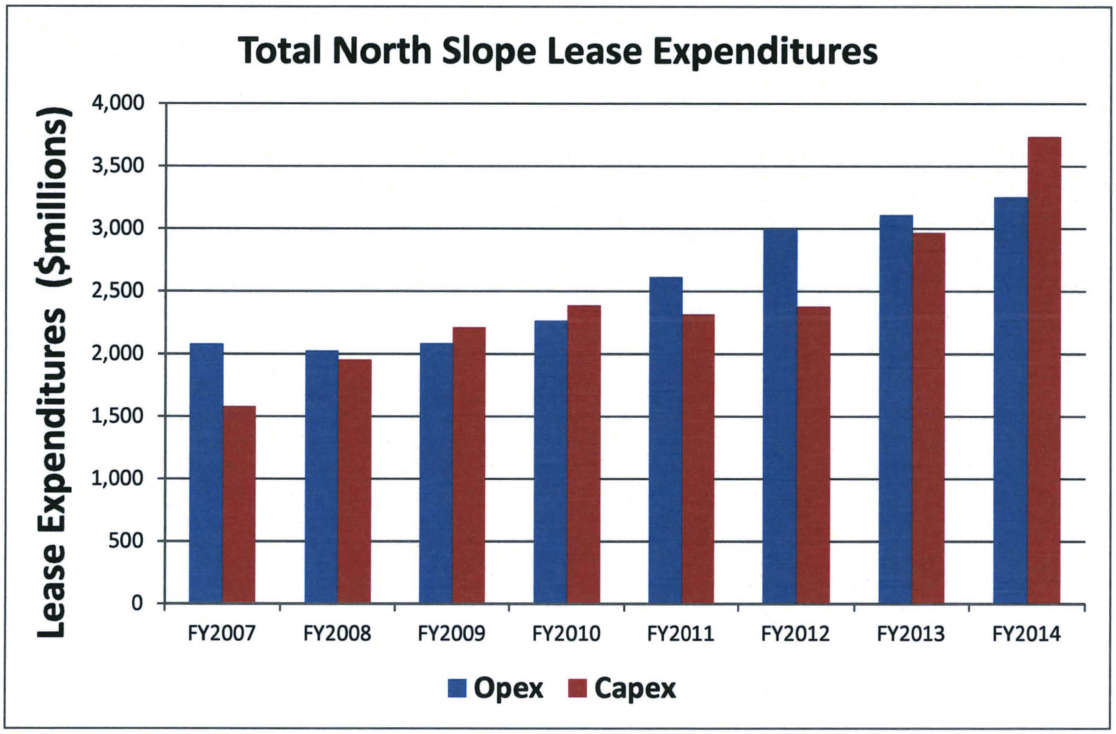
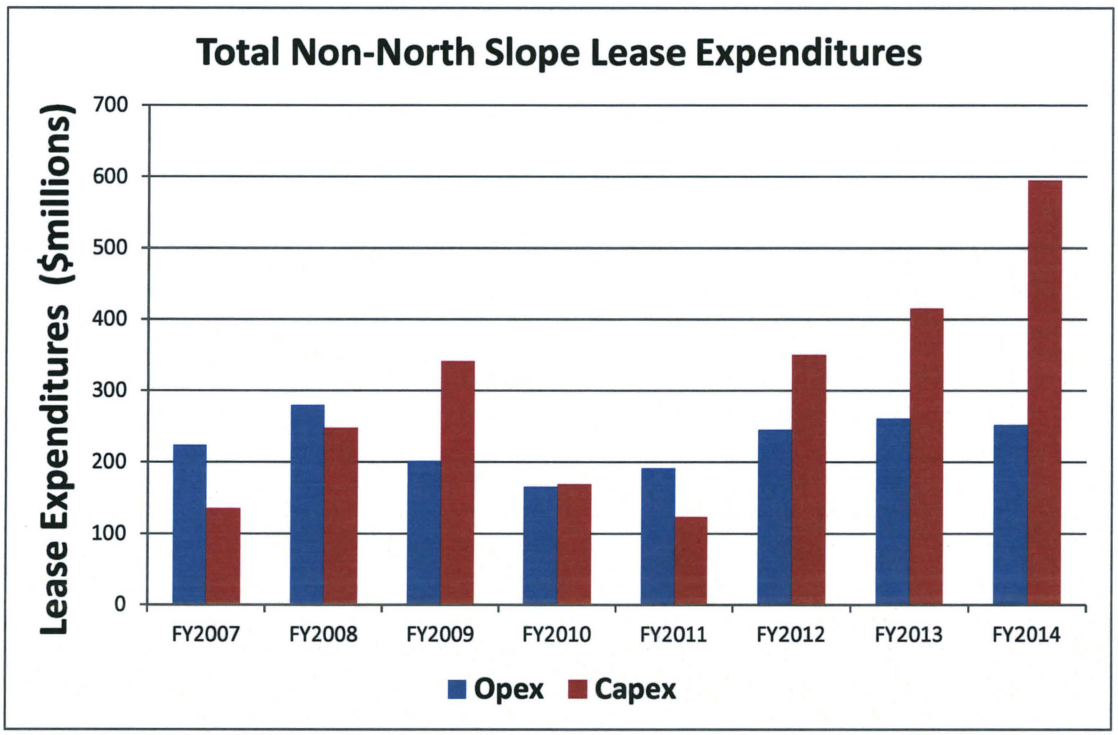


Figure 4-7. Cook Inlet and non-North Slope opex and capex.



5. Status of the oil-and-gas-related infrastructure in Alaska

The oil and gas infrastructure is well established in Cook Inlet and on the North Slope of Alaska, albeit very localized, with production linked to market by pipelines crossing vast areas of undeveloped lands. Infrastructure plays an important role in exploration and development and can have a direct effect on costs and new field economics. Much of Alaska's oil- and gas-related infrastructure is privately owned or controlled by the working interest owners of Cook Inlet and North Slope assets, whether single owner operators or combined working interest owners. In addition, oil and gas resources are brought to market by infield flowlines, joining with individual or other consortium owned common carrier pipelines, like the TAPS from the North Slope or lines surrounding Cook Inlet. Common carrier oil, condensates or dry gas pipelines are regulated by the Federal Energy Regulatory Commission (FERC) and the Regulatory Commission of Alaska (RCA).

North Slope

The North Slope oil and gas industry exists because the construction of the TAPS enabled transportation and marketing of the stranded North Slope oils of Prudhoe Bay and other associated fields. This 800 mile pipeline system extends from Pump Station One, in the vicinity of Deadhorse to Valdez. In Valdez, TAPS ends at the Valdez marine terminal where North Slope crude oil is shipped by tanker to U.S. West Coast refineries. The system is operated by the Alyeska Pipelines Service Company[18] and its subsidiaries, while tankers are controlled by the producer companies. To date, over 17 billion barrels of oil have been transported from the North Slope to the West Coast.

TAPS is a common carrier pipeline regulated by both FERC and RCA, with tariffs per barrel for oil transported ranging from $4.37 in 2011 to $6.68 in 2014. Within the North Slope operating fields, six common carrier pipelines bring oil to TAPS with charges in 2014 ranging from $0.36 for the Kuparuk Pipeline to $12.25 for the Badami Pipeline. The list of regulated pipelines and tariffs can be found at the DNR's web site.[19] Common carrier pipeline use is a cost factor to consider in expanding infrastructure on the North Slope.

The oil and gas field-related infrastructure of the North Slope, while permitted for development and regulated for operation by the State of Alaska, is predominately owned and operated by the oil and gas industry. The state maintains access to the North Slope via the Dalton Highway for road traffic, via the Deadhorse airport for air cargo and personnel, and via shipping regulations and pilotage, when required, for landings from the Beaufort Sea. Entry from the Dalton Highway into Deadhorse, Alaska is public, but access on the North Slope beyond the immediate Deadhorse area is restricted and controlled. Within Deadhorse, the transportation and utility infrastructure is managed by the Alaska Department of Transportation and Public Facilities (DOT/PF) and the North Slope Borough. Once departing Deadhorse, all transportation on the privately maintained roads must be approved by the North Slope unit operators. Transport of marine cargo must be done at private landings and docks and approved by the owners/operators of the specific infrastructure being used. A final restriction applies to air traffic over the North Slope. While air traffic has the right of free passage within restrictions established by the FAA, the use of private landing strips is restricted to those who have approval for the use of the facility.

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[18] Alyeska Pipelines Service Company is owned by a consortium of companies including the biggest producers of crude oil on the North Slope.

[19] The list of regulated pipelines and tariffs can be found at http://dog.dnr.alaska.gov/Commercial/PipelineTariffs.htm.

The North Slope infrastructure was recently updated into the "Alaska Department of Natural Resources 2014 North Slope Infrastructure Atlas", an atlas based on data from many sources, including working interest owners and operators. The atlas depicts the following:

- Pads and wells
- Processing facilities and pipelines
- Transmission and utility corridors
- Roads, air strips and fields, and coastal landings
- Bridges and culverts
- Borrow sites and mine sites

It is important to note that the current atlas does not include new developments at Point Thomson and the expansion of infrastructure from the Alpine field into the federal lands of NPR-A. Maps in this atlas are available by request to the DNR Division of Mining, Land and Water (DMLW), Resource Assessment and Development Section.

The infrastructure of the North Slope is being expanded to the east with the development of Point Thomson and the carrier line for gas condensate, which is sized to accommodate flow up to 70,000 barrels per day. Future infrastructure development will reflect expansion of operations and production at Point Thomson and at other leases held with access to the new line and infrastructure that will join with TAPS.

The infrastructure of the North Slope is being expanded to the west with the development into NPRA for Moose's Tooth and potentially to additional pads, as well as the exploration and development of the Greater Moose's Tooth unit. The newly constructed bridges across the channels of the Coleville River and gravel roads will allow for efficient development of the NPRA resources. This advancement will continue under federal regulatory control, but will depend on the state infrastructure in place.

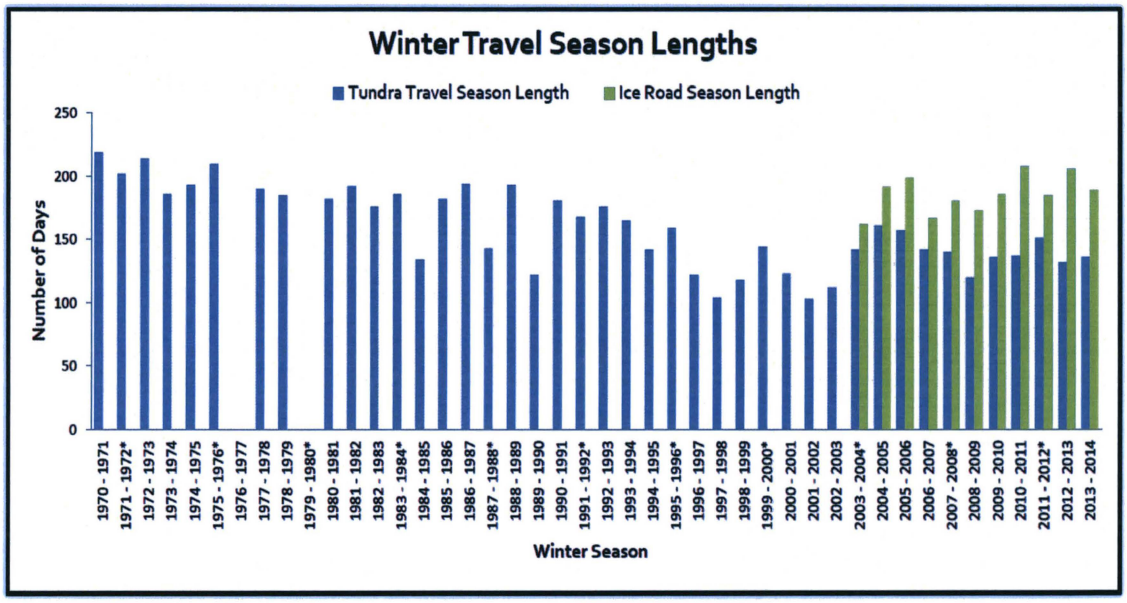
Future development of the Beaufort Sea is being planned as companies, including Repsol and Hilcorp explore leases in both state and federal waters. While plans have been announced and some exploratory drilling has been completed, decisions that will create infrastructure are yet-to-be-determined.

In considering the infrastructure of the North Slope, it is important to recognize the advantages of development near existing infrastructure. All production will likely pass through TAPS and exploration and development costs are lower near the Dalton Highway and Deadhorse. Access may require facility sharing agreements to utilize existing infrastructure for new development and production. New operators will need to recognize the risks, liabilities, and opportunities that come with North Slope oil and gas exploration and development. These points are important to consider in judging the competitiveness of Alaska, in accessing state leases, and in investing in development and the associated new infrastructure.

Outside of established infrastructure, the importance of ice roads and ice pads cannot be emphasized enough, as these are critical to development of the oil and gas resources while protecting the tundra. Ice road construction and off-road travel is regulated by seasonal environmental conditions that are monitored by the DMLW, Northern Regional Office (NRO). Tundra opening areas have been established throughout the North Slope. The date of tundra opening has ranged from as early as November 4, to as late as February 20. The tundra is closed when it appears as if thawing conditions have resulted in snow that will be too soft or too limited to permit travel without resulting in damage to the tundra. Once the tundra has been opened in the winter, there are no restrictions on the type of vehicles that may operate on the tundra

provided that vehicle operation does not negatively impact the tundra. The general winter off-road travel season has declined over the years (Figure 5-1). With concern for declining winter off-road travel season, NRO has developed best practices for early winter season tundra access. Innovations in ice road construction techniques and low impact vehicles have continued to stem the season's decline.

Figure 5-1. Winter travel season length approved from 1970 through 2014. Note the addition of ice road seasons based on best practices established with research studies beginning in 2003



Infrastructure deficiencies

Presently, the existing producers likely see no significant infrastructure deficiency identified in or near existing fields because the operators and the State have invested in developing and maintaining infrastructure over the more-than-40 years of development and production in the area. However, because much of Alaska's resource potential is in remote areas far removed from Prudhoe Bay, infrastructure costs will continue to be a hurdle to bringing new discoveries on-line, unless production rates and overall reserve volumes are of sufficient size to justify the capital expenditures for new infrastructure.

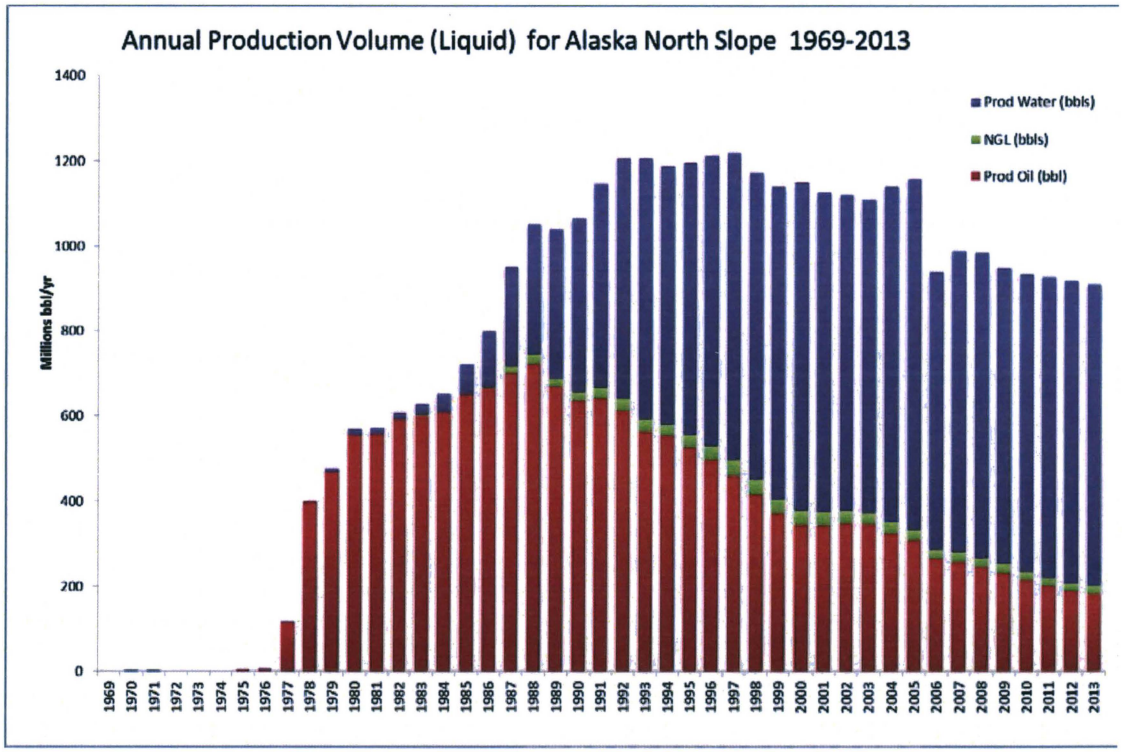
While not a deficiency, but relevant to the tundra travel season, is incident response. Given the history of operation of the North Slope with road less access to infrastructure, a specific challenge remains with access to Roadless infrastructure and facilities during an oil or gas incident. The Northstar, Badami, Alpine, and future Point Thomson pipelines are road less, as are many infield pipelines. Access to a location with a pipeline leak that occurs outside of approved tundra travel times could involve an extended duration, considerable expense and a long outage if a large amount of heavy equipment is required for repair. Even in winter, construction of an ice road will take time. The response capabilities to minor incidents have proven successful, but response to a major spill in road less areas is untested. The challenges of access to respond to incidents, including liabilities and costs involved, should be listed as a factor in considering Alaska's competitiveness.

One important point is the challenge of managing significant and increasing quantities of water produced with crude oil from mature reservoirs (Figure 5-2). Since 2010, the ratio of water production to oil and natural gas liquids (NGL) has been greater than 75% water to less than 25% oil and NGL's produced. Increasing water production, in part due to water flooding and enhanced recovery methods employed by North Slope operators, will either require increased water

handling capability or eventually may lead to accelerated decline in oil and NGL production. Similarly, natural gas production in some fields may also increase over time. As with water, increased use of gas handling facilities on the North Slope is an integral part of maintaining enhanced oil recovery. It is the combination of these approaches that add to the competitive challenge of Alaska, but are integral in sustaining production and managing decline of its mature fields.

With the decline in production of the North Slope over time, the volume in the TAPS and costs of operating and maintaining flow is an additional issue of competitiveness. While the TAPS is not deficient in transporting the oil from the North Slope to Valdez, it is facing challenges with reduced flow and age-related wear. One concern is the level of infrastructure required to keep the oil flowing during all contingencies in all seasons. Alyeska believes that TAPS has sufficient heating capacity for typical flow and average weather conditions. However, the outcome from a combination of atypical conditions is unknown. These might include unusually cold and long-duration weather fronts or upsets that reduce throughput, such as tanker loading problems, mechanical or electrical problems in TAPS or production upsets or facilities shutdowns on the North Slope. In oil, there is a small portion of water that cannot be economically removed. This is the subject of a consent agreement with Pipeline and Hazardous Materials Safety Administration (PHMSA), CPF 5-2011-5001S. Because low temperature operation and restart is a concern involving a single, long upset or a string of incidents, the scenario remains and should be listed as a concern, not as a deficiency, and be considered in the future of Alaska's North Slope oil and gas competitiveness.

Figure 5-2. North Slope liquids production since the discovery of Prudhoe Bay field in 1969. Liquids production may be a significant factor in the workforce level and investment in maintenance and technology to sustain North Slope production at or above a nominal decline rate.



Cook Inlet

The oil and gas fields of Cook Inlet and the surrounding area have been in production since 1960

on federal, state and private lands. Figure 5-3 is a map published by the Alaska DNR Petroleum Systems Integrity office. Additionally, a map of the existing oil and gas pipelines in Cook Inlet is available DNR's website.[20] Figure 5-4 shows the tariff rates and ownership of common-carrier pipelines in Cook Inlet are available through Federal Energy Regulatory Commission (FERC) and the Regulatory Commission of Alaska (RCA).

Cook Inlet has 34 units or fields recognized by DNR. Of these, 32 have a history of production of natural gas, oil or both. All are connected to infrastructure to bring the produced oil or gas to processing facilities. The inlet has 16 platforms with 2 shut in and others either producing natural gas and/or oil or being reworked to increase their production capability. Infrastructure includes oil pipelines and dockage for refining at the Tesoro refinery on the east side at Nikiski and the oil loading terminal on the west side at Drift River. The Nikiski Alaska Pipeline is the sole oil carrying pipeline to transport refined product from the Tesoro refinery to Anchorage, allowing fuel distribution from the Port of Anchorage to the Ted Stevens International Airport.

Natural gas pipelines cross the inlet from production platforms and onshore producing fields to common carrier lines on both the east and west side of Cook Inlet. This allows for natural gas to be transported from the production areas to markets in southcentral Alaska. Pipeline corridors run from Homer and Anchor Point, along the west coast of the Kenai Peninsula to Nikiski and further north and east to Anchorage, gathering additional production from the Kenai and Swanson River fields. Additional pipeline corridors carry gas from the Drift River to Anchorage, Palmer and Wasilla. The Cook Inlet Gas Gathering System (CIGGS) joins both pipeline corridors to allow for flexibility in flow direction to prevent service disruption.

During a period of concern for natural gas supply, a series of gas storage facilities were developed. Currently, the Cook Inlet Natural Gas Storage facility is in operation as well as other storage pools associated with different fields. Gas storage remains available to accommodate excess gas produced with increased drilling of new wells and the re-working of older wells throughout Cook Inlet's gas producing units and fields.

Frontier basins and exploration license areas

Surface access and infrastructure remain a hurdle in exploring for oil and gas resources in frontier basins, defined here as areas away from population centers and existing oil and gas production facilities. Exploration license areas (Figure 5-5) are areas of state land, outside the areawide sale areas, that are available for proposals to explore for oil or gas. Generally these areas are lacking in infrastructure and require review (finding) for the exploration to be in the best interest of the state. A best interest finding will detail mitigation measures to protect the environment and regulate activities, thus establishing standards for exploration and methods of access and infrastructure.

Six frontier basins (Figure 5-6) were established by the State of Alaska for exploration tax credits, in-part because of their lack of necessary infrastructure to efficiently access exploration prospects. However, unlike exploration licenses which apply only to state lands, frontier basins may include federal, state and private lands. The regulation of access and infrastructure may involve multiple regulatory agencies and is determined by the surface owner and the standards by which surface access and infrastructure is managed.

[20] http://dog.dnr.alaska.gov/GIS/Cookinletpipelines.htm

Figure 5-3. Oil and gas infrastructure in the Cook Inlet basin showing pads, platforms, and oil and gas pipelines.

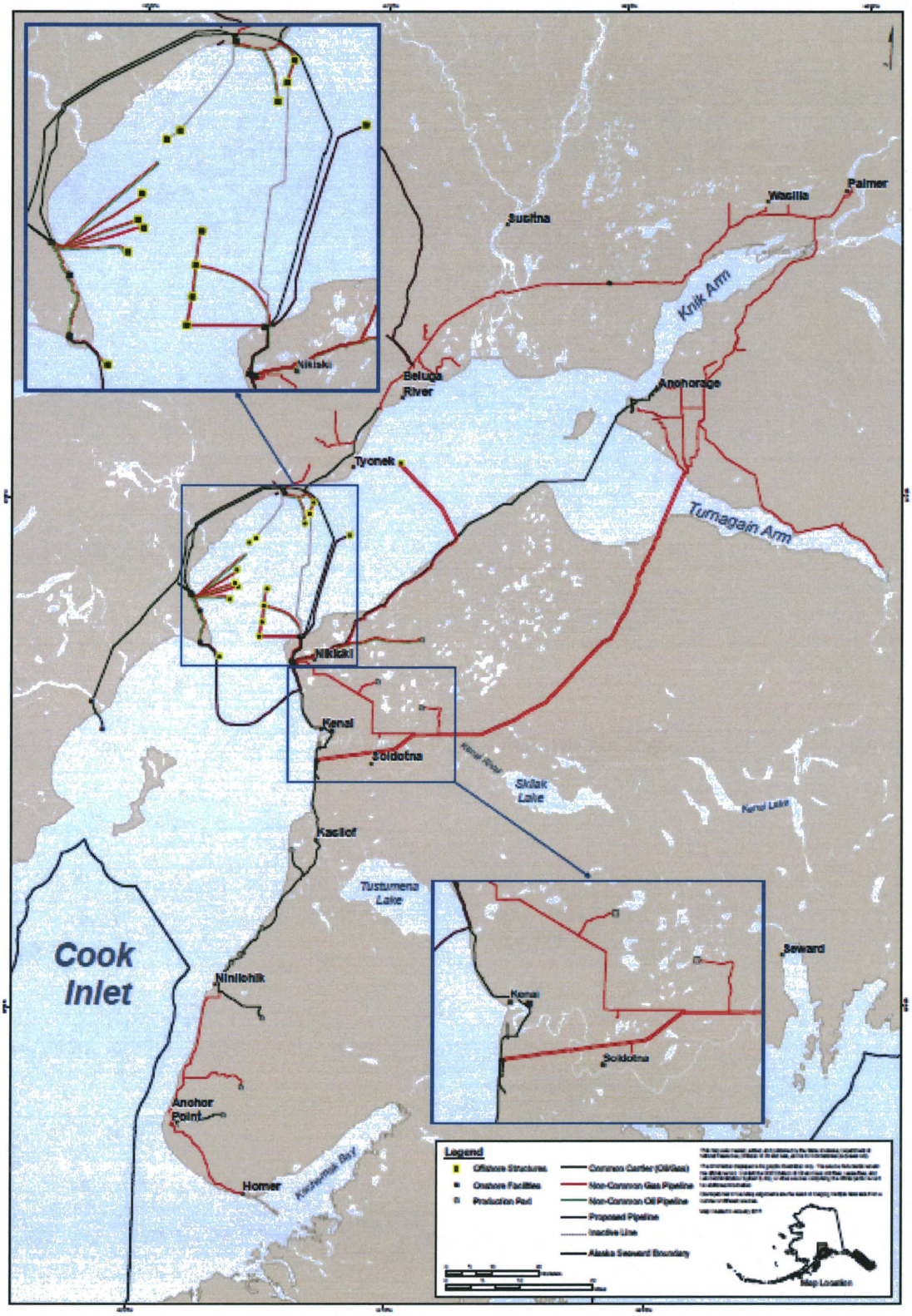


Figure 5-4. Cook Inlet and southcentral Alaska common carrier pipeline tariffs as approved by FERC and RCA.

Pipeline Name	Product	Units	2006	2007	2008	2009	2010	2011	2012	2013	2014
Alaska Pipeline Tariff (Enstar) Value	Dry Gas	$/mcf	$0.99	$1.16	$1.22	$1.16	$1.23	$1.06	$1.24	$0.69	$0.75
Beluga Pipeline Tariff Value	Dry Gas	$/mcf	$0.38	$0.05	$0.03	$0.22	$0.23	$0.21	$0.24	$0.25	$0.25
Cook Inlet Gas Gathering System Tariff Value	Dry Gas	$/mcf	$0.15	$0.15	$0.16	$0.28	$0.25	$0.24	$0.14	$0.23	$0.24
Cook Inlet Pipeline Tariff Value	Oil & Condensate	$/bbl	$4.69	$2.25	$3.16	$4.05	$13.40	$7.07	$6.48	$4.07	$3.15
Kenai Kachemak Pipeline Tariff Zone 1 - Main Line Value	Dry Gas	$/mcf	$0.30	$0.35	$0.26	$0.29	$0.27	$0.25	$0.25	$0.35	$0.29
Kenai Kachemak Pipeline Tariff Zone 2 - Happy Valley Spur Value	Dry Gas	$/mcf	$0.65	$0.85	$1.45	$1.93	$1.19	$0.98	$0.55	$0.23	$0.12
Kenai Kachemak Pipeline Tariff Zone 3 - Kasilof Spur Value	Dry Gas	$/mcf	$0.62	$1.19	$1.18	$1.19	$1.09	$1.19	$1.18	$4.75	$5.46
Kenai Nikiski Pipeline Tariff Value	Dry Gas	$/mcf	$0.05	$0.04	$0.04	$0.08	$0.10	$0.16	$0.08	$0.07	$0.07
North Fork Pipeline Tariff	Dry Gas	$/mcf						$1.95	$1.95	$1.95	$1.95
West McArthur River Pipeline Tariff Value	Oil	$/bbl	$1.11	$1.23	$1.23	$1.23	$1.51	$1.49	$1.48	$2.12	$1.91

Source: http://dog.dnr.alaska.gov/Commercial/PipelineTariffs.htm#cinlet.

Figure 5-5. Alaska's exploration areawide lease sales, existing exploration licenses and areas available for exploration licensing.

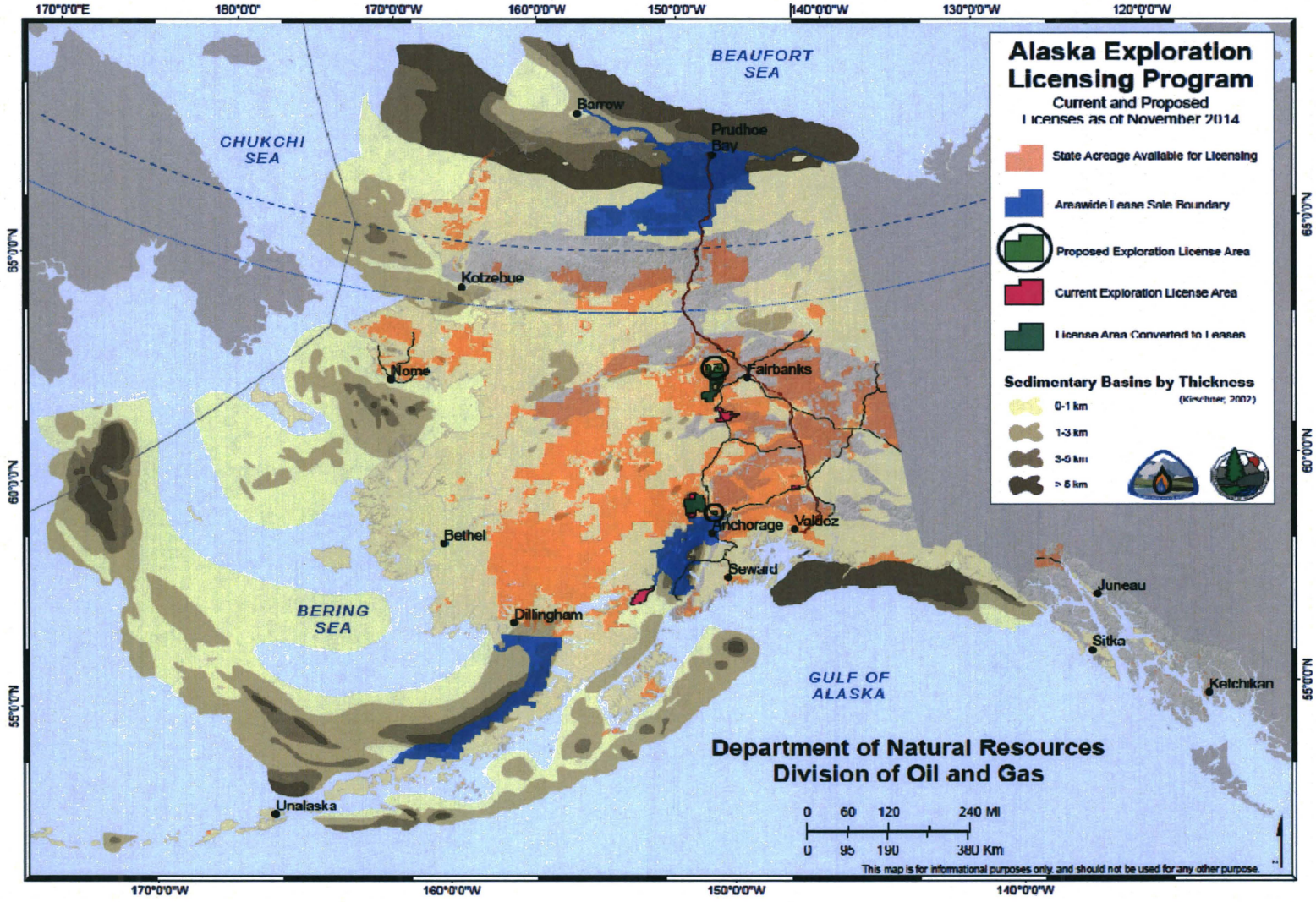
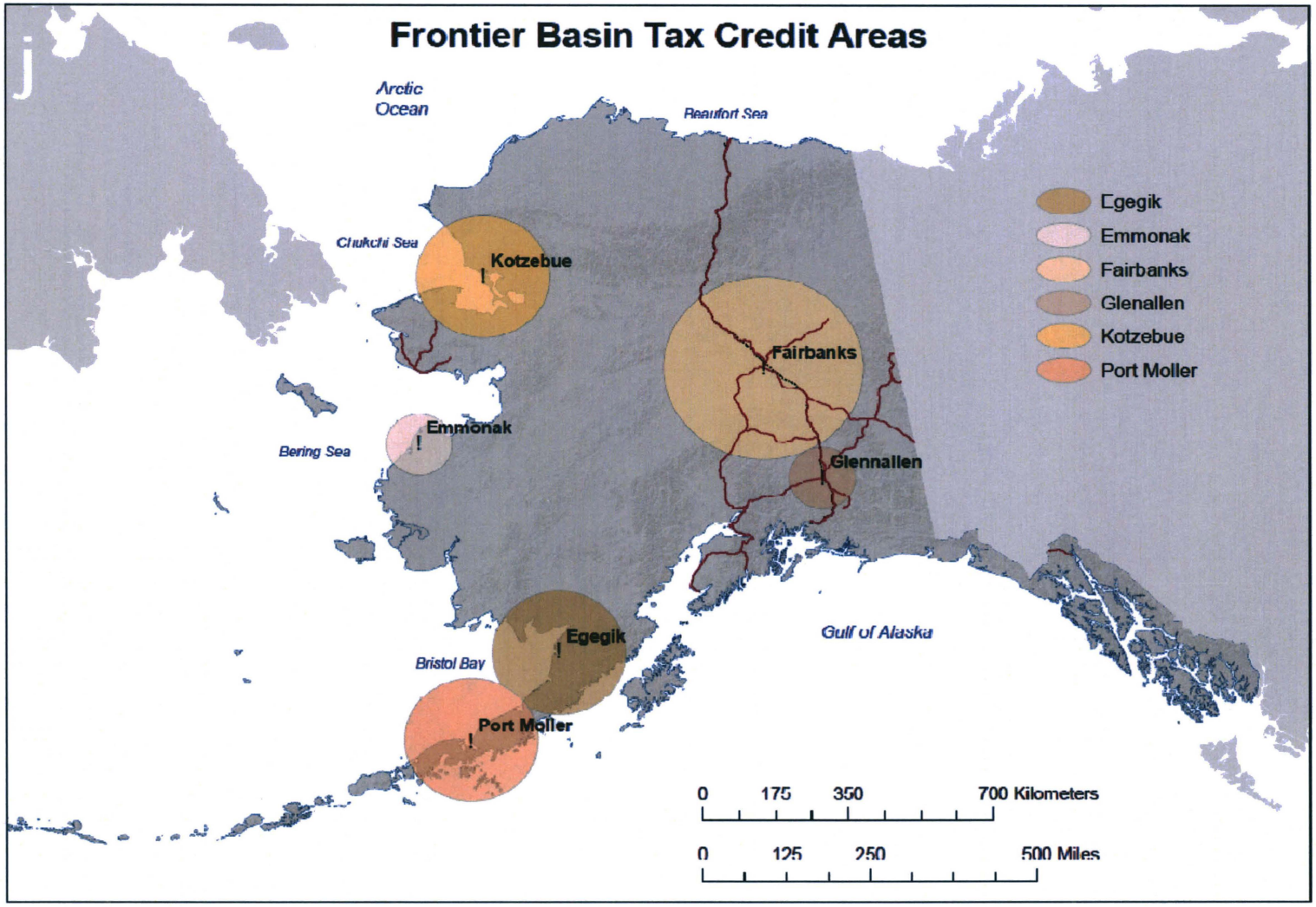


Figure 5-6. Areas in Alaska that may qualify for frontier basin tax credits.



6. Status of labor and employment in Alaska

Over the past decade the oil and gas workforce has grown from 8,000 to 15,000 employees. Total wages earned from oil and gas also rose from about $800 million to approximately $1.9 billion over this same period. Direct industry jobs are projected to increase to about 20,000 over the next five years. There are another estimated 30,000 direct and indirect jobs connected to Alaska's oil and gas industry activities. This combined workforce of direct and indirect jobs in the state of Alaska is approximately 45,000 workers, earning over $2.65 billion. Oil and gas industry jobs have historically been the highest paying jobs in Alaska, with the average annual income for an oil and gas industry worker at $127,148.

Oil and gas industry firms rely heavily on support contractors involved in transportation, civil engineering, power, industrial service and supply, pipeline construction, and asset maintenance. An estimated 50 – 70percent of the occupational skill sets required for oil and gas industry jobs are the same skills found in the construction and mining industry occupations.

The number of oil and gas industry jobs is at an all-time high for Alaska and for jobs located on Alaska's North Slope. As the number of oil and gas jobs have grown over the past decade, so too has the number of non-resident workers hired to fill the jobs. Today, more than half of the new industry jobs on Alaska's North Slope are filled by non-residents. The increase of North Slope jobs over the past decade has occurred during a national economic recession and a significant downturn in oil and gas industry jobs in other states. Dislocated workers, who possess the skill sets necessary for oil and gas industry jobs and specifically for the North Slope jobs, have helped fill the growing demand for qualified workers in Alaska.

Technology and electronic communications have allowed employment information and hiring processes to take place through the internet, which have allowed non-resident workers with appropriate skills and experience to learn about and apply for the same jobs as Alaska residents with the same qualifications, often without resident considerations. There are exceptions where project developers and employers have made residency a consideration and put forth the extra effort to hire Alaskans.

The development of Point Thompson

Over a three-year period ExxonMobil has invested more than $2 billion in the development of Point Thompson. During the 2014 work season approximately 1,200 Alaskans were employed on this project. At 50 percent "Alaskan hire," this project was far above other projects on the North Slope for use of in-state labor resources. This project helps to illustrate what can be done to increase resident-hire in the oil and gas industry and on the North Slope, in particular.

Workforce development efforts in Alaska

Pipeline construction training plays a critical role in developing a workforce that is ready, safe and has the correct skill set needed for Alaska's oil and gas industry jobs. For decades the Alaska Department of Labor and Workforce Development (ADOLWD) and Alaska's pipeline trade unions and their associated apprenticeship programs have delivered training to fill the workforce needs in construction of oil and gas pipelines. Apprenticeship programs provide training for specific skills required for the construction of pipelines and associated jobs in the oil and gas industry. There is a 52 acre training site located in Fairbanks, where workers are trained in practical,

hands-on methods of pipeline construction. The Fairbanks Pipeline Training Center is operated by a training trust composed of industry employers and trade unions involved in oil and gas work, which offer specialized training to develop the Alaska's workforce for this important industry. The success of this training is in their comprehensive approach to industry training and developing career awareness, partnering with others to provide pathways into the workforce. These include basic skills training through the ADOLWD Fairbanks Construction Academy, trade apprenticeship programs and working with the school districts to inform Alaska's youth.

Alaska's trade apprenticeship programs have helped to provide new workers to fill the high needs of job growth in the construction, mining and oil and gas industries. These programs are critical to meet industry needs as the skilled workers are aging out. There are more than 2000 apprentices being trained in Alaska to meet the workforce needs for these industries. Apprenticeship programs serve the entire state with training centers located in Fairbanks, Palmer, Anchorage, Chugiak and Juneau.

As a result, the 2014 ADOLWD Alaska Workforce Investment Board adopted the Alaska Oil and Gas Industry Workforce Development Plan 2014 – 2018. School administrators, teachers, guidance counselors and students are focusing on career pathways into the oil and gas industry. These efforts are helping to connect post-secondary degree choices with actual industry needs in Alaska. It is also helping students identify pathways to work through obtaining occupational certificates and gaining of the technical knowledge required by industry jobs. High school graduates are also finding a pathway to high paying jobs through apprenticeship programs, which give them the training to become highly skilled and qualified for the jobs available.

The workforce that underpins Alaska's oil and gas industry needs requires that adequate training opportunities exist and that knowledge of the skills needed are available to those helping guide workforce development. To fill the high demand, high paying jobs found in the oil and gas industry, Alaska must provide avenues of workforce development to meet these demands. This will put Alaska residents to work in these jobs and provide industry confidence that Alaska can substantially help meet future labor demands.

7. Regulatory environment and permitting structure

In Alaska various government agencies have a broad spectrum of authority to prohibit, regulate, and condition activities related to oil and gas. The implementation of regulations varies depending on the land ownership, lease specifics, and agreements between the parties.

Many of the permitting and planning requirements in place in Alaska focus on minimizing the impact of oil and gas development on the environment, specifically concerning water and air quality, habitat, fish, and wildlife, and the placement and preparedness for the storage and spillage of fuel and other hazardous substances. Multiple agencies administer and manage specific permits required to conduct necessary activities such as installing a culvert, building an ice road, and operating a drill rig. These agencies may be engaged at several different levels and throughout the life of a project. They also may require ongoing monitoring and reporting by the permitee, as well as on-site inspections conducted by agency staff. Additional regulations focus on potential impacts to the regional population and economy, subsistence and sport harvest activities, and access to the project areas. Regulations also routinely encourage local and Alaskan hire.

The implementation of these regulations affects the planning and construction of facilities, and the implementation of proposed operations. Multiple agencies may have regulatory authority when operations require permission from additional land owners for access, compensation for land owners, determination that an operator has informed the local population of their plans and received and replied to feedback provided, and the communication of local concerns and issues back to permitting agencies has occurred during plan implementation. Again, which agencies are involved is mostly dependent on the ownership of the lease upon which the activities occur and that of the surrounding land.

Federal

Onshore

The BLM issues permits for geophysical exploration and operation permits to drill oil and gas wells, and authorizations to construct pads and install production facilities on onshore federal leases in Alaska in the NPR-A and Cook Inlet. For the NPR-A the BLM implements 43 Code of Federal Regulations and in the Cook Inlet they implement regulations under the authority of the Mineral Leasing Act of 1920 (MLA). For more information on onshore federal lease regulations please see the BLM webpage.[21]

Offshore

The leasing and operations activities on the OCS are subject to the requirements of some 30 federal laws administered by numerous departments and agencies. In addition to the OCS Lands Act, other laws may apply to OCS exploration, development, and production. For a more detailed explanation of BOEM OCS lease regulations see the BOEM Leasing 101 instructions.[22]

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[21] BLM onshore federal lease regulations
http://www.blm.gov/ak/st/en/prog/energy/oil_gas/oil_gas_regs.html.

[22] BOEM Leasing 101
http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/5BOEMRE_Leasing101.pdf

University, Mental Health Trust, Native corporation, and private lands

Depending on the nature and timing of the oil and gas development and ownership of surrounding lands, a variety of state, federal and local regulations, policies, and programs may apply to private leases. Literature specific to each of these private land lease types may provide additional information regarding regulatory programs specific to these private lands.

State of Alaska land management

The majority of past and current oil and gas production in Alaska comes from state leases managed by the DNR. Three agencies within the DNR play specific regulatory roles in the exploration, development, and transportation of oil and gas resources: (1) the Division of Oil and Gas (DOG), (2) the DMLW, and (3) the State Pipeline Coordinator's Office (SPCO). The remainder of this section will focus on oil and gas development on state managed lands.

Division of Oil and Gas

The DOG focuses on state subsurface activities and surface activities required to develop those subsurface resources. The regulatory emphasis is on overall project planning approvals and contract requirements identified in the lease terms. Specifically, individual permits for necessary activities are administered by those agencies that hold the knowledge and expertise to regulate potential environmental impacts, including monitoring and mitigations, and in addition those who also regulate the hydrocarbon resource for conservation, among others.

In addition to existing laws and regulations applicable to oil and gas activities, the DOG's standard oil and gas lease contract requires that leases are subject to all applicable state and federal statutes and regulations in effect on the effective date of the lease. In addition, leases are subject to all future laws and regulations that go into effect after the effective date of the lease to the full extent constitutionally permissible.

The lease also requires that the lessee keep the lease area open for inspection by authorized state officials. Multiple state agencies may monitor field activities for compliance with each agency's terms. In addition, each lessee or permittee must post a bond before beginning operations.

A comprehensive and detailed summary of governmental (state and federal) powers to regulate DOG oil and gas leases can be found in each best interest finding (BIF), available online.[23]

Plans of operations

An oil and gas lease issued by DOG grants the lessee exclusive rights to drill for, extract, remove, clean, process, and dispose of (sell) oil, gas, and associated substances. The lease and regulations require a plan of operations (for a lease, for a group of leases, and for a unit) to be approved before any activities or operations may be undertaken on or in the leased area. Plan of operations applications are reviewed for compliance with statue and regulation, as well as terms of the oil and gas lease. Prior to approval, plans of operation applications are required to be made available for a public review and comment period lasting no less than 30 consecutive days.

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[23] Alaska Division of Oil and Gas Best Interest Findings
http://dog.dnr.alaska.gov/Leasing/BestInterestFindings.htm

Plans of operations include descriptions of how the applicant will meet a series of mitigation measures laid out in the BIF specific to that area. Mitigation measures address issues concerning private property; water and air quality; facilities and operations; habitat, fish, and wildlife; harvest activities; fuel and other hazardous substances management; and access. Local government organizations and other agencies may be consulted to implement mitigation measures. Exceptions to these mitigation measures may be requested and granted upon a showing by the lessee that compliance with the mitigation measure is not practicable and that the lessee will undertake an equal or better alternative to satisfy the intent of the mitigation measure. Additional conditions and project specific stipulations may also be imposed in the approval of a plan of operations.

Subsequent deviations in activities proposed by a lessee that fall outside of an approved plan require the submission to and approval by the DOG of an amendment to the plan. Submission to the DOG of an update on the status and completion of plan components is also required every November 1 and May 1, following plan approval and continuing throughout the life of the plan. Status and completion information is also used to guide the DOG during field inspections to ensure that operations are conducted in conformance with the terms and conditions contained in the plan approval. The status and completion submissions are also used to facilitate the DOG's continuing review of past, current, and planned future surface activities statewide, especially when considering the approval of new proximal plans of operations, associated amendments, and other activities.

Geophysical exploration permit

A geophysical exploration permit may be issued by the DOG. Seismic surveys related to oil and gas development are the most common activity authorized by this permit. Submission of seismic exploration and stratigraphic test data to the state is a permit condition; however, the permittee may request that geological and geophysical data be kept confidential. If the permit period (typically one year) is extended, the director may modify existing terms or add new ones. A permit remains in effect for the term issued, but may be revoked for cause, with 30 days' notice.

Regulatory upgrades to increase competitiveness

The DOG has recently undertaken a comprehensive, active, and critical approach to upgrading the state oil and gas regulatory environment and permitting structure conducive to encouraging increased investment while protecting the interests of the people of the state and the environment.

These updates ensure the submission of a complete application; adherence and easy identification of applicant compliance with statue, regulation, and lease terms; allow for straightforward assessment of multiple plans of operation in full and section by section; and allow for the public to review and for comment on plan components in a consistent meaningful manner.

At this time the proposed new plan of operations and geophysical exploration permit application updates are being introduced to industry and a review period is underway to allow for industry operators and contractors to view and comment on the draft materials prior to full implementation of the new system. Subsequent components staged for update, review, and implementation include the associated map products required in the application process, the associated amendment request submission and approval forms, and the status and completion reporting components.

In addition, information compiled routinely from the biannual plans of operations status and completion reports, combined with additional sources from multiple agencies, will be provided on an annual basis by DOG as a summary of current and ongoing surface activities on oil and gas leases and is available as a component of the DOG's annual report.

Division of Mining, Land and Water

Over the years, exploration operations on the North Slope have changed to reduced overall environmental impacts. In its infancy, gravel roads and pads were constructed to reach areas

targeted for exploratory drilling. Often these roads and pads were constructed without proper drainage resulting in excessive ponding and/or drying of the tundra adjacent to the gravel structures. Additionally, dry holes and uneconomic wells resulted in a number of abandoned roads and pads, many of which remain unused to this day. Ice road and pad construction developed out of a need to reduce environmental damage and recognition of the uncertainty in exploration drilling. This approach was supported by industry and was adopted as a mitigation measure in all North Slope lease sales. The Mitigation Measure (5(a)) lease term states the following:

> *"Except for approved off-road travel, exploration activities must be supported only by ice roads, winter trails, existing road systems or air service. Wintertime off-road travel across tundra and wetlands may be approved in areas where snow and frost depths are sufficient to protect the ground surface. Summertime off-road travel across tundra and wetlands may be authorized subject to time periods and vehicle types approved by DMLW..."*

Ice road and off-road travel permits

The NRO has the primary responsibility for issuing ice road and off-road travel permits for North Slope oil and gas activities. Permits are generally issued for five year increments and are typically issued for a broad area (i.e. state land between the Canning and Colville rivers). Permits contain stipulations intended to prevent damage to the tundra vegetation. They also require that if any damage to the tundra does occur, the damaged area must be rehabilitated to the satisfaction of the DMLW. Ice roads and off-road travel activities are requested, evaluated, and approved on an individual basis throughout the season. This allows the individual travel requests to be effectively evaluated with the current snow and soil temperature conditions and other activities occurring in the area.

Ice road construction and off-road travel is regulated by seasonal environmental conditions that are monitored by the NRO. Tundra opening areas and monitoring stations within those areas have been established throughout the North Slope and are visited on a weekly basis prior to a station meeting opening criteria. The tundra is opened to winter off-road travel when the soil temperatures reach -5°C at a depth of twelve inches (30 cm) and when there is sufficient snow on the ground to protect tundra vegetation. The snow standards differ for the coastal plain and the foothills areas; the coastal areas require a minimum of 6 inches of snow and the foothills areas requires a minimum of 9 inches of snow. The date of tundra opening has ranged from as early as November 4 to as late as February 20. There have even been some years where lack of snow or warm soil temperatures resulted in no tundra opening for a given area. Once the tundra has been opened in the winter, there are no restrictions on the type of vehicles that may operate on the tundra provided that vehicle operation does not negatively impact the tundra. In years of limited snowfall, the tundra may be opened conditionally, with the condition that vehicles must be restricted to areas where snow is deep enough to prevent damage to the tundra vegetation.

The tundra is closed when it appears as if thawing conditions have resulted in snow that will be too soft or too limited to permit travel without resulting in damage to the tundra. Operators are then given 72 hours to move their vehicles and other equipment onto the gravel road system.

The general winter off-road travel season has declined over the years. In 2003, the NRO conducted studies to determine the best methods for opening the tundra and allowing earlier winter access in response to the shortening seasons. These studies resulted in best practices for early winter season tundra access and established the monitoring system that is presently used by the DMLW. Innovations in ice road construction techniques and low impact vehicles have continued to stem the season's decline.

The NRO may approve site specific tundra opening and conventional ice road construction when specialized methods and equipment are employed early in the winter season. Pre-packing snow using summer-approved and/or low impact vehicles has two positive results with regards to reaching tundra opening criteria. First, packing snow decreases the insulation value of the snow and allows the underlying tundra soils to decrease in temperature faster than non-snow packed

tundra soils. Secondly, the packed snow trail effectively captures snow during wind and blizzard conditions effectively increasing the snow depth within the trail. Pre-packing allows operators to begin work earlier in the winter season and, coupled with temperature sensors installed within ice or snow road routes, individual ice and snow roads often reach opening standards before general winter tundra travel is opened.

Summer tundra travel is limited to vehicles that have been approved for use by the NRO. Each vehicle must pass a test to verify that it can operate on the tundra during the summer without causing damage to the tundra vegetation. Vehicles are approved in the configuration tested; for example, a vehicle tested with a payload of 1000 pounds would be limited to that payload when operating in the field. A vehicle tested and approved with smooth tracks would require retesting if the vehicle is to be operated with wheels or cleats.

Leases and easements

The DMLW administers land leases within the North Slope oil fields. These leases are primarily occupied by oil and gas support companies including construction, well work, camp operations, and spill response. In some instances, leases are issued to oil production companies for operations that may not be authorized under DOG lease operations approvals. Leases may be located throughout the oil fields, but primarily reside in the state surveyed area of Deadhorse. Tideland leases at primary dock facilities are also managed by the DMLW. These include West Dock and Oliktok.

Easements for fiber optic cables, cell towers, roads, and electrical transmission may be authorized by the DMLW on state land. These easements often support the oil and gas service industry and the general worker population.

Temporary water use authorizations

The DMLW Water Section is tasked with issuing temporary water use authorizations for water extraction. Water is a major component of oil and gas operations for camp operations, reservoir water flooding, and ice road construction.

Other miscellaneous land use permits

The DMLW may issue a wide range of permits for other temporary activities throughout the North Slope. These include barge landings, remediation and rehabilitation projects, research, geotechnical drilling, material site exploration, and storage.

Competitiveness

Outside and within Alaska there are areas of significant size where individuals own the surface and/or mineral estate and all of the financial, environmental, and additional requirements for exploration, development and production are often private confidential agreements between the surface and/or mineral estate owner and the lessee or operator. Additionally, much like a private owner, the State of Alaska also has the position of serving both as promoter of the resource potential for development and as the regulatory body. The importance variance from the established peer group consisting mostly of private lease agreements, is that the State of Alaska must develop its resources in the best interest of the state for the maximum benefit of all Alaskans and therefore must weigh the current and potential multiple uses of the land with the potential impacts and benefits from oil and gas development through a public process.

In maintaining that balance, the state has developed and codified a transparent and public regulatory environment through the Alaska Lands Act, AS 38.05 with specific sections for oil and gas leasing, unitization, and exploration. This begins with the establishment of the BIFs, which define the regulatory concerns of the State of Alaska, and provides potential operators with the issues and components of operations requiring mitigation. An applicant must demonstrate how they intend to mitigate the identified concerns through submission of a mitigation measure analysis required as part of their plan of operations application. The public can weigh in on both the scope of work identified in the plan application as well as how the operator will meet the

voiced concerns implemented by the mitigation measures developed at the time of lease issuance.

The BIFs provide all potential industry players, as well as Alaskans, with the regulatory roadmap for development. The plan of operations process then refines requirements specific to an operator's plan. This transparent process engages the public to ensure that plan approval balances the needs of Alaskans with those of applicants.

This transparent, public, well-established, and often repeated process provides a clear, consistent and predictable regulatory environment competitive with and maybe more advantageous than exclusive, confidential, and one-time agreements with private individuals. This process has proven effective in the development of the North Slope and Cook Inlet oil and gas fields since discovery and provides the opportunity for continued successful development of the state's oil and gas resources.

Water quality management

The Alaska Department of Environmental Conservation (DEC)[24] Water Division regulates water quality through water quality and wastewater standards found in the Alaska Administrative Code at 18 AAC 70 and 18 AAC 72. These regulations provide specificity for the State of Alaska's implementation of the federal Clean Water Act. The state's water and wastewater regulations are based on the general prohibition principle, such that no person may cause or contribute to a violation of the water quality standards in waters in the state, and discharges to waters in the state must be authorized by an Alaska Pollutant Discharge Elimination System (APDES) permit. These water quality standards apply to both marine and fresh waters and protect water quality for a wide variety of uses, including growth and propagation of aquatic life, which includes marine mammals and their prey.

For waters that are of naturally high quality, the water quality standards include an anti-degradation provision that prohibits any degradation of water quality unless certain conditions are met and uses of the water are protected. The Division's Non-Point Source Water Pollution Control Program regulates storm water pollution of water bodies through review and approval of construction plans and storm water pollution prevention plans from industrial sites.

Industrial wastewater discharges - oil and gas wastewater discharges

Discharges from oil and gas facilities can be categorized generally as onshore and offshore. Offshore typically includes production platforms, exploration jack-up rigs, and geotechnical surveys using water based drilling fluids. Onshore includes well pads, processing facilities, refineries, terminals, and large pipelines including horizontal direction drilling under or into water bodies. Offshore discharges include drilling fluids and drill cuttings, produced water, water flood, domestic wastewater, graywater, desalination, non-contact cooling water, deck drainage and other miscellaneous discharges that are similar to vessels. Onshore discharges do not have discharges of drilling fluids and drill cuttings or produced water as these wastes are commonly disposed into underground injection control wells. Common onshore discharges includes domestic wastewater, excavation dewatering, hydrostatic test water, secondary containment water, and horizontal direction drilling when drilling fluids are used that are, or can be, discharged to a surface water.

Water quality monitoring and assessment

The DMLW Water Division Alaska Monitoring and Assessment program (AKMAP) conducts annual surveys that report on the status of Alaska's water resources with a calculated statistical

[24] The DEC's responsibilities include the permitting and authorization of certain actions relating to oil and gas exploration and production. The main areas DEC regulates include: oil spill prevention and response, pollutant discharges, waste disposal, and air emissions

confidence. This provides resource managers, elected officials, and the public an understanding of the "big picture" of Alaska's water resources. No similar probabilistic sampling surveys are currently providing regional, ecological information on such a large scale within Alaska. The DEC Environmental Monitoring and Assessment Program (EMAP) implementation strategy is DEC's plan to sample and report monitoring data for large regions of Alaska in the near future. The AKMAP has sampled coastal and fresh waters since 2002. The first wetland monitoring occurred in 2011 on the Arctic Coastal Plain.

Air quality management

Oil Exploration and production typically utilize several air permits. The DEC Air Quality Division regulates air quality for the State of Alaska through the air quality standards found in the Alaska Administrative Code at 18 AAC 50 and the vehicle emission standards at 18 AAC 52. The State of Alaska has primary authority for implementation of the federal Clean Air Act on state lands and federal lands.

Minor permits (Alaska Air Quality Minor Permit) are required to change existing air quality permit requirements. The permits ensure smaller new and increased sources of pollution comply with emission standards and do not cause a violation of ambient air quality standards. Minor permits also are the administrative vehicle for a variety of housekeeping tasks related to permits.

New and modified stationary emission units categorized in regulation by the type of source and by its potential emissions require a minor permit. Any new or modified source of air pollutant emissions should be reviewed against the regulatory thresholds. Typical emission units requiring permits include incinerators, coal preparation plants, boilers, stationary engines, or turbines.

Minor permit actions are also used extensively to change the conditions of existing permits, such as to remove an emission unit which has been decommissioned, or to establish limits on new equipment which avoids classification under a more rigorous permit. For example, a unit used intermittently may require a major source permit based on its potential emissions, but those potential emissions can be reduced by legally limiting the operation of the unit through a minor permit.

These permits are often necessary before beginning construction or modification of an air pollution source categorized in regulation. Applicants must provide descriptive information about the emission units and a demonstration that emissions will not interfere with attainment and maintenance of Ambient Air Quality Standards. The application process typically takes four to six months from initial application, including any re-work by the applicant to address incomplete applications and incorrect modeling. There is a minimum 30 day public comment period. Permits are required to be issued or denied within 30 days of the close of the comment period.

These permits can be derailed by incomplete permit applications, lack of representative meteorological data for use in modeling[25], modeling that does not meet the guideline on air quality modeling, controversial projects that draw extensive public comment, or disputes with applicants or their consultants over required limits. To minimize these delays, up front discussions with air permit program staff typically results in the development and review/approval of a modeling protocol which, if followed, ensures acceptable modeling analyses.

A "New Source Review/Prevention of Significant Deterioration (NSR/PSD) construction permit may be required to ensure large new and increased sources of pollution comply with emission

[25]Modeling is required for a complete permit application. Five years of national weather service data or a minimum of one year of site specific representative meteorological data is needed in order to perform refined modeling. The intent is to ensure the worst met conditions for pollutant dispersion is modeled. It is possible to do screening modeling without using actual meteorological data, but that modeling is very conservative. Most applicants will need to do refined modeling to demonstrate compliance with the ambient standards.

standards, do not violate the ambient air quality standards , and do not cause a deterioration of air quality in the area or interfere with improving air quality in a non-attainment area.

What activities require an NSR and/or PSD permit? A new major PSD or NSR source, or a major modification to an existing major PSD or NSR source. A major PSD source has the potential to emit 250 tons per year (TPY) of a regulated pollutant; a major NSR source has the potential to emit 100 TPY of the nonattainment pollutant or any precursor.

A major modification is a physical or operational change that causes a net emission increase greater than a threshold set in regulation. For example, adding a new coal boiler to a central heat and power plant would likely be a major modification; however, simultaneously retiring an existing boiler would reduce the net emission increase and could avoid major modification permitting for the new boiler. A minor permit would be required to document the changes.

A source may be NSR major for a nonattainment pollutant and also PSD major for other pollutants. For example, a source in the Fairbanks nonattainment area could require a major NSR permit for PM2.5 as well as a PSD permit for other regulated air pollutants.

An NSR/PSD permit is required before beginning construction of a major new source or major modification to an existing major source. The application must contain descriptive information about the emission units; and for PSD: demonstrate that the source will apply the best available control technology , provide one continuous year of pollutant monitoring data for the area where the source will be built or modified representative of the year preceding receipt of the application, provide modeling to show the maximum ambient[26] concentration of pollutants expected from the source consistent with the averaging times for the ambient standard of that pollutant using a minimum of one year of meteorological data and demonstrate that growth associated with the project will not impair visibility, soils, and vegetation of the area.

The Clean Air Act "Title V Operating Permit" compiles all currently applicable Clean Air Act and air quality control requirements into a single enforceable document for a given source classified as requiring an operating permit. A permit for an area source that requires a permit only because it is subject to one or more federal standards will only include the applicable federal standard that triggers an operating permit.

A Title V operating permit is needed for any stationary source which has the potential to emit 100 TPY or more of a regulated air pollutant, or 10 TPY of an individual hazardous air pollutant, or 25 TPY of all hazardous air pollutants combined, or which contains an emission unit subject to a Federal New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (a.k.a. Maximum Achievable Control Technology standards).

Because potential to emit is calculated assuming all emission units operate at their maximum rate 24/7, some sources can establish a legal limit to reduce their potential to emit to avoid Title V permitting.

An application is due within 12 months after the source becomes classified as requiring an operating permit. Sources are categorized by the type of regulated activity and by being a major source of emissions. A permit applicant who submits a timely and complete application may operate and continue to operate under that application until the department issues a final permit.

The application process typically takes 12-24 months. There is a minimum 30 day public comment period and a 45-day EPA draft permit review process. Permits are required to be issued or denied within 30 days of the close of the EPA review period.

[26]Ambient air means any location to which the general public has access. In a military context, ambient air can be on base where spouses or children, or other members of the general public (not soldiers or employees) have access.

The main issues that delay permits include disputes with the client or EPA over applicable requirements and monitoring, controversial projects that draw extensive public comment, non-compliance with pending enforcement, new or modified emissions standards promulgated during the review process, and client delays in supplementing applications.

Solid waste disposal

Under the general provisions of Subtitle D of the Resource Conservation and Recovery Act (RCRA), the DEC Division of Environmental Health, Solid Waste Program (SWP) has an approved program for regulation of solid waste disposal in Alaska. The state's solid waste management regulations, based on the federal standards in 40 C.F.R 257 and 40 C.F.R 258, are found in the Alaska Administrative Code at 18 AAC 60. These regulations make a general distinction between municipal and non-municipal disposal facilities and include requirements for the design, operation, closure, and monitoring of those facilities to minimize harm to human health and the environment.

The SWP permits and regulates both municipal and non-municipal disposal facilities in the arctic region of Alaska. Non-municipal facilities are associated with the oil and gas industry and the mining industry. Municipal facilities are found in every community, and at present, every disposal facility on the North Slope and adjacent areas is either permitted or authorized under a plan approval.

Oil and gas solid waste facilities

The SWP regulates oil and gas drilling waste management facilities throughout the State. Drilling waste is generated by oil and gas exploration and production activities. Drilling waste, which consists of drilling mud, cuttings, pigging waste, fluids, and other related wastes, is a solid waste that is excluded from regulation as a hazardous waste through 40 C.F.R 261.4(b)(5). However, drilling waste may include contaminants that pose a significant public health and environmental risk, and as such, drilling waste storage, treatment, and disposal facilities must be designed and operated to minimize the potential for contaminant release. The SWP requires surface water monitoring at permanent oil and gas solid waste facilities and inspects these facilities annually.

Drilling waste is primarily disposed of by underground injection although management can involve surface storage of solid waste prior to injection. The SWP authorizes drilling waste management through several mechanisms, including individual solid waste permits, solid waste general permits, solid waste treatment permits, and temporary storage plan approvals.

Municipal solid waste facilities

Municipal solid waste landfills are subdivided into three classifications based on the average tonnage of waste received each day. The three classifications include:

Class I (greater than 20 tons per day)
The lone Class I landfill on the North Slope is the Oxbow Landfill at Prudhoe Bay. This landfill is designed as a freeze-back landfill, which means that the overall intent is for the disposed wastes to become permanently frozen. The progress towards achieving freeze-back is monitored by periodically measuring the temperature below, within, and around the waste pile.

Class II (5 to 20 tons per day)
The only Class II landfill on the North Slope is located in Barrow. This landfill was opened in July 2007 and is located approximately six miles inland from the coast. Because this landfill is operated in conjunction with a thermal oxidation system incinerator, it receives only incinerator ash and inert wastes. A second landfill in Barrow is in the process of being permanently closed.

Class III (less than 5 tons per day)

There are seven Class III landfills on the North Slope located in the following communities: Atqasuk, Kaktovik, Nuiqsut, Point Lay, and Wainwright.

The specific requirements for design, operation, monitoring, and closure of the landfill vary with the classification: the larger the landfill, the more stringent the requirements. Class I and Class II landfills are inspected at least once per year; permitted Class III landfills are inspected at least once every five years.

Oil spill prevention and response

The DEC Division of Spill Prevention and Response (SPAR) is responsible for protecting Alaska's land, waters and air from oil and hazardous substances spills. SPAR regulates spill prevention through review and approval of spill prevention plans for oil terminals, pipelines, tank vessels, barges, refineries, oil exploration facilities and oil production facilities. SPAR ensures response preparedness through the review and approval of oil discharge contingency plans, inspections, spill response exercises, and drills. Spill contingency plans are required under Alaska Statute AS 46.04.030 and Alaska Administrative Code regulations at 18 AAC 75. They document a facility-wide spill prevention program that ensures personnel, equipment and financial resources are available for the company to adequately respond to spills.

The State of Alaska requires oil spill contingency plans for the following facilities:

- Oil and gas exploration facilities (onshore and off)
- Crude oil transmission pipelines
- Flow lines and gathering lines
- Non-crude oil terminals (over 10,000 barrels)

Contingency plans are valid for five years. During that time major and minor amendments are possible. Major amendments require a public process for review of the changes whereas minor changes do not.

In addition to documenting response capacity, companies are also required to provide proof of financial responsibility as required under Alaska Statute AS 46.04.030. Companies are required to show they have the financial capacity to clean up a spill if it occurs and restore the environment.

Contaminated sites

The DEC Contaminated Sites Program oversees or conducts cleanup of contaminated sites based on their danger to public health and the environment. The contaminated sites cleanup process is governed by Alaska Statutes at Title 46 and Alaska Administrative Code regulations at 18 AAC 75 and 18 AAC 78. Previous exploration and production practices (before environmental permits existed) resulted in several contaminated sites in Alaska. Some exist where existing production is occurring. In cases where remediation is not possible due to active infrastructure, the sites are monitored to ensure contamination is not leaving the site with plans to remove the contamination when the production activity ceases.

8. Alaska's oil and gas fiscal system

Elements of Alaska's fiscal system

Alaska's fiscal system for oil and gas has four major components that generate State revenue:

1. Royalty
2. Property tax
3. State corporate income tax
4. Production (severance) tax

Although there have been changes made to the various components over the years, each component has been part of the oil and gas fiscal system since the 1970s, when oil began flowing from the North Slope. In this section, we provide a brief summary and overview of the four major components of the fiscal systems. Note that while major elements of Alaska's fiscal system apply in the same way to North Slope and non-North Slope areas of the state, this discussion is focused on the North Slope. Subsequent reports by the Board will focus on Cook Inlet and non-North Slope areas, where a number of different statutes and regulations apply.

Alaska's fiscal system for oil and gas also has special incentives, generally in the form of tax credits to operators. The number of incentives that may decrease revenue to the State of Alaska, at least in the short-term, has grown considerably over the past 10 years as the fiscal system has changed. Due to the number of incentives, the credits applied, and their significant impact on the total revenue picture for the state, the following discussion of the components of the fiscal system concludes with a special section describing the incentives in oil and gas royalty and taxation.

In addition to the revenue-raising components mentioned above, over which the state has control, there is an additional fiscal element controlled only by the federal government: federal CIT. The federal CIT rate component for all U.S. state and federal fiscal regimes is assumed to be 35 percent. The interaction between the elements that the state controls (royalties, taxes and credits) and the very significant federal income tax diminishes any efforts by the State of Alaska to materially modify the overall fiscal system in favor of lessees or operators on Alaska lands.

Oil and gas that is produced onshore in the state of Alaska or offshore within state boundaries is subject to the four revenue-generating components of the Alaska's fiscal system listed above. Together the four components typically provide almost 90 percent of the state's general fund unrestricted revenue (GFUR), as shown in Figure 8-1.

Figure 8-2 shows a group of data series related to oil and gas production, taxes and credits, and how they relate to each other. Note that the values for the pie chart in Figure 8-1 may not match the values in the Figure 8-2 data table because the pie chart shows only unrestricted GRUR revenue, while the table includes both GFUR and restricted revenue components.

Royalty, rents and bonuses

In natural resource extraction, royalties generally represent that portion of the revenue from the sale of minerals that is apportioned to the lessor by a lessee who has leased and produced something of value from a property. Currently in Alaska, the majority of leases for oil and gas extraction are on land where the state has title to the mineral estate. Therefore, in Alaska, most of the royalties for oil and gas extraction are apportioned, or paid, to the state. Although leases have varying royalty rates, most State of Alaska leases have royalty rates of 12.5 percent. This means that the State of Alaska receives approximately 12.5 percent of all oil and gas produced on state leases. The state royalty may be paid in kind or in value at the state's discretion. When royalties are paid "in kind," the state receives its royalty in barrels (or cubic feet for natural gas). When royalties are paid "in value," the state receives its royalty in dollars.

In some oil and gas lease sales net profit share (NPS) terms were offered. The NPS term can

either be in addition or an alternative to the state's royalty share of net production income. The NPS accounting allows the lessee to recover qualified development and operating costs before the lease enters "payout" and begins remitting a share of income (net profit) to the State of Alaska." In some cases, the NPS rate is greater than 30 percent.

Figure 8-1. Petroleum revenue components of the Alaska General Fund Unrestricted Revenue (GFUR), FY 2014

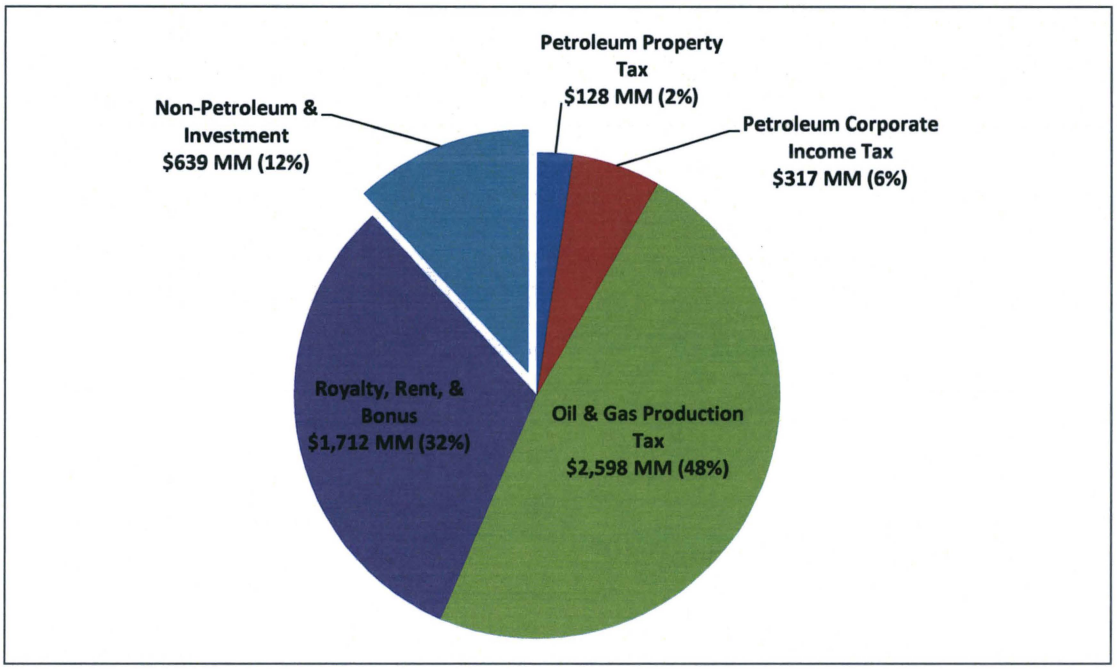


Figure 8-2. Alaska petroleum revenue-related data series, including gross production value, tax revenue streams and credits, FY 2011 through FY 2014.

Statewide Oil and Gas Revenue & Credits	FY 2011 $ MM	FY 2012 $ MM	FY 2013 $ MM	FY 2014 $ MM
Gross Production Value	19,918	23,027	19,787	NA
Royalty Revenue (not including bonus, rents, and interest)	1,821	2,023	1,748	1,685
Oil and Gas Property Tax Liability (total including municipal share)	477	490	530	548
Production Tax Before Credits	4,939	6,509	4,599	3,486
Production Tax Credits - Claimed Against Tax	386	363	549	888
Production Tax Liability After Credits (including Hazardous Release surcharge)	4,553	6,146	4,050	2,598
Credits Claimed as Cash Purchase	450	353	369	593
State Corporate Income Tax petroleum	542	569	435	317

The administration of most leases owned by the State of Alaska and the collection of associated royalties is a DNR responsibility.

The federal government also leases land in Alaska for oil and gas extraction, and the state

receives a portion of the royalties collected on these leases. In the NPR-A, the state receives 50 percent of the royalties collected by the federal government. In federal offshore leases that are greater than three miles from shore and less than six miles from shore, the federal government pays the state 27 percent of the royalties it collects from these properties.

Royalties are a significant component of Alaska's fiscal system, often accounting for 30 percent or more of the unrestricted oil and gas revenue paid to the state. Because royalties are paid without regard to oil and gas prices or whether there is any profit associated with oil and gas production, it is considered a regressive element of Alaska's fiscal system.

Oil and gas property tax

The State of Alaska levies a property tax on the full and true value of all oil and gas property in the state. The oil and gas property tax is administered by DOR and is assessed annually. The tax rate is 20 mills. Oil and gas property that is within local boundaries may be taxed on the local level and that amount is deducted from the property tax paid to the state.

The oil and gas property tax is a relatively small component in Alaska's fiscal system, generating revenues of about $100 million per year in recent years. However, the tax is an important component of local governments that have oil and gas property. Up to $400 million per year is split among fewer than 10 local governments.

Like royalties, oil and gas property tax is a regressive element in Alaska's fiscal system, as they are collected without regard to prices or profit.

Corporate income tax

Alaska's CIT for oil and gas is administered by DOR and uses a modified apportionment method, whereby a corporation's tax liability is based on the size of its Alaska operations relative to its worldwide net income. The apportionment factors used to determine a corporation's Alaska tax liability are the Alaska operations' (1) tariffs and sales; (2) oil and gas production; and (3) oil and gas property. The CIT rate is progressively graduated to the top tax rate of 9.4 percent levied when net income exceeds $222,000 for the year.

Oil and gas CIT revenues have comprised about 10 percent of the state's unrestricted petroleum revenues in recent years. In addition to mirroring the federal tax code with regard to tax credits, there are several state tax credits applicable to the CIT. These will be discussed in detail in the "Tax Credits" section of this chapter.

Oil and gas production (severance) tax

Among the largest revenue generating components of Alaska's fiscal system for oil and gas is the production tax. The production tax is administered by DOR. The current production tax was passed by the legislature in 2013 as Senate Bill 21 (SB 21). Like the two preceding production tax system, SB 21 taxes the net profits of production, after most operating and capital expenses have been deducted. The current production tax also offers credits for taxable barrels of oil produced, for exploration, and for companies that produce less than 100,000 barrels of oil per day. Prior to the implementation of a net profits-based production tax, Alaska taxed production based on the gross value of oil and gas as adjusted by an economic limit factor.

The current state production tax, SB 21, is less complex than its predecessor production tax system, Alaska Clear and Equitable Share (ACES). The new system has one tax rate for North Slope production: 35 percent. Also for purposes of taxation, production on the North Slope is divided into two groups: (1) production from existing "legacy" fields; and (2) new production. New production, if it meets certain criteria, is eligible for a 20 percent or 30 percent gross value reduction (GVR). The starting point for calculating the production tax on new production is 80 or 70 percent of the gross value of the oil or gas. This production is also allowed a $5 per taxable barrel credit against their tax liability. Production from existing "legacy" fields does not receive a

GVR, but instead of the $5 per barrel credit, this production receives a per-barrel credit that ranges from $0 to $8 per barrel, depending on the wellhead value.

The basic tax calculation of the state production tax is as follows[27]:

Production Tax Liability = [(Value – Costs) * Tax Rate] – Credits

Value

Value of production from existing "legacy" **fields**
= Volume of Non-Royalty Oil & Gas Produced * Wellhead Value
Value of new production
= Volume of Non-Royalty Oil & Gas Produced * Wellhead Value * 80 or 70 percent

Costs = Operating and Capital Expenditures

Tax Rate = 35 percent

Credits

Credits on production from existing "legacy" **fields**
= Value of $0 to $8 per taxable barrel of oil produced
Credits on new production
= Value of $5 per taxable barrel of oil produced

Minimum tax, production from existing "legacy" **fields**
= 0 - 4 percent of Value (depending on oil price) before Costs are subtracted less applicable credits

Additional fiscal elements

Lease bonuses and rentals are two additional components that contribute minor amounts of revenue to the state. However, in some jurisdictions these two fiscal components can contribute materially to government take, so they are worth discussing here.

Bonuses are cash payments received by the state, usually at a lease sale, to win the execution of an oil and gas lease. Normally the state's sale terms establish the bonus payment as the bid variable so that the bidder offering the highest bonus bid wins the lease being offered. Since 2000, annual revenues from lease bonus payments have ranged from as low as about $2.5 million in 2005 to as high as $64.9 million[28] in 2014.

Lease rentals are periodic cash payments received by the state to maintain an oil and gas lease and the rights granted under it. Alaska's statutorily established rates per acre for oil and gas leases are as follows:

1. First year: $1
2. Second year: $1.50
3. Third year: $2
4. Fourth year: $2.50
5. Greater than five years: $3 annually

Most State of Alaska lease contracts state that rental paid for a lease in advance, at the beginning of the year, can be claimed as a credit against royalty payments due under the lease

[27] It should be noted that this formula is a basic simplified example of the tax calculation. Numerous location, project, and company specific variations of the tax calculation occur.
[28] Based in-part on preliminary sale results. Final sale results will only be available after leases are issued.

for that year. Thus, on Alaska state land, even relatively small production volumes result in refunding of most rental payments through credits against royalty.

Tax credits and royalty incentives

Tax credits are also an important element of Alaska's fiscal regime and have played a large role in the competitiveness of Alaska's fiscal system. Most of the tax credits in current law were implemented with the change to a production tax based on net profits. The tax credits were intended to incentivize certain activities, such as oil and gas exploration and development. Over the past eight years, the tax credits program has expanded. In 2010, many new tax credits were introduced for the non-North Slope areas of the state. The credits appear to have been successful in incentivizing the activity sought, especially in Cook Inlet, where the number of companies exploring for and drilling wells, and oil production has increased significantly since 2010.

Credits applicable to the oil and gas production tax

There are currently three major categories of tax credits available against the Alaska production tax. AS 43.55.023 offers credits for certain capital expenditures, well lease expenditures, and expenditures leading to net operating losses. AS 43.55.024 offers several types of credits, including per-taxable barrel credits and credits to producers of oil and/or gas that produce fewer than 100,000 Btu equivalent barrels of oil and/or gas per day. AS 43.55.025 offers credits for exploration expenditures that meet certain criteria related to distance from existing units or wells and for the first persons to drill wells in certain areas of the state. These three categories of tax credits make up the majority of the tax credits used against or in connection with the oil and gas production tax. Below are more detailed descriptions of credits applicable to the oil and gas production tax in Alaska.

Alternative Credit for Exploration, AS 43.55.025(a)(1)-(4)

The Alternative Credit for Exploration is a transferable credit for expenditures for certain oil and gas exploration activities. Outside of Cook inlet, the credit is 40 percent for seismic costs outside an existing unit, 30 percent for drilling costs greater than 25 miles from an existing unit, 30 percent for pre-approved new targets greater than three miles from an existing well, and 40 percent for pre-approved new targets greater than three miles from a well and greater than 25 miles from an existing unit. The three-mile limit has been dropped for wells in "Frontier Basins," as described under the Frontier Basin Credit below. For Cook Inlet, the credit is 40 percent for seismic costs outside an existing unit, 30 percent of qualified drilling costs greater than 10 miles from an existing unit, 30 percent of costs for pre-approved new targets, and 40 percent of costs for drilling done greater than 10 miles from an existing unit and pre-approved new targets. The credit expires on July 1, 2016, for the North Slope and Cook Inlet; for areas other than the North Slope and Cook Inlet, the credit expires January 1, 2022.

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

This credit is a transferable credit for a carried-forward annual loss, defined as a producer or explorer's adjusted lease expenditures that are not deductible in calculating production tax values for the calendar year. The credit is currently 25 percent of the carried-forward annual loss. Beginning January 1, 2014, the credit for carried-forward annual losses incurred on the North Slope increased to 45 percent of the loss, and certificates for these credits may be taken in a single year. On January 1, 2016, the credits for losses incurred on the North Slope decreases to 35 percent of the loss.

Cook Inlet Jack-Up Rig Credit, AS 43.55.025(a)(5)

This credit is for exploration expenses for the first three wells drilled by the first jack-up rig brought into Cook Inlet. It is only for expenses incurred in drilling wells that test pre-Tertiary strata; all three wells must be drilled by unaffiliated parties using the same rig. The credit is 100 percent of costs for the first well up to $25 million, 90 percent of costs for the second well up to

$22.5 million, and 80 percent of costs for the third well up to $20 million. If the exploration well is brought into production, the operator repays 50 percent of the credit over ten years following production start-up.

Education Credit

See "Credits Applicable to Multiple Tax Programs."

Exploration Incentive Credit, AS 38.05.180(i)

The exploration incentive credit is a non-transferrable credit for the cost of drilling or seismic work performed under a limited time period established by the DNR Commissioner. Credit may be granted for up to 50 percent of the cost of drilling or seismic work, not to exceed 50 percent of the tax liability to which it is being applied. This credit may also be applied against the state royalty.

Frontier Basin Credit, AS 43.55.025(a)(6)-(7)

The Frontier Basin Credit is for expenses for the first four persons to drill exploration wells and the first four persons to conduct seismic projects within an area designated in AS 43.55.025(o) and (p), also called the "Frontier Basins." The credit is for the lesser of 80 percent of qualified exploration drilling expenses or $25 million; or for seismic projects, the credit is for the lesser of 75 percent of qualified seismic exploration expenditures or $7.5 million. It includes expenditures incurred for work performed after June 1, 2012 and before July 1, 2016.

Per-Taxable-Barrel Credit, AS 43.55.024(j)

Beginning January 1, 2014, there is a per-taxable-barrel credit for oil production on the North Slope. This credit cannot be transferred, carried forward, or used to reduce the producer's tax liability to less than zero. In areas that qualify for a gross value reduction (GVR), the credit is five dollar per taxable barrel. Those areas are defined in AS 43.55.160(f) and (g). For areas that do not qualify for a GVR, the credit is on a $10 increment sliding scale. The sliding scale credit is a dollar-per-taxable barrel credit ranging from zero dollars per barrel at gross value at point of production (GVPP) values greater than $150 to $8 per barrel at GVPP values less than $80 per-barrel. The sliding scale credit may not reduce the producers' tax liability to less than the minimum tax established under AS 43.55.011(f).

Qualified Capital Expenditure and Well Lease Expenditure Credit, AS 43.55.023(a) and (1)

This credit is a transferable tax credit for qualified oil and gas capital expenditures in the State. It can be taken in lieu of exploration incentive credits under AS 43.55.025 and gas exploration credits under AS43.20.043. The credit is 20 percent of eligible expenditures anywhere in the State, or 40 percent for qualified well lease expenditures for areas other than the North Slope. The qualified capital expenditure credit was no longer available for North Slope capital expenditures beginning January 1, 2014.

Small Producer / New Area Development Credit, AS 43.55.024(a) and (c)

The Small Producer Credit is a non-transferable credit for oil and gas produced by small producers, defined as having average taxable oil and gas production of less than 100,000 BTU equivalent barrels per day. The credit is available until the later of 2016 or nine years after the first commercial production of oil and gas on the properties for which the credit applies. The small producer credit is capped at $12 million annually for producers with less than 50,000 BTU equivalent barrels per day. The credits then phases out, reaching to zero for producers with 100,000 or more BTU equivalent barrels per day. The credit may only be used against a tax liability, providing the producer has a positive tax liability before the application of credits. The New Area Development Credit is a credit of up to $6 million per company annually, for oil or gas produced from leases outside Cook Inlet and south of 68 degrees North latitude, providing the producer has a positive tax liability on that production before the application of credits. The credit is available until the later of 2016 or nine years after the first commercial production of oil and gas on the properties for which the credit applies.

Transitional Investment Expenditure Credit, AS 43.55.023(1)

The transitional investment expenditure credit is a non-transferable credit for qualified oil and gas capital expenditures incurred between March 31, 2001 and April 1, 2006. It is only available to companies that did not have production in commercial quantities prior to January 1, 2008. The credit may not be used after December 31, 2013. The credit is 20 percent of qualified oil and gas capital expenditures incurred between March 31, 2001 and April 1, 2006, not to exceed 10 percent of the capital expenditures incurred between March 31, 2006 and January 1, 2008.

Credits applicable to CIT

There are several credit programs targeted specifically at oil and gas CIT in Alaska. Two of the credits under this program pertain to natural gas. AS 43.20.023 provides a credit of 25 percent of qualified expenditures for exploration and development of Cook Inlet and non-North Slope natural gas reserves. This credit was extended and expanded in the 2010 legislative session. A second oil and gas CIT credit provides a credit for the costs incurred to establish a natural gas storage facility or LNG storage facility. Over the past two years, two more credit programs were established under the CIT system. An oil and gas industry service expenditures credit was added to incentivize in-state manufacturing or modification of oil and gas tangible person property. Another credit was added in 2014 to assist in-state refineries with qualified infrastructure expenditures. Below are more detailed descriptions of credits applicable to CIT in Alaska.

Gas Exploration and Development Credit, AS 43.20.043

The Gas Exploration and Development Credit is a nontransferable credit for qualified expenditures for the exploration and development of non-North Slope natural gas reserves. The credit is 25 percent of qualified expenditures for investment after January 1, 2010; investments in existing units qualify. The credit is capped at 75 percent of tax liability as calculated before applying other credits.

Gas Storage Facility Credit, AS 43.20.046

The Gas Storage Facility Credit is a non-transferable credit for the costs incurred to establish a natural gas storage facility. The credit is $1.50 per thousand cubic feet of "working gas" storage capacity as determined by the Alaska Oil and Gas Conservation Commission. It does not apply to gas storage related to a gas sales pipeline on the North Slope. To qualify, the facility must operate as a public utility regulated by the Regulatory Commission of Alaska with open access for third parties. It is effective for facilities placed into service between January 1, 2011 and December 31, 2015. The maximum credit is the lesser of $15 million or 25 percent of costs incurred to establish the facility.

LNG Storage Facility Credit, AS 43.20.047

The LNG Storage Facility Credit is a non-transferable credit for the costs incurred to establish a storage facility for liquefied natural gas. The credit is the lesser of $15 million or 50 percent of the costs incurred to establish the facility. It applies to facilities with a minimum storage capacity of 25,000 gallons of LNG and are public utilities regulated by the Regulatory Commission of Alaska (RCA). It is for facilities placed into service after January 1, 2011.

Oil and Gas Industry Service Expenditures Credit, AS 43.20.049

The Oil and Gas Industry Service Expenditures Credit is a credit of 10 percent of qualified oil and gas industry service expenditures that are for in-state manufacture or in-state modification of oil and gas tangible personal property with a service life of three years or more. The credit may be applied to CIT liabilities in amounts up to $10 million per taxpayer per year. The credit is effective for expenditures incurred after January 1, 2014. The credit is not transferable but any amount of the credit that exceeds the taxpayer's liability may be carried forward up to five years.

Internal Revenue Code Credits Adopted By Reference, AS 43.20.021

Under Alaska's blanket adoption of the federal Internal Revenue Code, taxpayers can claim all

federal incentive credits. Federal credits that refund other federal taxes are not allowed. Multistate taxpayers apportion their total federal incentive credits. In most cases the credit is limited to 18 percent of the amount of the credit determined for federal income tax purposes which is attributable to Alaska.

Education Credit

See "Credits Applicable to Multiple Tax Programs."

Minerals Exploration Incentive Credit

See "Credits Applicable to Multiple Tax Programs."

Veteran Employment Tax Credit, AS 43.20.048

The Veteran Employment Credit is a non-transferable credit for CIT payers that employ qualified veterans in the State. A "qualified veteran" is a veteran who was unemployed for more than four weeks preceding the employment date and who was discharged or released from military service not more than ten years before employment date (for a disabled veteran) or not more than two years before employment date (for a veteran who is not disabled). The credit is $3,000 for a disabled veteran or $2,000 for a veteran who is not disabled for employment for a minimum of 1,560 hours during 12 consecutive months following the veteran's employment date. For seasonal employment, the credit is $1.000 for a veteran employed for a minimum of 500 hours during three consecutive months following the employment date.

Credits applicable to multiple tax programs

Additional credit programs are less targeted and may be applicable under multiple tax programs including those benefiting oil and gas exploration and development in Alaska. Below are more detailed descriptions of these credits applicable to multiple tax programs in Alaska.

Education Credit, AS 21.96.070, AS 43.20.014, AS 43.55.019, AS 43.56.018, AS 43.65.018, AS 43.75.018, AS 43.77.045

The Education Credit is a nontransferable credit applicable to the state CIT. Fisheries Business Tax, Fishery Resource Landing Tax, Insurance Premiums Tax, Title Insurance Premiums Tax, Mining License Tax, Oil and Gas Production Tax, and the Oil and Gas Property Tax. It is a nontransferable credit for contributions to vocational educational programs, accredited Alaska universities or colleges for educational purposes or facilities, annual intercollegiate sports tournaments, Alaska Native educational programs, and facilities that qualify under the Coastal American Partnership. The credit is available for up to 50 percent of annual contributions up to $100,000, 100 percent of the next $200,000, and 50 percent of annual contributions beyond $300,000 up to $10 million. The credit for any one taxpayer cannot exceed $5 million annually across all eligible tax types. The credit at these rates is effective from January 1, 2011 until December 31, 2020, at which point the maximum credit for any taxpayer is $150,000 per year.

Film Production Credit, AS 43.98.030, under AS 21.09.210, AS 21.66.110, AS 43.20, AS 43.55, AS 43.56, AS 43.65, AS 43.75, AS 43.77

The Film Production Credit is a transferable credit for expenditures on eligible film production activities in Alaska. Effective July 1, 2013: (1) a producer must spend at least $75,000 in qualified expenditures over a consecutive 24-month period to qualify, (2) the credit is 30 percent of eligible film production expenditures, plus an additional 20 percent credit for wages paid to Alaska residents, plus an additional six percent credit for filming in a rural area, plus an additional 2 percent credit for filming between October 1 and March 30, (3) the credits must be used within six years, (4) the tax credit applies to multiple tax programs in addition to CIT. The program is capped at a $300 million maximum budget for all projects and expires on July 1, 2023.

Minerals Exploration Incentive Credit, AS 27.30.030, AS 43.20.044

The Minerals Exploration Incentive Credit is applicable to the CIT, Mining License Tax (MLT), and

Mineral Production Royalty. It is a non-transferable credit for eligible costs of mineral or coal exploration activities and must be used within fifteen years. The credit is 100 percent of allowable exploration costs with a maximum of $20 million. For MLT, the credit is limited to the lesser of 50 percent of the MLT liability at the mining operation at which the exploration occurred or 50 percent of total MLT liability. For CIT, it is limited to the lesser of 50 percent of MLT liability at the mining operation at which the exploration occurred or 50 percent of total CIT liability. For mineral royalty, the credit is limited to 50 percent of royalty liability from the mining operation at which the exploration activity occurred.

Credits applicable to royalty

In addition to tax credits and incentives, there are several royalty related incentives in current law that are not discussed in detail in this report. Many of them are tailored to a specific project, economic criteria, or lease type. For example, there is a licensing program that allows for more favorable lease terms for explorers to gain access to large tracts of state land. For economically challenged projects, the DNR commissioner can modify royalty terms to incentivize production.

Oil and gas credit and incentive history

Figure 8-3 summarizes the tax credits in current law that are applicable to the oil and gas production tax and the state CIT, and the amount of credits used in each of the past three years. Figure 8-4 shows history of total oil and gas production tax programs in Alaska from 2008 through 2014 broken down by those used by producers against their tax liability and those purchased by the state for cash. We note that there has been an increasing use of tax credits in total, especially those authorized at AS 43.55.023, over the three-year period. Figure 8-5 summarizes the oil and gas credit programs and their dates of enactment and expiration.

Figure 8-3. Alaska tax credit programs that may apply to oil and gas exploration and development.

Alaska Tax Credits Claimed[1] ($millions)			
Credit Type and Applicability[2]	Total Credits Claimed in FY ($millions)		
	2012	2013	2014 [1]
Credits Applicable to the Oil and Gas Production Tax			
Alternative Credit for Exploration (AS 43.55.025), Cook Inlet Jack-Up Rig Credit, and Frontier Basin Credit	$57	$11	$59
Carried-Forward Annual Loss Credit (AS 43.55.023(b))	Totals included in Qualified Capital Expenditure Credit		
Cook Inlet Jack-Up Rig Credit (AS 43.55.025(a)(5) and (l))	Totals included in Alternative Credit for Exploration		
Exploration Incentive Credit (AS 38.05.180(i))	$0	$0	$0
Frontier Basin Credit (AS 43.55.025(p))	Totals included in Alternative Credit for Exploration		
Per Taxable Barrel Credit (AS 43.55.024(j))	Credit program began on January 1, 2014		$492
Qualified Capital Expenditure Credit, Well Lease Expenditure Credit, and Carried-Forward Annual Loss Credit (AS 43.55.023(b))	$606	$854	$861
Small Producer / New Area Development Credit (AS 43.55.024(a) and (c))	$53	$53	$54
Transitional Investment Expenditure Credit (AS 43.55.023(i))	Cannot be reported due to taxpayer confidentiality		
Credits Applicable to the Corporate Income Tax			
Film Production Credit (AS 43.98.030)	$3	$6	$21
Gas Exploration and Development Credit (AS 43.20.043)	Cannot be reported due to taxpayer confidentiality		
Gas Storage Facility Credit (AS 43.20.046)	$0	$0	$15
In-State Gas Refinery Credit (AS 43.20.053)	Credit program began January 1, 2014		
Internal Revenue Code Credits Adopted by Reference (AS 43.20.021)	Not tracked		
LNG Storage Facility Credit (AS 43.20.047)	Program began in 2012	$0	$0
Oil and Gas Industry Service Expenditures Credit (AS 43.20.049)	Credit program began January 1, 2014		
Veteran Employment Tax Credit (AS 43.20.048)	Program began in 2013	$0	$0
Credits Applicable to Multiple Tax Programs			
Education Tax Credit (AS 21.96.070, AS 43.20.014, AS 43.55.019, AS 43.56.018, AS 43.65.018, AS 43.75.018, AS 43.77.045)	$4	$7	$3
Total All Credits	**$729**	**$940**	**$1,506**

[1]FY 2014 credit totals are estimated pending annual tax filings

[2]The Alaska DOR "Revenue Sources Book" (http://www.tax.alaska.gov/programs/sourcebook/index.aspx) can provide additional descriptions, applicability information and other details on specific credit programs.

Figure 8-4. Credits applicable to the oil and gas production tax program in Alaska, broken down by those used by producers against their tax liability and those purchased by the state for cash.[1]

	($ millions)						
Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014 [1]**
Statewide Credits							
Credits Used against Tax Liability	557	378	333	386	363	549	888
Credits Purchased by the State [2]	55	54	193	450	353	369	593
Total Statewide Production Tax Credits	612	432	526	836	716	918	1,481

[1] FY 2014 credit totals are estimated pending annual tax filings.

[2] Credits purchased by the State consist primarily of production tax credits purchased, but also include corporate income corporate income tax credits available for state purchase from the Oil and Gas Tax Credit Fund. These include the gas storage facility credit, LNG storage facility credit, and refinery credits.

Figure 8-5. Enactment and expiration dates applicable to the oil and gas production tax credit programs.

Credit	Year Enacted	Sunset/Expiration Date
Exploration Incentive Credit	1978	None
Qualified Capital Expenditure & Well Lease Expenditure Credit	2006 Amended 2007	None
Carried-Forward Annual Loss Credit	2006 Amended 2008	None
Small Producer/New Area Development Credit	2006	2016
Transitional Investment Expenditure Credit	2006 Amended 2008	2013
Alternative Credit for Exploration	2003 Amended 2008	2016
Cook Inlet Jack-Up Rig Credit	2010	2016
Frontier Basin Credit	2012	2016
Federal Tax Credits	1975	None
Gas Exploration and Development Credit	2003 Amended 2010	None
Gas Storage Facility Credit	2011	2015
LNG Storage Facility Credit	2012	None
Film Production Credit	2008 Amended 2012	2023
Education Credit	1987 Amended 2012	None

9. Fiscal system comparisons

This report began by presenting information comparing Alaska with a group of peers based on non-fiscal criteria that oil and gas companies may consider when deciding where to invest exploration, development and production dollars. In the previous section Alaska's fiscal regime was summarized. In this section the basic styles of worldwide fiscal regimes are outlined followed by a comparison of Alaska's fiscal regime and Alaska's peer group.

Fiscal regime styles

There are nearly as many types of contractual arrangements between governments and oil and gas companies as there are jurisdictions with mineral resources to recover. Among the many general types of agreements, the basic differences tend to be in various approaches to the four following areas:

- Ownership. Are the hydrocarbons owned by the oil company in the ground or at the wellhead or elsewhere, or are they owned by the state throughout?
- Payment. Is payment made by companies receiving hydrocarbons by lifting hydrocarbons they own, or in lieu of payment for cost and profit recovery?
- Profit drivers. Is the contract structured such that the oil companies are fully exposed to price risk, or are their returns fundamentally driven by payments based on the amount of money invested?
- Operational freedom. How do contractual and administrative terms affect the degree of freedom with which companies can operate and vary their investment decisions within the country?

It should be noted that there is no one best approach. None of the specific approaches discussed is necessarily more or less beneficial to all jurisdictions than the others, as the specific levels of payments and handling of risk can and do vary greatly from country to country and contract to contract.

Typically there are taken to be three "headline" styles of petroleum regimes: concessions, production sharing contracts (PSCs) and service contracts (Figure 9-1). Typically, under a concession arrangement, the fiscal components are handled separately from the award of rights to explore and produce, while under PSCs and service contracts the fiscal structure tends to be tightly interwoven with the underlying contracts specifying each party's rights.

However, as with any generalization, care must be taken as it is possible to construct any of the headline regime styles to look and act very much like another. In particular, the financial returns from each may be very similar, notwithstanding more obvious differences. Indeed, when countries look to update or modify their petroleum contractual or fiscal regime, they are always "benchmarking" it against those of other countries, and aspects are "borrowed" from one to another regardless of the headline contract style involved.

Complexity

An important consideration with all types of fiscal systems is the issue of complexity. Fiscal regimes need to be complex enough to properly compensate governments and mineral owners, and project investors and developers over the entire life of a project, as well as fairly treat a broad spectrum of different project types and sizes that may fall under the same system. On the other hand, fiscal systems that are overly complex can discourage investment when investors can't reasonably forecast their possible profits, costs, timing, and risks in a particular jurisdiction. The system that attracts investment most successfully is likely to be the least complex system that still properly allocates costs and benefits at the lowest risk possible.

Production sharing contracts

The first PSCs were signed in 1967 with Indonesia. These contracts are also known as production sharing agreements (PSAs) in some locations. The two parties to the PSC are the owner-country usually in the form of a national oil and gas company (NOC) and an international oil and gas company (IOC). Unlike tax and royalty systems, PSCs generally transfer title to the produced hydrocarbons at the export point (as opposed to at the wellhead in tax/royalty systems, under which the resource in the ground is owned by the state). PSCs typically differ from service contracts in that reimbursement to the IOC is in-kind and the parties to the PSC own the rights to their share of the oil.

In general, PSCs divide gross production into what is frequently referred to as cost oil (oil or gas applied to reimburse costs) and profit oil (that in excess of cost oil) with the contractor receiving its compensation from cost oil and a share of the remaining profit oil.

Service contracts

A service contract is a type of agreement whereby an IOC performs exploration and/or production services for the host government within a specified area for a fee. The host government maintains ownership at all times of the hydrocarbons produced, and usually the IOC (contractor) does not acquire any rights or title to the oil and or gas, except where a contractor is paid its fee in kind (oil or gas) or is given a preferential right to purchase production from the host government. Pure service agreements between a host government and an IOC are rare. These forms of arrangement are used in Iran, Saudi Arabia, the Philippines, and Kuwait, but are not used by governments in North America or Europe.

Concession contracts

The current tax and royalty schemes grew out of concession systems commonly seen in the early part of the 20th century. The concept of tax and royalty fiscal regimes is easy to describe in that the government owners of the mineral lease tracts for exploration and development directly to an oil and gas company contractor group either through negotiations or through some sort of competitive bidding. An initial cost typically includes acreage rental payments plus fixed or variable royalties. The government authorities tax the contractor group members based on their profitability from the leased tract (block).

The OCS mineral leases represent a tax and royalty scheme. While most OCS leases contain a competitive bid and fixed royalty payments, tax/royalty schemes can include work commitments, variable royalties, net profit interests, etc.

A number of countries with tax/royalty regimes include, in addition to corporation tax, various forms of "rent" or taxes to capture a greater share of the economic benefit arising from operations, whether these result simply from highly profitable fields or from windfalls such as high petroleum prices. Examples include the U.K.'s Petroleum Revenue Tax, Norway's Supplemental Petroleum Tax, Brazil's Special Participation, Australia's Petroleum Resource Rent Tax and Alaska's ACES production tax, now replaced by SB 21. In the case of the U.K., Norway and much of offshore Australia, no royalty at all is levied and the countries rely on "rent" and income taxes for virtually their entire share of profits.

Leases granted under a tax/royalty style arrangement are quite different from the old style concession agreements, even though the term "concession" may still be used (as well as "permit" or "license"). While details vary from one jurisdiction to another, they all contain significant term provisions, usually involving relinquishment of some part of the acreage at various stages such that only the immediate producing area remains held for a long time (typically the life of production). In some jurisdictions, minimum work obligations will also apply to different holding

periods. Operators are generally able to report their "net" booked reserves[29], which are 100 percent of the gross reserves less royalty.

Elements of comparison and definitions

In Figure 9-2 terms are used to classify some of the categories of government take commonly found in concession fiscal regimes. To clarify their use for the purpose of this publication, definitions for several other terms are presented below.

Royalty

The landowner's share of production, generally considered to be free of expenses of production. The landowner's royalty was historically frequently set at 1/8th of production, but it may be any fractional share or percentage of production.

Royalty may be payable in-kind (where the royalty owner is entitled to a share of the oil or gas as produced) or in-value (where the royalty owner is paid in money for the value or market price of his share of the production).

Rental fee (delay rental)

A lease covenant or term which provides for a flat sum periodic payment to the lessor by the lessee for the privilege of holding or maintaining a mineral lease and deferring the commencement of drilling operations or the commencement of production during the primary term of the lease. A lessee's failure to make the rental payment to the landowner in a timely fashion can result in the termination of the lease.

Property/ad valorem tax

A tax based on the assessed/appraised fair market value of real or personal property imposed by a governmental jurisdiction. The property/ad valorem tax is typically payable by the owner of the real or personal property, so lease operators are not automatically responsible for a property tax liability of a working interest owner. In Texas (and in some other states), this tax becomes payable only when minerals are producing (as opposed to non-producing), and are billed and collected once per year. Sales tax rates shown in Figure 9-2 are assumed to be for capital expenditures only. This treatment will understate the total sales tax revenue for those states that impose general sales tax to the extent that there are other taxable inputs (i.e., non-capital goods used in operations and production).

Corporate income tax

A tax levied by a government directly on a corporation's income. CIT on oil and gas is often associated with targeted incentives and credits, such as depreciation of assets and credits for certain activities and ventures.

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[29] Booked oil and gas reserves are estimated quantities of hydrocarbons that have a high degree of certainty, usually 90%, of existence and exploitability. In other words reserves are estimated quantities of hydrocarbons that a company believes to exist in a particular location and can be exploited. According to the Securities Exchange and Commission (SEC), oil companies are required to report their booked reserves to investors through supplemental information to the financial statements. It is important to note oil still in the ground is not considered an asset until it is extracted or produced. Once the oil is produced, oil companies generally list what isn't sold as products and merchandise inventory.

Net tax/profit share

The use of the term net tax in this document refers to the resource tax on the value of the resource net of most costs of production.

Gross/severance tax

The use of the term gross tax in this document refers to the resource tax on the value of the resource before subtraction of most costs of production.

Indirect sales/value-added tax

A sales tax is a type of indirect consumption tax on oil and gas operations by which a tax is levied on final sales or on the receipts from sales. A value-added tax (VAT) is a similar type of indirect tax on oil and gas operations by which a tax is levied on a product whenever value is added often at many stages of production, marketing and at final sale.

Participation/joint venture

Typical joint ventures (JV) for development share the risks and benefits from oil and gas development and are associated with concession regimes. The national oil company (NOC) partner (participating in a project on behalf of the government that owns the resource) may receive a relatively large initial payment for the execution of the JV and the contractor group partners may carry 100 percent of exploration costs and potentially all costs "to the tanks" for first oil. Subsequent capital and operating costs are shared in the proportions of the JV ownership. Management decisions for the field and staffing of the JV are also shared with the host government, typically via the NOC as the JV partner. There is nonetheless a clear separation between the government as a taxing and licensing authority and the government-owned IOC JV partner. Some portion of the exploration and development "carried costs" are typically reimbursed by the NOC partner to the contractor group either in cash or oil. Ownership of the crude government share of the crude oil is independent of the contractor group ownership. The contractor group is typically entitled only to book reserves for their share of the JV's gross reserves less any government royalty and potentially the reimbursable costs if they are repaid from crude oil.

Peer group jurisdictions

Figure 9-2 includes the highlights of the fiscal regime Alaska offers oil and gas companies interested in doing business in Alaska compared to a group of peer jurisdictions. The information presented in Figure 9-3 and in Chapter 5 of this report will be used to compare Alaska to several other jurisdictions with which we believe the state competes for oil and gas industry investment.

Alaska is compared to other concession-based fiscal regimes largely because of the difficulty of making clear comparisons with the fundamentally very different contract-based fiscal regimes.

Alaska's peer comparisons selected here include a representative group of states and provinces in the U.S. and Canada. Companies doing business in the U.S. and Canada can relatively easily shift the location of their operations and corporate focus to any fiscal regime they see as more beneficial in either of these two countries. However, most of the onshore states and provinces have much lower undiscovered resource potential than Alaska, and do not offer the attraction of conventional "elephant-size" prospects like Alaska does.

California

California (Figure 9-4) is a state with resource potential and historic production similar to Alaska. Issues regarding regulations and environmental concerns make California a reasonable addition to the peer group for Alaska. As in all of the onshore Lower 48, capital and operating costs are

generally assumed to be lower than in Alaska. Infrastructure is well established and much more extensive than in Alaska.

North Dakota

North Dakota (Figure 9-5) has historically experienced lower production volumes than Alaska; however, its production now surpasses Alaska, largely on the strength of shale oil production in the last five years. Capital and operating costs are generally assumed to be lower than Alaska. Infrastructure is well established and much more extensive than in Alaska.

Oklahoma

Oklahoma (Figure 9-6) has experienced lower production volumes than Alaska for more than 25 years, and its production is stable to slightly increasing in recent years. As in all of the onshore Lower 48, capital and operating costs are generally assumed to be lower than in Alaska. Infrastructure is well established and much more extensive than in Alaska.

Texas

Texas (Figure 9-7) is the perennial powerhouse of oil production and potential in the U.S. Production volumes are higher than in Alaska, and its production has been steadily increasing in recent years, largely on the strength of shale oil production. As in all of the onshore Lower 48, capital and operating costs are generally assumed to be lower than in Alaska. Infrastructure is well established and much more extensive than in Alaska.

U.S. Gulf of Mexico Outer Continental Shelf

The Gulf of Mexico OCS (Figure 9-8) is another material oil and gas supply source for the U.S. Oil production volumes in the Gulf of Mexico are higher than in Alaska, but were down in 2010, likely due to BP's Macondo well blowout and spill that occurred that year. Offshore infrastructure is well-established and extensive. Producers under the U.S. OCS fiscal system experience significantly lower overall government take than in Alaska. There is no state or local CIT, property tax, severance tax, production tax or sales tax.

U.S. Beaufort and Chukchi Sea Outer Continental Shelf

The Beaufort Sea and Chukchi Sea OCS (Figure 9-9), off Alaska's northern coast, has seen very minimal historic production (from the Northstar field), but has several discovered accumulations and significant potential. There is no infrastructure in the Alaska OCS. Our assumption is that costs will be high and environmental restrictions and permitting hurdles will be greater than onshore Alaska. The U.S. OCS fiscal system has significantly lower overall government take because there is no state or local CIT, property tax, severance tax, production tax or sales tax. Producers under the U.S. OCS fiscal system experience significantly lower overall government take than in Alaska.

Alberta

Alberta, Canada (Figure 9-10) has greater production volumes, reserves, and resources than Alaska, a large portion of which is heavy oil and oil sands. However, anecdotal evidence indicates that costs are lower there than in Alaska.

In Alberta, as in the rest of Canada, fiscal terms differ significantly from Alaska. Generally, royalties in Canada are not fixed. Usually the provincial lease contracts allow the government to modify royalty rates at its discretion. In Canada, oil and gas corporations are taxed at the same rate as other corporations. Corporations are taxed by the Canadian federal government and by one or more provinces or territories. The basic rate of federal CIT is 26.5 percent, but this rate may be reduced to 16.5 percent by an abatement of 10 percent on a corporation's taxable income earned in a province or territory. Canada's federal CIT rate is 16.5 percent, lower than the 35 percent U.S. CIT. The Alberta provincial CIT rate is 10 percent.

Northwest Territories

Northwest Territories, Canada (Figure 9-11), unlike Alberta, has no production history; however, potential is significant. Currently, the Canadian federal government manages oil and gas resources in the Northwest Territories; therefore, the fiscal system is very similar to the Canadian federal offshore Beaufort Sea described below. Costs here are assumed to be similar to Alaska and infrastructure is limited. The Northwest Territories' fiscal terms differ significantly from Alaska. Generally, royalties in Canada are not fixed. Usually the provincial lease contracts allow the government to modify royalty rates at its discretion. The Northwest Territories' provincial CIT rate is 11.5 percent.

Canada Federal Offshore Beaufort Sea

Canada's federal offshore Beaufort Sea (Figure 9-12), like the Northwest Territories, has no production history; however, its potential is significant. Costs here are assumed to be similar to offshore Alaska, and infrastructure is limited.

Australia

Australia (Figure 9-13) is included in Alaska's peer group because it has a concession-based fiscal regime and easy access to Pacific Rim markets. In recent years, some Australian oil and gas companies have become interested in Alaska and are now actively pursuing projects here.

Norway

Norway (Figure 9-14) is included in Alaska's peer group because the country applies a concession-based fiscal regime, has a resource base similar to Alaska, and is often the subject of comparison in debates about Alaska's fiscal regime. Like Alaska, the Norway's North Sea basin is generally considered mature by oil and gas industry standards.

United Kingdom

The U.K. (Figure 9-15) is included in Alaska's peer group because the country applies a concession-based fiscal regime, has a resource base similar to Alaska, and is often the subject of comparison in debates about Alaska's fiscal regime. Like Alaska, the U.K.'s North Sea basin is generally considered mature by oil and gas industry standards.

Excluded jurisdictions

The list of peers for Alaska's oil and gas fiscal regimes is short. This is to facilitate, to the extent possible, more direct, logical comparisons. Of the hundreds of jurisdictions and fiscal regimes in the world, only those with the most reasonable parallels to Alaska were selected for inclusion in the peer group. This meant excluding the vast majority of jurisdictions. The logic for excluding jurisdictions from the peer group is the same as the logic used to determine which jurisdictions to include.

Excluded states and provinces

A number of other states located in the western U.S. were considered for inclusion in the peer group. However, most of the states excluded from the peer group have significantly smaller oil and gas endowment and smaller production volumes than Alaska and its peer group. States that were considered but excluded are Colorado, Kansas, Montana, New Mexico, South Dakota, Utah, and Wyoming. Despite their exclusion from the peer group, their fiscal systems are similar to the states that were included, so they are not totally unrepresented in the chosen peer group.

Similarly, several provinces and offshore federal waters of Canada were considered for inclusion in Alaska's fiscal system peer group. But, with the exception of Alberta, sufficient data were unavailable or the resource endowment and historical production were too small to warrant comparison.

Fiscal system exclusions

Internationally, many jurisdictions are excluded from the Alaska peer group because their fiscal regime is not a pure concession-type fiscal system. It is unlikely that Alaska would ever consider moving to a production sharing contract or a service contract fiscal regime and therefore, it is logical that these countries are excluded from Alaska's peer group. This exclusion group based on fiscal system type is comprised of countries such as Indonesia, New Guinea, Myanmar, Angola, Nigeria, Egypt, Iraq, Brazil, Columbia, Mexico, and Venezuela.

Geographic location exclusions

A second criterion for excluding some foreign countries is their geographic location. Many countries were excluded based on their location away from the Arctic region or the Pacific basin. The logic for this is that the refineries that Alaska's oil supplies are all located in Hawaii or on the west coast of the U.S. and the economic barrier may be higher for them to shift their supply source to other countries outside the Pacific basin. The exclusion group based on geographic location is comprised of countries such as South Africa, Angola, Nigeria, Egypt, Iraq, Brazil, Columbia, Mexico, Venezuela, and Argentina.

Production history exclusions

A third criterion for excluding certain countries is the resource base and production history. Filtering fiscal systems in this way will exclude jurisdictions with a resource base or production history that is longer than Alaska's, such as Russia and many Middle Eastern countries, or where production history, reserves and undiscovered resource are much less, as in most U.S. states, most Canadian provinces, Thailand, Vietnam, Greenland, and Iceland.

Figure 9-1. Petroleum legal arrangement classifications.

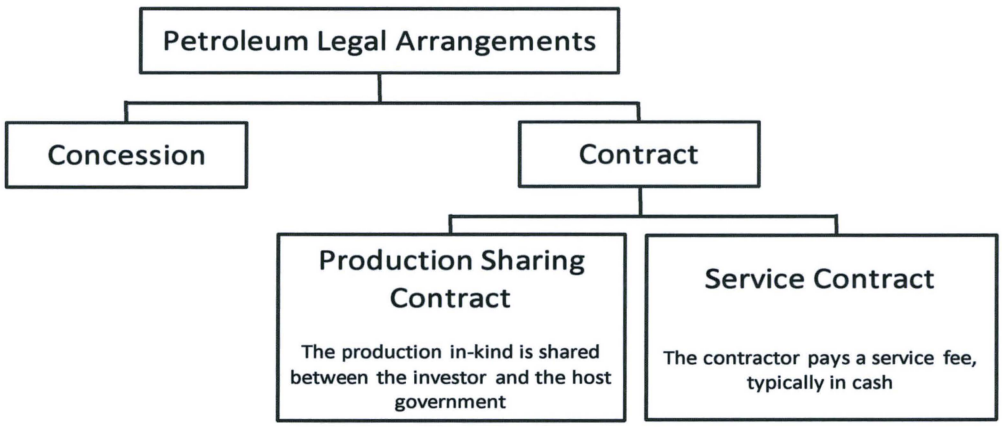


Figure 9-2. Petroleum fiscal regime peer group highlights.

Jurisdiction	Royalty (% of Gross Production)	Rental Fees ($ per Acre)	Property /Ad Val. Tax	Federal Corp. Income Tax Rate	State/ Province Corp. Income Tax Rate	Net Tax / Profit Share (net of costs)	Gross / Severance Tax	Indirect Sales / VAT Tax Rate	Partici-pation
U.S./States									
Alaska	State: 12½% - 16⅔% Federal: 12½%	State: $1 - $3 Federal: $1.50 - $2	Yes	35%	9.4%	North Slope: 35% and up	Gross minimum tax may apply	none	-
California	Federal: 12½% Private: 16⅔% - 25%	Federal: $1.50 - $2 Private: $5 - $30	Yes	35%	8.84%	-	$0.1063/bbl. $0.1063/MCF	7%	-
North Dakota	State: 16⅔% Private: 12½% - 25%	State: $0 - $1 Private: $1	None	35%	6.4%	-	5% - 11.5%	5%	-
Oklahoma	Private: 12½% - 20%	Private: $1	Yes	35%	6%	-	7.2% (reduced at low prices)	4.5%	-
Texas	Private: 12½% - 30%	Private: $3.50	Yes	35%	1% of Net Taxable	-	$0.0063/bbl. $0.0667/MCF plus 0 - 4.6% oil and liquids and 7.5% gas value	6%	-
U.S. GOM OCS	Federal: 18¾%	Federal: $7 - $16	None	35%	-	-	-	none	-
U.S. Alaska OCS	Federal: 12½%	Federal: $2.50 - $20	None	35%	-	-	-	none	-
Canada/Provinces									
Alberta	Province: 0% - 40%	Province: $1.35	None	16.5%	10%	-	-	5%	-
Northwest Territories	Province: 1% - 5%	work commitment, no rental	None	16.5%	11.5%	-	-	5%	-
Canada - Beaufort Sea	Federal: 1% - 5%	work commitment, no rental	None	26.5%	-	-	-	5%	-
International									
Australia - Deepwater	none	Federal: $0 - $1	None	30%	-	40%	-	10%	-
Norway	none	Federal: $20 - $80	None	28%	-	50%	-	25%	20%
U.K.	none	Federal: $0.1 - $30	None	30%	-	32%	-	20%	-

Figure 9-3. Alaska fiscal system highlights (needs work).

Royalty:	Generally 12½ or 16⅔ percent, most production pays at 12½ percent. Higher royalty rates on some private lands do exist, but generally private rates are not lower than state rates. Natural gas royalty rate is the same as oil on state and federal lands. Most production in Alaska is on state-owned lands.
Rental Fee:	Alaska state lands: 1st year - $1, 2nd year - $1.50, 3rd year - $2, 4th year - $2.50, and 5th and subsequent years - $3 per acre. Rental is creditable against royalties. Federal lands: $1.50 per acre delay rental for years 1 – 5 and $2 per acre thereafter.
Property/ad valorem tax:	The State of Alaska levies a property tax on the full and true value of all oil and gas property in the state. The property tax is assessed annually and the tax rate is 20 mills. Oil and gas property that is also within local boundaries may be taxed on the local level and that amount is deducted from the property tax paid to the state.
CIT:	The U.S. federal CIT rate is 35 percent. The state CIT rate for oil and gas is graduated with the top tax rate of 9.4 percent levied when net incomes exceed $90,000 for the year. The CIT for oil and gas uses a modified apportionment method, whereby a corporation's tax liability is based on the size of its Alaska operations relative to its worldwide net income. The apportionment factors used to determine a corporation's Alaska tax liability are the Alaska operation's (1) tariffs and sales; (2) oil and gas production; and (3) oil and gas property.
Net Tax/Profit Share:	The Alaska state production tax is fundamentally different than all other federal and state jurisdictions in the U.S., in that it is a "net" tax, after most costs and expenses are subtracted from revenue. This aspect of Alaska's fiscal regime remains unchanged despite changes made to the state's oil and gas production tax that went into effect in 2014. The production tax formula consists of two primary pieces: a base tax rate of 35 percent. With the 2014 tax changes, variable credit mechanism was created, with the value of the credit changing with an inverse relationship to the value of the oil produced. A company's tax liability may be reduced by credits that are included in the production tax system. Additionally, Alaska has a 4 percent gross minimum tax that may apply in some circumstances (see Gross/Severance Tax section below). The basic tax calculation of Alaska's production tax is as follows: **Production Tax Liability = [(Value – Costs) * Tax Rate] – Credits** **Value, production from existing fields** = Volume of Non-Royalty Oil & Gas Produced * Wellhead Value **Value, new production** = Volume of Non-Royalty Oil & Gas Produced * Wellhead Value * 80 or 70 percent **Costs** = Operating and Capital Expenditures **Tax Rate** = 35 percent **Credits, production from existing fields** = Value of $0 to $8 per taxable barrel of oil produced **Credits, new production** = Value of $5 per taxable barrel of oil produced

Gross/Severance Tax:	**Minimum tax, production from existing fields** = 4 percent of Value before costs are subtracted
Indirect Taxes:	None.
Incentives and Credits:	Alaska offers, by most accounts, generous incentives targeted in several ways. See Figure 8-2 for details on many of Alaska's credit incentives. In addition to tax credits listed in Figure 8-2, Alaska offers special incentives for Cook Inlet and other "non-North-Slope" oil and natural gas production, royalty modification, natural gas storage. Royalty modification, or reduction, on State of Alaska leases may be considered if an operator shows the state that a development project is uneconomic if developed without royalty modification. In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and the carry-forward of tax losses.

Figure 9-4. California fiscal system highlights.

Royalty:	Federal lands: Most production pays at 12½ percent. Natural gas rate is same as oil. Private lands: Generally 16⅔ or 25 percent, most production pays at 16⅔ percent. The majority of production in California is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental Fee:	Federal lands: $1.50 per acre delay rental for years 1 – 5 and $2 per acre thereafter. Private lands: $5 to $30 per acre, assumed to be $20 per acre.
Property/ad valorem tax:	Property tax, administered by counties, is based on the lesser of the market value of the property and the Proposition 13 tax cap value. The rate is assumed to be 1 percent. This rate reflects a statewide average for counties and school districts.
CIT:	The U.S. federal CIT rate is 35 percent. The state CIT rate for oil and gas is 8.84 percent.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	An Assessment Tax applies at $0.14062 per barrel oil or per 10,000 cubic feet natural gas.
Indirect Taxes:	7¼ percent sales tax.
Incentives and Credits:	In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and tax loss carry-forward.

Figure 9-5. North Dakota fiscal system highlights.

Royalty:	North Dakota state lands: Most production pays at 16⅔ percent. Natural gas rate is same as oil. Federal lands: Most production pays at 12½ percent. Natural gas rate is same as oil. Private lands: Most production pays at 18 ¾ percent. The majority of production in North Dakota is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental Fee:	North Dakota state lands: $1 per acre (during exploration period only). Federal lands: $1.50 per acre delay rental for years 1 – 5 and $2 per acre thereafter.
Property/ad valorem tax:	None.
CIT:	The U.S. federal CIT rate is 35 percent. The state CIT rate for oil and gas is 6.4 percent.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	The overall tax is comprised of two pieces, 1. Severance Tax and 2. Oil Extraction Tax, that sum together for a total tax rate of 11½ percent, before incentives and credits. The Severance Tax is 5 percent of gross value and is effectively an irreducible minimum tax that is unaffected by any incentives or credits offered by the state. The Oil Extraction Tax starts at 6½ percent of gross value, but may be lower if production qualifies for incentives or credits offered by the state.
Indirect Taxes:	5 percent on all capital goods brought into the state.
Incentives and Credits:	North Dakota offers incentives for certain types of activities and ventures. These programs include lower Oil Extraction Tax (OET) for very-low-production volume (stripper) wells and when WTI oil price minus $2.50 falls below an inflation adjusted "Trigger" price, recently at $46.78. To encourage horizontal oil wells the OET is reduced to 2 percent for the earlier of 75,000 barrels produced, 18 months, or $4.5 million in gross production revenue. To encourage production in the Bakken Formation, the OET is reduced to 2 percent for the earlier of 75,000 barrels produced, or 18 months. In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and tax loss carry-forward.

Figure 9-6. Oklahoma fiscal system highlights.

Royalty:	Private lands: Rate range between 12½ and 20 percent, average assumed to be 18¾ percent. Virtually all production in Oklahoma is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental Fee:	Private lands: assumed to be $1 per acre delay rental.
Property/ad valorem tax:	Oklahoma assesses a Franchise Tax at $1.25 per $1,000 invested, to an annual maximum of $20,000 per corporate entity.
CIT:	The U.S. federal CIT rate is 35 percent. The state CIT rate for oil and gas is 6 percent.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	1.2 to 7.2 percent total, broken down in four pieces. 1. Petroleum Excise Tax at 0.095 percent rate; 2. Energy Resources Board Fee at 0.1 percent rate; 3. Marginal Well Fee at $0.0035 per barrel oil and $0.00015 per thousand cubic feet natural gas; and 4. Gross Severance Tax assessed based on price as follows: 7 percent if the statewide average price of Oklahoma oil equals or exceeds $17.00 per barrel oil or $2.10 per mcf natural gas, 4 percent if the statewide average price of Oklahoma oil is less than $17.00 but is equal to or exceeds $14.00 per barrel oil or is less than $2.10 but is equal to or exceeds $1.75 per mcf natural gas, 1 percent if the statewide average price of Oklahoma oil is less than $14.00 per barrel oil or $1.75 per mcf natural gas.
Indirect Taxes:	4.5 percent on goods and services.
Incentives and Credits:	Oklahoma offers incentives for certain types of activities and ventures. Beginning July 1, 2012, in lieu of an incentive rebate for horizontally drilled and ultra-deep wells, a reduced tax rate shall be levied. Horizontal wells will be levied at 4 percent for the first 48 months of production. Deep wells drilled between 15,000 and 17,499 feet will be levied at 4 percent for 48 months and deep wells drilled below 17,500 feet will be levied at 4 percent for 60 months. Upon expiration of the incentive terms of 48 and 60 months, the Gross Production Tax Rate will be levied at the 7 percent base rate. Additionally, exemptions are available from the Gross Production Tax levied on oil and gas produced from certain wells. The exemption is equal to 6/7ths of the 7 percent Gross Production Tax and is rebated back to producers of qualified wells. Producers are eligible to file claims for refund on a July through June fiscal year basis. Wells qualifying for the exemption are as follows: horizontally drilled wells, the reestablished production of a well that was non-productive for one year, production enhancements such as work overs and recompletions, wells drilled and completed at a depth of 12,500 feet or greater, wells classified as "New Discovery", wells meeting the criteria as being "Economically at Risk", and wells that are drilled and completed based on 3-D seismic technology. In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and tax loss carry-forward.

Figure 9-7. Texas fiscal system highlights.

Royalty:	Private lands: Rate range between 12½ and 30 percent, average assumed to be 25 percent. Virtually all production in Texas is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental Fee:	Private lands: assumed to be $3.50 per acre delay rental, exploration period only. University lands: $25 per acre at the time of the bid, then $5 per acre annually thereafter. Rental is creditable against royalties.
Property/ad valorem tax:	Property taxes assessed at 2.5 percent, levied on the fair market value of reserves as determined by discounted present value. This rate reflects a percent average for counties and school districts.
CIT:	The U.S. federal CIT rate is 35 percent. Texas has no state CIT, however it does levy a Corporate Franchise Tax at 1 percent of "net taxable earned surplus."
Net Tax/Profit Share:	None.
Gross/Severance Tax:	Oil Production Tax is 4.6 percent plus Regulatory Tax at $0.001875 per barrel plus Oil Field Clean-Up Fee at $0.00625 per barrel oil. The oil severance tax may be reduced if production qualifies under certain incentives. Gas Production Tax is 7.5 percent plus Oil Field Clean-Up Fee at $0.000667 per thousand cubic feet natural gas.
Indirect Taxes:	6 percent on goods and services.
Incentives and Credits:	Enhanced Oil Recovery (EOR) projects are taxed at 2.3 percent of the market value. Oil produced from well bores certified by the Texas Railroad Commission as 2-year or 3-year inactive well bores is exempt from the tax for 10 years. Producers are eligible for a production tax credit for crude oil from low producing wells ranging from 100 percent if the average price is $22 or less to 0 percent if the average price is more than $30 per barrel. A certified orphan well put back in production is eligible for a 100 percent exemption from the oil production tax and the oilfield cleanup fee. In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and tax loss carry-forward.

Figure 9-8. U.S. Gulf of Mexico Outer Continental Shelf (OCS) fiscal system highlights.

Royalty:	18 ¾ percent (2008 terms). Natural gas pays the same royalty rate as oil.
Rental Fee:	If water depth <200 meters: $7 per acre for years 1 – 5 and $16 per acre for years 6 – 10. If water depth >200 meters: $11 per acre for years 1 – 5 and $16 per acre for years 6 – 10.
Property/ad valorem tax:	None.
CIT:	The U.S. federal CIT rate is 35 percent. Capital investments in developing oil and gas production sites typically fall into two broad categories, Tangible and Intangible, with tangible being further categorized into two categories. Company classification, Independent or Integrated, is also important. A firm is Independent if its refining capacity is less than 75,000 barrels per day or its retail sales are less than $5 million for the year. Intangible exploration costs are those incurred to identify promising sites and bonus bids paid to acquire lease rights and are subject to Depletion, either cost depletion (UoP) or percent depletion (15 percent). Percent depletion is limited to independent producers and to the value of 1,000 barrels of oil equivalent per day and cannot exceed 100 percent of property taxable income, and 65 percent of the income from all sources before depletion. If daily production exceeds the 1,000 barrel per day threshold, the allowance is multiplied by 1,000 divided by the actual average daily production. The other intangible category is Site Development. Site development costs have no salvage value and are referred to as Intangible Drilling Costs (IDCs). Dry hole costs also fall into this category. Tangible costs, drilling equipment and improvements to property, are recovered under the Modified Accelerated Cost Recovery System (MACRS). MACRS recovery is typically over seven years, but five years is used for drilling equipment. Special rules exist for geological and geophysical expenses. Loss carried forward term is 20 years.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	None
Indirect Taxes:	None.
Incentives and Credits:	The U.S. federal government offers incentives for certain activities and ventures, including royalty reduction, research and development credits, IDC deductions (mentioned above) and the carry-forward of tax losses (mentioned above). Royalty reduction on certain leases, referred to as Royalty Suspension Volume (RSV). Qualification for RSV depends on the particular lease and is triggered at a particular low-price threshold. The threshold price is initially fixed, but increases based on an inflation adjustment.

Figure 9-9. U.S. Beaufort Sea and Chukchi Outer Continental Shelf (OCS) fiscal system highlights.

Royalty:	12½ percent (recent lease sales). Natural gas pays the same royalty rate as oil.
Rental Fee:	1st year - $2.50, 2nd year - $3.75, 3rd year - $5, 4th year - $6.25, 5th year - $7.50, 6th year - $10, 7th year - $12, 8th year - $15, 9th year - $17, and 10th year - $20 per acre.
Property/ad valorem tax:	None.
CIT:	The U.S. federal CIT rate is 35 percent. Capital investments in developing oil and gas production sites typically fall into two broad categories, Tangible and Intangible, with tangible being further categorized into two categories. Company classification, Independent or Integrated, is also important. A firm is Independent if its refining capacity is less than 75,000 barrels per day or its retail sales are less than $5 million for the year. Intangible exploration costs are those incurred to identify promising sites and bonus bids paid to acquire lease rights and are subject to Depletion, either cost depletion (UoP) or percent depletion (15 percent). Percent depletion is limited to independent producers and to the value of 1,000 barrels of oil equivalent per day and cannot exceed 100 percent of property taxable income, and 65 percent of the income from all sources before depletion. If daily production exceeds the 1,000 barrel per day threshold, the allowance is multiplied by 1,000 divided by the actual average daily production. The other intangible category is Site Development. Site development costs have no salvage value and are referred to as Intangible Drilling Costs (IDCs). Dry hole costs also fall into this category. Tangible costs, drilling equipment and improvements to property, are recovered under the Modified Accelerated Cost Recovery System (MACRS). MACRS recovery is typically over seven years, but five years is used for drilling equipment. Special rules exist for geological and geophysical expenses. Loss carried forward term is 20 years.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	None
Indirect Taxes:	None.
Incentives and Credits:	The U.S. federal government offers incentives for certain activities and ventures, including royalty reduction, research and development credits, IDC deductions (mentioned above) and the carry-forward of tax losses (mentioned above). Royalty reduction on certain leases, referred to as Royalty Suspension Volume (RSV). Qualification for RSV depends on the particular lease and is triggered at a particular low-price threshold. The threshold price is initially fixed, but increases based on an inflation adjustment.

Figure 9-10. Alberta (Canada) fiscal system highlights.

Royalty:	0 to 40 percent. Royalties in Alberta are the primary vehicle by which the province assesses its portion of economic rent. Unlike in the Alaska and other U.S. states, royalty rates in Alberta and other jurisdictions in Canada are not set in the lease contract, leases in Alberta simply state that the royalty is established by the provincial government. This leaves the royalty subject to change as government deems appropriate.
Rental Fee:	C$3.50 per hectare (approx. $1.35 per acre) per year.
Property/ad valorem tax:	None.
CIT:	In Alberta, the Canadian federal CIT rate is 16.5 percent. The basic rate of Canadian federal corporate tax is 26.5 percent, but it is further reduced to 16.5 percent by an abatement of 10 percent on a corporation's taxable income earned in a province or territory. The Alberta provincial CIT for oil and gas is 10 percent. Exploration costs are expensed. Land purchase costs are depreciated as Canadian Oil and Gas Property Expense (COGPE) at 10 percent declining balance from the date incurred. Development well intangibles are depreciated at 30 percent declining balance. Facilities and well tangibles are subject to the half-year convention and depreciated at 25 percent declining balance from the start of production/Available for Use (AFU) date. AFU rules are relaxed through the Long Term Project (LTP) rules, including the 24-month Rolling Start (RS) rule. Loss Carry Forward term is 20 years.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	None.
Indirect Taxes:	Exempt. Canada's goods and services tax (GST) or harmonized sales tax (HST) generally does not apply to oil and gas operations.
Incentives and Credits:	Alberta has established programs whereby royalty rates are lowered to incentivize several different types of activities and ventures. These programs include special terms for low production volume wells, low price conditions, horizontal wells, deep gas wells, oil sands projects and coalbed methane, shale gas, solution gas, condensate, and natural gas liquids (NGL) production. The corporate tax rate is 3.0 percent for firms that qualify as "small businesses." In addition to provincial incentives, the Canada federal government offers incentives for research and development in the form of scientific research and experimental development credits (SR&ED).

Figure 9-11. Northwest Territories (Canada) Onshore fiscal system highlights.

Royalty:	1 to 5 percent sliding scale. Royalty sliding scale escalates on 18-month intervals. Natural gas pays the same royalty rate as oil.
Rental Fee:	None. Work expenditure commitments may apply.
Property/ad valorem tax:	None.
CIT:	In Northwest Territories the Canadian federal CIT rate is 16.5 percent. The basic rate of Canadian federal corporate tax is 26.5 percent, but it is further reduced to 16.5 percent by an abatement of 10 percent on a corporation's taxable income earned in a province or territory. The Northwest Territory provincial CIT for oil and gas is 11.5 percent. Exploration costs are expensed. Land purchase costs are depreciated as Canadian Oil and Gas Property Expense (COGPE) at 10 percent declining balance from the date incurred. Development well intangibles are depreciated at 30 percent declining balance. Facilities and well tangibles are subject to the half-year convention and depreciated at 25 percent declining balance from the start of production/Available for Use (AFU) date. AFU rules are relaxed through the Long Term Project (LTP) rules, including the 24-month Rolling Start (RS) rule. Loss Carry Forward term is 20 years.
Net Tax/Profit Share:	Profit share is levied after "payout" at the rate of 30 percent. Payout is determined based on recovery of previous royalty payments, uplifted capital, operating and exploration expenses, plus a rate-of-return allowance of the long term government bond rate plus 10 percent. In determining payout, capital and operating expenses can be uplifted by 1 and 10 percent respectively. The gross royalty is always payable and is creditable against the profit share.
Gross/Severance Tax:	None.
Indirect Taxes:	Exempt. Canada's goods and services tax (GST) or harmonized sales tax (HST) generally does not apply to oil and gas operations.
Incentives and Credits:	The Canada federal government offers incentives for research and development in the form of scientific research and experimental development credits (SR&ED).

Figure 9-12. Canada Federal Offshore Beaufort Sea fiscal system highlights.

Royalty:	1 to 5 percent sliding scale. Royalty sliding scale escalates on 18-month intervals. Natural gas pays the same royalty rate as oil.
Rental Fee:	None. Work expenditure commitments may apply.
Property/ad valorem tax:	None.
CIT:	In Canada the basic rate of federal corporate tax is 26.5 percent. Offshore areas are not subject to any federal corporate tax abatement and pay taxes at the full federal rate. For Canadian income tax purposes, a corporation's worldwide taxable income is computed in accordance with the common principles of business (or accounting) practice, modified by certain statutory provisions in the Canadian Income Tax Act. In general, no special tax regime applies to oil and gas producers. Depreciation, depletion or amortization recorded for financial statement purposes is not deductible; rather, tax-deductible capital allowances specified in the Income Tax Act are allowed.
Net Tax/Profit Share:	Profit share is levied after "payout" at the rate of 30 percent. Payout is determined based on recovery of previous royalty payments, uplifted capital, operating and exploration expenses, plus a rate-of-return allowance of the long term government bond rate plus 10 percent. In determining payout, capital and operating expenses can be uplifted by 1 and 10 percent respectively. The gross royalty is always payable and is creditable against the profit share.
Gross/Severance Tax:	None.
Indirect Taxes:	Exempt. Canada's goods and services tax (GST) or harmonized sales tax (HST) generally does not apply to oil and gas operations.
Incentives and Credits:	The Canada federal government offers incentives for research and development in the form of scientific research and experimental development credits (SR&ED).

Figure 9-13. Australia Federal Offshore fiscal system highlights.

Royalty:	See Production Tax.
Rental Fee:	Various application, permit and annual fees apply, up to about $1 per acre. Work expenditure commitments may apply.
Property/ad valorem tax:	None.
CIT:	The Australian federal CIT rate is 30 percent. Facilities depreciation is based on prescribed "effective life."
Net Tax/Profit Share:	The Petroleum Resource Rent Tax (PRRT) applies seaward of the territorial sea boundary, with the some exceptions. The PRRT is levied at 40 percent of taxable profit (income) after payout. Taxable profit is determined by deducting from assessable receipts, the total of deductible expenditures, plus certain expenditures. Payout occurs when a project has earned a return allowance equal to Australia's long-term bond rate plus an allowance of 5 percent or 15 percent depending on the specific project. PRRT is deductible in calculating CIT.
Gross/Severance Tax:	None.
Indirect Taxes:	All sales within Australia are subject to goods and services tax (GST) at the rate of 10 percent. Both Australian-resident and non-resident entities engaged in the oil and gas industry may be subject to GST on services and products supplied. All commercial transactions have a GST impact. Certain exported products and services and other transactions may qualify for exemptions.
Incentives and Credits:	None.

Figure 9-14. Norway Federal Offshore fiscal system highlights.

Royalty:	None.
Rental Fee:	Various rentals and annual fees apply, from about $20 to $80 per acre depending on the status of the lease block.
Property/ad valorem tax:	None.
CIT:	The Norwegian federal ordinary CIT rate is 28 percent. Expensing of certain costs is allowed. Depreciation of certain asset classes is based on a straight-line depreciation schedule. Additional tax elements apply.
Net Tax/Profit Share:	Special Tax, sometimes referred to as the "Hydrocarbon Tax," is assessed at a 50 percent rate. Uplift of all capital expenses is at a rate of 7½ percent for a period of four years, 30 percent total. Hydrocarbon tax is not deductible against CIT.
Gross/Severance Tax:	None
Indirect Taxes:	Exempt. Norway's value added tax (VAT) generally does not apply to goods and services used in offshore oil and gas operations.
Incentives and Credits:	7½ percent "uplift" of capital expenses under Special/Production Tax (described above). Losses may be carried forward indefinitely for offshore activity and may be transferrable in some cases. Interest on such losses is set by the Ministry of Finance annually; for 2011 the rate was 1.9 percent. Effective from 1 January 2005, an upstream company may also be refunded the tax value of exploration expenses for each tax year loss, including direct and indirect expenses related to exploration activities on the NCS (except for financing costs). The refund is made on 22 December in the year following the tax year for which the expenses were incurred. For example, NOK100 million spent on exploration expenses in 2012 may result in a cash refund of NOK78 million on 22 December 2013. The refund of exploration costs has opened up the opportunity for third parties to fund exploration activities. The claim on the state can also be pledged. In general, banks may typically be willing to fund 80 percent to 90 percent of the tax value of the exploration tax refund (i.e., 65 percent to 70 percent of the exploration cost basis).
State Participation:	Unlike all other jurisdictions discussed in detail in this report, Norway retains the right to exercise a participation interest in offshore oil and gas blocks. Various interest shares have been exercised, in recent bidding rounds about 20 percent participation. These participation interests are managed by a state-run company, Petoro.

Figure 9-15. United Kingdom Federal Offshore fiscal system highlights.

Royalty:	None.
Rental Fee:	1st and 2nd years - $0.10 per acre, 3rd through 6th years - $0.60 per acre, then escalating to a maximum of about $30 per acre in the 15th year. There is a mandatory 75 percent relinquishment at the end of Year 3 and a further 50 percent at the end of the primary term in Year 6.
Property/ad valorem tax:	None.
CIT:	The U.K. federal CIT rate is 30 percent. Taxable income is ring-fenced for upstream oil and gas activities. Additional tax elements apply.
Net Tax/Profit Share:	Supplementary Charge is tax (32 percent from 24 March 2011 and previously 20 percent) on UK exploration and production activities that is in-addition to CIT. Taxable profits for supplementary charge purposes are calculated in the same manner as ring-fence trading profits but without any deduction for finance costs. Finance costs are defined very broadly for this purpose and include the finance element of lease rentals and any costs associated with financing transactions for accounts purposes.
Gross/Severance Tax:	None.
Indirect Taxes:	The standard rate of value added tax (VAT) in the U.K. is 20 percent, with reduced rates of 5 percent and 0 percent. The VAT is potentially chargeable on all supplies of goods and services made in the U.K. and its territorial waters.
Incentives and Credits:	The U.K. offers incentives for certain activities and ventures, including a Ring Fence Expenditure Supplement and certain research and development allowances.

10. Summary

Alaska is fortunate to be endowed with abundant natural resources, especially oil and gas. Additionally, the state is well positioned geographically to market those resources to a large area of the world. It is the responsibility of Alaska's government to continuously review its competitiveness in critical categories related to oil and gas exploration and production compared to similarly positioned jurisdictions.

In this report, a logical peer group is established for comparison. Alaska's peer group selection is largely tied to three elements, production and reserves, geographic location, and fiscal system type. Information is also presented on lease sales, infrastructure, permitting, and workforce availability. Other criteria may be added to this list as future discussion relates to competitiveness.

While it is important for Alaskans to look at Alaska's fiscal regime from the state's perspective, focused on state revenue, to help understand potential risks to Alaska's revenue stream, it is equally important that we consider the perspective of industry investors in Alaska. Most oil companies look at more than one jurisdiction when making decisions on where to invest, and they will only invest in a place where they believe there are resources to find and where there is reasonable certainty those resources eventually can be produced and sold at a reasonable profit. If we look at natural resource development from both the industry and landowner perspectives, we will improve the long-term benefit to Alaskans from those resources.

Ongoing work and future deliverables

The Board is a relatively newly constituted board with the potential to establish the necessary framework to the continuing conversation the state is engaged in on the topic of maximizing the benefits of our oil and gas resources for the people of Alaska. The Board is looking at several tasks that they hope to accomplish over the short- to intermediate-term.

Future efforts of the Board will require funding and DOR support to move forward in a meaningful way. One of the first steps was to ascertain who are we competing with? In this publication we have established an initial peer group, but this group should not be considered a final unalterable group. The Board will continuously review this list of peers and change it as necessary. We may also modify the criteria used to select peer group members. For example, we may have a different set of peers when considering Alaska's competitiveness with respect to exploration and development of natural gas than crude oil and liquid hydrocarbons.

After peer group selection and analysis, another priority of the Board is to poll a broad range of oil and gas exploration and development companies to better understand Alaska's perceived relative strengths and weaknesses with our global peers. We plan to survey a representative group of large to small companies, including existing producers and lease owners, as well as other companies, such as service companies, that would represent companies not active in Alaska. This undertaking will take funding. We have prepared a draft RFP for the survey effort, with a budget for up to $300,000, to be considered by DOR and the Alaska Legislature. An effective survey of this type could take up to nine months, just to collect the survey data. Then additional time will be required to compile and analyze the collected data. It is paramount to be able to compare our strengths and weaknesses against other peer jurisdictions to insure that we are getting the greatest benefit from Alaska's resources while continuing to attract investment to the state.

As we review our competitiveness we need to consider the items that the State of Alaska has control of, or can influence, such as permitting, infrastructure, labor, lease costs, taxation, royalties and access to resources. We need to be able to do a grounded comparative analysis of

our fiscal structure versus our peers. One of our thoughts moving ahead is to build a dashboard of critical measurements for Alaskans to easily review using principally, but not limited to items that are currently being measured by various state and federal agencies that can be compiled and provided on a single website. Our goal is to track past, current and projected future statistics and projections for a group of key diagnostic criteria that will help interested parties view specific progress or trends related to the oil and gas industry in Alaska compared to peer jurisdictions. These measures could be items like number of wells being drilled, production, resource pricing, permitting and other pertinent trending data. This will be maintained on a recurrent basis so interested parties have a baseline to current view of the industry.

The next required deliverable from the Board is a report to the Alaska State Legislature due on or before January 15, 2017. For the January 2017 Competitiveness Report the Board is asked to provide written findings and recommendations regarding:

1. the state's tax structure and rates on oil and gas produced south of 68 degrees North latitude;

2. a tax structure that takes into account the unique economic circumstances for each oil and gas producing area south of 68 degrees North latitude;

3. a reduction in the gross value at the point of production for oil and gas produced south of 68 degrees North latitude that is similar to the reduction in gross value at the point of production in AS 43.55.160(f) and (g); and

4. other incentives for oil and gas production south of 68 degrees North latitude.

The Board's final statutorily required deliverable is a report to the Alaska State Legislature due on or before January 31, 2021. For the January 2021 Competitiveness Report the Board is asked to provide written findings and recommendations regarding:

1. changes to the state's fiscal regime that would be conducive to increased and ongoing long-term investment in and development of the state's oil and gas resources;

2. alternative means for increasing the state's ability to attract and maintain investment in and development of the state's oil and gas resources; and

3. a review of the current effectiveness and future value of any provisions of the state's oil and gas tax laws that are expiring in the next five years.

Appendices

Appendix A-1. Alaska Oil and Gas Competitiveness Review Board members:

THOMAS W. HENDRIX JR (Chair)
Vice President, Oil & Gas
Carlile Transportation Systems, Inc.

RANDALL J. HOFFBECK
Commissioner
Alaska Department of Revenue

MARK MYERS
Commissioner
Alaska Department of Natural Resources

MIKE GALLAGHER
Commissioner
Alaska Oil & Gas Conservation Commission

KRISTIN RYAN
Spill Prevention and Response Director
Alaska Department of Environmental Conservation

KARA MORIARTY
President/CEO
Alaska Oil & Gas Association

PETER J. STOKES, PE, MBA
Consulting Petroleum Engineer and Commercial Manager
Petrotechnical Resources of Alaska

CURT FREEMAN
President
Avalon Development Corporation

TOM MALONEY
CH2M Hill

A.J. "JOEY" MERRICK II
Business Manager/Secretary Treasurer
Alaska Laborers' Local 341

RODNEY BROWN
Business Manager
UA Local 375

We wish to thank staff at the Alaska Department of Natural Resources, Alaska Department of Environmental Conservation, and Alaska Oil and Gas Conservation Commission who helped assist in compiling data, providing graphics and writing this document.

This publication was produced and edited by staff of the Alaska Department of Revenue - Tax Division on behalf of the Alaska Oil and Gas Competitiveness Review Board. Copies are available to download on the Board's website, which is also accessible through the Department of Revenue main web page. This publication is exclusively available online.

Alaska Oil and Gas Competitiveness Review Board web page:
http://dor.alaska.gov/OilGasCompetitivenessReviewBoard

Alaska Department of Revenue main web page:
http://www.dor.alaska.gov

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Oil and Gas Competitiveness Review Board comments **3/13/2015**

From: wmolson@gci.net [mailto:wmolson@gci.net]
Sent: Friday, March 13, 2015 1:53 PM
To: Rep. Paul Seaton; Rep. Les Gara; Rep. Benjamin Nageak; Rep. Bob Herron
Subject: Friday March 13th

Representatives

The testimony from the "Oil and Gas Competitive Review Board" before the House Resources Committee today increased my doubts that last session's Senate Bill 21 was a good decision. The Review Board has not been able to do what they were assigned to do.

It reminds of the old poem:

They tackled the job that couldn't be done.
With a smile they went right to it.

They tackled the job that couldn't be done,
And they couldn't do it !

Wallace Olson, Auke Bay

ALASKA GASLINE DEVELOPMENT CORPORATION

BOARD OF DIRECTORS REGULAR MEETING

March 12, 2015
9:00 a.m.
Anchorage/Juneau/Fairbanks

AGENDA

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XIV. Adjournment 231

PROCEEDINGS

(On record - 9:01 a.m.)

BURNS: Madam Clerk, would you call the role, please.

GRAHAM: John Burns?

BURNS: Present.

GRAHAM: Dave Cruz?

CRUZ: Present.

GRAHAM: Fred Parady?

PARADY: Here.

GRAHAM: Heidi Drygas?

DRYGAS: Here.

GRAHAM: Hugh Short?

SHORT: Here.

GRAHAM: Rick Halford?

HALFORD: Here.

GRAHAM: Joe Paskvan?

PASKVAN: Here.

GRAHAM: We have everyone here and we have a quorum.

BURNS: So let the record reflect for the first time in a while we do have a full Board. I want to welcome everybody, all the new Board Members, so appreciate it.

UNIDENTIFIED: Thank you.

BURNS: It's quite a project that we'll all signed up for. So at this time Safety Moment, Gwen or Dan?

FAUSKE: Thank you, Mr. Chairman, and welcome everybody and

to the audience here.

In the event of an emergency, please, evacuate the building using the stairs, in our area they are to the left as you exit Suite 604, AGDC's Board room.

The 6th floor's muster point is the northeast corner of the parking lot next to A Street which is that way. Please evacuate for any alarm, audible or visual.

If you are unable to evacuate, there are four windows in our offices with big red dots. I'm not sure I'd recommend leaping out of these windows, but these indicate breakaway -- the ones with the red dots do indicate --.....

(Simultaneous speech)

FAUSKE: .....do indicate breakaway windows to emergency responders. Please go to one of these offices for assistance and see the map located on the wall at the Board room entry. Where is that? It's on.....

GRAHAM: It's out there.

FAUSKE: Yeah, it's out -- out here. The restrooms are located in the hallway outside of this room to the left.

BURNS: Great. And I would just note, notwithstanding the weather conditions outside, we are entering spring, fingers crossed and so, you know, it's a treacherous time to be walking, so just all exercise extreme

caution as for entering and exiting buildings.

So the next item is the approval of the agenda.

CRUZ: Motion to approve.

BURNS: Question's been made. Any discussion? All right. So call the question, all in favor of approving the agenda?

IN UNISON: Aye.

BURNS: Any opposed? The agenda has been approved.

The next item is the approval of the minutes, January 8th meeting and I believe at that meeting, Madam Clerk, there were just four Board Members, right?

GRAHAM: Correct.

BURNS: So those four who were in attendance, is there a motion to entertain?

PARADY: So moved.

BURNS: So moved.

DRYGAS: Second.

BURNS: All right. Any discussion or revisions, corrections? All right. It's been moved and seconded. All in favor of approval of the minutes?

CRUZ: Aye.

PARADY: Aye.

DRYGAS: Aye.

BURNS: Aye. Okay. The minutes are approved.

At this time, as we always do, at our meetings we

invite Public Comment and so anybody who either present here in Anchorage or who would like to address the Board telephonically, they are certainly invited to come forward, so anybody in Anchorage who would like to come forward and to address the Board, make some public comments? Don't hesitate. All right. Your comments are welcome.

All right, seeing nobody in Anchorage, anybody statewide? Anybody in Fairbanks? All right. Nobody in Fairbanks. Anybody in Juneau? Anybody statewide who would like to address the Board?

All right. So seeing that there are no public comments let's move onto the President's Scorecard. Dan.

FAUSKE: Thank you, Mr. Chairman. For the Board Members you'll see in your packet a -- sort of a large foldout sheet.

BURNS: What item specifically?

DRYGAS: Seven.

FAUSKE: Tab 7.

BURNS: Seven.

FAUSKE: And this is what's known as the President's Scorecard. We had initiated this a few months back. It used to be I'd just, kind of, give a report as to who we met with and the various things and then the

Board, and I thought it was a good move, decided that we wanted to get into more strategic areas and just list to the Board where we currently stand in certain areas.

And so if you look at the upper left, you have Financial Performance. The Strategic Objective is to execute business operations to optimize financial expenditures. The Targets, our expenditures are less than or equal to budget. Project percentage completion is greater than or less than percentage -- or excuse me, greater than percentage spent.

Executive and Support at 51 percent. The AKLNG Actuals at a minus two, that looks weird, but the AKLNG at this time does not supply percent of work complete so it can't be calculated. It's not that we don't have it, but they just don't supply it on a regular basis. We can develop those numbers. It's not an onerous thing, it's just the way the AKLNG spend plan comes through.

The ASAP Actuals are at 37 percent. The AG monthly financial report, ASAP Monthly Report -- or Project Report, AKLNG Monthly Project Report. ASAP at 38 to 36 percent. The ASAP Monthly Project Report and the AKLNG Monthly Project Report.

On the Schedule, complete planned, on the Objective

is to complete planned work within approved program and project schedules. Critical path milestone met equal 100 percent. Actuals at 100 percent. And the February milestone is submitting the first draft of Resource Reports 1-12 to FERC was achieved.

The Pre-FEED schedule has been updated now that sub-project engineering contractor control schedules have been received and integrated with the overall result that the Enter FEED milestone has slipped three months to June 1, 2016. This is on the AKLNG. And several other 2016 and fourth quarter 2015 milestones have also shifted to the right as the schedules have been expanded somewhat.

On the Health and Safety Performance, objective is to achieve health, safety, security and environmental incidents below Alaska Oil and Gas industry averages. Lost time to injuries at 200,000 manhours is less that 2.4. Recordable incidents per 200,000 manhours is 8.7. Near Misses zero. Reportable Spills zero.

Two notes, AGDC's Risk Manager determined to evacuate our building offices for a very strong burning smell. This happened several weeks ago. The alarm system had not worked properly. We did evacuate the building. Employees sheltered in the adjacent building and after 45 minutes the Risk Manager signaled the all

clear after building -- I became concerned that I thought frostbite was more of an issue than what was going on in the building, but we did get that cleared up with Ravnit and our Risk people.

It was troubling because there was absolutely a smell in the building and everybody -- you know, it was pretty strong and we were wondering what the heck's going on.

AKLNG, the following is not part of the AGDC LNG remit, but did occur under the AKLNG project umbrella so is reported. At Prudhoe Bay as part of the Gas Treatment Plant trenching preparation, about a half a gallon of hydraulic oil was spilled on the sea ice. Spill was immediately contained and completely cleaned up and agencies were notified.

Development of Commercial Agreements. The Strategic Objective is to advance initiatives and agreements timely to advance projects. Commercial milestones met 100 percent. Term sheets, documents drafted and approved and documents executed. The AGDC Monthly Commercial Report, AKLNG Monthly Commercial Report are the Reporting Systems.

Compliance, objective is to comply with applicable legislative and legal requirements and corporate commitments. Targets are Legislative reporting per

statutory requirements at 100 percent. Regulatory Permit Completion Reports at 100 percent.

The AGDC Annual Report was published on 1/10/2015, Senate Bill 138 required AKLNG Project Briefings to the Legislature. These were conducted on 1/30/2015 and 2/18/2015. A follow-up was requested and is scheduled for 3/13/2015, that is tomorrow in Juneau. The ASAP Monthly Project Report, AKLNG Monthly Project Report are the reporting systems.

Under Project Options, maintain viability of project options to initiate construction start within two years of sanction. The -- as you read across the Project Execution Milestone Completion at 100 percent. Technical Team Core Staffing at 100 percent and the same reporting systems apply to this report as well.

So that, sir, completes the report card.

BURNS: Are there any questions or comments?

SHORT: I've got a question.

BURNS: Yeah.

SHORT: So under the section of Schedule, and the three month, as you've called it, a slip of three months, is it -- can you talk a little bit about that and what caused that slip and is this something that has happened before or is this the first time in our project schedule Pre-FEED has slipped?

FAUSKE: No, sir, Mr. Short. As a result of the JVA and some of the agreements to get signed was delayed, that dropped the schedule back somewhat just based on the fact that agreements weren't put in place as quickly as they thought, so it slipped that schedule as to the completion of Pre-FEEd from first quarter 2016 to second quarter 2016 and that is currently the schedule we're on.

SHORT: Okay, thank you.

FAUSKE: So we're start- -- it's ramping up much quicker now and as you hear when the AKLNG folks give their report, there's a lot of work going on and it's -- but it's just tough to catchup completely.

SHORT: Thank you.

BURNS: But, Dan, I think that's the first time that has been noted that there's been a slip in the schedule that I understand, is that right?

FAUSKE: And that -- Mr. Burns, that was announced (indiscernible) at the meetings, at the updates that we gave on those dates that I showed in January. The led -- when we testified in front of House and Senate Resources that information was made public that, that schedule had slipped.....

BURNS: Um-hum. (Affirmative)

FAUSKE: .....out to that point.

They also have, from that date forward, one year to -- I think it's September of 2017 where the -- they have a year roughly to make the FEED decision and that's the final engineering and design.

They're currently in Pre-FEED, but once you go to the FEED, that -- they scheduled it out to about 2019 and then they'll make the FID, the Final Investment Decision.

What's significant about FEED is that where some real money starts. I mean, we're already spending real money, but I mean, this is -- gets into the billions of dollars to enter into the FEED. The State would be a 25 percent equity shareholder in that under the current agreements and you can see a State response -- or requirement as high as a billion dollars or eight, 900 million depending on what the FEED estimate costs are and the producers and TransCanada and the others that share in that.

SHORT: Do you expect any associated cost increases because of the slippage or is that negligible?

BURNS: Who are you looking for, Joe?

FAUSKE: I don't so. I mean,.....

SHORT: No (ph)?

KRUSEN: Minimal (ph).

FAUSKE: Minimal. Minimal from -- when Fritz and some of

these folks come up we can get into more of that if you'd like, but we've been.....

BURNS: And, Dan, one just follow-up. On -- I guess, on Friday, tomorrow you're having a presentation, you're giving a presentation what -- what's that about?

FAUSKE: That is about the follow-up to the sponsors. That is also to deal with, in their language, the Governor's Plan or our plan going forward. They delayed us. We were originally scheduled to come down with the plan going forward two weeks ago -- a week ago Monday. And then that -- that schedule slipped at that time.

I know Marty Rutherford and I think Donna Keepers from Revenue were both sick. It just was one of those where they rescheduled us. We were originally scheduled -- we would have testified via phone and then they called us literally at the 11th hour.

You might recall that was the day Governor Walker had his press conference where he was fairly upset over the fact that House Bill 132 had been introduced right across and he had a chance to comment on that Bill. That was also the day we were scheduled. And then they had canceled that hearing. Not because of Governor Walker, but because of just the people that they needed there couldn't be there, so that's what this is about tomorrow.....

BURNS: Okay.

FAUSKE: .....is to lay out the intentions of this Corporation going forward.

BURNS: And who is going to be in attendance at that from AGDC?

FAUSKE: It will be myself, Joe Dubler, Frank Richards.....

GRAHAM: Miles.

FAUSKE: Miles, I think the four of us.

BURNS: Okay.

FAUSKE: We'll have others available by phone if we need depending on what level of detail they want to get into.

BURNS: Any further questions of Dan on the Scorecard? This is -- just for those new Board Members, this is something that we developed in conjunction with the Board and several of the committees just to understand on a monthly basis where the project stands on each of the facets of the project, so, you know, we -- the sense of just, kind of, a performance management matrix. So if you have any comments or as you look though it over time if there's anything you'd like to see enhanced about it let us know, so.....

All right. Next item of business, New Business, AGDC Management/Operational Issues. First is the Financials, so.....

FAUSKE: And for the Board Members, Bruce Tangeman, one of our VPs on the Admin Services side. Former Deputy Commissioner of Revenue you might remember and other things in his career is here to present. So, Bruce, if you would.

TANGEMAN: Thank you, Dan. For the record, Bruce Tangeman, vice president of Finance and Administration. Under Tab 8A you have a two page summary of the Corporation's financials as of January 31st, 2015.

And just to orient you to the first page top to bottom we have the ASAP project expenditures and the corporate allocation section. Below that we'll have the AKLNG project expenditures and the AGDC overhead allocation. And then down at the bottom is a little more detail on the ASAP expenditures to date.

So up top we put in place a cross allocation method when we inherited the AKLNG project, so we have two pots of money that we're drawing from. So we put in a -- with the help of our auditors, BDO, we put in place a cost allocation method in order to spread the corporate costs between the two fund sources.

So left to right we have year to date costs, year to date budgets and variance and the column after that is the revised budget. The only revision that has taken place took place in January when the Board instructed

us to throttle back the ASAP project in order to line up calendar-wise with the AKLNG project. And Frank and Joe will certainly be talking to more details of the two projects, but that's the only budget revision that has taken place.

I think you can see that we're well under budget. It's important to note that every dollar that's not spent on the Corporation's overhead, is a dollar that's available for the projects, so we're very judicious in how we spend out dollars and especially how we fill positions.

Dan's mentioned many times that we're not here to put a bureaucracy in place. We have a short window and we know exactly what are game play -- what our jobs are here to do, so we're very judicious in how we spend our dollars on the corporate side.

To that, the second page is more of a breakdown on the executive side of the house. Joe will give more details on the AKLNG spend under one of the future tabs and Frank will do the same for ASAP, but on page two you get a breakdown of the different functions within the Administrative side of the house. And, again, we're underspending our budgets which is good.

There's been no budget variance to date and at the bottom you see a breakdown between the two fund

sources. So, again, we're about 85 percent of the corporate overhead is charged to ASAP and about 15 percent is charged to the AKLNG.

BURNS: Um-hum. Any questions so far?

PARADY: Mr. Chairman?

BURNS: Yeah.

PARADY: Could you restate that last statement? I heard it, but I want to make sure I caught it.

TANGEMAN: Yes, sir, Mr. Parady. The cost allocation method breaks down the corporate overhead expenditures, 85 percent go to the ASAP fund -- instate fund and 15 percent go to the AKLNG fund.

PARADY: Thank you.

BURNS: So, Bruce, the expenditures on the first page, are those -- we've talked about the ASAP project expenditures, my understanding is that at least from a couple Board Meetings back we wanted to ensure that the expenditures that we were doing on ASAP were complimentary to the AKLNG and my understanding is that, that is the case, is that right?

TANGEMAN: Yes, sir and that's reflected in the revised budget where you instructed us to throttle back ASAP to line up with the AKLNG project.

BURNS: And so are the expenditures then that are allocated to ASAP, how do those reflect the fact that those are

complimentary expenditures meaning that they benefit both of the projects? How do you make the determinations as to whether they should be on the ASAP side or the AKLNG side?

TANGEMAN: I'm going to defer that question to Frank because he can speak to how those different types of expenditures are beneficial to both options, so I'll defer to Frank on that.

BURNS: All right. Any questions of Bruce on it, so that the upside of this is we're under budget on everything at this juncture?

TANGEMAN: Yes, sir.

BURNS: Good. All right. So anything -- any further on the AGDC Management/Operational issues. So did you need to talk a moment to talk to Frank?

CRUZ: Yeah. I want to take a little break.

BURNS: Okay. Why don't we take just a five minute break. I think Dave wanted to touch base with Frank, so if you don't mind we'll take just a five minute break.

SHORT: At ease.

BURNS: An at ease.

(Off record - 9:19 a.m.)

(On record - 9:25 a.m.)

BURNS: All right. The next item of business is New Business - ASAP, Frank, at this -- my understanding,

Frank, is this is a primer for the new Board Members bringing everybody up to date as to where we are on ASAP and then a discussion as we move forward -- as you progress forward.

RICHARDS: Mr. Chairman, yes. Frank Richards, vice president of Engineering and Program Management for AGDC. And as you suggested I think that we -- it would be beneficial for the new Board Members to really -- to go over what I'm calling the Gasline Project Primer and this was essentially what we provided to the Board in January, so for those Board Members that have heard me previously I apologize for repeating. It's -- do you all have a copy?

PARADY: Yes.

UNIDENTIFIED: We do.

PARADY: Yes, sir.

RICHARDS: Okay. And then in your Board packets I also would refer you to a Pipeline Cheat Sheet. I believe that was in there also, so if you see.....

DRYGAS: What Tab is that at?

UNIDENTIFIED: It's at the very beginning.

GRAHAM: It's in the front.

RICHARDS: It was a looseleaf cheat sheet.....

BURNS: See Heidi we heard, the Staff heard you. I think it's this one right here.

DRYGAS: (Indiscernible) -- so that -- did I ask for this?

BURNS: Pipeline cheat sheet.

DRYGAS: I wonder -- I -- and yet I -- mine is missing.

BURNS: Here.

RICHARDS: So on the cheat sheet if you hear me.....

BURNS: But I need mine back.

(Simultaneous speech)

CRUZ: I've got one right here.

DRYGAS: Okay.

BURNS: Go ahead, Frank.

RICHARDS: Mr. Chairman, if you hear me falling into acronyms, I apologize. I will try and enunciate all of the acronyms so that new members and the public can understand what I'm talking about, but it's so easy in this arena to fall into the tentacle (ph) jargon, so please, if I stray from that ask me and I will bring it back to where we are.

But on this cheat sheet you see that we talk about the American Society of Mechanical Engineers, ASME B31.8, that's essentially industry guidelines for pipeline loading evaluation. And then I will refer to American Petroleum Institute, API.

Then there's also the -- what's known as the American National Standards Institute or ANSI and this is really where we get the standards for maximum (ph)

pressure and temperature ratings for pipe, as well as their flanges and fittings, so this is some of the guidance that we use in our technical design criteria.

And then you'll see midway down the page is a table of ASME/ANSI or American Society of Mechanical Engineers and American National Standards Institute pressure classes. So Class 600 refers to a maximum pressure of about 1,480 psi, pounds per square inch as opposed to ANSI Class 900 which is 2,220 psi, pounds per square inch maximum gas pressure in the pipe, so there's are some of the key defining pressure requirements.

And then on material grade, when we talk to the strength of the pipe we usually refer to that in X classes. So X70 would be 70,000 pounds per square inch, the strength of the steel as opposed to X80 which would be 80,000 pounds per square inch.

On the back of the page it talks about location class and this is really where the Pipeline Hazardous Safety Administration has identified to us how we should include in areas where there's human habitation and they define it by occupancy in terms of buildings, so we use that as along a pipeline route and then that determines what class we have to -- of class of pipe we have to put into those areas where the pipeline is

running and that's essentially relating to wall thickness.

And then when I talk about strain based design, that is, again, a design criteria requirement by the Pipeline Hazardous Materials Safety Administration otherwise known as PHMSA which talks about in areas across Alaska we have discontinuous permafrost and you have the potential for frost heave or frost settlement and then you have to look at the strain accumulation on that pipe and that's where we exceed the strain capacity or the design requirements in the PHMSA's code then we have to come up with an alternative analysis which is called strain based design.

BURNS: Frank, let me stop here. Can everybody hear Frank's presentation?

UNIDENTIFIED: It's a little difficult.

BURNS: Yeah, if you could speak up, Frank, I'd appreciate it for those in the back.

RICHARDS: I'm sorry, Mr. Chairman, the mic will not move for me, so I will. All right.

BURNS: Speak louder than.

RICHARDS: Under Abbreviations, these are, again, common abbreviations used from pounds per square inch to TAPS which is the Trans Alaska Pipeline System and Alyeska which would be Alaska Pipeline Service Company or APSC.

And then on the -- there's indications on page 3 which are essentially figures identifying common machinery used in pipeline construction. The first one is a sideboom which actually is used to lower the pipe into the trench.

And the bottom one is a chain trencher which is essentially a piece of machinery that with the right ground conditions it's almost like slicing through butter with a hot knife. You can actually get great production, keep the amount -- the trench width to a minimal and produce right next to it a castoff of a good material that you can potentially use then as backfill on the pipe.

And then on the final page is, again, typical sections of what our common right-of-way would look like whether it be a rock ditch which would be rock excavation either blasting and -- drill and blast and then excavation as opposed to an ice road which would be essentially using frost pack or ice to be able to go across the ground and not damage the underlying substrate.

So just typical sections just to give an indication of the right-of-way widths, what the type of machinery is, what it looks like in terms of a spoil pile on one side, the equipment and pipe on the other and then a

travel way to allow for flow around the pipe sections.

BURNS: Yeah. Now, we have ordered and are testing pipe currently, is that right?

RICHARDS: That's correct, Mr. Chairman.

BURNS: We've got what -- in what class and X grade are we currently testing?

RICHARDS: We had put out a solicitation for X70 pipe and this was, again, for areas where we had the strain based design approach to -- in order to prove to PHMSA that our design models were going to be able to withstand the strains that we anticipate from the discontinued -- essentially the thawing of discontinuous permafrost.

So we had pipe mills from Germany, Japan and India that offered or came -- came to us and could meet the criteria of essentially meeting the metallurgy requirements that we had put forward in those specifications.

We are complete now with the small scale testing. And that the -- the individual mills have met the requirements that we gave them for that and that's essentially looking that did they meet the original stress strain curves.

And now we have sent samples into what is known as mid-scale testing and that's being done at Edmonton at the Seafarer facility. So it's very -- it's proving

out that our -- the mills that can provide this type of pipe around the world are able to meet it -- meet the requirements.

Unfortunately there aren't mills in the U.S. or North America that are meeting this standard of pipe at this time, but there's hope that they will be able to meet that metallurgy requirements in the future.

BURNS: So you made a decision on the X70 from the standpoint we've now identified where we were getting it, would be getting it can meet those standards.....

RICHARDS: That's correct,.....

BURNS: .....consistently?

RICHARDS: .....Mr. Chairman, to identify that yes, that there are capabilities around the world to be able to meet the requirement. And, again, this is for the strain based pipe,.....

BURNS: Right.

RICHARDS: .....the location. So we have a pipeline that's approximately 740 miles long. We are trying to define how -- which of those areas are going to actually require this and right now we had thought it was going to be approximately 100 miles, but our analysis is showing now that, that is being reduced significantly between anywhere from five to 20 miles. So that means that those sections of the pipeline would require this

specialized steel, so it's not as large a volume as we had originally intended or thought it would be.

BURNS: And then the ANSI, the ANSI class is the -- is the testing on the six or the nine currently or is it -- have we even.....

RICHARDS: Mr. Chairman, we were going with 1,480 psi pipe, so that would meet the.....

BURNS: The 600.

RICHARDS: .....ANSI 600 pound class.

PASKVAN: Mr. Chair?

BURNS: Yeah.

PASKVAN: If I'm understanding what you're saying on the X70, that may be a maximum of 20 miles. I assume then the other 720 assuming that hypothetical is X52 capacity?

RICHARDS: Through the Chair, Senator Paskvan, old habits. The remaining pipe we decided to go with X70 as well, so.....

PASKVAN: Okay.

RICHARDS: .....that we would be able to have that pressure class and in the anticipation of it provides strength. It's a standard class pipe. The line pipe can be manufactured in the U.S. and we feel would meet our needs.

BURNS: Good. Any questions? All right. Keep going.

RICHARDS: Okay, Mr. Chairman. Now, going back to the Gasline

Project Primer, on page number 2 AGDC is in the fortunate position of having two corporate responsibilities. We were initially geared up by the Alaska Legislature to focus on the ASAP project and then with the passage of Senate Bill 138 we were given the responsibility of also representing the State of Alaska in a 25 percent ownership of the LNG plant for the Alaska LNG project.

So I wanted to take the opportunity to identify the two different initiatives that we are working on currently. And to somewhat show a little bit of the difference between the two because, again, with the stand-up of AGDC with -- under House Bill 4 for the ASAP project, it was really with the intended purpose to provide energy for Alaskans because at that time the AGIA process was underway and TransCanada and Exxon Mobil were advancing a pipeline project for export.

So the Legislature gave us the mandate to provide for energy relief for Alaskans and under that -- at that time the AGIA statute was in place. The AGIA license was in place, so that we were limited on the ASAP project to 500 million standard cubic feet a day. So it was statutorily defined for us, as well as contractually.

Whereas with the evolution now of a new project and

the formation of the Joint Venture that Dan referred to with the Alaska LNG project, we now have the major producers, Conoco, BP and Exxon Mobil, along with TransCanada representing the State's ownership on the midstream or the pipeline and the gas treatment plant and AGDC representing the State's interest in the liquefaction plant. We now have that team working towards export for the large scale commercialization of the North Slope resources.

FAUSKE: If I may, Mr. Chair, on the AKLNG side to give you a scope, the proposed liquefaction plant where they chill the gas and prepare it for tankers to be shipped is 20 times the size of the current plant that you've all driven by in Nikiski and it is at a cost of between 20 and, what, $24 billion for just that plant.

The GTP, gas treatment plant, on the other end is -- someone help me out, 18 -- I think it's 18.....

RICHARDS: Fifteen -- 15 to 18.

FAUSKE: Fifteen to 18 billion for that plant. It, too, is a huge complex. And then the pipe it's hard -- it's not inco- -- but it's a significant cost, but the two big drivers are the gas treatment and the liquefaction on the other end are really the two biggest items in this overall value chain going down in terms of construction.

DRYGAS: Can you repeat again, what was the cost for the LNG plant?

FAUSKE: Between 20 and 24 billion.....

DRYGAS: Yeah.

FAUSKE: .....have been the latest estimates. Those, again, are estimates and that engineering work is going on, but it's a huge, huge complex. And they're purchasing land and there's -- you've seen that in the papers where -- you know, to -- to get the site secured where you would have the ability and then they'll start testing that. They, we're part of that, boreholes and all this other stuff to design it to -- I remember reading one article in the paper just the weight of the plant is unbelievable, so you have to test if the ground can hold that type of -- I mean, it's in the hundreds of millions of tons and so that work is ongoing, so.....

BURNS: Dave and then Hugh.

CRUZ: Yeah. So through the Chair, I want -- for the new Board Members I want you to bear in mind that we are only a partner in 25 percent of the liquefaction process. We're not midstream and we're not in the GTP on the Slope, so there gets to be some misconceptions in the press that we are 25 percent partner in that. We are not, only that item.

BURNS: Hugh.

SHORT: My question is how does this project compare globally to -- let's just talk about liquefaction. You mentioned the 20 to 24 billion, how does that -- the output of the liquefaction, the size of the liquefaction compare globally to other liquefaction projects either built or currently in construction?

RICHARDS: Mr. Chairman, I would like to bring Fritz Krusen to the to stand. Fritz.....

BURNS: Absolutely.

RICHARDS: Fritz was hired specifically as the vice president of the AKLNG coming with 30 plus years of experience with ConocoPhillips in liquefaction.

BURNS: And actually -- I mean, I think this is a good point which we're -- in Frank we're got ASAP. In Fritz we have AKLNG.

SHORT: Sorry to veer off the other project, but this is so darn interesting.....

BURNS: Yeah.

SHORT: .....I've just got to know.

BURNS: No, but, Dan, if you want to clarify just the organizational structure so that, you know, we try to keep things.....

FAUSKE: That's a good question, Mr. Chairman. We've had the ability recently to crossover, to use people on both

sides of AKLNG and ASAP. And there's been some contention on that here recently based on how people perceive it and the sharing of data, but currently Frank has been primarily the ASAP side. Fritz is totally AKLNG, but then supplies guidance on the ASAP. You know, after 36 years with ConocoPhillips and at the end of his career he was a global lead for ConocoPhillips, so he brought a great deal.

We were fortunate that he had two daughters here and wanted to get back to Alaska, so one of the daughters is a psychologist which we plan to use here in the near future. She's offered her services, so.....

And then Frank has been primarily in the ASAP side on the engineering, so we've had this, but there is a distinction as to function and roles. And there is a distinction as to the sharing of data and how you firewall that and how everyone can -- can (indiscernible).

What we've tried to do is maximize the ability of people and minimize the numbers of people. In other words, like I -- I think it was Bruce made a comment that we have limited ourselves to not create a bureaucracy that has to be fed.

Most of the people that we have our consultants that come and go with phases of the project that they work

on and as far as core staff we've kept that to a pretty good minimum which is always going to be the intent because that's just the way it is. This is a project organization. It's a pipeline company basically, so.....

BURNS: So, no, let's get Hugh's question answered first.

UNIDENTIFIED: Okay.

KRUSEN: So, for the record, Fritz Krusen, vice president of LNG for AGDC and then I'm also what's called the Project Steering Committee representative for AGDC on the AKLNG project.

BURNS: Fritz, if you could talk and speak a little louder we'd appreciate it.

KRUSEN: Okay. I was trying to get into the mic, but I'll just.....

BURNS: That mic is over there, that doesn't help us.

CRUZ: No, he's got another mic.

BURNS: Oh, got cha.

KRUSEN: So through the Chair, Mr. Short, we mix units quite a bit so we talk about LNG output in millions of metric tons per anum, so the Kenai LNG plant that Dan referenced earlier is about 1.3 mtpa. World standard these days is around fiveish mtpa and quite often there's two trains, 10 mtpa.

By the time you bring that up to Alaska where it's

colder and we're going to bring the gas in at higher pressure, that's six mtpa per train, 12 mtpa for a two train project, but where AKLNG differs it's a three train project, so it's at least a third bigger, maybe -- maybe approaching 50 -- you know, twice -- 50 percent bigger than the typical two train LNG project in Australia, anywhere else.

FAUSKE: Something that might help and I'd like to -- I always forget the number, but the conversion of billion cubic feet of gas converts to what, about seven.....

KRUSEN: Yeah

FAUSKE: .....tons.

KRUSEN: I can never remember the number. What I do remember is we've got about 900 million coming into each LNG train and we've got about six mtpa going out of each, that's something I can remember.

FAUSKE: And the AKLNG as designed, I think, it at 20 million.

KRUSEN: The license will be for 20 million.

FAUSKE: Twenty million tons per anum produced based on 3.3 billion. After you've netted out the gas to run the pipeline, it's about 2.7 billion feet of gas. And taking out Alaska use to produce 20 million tons of LNG a year.

SHORT: Can I ask a follow-up?

BURNS: Okay.

SHORT: So given the fact that this is 50 percent larger than the typical LNG plant and you mentioned Australia, is that a factor of the amount of known reserves of gas on the North Slope? Is that a fact- -- what's that's a factor of? Why is it 50 percent larger?

KRUSEN: So, yes, it does reflect what the project thinks is the appropriate way to monetize the gas reserves on the North Slope, Point Thomson and Prudhoe Bay. So it seems to be a nice size to efficiently monetize that over a typical 20 year LNG contract.

SHORT: And with known reserves and the known projection of 20 mtpa, how long would we produce LNG given known reserves today based on this liquefaction size?

KRUSEN: So this is maybe a little slippery ground for me because we're supposed to be the downstream guys and we're now talking about upstreamie (ph) stuff, but it would appear that, you know, we're, sort of, at plateau for about 17 years-ish and then we begin to slip off plateau and one, you're still producing from Prudhoe Bay and from Point Thomson, but you have to go out and find other gas to keep the three trains running fully.

FAUSKE: One of the premisses on AKLNG is if you've looked at the financials it's gas to be found as listed. You know, that's recognized within the development of the

project that not all the gas is available to carry it out beyond, I think, it's 20 years or 25. I mean, if you look at long term firm transportation commitments at 20 and 25 years, so that's recognized.

I think we could help -- the large plants currently, Australia, ConocoPhillips is involved, that's a huge complex.

KRUSEN: Two train, 10 (simultaneous speech).....

FAUSKE: Exxon is in New Guinea with another large -- I don't know the number, but we compare -- this would be the largest project in North America, but I'm not sure on a world scale. It's got to be right up -- AKLNG I'm talking about now.

SHORT: Yes, sir.

FAUSKE: There's talk of British Columbia, a couple on the -- not near this size.

KRUSEN: I haven't kept up with those two (ph).

FAUSKE: Yeah.

KRUSEN: My speculation would be they'd be around 10 mtpa.

FAUSKE: Yeah, so this is a large project on a world scale. Whether it's the largest or not, I don't know, but it's right up at the top. We can find that out for -- I mean, get you a ranking

SHORT: I think there's going to be a lot of information over a period of time then. I'll request, just get an

idea of the macro (ph) of how this project scales compared to other projects. At the end of the day, I feel my job is to try and make this the most competitive project in the world so we can get it built.

So the better I understand the overall global completion, the global market and then how we can -- how I can as a Board Member help this project move forward to be competitive will help me do my job.

KRUSEN: I would add, AKLNG did a lot of pre-work as things were coming together for the Joint Venture that, sort of, reinforced in their mind that this 18 to 20 mtpa export and that method of monetizing the North Slope gas, sort of, hit the sweet spot for what they currently know.

BURNS: Um-hum. (Affirmative) Rick.

HALFORD: I would appreciate it if we could somehow we could put together that run-on sentence of comparison so we have a scale that we can use, metric tons per year, billions, trains, you know, so we can convert to the systems that you go back and forth and knowing.

I understand it briefly when you say it and then I come back and try to figure it out and have to figure it out again every time. And if we had a simple scale that we could understand it on would be appreciated.

KRUSEN: So why don't I go away and create an LNG cheat sheet like Frank did for pipeline.

HALFORD: Thank you.

BURNS: I think that would be helpful. Any other questions for Frank? Oh, yes, go ahead, Joe.

PASKVAN: Just one observation because as I understand then with three trains, than the maximum flow rate for the Alaska LNG project is 2.7 Bcf a day?

KRUSEN: You know, we have annual averages and we have maximums and so the maximum is probably higher. The maximum into the LNG plant is probably 2.8 billion, maybe a little bit above that. The annual average is 2.7.

PASKVAN: Okay.

RICHARDS: If I may, the key point is that's into the plant,.....

PASKVAN: Correct.

RICHARDS: .....so then the output is less.

PASKVAN: Correct.

KRUSEN: And just -- I will be back for the -- I think the next agenda item, so.....

BURNS: Yeah.

KRUSEN: .....if there's a lot of AKLNG type questions, perhaps, I can help with that.

RICHARDS: Fritz, why don't you stay 'cause I'm going to

continue on with talking about the Corporation initiatives and if there are question on the LNG that would be great.

KRUSEN: Sure.

BURNS: And just for the new Board Members, we historically structured it so we have a report on both of the projects independently because this is the problem that happens, you get this bleeding over and pretty soon you don't realize what project you're talking about.....

SHORT: Right.

BURNS: .....and so we've had a discreet structure where we move forward with the AK- -- or the ASAP project and then we'll talk about the AKLNG and then there will be, kind of, a lap-up (ph) as to how -- you know, the interrelationship between the two because we -- you know, those of us who started on have the same issues and we've bleeding back and forth quite a bit. Yeah.

CRUZ: You know, for the benefit, I chair the Tech Committee for -- so I'm dealing with Frank and Fritz and all the group together and I asked the same questions you were asking and the average worldwide plant, it produces -- export facility, a little over 900 million cubic feet per day, that's the average when you look at them. There's bigger, there's smaller, but that's the average if that -- it gives you a

perspective of things.

SHORT: Three times bigger (ph).

PARADY: (Indiscernible) trains? I'm just.....

BURNS: The question is how many trains -- based on how many trains? Frank, go ahead, please proceed.

RICHARDS: All right. Mr. Chairman, again, on the design objectives, as I said, Alaska LNG was commercialization of the North Slope resources. What they are doing though is feeding into a liquefied plant in Nikiski so, therefore, that quality of gas is different than the ASAP. So ASAP was, again, lowest cost gas to Alaskans.

So in 20- -- summer 2013 we, within the ASAP project, changed our design premiss to provide for utility grade gas. Meaning gas that would come off the line, could flow into an existing utility and be used without any further conditioning.

So ASAP takes gas from the North Slope, conditions it, brings it down a pipe. Can go into Fairbanks. Can flow into what is now the Enstar system and be used without any further work, so that was a key deciding factor.

So the differences in the gas then is the amount of conditioning that you do on the North Slope to meet those two specs. So for the utility grade gas we're at about three percent CO2, as opposed to the LNG quality

gas which is down to approximately 50 parts per million.

So if I may I'll refer to the charts that we have on the wall. These are depictions of the gas conditioning facility for ASAP on the North Slope. So this is approximately a mile to the west of the central gas facility. An existing gas facility that proces- -- uses -- process the gas on the North Slope to re-inject into the reservoir.

This facility is a two train, 250 million standard cubic foot a day conditioning facility. So that means that we will take the gas from the Prudhoe Bay Unit, we'll condition it down to that utility grade specification and than push it into a pipeline.

So incorporated into this is a compressor station that would pressurize the gas up to the maximum allowable pressure to be able to flow down through the pipe. Two trains or two conditioning units that would then strip out the carbon dioxide and the hydrogen sulfide to be able to meet the -- essentially the Enstar quality gas specification.

So this plant here represents approximately $3.3 billion worth of facility. It's located, again, on a -- would be located on a pad, approximately 70 acres worth of gravel that is the same location that AKLNG

would likely use for their gas conditioning facility as well, but the scale for the AKLNG project is six times larger in terms of the gas flow.

So when we talk about the two projects, we've got so many commonalities, same pad location, proximity to the Prudhoe Bay fields and then ultimately feeding down and providing gas for Alaskans.

BURNS: Um-hum. But that's been the intent, though, is to maximize the symbiotic relationship, if you would, between the two and we've gotten the -- as I understand it, the permit from DNR is for both projects, you know, all of that stuff, so we've sought to do that intentionally?

RICHARDS: You're correct, Mr. Chairman. Actually the land was withheld by DNR for a project, so.....

BURNS: For a project, that's right. And we consented to it because it's going to one of the two?

RICHARDS: That's correct.

BURNS: Now, as I understand that, that design has been -- that's fully designed and a Level 3 cost estimate has been obtained for that, correct?

RICHARDS: That is correct, Mr. Chairman. So that means the last two years we've been working on a design premiss for utility grade gas at 500 million cubic foot a day maximum flow and that's what that plant is designed to

handle.

BURNS: Hugh.

SHORT: Mr. Chairman, so this project is contemplated to deliver gas to the Enstar line and offshoot to Fairbanks with a planned distribution system built-out or expanded in Fairbanks.

What was the discussion or what is the plan for those locations that are off of the road system that currently aren't connected either to the gas infrastructure in Southcentral Alaska or the planned infrastructure that's being contemplated in Fairbanks with the ASAP plan?

Has there been a discussion around how other parts of Alaska benefit from this amount of gas getting to Southcentral Alaska?

RICHARDS: Yes. We were given the charge under HB 4, I believe it was Senator Hoffman who put in the language that identified that AGDC must look at other transportation mechanisms to meet the energy needs of Alaskans that wouldn't be able to connect into this pipeline. So -- but the language is that we contemplate that work once we have a pipeline in place.

So what we have been focusing on is initially design the pipeline and now we're looking at what will be the offtake points, so Fairbanks would be a major offtake

point. And we have a 27 mile lateral leading into Fairbanks connecting into a yet to be built future distribution system across the Fairbanks North Star Borough.

And then we'll have offtake point designs for smaller communities and -- to be able to have access, so -- because the key driver by the Legislature is, again, to maximize access by Alaskans, but in order to do that we need to know the costs.

And the language was other transportation mechanisms, so we are to look at pipelines. We are to look at barge systems. Iso tank (ph) containers. Whatever the mechanism may be to be able to, again, economically provide for future energy delivery to other Alaskans.

BURNS: Okay. Yeah.

CRUZ: So you -- one of the methodologies that -- looked at is very similar to what's done in other parts of the world as ISO containers. That's what you see riding on the back of a truck. You see a forklift taking one, set 'em on a barge or a ship. And basically we are in still in the infantile stages within our Committee dealing with that, but what -- the discussions we've had is going to an intermodal type freight aspect.

So how do we get gas to Tanana, Galena. We have an

offtake point at or near the Yukon River. We fill these ISO containers. They go on a barge. They go down river. You come up, you switch 'em out at the village, you know, that has for power generation or their distribution system for gas within that, those are things to come. And you load the empties up and they go back. Very similar to what's done today with diesel, just done with an intermodal freight type transportation set up. That's what's done in other worldwide places.

FAUSKE: Mr. Chairman, to add to the point. When HB-4 was passed -- House Bill 4 there was a provision also that we were to add a percentage of propane to the mix and so we're currently configured at about one and a half percent propane which is 4,000 barrels a day roughly of propane.

And the intent then was to explore, what Dave Cruz just talked about, is propane down the Yukon, propane down the Richardson Highway and to see what the market was and so that was taken into consideration at the time the Bill was passed.

BURNS: Frank.

RICHARDS: So, again, the terminus of the two different -- of the projects are at two different locations. The ASAP project terminates at Milepost 39 of the Beluga

Pipeline which is one of Enstar's distribution lines that feed into the Mat-Su Borough and into Anchorage.

Whereas, AKLNG project is terminating now at -- the preferred alternative at Nikiski for the new LNG plant.

The design capacities as I said previously 500 million for ASAP and 3.3 billion standard cubic feet a day for AKLNG.

And then when you get down to the cost estimates ASAP with the completion of our Class 3 level work in December our new cost estimate was approximately $10 billion as opposed to the range of 45 to 65 billion for the Alaska LNG project.

Workforce is fairly close, AKLNG, again, is three mega projects wrapped up into one with the gas conditioning facility on the North Slope, a major pipeline project and then a huge LNG plant at Nikiski. So a tremendous amount of work force will be necessary, a tremendous amount of steel will be necessary and will consume a good portion of the world's production.

FAUSKE: Yeah, Frank, if I may. The original estimate that many saw was 7.5 billion, you know, and that was at plus or minus 30 percent which was a Class 5/4 estimates. As you come down in class lower is better. At Class 3 you can see where plus or minus 20 percent. You end up getting to Class 2 before you go into

sanction, you know, as you start it at plus or minus 10.

What we appreciated was the fact that for -- there were many that thought it won't pencil. When we first started -- this was House Bill 369 which was what created the team to write a report to see if it was even feasible. To end up in nominal terms that we stayed within the plus or minus 30 percent that we had told people it would as it climbed up closer to 10 and you can factor in inflation and everything else on that as you're going over a two year period.

On this project every year delays about $220 million as just the normal cost and so that number is pretty significant. And so that number is pretty significant and those estimates now are getting real solid.

And what we did here was we asked contractors and we paid them, not like -- but we paid them for their time to get hard numbers. To really put not just, kind of, a cocktail nap, but to get -- drill down into it.

Dave Cruz was very instrumental in that with our team to bring them in here, a variety of different contractors and asked them to get engaged into these estimates. So you can take a pretty good level of confidence in that Class 3 estimate and as you move it down if this project were, you know, to continue. So

we're staying within the arena that makes it feasible. We're still at a point on the tariff where we're competitive to get gas to Alaskans at a price equal to or less than imported LNG, but where you start getting weak is you only need 250 million feet for instate use, but, you know, plus or minus. That residual, the whole tariff model is based on the fact that you'll see it and that's where you start -- start looking (indiscernible). Can you sell that gas to someone at 10 bucks or 11. Can you sell it to a Donlin creek or an Agrium or some large commercial activity that would buy it and so that's been the pressure on the 500 all along.

BURNS: And let me just make sure that I understand though, Dan. The -- when we've done this and done the Cost 3 estimate, my understanding was that's essentially something that you could put out for bid?

FAUSKE: Correct.

BURNS: I mean, it's at that juncture.

FAUSKE: Yeah.

BURNS: And that, the final Cost 3 estimate had almost a 10 percent contingency in it, if I understood?

FAUSKE: Correct.

BURNS: And the total cost of that was about 10 -- 10 billion I think it is?

RICHARDS: That's correct, Mr. Chairman. So when you're referring to the gas conditioning facility, we essentially -- with the advanced design that had been completed by Arctic Solutions, joint venture of Fluor and WorleyParsons, they went out to vendors and actually got quotes, price quotes for the major process units. So the major process vessels. So they were tangible. These weren't WAGs, wild ask guesses. These were essentially vendor quotes that you could then recognize that you have a level of confidence in you cost estimates.

And as Dan described working with pipeline and civil contractors, as well as Mr. Cruz, we were able to get essentially right-of-way or work crew level estimates from the pipeline side of the house. So we feel that -- we feel that our confidence level in this Class 3 estimate is very good.

CRUZ: Yeah. So to (indiscernible) English (ph) for the new Board Members, if we didn't have AKLNG today and we were going to build a 500 million cubic foot per day pipeline, we are ready to go and have a recourse tariff developed -- or we have -- or submitted to.....

FAUSKE: RCA.

CRUZ: .....Alaska Regulatory Commission. They will come back with a resource tariff. We've been promised 60

day turnaround, Mr. President.

FAUSKE: Yeah.

CRUZ: Sixty day turnaround.

FAUSKE: Yeah, that's what we've -- yeah.

CRUZ: Sixty day turnaround from Alaska Regulatory Commission. At that point we then can go Open Season. So effectively under the schedule that we have that we are still trying to pursue, the long lead items, pipe, heavy equipment, camps and that we need to be ordering in January of 2016 if we are going to build this 500 million cubic foot pipeline today. That's the threshold we are. This is not a WAG. This is hard and fast that can go to bid.

So that's a -- we have a -- we have a huge resource of extremely highly qualified people that came up with these numbers. And I can't thank this Staff and the people that I've had the opportunity to work with to refine this number. It was brought out to Alaska contractors, that's another thing that it's just not a bunch of Lower 48 consulting firms that come up with a number and here's what it is.

It was actually vetted though contractors in Fairbanks. Very well known Fairbanks contractors. Very large contractors based throughout. Peter Kewitt as an example. Major players came in and stepped up to

help in this process and that's how we were able to achieve a real number at less then 10 billion to build this thing, so.....

BURNS: Hugh.

SHORT: So I take a lot of -- I think what you've just stated gives me a lot of comfort.

Where I don't have a lot of comfort and it's my experience -- I spent three years on the AIDEA Board of Directors and as the tail end as Chairman we had a project which was trucking LNG to Fairbanks. And that project had a similar problem to what you just stated, Mr. President, which is about three Bcf was what's needed for the Fairbanks (indiscernible - coughing). Maybe you could push it to four. Maybe on a good day you could push it to five. The project scaled at nine Bcf. That's what the plant was needed to be built at.

Ultimately what happened was you could -- there was a gap between how quickly you could build out distribution, grow the demand in the markets and bring the cost down of the delivered gas to the project.

Now, we know what happened. We can follow, sort of, the process because that project died. It's dead. They're now talking about a different route.

And so I think on the construction side, you know, I think they did a pretty darn good job of cost

estimates on that. They bought in a lot of really good people. Where the project ultimately failed was it came in at -- came in at about $19 when it needed to be about 15.

And so, I guess, as a new Board Member I'm interested to understand the economic side, the tariff side of this.....

FAUSKE: Sure.

SHORT: .....especially if we're counting on Donlin Creek and Agrium and other large consumers of this given the fact that we've had a pre-abysmal track record with developing in Alaska on large projects over the last 20 years, so that's my concern.

FAUSKE: That's a very good concern. As Mr. Cruz pointed out, you do your RCA, your recourse tariff filing. What's key to this project that's different than AKLNG is that there's an Open Season on this project.

SHORT: Um-hum. (Affirmative)

FAUSKE: AKLNG will not have an Open Season because all the owners are present.

In this case for ASAP you would -- an Open Season, a bid process.....

SHORT: Sure.

FAUSKE: .....before you would ever start construction or, you know, pre-ordering materials you would have some

firm commitments from the buyers.

When I mentioned Donlin I was just using an example of what's out there. When we originally did the tariff estimates for Fairbanks, we had 'em at 60 million feet of gas a day. They're now down to what we think's about 23, (indiscernible) from all -- part of it's Flint Hills, University, Military and so you need to adjust accordingly.

The sad part about that is that -- and I reminded Anchorage folks of this and when you talk to Fairbanks folks and you get that normal -- you know, the head butting that's gone on forever, is that it's in all our best interest for the most amount of gas possible going into Fairbanks 'cause it drives the tariffs down for everybody and so that's the driver.

And so then the issue was get your local distribution system in place so that when that gas gets, you've got maximum going as quickly as possible to drive those tariffs. So.....

SHORT: Sure.

FAUSKE: .....it's a number we're watching very closely because at 20 to 23 million feet a day that's a different number. Now, will Flint Hills open back up if there's gas coming. You know, that's been -- we have Fairbanks folks here that know that issue far

better and I, that's certainly been an indication.

One of the nice things about Donlin Creek and up they've met with us numerous times. They're getting ready or they were, they were going to spend a billion dollars for their own pipeline, but they never believed that this thing would go anywhere, so they continued those plans, but if you get Donlin Creek in -- and help me out here even if I'm wrong, you've got 100 miles, 110 miles from Bethel.

All of a sudden you've got a whole new arena that could open up and so that's been not only resource development, but the idea of all -- you're still 100 miles away, but you're not 500 miles away. I mean, all that -- that's how that stuff goes. So we're on -- these are numbers that we are watching very closely.

SHORT: Good.

BURNS: But, you know, what the conundrum is -- is -- precisely is you've, kind of, indicated -- I mean, the analysis here was based on the 500 and that was because House Bill 4 had it constrained at 500 because of AGIA. 138 comes in and -- Senate Bill 138 comes in and AGIA is no longer in play, but we have started the analysis and we had progressed quite a ways in that analysis under House Bill 4 with the 500.

And so it's neither prudent nor practical to start

all over because we were uncertain, as I understand it, uncertain as to the viability of the project at all. And so we progressed through the 500, you know, million standard cubic feet analysis and found, you know, pleasantly that it is a viable project. I mean, Frank will walk through the analysis.

The caveat to that though is that you have to find a market for the full 500 as the two of you guys have.....

SHORT: Sure, yeah, yeah.

BURNS: .....indicated. And so the conundrum that we're in and that leads us, you know, as we will be talking a little later is that how do you maximize volumes to bring down the tariff and find a market that you can expand, you know, the purchase for that additional gas. I mean, that's, that fine point. It -- you know, that's going to be the focus of major discussion a little bit later because we've done the analysis and Frank will lead into it, and that the 500 is viable at the 500 tariff assuming you have full 500.

SHORT: Sure.

BURNS: We just don't have it. Even if you factor in the propane and all this other stuff, and so how do you maximize -- how do you maximize the ASAP pipe to increase volumes in a way that you've now, you know,

maximized the benefit for the State of Alaska.

SHORT: And to that point, Mr. Chairman, I think the challenge in the Fairbanks project just as going to what I know about that project, it took about six years to build that demand, so it was a six year build-out. And you did not cross break even until year four, year five, early year six and so that required years one through year four or maybe year five to have some sort of subsidy to offset the loss taken because you didn't have the demand side figured out. And then hopefully year five or year six or seven you cross and then it's past break even and I think that, that's.....

BURNS: Yeah. Nope and that's the same -- that's.....

SHORT: And I think that's.....

BURNS: .....precisely the same dilemma that's here.....

SHORT: Yup.

BURNS: .....because if you're just going to rely on instate use.....

SHORT: Yup. Yup.

BURNS: .....it's not going -- you know, it's going to be very, very difficult. So anyway.....

FAUSKE: Well, one of the terms that might help the Board and I'll be just real quick is you'll hear is anchor tenant.

BURNS: Yeah.

SHORT: Sure.

FAUSKE: A (indiscernible) you know, a major anchor tenant or a utility. It's -- besides residential.

SHORT: Perfect (ph).

BURNS: Frank, we keep going back and forth, sorry. Rick.

HALFORD: Just when you mention 250 as the instate use, that included all of Cook Inlet's gas.....

BURNS: A percentage of it.

HALFORD: .....or not?

FAUSKE: We're talking Railbelt usage.....

RICHARDS: And Fairbanks.

FAUSKE: .....and Fairbanks.

RICHARDS: Exclusive of gas from Cook Inlet.

FAUSKE: Yeah, exclusive of.....

RICHARDS: So we didn't -- we looked at.....

HALFORD: Okay.

RICHARDS: .....what was the need.

FAUSKE: Yeah.

HALFORD: Okay.

BURNS: We're just displacing (ph).

FAUSKE: And we have refined that study now and there's some others that we can have on the -- we just got those, didn't we?

RICHARDS: Yeah, we can -- we're not -- we didn't prepare anything for today's discussion, but we will be glad

then the updated instate need.

FAUSKE: We'll get that to the -- the upstate use -- or Statewide usage. It's just a new report that's been -- people have been working on. I'll get you -- we'll get you that.

BURNS: Good. Frank, please.

RICHARDS: Mr. Chairman, I'll wrap up here quickly on the comparisons. Again, for the ASAP project one compressor station built into the gas conditioning facility. That provides enough pressure for the gas to flow from Prudhoe Bay all the way down through into the Enstar system.

For the Alaska LNG project they have, again, compressors at their gas treatment plant, but then they also have intermittent plants along the route and that's because they are pushing it at a higher volume with a different quality gas, so differing approaches there.

And then one correction I will make and I apologize, on the slide for ASAP under completion date in construction you show old numbers of 2016 and 2021. I gave Gwen an old slide and that's my mistake. We're now looking at final investment decision in 2019 and then completion of construction in 2024.

And the reason why we did this was with the passage

of Senate Bill 138 the focus of the State was that the priority project was the AKLNG project and, therefore, AGDC completed our work efforts for the Class 3 work on ASAP in December, but then we also looked at what was going to be the best use of continuing engineering into the next year while the AKLNG project marched towards a Pre-FEED decision in first quarter 2016, so we reduced our work plan efforts and, therefore, that impacted our schedule.

FAUSKE: I hate -- but these points keep coming up 'cause I remember these are new Board Members and so one you'll find helpful, I think.

When we were run through the funding round a year or so ago there were many that were troubled that we were doing two projects and that people wanted to have a backup. And our response has always been we just don't know enough yet to make an either or decision on which one. And our target date has always been first, second quarter of 2016 whether the large project makes its' FEED decision or not.

And then at that time it's always been the idea that this project would meld into that one and that our goal then was not to duplicate work. That we would work closely with the other project and do work that was beneficial to that project and we did work that was

beneficial to them as well, so we've had this very good relationship.

In fact, right now we're doing the winter work season on borehole testing. ASAP -- or AG- -- ASAP side is doing it for AKLNG.

And then you get to that 2016 date where you go okay, here we are 'cause you're not going to have two projects. I think everyone is in total agreement with that. And so I think we've done a great job of air quality testing and all this stuff where you could have the same tests going on within a mile of each other and totally wasting the State's money. We have not allowed that to occur.

So as you watch this, bearing in mind that a little over a year from now we should be in a position where there's going to be a decision one way or the other as to which project goes.

BURNS: And the only thing I would add to that because I think the -- and Joe can probably later on in the presentation when we get to the AKLNG, our understanding at least from the Board's perspective is that the relationship has been literally exemplary, the cooperation between AGDC and AKLNG and so, you know, that's a huge positive.

The thing that we wanted to ensure though is that,

you know, the recognition that there really would only be one project, okay, is real, but what AGDC always wanted to ensure and the way we understood AK -- I mean, House Bill 4 and Senate Bill 138 is that we need to maintain a viable alternative project if AKLNG does not proceed forward because Alaska has been waiting for -- what are we, nearly 40 years or something.

And so, you know, it's important that we maintain the viability of an alternative project. And in so doing ensure that it truly is a viable project. And so there were some things when AO 271 came out, for example, that really, you know, wanted to make sure that there was a freeze on discretionary, the -- you know, what we did was we tasked some efforts in that, but always maintaining the viability of the ASAP project. Continuing with the supplemental Environmental Impact Statement, moving things forward so we maintain that viability because if you park a project halfway through you lose it.

And so where we're at, at this juncture is we -- you know, we've gone through on the ASAP at the 500 and one of the issues that will come forward to this Board today is -- you know, is evaluating the benefit of expanding volumes through the ASAP 36 inch line. No change in pipe diameter, you know, that sort of thing.

It's just expanding the volumes through that to capture a, you know, market beyond it, but that's been the -- that's been the responsibility of AK -- of AGDC is marshaling -- a shepherd (ph) in two new projects knowing that there will only be one that moves forward. And if AKLNG moves forward which is everybodys' hope that, that then -- you know, then all the things that we are spending on will be -- have been a significant benefit to AKLNG project.

But the flip side of that is if AKLNG does not move forward and the only reason substantively that it would not move forward is if it does -- it would be simple economics. And so either it's going to move forward or it's not going to move forward, but Alaska cannot be left in the position of having no alternative.

That was very clear in House Bill 4. I think it was unchanged in SB 138. And it's been this Board's mission to ensure that, that alternative option exists. The focus has been on AKLNG. The commitment of, you know, the Legislature and the Administration and this Board has been, you know, advancing AKLNG, but we've got to maintain the viability of an alternative.

RICHARDS: Mr. Chairman, if I may then let me just identify to the Board what AGDC has accumulated in regards to what I describe as assets for the State of Alaska. And as

you've heard we have a State right-of-way. Essentially that's a lease that was granted to AGDC by the Department of Natural Resources for the pipeline alignment across State lands.

I'll refer you to the charts over here on my right which depicts the alignment from Prudhoe Bay down through to the terminus of the ASAP project.

Now, as Dan referred to, we have been working with our partners at Alaska LNG and our routing engineers have essentially landed on a common alignment for what I describe as 98.5 percent of the route. So from Prudhoe Bay all the way down through to the crossing of the Susitna River on the Parks Highway Bridge we have essentially a common alignment, so therefore, the asset that AGDC holds for the State is valuable for both the ASAP project, as well as AKLNG.

We have had published in the Federal Register a final Environmental Impact Statement. Again, that was in 2012, but it was on the old design premiss of a high pressure, liquids rich gas stream. And with our concept change to a lean gas in 2013 we've initiated a Supplemental Environmental Impact Statement and that is underway now with the Army Corps of Engineers.

So with that work we've updated what's known as a plan of development which the major land owners, both

State and Federal agencies require that we have. We've completed what is the precursor to the SES and it's called an Environmental Evaluation document. And we have done public scoping now in 16 communities along -- within Alaska to follow the Federal process for public involvement in that Supplemental Environment Impact Statement.

We have continued to do extensive field work along the alignment where we not have completed our waterways site visits so that we now can define the approximately 480 different waterways that the pipeline will be crossing. And we're looking at the best ways to cross those and we'll come up with those typical plans to be able to present to the regulators.

We've conducted a 2-D terrain unit mapping along the entire route. We've conducted what is known as our cultural resource mapping which is the requirement of Section 106 which is the Historic Preservation Act. And then we've also done wetlands delineation and sought jurisdictional determination from the U.S. Army Corps for the wetlands that will be impacted by not only the construction right-of-way, the access roads, but the permanent right-of-way as well.

So that right there in terms of the regulatory world we've done a considerable amount of work.

Now, shifting on to slide what is titled 8 and I apologize for the numbering, we have other hard assets. These are the geotechnical boreholes that we have completed for AGDC along this alignment. As Dan indicated previously, we have work with our partners at AKLNG and we have sought not to duplicate efforts.

So primary where AKLNG and the partners had a tremendous wealth of information north of Livengood, from Prudhoe Bay to Livengood, AGDC did not. And so we elected not to do work there in the hopes of being able to work out an agreement to obtain that information from our partners in AKLNG and we did that in late last year. So we have now received that information to AGDC. And in return we have shared boreholes that we had south of Livengood along the alignment with AKLNG, so it was a win/win for both projects.

As Dan mentioned also air quality monitoring at the gas conditioning facility, we have been doing that and have that in hand. And we've been working on an air permit requirements with the Department of Environmental Conservation for that gas conditioning facility on the Slope, so that is far well (ph) advanced.

The strain based design pipe I talked about earlier, we've completed our line pipe specifications. This is

the main line pipe that would be other than stain based design. And we've completed our -- what's known as a Project Execution Plan. And this is a very detailed document that outlines not only how we'll do the efforts that we've done to date, but also how we will move this through to execution phase, construction and then into operations afterwards. So it's a guideline that would provide essentially a tremendous wealth of information in terms of how to build this project.

FAUSKE: Frank, I think down on the 2nd where their -- the project team is located in the conference room there, we have the -- correct me if I'm wrong. I always get all the names wrong, but the Project Exec- -- the spreadsheets, the gantt chart, aren't there 80.....

RICHARDS: Work breakdown structure.

FAUSKE: Work breakdown structure. I think there's 8,400.....

RICHARDS: Lines.

FAUSKE: .....lines on there of all the -- if you get a chance go down and look at. It's pretty impressive. I mean, when you get to thinking there's a awful lot that goes on to one of these things, but that's all spread across the wall so you can get, kind of, a visual on the amount of work that goes into doing one.

RICHARDS: So the documents that I just referred to is the

information that we hold. We hold that in AGDC and it is literally thousands and thousands of assets, as they're called.

And now we did receive, again, information from our partners in Alaska LNG and under the Cooperation Agreement that limited -- that was limited to the ASAP project at 500 million standard cubic feet a day, so that information was for that project. We've cordon that off and it will not be used on other work efforts going forward other than 500 million.

BURNS: Unless there's -- unless there's an agreement otherwise.

RICHARDS: That's correct, Mr. Chairman. So now I'll turn it back to Fritz and ask him to give an update on the AKLNG milestones.

KRUSEN: Okay. So now we're moving to section.....

RICHARDS: No, no, we're going to go through here, so what's been done to date (ph).

KRUSEN: All right.

BURNS: So before we transition to AKLNG, are there any questions of Frank relative to ASAP? Okay.

People need a break?

UNIDENTIFIED: Yes.

BURNS: Okay. Let's take a five minute break.

(Off record - 10:29 a.m.)

(On record - 10:44 a.m.)

BURNS: All right. Just before the break Fritz was up to bat on the AKLNG.

KRUSEN: Okay. So I'll try to speak a little louder than I did in the past. Everybody hear me okay?

(Simultaneous speech)

KRUSEN: All right. So we're on a slide that is entitled Alaska LNG Milestones and I'm showing page number 5 on the lower right hand side.

GRAHAM: It's not done correctly.

KRUSEN: We're still in Tab 9, Section 9, are we not? Okay. All right. So I'm going to read down this. This is, sort of, the history of getting to where we are today.

Maybe a dot point that isn't there, maybe the very first dot point is the Joint Venture Agreement or JVA was signed on the 30th of June, 2014, so that's what actually bound AGDC, TransCanada, Exxon Mobil, BP and ConocoPhillips in the Pre-FEED effort.

One of the first things they did then -- one of the first things we did was filed an export application with the U.S. Department of Energy, so if we're going to export LNG we've got to get our paperwork in place. And they were very prompt in their response, November 20th they authorized LNG exports to Free Trade Agreement countries and that's a really big deal.

We made an application to FERC, this is a FERC project not -- that's the one thing it differs from ASAP on. This is a FERC led project. You want that. FERC looks after energy, so we -- they've made a prefile request on September 8th and we've been working on the Draft Resource Reports. There's actually 13 Resource Reports that go in. All in all the first 12 -- I guess maybe jump down a little bit, the first 12 were submitted in February of 2015.

We briefed the Joint House and Senate Resource Committees on the 29th of September. There have been subsequent individual briefings.

We've been all over the State, but one of the more interesting sessions was the media tour in Nikiski on the 9th of October. We all got on the news.

Our Board approved our 2015 budget. We were the first of the co-ventures to approve the AKLNG budget, so I certainly appreciate everybody's quick response.

Even though this is a Pre-FEED effort, there's still a lot of real activity going on, so the LNG plant site, geotech work was done and the Cook Inlet site investigations were done, more to come in 2015.

As Frank described, we have signed agreements on how to share information between AGDC and ASAP -- I'm sorry, between AKLNG and ASAP.

And late last year the contracts for the various sub-projects were awarded. So for the gas treatment plant URS or actually they want to be called something else now. I think it's AE COM, but they're the prime contractor in Denver and they've got CBI and AES, ASRC's engineering bunch.....

FAUSKE: Fritz, if I could, CBI is Chicago Bridge and Iron which is a name that's familiar up here and AES is Arctic Slope, maybe you were going to get there, but.....

KRUSEN: Um-hum, right.

FAUSKE: .....Arctic Energy Services.

KRUSEN: The pipeline, that's being done by WorleyParsons in Calgary. The LNG plant, CBI is the lead contractor and they've teamed up with Chiyoda one of the big Japanese EPC firms and AES, that's being done in Houston.

And the marine facilities are being done by an outfit called CH2M Hill in Houston with the Alaska content being provided by the CH2M Hill office in Anchorage. So world class contractors engaged, but also Alaska content involved.

So, I think, back over to you, Frank.

RICHARDS: Yes. Mr. Chairman, the next slide is really, kind of, a history lesson that we've talked about in terms of the 500 million limitation on ASAP and I think we've

talked about that, so maybe I can skip that unless there's questions.

All right. So in regards to the next slide, it's called the Alaska LNG/ASAP Coordination and this is where we've talked about some of the agreements and the cooperation that we have working with our partners at AKLNG. Predominately it was originally around a lot of the information north of Livengood. And as I described to you earlier that information has been shared with us and we in turn shared information that we had with AKLNG, so the information flow is occurring back and forth.

We are continuing to hold workshops with our partners at AKLNG at the technical level in regards to waterways work, geohazards work. We are using, in many cases, the very same contractors because they're world class contractors.

When we talk about geohazards in the Denali Fault Crossing, the paleo seismologist who helped predict that TAPS would experience a major fault and it did in 2002, is the same guy that's now consulting with AKLNG and ASAP. So he's now predicting a fault rupture on the Denali Fault just south of Denali National Park during the life of the ASAP project and the AKLNG project, so we had to make sure that we design

accordingly, so the work is going forward.

We are continuing to foster those relationships. We have agreements in place and we are utilizing the assets then that we have accumulated for ASAP in conjunction with AKLNG.

So the last slide was, again, on the Near Term Focus and I think that's part of the discussions that we'll be having next, Mr. Chairman.

BURNS: Okay. So, Frank, just to clarify for me. I understand the relationship to be exemplary between AGDC and AKLNG. I mean, have I -- have I misstated? I mean, it's a good working relationship, sharing of the data. Are there any issues?

RICHARDS: Well, I think you can have two perspectives here because, again, Fritz is working it from the project side from within AKLNG and I'm looking at it from the project side within ASAP. And as I said, we have.....

BURNS: From your perspective.

RICHARDS: From my perspective, again, ASAP, the technical team has -- is a world class team as well and so we are utilizing very qualified, highly experienced, capable engineers. And so we have essentially a team that has value with the work product that we've developed to the AKLNG partners and they see that, so then they are, again, soliciting work activities with us. And as Dan

said, the AGDC team is out in the field right now doing the field work.

Because under House Bill 4 one of the powers that the Legislature granted to us was that the State agencies, the regulatory agencies have to give priority basis to AGDC project, permit submittals, authorizations, so we rise to the top, so therefore, we are able to get our permits through very quickly because, again, it was a Legislative mandate that AGDC has priority projects.

FAUSKE: I.....

BURNS: And Fritz -- I'm sorry, go ahead.

FAUSKE: I just want to add. I mean, to be tot- -- you know, for the -- it's been a little strained here lately based on some of the announcements and what this organization is going to do and that's normal. It's just been a potential change in pace, you have the Governor's comments and some of the reaction back which has been felt on our side by participation and data and stuff and we're sorting through all that, so -- but it's a good relationship which gives you the ability to sort through some of this stuff because we do talk and communicate all the time, so.....

BURNS: Good. And, Fritz, from your perspective, the relationship?

KRUSEN: I would agree. It's been exemplary up to this point. We do have some things to work through now, but, you know, we're all motivated to make something happen.

BURNS: Okay. Any questions, any comments?

Okay, that leads us to, I think, the primary topic so, Frank, do you want to work forward?

RICHARDS: So, Mr. Chairman, under Tab number 9 essentially we're talking about new business with ASAP. Mr. Cruz identified that we have what is known as a Tech Committee or Technical Committee and that's essentially a subcommittee of the Board of Directors whose focus is to interface with Staff on the technical basis of the projects.

So in those subcommittee meetings we present detailed updates on the major, functional areas that each project is working and provide updates and issues that are coming forward and so we do that on a monthly basis usually the day before the regular Board Meeting and that's just one of several subcommittee meetings, so.....

BURNS: Dave, do you want to add to something (ph)?

CRUZ: Yeah. And so Tech Committee is permitting. First of all, that's the biggest challenge as to any project today. We have cooperation through AGDC of State

agencies. I am reserving my comments for cooperation with Federal agencies in this State, so -- but that's what -- so we have a very good team, so that's one of the things our committee deals with.

The second thing is the engineering side that we're constantly interfacing with our consultants, as well as our own team in the engineering aspects. Why do we chose 36. What pressure is operate is (ph). What capacity is bridges. Multitude. We've got to have good engineering.

And final is construction, how do we built it, what does it look like. What type of equipment are we using. When do we need to order this equipment to met deadlines, so that's -- so it's a very, very active committee.

And I'm glad to see all the new members here because leave your calendars open. Chairman Burns will assign you to a committee and you will be able to participate. This is a Board, as Mr. Fauske will attest to, that does not meet once a month and get a statement and we vote on a few issues going this is (ph) -- because of our Chairman Burns and the way we set this up in the beginning, you will need to be participating on committees. All of you bring expertise into a different field that will help.

And so I had a couple of additional members, they're gone now, so I am definitely looking for some committee members to come in, but that is -- what's different about this is you are truly entrenched in it and you can work together with the Staff and with the consultants.

You can question 'em and you can have just -- like, Mr. Short is saying why are we doing this and you can have some involvement. And it's been a great, great experience to work from because it's good old -- some good old Alaskan engineering.

I know there was one comment one time, I'm going to share this once and I'll get off my -- my stand. So we had a discussion and there was, you know, about who were the Arctic pipeline experts in the world. And I boisterously stood up and said it's the Alaskans 'cause we're the only one that's ever built it and made it work and that is the Arctic pipeline experts and we have great people here. Like I said, I can't say enough.

What Fritz didn't say when he came in here, I want you to understand, Fritz is an employee of AGDC. He is not a consultant. Frank is an employee of AGDC, so great, great people, so anyway that's my little diatribe there.

BURNS: All right.

SHORT: Could I ask.....

BURNS: Yup.

SHORT: .....what committees exists?

BURNS: Yeah. You know, we'll get back to that. It's on the agenda later on, on just committee discussion and assignments.

SHORT: Perfect.

RICHARDS: Chairman Burns, I'll refer you to what's Titled ASAP Reconfiguration, a slide that we prepared. And, again, subcommittee Chairman Cruz, I don't know if you want to give a preface to this.

CRUZ: Okay. Frank, let me get that. Where is -- what Tab is that under, A, B, C?

RICHARDS: It should have been a handout.

FAUSKE: It's a handout, Dave.

BURNS: Yeah, it's a separate handout.

CRUZ: I'm getting a lot of paper up here now, so -- okay, I think I've got it.

BURNS: And so you're on slide 10?

CRUZ: I'm on slide 10, so the reconfiguration. So -- yup, we've go it.

DRYGAS: And Frank, I just wanted to say thank you very much for this.

RICHARDS: You're welcome.

DRYGAS: This -- I needed some help with the alphabet soup, so I appreciate that.

FAUSKE: We'll get you another one on.....

KRUSEN: LNG.

GRAHAM: AKLNG.

FAUSKE: .....LNG stuff.....

DRYGAS: That would be great, thanks.

FAUSKE: .....that Fritz was going to put together, so we'll have that for you. Also have stuff for you from our questions yesterday.

(Simultaneous speech)

BURNS: All right. Go ahead, Frank.

RICHARDS: Well, Mr. Chairman, again, referring to the slide that subcommittee Chairman Cruz tasked the AGDC Staff to look at, reconfiguration for the ASAP project. And, again, with 500 million limit- -- relaxation 500 million, then the concept is what can we do for ASAP project to make it -- or continue to have it to meet its not only Legislative intent, but also the primary objectives and that's really to keep alive a backup plan to the AKLNG project, so that means looking at something other than what we had originally designed to.

And so with that then is, again, we have to live within the intent that the Legislature gave us. The

provisions within Alaska Statute 31.25 that directs us on what our abilities are as an organization to advance a project.

And then make sure that we're looking at the economic viability of a project because as Dan has said for the 500 million we came up with a tariff that beat the price of imported LNG. However, it required additional volume sales to a yet to know large customer.

And we also have to make sure that we maximize the benefit for Alaskans and that means revenue to the treasury, jobs and affordable energy.

And the key is that we continue to work on the assets that we've already built on. The assets that we've accumulated and what we can make sure that we -- what we are going to do into the future will have transferability, will accelerate the development of the Alaska LNG and then utilize the leverage, the existing funds that we have.

And for the Board, we have two different fund sources in statute. One is the instate natural gas pipeline fund that was set up originally for ASAP and then we have the Alaska LNG fund which is there for the Alaska LNG project and our share of that portion of the project.

And then we're also to have commercial discussions with the market, that was part of the other charge that Chairman Cruz gave us.

So moving on to slide 3, the strategy is to look to again leverage, increase the leverage that the State has and the optionality of an ASAP project through extended volume and capacity in the project. And, again, having the project lead to tidewater, so it would be for both instate as well as export markets and then we would build on, as I said, the existing assets that we have and with a key of not wanting to duplicate the work or -- and to avoid competition.

So in terms of success factors.....

BURNS: What do you mean by that -- that bullet, avoid duplication of the AKLNG and competition with AKLNG, is that what you're talking about?

RICHARDS: Avoid duplication of work efforts, so if AKLNG is designing a pipeline route through Atigun Pass, we shouldn't have to -- we can --.....

BURNS: Right.

RICHARDS: .....we don't have to do the same thing for the ASAP project.

BURNS: And that's precisely what we're doing currently, right?

RICHARDS: We are working on a common alignment, correct. So

with that then we want to make sure that we have maximum durability and transferability of our work product.

BURNS: Right. So a status quo moving forward essentially.....

RICHARDS: Correct. And there again, two different.....

BURNS: .....preserving the relationship?

RICHARDS: .....volume -- two different size projects. We are at 36 inch and Alaska LNG is at a 42 inch.

FAUSKE: Frank -- if I may, Mr. Chair. Does that map show where they break off? That's just ASAP, isn't it?

RICHARDS: This is just ASAP. So the departure point from a common alignment is at the Sustina River Crossing on the Parks Highway.

FAUSKE: Yeah. Where AKLNG goes off further to the west and south.....

RICHARDS: Correct.

FAUSKE: .....crossing Cook Inlet and on into Nikiski, that's where -- but other than that we're, what, 99 percent.....

RICHARDS: Yes.

FAUSKE: .....same alignment with the other project.

RICHARDS: So, Mr. Chairman, on slide 4 again what we thought were -- would be critical success factors for a reconfigured ASAP was to maintain that alignment

between the State of Alaska and the North Slope producers.

Again, AGDC has the role of we are partner in the AKLNG project and we have the responsibility for the ASAP project, so we want to make sure that we are ensuring that the State's ability to advance an independent project that's economically viable as an alternative is very, very important.

And then we want to make sure to the best of our ability to obtain concurrence with the AKLNG Joint Venture Agreement partners on that to ensure that we've got complementary as opposed to competitive orientation on the project.

And then lastly maximizing the resources that we have within AGDC to accelerate the FEED. And the FEED is front end engineering and design decision, so that's -- right now for the AKLNG project is scheduled in the second quarter of 2016, so again, what we can do to help advance that or accelerate that, that FEED decision and make it more -- a more robust decision is very key in terms of success.

Switching onto slide number 5, my underst-.....

CRUZ: Frank, so what I wanted to -- for the new Board Members and the press and the audience here today, since I've been on this Board I cringe every time

somebody says oh, this is the bullet line. A 36 inch pipeline in today's world is a major gas transmission line. It is not a bullet line.

So I like to refer jokingly with my Committee members, you mean, the six inch smaller line than the 42, so -- but that's one thing you've got to remember, this is not the bullet line. A 36 inch pipeline in today's world is a major gas transmission line and we all need to remember that, so go ahead, Frank.

RICHARDS: And in that regard I would invite the Board to come down to our lobby where we have a piece of the 36 inch pipe provided to us by Flowline in Fairbanks sitting in our lobby as a reminder of just how large a 36 inch pipe is as opposed to a 42 inch pipe, a six inch difference.

FAUSKE: Can I take just a minute to explain how that.....

BURNS: The difference in six inches?

FAUSKE: Excuse me?

(Off record comments)

FAUSKE: Several years ago we were originally at 24 inch, 2,500 psi and we were hauling liquids meaning NGLs, GTLs and LNG. And there was a great deal of interest or concern by people that wanted all those liquids with the, you know, components that reside within the gas because of offshoot industries that could come.

So as a result, we conducted some -- three, what I view as very good studies on LNG, NGLs, natural gas liquids and GTLs which is gas to liquids such as converting diesel -- or gas to jet fuel, if you will and LNG.

And at the time even though we've kept the door open on all three possibilities, the most likely candidate for commercial success was LNG and I think our studies have proven to be correct.

As a result when you were hauling that high pressure gas with all the liquids in it, to do the offtake at Fairbanks at Dunbar, the Railroad crossing out there which then led -- I think it was a 27 or 35 mile.....

CRUZ: Lateral.

FAUSKE: .....lateral. Thank you. Into Fairbanks, you had to build a straddle plant to pull those liquids off and get the gas down to utility grade, that's straddle plant was 250 million just for the plant. And then you would -- gas would recycle back out. You'd bring it on down to Beluga, Enstar's point.

The Staff, through the Board, made a decision, this no longer makes sense and we converted and we optimized the line and took it up to the 36 inch utility grade because we've always been a gas pipeline. We've never been an LNG project.

And since its inception ASAP has been, we'll get the gas to Beluga and then someone from there will either convert it to this or that or do, but our job is to get it down at the lowest possible cost to benefit Alaskans and then knowing that we'd had to see that residual to help with the tariff model, so this was a decision.

It's been over two years when we optimized to the 36, so I wanted to just give you a little history of how this all came about.

BURNS: Frank.

RICHARDS: Mr. Chairman, on slide 5 the Initial Parameters is a -- as we understood them from Chairman Cruz was to maintain our 36 diameter pipeline, so stay within that size of pipe, work towards, again, pipeline and gas conditioning facilities only, so not include an LNG facility in our work package.

And then the ultimate goal then -- or the near term goal will be to provide to the Board an estimate of what the work activity and the cost to be in order to move forward for increased volumes for two different classes of pipe at this time. And so that would be in the range of from 1.4 to 1.6 billion cubic feet a day for ANSI 600 pound class and about 2.4 to 2.6 billion cubic feet a day for ANSI 900.

And then come back to you with what it would take in

order to complete that work effort likely through a Class 3 effort.

BURNS: Will you (ph) speak to it?

CRUZ: Yeah. So as -- through our Committee we've always -- that's the beauty of this 36 inch pipe and I really applaud this organization because that was done prior to us forming up as the gasline Board, so it was very, very -- somebody is going to say well, it was my idea. I was the 36 inch guy, but it was really -- that is a huge deal to make this project viable.

So the -- in starting to look at some different opportunities there on increasing the volume through this 36 inch line, we don't change our right-of-way width. We do not have substantial chance that would effect an EIS. We are still in the Supplemental EIS.

What we will have to look at is compressor stations, how many of them we truly need. What is the cost for them. So this is our first shot at what does it take to get to -- on an ANSI 600 1.4 to 1.6 and on ANSI 900 36 inch line 2.4 to 2.6. So that is -- that's what our challenges are today and how we're going to move forward in our Committee.

BURNS: So, the -- this is what the Tech Committee is asking Board approval on?

CRUZ: Right. And so what we're asking from the Board is

on our Resolution here.....

BURNS: Well, we'll have Hugh introduce it, but (simultaneous speech).....

CRUZ: Okay.

BURNS: Okay.

CRUZ: Is approval to go ahead and come up with a ROM, what is this going to cost to come up with these two different numbers. And so our Staff were looking at a couple of weeks. We're -- Frank is used to timelines is to produce a ROM, this is what the number is, so that's what we're looking and asking for the Board today from, is allows us the authorization to develop a cost to do both -- both these analysis.

PARADY: Mr. Chairman?

BURNS: Yes.

PARADY: Mr. Chairman, I think given this discussion and background we're ready for the Resolution which I would like to move. I want to read it into the record be- -- for Gwen especially. I have three minor edits as we go in.

So I would like to move Resolution 2015-01. Resolution of the Board of Directors of the Alaska Gasline Development Corporation directing Staff to prepare a schedule and cost estimate for preparation of a Class 3 estimate for the ASAP Project under certain

specifications and approving related matters.

Whereas, in order to further development -- excuse me. I'm going to.....

Whereas, in order to further develop the benefits to Alaskans of the ASAP project. I want to delete those next two words, work plan. So.....

BURNS: Well, just read it as you would propose it to be in the record.

PARADY: Okay. Whereas, in order to further develop the benefits to Alaskans of the ASAP project, the Board of Directors, (the Board) of the Alaska Gasline Development Corporation (AGDC) is interested in having a Class 3 estimate of costs and a projected schedule for the ASAP project under each of the following assumptions: (1) 36 inch diameter pipe using American National Standards Institute (ANSI) class 600 pipe and (2) 36 diameter pipe using ANSI class 900 pipe.

Now, therefore, be it resolved by the Board of Directors of the Alaska Gasline Development Corporation as follows:

Section 1. Subject to modification of Administrative Order 271 as necessary, the Board hereby directs Staff of AGDC to prepare a work plan for presentation to the Board including a schedule and an estimate of cost for preparation of a class 3 estimate

for the ASAP project under each of the following assumptions: (1) 36 diameter pipe using American National Standards Institute (ANSI) class 600 pipe and (2) 36 diameter -- 36 inch diameter pipe using ANSI class 900 pipe.

Section 2. This Resolution shall take effect immediately upon its adoption. Dated this date.

BURNS: All right.

PARADY: So let me pass this to Gwen.

BURNS: And that's the -- that is the motion. Is there a -- I mean, it's been moved. Is there a second?

CRUZ: I'll second it.

BURNS: All right. Open for discussion. Why don't we just go around.....

DRYGAS: Fred, I just.....

BURNS: .....all the way through. Joe, do you want to start off?

PASKVAN: Sure. As I understand the three changes are: in the first line take out work plan. In Section 1 on the second line add right after the comma, for presentation to the Board. And then the last sentence in Section 1 is eliminated.

PARADY: Yes, sir.

PASKVAN: I don't have a problem with that at all.

BURNS: Okay. Any discussion on the Resolution itself?

Okay.

PASKVAN: No.

BURNS: Heidi.

DRYGAS: I'm just making sure I have the correct -- okay. So the second one, okay. I just wanted to make sure I had the correct language. No.

BURNS: Rick.

HALFORD: No questions.

BURNS: (Simultaneous speech).....

CRUZ: No questions.

PARADY: I'm good.

BURNS: Fred? Hugh?

SHORT: I guess my only question is the 600 class ANSI pipe versus the 900 class ANSI Pipe would facilitate what is contemplated in the ASAP reconfiguration of one and a half Bscfd versus two and a half Bscfd?

BURNS: That's what the intent is, is to.....

SHORT: That's what the intent is.

BURNS: Yeah.

SHORT: Okay.

BURNS: Joe.

PASKVAN: Yes, the question that I have and I don't have a problem with this is, is there a reason why we wouldn't look at a Class 1,500? In other words, I don't know what the difference in magnitude of the pricing of the

pipe itself. I assume everything else, installation cost is the same, but in this pipeline cheat sheet they -- it just shows a class 1,500.

CRUZ: Just pretend you didn't see that.

PASKVAN: So I was just wondering why --.....

BURNS: Which isn't a question (ph).....

PASKVAN: .....why we wouldn't have the same -- you know, three options, class 600, class 900 and class 1,500, that's my sole.....

RICHARDS: Mr. Chairman, Senator Paskvan, when we look at an ANSI class 1,500 you're essentially looking at definitely increased wall thickness in order.....

PASKVAN: Um-hum. (Affirmative)

RICHARDS: .....to handle the increased pressure. So then you look.....

PASKVAN: Um-hum. (Affirmative)

RICHARDS: .....at the issue of constructability. So with that increased wall thickness if you're approaching an inch or greater than an inch, than you've got a major challenge with the weld ability of that. More steel, heavier equipment, constructability issues. It's really -- that's part of the issue.

And then it was the direction by the Chairman to look within the volume parameters of the two smaller classes.

CRUZ: Joe, the pipelines -- that would be over one inch thick.....

PASKVAN: Um-hum. (Affirmative)

CRUZ: .....which is -- now that's a huge ordeal in attainability.....

PASKVAN: As a practical matter (ph).....

CRUZ: .....in the weld process, everything else, so it's very -- very uncommon.

PASKVAN: And what prompted that question was is that I understand Point Thomson is one of the highest pressure gas fields in the planet and wondering whether this pipe -- in other words, I understand the pressure that comes out of the gas treatment facilities is different than the pressure that's in the.....

CRUZ: The reservoir.....

PASKVAN: .....Point Thomson Unit itself,.....

CRUZ: The Reservoir.....

PASKVAN: .....but I just want to make sure that we're not missing.....

CRUZ: No,.....

PASKVAN: .....that. Okay.

CRUZ: .....we can take their gas with no problem.....

PASKVAN: No. I just -- making sure that it's there.

CRUZ: Yeah.

BURNS: Okay. Any further discussion? Any further

discussion?

(Side conversation)

BURNS: Is there any further discussion? Rick?

HALFORD: The -- this question basically is just limited to the pipe itself. Does it imply an up-scaling of the gas conditioning plant and everything else or is it only the pipe?

CRUZ: Only the pipe at this point.

BURNS: Right. And it's a process of identifying a work plan that ultimately -- we're looking at Class 3 estimate. My understanding is Class 3 estimate relative to the pipe, but the work plan we'll have to identify what other things are necessary to achieve what that is -- what goes along with it.

FAUSKE: It'll have -- I'm sorry, but it will have to include.....

BURNS: Yeah.

FAUSKE: .....some work on the plan (ph).

BURNS: Yeah.

FAUSKE: I mean, -- correct?

DRYGAS: It's just that this.....

CRUZ: Well, no, not -- not.....

DRYGAS: ..... Resolution is limited.

CRUZ: .....entirely, so -- that's something we haven't really vetted though our Committee as -- all I'm

looking for is, what does it take to get this pipe to move these two different volumes.

Then we're going to get into Ford and Chevy. Is AIM Technology better than the Fluor process on that. And those are things that I think we can get there if the Board would like to see that on the gas treatment facility, but right now I'm specific just wanting this information.

BURNS: So -- but let me ask, kind of, following up on it. Why just limit it to this? I mean, knowing that -- as I understand from Frank, there's no way that you can put the volumes through assuming that you're either at the 1.4 or the 2.4, you can't generate sufficient volumes to the (ph) existing treatment plant, so why wouldn't the work plan look at, you know, all the -- identify all of the steps that might be necessary, but focusing predominately on cost estimates relative to the six and 900?

But it would be important for the Board to know in order to achieve these volumes what other steps have to be taken along the way? I mean, that would be, kind of, what I'd -- I guess I'd like to see, not just a part of it, because then we're -- then we're -- naturally we're onto the question that Rick says is that okay, what else?

CRUZ: So.....

BURNS: So -- okay.

CRUZ: Frank and I have discussed and that, that would be a total re-engineering of the gas treatment facility as it currently stands. And that's going to take longer than two weeks to come up how much does that cost, so that's -- that is a lot bigger undertaking right now.

Some of the different ideas you have on this is what would the producers like to see for a gas treatment facility. Would they want three of their own and re-injecting and handling their own gas the way they do? There's a lot of different variables.

So if you look at the Alyeska Pipeline model for discussion purposes, Pump 1 is a pump station and a metering station. The producers that are feeding that have a spec that they have to meet. It comes over there. They take care of their own processing to get it to a pipeline spec to come down the Trans Alaskan. That's why I didn't want to wade into this as a Committee right now until we found out, you know, what would be the best methodology.

Right now what we were saying we would -- if we go to that extent, well, this is the prefect model for everyone. I don't know it is. I like Ford trucks. John likes GM. So I'm not -- I can't speak for them.

All this is, is a transmission line remember, that's.....

BURNS: Rick.

HALFORD: Well, I don't mind separating it out. I, kind of, think that's a smaller bite to take and it's faster and it's better, but I just wanted to make sure that's what it actually did because -- I mean, you can go 600 or 900 and if you go the heavier pipe you don't have to use it initially if you don't have the use. I mean, there's lots of options along the way, so I have no problem with asking the question.

BURNS: Um-hum. (Affirmative)

HALFORD: And I think the gas treatment plant is a huge issue, but that's another issue totally separate.

BURNS: Um-hum. (Affirmative) Hugh.

SHORT: Let's take the gas treatment plant aside and say that's another issue completely. That still leaves the eight to 15 compressor stations that need to contemplate different volumes and is that part of this as well?

BURNS: Yes.

SHORT: It is?

CRUZ: Yes.

SHORT: Okay. So we're including in his two week cost estimate increased compression.

CRUZ: Increased compression to meet that volume through the 36 inch line.

PARADY: Mr. Chairman?

BURNS: Yeah.

PARADY: I just want to note that in working with this language I don't believe we're under a two week cost estimate. We're under the time necessary to get a quality job done and.....

BURNS: Um-hum.

VASSAR: Mr. Chair, if I could.....

(Telephone interference)

BURNS: Excuse me, however is on the line, if you could mute your phone it would be appreciated. So, Frank, let me ask you this, the.....

FAUSKE: Get to the mic, Ken.

VASSAR: Mr. Chair -- Mr. Chairman, could I.....

BURNS: Yeah. Sure.

VASSAR: Of course the Board can ask Staff to do what you want us to do, but whatever that ends up being we want the written language in the Resolution to be clear of what you're asking us to do. So I'm going to point out that what the current iteration of the Resolution asks for is a work plan for the ASAP project. The ASAP project is not just pipeline.

BURNS: Um-hum. (Affirmative)

VASSAR: So if you want to narrow that down, we're going to want to change the language a little bit.

BURNS: So let me ask you this question, Frank. Is it -- are you able to just identify quickly what the necessary steps are along the way if you're going to increase from six to -- you know, from the existing to six or nine, okay? So would you have -- is it that difficult of a job to say okay, you're going to have to do something on the treatment plant. You're going to have to put in 14 compressors. You're going to have to, you know, up-size the -- or increase the ANSI on it, you know, all the things to identify.

And then also to say okay, if you do that, you're going to have to go back for a Supplemental EIS, you know, that sort of thing. So that, you know, to me I guess I was thinking that, that what was going to happen in the context of the plan, but then focusing on predominately what the cost would be on a Class 3 estimate of up-sizing the pipe from six to nine, that sort of thing in pressuring it.

RICHARDS: Mr. Chair,.....

BURNS: I mean, we could do it in two steps. We could actually come back and if you said here's the cost estimate on the six and the nine. Then we could at that point in time, you know, sanction moving forward

or sanction, you know, doing the cost estimate on the other aspects of it.

We could do it in a two step process, but I -- you know, I guess I'm trying to get a sense from you as to, you know, in developing a work plan, you know, how difficult would it be to say that aside from this, you also need to look at the following six or seven additional points.

RICHARDS: Mr. Chairman, the three major work tasks that I see for the ASAP project in looking at reconfiguration is going to be work on the pipe. We've already designed the 36 inch ANSI 600 pound class without compressor station.

So the second major focus is going to be on the facilities. And the facilities are not only a new gas treatment facility, but also the compressor stations necessary to allow that volume to flow through to a terminus.

And then the third would be the environmental, regulatory and lands aspect in regards to work that we would have ongoing in our Supplemental Environmental Impact Statement and other major Federal and State authorizations.

So key for the work plan that I envisioned providing back to you was going to be identifying those three

major areas and the work that would be necessary to conduct those two of (ph) Class 3 level estimate.

BURNS: See that's what I.....

UNIDENTIFIED: Yeah.

BURNS: .....anticipated as a result of this, that -- that -- you know, they are tasked -- we're asking them to do this, but as part of that, to do an identification. Exactly what Frank is saying is, what are the steps that are necessary along the way to achieve that, not to go and do the actual engineering and all that other stuff, but to tell us so that we as a Board can be informed that if you do X these are the things that have to be also addressed. If you do Y, you know, here's the other issues. And then we'll have that in the context of the full discussion.....

RICHARDS: Correct.

BURNS: .....and then we'll make the determination as to what's the next step.

RICHARDS: So with that then would be development of authorization for expenditure at that (ph) next point.

BURNS: Yup.

RICHARDS: So if you choose one versus the other, then you wanted us to immediately start the work, it would take Board action to authorize those expenditures, so we need to be able to provide that to the Board as well.

BURNS: Um-hum. (Affirmative)

PARADY: Mr. Chairman.

BURNS: Yes.

PARADY: Mr. Chairman, I'd like to move to discussion of the Resolution and just piggyback on Mr. Halford and Mr. Vassar's comments and Frank's which is that in reading the language we have before us it's directing AGDC to prepare a work plan, so we're directing our President and his Staff to give us this work plan and this boundary between pipe, compression and gas -- what's the word I want.....

KRUSEN: Gas treatment plant.

BURNS: Conditioning.....

PARADY: Thank you, conditioning plant. I trust his judgment in bringing the necessary options back to us for further consideration.

BURNS: So let me ask you, let me clarify. What I understand you to just be saying is that you believe that this Resolution is sufficiently broad enough to accomplish precisely what Frank is --.....

PARADY: Yes, sir, I do.

BURNS: .....is indicating?

PARADY: And it's constrained by common sense, so.....

BURNS: Now, I mean, we -- let's -- further discussion on it, you know, because Rick -- you know, Rick asked the

question, does this -- is what this is doing just asking us to cost the six and the nine. And the response from another Board Member was yes, that's all that's being asked, but what I'm hearing from Frank is that in the context of this, he would identify all the different -- all the different components, not necessarily to do the cost estimate of 'em.

RICHARDS: Um-hum. (Affirmative)

BURNS: And so I'm hopeful that as I read it part and parcel with the plan is to do exactly what Frank indicated that he'd be doing, but an added focus on that was to delve into a cost estimates relative to six and nine. Identify all the other issues that are -- you know, are ancillary to it and then focusing on as -- as -- you know, the primary purpose, the up-sizing of the six and nine.

SHORT: Could -- could.....

BURNS: So let's go through and -- yeah.

SHORT: So I've got two -- two questions. Question 1 would be what is the timeline to have a cost estimate between 600 and 900?

And then my second question is I find that somewhat helpful, but I don't find it completely helpful to make a informed decision.

Back to your truck, you know, I want the 5.7 liter

versus the 6.3 liter or 6.5 liter. That's somewhat helpful, but it doesn't get me to the answer that I need which is you've got pipe, which we're talking about and that seems to be the lowest hanging fruit here. Then you've got facilities which seems to be the hairiest part of this deal.

All right. And then the environmental, regulatory and lands issues which I'm going to make an assumption that those are the least of our concerns in this part of this conversation initially, so -- of the three.

And so how do I get to the point where you can give me a cost estimate contemplating what is in the presentation that I saw which is one and a half versus two and a half and what's the timeline for that?

BURNS: Well, so let me paraphrase what I understand your question to be. So a timeline generally for the pricing, but then also the -- is that you believe that, that's just a tip of the iceberg. You want to know what else would be necessary to really -- to make an informed decision on a go forward basis.

SHORT: Yeah.

BURNS: Okay. And so.....

RICHARDS: Mr. Chairman, when we talked about the options that would be available for reconfiguration, it was -- again, we were looking at standard 36 inch pipe.

Normally in a project you'd be looking at your market to define what is the market --.....

BURNS: Um-hum. (Affirmative)

RICHARDS: .....want does the market want and then with those commercial discussions you would define the throughputs that you would want to design to.

Here we're talking about what can be, not what should be,.....

BURNS: Um-hum. (Affirmative)

RICHARDS: .....so we really need to make sure we have an understanding then of the end use of that gas.

So my intention, again, based on conversations with Chairman Cruz was give me the options available of what can be at this point.

BURNS: Rick.

HALFORD: And to that end, if it's driven by the economics, not the politics and all the other things. If we -- I mean, we may come back with something that says the difference in the higher pressure pipe is not that much and that's the thing that you can't -- if you don't have the pressure of the pipe, you can't add the compressor stations, you can't upgrade the plant, you can't do anything else.

So if you just got the capacity at some future date to make the project more economically feasible by

adding things later when you have the market developed, I just thought that, that was.....

BURNS: Um-hum. (Affirmative)

HALFORD: .....a more limited question within the realm of maybe political and economic reality to give us the other decisions further down the line,.....

BURNS: Okay. So.....

HALFORD: .....that's all I was.....

BURNS: Okay. Now -- and I appreciate it. So let me make sure that I understand what -- I think it's crystallizing for me.

The purpose of doing this assessment is just to see what's available. Okay. From the standpoint of, you now, is it possible to up-size it to get to these volumes.

All right. And then the second stage, the second question is okay, now, if it's possible what else has to go and what other steps are necessary because you've got -- as Rick is saying, you've got the economic side of it, but unless you know the universe of possibilities you got -- you're limited.

So let's make sure that -- let's, you know, go back on this because as I understand it, the Resolution is requesting Staff to identify what would be part of an up-sizing project in this regard, but to focus

primarily on the cost analysis of increasing the ANSI from six to nine, that's -- I under- -- I see it as two part.

I see it.....

DRYGAS: So this is Phase 1 bec-.....

BURNS: Well, what I see -- yeah. What I see in this Resolution -- this Resolution is asking Staff, and maybe it's not as artfully drafted as it ought to be, but what I see.....

PARADY: It serves its purpose.

BURNS: Yeah. Is that the Resolution says Staff go forth on our behalf, identify what -- you know, in order to get to six and nine, increasing to the 1.5 to 2.5 and that, give us a cost estimate associated with the pipe, so that identifies the universe.

As a corollary to that, tell us also what are the steps in a work plan, what are the other things that we might have to also address down the road.

So step 1 as Heidi is saying is this, once we see what the universe is, then we look at, you know, marketability and all these other things and then we make the determination as to what the next step is, so it's a multi-phased approach.

FAUSKE: If I may, you already know what the next step is, don't you? If you go a bigger pipe, you have to have

a bigger GTP. So we come back and say here's your bigger pipe. What's next? Bigger GTP, so how.....

BURNS: Um-hum. And the question is do we want --.....

FAUSKE: .....long do we want to take on this,.....

BURNS: .....I guess, is what I'm asking?

BURNS: .....market it first or do we do the GTP.....

FAUSKE: Excuse me?

BURNS: Yeah. Do we market it first to see if there's customers before you do that, you know, that sort of thing. I mean,.....

FAUSKE: Okay.

BURNS: .....those are the issues I think. Once you have a -- once you've got the sequence. First is identify the breadth of the universe and then say, okay, you know, we can do this. Now, should be do it and what's associated with doing it. You know, should we do it. Is there market for it, you know.

And all that is doing -- I mean, the irony of it really is all this is doing is ensuring the viability of an alternative project because we're not going to do any of this if the AKLNG project, as everybody is hopeful, moves forward.

Okay. But if it doesn't move forward, you know, it's very clear to us -- at least to me as a member of AGDC, that my responsibility as a Board Member is to

ensure the best interest of the State of Alaska and the state residents are looked after and that's the viability (ph) of an alternative.

FAUSKE: I'd like to ask a.....

DRYGAS: So then.....

FAUSKE: .....question if I may?

BURNS: Yeah.

FAUSKE: What level is AKLNG at right now in their pipe design?

RICHARDS: They are in Pre-FEED, so pre-front end engineering and design. They are working.....

FAUSKE: On a 42 inch.....

RICHARDS: 42 inch, ANSI 900?

KRUSEN: ANSI 900.

RICHARDS: Pound Class, so they are working towards a Class 4 estimate.

FAUSKE: Okay. So in a perfect world that could be information we could achieve, right?

RICHARDS: Yes.

KRUSEN: Yeah (ph).

DRYGAS: I think it would.....

BURNS: Heidi.

DRYGAS: .....be prudent to make sure -- there's enough questions on the Resolution as drafted, but it sounds like we should be careful that this reflects the intent

of the Board and it sounds like it's close, but we can do better. And I think I'd feel comfortable if we took time to make sure if we vote on this, we give a clear directive to Staff in this Resolution, not necessarily just what's on the record. I think that's probably a wiser course of action.

BURNS: Yeah, I think that is probably a perfect time to take a break.

SHORT: Could I ask a quick question?

BURNS: Yeah, Hugh.

SHORT: What is ASAP right now, a Class 600?

RICHARDS: ANSI 600.

FAUSKE: ANSI 600, yes.

SHORT: ANSI -- okay, all right.

FAUSKE: But the -- it's been designed to 500 feet.....

UNIDENTIFIED: The volume.

FAUSKE: The volume has.

SHORT: But the pipe itself is.....

FAUSKE: The pipe -- the pipe.....

SHORT: .....600.

BURNS: ANSI 600, right.

FAUSKE: Correct.

SHORT: Okay.

BURNS: No compression, so.....

SHORT: Yeah, got it.

BURNS: So let me -- so, we'll.....

SHORT: Ten minutes.....

BURNS: .....take a break for lunch. We'll take an early lunch, but do I have a couple volunteers to work on this Resolution? Hugh.

SHORT: Sure.

BURNS: So we'll have Fred and Hugh.....

PARADY: Yeah.

BURNS: .....and I'll work with you guys on it, so the three of us and that way we don't have a meeting. All right. We'll take an hour break until 1:30 --.....

RICHARDS: 1:30, Mr. Chairman?

(Simultaneous speech).....

BURNS: .....or 12:30, I'm sorry.

(Off record - 11:38 a.m.)

(On record - 12:30 p.m.)

BURNS: Back on the record after a very nice lunch. We're back on record. Where we left it prior to the break was the Resolution. And so the group that was working on it, what's the decision? Do you have something different or.....

PARADY: Mr. Chairman, I think our three member discussion centered around -- after going back and forth that we use the Resolution as it's currently worded.

BURNS: All right. Any further amendment to it? Rick?

HALFORD: Well, just as I understand it then the primary purpose is to look at the pipe quality and get a number. And we recognize that other things may be affected by that, but we get that number and that's part of all the alternative data we have if it ever needs to be utilized and pursued in the hope that we don't have to go forward with it, but at least we know.

BURNS: Right. So the focus is simply on the numbers on the six and the nine and that will be what Staff will be directed to through the Resolution and the Tech Committee will work with Staff in conjunction with that.

Okay. So any further discussion on the Resolution?

SHORT: Question, I'll.....

CRUZ: No.

BURNS: Yes. Okay. Question's been called. All in favor?

IN UNISON: Aye.

BURNS: Let's -- we actually have to have a roll -- roll call, so let's go ahead.

GRAHAM: John Burns?

BURNS: Yes.

GRAHAM: Dave Cruz?

CRUZ: Yes.

GRAHAM: Fred Parady?

PARADY: Aye.

GRAHAM: Heidi Drygas?

DRYGAS: Yes.

GRAHAM: Hugh Short?

SHORT: Yes.

GRAHAM: Rick Halford?

HALFORD: Yes.

GRAHAM: And Joe Paskvan

PASKVAN: Yes.

GRAHAM: Thank you.

BURNS: So the Resolution is read into the record. It passes unanimously.

All right. Next item, Frank.

RICHARDS: Mr. Chairman, I'm walked in late for the -- was there change to the Resolution or is the direction to work solely on the pipe question?

BURNS: Yup, that's the focus of the Resolution.

RICHARDS: All right.

BURNS: So Dave can work with you after.....

CRUZ: So we'll work it out, Frank. We know we're going to have another component to this. We'll come back at our next Board Meeting and address the other components.

RICHARDS: If I may, Mr. Chairman,.....

BURNS: Sure.

RICHARDS: .....can I just articulate some of the challenge with that?

Well, I'm going to present to you in my next presentation the ASAP update and in that it identifies where we are essentially with our facility's contractor and they are now completing their work efforts that we have provided to them at the end of a two year process.

BURNS: Um-hum. (Affirmative)

RICHARDS: And they will be done with their work efforts first part of April and then they are disbanded. So if we then in the next Board Meeting want to come back and start doing a facility's work effort, we have to restart a whole new team, so there is a major challenge there.

If we want the continuity of the project to be able to advance the work utilizing the folks that have put together the work product that has allowed us to reach this point, we need to retain that team.

BURNS: Okay. So let me make sure that I understand. I -- so we are at a position of potentially losing part of the team that has worked so diligently on ASAP?

FAUSKE: Correct.

RICHARDS: That's correct, Mr. Chairman.

CRUZ: On the GTF.

RICHARDS: On the gas conditioning facility, so that --.....

BURNS: All right. (Simultaneous speech).....

RICHARDS: .....that includes.....

BURNS: Is that okay?

RICHARDS: .....the services of Arctic Solutions who has done the major lift. They are the major design contractor, as well as our individual project management contractors who have been overseeing their work. So that's an additional four bodies who have been overseeing as AGDC's representatives in the Arctic Solutions' offices.

BURNS: Do you have a.....

SHORT: I have a comment.

BURNS: .....question?

SHORT: I think in -- thanks for pointing this out, Frank. And, I think, given the Resolution it would be prudent for the Board to provide the ability for the continuity of that group to move forward and not disband to slow down the work, but to keep the continuity there because we don't want to have to hit reset on that portion of this should there be some project we need to look at.

BURNS: Is there any way to do that in the context of this Resolution? I mean, because it's critical that the continuity of that team continue is what I understand you to be saying.

RICHARDS: That is true, Mr. Chairman. We had -- again, with the Administrative Order overlying us and the issue regarding discretionary versus non-discretionary work,

we had developed work plans that, that team would -- could perform for us. And that includes some looking at the work of Point Thomson gas and the impacts of Point Thomson gas.

We have not yet kicked them loose on compressor stations, but that's the next evolution because anything that we do on the reconfiguration of ASAP, the critical path for us to move forward is going to be through the facilities. It's going to be through that gas conditioning facility redesign and the compressor stations, so that's where the facility's teams are most warranted.

BURNS: Okay. So what I hear you to be saying is that if we just focus on the pipe, we lose that team because that team will have nothing to do?

RICHARDS: That is correct, Mr. Chairman.

FAUSKE: They'll go elsewhere in the world and we're -- which is a heavy demand. There's a lot of work going on.

HALFORD: Well, that's a totally different question and that combined with the Administrative Order 271 -- I mean, that is a change that is definitely going to take something, so I would suggest we -- if we're going to address that, we address it with another resolution that starts out with the same thing, subject to the withdrawal or modification of Administrative Order 271

as necessary, Staff is directed to take whatever appropriate actions there are to maintain that team for future use.

I don't know what -- I don't know -- I mean, how do you get from here to there, but I think the Administrative Order -- basically if it's not teeing, kind of, says a big project that's not ongoing it's a -- it's a big change, that's the big money project, but it's driven by the Administrative Order more than anything else.

PARADY: Mr. Chairman?

BURNS: Yeah, go ahead.

PARADY: I just want to read from the Administrative Order. It says, to the extent spending is non-discretionary. This is B, such as contractually required spending and salaries of existing agency personnel continue to work on the project till further notice. We may need a modification, but there's also this idea that we not stop cold in the middle of the stream and lose the benefit of what's been built.

BURNS: Um-hum. (Affirmative)

PARADY: The Order is straddling both sides of this. We're in a fiscal crisis. We've got to half discretionary spending, but we also have a duty to Alaska's future to sort some of these project options out and I think

that's resolvable with some dialogue with the Governor and somewhat within the meaning of the Order as it currently exists, but I -- so I like your language that's -- picks up the same thread and then takes it into this topic area.

BURNS: Thanks. Go ahead.

SHORT: And I would just suggest that we do that in a separate motion from the Resolution. Come up with a motion that directs....

PARADY: We've adopted (simultaneous speech).....

SHORT: .....our resolution (ph).

PARADY: So let's develop some language that puts that in motion with our executive (ph).....

BURNS: So let me ask Frank. What is it that you are.....

PARADY: Wanting (ph).

BURNS: .....needing, okay, to ensure the continuity of that team and to use them in a way that benefits the ASAP project? I mean, we're not -- we don't want to just pay, you know, for them to tread water.

RICHARDS: No, I would -- it would be beneficial for the project, as well as for the State to be able to do work that is, again, going to be able to advance the project.

So in that, if you remember -- for the new Board Members, at the last Board Meeting we presented to the

Board a decision tree that essentially we use when looking at authorizing work expenditures for the ASAP project under Administrative Order 271, so that it meets the intent of what our interpretation of that Administrative Order was, so that we are making sure that we are doing non-discretionary work. That we are not doing discretionary work that has transferability, durability, viability to the ASAP project so to, again, meet the intent of the Administrative Order.

I'm going to ask Ken to join me because, again, we -- when we go through our process for authorization of work expenditures, we get a legal review who then looks at the intent of the Administrative Order for -- to make sure that we are complying with the law.

BURNS: So, Ken, let me ask you, is the -- because you're going to be giving us a legal analysis on AO 271, is it appropriate to go into Executive Session to have that discussion?

VASSAR: Mr. Chairman, I do not believe it is.

BURNS: Okay. All right. So what is -- so I just need to understand, Frank. What is it that you need from this Board relative to that team?

FAUSKE: I'd like -- can I help here? What we're saying is that without continuing work -- this isn't a threat. It's just the reality of the world you're in. We were

downsizing that work prior to the AO 271. We had already -- we were so far ahead AKLNG that you folks and -- you know, the Board, made a conscious decision to go we're going to hold our spend plan down because it's -- we've got to let AKLNG catch up.

Then the Order came out and we were way ahead of that. As you know we met with the Governor and we briefed him, but subsequent to that we cut the spending by $90 million. We went down to a $60 million spend to do work conducive to both projects with the idea of melding them by second quarter 2016 and to comply to AO 271.

What happens then is we had already decided knowing that we were trying to keep that A team together, but that there had to be some work and then all this stuff about new plans and.....

BURNS: Um-hum. (Affirmative)

FAUSKE: .....what we're going to do.

What's going to end up happening is if we don't have work for them, they're doing to disband and go off and do what they do. They're high priced, very qualified people. They're WorleyParsons and Fluor. They're.....

BURNS: So no, I understand.....

FAUSKE: .....well known in the industry and that's -- and that's just common.

Now, if we decide we want to try and keep 'em, they're going to do the work on the gas treatment plant. That would be probably -- but we're not going to do the gas treatment plant, so what we're suggesting to you we stand a chance here of loosing that A team. And what that means is your scheduled gets -- 'cause it takes a while to ramp that stuff back up again. Now if, in fact, they do disband and send people off.

It's, kind of, like AKLNG, as you get more familiar with it. These oil companies have sent their A -- they have people from all over the world they've sent in here to concentrate on that. This is the same thing. They've pulled them off of Mozambique or New Guinea or wherever they're at and they have focused a lot of them here.

The same thing will happen on the other side, call us when you've got something and we love working with you, but we're going to -- four of.....

BURNS: Okay. So -- so.....

FAUSKE: .....our people are going over here and three going --.....

CRUZ: Let me ask a technical question (ph) (simultaneous speech).....

BURNS: Yeah, go ahead.

FAUSKE: .....so that's where we're at.

CRUZ: Okay. So, Frank, the Fluor technology that we got, is this more just bumping up more trains, is that -- on our GTF or -- I understand where we're going with this to meet 2. -- can we get to that or do we have to go to a AIM process, that's -- and so what I'm saying is, are you going to -- are we totally going to reconfigure that and the only the same as the -- 'cause the.....

RICHARDS: It's the pad.

CRUZ: The pad gets bigger, so that's relatively easy. Is it just more trains?

RICHARDS: It's going to larger -- larger scale on the processing units, larger utilities associated with larger compressors, so that's one part of it. We have to make a decision ultimately in terms of what gas composition we want to drive forward to, but my goal -- or my understanding what you'd asked of us was to come back to you and identify what is -- what it's going to take to conduct the next step.

And that next step would be up-sizing of the pipe, but the pipe is a component of an integrated system which is the gas conditioning facility. In order for more volume to flow through that pipe, you need compressors, so that compressor work needs to be identified. And you need to then look at the optionality of where those compressors are going to be

and the horsepower associated with those for the lowest cost of service.

CRUZ: So what you're telling -- we're not constrained having to switch to an AIM tech -- AIM process. We can still say -- stay the Fluor process, so we're not reinventing the wheel there, that's all I'm trying to get is bigger pad expansion. I understood, you know, a few other items.

What I don't want to get to and I don't want -- I want to be able to pass the test with you guys is like, oh, yeah, well, that's another nine million, I should have told you that, you know, that's what I'm concerned about is the market dictates, but we have two options there.

What we're asking to do 1.5, 2.5, okay. So we have to look at a cost -- if we're going to do that let's just say that the producers don't want to build a GTF for this, you know, don't want to follow the Alyeska model or whatever you want to call and they want -- they come on board and say well, you guys do this and you guys do this and we'll do this on the -- on the other end. You guys do all the input in.

So I just want to know walking into this that it's not reinventing the wheel, is probably my biggest thing. That's my biggest concern 'cause it's a big

plant and as long as I have a comfort feeling with that than I can say to you well, this is a really good -- good, smart move.

FAUSKE: But Dave, if it's (ph) the intent that the design of the pipe is to get a cost estimate as to what that cost, the next logical step is you have to have a gas treatment. You have to have that. So we've got the pipe and we go, okay, now we've got to go -- and if I go back to the Governor's comments and others, schedule.

CRUZ: Right.

FAUSKE: Everybody is trying to compress this because of all the desires. So we're handcuffing ourselves from one regard is that we can do this, but it just takes more time -- more time. Time is money. And then I'll finish.

(Simultaneous conversation)

FAUSKE: Just one other question. Tomorrow, as I was reminded, we're in front of House Resources. This Corporation is sitting on $200 million that -- and I used to joke with my friend Senators, it's a time when they'll take your lunch money down in Juneau when you're -- it's tough time. I think we need to be prepared to what is the money going to be used for. I know we can't answer it all tomorrow, but when we start

looking at this schedule, I think we need to be helping ourselves now. Well, we think it's going to be this and here's the time frame.

CRUZ: So here's a quick question for Fritz. You don't see an issue in a global market place, Fluor versus AIM technology that somebody is going to say well, why the hell did you guys do it that way?

KRUSEN: Well, thanks for inviting me up 'cause I do have an opinion on that.

CRUZ: Okay.

KRUSEN: And it seems to me that as we -- so the Fluor solvent was an excellent solution for ASAP 500 million a day and we were selling Enstar type gas to the users and where you're supplying some base load industrial tenant. Great, great, great selection for that.

As you go bigger if you aspire to supply an LNG project with your pipe and I don't know what you'd be doing if it wasn't that, the Fluor solvent begins to have two problems. The richer stuff that you want in the gas gets stuck in the Fluor solvent, so it's not so good for that. Point Thomson has got richer gas. You want that Point Thomson gas to move down.

Prudhoe Bay is using immiscible injectant to wash oil off rocks, but maybe the day comes when you want to ship that out and sell it. You can't do easily with

the Fluor solvent. So as you go big, I think, it almost forces you to switch to an Aiming technology.

You could always fall back to a Fluor solvent if we end up being, you know, a 500 million a day project, but I think that's the sweet spot for it. If you aspire to supply LNG you really need to go to Aiming.

FAUSKE: A question to help. Fritz, the Aiming technology could be done at this end? I mean, that's what.....

KRUSEN: You would have to do it on the North Slope and then the question is would you also choose to do it at this end. Or would.....

FAUSKE: Okay. Because currently.....

KRUSEN: .....you do it only one time at the Slope.

FAUSKE: I was trying to help out with -- yeah, all right.

KRUSEN: I mean, in my own mind there was a time when I thought we could do the Flour solvent at the Slope, finish it off with Aiming down here, not if you're trying to ship Point Thomson gas, not if you're trying to supply an LNG project, not if you want to keep the hope of possibly moving MI off the Slope some day, you've got to switch to Aiming on the Slope.

CRUZ: And you guys are curr- -- currently doing the AIM.

KRUSEN: Yes. We're doing Aiming and the (simultaneous speech).....

FAUSKE: AKLNG, is.

KRUSEN: Yeah, AKLNG, yes.

CRUZ: Okay. So that's my only hesitation from our Committee is, okay, step in Frank. We're scraping that plant. To go to a billion and a half we've got to go to Aiming which may not be a difficult deal because there's people -- that's well accepted and all we're looking for is we asked -- we asked them a level 3, that's a pretty detailed -- we paid a lot of money to get that design right there, so what does that cost to get a billion and a half plant or a two and a half billion? I have no idea, so.....

RICHARDS: And that's what the work plan would identify for you.

CRUZ: Okay.

RICHARDS: We'll come back to you and say here's the work that would take you to a new technology at a larger volume, that's what we'd come back, so again, I'll come back with that suite of -- of work packages for gas conditioning, compression, pipe, (indiscernible).....

CRUZ: So and this.....

RICHARDS: .....and then.....

CRUZ: .....would be adaptable -- so say the producers liked this, you know, market changes and whatever and the producers are coming on board. We can share this. Hey, there's a GTF for you that's AIM Technology that

works, so we're -- so from that sense we're not.....

FAUSKE: They're currently doing it.

CRUZ: Right. But they're doing it at a different volume then what we're looking at, so that's all I'm saying is -- and I -- okay. So I have a good perspective. I don't want to belay it. I just don't want to get a surprise that well, we need 210 million now to do that so you've got to go ask the Legislature for another $10 million.

FAUSKE: But I.....

CRUZ: That's what I'm concerned about.

FAUSKE: And I share that. I think we're going to get that anyway tomorrow because -- I just can't imagine a legislative body, and I've sat in front of many of 'em, accepting our cha- -- you know, and they'll hear us out and what are we changing. There's always the question is any idea what this costs. And you folks -- well, yeah, maybe, kind of or we're going to have to fine tune it and that might be a good enough answer, I don't know, but I --.....

CRUZ: Well, okay.....

FAUSKE: .....you know, I just -- they're going to ask the question I would -- I can't imagine them not asking it.

CRUZ: So Frank is right and Fritz is right. So I would support whether we use Mr. Halford's resolution or

modification, that we at least get this data, what it costs, so we're not sitting there assuming someone else is going to do this. That this is the next step that we're going to do.

FAUSKE: For the GTP?

CRUZ: For the GTP, so (simultaneous speech).....

FAUSKE: Okay.

BURNS: So Frank, I want to make sure that I understand what you're asking for. You're asking for the work plan to encompass not simply the pipe, but also the GTP.....

RICHARDS: And compressors.

FAUSKE: And compressors.

BURNS: Okay. And -- and.....

RICHARDS: Fac- -- I call 'em facilities.

BURNS: Okay. And so unless we do that you lose the team. Unless.....

RICHARDS: Correct, right, so.....

BURNS: .....we do that you lose the team?

RICHARDS: That's correct, Mr. Chairman.

BURNS: Okay.

CRUZ: And we'd lose the time.

BURNS: Rick.

HALFORD: Question on timing, would you go over what you said about when they're going to have the completion of the phase they're on at the 500 level and when you have to

make this commitment to go forward?

RICHARDS: Yes, Senator, the work that they -- that's depicted by these charts is the Class 3 level work. And, again, that Class 3 is from the American Association of Cost Estimators. And it's a level that defines approximately 30 percent design effort.

HALFORD: Yes.

RICHARDS: They completed that work and provided to us their Class 3 estimate in December. They are now finishing up essentially their documentation. They're wrapping a ribbon around all of their product and that will be to us the first week of April, that's the completion of the FEED effort, front end engineering and design for the gas conditioning facility.

They are now working on offtake point designs for us and that work will be wrapped up the second week of April. And once that is done, the work product that we have coming from Fluor is complete.

FAUSKE: But see, if I may, what troubles me about that and we've had this discussion internally, if we're going to change, which is fine, that's good. We're now spending money on offtake facilities that I don't know that they're compatible.

RICHARDS: For both. Well, we -- they did it -- we had two packages with them. They completed the one for ASAP

and they will soon complete the one for the AKLNG.

FAUSKE: So we're not blowing money on.....

HALFORD: No, no (Simultaneous speech).....

RICHARD: This is AG- --.....

FAUSKE: Okay, good, I.....

RICHARDS: .....this is AGDC's -- one of our roles is offtake point design, so we did it for both ASAP and AKLNG because they're going to be different based on the gas composition.

FAUSKE: So that design of work at 1.5 or 2.5 billion.

RICHARDS: It's based on the gas composition.

FAUSKE: Okay, got cha, all right.

RICHARDS: Yeah.

BURNS: And so, Frank, is there a possibility or a likelihood of being able to share data with AKLNG as we move forward, you know, assuming that the Board were to sanction a work plan to develop these other cost estimates, is there a possibility to share the data and to provide benefit to the AKLNG project as well?

RICHARDS: I'll talk first to the gas conditioning facility. And Fritz in his previous life worked on gas treatment plant on the Slope based on probably two iterations ago and so they have done a tremendous amount of work already on gas conditioning on the North Slope and they have that.

Now, they're advancing that or combining all their efforts and advancing that, so in regards to an ASAP project starting over on an Aiming process, we'd be starting from square one and then advancing, so AKLNG is on the facilities design far in advance of where we are.

On compressors, we have none no -- we have essentially done no work on compressor stations as well, but the AKLNG has. And they've already, I believe, you know, designed their kit which is essentially they've optimized what the turbines would be and the -- based on the horsepower and the cost of service.

We'd be starting again anew (ph), but we're going to need compressor stations in any event on any of the design premiss that you've given me,.....

FAUSKE: In the past.....

RICHARDS: .....so we have to start.....

FAUSKE: In the past, John, they have been very clear that they would not share data if they felt we were a competitive.....

BURNS: Um-hum. (Affirmative)

FAUSKE: .....project. If they felt. Whether we feel it or not, if they feel this is competition they've said that publicly. We need to work with them. Maybe we can get

through this. I don't know, but they have said it, so I'm just bringing the Board up to speed on comments that have been make.

BURNS: No. And I appreciate that. And, you know, let's maybe talk about that a little bit because, you know, from -- at least, you know, from my perspective having been on this Board from inception the -- the focus has always been on, you know, having a primary AKLNG -- after 138 was passed, a primary as AKLNG and having a viable alternative secondary.

And if AKLNG moves forward, as you said, there's going to be a point of convergence at some point, hopefully, in the very near future and a decision will be made. And the decision, presumably, you know, will be made on pure economics and if the AKLNG line, as we are all hopeful, moves forward then all of this becomes, you know, essentially meaningless, but the risk is that if it does not move forward, than we really are stuck without an alternative.

And I would hope that the producers would see the ASAP line, particularly if it's able to be increased in volumes, as a viable benefit to them if the AKLNG does not move forward. And to me, you know, I would hope that the parties could share the data in that respect because there is a symbiotic relationship and there

should be a mutual, you know, desire to achieve the objective which is gas to market.

FAUSKE: I'm not -- I'm not the head of the fan club for the petroleum industry, but I'm going to tell you this, that is not how they view the world. This is information they've spent billions of dollars on. Some of it, I think, they probably do overact on their ability to protect it, but it's their call and that's what I'm getting at.

Whether we think it's right or not, I've said this for years, we're asking people for their stuff and you just -- it's just frustrating.....

BURNS: No, and.....

FAUSKE: .....I know, but I share your belief (ph).....

BURNS: But my understanding.....

FAUSKE: I hope we can get there.

BURNS: Yeah.

FAUSKE: I'm just saying.....

BURNS: Yeah. My understanding.....

FAUSKE: .....there have been bumps.....

BURNS: .....is that we have data that -- is there data that we have data that they have asked for?

FAUSKE: We just transferred some- -- go ahead.

RICHARDS: No, Mr. Chairman, when we -- we each presented data that we felt -- or was available to essentially

exchange and we provided a very detailed list of the work products that ASAP had generated including, you know, the gas conditioning, but that was certainly something they didn't want.

They elected to only take a very small percentage of the option that we gave them. They felt becaus- -- the reason why -- one of the reasons is because they felt that we were to advanced. The information that we had was FEED quality. They're in the Pre-FEED effort. They don't want to expend money because they're budget constrained in Pre-FEED and they don't necessarily need the detail that we were offering to them.

FAUSKE: But they liked the information.

RICHARDS: The information was -- yeah, met industry standards, done by world class folks and they offered to buy it on the cheap, but I said no 'cause that wasn't in the best interest of the State.

BURNS: Um-hum. Well, I -- you know, I would hope that there would be a way that we could ensure (ph) the sharing of the data because there's nothing -- and I'm just speaking individually. There's nothing that I think that we have that I would not want the AKLNG project to not -- you know, that I would not want them to have because honestly -- you know, and speaking as an Alaskan, I want to see a gas line go.

And if we have to -- and, you know, everything that we have developed have to give it over to AKLNG, I'm all for that as long as there's a symbiotic relationship that we -- we are receiving the information relative to allow us to have that alternative option because I think there -- unless I'm mistaken, everybody is focused on ensuring to the best that we can the viability of AKLNG, but, you know, the world being what it is, you know, sometimes the things that we want don't come to reality and we waited for 40 years and we should not have to wait any longer for a gas line.

I mean, we are 3.5 billion deficit. We've got to be able to figure out ways to increase some revenue, so.....

RICHARDS: I can assure you, Mr. Chairman, that we have -- we are working cooperatively, diligently to be able to advance the -- as you just suggested. We are not withholding information back, but again, the issue would be if they've offered up something that we feel is of value, they want -- they want recompense for it and vise versa.

FAUSKE: We will be, you know, be aggressively pursing the very thing that you suggest. I'm just warning the Board, it's going to be bumpy ride and so.....

SHORT: So can I ask a question now (simultaneous speech).....

FAUSKE: .....so maybe we can get there.

BURNS: Hugh.

SHORT: So we're the second largest member of AKLNG.

FAUSKE: Correct.

SHORT: Correct. Let's assume AKLNG moves down the path. Let's assume we're to next June and we need to make a decision and it's a no go. All right. We're not moving this to FEED. At that point in time, who owns the data that has been produced by AKLNG?

RICHARDS: Come on up (ph).

FAUSKE: Joe. This is a comp- -- good question, but is a complicated issue.

SHORT: And let me just preface my question with this, we are the second largest member and we, under the Chairman's statement, are sharing data and I'm assuming Exxon, BP, ConocoPhillips are sharing data to the collective good of the project.

And we have a data room that's accessed by everyone who's members and then you have everyone having their own data room of what we're going to share as a member of AKLNG. Who -- at what point in time -- when it does not go into FEED, should it not go into FEED, who owns that data and what's done with that data?

DUBLER: Through the Chair, Mr. Short, that's a seemingly simple, but realistically complicated question because while it's true that the State parties combined own the second largest portion of the AKLNG project, the State parties are, in fact, two separate parties. One being TransCanada in the midstream which is comprised of the two lines from the respective fields to the gas treatment plant and the main pipeline down to Nikiski. So TransCanada represents the State in that portion of the project.

AGDC represents the State in the LNG portion of the project which is comprised of the LNG and marine terminal, so it's two different pieces.

The overriding, I guess, principle that applies to data is if you pay for it, you have ownership of it. So with regard to the LNG plant and marine terminal, AGDC would have a right to the data that was generated for that portion of the project.

TransCanada would have a right to the data for the midstream portion of the project which, again, is the pipeline and the GTP and the two lines from the respective fields.

So what that means for AGDC is that the -- and this is where it gets a little tricky. For ASAP, AGDC is by statute forbidden from building an LNG plant. So in

the event AKLNG goes away, we would have data to build an LNG plant, but not statutory authority to build an LNG plant. We would not have data to build a GTP and a pipeline, but we would have the statutory authority to do so.

SHORT: That doesn't make sense to me.

(Indiscernible)

SHORT: Yeah, I just said it doesn't make sense 'cause if we are contemplating a gasline and a GTP in a (ph) liquefaction and ASAP -- or not liquefaction, but the other two components. And in the other project we don't have the ability to have data on the pipeline and from field (ph) to GTP, then we're investing all this money into data that's not going to get us any further along the way, is that how you see this?

DUBLER: Through the Chair, Mr. Short, yes, that is -- I mean -- and, again, the overriding principles were and always have been if you pay for data you get to keep data.

Now, having said that I don't know what the agreement is between the State of Alaska and the other party that's representing the State in the midstream, TransCanada. They may well have the ability to get that data if AKLNG goes away and we have not see those agreements, so that -- it may be available through the

State of Alaska. I do not have the answer to that question though. We're not a party to those agreements.

BURNS: Okay (ph).

FAUSKE: The sharing of data has always been one where if they didn't view us or fear us as competition everyone was comfortable and especially if we were doing work that was of benefit to the other project.

I said this earlier this morning, back and forth, where we're not duplicating work, double spending State money. That's been the issue.

The issue that's always been the sticker is volume. Go above the volume (ph) sometimes it's arb- -- but it's always been this 500 which is a trailer from AGIA, but then it's just stopped and it's always been the trigger point if you go above that and that's where the debate then begins and just -- just letting the Board know that, that's where the argument will be.

CRUZ: Right.

FAUSKE: We'll have to see how we -- how we fare on that.

SHORT: So could I ask you a question. Let's assume you're a king -- you've king for a day, Mr. President, and.....

FAUSKE: You need to let my wife know if that happens, so.....

SHORT: Well, good luck with that. What would you do in the situation? What would you do in the situation?

FAUSKE: What would I do?

SHORT: What would you do?

FAUSKE: I would work very hard to try and figure out a way to share data and protect the State's interests so that we don't end up standing around the curb with our clothes gone, if you know that old saying, if they don't go to Pre-FEED. Meaning, we can't end up with the -- the finest design 500 million feet gas pipeline in the world that isn't used, but if there was a way to share that data, not get everybody riled up and end up at the end of the day that they decided not to go -- they, we're part of they. We're 25 percent on the -- but Dave's point is, we're 25 percent of the whole thing if you include the State.

AGDC's 25 percent of liquefaction, but the cumulative aggregate, 25 percent -- State's 25 percent owner. If they decide not to go, we want to be able to pick up the pieces and go. That's, I know, what the Governor and others have been -- have intended and that's a good goal. The trouble is getting there.

I mean, you know, the sharing of the data, the trusting of each other. So if I were king for a day I'd set up a system which I think we're trying to do.

We're troubled with where we get to share the data 'cause I think I sense from the Board it's data sharing -- and data sharing's key. It's expensive stuff, but if we could get to a point where we could do that and Pre-FEED fails. FEED fails for AKLNG. The State of Alaska is left in a good position where it has valuable data and could then determine through marketing efforts with -- on a merchant (ph) based program where marketers -- you market your gas. Buyers come in, which can be done, you at least have all this information that can be used. That would be, to me, ideal 'cause you haven't lost all the time or energy or money.

BURNS: So Dan, let's -- I mean, for certain we -- and I think you guys have been doing this, continue those efforts to get that data sharing,.....

FAUSKE: Sure.

BURNS: .....but in the meantime, in order to preserve the State's best interest, okay -- I mean, what I'm hearing from Frank is that in order to do that, in order to serve our best interest, that we need to move forward and authorize the -- you know, the evaluation in the work plan to address these other items, the GTP -- you know, not just the pipe, because, you know, that gets resolved. If you guys are successful in having the

dialogue and having a pure sharing of the data, then, you know, we're not in a position of having to, you know, do the funding in order to ensure that we've got a viable project up.....

FAUSKE: Um-hum. (Affirmative)

BURNS: .....until that Pre-FEED, but until that happens the longer we delay on that, the more behind and handicapped the State of Alaska.....

FAUSKE: Oh, yeah.

BURNS: .....becomes. And so.....

FAUSKE: But back to Hugh, that's the worst place to end up in my.....

BURNS: Yeah, yeah. And -- and -- but that -- we're.....

FAUSKE: That would be horrible to end up there. That would just be bad.

BURNS: .....we're, kind of, right there. The problem is we're, kind of, right there is what I'm sensing. And so -- and I'll reserve the decision on the motion.

Yes, Dave.

CRUZ: So too much wording is focused on competition. These producers are not our competition. These are our clients. They're the ones that's going to ship whether it's an ASAP line, it's an AKLNG line, they're still -- you know, and they are a customer of ours, so I don't view it as a competing line.

We're not selling -- never once have we said well, we're going to sell our own gas over here to whoever. We've never, ever got to that, that's not the State's place. All we're doing is providing a highway to get gas to, so someone else can sell their product. So I think too much focus is on that word competition and what -- we've got to get by that, so.....

FAUSKE: And, Dave, all due respect, I couldn't agree with you more. They don't care about -- I'm not being crass here. This is.....

CRUZ: Well, they should care about it.

FAUSKE: But -- but -- I'm not saying they don't care. I'm saying, they're separate companies that own the gas and all this. And Joe, you've dealt with (indiscernible). I couldn't believe -- I couldn't agree with you more. It's just we're not in control of that decision. We don't get to go in and tell 'em you will do that. We don't get to.

So what you have to do then is negotiate and.....

UNIDENTIFIED: Um-hum. (Affirmative).....

FAUSKE: .....work with and give a little bit, take a little bit.

CRUZ: So it's down to my original point,.....

FAUSKE: It takes forever.

CRUZ: .....my -- and it gets down to my original point is,

it's just a -- it's a commercial deal on a tariff per SCUF (ph) move down this line. If we are -- can offer a better price at a faster turnaround, all we're doing is providing a service. We're not competition. We are not taking and drilling our own wells up there and saying our gas is going in before yours. We're not gas balancing (ph). I know that. I know what you're saying, Dan,.....

FAUSKE: Yeah.

CRUZ: .....so I agree that we do need -- I'm supporting Frank. We are -- we have to know -- we have to have an idea on the ROM (ph) cost to do this GTF to handle a billion five and 2.5. We have to have that 'cause we cannot speak.....

FAUSKE: Joe, want to (indiscernible).....

BURNS: Yeah, Joe.

PASKVAN: I'm trying to get up to speed with a lot of information that the Board has obviously dealt with in the past, but as I am perceiving from what Frank has said is, is that the design team that put together this gas treatment facility has been in place, know what they're doing. They have industry standards as far as what's come out of that process and they're expecting to be fully done with a couple of weeks.

RICHARDS: Yes.

PASKVAN: So they -- that team was anticipating that they would disband, so to speak, 'cause they will have done they're job.

BURNS: Um-hum. Affirmative)

PASKVAN: Ultimately the question is, is that -- and I'm trying to -- in the event it's -- what I'm hearing you say is that these -- this team because they are specialized knowledge and work very well together as a team, can provide this information that you say would be necessary to get to the 1.5 or the 2.5 that has been addressed, can do that most efficiently and that data would be information usable by AKLNG also, is that --.....

BURNS: If they want it.

PASKVAN: .....is that accurate?

And then the second point is, is to the extent that they were not maintained and you were to have to try and assemble a team later, is that -- and I assume it's doable, but I assume it's doable at a hell of a increased price?

BURNS: Well, and.....

PASKVAN: And so I -- yeah, in other words, I'm just trying to figure out what are the real parameters that we have to make a decision.

FAUSKE: Arctic Solutions -- and I know Frank -- Arctic

Solutions is also working on AKLNG.

RICHARDS: WorleyParsons is, Fritz, defined as the pipeline engineer for AKLNG. Fluor is doing some work for them, but to a lesser extent.

If I may I'll take your second question first.

PASKVAN: Okay

RICHARDS: If we terminated work right now and then in a month's time you said go forward and design me some pressure stations or revamp this gas conditioning, we would have to go out for solicitation. We would have to find out, you know, the -- the pool of candidates to take this on at this level with Arctic experience is extremely small.

AKLNG our other priority project has the main competition already wrapped up and they're doing the work for them, so that's part of the challenge.

Your first question yes, the team that we have available is probably going to be the most efficient of the (ph) least costly to be able to do additional work. And as we talked about -- when we saw that we were going to be doing -- we had to ramp down our work and we were going to be reducing our work scope for the ASAP project by $90 million over the next year.

We ramped it from about 150 million spend down to 60, it included work that was going to be beneficial to

keeping that design team working on durable, transferrable work product that would be helpful to ASAP in its next evolution.

So we need to -- as ASAP evolves and if it were going to be providing gas not only from Prudhoe Bay Unit because this plant is only designed to take Prudhoe Bay gas. We haven't considered -- because Point Thomson when we initiated this work was not -- had not been resolved, hadn't been under construction.

Now, we've got Point Thomson, so one of the work products that we have on the books ready to go is looking at the Point Thomson gas stream and how that will then impact the processed units, so that's work that we could have Arctic Solutions do for us, looking at the compressor stations is the next evolution of work, that's work Arctic Solutions can do for us.

That's why I raise the issue because they're an efficient team, they're a quality team and they can get it done on a schedule that we want.

BURNS: Okay.

PASKVAN: Mr. Chair, if I.....

BURNS: Yeah.

PASKVAN: What is the time limit that you would expect that they would take to put together the gas treatment facility and compressors component that you are

recommending at this time, is that two weeks, three weeks?

And then as I'm understanding what you're saying, at the end of that period of time whether it's two weeks or a month or whatever it is, than that team will disband anyway.

RICHARDS: That's right, unless we evolved into the next phase, so we that -- we'd already been -- begin the discussions with Arctic Solutions in terms of what it would take to look at work products and so I was cavalierly saying two weeks. And I'll give you a rough -- rough order of magnitude because that was my direction, give me a rough number in terms of what that next traunch of work is going to be. If that's acceptable to the Board and we can put that into an authority for expenditure, than we'll be advancing.

If you want defined work that identifies clearly.....

PASKVAN: Um-hum. (Affirmative)

RICHARDS: .....every single work activity and develop that work breakdown structure to design a Class 3 level estimate for this, it's going to take a lot longer than that, but I can get you a rough order of magnitude within a couple weeks to define the work flow (ph).

FAUSKE: But if -- which is really important to have a budget

anyway. I mean, we've got a finite amount of money.

BURNS: Yup.

FAUSKE: We're not asking for any money this Legislative Session, so I think the Board would find that helpful anyway to know.....

BURNS: Yup.

FAUSKE: .....all right, what are we dealing with here. How much is going to go out. You know, you, the Board, to give us good direc- -- I mean, it's obvious you have to know -- you have to know what kind of money, you know, you have at your disposal.

BURNS: Okay. So let me end (ph) some discussion. I'll entertain a motion.

PARADY: Mr. Chairman, and Members of the Board, for discussion as I've listened to where my colleague, Mr. Halford, started this discussion off some half hour ago or 45 minutes ago and then to the back and forth and I appreciate -- I mean, this has been a deep dialogue we've had going.

So I'd like to offer some language that is certainly open for amendment, but I would like to move that subject to modification of Administration Order 271 as necessary, the Board directs the Staff of AGDC to further assess the components associated with Resolution number 2015-01. And develop a rough order

of magnitude cost estimate and impact to the schedule of the ASAP project.

What I'm trying to do there is open the door to the concern that's been expressed, but not obligate us to.....

BURNS: Future expense.

PARADY: .....expenses we're not prepared to deal with in this meeting.

BURNS: All right. So that's the motion. Is there is second?

CRUZ: I'll second.....

PASKVAN: I'll second it.

BURNS: All right. It's been moved and seconded. Any discussion? Hugh.

SHORT: I've got a tactical question. Is there any legal reason that we cannot move forward with the Resolution and the motion that was passed?

And back to the competitive -- the word that you've been using and others have been using competitive, is there any legal reason that we cannot move forward with reconfigured ASAP?

FAUSKE: The only legal reason would be -- and we've discussed earlier, was the interpretation of AO 271,.....

BURNS: Um-hum. (Affirmative)

FAUSKE: .....discretionary versus non-discretionary. I think we'll get that sorted out.

The competitive is a subjective debate. We have -- we can --.....

BURNS: (Simultaneous speech) two projects.....

FAUSKE: .....we, this Board has the right to do whatever they want and, you know, what I'm saying. Those that would be handled through negotiations, but there's certainly no legal impediment to -- I mean, I'm not a lawyer, but I -- I do know one and.....

GRAHAM: Two, three, four.

FAUSKE: I know several, Mr. Chairman.

VASSAR: Mr. Chairman, Members of the Board, for.....

BURNS: Give a smile, come on, Ken, smile.

VASSAR: .....for the first time in three attempts I'm going to introduce myself, Ken Vassar, general counsel.

I agree with Dan (ph). I believe that a modification of AO 271 is necessary, but apart from that I don't think there is any other legal impediment.

BURNS: Yeah, okay.

SHORT: I mean, from a -- just to follow-up on that. I mean, I'm sitting here trying to get up to speed as quickly as possible. And I feel like I have a beautiful date for the prom. All right. She's beautiful. I like her. She thinks -- seems to like

me. We've got a date. She's bought the dress, I think. I've rented the tux, but I also want to make sure that I go to the prom. And so I need to make sure that in case she's so beautiful maybe -- maybe she -- maybe she doesn't go with me, but I still make it to the prom. Okay.

(Simultaneous speech)

BURNS: So you're going to drive yourself, I got it. Okay. I knew there was a moral to this story. Holy cow.

FAUSKE: You need the keys to Dad's car, that's what you need,.....

BURNS: Yeah, that's right, that's right.

FAUSKE: .....as we all did (ph).

SHORT: Ken just gave me the keys because Dad said I could take the car, okay. So I'm trying to figure out there's no legal reason to not move forward with the reconfigured ASAP line that has more capacity. And there's legislation through HB 132 that would limit it to one Bcf -- one T- -- Bcf.

PARADY: Under consideration.

SHORT: Under consideration.....

BURNS: Under consideration.

SHORT: .....that's -- in the Legislature. So I'm just trying to get a lay of the landscape here. The language that we put together through 2015-01, as well

as the language that Commissioner Parady just read, provides a path forward for you to go out and explore this further utilizing the team that you have so that they don't disband.

RICHARDS: Correct.

FAUSKE: Correct.

SHORT: Okay.

BURNS: All right.

SHORT: That's just (simultaneous speech).....

FAUSKE: Just for one -- just two seconds.

BURNS: Yeah.

FAUSKE: When we were at the real peak of this, we had, I think, 110 people working in California.

RICHARDS: 130.

FAUSKE: 130 to give you an idea and we've scaled that way back, but it's -- it's a major operation and they were headquartered there and that's where the work came out of, but.....

RICHARDS: 200,000 person hours.

DRYGAS: What are we at now?

FAUSKE: Seven -- we're down to how many, 30 or.....

RICHARDS: A handful.....

FAUSKE: Yeah, it's.....

RICHARDS: We are -- we are down to probably 15 wrapping that up, plus the four that we have on retainer.

BURNS: Well,.....

FAUSKE: But they're prepared to.....

DRYGAS: Why California?

FAUSKE: .....continue. They've enjoyed the work.

CRUZ: 'Cause that's the only place you'll find them.

FAUSKE: We've got a great relationship with them, but, you know, it's just business. If we don't have something for them, they're going to utilize -- so we're open. We -- if we're -- to do the Board's work, you know, bidding, we're hoping that we can, you know, maintain that to expedite the schedule and get you the answers back sooner rather than later.

BURNS: Okay.

DRYGAS: Why California?

FAUSKE: It's mission -- what's the.....

RICHARDS: Well, Fluor is headquartered in California and their process engineers are located there, so in order for them to be able -- actually Fluor and WorleyParsons both have project offices down there. And so in this particular case Arctic Solutions is a Joint Venture between those two entities and they do the preponderance of the work on the North Slope for the oil producers in terms of process engineering. They've combined two offices in this -- and this particular project they headquartered it in their Aliso Viejo

office in California.

BURNS: All right.

FAUSKE: Do you want to say something?

BURNS: So -- Joe, did you have something to add to the motion, the underlying motion?

DUBLER: Mr. Chairman, just to add to the answer to Mr. Short about legal problems with the motion. I just want to ensure that you weren't talking about contractual.....

SHORT: Um-hum. (Affirmative)

DUBLER: .....because there are contractual issues with going above 500 and those are the con- -- some of the contracts we have with AKLNG if we go over 500, and I can't really go into too many details, but the gist of it is if we go over 500 the data we've received from AKLNG won't be able to be used on the ASAP project.

BURNS: Oh, I see what you're saying.

DUBLER: So that -- I mean, that's a contractual -- I just want to make sure the Board was aware of that, that when you said legal, that technically that isn't a legal issue, but that is a consequence of the action that the Board's contemplating.

FAUSKE: I'm glad you said something (ph).

CRUZ: That works both ways.

DUBLER: You're right, it does.

BURNS: Yeah. Yeah. And, you know -- I mean, honestly as

I understand the whole rationale here, ideally we don't get into this situation because it should be open sharing of the data. Unrestricted, open sharing of the data because it's a -- it truly ought to be a symbiotic relationship and so that would be really what we would urge that you, you know, continue.

I know, you've been beating those drums, but in the meantime, you know, Alaska is -- our Board is responsible for marshaling these two projects and we've done a dog gone good job to date of it and we're not going to deviate the focus. You know, we're advancing and we've committed lots of, you know, effort on the AKLNG and, you know, anything that is necessary we've tried to bend over backwards on that, but at the same time we've got to preserve the optionality on the ASAP.

And so, any further discussion on the motion? Okay. All in favor? If you would you take a roll call, please.

GRAHAM: John Burns?

BURNS: Yes.

GRAHAM: Dave Cruz?

CRUZ: Yes.

GRAHAM: Fred Parady?

PARADY: Yes.

GRAHAM: Heidi Drygas?

DRYGAS: Yes.

GRAHAM: Hugh Short?

SHORT: Yes.

GRAHAM: Rick Halford?

HALFORD: Yes.

GRAHAM: Joe Paskvan?

PASKVAN: Yes.

GRAHAM: Okay.

BURNS: All right.

GRAHAM: Unanimous.

BURNS: Okay. The next -- you guys want to take a break or do we want to.....

UNIDENTIFIED: Break.

BURNS: Take a five minute -- let's take a 10 minute break.

(Off record - 1:26 p.m.)

(On record - 1:44 p.m.)

BURNS: All right. We're back on record and we are on 9b, Project Update. Boy, we've been -- we've been slugging away for a lot of hours and we've got a lot left to go, so I apologize to everybody. It's taken a lot longer, but, you know, it's important that we have a real candid dialogue on these issues because it's -- you know, I mean, we just -- it's critical to the State.

Anyway, so 9b, Frank, you're still up. This is, kind of, the Frank show.

RICHARDS: Thank you, Mr. Chairman, I really appreciate that. I'm almost done. Some of these items we've talked in great detail. The facilities design specifically with Arctic Solution. They will be done and demobilizing their team and completing their work efforts by mid-April.

BURNS: Okay. You're specifically to reference -- to orient everybody you're in Tab 9b then, February 2015 activities?

RICHARDS: That is correct.

UNIDENTIFIED: This?

RICHARDS: That's correct, Mr. Chairman, page 1.

BURNS: Okay.

RICHARDS: What I define -- usually provide in an update of ASAP is the key functional areas of the project, so for instance, the first one is Facilities Design. That, again, is Arctic Solutions and they're work on the gas conditioning.

On the Pipeline Materials, this has to do with the testing of the pipe to make sure that it's meeting the design parameters. As I said earlier, the small scale testing is complete. We're now migrating on to the mid-scale testing. At the direction of the Board, we have put on hold the full scale testing until a future date.

Within the Civil work items we've been primarily working back and forth with our folks in environmental, regulatory and lands making sure that we've got good delineation for the Army Corps Section 404 permit.

And then also coordinating with the Department of Transportation and Public Facilities for use of the highway bridges. So the goal is to deal with utilize existing infrastructure to the maximum extent possible and we have been doing that through -- for instance, on the Yukon River bridge we'd applied for a utility permit because the issue on the Yukon River bridge was one concern on security related issues. So that's a process that we're now working with DOT, but also with the State Pipeline Coordinator's Office.

The Geotechnical Field Program, this is where we're drilling geotechnical holes to essentially assess the ground conditions. Work is underway today as we speak. We've completed the work in the Prudhoe Bay area with 31 additional holes in the gas conditioning site.

Doing 156 more holes on the North Slope. This is essentially delineating not only the centerline, but also in regards to work on materials sites because material for bedding and padding and work pad is going to be very important for the construction of this project.

I talked to you earlier about our pipeline design regarding geohazards and we have worked on a Fault Study that was now complete by the Geologic and Geophysical Survey, part of DNR. And we're also conducting joint workshops with AKLNG on liquefaction coordination with Alyeska Pipeline Service Company and our routing workshops.

And then for our waterways work we've identified new waterways designs for what we're -- what we call Revision 6.1 of our alignment which is the joint or common alignment with AKLNG.

So moving on to page 2 under Environmental, Regulatory and Lands we've been doing a tremendous amount of permitting for the borehole and winter field program and that's work that AGDC is doing for both work for ASAP, as well as work for AKLNG.

And we've been working with the Army Corps of Engineers and our third party contractor on our Supplemental Environmental Impact Statement, but I would like to point out that on March 2nd the Army Corps suspended work on they SEIS pending the outcome of the Legislative season because as Alaskans they read the newspaper.

They have seen the stories that are going back and forth between the Legislative and the Administration

and they were concerned that -- where ASAP was going to go and what it was going to become, so rather than continue the work, they identified that they would suspend it for two months pending the outcome of the Legislative process.

BURNS: So did you hear that directly from them?

RICHARDS: Yes.

FAUSKE: Yes.

BURNS: That's incredible. So essentially the politics that are going back and forth has stopped the SEIS process?

FAUSKE: Yes (ph).

RICHARDS: Mr. Chairman, part of the challenge that the regulatory world has is that they -- for ASAP we've been working with them and on the State side we have priority. On the Federal side they see this as a project, but there's also another project that they're also working on and that's AKLNG. So they wonder which project is real, which project is going forward.

FAUSKE: They're also balancing the use of their resources at this time and maybe a bit of an overreaction, but that's -- it is what it is.

BURNS: Okay.

FAUSKE: We have a great relationship with them and we'll -- that will get -- I think, as soon as some of the dust settles or -- we'll be right back in stride with them,

but that's the action they took.

BURNS: Okay. So they can put it back on? If.....

FAUSKE: Yes.

BURNS: .....there's a sense of a direction they can put it back on. Okay, good.

RICHARDS: Absolutely, Mr. Chairman.

CRUZ: Remember that's an arbitrary decisions they made.

BURNS: Um-hum. (Affirmative)

RICHARDS: So, again, with all the assets that we have gained within AGDC, we are putting in place a Content Management System which is essentially a commercial product to be able to do electronic document management, so that's all of our drawings, all of our files, all of our specifications that are coming in from our contractors as we've completed our Class 3 work. And then we are continuing to prioritize our ASAP Quality Program procedures and approval process.

And then in the Legislative world there have been a couple of Bills that were dropped last week. SB-70 was a Bill by the Administration seeking authorization for a natural gas pipeline through State park lands or Title 41 lands where those lands had been withdrawn from the public domain and we really need to be -- the State needs to have the authority by the Legislature to allow a natural gas pipeline to flow across those

lands.

There was a companion Bill that was also drafted by Representative Talerico and is now in House Resources with hearings starting next week. As we have two companion Bills that are out there ongoing, but both of which will benefit either project, ASAP or AKLNG because of our common alignment crossing those State park lands.

CRUZ: So -- you know, so, Frank, for the benefit of the new members explain what we're crossing in the State parks. This is going down the road right-of-way and where else?

RICHARDS: Well, we're actually crossing Denali State Park, about 38 miles of the park, so we're not actually in the road right-of-way. We're outside the road right-of-way and we're in many instances on the west side. And from our Public Hearings, that's where folks wanted us to be, but when the Legislature under House Bill 4 directed DNR to provide us a right-of-way, they provided us right-of-way on Title 38 lands which were in the public domain, but DNR didn't -- felt they didn't have the ability to provide a lease across Title 41 lands and so this will provide us that.

Besides Denali State Park, we are crossing Willow Creek recreational area. We are crossing -- or we

included in the language a description for Captain Cook State Park which is for the AKLNG route. So when AGDC represented to the Administration and to the Legislature, we combined the State lands that we saw that either project or both projects would need to be able to have the authority to do. So that work is ongoing and we continue those hearings.

BURNS: Okay.

RICHARDS: Moving on to Tab number C, Mr. Chairman, is a monthly update on the expenditures of the ASAP project. And as Dan reported in his President's Report one of the key matrix is the percent spend versus percent complete. So through the end of January we had spent 36 percent of the monies appropriated to AGDC for the ASAP project with the physical percent completion of 38 percent.

So since January 1 of 2013 on the totals line, the far right hand number is 110,714,156, that's the amount of money that we have spent essentially since passage of HB-4.

The bottom line in the tinier font the grand total of 159 million is essentially the money that AGDC has spent since the inception of House Bill 369 up through House Bill 4, so it's all the work that we've done to date representing a total.....

BURNS: During AHFC then. When AGDC was under the purview of AHFC?

RICHARDS: Yes, sir.

FAUSKE: Correct. 369, Mr. Chair, remember.....

BURNS: Right.

FAUSKE: .....when we wrote a report and did that work.....

RICHARDS: And that concludes my report, Mr. Chairman.

PARADY: Mr. Chairman?

BURNS: Yup.

PARADY: Mr. Chairman, Frank, I just want to open the door to a conversation later today about some of those right-of-way issues as to pertains to work I'm involved with in the context of the Cook Inlet gas supply to Fairbanks. I just want to chat about the lay of the land, so.....

RICHARDS: Be glad to.

BURNS: On record or off? It's not part of this.

PARADY: After the meeting.

BURNS: Yeah, okay, got it.

FAUSKE: Mr. Chairman?

BURNS: Yeah.

FAUSKE: You asked me to remind you, I was wondering if this might be an opportune time. Senator Halford had asked us a question yesterday on the work that was done in the past on a small diameter, eight inch, steel line

coming off, I believe, it's Pump Station 4 that would have supplied gas to Fairbanks. Mike Thompson worked on that project so I called Mike yesterday and asked him to prepare a brief statement to bring the Senator up to speed if -- with the Board's permission, Mike's here if we want to hear that information.

BURNS: It's not on the agenda, but if everybody would entertain, we'd go off script and let Mike come in.

FAUSKE: All right.

BURNS: Okay.

FAUSKE: Thank you. This should be quick, so we'll.....

THOMPSON: Yeah.

FAUSKE: Thank you, Mr. Chairman.

BURNS: Yeah. Go ahead, Mike, state your name for the record, please.

THOMPSON: Thank you, Mr. Chairman. Mike Thompson, I'm the ASAP Environmental, Regulatory and Land Manager and.....

FAUSKE: Mike, just give them some of your history, so -- I know that most of them probably know you.

THOMPSON: Yeah, I've been in Alaska all my life, lived in many different locations around the State mostly in areas associated with fisheries. I'm a fisheries biologist.

And in about 1991 I moved from Kodiak to Anchorage, joined the State Pipeline Coordinator's Office and from

about '91 until 2012, thereabouts, 2013 I worked in and out of that office, so a fair amount of experience on permitting and regulating pipelines.

And as part of that job, actually that's a good segue, when of the things we were looking at a few years ago and it was very high level, conceptual work, was the -- what was the opportunity to use the Trans Alaska Pipeline System fuel gasline which goes from Pump Station 1 to Pump 4, a distance of about 145 miles to extend that pipeline down into the Fairbanks area to provide gas there. And it was being eval- -- this project was being evaluated simultaneously with the LNG trucking project everybody probably remembers.

So what I did was I -- Dan asked me about that yesterday. I put these few bullets together just to describe the high level evaluation process we went through.

And we did determine that there was excess capacity in the pipeline itself. It's a 10 inch pipeline that's downsized to an eight inch pipeline at Milepost 21. There's a pig launcher receiver there, so there is excess capacity in the pipeline.

It supplies Pump Station 3 and Pump Station 4 and their peak loads are during the winder months as you can imagine. And so what we looked at was taking that

excess capacity and how do you deliver that to Fairbanks. And we landed on one compressor station which would be at the -- near the Chandalar DOT site just south of Atigun Pass. And taking the eight inch steel pipeline and extending that down into the Fairbanks area.

Some of the things we found were that during the peak winter use months we'd need storage in the Fairbanks area.

The pipeline itself was fairly expensive for an eight inch pipeline to run about 240 to 250 miles. In other words, the cost per mile of pipe related as a function of capacity seemed somewhat high when we were looking at a potential larger in diameter gas pipeline in the future. In other words, why would you invest in that if there's another larger pipeline coming at a later date.

And the other things that became apparent were that it's not a common carrier pipeline. It's considered an ancillary feature of the TAPS pipeline and, therefore, we didn't know how we would develop a tariff structure for that pipeline. What would be charged to ship the gas, so we never resoled that issue, but it was identified as an issue.

The other thing is, in working with Alyeska, Alyeska

was quite clear that their needs had to be met first if there was any pressure on the capacity itself. And that they may have had some future needs for that gas at Pump Station 5 where they were going to provide additional heat into the crude stream, so I think since then they've determined that they're going to use diesel and probably are actually heating the oil there, so those are some things we learned.

One of the key issues and we were under some timing constraints and the air permitting itself for the compressor station was going to take up to three years to do and that just really was difficult in trying to meet a schedule that we had.

So that's just a quick summary.

BURNS: Thanks. Rick.

HALFORD: The reason I asked the question was that when I heard what came out as a real Fairbanks demand it was so low that I thought it might be something to look back at. What was the capacity of a 10 inch line at the part that you're talking about?

THOMPSON: That I couldn't answer here today. So this -- this was put together just totally on memory. Those bullet -- I mean, the work was done three or four years ago, so.....

FAUSKE: Do you have any idea on that, Dave?

HAUGEN: No (ph).

FAUSKE: We'll get -- we'll get that answer. That's a good question.

THOMPSON: Well, what I would.....

HALFORD: (Simultaneous speech) question for -- I was just looking for an immediate response to a problem or a more immediate response than the other things we're talking about, that's all.

FAUSKE: If I could on that, we looked at it because -- and tell me if the work got done, but they did a bunch of work on that because frost heave keeps messing with that line. And we knew they were going in to work on it, so we explored well, why don't -- maybe there's an opportunity here while they're doing the work to talk about running it further down. It involved and -- you know, some of our funding, work with 'em, see if we couldn't get a line down and.....

THOMPSON: So -- you know, I don't want to minimize the work that was done. I mean, we met with DEC. We met with Alyeska Pipeline. Alyeska was very involved in these discussions. I'm not sure how supportive they were, but they didn't oppose the idea outright and those numbers were wrong. They actually modeled, you know, the hydraulics of the system and so I know that information is out there and available and it

might.....

FAUSKE: But we'll get it.

THOMPSON: .....be publicly available if we're go -- if we were to go to the State Pipeline Coordinator's Office.

FAUSKE: You know, the way things go, it still could be -- it could be viable again, you know. This thing.....

HALFORD: Yeah. I just wanted.....

FAUSKE: .....keeps morphing.

HALFORD: .....to look again.

FAUSKE: Yeah.

PASKVAN: Mr. Chairman?

BURNS: Yeah.

PASKVAN: My question along the line of Senator Halford's was not just capacity, but what the excess capacity was that you had determined existed, you know, so that we would.....

THOMPSON: No, and that was seasonally driven as you can imagine. In the summer months excess capacity was higher and how do you capture that, you know, through storage obviously.

And another idea that was floated, if we are going to build a larger diameter gas pipeline, let's build that south of Atigun.....

PASKVAN: Um-hum. (Affirmative)

THOMPSON: .....and, you know, 36 or whatever that is and then

we'll use this line. We'll actually pack the larger line. The larger line then becomes your storage, you know,.....

PASKVAN: Um-hum. (Affirmative)

THOMPSON: .....for Fairbanks area or other downstream users. So there were a lot of ideas that were being floated to try and economically bring this gas to Fairbanks and we just couldn't get it quite to work at that time anyway.

BURNS: Fred.

PARADY: Mr. Chairman, Members of the Board, and Mr. Halford, I'd like to offer that the AIDEA project team lead on this project is Bob Shevik (ph) and I'll take this communication to him and just fold it into the discussions that are hard work. They're -- it's well beyond discussions that are ongoing on this effort.

FAUSKE: That's a good idea, thank you. All right. Thank you,.....

BURNS: Good. All right. Thanks, Mike.

FAUSKE: .....Mike. Any.....

BURNS: I'm good (ph).

FAUSKE: Mr. Chairman, again, thanks for letting us get that in there.

BURNS: No, absolutely, appreciate it. Joe, AKLNG. Joe, Fritz, come on up, thanks. So this is item 10 in your packet.

KRUSEN: Okay. Ready to begin. So I think we're on Tab 9 and Section A of Tab 9. I'm just opening that up.

BURNS: I think we're on Tab 10A.

KRUSEN: Ten. Oh, 10, I'm sorry, Tab 10, there we are. 10, Section A, so I'm going to talk about the Alaska LNG technical activities in the month of February. You call got, kind of, caught up earlier on what we did last year.

I think you've heard a lot already about the AKLNG/AGDC cooperation and interface. Frank described how AGDC is doing the boreholes for both AKLNG and ASAP along the northern bit of the line, the southern bit of lone along Cook Inlet, so won't go over that.

And then, I think, Frank touched upon the fact that AGDC is responsible for offtake facility design for both projects, so we're working that and they're pretty far along on the ASAP version which is a bit of a leaner gas. And then once we get that done, we're going to plug in something to take care of the AKLNG richer gas, so we'll know more about that in a couple of weeks.

AKLNG is divided into sub-projects, so it's a massive project and the first sub-project as we go from north to south is the gas treatment plant, what's happening at Prudhoe Bay Unit to make it ready for

AKLNG and what's happening at Point Thomson Unit to make it ready to export gas.

Really the news there is that for the gas treatment plant there was a design review held last month where the experts, the gas treating experts, the Aiming experts from the three producers Exxon Mobil, BP and ConocoPhillips got together and really augured in on some of the details of the Aiming system design that they're going to do, so that was a good session.

Pipeline also held what's a CoV, Co-Venture workshop where everybody is invited. Frank and I and another person from AGDC went to that. Results from there, a little bit analogous to what you heard on ASAP. They've decided to lock in on the X70 grade of pipe and use a .72 design factor for the strain based portions of the route. That is, the parts of the route that are in discontinuous permafrost or in, sort of, slumping soils, that kind of thing.

They presented their work where they, sort of, (indiscernible) a little closer on pipeline capacity. They, kind of, had this notion at the start of Pre-FEED that the 42 inch line operating ANSI 900, 2075 maximum pressure with eight compression stations was the right way to do, but they looked at alternatives and they came out of that, once again, feeling that for the

AKLNG project that 42 inch ANSI 900, eight compressor stations is the right pick for them.

With that said it's not out of consideration that you would do a 48 inch. The State has some interest in -- in fact we're obligated to look at 48 inch and so we've asked that they try to keep alive any optionality for 48 inch so that can go into the Resource Reports if it comes to past that, that's what everybody lands on instead of 42, but meanwhile the work continues, the engineering work continues on the 42 inch case.

We talked a little bit about the Cook Inlet Crossing. There's an eastern crossing, kind of, up by Point Mac and there's a western crossing that begins a little bit west of the Village of Tyonek and then comes into the Kenai Peninsula at the Boulder Point.

And looking to routes, there was just, boy, that whole Point Mac looked a little messy so we came to the conclusion that we'll focus on the western route, the Tyonek to Boulder Point. And that's where we'll do the sensing and then the boreholes and stuff like that, the offshore boreholes for the summer 2015 program and will just keep the eastern route alive as an option in the permit request and that's saving money, so.....

BURNS: Fritz, Hugh has a question.

KRUSEN: Yes.

SHORT: Fritz, could you explain the messiness of Point MacKenzie then?

KRUSEN: Yes, several things going on there. It would appear that the bottom conditions are not stable, so there was some bathymetry work done five years ago. They did some last summer and there -- boy, it looks like things have moved around. So it looks like there is a lot shifting sands at the bottom up there. Whereas we don't see that same feature for the western route, much more stable.

There's also just a lot of things happening up there. There's, sort of -- if you will, it's almost like an offshore version of an on shore pipeline pinch point. So you've got the fiber optic cables coming in. You've got the -- what do you call it, the --.....

CRUZ: Chugach's power.

KRUSEN: .....the fairway into the Port of Anchorage and some other things going on. Oh, you've got the power cable, so what -- how do you anchor your pipe lay (ph) vessel with all this stuff going on and that was a big concern, too. How do you anchor a pipe lay vessel and move it down without breaking something.

SHORT: Has the Beluga issue been contemplated, discussed?

KRUSEN: Yes, yes. And both routes will, sort of, trigger considerations, but, you know, on think on the map.....

(Telephone interference)

BURNS: Anyway, if you're on the phone if you could, please, mute your phones, please.

KRUSEN: So yes, both -- both areas will trigger investigations into the Beluga situation. However, I think it's generally acknowledged that the upper bit is more serious then the western bit.

SHORT: And that was taken into consideration.....

KRUSEN: Yes.

SHORT: .....in your decision?

KRUSEN: Yes. Yes. And then our favorite acronym, PHMSA, Pipeline and Hazardous Materials Safety Administration, when you do things like do a pipeline to a strain based design, something that's different than what they do in the Lower 48, you have to get a special permit.

One of the conditions of that special permit was it has to be renewed every five years, so the AKLNG project team met with PHMSA and got them to say okay, we're not going to force that upon you, so that was a good thing. That's progress. It's nice to have your permit in place and not to know that five years later somebody could change the rules of the road.

Moving down to the LNG plant, we, the Project Steering Committee folk, haven't seen a lot of the results yet. They've been working hard, sort of,

churning doing their project team stuff. We will be exposed to their work for the first time next week, so I'll be going down and some others will be going down to participate in the -- as LNG presents their workshops.

Marine, they also held a workshop in February and a lot of things discussed there, but maybe the most interesting thing is the jetty locations. They will have two jetty lo- -- two jettys.

As you go, sort of, from the Kenai River -- gosh, which direction is -- I guess, north. Yes, north, you come to the LNG -- the AKLNG plant site and then to the Agrium jetty, the existing ConocoPhillips LNG jetty and then the Tesoro KPL jetty.

And so you get -- the closer you -- the further you are away from the mouth of the Kenai River and the closer you get to that Agrium jetty, the sooner you're into deep water and that's good.

But the problem is that if Agrium goes back into operations, there have some times been ships that got away from their jetty, so until we get all that figured out we're actually going to be as far south as we can, that will be the reference case. And then we'll, sort of, hold this optimistic upside case of being close to the Agrium jetty if we're able to work things out.

So those are the four sub-projects, but there's a team called the Integration Team that, sort of, is the glue that holds everything together. So I think -- I think we talked a little bit about the Pre-FEED master schedule. It's been reissued. I don't know if it's official yet, but it's awful close to official.

So -- I mean, they had a schedule going in, but as you heard the JVA got signed late, project team got stood up late, contractors kicked off late, so contractor said, you know, get all your schedules together. We'll integrate them and the bottom line is that the milestone for making a decision going into Pre-FEED has shifted to the right by three months from March 1st, 2016 to June 1st. Now, that's just a diamond on the map. There's actually a band around it when you make the decision, but that's the milestone.

And there's a lot of things that went into that, but basically it's a recognition that with the late start, lots to do, LNG is going to take another month. The task of integrating all the sub-projects is going to take another month and then just a recognition that a lot of this is going to be happening over the 2015 to 2016 winter holidays and that's going to slow things down, so there's a lot more going on than that, but that's, sort of, the short version.

We talk about what a big engineering project is and I think as Mr. Cruz said, but it's also a huge permitting project for ASAP, ditto for AKLNG, but as I mentioned before the first draft of Resource Reports 1 through 12 which are required for the FERC EIS methodology, those went in, in February.

There's going to be a second draft once we're done with all the Pre-FEED stuff. All those results go into the second draft and that will be February of 2016. And then good news from that submittal FERC have already issued their Notice of Intent to start work on the AKLNG Environmental Impact Statement, that was -- that's March business, but we thought that was so important that we wanted to get it into this.

And comments on that, Joe?

DUBLER: No, no (ph).

KRUSEN: Yup. So anyway it's a big -- once again, it is a sign that the Federal Government is taking this project seriously. So, you know, when you think about how quickly they granted the DOE, granted the Fair Trade Agreement countries export license, when you think about how quickly FERC turned this around, we think that's a positive sign.

So, you know, normally I speed through this stuff pretty fast and I realize that we've got some new folks

here, so I just -- you know, can I ask this with any -- answering any questions on AKLNG?

BURNS: Anybody any questions on AKLNG?

PASKVAN: Just.....

BURNS: Yeah.

PASKVAN: I mean, it's -- as far as countries under the Free Trade Agreement,.....

KRUSEN: Yeah.

PASKVAN: .....I assume India is still one of those and that's a.....

KRUSEN: I don't know about -- I think India might be and, you know, it could be a target. I think South Korea is.....

DUBLER: South Korea is.

KRUSEN: .....and -- and I don't know about India though.

DUBLER: Japan is not. I know South Korea is and Japan is not.

KRUSEN: Yes.

DUBLER: I do not know about India.

KRUSEN: Yeah.

FAUSKE: On that, did you -- are you talking about the pipe? Some -- when we ordered the pipe that you referenced earlier Japan is not.....

KRUSEN: Right (ph).

FAUSKE: .....and so when we're done testing the pipe it has

to be destroyed under the terms of the Free Trade.....

DUBLER: Or we day large duty.

FAUSKE: Yeah. In other words, you have to destroy the pipe. You can't cut it up into little -- it has to be destroyed. Just a little tidbit you'd find handy in your.....

PASKVAN: Well, I didn't know we are -- my question was going to lead us down this path, but, I mean, I guess that's.....

KRUSEN: But, yeah, South Korea is the only one I know of, maybe India. Unfortunately, you know, the other folks that we'd like to talk to that's yet to come.

PASKVAN: And what is the process that this Board needs to understand about getting.....

KRUSEN: I'll have to get.....

PASKVAN: .....those people in line so that we can talk to them?

KRUSEN: I'll have to get you -- get back to you. I know that Senator Murkowski is trying to get after the DOE on this and keep them -- I did see a press release on that.

DUBLER: And just for clarification, that will be an issue for whoever is marketing the gas. And at this point in the project it hasn't been determined whether that will be AGDC, whether the State Department of Natural

Resources will market the gas since they're technically the owner, technically they are the owner of any gas that would come through this project or whether they would assign that to the producers for the producers to market the gas on their behalf.

So -- and that determination hasn't been made, but whoever ends up doing it would be concerned with what countries they could market it to.

BURNS: Any other questions? Okay, great. The next item is on b.

DUBLER: Mr. Chairman, the budget numbers you have in front of you are actually budget versus actual comparisons. There's three columns. The first set of -- actually there's nine columns. The first set of columns of numbers are the Prior Cumulative. Those were the numbers through December of 2014.

The current month of January, 2015 we had a budget for LNG facilities and, again, we're back to -- all we're showing is LNG and Marine which is the only portion of the project that AGDC participates. LNG facilities had a budget for January of $1.5 million and change and the actual was $1,013,000 for a $500,000 variance.

The marine facilities also had a positive variance. And I noticed when -- and I believe it was -- Bruce was

earlier discussing variances on the project and under spending on a project is generally considered a positive variance, that's only if it's not significantly underspending because that means you're not getting enough work done.

I mean, so you want to be close to a budget. You want to be hitting your targets 'cause otherwise like Fritz said earlier, we got a little bit of a slow start on the project and you can see with the year to date actuals, we have a $5 million underspend so far to date. That means we're not doing nearly as much work as we had intended to and we are catch- -- we are catching up though, I will say that.

There -- the numbers coming in February and March are looking better. They're spending more money. They've got more people on board and they're getting more things done.

So the overall participating interest for AGDC for January, we had $2.24 million budget and 1.63, so we're about 50 percent under budget for January.

And the year to date actual we're a little bit lower than that, 12.7 budget and we've spent 7.6 with a variance of 5.1.

The numbers down below are the Corporate expenditures and Bruce talked about those earlier as

well. The operating budget and the CAM, is the Corporate Allocation Method is the acronym they came up with, and that was a method that was approved by the Board of Directors to allocate things like the computer system, the phone system, the -- you know, the overhead, the accountants, that kind of -- and actually Bruce, I think, is in there, too. He's, kind of, overhead, but allocate all of those kinds of costs, G&A basically.

So what -- and what it does, Bruce talk -- I mean, Bruce, it was 85/15 ASAP and AKLNG. And the reason for that is that most of the Staff and contractors we've got in this building work on ASAP.

AKLNG dedicated employees Fritz, I think, Jenny (ph) is and part of my time, part of Daryl's time, part of the Commercial Team's time and then some SMEs or subject matters experts from the Technical Team work on AKLNG as well, but the whole rest of the Staff are either Admin Overhead or they are ASAP.

So that's why -- it sounds like a big difference, 85 to 15, but it has to do with the amount of money that comes through here and the amount of people, so that's why that number may seem out of whack to you, but the budget to date for AGDC corporate expenditures $4.7 million total. Yeah to date actual 2.9 with a variance

of 1.7, so those are lower as well.

And with that, Mr. Chairman, if you have any questions I'd be happy to address them.

BURNS: Fred.

PARADY: Mr. Chairman, and I might direct this either to you or to our President, but if you do percentages on those numbers, the project expenditures year to date are at 60 percent of budget. The Corporate are at 62. The total's 60. The monthly Corporate -- or, excuse me, monthly project are at 52 percent and the monthly Corporate are at 63. So we're popping along at a slow -- I'm speaking to your point that we're popping along at a slow rate of activity and I just would like some discussion about that rate compared to our overall goals in terms of alignment, et cetera 'cause, you're right, that's an opportunity cost here (ph). Times a wasting (ph) and in -- in some respects depending on what you're trying to do with time.

FAUSKE: If I may on that and I know Joe can add, but in the work on the AKLNG side I'm part of what's known as the Sponsor's Group, that's the presidents on down.

PARADY: That's the big overhead.

FAUSKE: Yeah. Well, yeah.

PARADY: I'm sorry, I should have restrained myself. I hope.....

FAUSKE: I pale -- I pale in.....

PARADY: .....that was taken in good fun.

FAUSKE: .....comparisons to some those guys. The work -- we spend an awful lot of time -- and I'm going to say this in a complimentary manner, these are three corporations, TransCanada being, kind of, a separate entity. When we gather and we meet it is not always -- it's -- it's time consuming and there's a lot of decisions that take a great deal of time to make which does have an affect, in my opinion, on expenditure levels and the amount of work getting done.

There is still an unbelievable amount of work to be done in regards to the gas balancing, governance, commercial terms and a variety of issues. And so that is part of the explanation and I think that's an accurate one and Joe -- it's just things -- things that you think are going to go lickety-split get hung up because corporates are fighting over who's the L one, the lead or who answers to who, what piece of that goes, but I -- it's getting better. You know, they're -- I mean, we're spending money. You know, they -- you know -- but it could be getter I would think and.....

DUBLER: We had expected to kick off the effort earlier in 2014 than actually happened. It didn't really get going until July 1 of 2014, so we did miss part of 2014

summer field season.

What that means is that instead of a normal ramp up like this and then some work and then a ramp down, it was more like this and then ramping up fast and spending more fast and then it's going to drop faster.

So, I mean, we're in the phase right, and Fritz, correct me if I'm wrong, but all the major contractors have been named. They have all staffed up and they're all working full time on their component -- their particular components of the project and they still expect -- I don't think any of the end dates have shifted, have they? They're just going to get more. I mean, they haven't pushed any.....

KRUSEN: LNG did shift a month. Everything else.....

DUBLER: A month, okay.

KRUSEN: Yeah, yeah. So and I would just say from the Technical side we are at pace. We're beginning to get confidence in the burn rate that we're seeing. You know, I think next month we can say this is the monthly burn rate and just be -- you know, feeling real good about that.

At the same time with the $50 barrel oil, we're all trying to figure out ways we can reduce the costs of the AKLNG project spend and so there are deliberate steps taken to move out scope -- or remove scope if you

really don't need it so the Cook Inlet east crossing versus west crossing, well, come on guys, let's do our homework now and see if we can maybe not do twice a much field work. So yes, we're going to run a little longer, three months, but we're trying to take scope out to bring the burn rate down.

BURNS: Um-hum. Let me -- do you have another follow-up?

PARADY: No, sir.

BURNS: You know, if you look at our -- from the ASAP -- at what we have required you guys to do on the ASAP, there's a percent spent versus percent completion. That's not in this one. And, I think, it would be beneficial to know that the money that's being spent, how that tally's to the completion -- the project completion. And I think it would be very helpful to have something similar to what's on 9c because I -- these numbers are meaningless to me.

PARADY: Um-hum, 'cause you can't orient them (ph).

FAUSKE: Let's just go back,.....

BURNS: Yeah.

FAUSKE: .....if I may, Mr. Chairman, to what I said this morning on the corporate scorecard -- the scorecard.

DUBLER: Yes, yes, that's exactly what it is.

FAUSKE: Well, that data is not supplied and so.....

KRUSEN: We do in the monthly report get to see the spend co

(ph) and how it's doing against the target and they're supposed to put a new -- you know, reduced target on it, so we can -- we can see a tracking, but thus far that, you know, translated into 35 percent actual versus 37 percent planned or something, that hasn't been done. I can certainly ask.....

FAUSKE: We will work on getting that.

DUBLER: Well, no, what he's asking about he -- what you're talking about are both financial numbers.

KRUSEN: Yes.

DUBLER: He's talking about percentage complete number versus percentage spent numbers.....

KRUSEN: Oh.

DUBLER: .....to show you a ratio. Basically a -- what do they call it. A earned -- earned.....

KRUSEN: Yeah, earned value.....

DUBLER: Yeah, earned value, that's what it is. So you can say are we -- have.....

BURNS: Because we spent a lot of time in developing.....

DUBLER: Yes.

BURNS: .....the charts that's on 9c and it has value. I mean, we know.....

DUBLER: Yes.

BURNS: .....you know, it's performance management.

DUBLER: Yes.

BURNS: And it's great that you guys are -- maybe it's bad. It sounds like that you guys are underspending on the AKLNG, but you may be way over spending in comparison to -- to.....

DUBLER: To the work that's being done,.....

BURNS: .....get it completed (ph).

DUBLER: .....that's correct. And, Mr. Chairman,.....

BURNS: And -- and I -- yeah.....

DUBLER: .....we have asked them about that in Pre-FEED, but the response I got was Pre-FEED they don't do that. In FEED and EPC (ph) they do. It's the part of the project that they're in right now, they typically don't do percentage complete of work. We can ask again and see if they -- if they.....

BURNS: See what we can do. You know, why that would also be of benefit because this -- for the first time I've seen a slip of three months. You know, I've never seen a slip prior to that and there's a slip of three months and I think it helps us to evaluate things in context. You know, if we see where the spend rate is compared to completion rate, that sort of think.

Anyway, I guess, my only -- my desire is if you guys could mirror the one similar to this one and if that -- if the Boards.....

SHORT: No, I agree.

PARADY: Yeah.

BURNS: Okay.

PARADY: I agree.

BURNS: Yeah, okay.

PARADY: Sign us up.

BURNS: Sign -- anything else on AKLNG financials?

DUBLER: None from me, Mr. Chairman.

BURNS: Anything further on AKLNG?

DUBLER: (Shakes head in the negative)

BURNS: The next item was a -- we were hoping to have a representative from DNR. And I guess what I would suggest, Dan -- I mean, and leave it to the Board to see if they're in line with this, I would like there to be a standing invitation to DNR, DOR and to AKLNG, you know, Steve Butts. It's my understanding that Steve is, kind of, the lead on the AKLNG side of it. And, you know, to have them, you know, be participants and attend the AGDC, so we can have those candid dialogues and make sure that there are any questions or concerns that they have. I'm assuming that you've already been inviting.

FAUSKE: Marty is out.....

GRAHAM: She's in Juneau.

FAUSKE: She's in Juneau testifying. We were even going to try and attempt -- I think she's testifying, to try to

set up a call and it just got too complicated, but yeah, she's.....

BURNS: You know, the other thing, it harkens back to the prior Administration, I understood that DOR was tasked with doing the research to determine whether or not Alaskans could invest in the gas pipeline. And, I mean, I see Bruce -- Bruce, if you want to comment on that. What is the status of that evaluation?

TANGEMAN: So that is called the Lazard Report. That's a company that came on to study just that part. They've rolled out their preliminary report, presented it to the Legislature in late January. A lot of it is 101 type financing issues. They're due to roll out the final report in October of this year and part of that --.....

BURNS: What were the preliminary.....

TANGEMAN: .....part of that operating expenditure is under AKLNG that Joe is speaking to is being fund- -- it's a two and a half million dollar study that is being funded through us from that fund.

FAUSKE: We were -- this is a -- goes back to a House Finance meeting. I had the question of me. Other times I did some work years ago for Governor Hickel on the idea of creating a fund back in the days when the State didn't have -- you know, and how could we raise money. And so

it was a specific request of us that we include in our analysis, when we get to the financing stage, the ability to create a mutual fund or some type of -- some type of instrument that Alaskan citizens could use to invest in the fund.

And when you look at it if you -- let's say, AKLNG goes and you've got this fund that's going to pay a return on equity of probably 11 to 13 percent, I know many will go well that -- I'm in. Your -- your partners are BP, Exxon, ConocoPhillips, TransCanada and Alaska -- the State of Alaska that has the makings of the creation of a pretty unique fund.

The theory being that people could say I want to -- I'm just -- I don't want to, you know, just get -- just a theory. People could say well, I want for the next 10 years take my permanent fund. I want to roll it into that mutual fund with a guaranteed rate of return and then we know -- that was discussed openly at a House Finance and even a Senate Finance 'cause they Alaskans to have the opportunity to invest. And then through financial firms and others would be to create -- well, we've met with several banks and the idea of be thinking down the road of how to create.....

BURNS: So that's -- that's ongoing?

FAUSKE: That's ongoing.

TANGEMAN: And I -- and.....

BURNS: Okay. And that applies to both projects I'm assuming. I mean, the principle is the same I would imagine.

FAUSKE: Absolutely.

TANGEMAN: And I think the initial report that Lazard rolled out was more of a 101 general look and I think they got a lot of feedback, especially in the committees they were in that were more geared towards that type of how Alaska wants to treat this, so I think that's some of the takeaways they took out of this and will be rolled into the October final report.

BURNS: Okay, great.

FAUSKE: So that's ongoing.

DRYGAS: Can you send the Board Members a copy of that.

TANGEMAN: Absolutely.

DRYGAS: Thanks.

TANGEMAN: Um-hum. (Affirmative)

BURNS: Good. So we are at the end of New Business. Is there anything for discussion in Executive Session? Don't see any.

Other Matters to Come Before the Board. The only matter that I am aware of is committee assignments and rather than me do the assignments unilaterally, there are three committees.

GRAHAM: Four.

BURNS: Four committees. We've got -- just read through them if you would. Governance, we've got Governance. We've got what Dave refers.....

GRAHAM: Commercial.

BURNS: .....to as the Tech Commercial, the Commercial and the Audit, okay, and those are the four. And we are, because we are subject to the Opens Meeting Act, limited to three Board Members on each of those committees.

And so what I would appreciate if you would do is to shoot me an e-mail as to which committee you would like to be on and then I will call and talk about it because some may have more strength in Commercial even through they may want to work on the Tech side of it. I mean, we want to -- we'd really like to get the maximum benefit of your expertise in the appropriate committees.

PARADY: Mr. Chairman?

BURNS: Yeah.

PARADY: Might I ask Gwen that she e-mail us that detailed list and who's where so that we can.....

GRAHAM: No problem.

PARADY: .....respond to her?

GRAHAM: Um-hum. (Affirmative)

BURNS: Okay.

PARADY: To you through her.

BURNS: Yeah. Now, that will just list the four that are currently on it.

GRAHAM: Um-hum. (Affirmative)

BURNS: Okay, good. So the three new ones.....

GRAHAM: Yes.

BURNS: .....if you can just let us know. And we can shuffle assignments around, too. I mean, if -- you don't necessarily have to be (indiscernible).....

PASKVAN: Are we.....

BURNS: Yeah.

PASKVAN: .....picking two committees or.....

BURNS: Yeah.

PASKVAN: .....just -- okay.

BURNS: Well, you know, some people can -- because Tech Committee is very intense, okay. And -- and -- I mean, you're -- there's the task master right there.

CRUZ: Ouch.

GRAHAM: Three or four hours at a time.

BURNS: Other committees, you know, get canceled and he just drives 'em hard, but you can see the results of it and so that's a -- that's a very labor intensive committee. And the Commercial Committee, kind of, ebbs and flows. There will be a lot of flow as we move forward here.

The Governance Committee, we're getting pretty well situated with all the governance documents, but we essentially started from ground zero. We've got to work on -- I think, Miles, we still have the Communication Policy that we need to develop. And there are -- there are a couple others.

FAUSKE: (Indiscernible) Governance.....

TANGEMAN: Yeah, (ph) level two policies.....

FAUSKE: Level two policies and we can work -- that's ongoing, but when we get everybody up and running here that will help and we'll get that done, John.

BURNS: Okay.

CRUZ: And one thing I want to add to the committees, you need to be present at the committee. Do not call in because it's just disruptive to the flow of our work, so.....

BURNS: And the Committees generally are the day before.

CRUZ: Right, so we try -- we try -- you know.....

BURNS: But they'll be -- you know, I mean, the Tech Committee is many hours. Governance -- I mean, the Financial Committee, you know, like I said, that ebbs and flows, but you know, it's two and three hours.

FAUSKE: Mr. Chair, I think for the members, I think this would be an area that you'll enjoy in reference to some of the experts we have. You really get down in the

weeds. I mean, they -- you know, we cover a lot here, but you can -- you can really get down and meet the folks that are making sense out of the madness, if you will, but they're why it's designed this way, why it does that.

BURNS: And the other thing is, you know, as a Board we just can't know it all and so we are critically dependent on those committees to delve into the details and then to report back because we've got the fiduciary responsibility. And as great as the Staff is, you know, we've got to also -- you know, it's a series of checks and balances and so we rely on the Board Members.

Now, you know, we still have to get through this issue of the confidentiality agreements in the context of the Committees. And, you know, we're -- I'll work with Ken on that because there are only two Board Members who have signed confidentiality agreements and a lot of the data that is discussed in these, like in the Tech and the Commercial Committees, is subject to confidentiality agreements, so -- yeah.

PARADY: Mr. Chairman, I had being going to bring that subject up under Other Matters to Come Properly Before the Board. It was my understanding that Mr. Vassar and Mr. Juday were revisiting those confidentiality

agreements to consider what modifications might be appropriate such that we can have some further discussion at the Board level and in our respective roles, if you will, as to what we can sign or what's necessary to be signed.

I would like for those confidentiality agre- -- I understand the need for confidentiality, so does the Governor, but it's to be as limited as possible.

And then I also wanted to offer -- I offered extensive commentary to the Governance documents as they currently exist, but on a conceptual level for just the joy of discussion and dialogue as we get in the harness with each other, I think it would be interesting to consider not a confidenti- -- in addition to a confidentiality policy, a transparency policy.

The hallmark of this Administration is transparency and to the degree we can establish the criteria we intend to govern around transparency, it's the flip side of the confidentiality coin and I just think it leads to an interesting discussion at the Board level. Again, responsive to your thought about our fiduciary duties and our responsibilities to supervise this operation.

BURNS: Okay. Ken, can I impose on you to, kind of, give

the overview as to where you and Jerry landed relative to the series of questions that were asked regarding the confidentiality agreement because what we're -- in the committee assignments that are going to happen and you're aware of those committees and some of the comm-- you know, two of the committees specifically are dealing with often very confidential information particularly when we are asking contractors to put low (ph) numbers, you know, these sorts of things.

And so, you know, if a Board Member is participating in that committee, okay, without a CA, okay, there is no Board Meeting and so there's no Executive Session that applies to that Committee.

VASSAR: Right.

BURNS: Now, we can deal with the confidentiality in the context of an Executive Session at the Board level, but that doesn't help us at the committee level, so where did you guys land on giving us a road map forward?

VASSAR: If I could, Mr. Chairman, Members of the Board, just a couple of things about the Committees. First, because it does feed into this, but two things especially for the new members of the Board. We've been through this before.

The committees are sized at three members or less because, as the Chairman says, if -- whenever four of

-- four of you are together that's a meeting and the public is entitled to participate in that meeting, so the committee meetings -- the committees are set at three members. That makes it not a meeting. It's not subject to the Open Meeting Act and you can talk about anything you want.

We have had on a previous occasion, in all innocence, a Board Member who felt like rotating around and listening into meetings even though they weren't a member of the meeting and when that happens now you've got four in a room and it's a meeting, so please keep it to three or less.

Also committees cannot take action. The committees are for the purpose of gathering information. If the committee takes an action such as, for example, telling Staff to conduct some kind of study or some other action, now that's a meeting. As long as you -- the committees cannot take actions. You can report back to the Board. Committees cannot take actions.

On the issue of confidentiality as Mr. Parady has -- Commissioner Parady has alluded, in essence what the letter that we've put together suggests is that the Board should consider a regulation going forward or at least a policy that, number one, identifies the kinds of information that we need to keep confidential. And

the -- up until this point the default position has been that all of our information is confidential and we only make it public through some deliberate action.

What we're proposing which, I think, is consistent with the Governor's desire for transparency is that the Board would consider a regulation or a policy that would say -- that would define what kinds of information need to be kept confidential and then the default would be that everything else would be available to the public.

We are aware that the Board Members are not planning to sign the confidentiality agreements and, again, in the past we've used confidentiality agreements for one of two reasons; either to protect the information that AGDC has gathered or because we have to have confidentiality agreements to protect the information that other people have given to us.

Commissioner Parady.

PARADY: Yeah, Mr. Chairman, and I apologize to interrupt, but I want to correct a mis-impression you just stated. I would not say that I'm not intending to sign a confidentiality agreement. I am awaiting the work necessary to narrow that confidentiality agreement sufficiently that I can sign it. It's a view of the Administration that those agreements are overly broad.

Now, I don't know that we can get to a middle ground that suffices, but I'm intensely interested in that work and reaching a reasonable balance of the peoples' interest and the projects' interests, but under the proprietary nature of confidential information, I -- that's reasonably acceptable, we just have to work out some of these different perspectives, but I -- it's not that I don't in- -- or any of us don't intend to sign it. It's that it's -- in its current form it's not workable.

BURNS: Now, let me make sure that I understand this because that's a different paradigm than what we had all been operating under. The prior paradigm, and I think you guys as the lawyers who have been looking at this, was that there was not going to be a CA. So if it's a matter of narrowing.....

PARADY: (Simultaneous speech).....

BURNS: .....the CA -- if it's a matter of narrowing the CA, that puts us down to a different -- that moves us in a different direction and so I think we need to get some clarity on that.

PARADY: The understanding I had, Mr. Chairman, and with all due respect, was that the confidentiality agreement in its current form was not signable from my perspective, but I think there's room for discussion of an

appropriate balance there. And it may not be in a place that's acceptable to our partners. I'm not sure how that resolves itself,.....

BURNS: Right.

PARADY: .....but I believe it's open to further work, hard work. And I would like to ask my colleague, Mr. Short, who has substantial experience in this area given his financial industry experience just for his thoughts.

SHORT: I was going to say it's not a paradigm, it's a parody.

BURNS: Yeah, it is a parody.

SHORT: No, bad joke.

BURNS: Parody.

SHORT: So I believe that I think it's going to be very difficult -- and it's my personal opinion, that it's going to be very difficult to navigate AKLNG and ASAP without some sort of confidentiality agreement in place.

BURNS: Yeah.

SHORT: Now, how that takes form and how that looks through the drafting and development of it is very important. I think it bears a longer discussion at the Board level and probably some direction and some work for our general counsel to embark.

Now, again, that's my personal opinion. I think

that -- I think it's an area that we need to address. I do -- I am interested in what -- executive sessions, how those can substitute CAs in conversations and how those can be used as another tool along side a CA, so those are my comments.

BURNS: Okay. So just parking the question for a moment. I mean, what I'd like to -- I'd like to request that the two -- our AKLNG attorney and our ASAP attorney to do is look at the existing CA because we cannot -- I understand that you haven't looked at it to see if it can be somehow re-crafted at this juncture, is that correct?

DRYGAS: I'm.....

VASSAR: It can -- it can be re-crafted, although the difference --.....

BURNS: I'd ask you to do that.

VASSAR: .....the difference be-.....

BURNS: I mean, subject to the will of the Board, if that's -- if that truly is an option that we ought to look at.....

VASSAR: The difference between.....

BURNS: .....potentially crafting.....

VASSAR: .....what I was suggesting and what Commissioner Parady said is very minimal. It's a very thin difference. In each case it comes down to how do you

want us to define what's confidential, that's the issue.

BURNS: Um-hum. (Affirmative)

VASSAR: That's the key factor.

BURNS: Um-hum. (Affirmative)

VASSAR: Once we have an idea of what it is you want to keep confidential then we will work a confidentiality agreement to fit that. I'm not sure that the existing one wouldn't fit that. If we have a definition of what's confidential, the confidentiality agreement only requires you to keep confidential what's confidential.

BURNS: Um-hum. (Affirmative)

FAUSKE: But if I may, we don't always get to determine what's confidential.

VASSAR: Well, this gets.....

FAUSKE: Some other company comes and says this is confidential.

VASSAR: And that would be part of our definition.

FAUSKE: All right.

DRYGAS: I'd suggest, and what I had understood, is that the CA was to be discussed by general counsel and the Attorney General because I think that would be the best way to proceed.

BURNS: Which is what we got. The AKLNG is the AG's office.

DRYGAS: Well, I guess I realize that. I was actually hoping

that the Attorney General would be involved himself. And I had actually hoped that, that would have happened prior to this meeting.

VASSAR: Do you want to address that (ph)?

DRYGAS: I realize we all have other things to do, but I -- I agree with Commissioner Parady is I don't think that it's necessarily that we wouldn't be able to sign anything. It's the limiting the scope and if that means we have to define what confidentiality means, then I think it's incumbent upon general counsel and the Administration to, kind of, work together to define that because transparency is, kind of -- is paramount.

And understanding that there are certain things that we have to keep -- we have to keep confidential, but there's got to be a way, I would think, to be able to strike that balance to where the Administration and the Board Members would feel comfortable signing it.

FAUSKE: If -- do you happen to know, Commissioner Drygas, did the same embargo, if you will or prohibition -- 'cause as the Governor had announced, he thought they were too broad and the AG that he applied to his Commissioners -- his Commissioners won't sign it. Does that apply to Mr. -- Senators Halford and Paskvan, are they -- and Mr. Short? I don't know the answer to the question.

BURNS: The three public?

DRYGAS: Um-hum. (Affirmative)

FAUSKE: Yeah, I don't know if that's been stated.

DRYGAS: I -- I couldn't speak to that. I don't know what conversations they've had with the Governor.

FAUSKE: We need to glean that out, too.

SHORT: Could I make a.....

BURNS: Sure.

SHORT: .....suggestion for a path forward? And you just had a conversation around our committees and it would seem that this --.....

BURNS: Governance Committee.....

SHORT: .....this could be in the Governance Committee. We should make this a priority of the Governance Committee with our two general counsels and it should be completed and some recommendations put forth prior to next Board Meeting as to.....

BURNS: Okay.

SHORT: .....the next -- the direction in this (ph).

BURNS: Okay. In the meantime though, you know, we're going to have a very busy next couple of -- I mean, busy committees coming up.....

DRYGAS: Um-hum. (Affirmative)

BURNS: .....and so we're obviously not going to be able to work through the CA between now and then. And I'm,

kind of, wanting to understand how on the Tech side and the Commercial side we can navigate through because on the AKLNG we're bound by numerous confidentiality agreements. And AGDC itself is bound by various confidentiality agreements even though Board Members may not be. And so I'm just asking for, you know, a process. Just walk us through -- navigate us through the concerns? Fred.

PARADY: Well, Mr. Chairman, I'm frankly a little bit surprised. I -- and I obviously had a mis-impression, but coming out of the dialogue over Commissioner Drygas -- between Commissioner Drygas and myself when we were appointed prior to the last meeting and I was in attendance at the last meeting by phone,.....

BURNS: Um-hum. (Affirmative)

PARADY: .....but I understood that we had work proceeding on these confidentiality agreements between the two gentlemen sitting in front of us. I feel like we've lost a month. So you're speaking to we're under the gun in the need to get our committee work going.

I'd like a draft prepared and I'd like to see it next week. I mean, I don't know if that's reasonable. Maybe it's two weeks, but let's get this show on the road and get some ideas on the table. I don't know how it will turn out, but I know we have to think our way

through it in order to be able to work together effectively.

BURNS: Um-hum. (Affirmative)

CRUZ: So on the Governance Committee, my suggestion is to limit it to only two attorneys 'cause we're going to have -- isn't there some weird Alaskan law you've got five attorneys in one room something bad happens, you know.

DRYGAS: And I'll add to that, that as of right now I believe that it is John Burns, myself and Fred Parady on the Governance Committee, so this.....

BURNS: No, I'm off. I'll -- I'll.....

DRYGAS: Oh, you're off, okay.

BURNS: .....step off.

DRYGAS: 'Cause there are already -- there's.....

BURNS: Yeah, (simultaneous speech).....

DRYGAS: .....already two attorneys on.....

PARADY: I'm not an attorney.

DRYGAS: John and I are.

CRUZ: But I'm going to -- the next big one we've got is that Commercial Committee because that's -- we've got to have some good sales people.

BURNS: Anyway, I guess we're not going to resolve it here, but, you know, Ken, if the two of you guys can give us some guidance on -- and we want to be able to -- I

mean, the reality is, we understand the balancing, but, you know, the practical reality is work's got to get done and we need to be able to move it forward.

And to do so to ensure that all the information that's necessary to be reviewed, can be reviewed, so that the Board can made appropriate decisions. And that we're not violating AGDC's confidentialities, that we've not violating the relationships with AKLNG, all of that stuff.

FAUSKE: But I have a concern there, if I may just state it quickly. Mr. Juday is with the Attorney General's Office. It was the Attorney General of the State that determined that the confidentiality agreements were too broad. So Ken can write till he is blue in the face. If -- it's the Attorney General that needs to, I think, determine the breadth of the confidentiality agreements that the Governor is willing to allow his Commissioners to sign, correct?

JUDAY: I don't know that, that's correct.

FAUSKE: Well, I -- again, I stand corrected then. I just wondering who....

BURNS: Yeah. Jerry, do you want to comment?

JUDAY: The Attorney General -- we have been working with the Attorney General, to answer Commissioner Drygas' question. We've developed some draft documents.

They're in process.

BURNS: Okay.

JUDAY: It's just not completed yet and.....

BURNS: Okay.

JUDAY: .....so we can attempt to advance that to get it to some sort of completed level to where we'd recommend something to Governance Committee to look at it.

FAUSKE: All right.

JUDAY: This is a confidentiality policy or regulation and then you guys can take it from there.

DRYGAS: Well, I guess I would just echo Commissioner Parady's concern, it's been two months, so I, kind of, hoped that we'd have something before this, so I'd say the sooner the better.

BURNS: But I guess.....

JUDAY: Understood.

BURNS: But I guess what I hear you to be saying, Jerry, is it's a regulation? It's not a modification of the existing CA, a narrowing of the CA. It's a regulation, then it's got to go through the whole administrative process.

JUDAY: Chair, when you say CA you're confusing me 'cause there is many different CAs. There is a CA that AGDC has in place itself that it had been using that you signed,.....

BURNS: Yup.

JUDAY: .....that and Mr. Cruz signed. And if you're talking about narrowing that CA, yes, we can do that. Ken can rewrite it and revise it to appropriate correl it, however it needs to be.

There are many other CAs in place for the AKLNG project which we cannot unilaterally modify and we'd have to negotiate with our partners about that and that would be a difficult undertaking, not that it's impossible.

BURNS: Yeah, and nobody is -- nobody is anticipating that we would modify anything other than at this juncture I believe is the CA that relates to the Board, the Board's ability to see the documents, to participate in, you know, the candid discussions relative to the documents with the parties and ensure that confidentiality.

VASSAR: And this is the very first time that I have heard that signing confidentiality agreements was an option.

JUDAY: Same here.

VASSAR: This was not.....

BURNS: Yeah.

VASSAR: .....the option, as I understood it, so if that's an option that's fine, but as I said not at all sure that the existing CA doesn't work if you have a policy or a

regulation that narrows down what the confidential information is and that's what we've been working on. We've been working with the Attorney General on that and nothing that the Board has done has violated any existing confidentiality agreements.

PARADY: Mr. Chairman?

BURNS: Yeah.

PARADY: Mr. Chairman, again and with respect, but I want to push back at that. On February 3rd I sent an e-mail to the Board Chairman, the President. I did not include Mr. Vassar, but Mr. Tangeman and it says under Item 9, I had substantial comments to the Governance Policies which I took -- I labored over. It took a long time to put that together.

Said, I would like to discuss with the Board's attorney and the Attorney General. Perhaps, it's a place to have a deeper discussion of the confidentiality agreements being required of the Board as to their scope and applicability and any possible revisions. The confidentiality policy discussion could also be turnaround to discuss transparency. Maybe we need a transparency policy as well.

This is five weeks past that date. This isn't news and it's work that needs to be done and I just want to get on with it.

BURNS: No. And I appreciate it. So we -- if you guys can advance that process, we will put together the Governance Committee and we will that Committee scheduled soon.

SHORT: And just.....

BURNS: Yeah.

SHORT: .....one comment and this is something the.....

BURNS: Thanks, Fred.

SHORT: .....President said, but I don't --.....

BURNS: (Simultaneous speech) that again, would you (ph)?

SHORT: .....I'm not entirely sure how we can forecast or understand what's going to be confidential and what's -- you're going to put a list together and it's going to have a lot of buckets and those buckets are going to be this -- you know, commercial bucket -- I don't know, Tech- -- technical budget and there's going to be some other existing documents.

Going forward there's going to be things that are going to hit us on a daily, weekly, monthly basis that will have to be assigned into a bucket and then a confidentiality agreement will either have to apply or not apply. And so I think that the exercise of going through and cataloguing everything is great and I encourage it, but that -- that's less than half the problem.

The problem is going to be next week we get a letter from a partner that requires a decision to be made. We have to move forward on some sort of a confidentiality agreement, how do we handle that? That's going to be the real business decision we're going to have to make. It doesn't necessarily help looking in the rear-view mirror as to what's confidential or not, so that's what I'm really interested in.

BURNS: And that's the reality of how some things have happened. You get agreements at the last minute and, you know, the Special Board Meeting or something that you're approving, you're looking at an agreement, then having to make a determination.

VASSAR: Well, there would definitely be a definition of what kinds of information is confidential. So as I mentioned to Mr. Fauske, if we receive information that is given to us under a Confidentiality Agreement from an outside party and that information is confidential pursuant to that Confidentiality Agreement that we've ready signed, well, I mean, that's pretty easy. That's confidential information.

If we develop information, if ASAP develops information, we may want to keep that information confidential because it has cash value and it looses cash value if we make it public and we have a

responsibility to the State to preserve the value of the State's assets, so that might be a category of information that we would say in this regulation would be confidential.

Hopefully we could develop those kinds of buckets, as you say, that are clear enough that as the information is developed, we can assign them as we get it, but there may be instances -- I mean, it's difficult to cover every possible circumstance and there may be instances where we do have to ask the Board to make a decision.

BURNS: Okay. So rather than belabor this further, if you guys -- as I understand it, there is something that you're dealing with. If you could advance that, in the mean- -- and look at the existing CA to see if there can be -- you know, to -- in the context of what -- you know, the transparency issues and the public -- the concerns that have been discussed here, if we can -- if there's a way to narrow the CA just as relates to the Board.

And then in the meantime Gwen, we'll try to get the Governance Committee staffed up and then have a Governance Committee meeting within the next two weeks.

GRAHAM: Okay.

BURNS: That will hopefully get us resolved before the Tech

and the Commercial Committees, you know, that will be the day before the next Board Meeting, so -- okay.

Any Other Matters to Come Before the Board? Anyone? Joe.

PASKVAN: Just an information matter is -- and we can do this after the meeting, is to get a list of who is on what Committees currently, so that we know where we need to pigeon hole our number one and number two pick, so to speak, if we can do that? I mean, I'm just trying to figure out.....

BURNS: Sure. And you can.....

PASKVAN: It's obvious I know who --.....

BURNS: .....just shoot an e-mail?

GRAHAM: I will.

PASKVAN: .....what Committee Dave's on, so.....

BURNS: Yup. Okay. Anything else to come before the Board?

SHORT: Just.....

BURNS: Yup.

SHORT: .....at least three of us have confirmation hearings and any support --.....

BURNS: Miles, do you want to address this?

SHORT: .....any support from Miles to help.....

BURNS: Confirmation hearing process.

SHORT: .....coordinate this confirmation process and, sort of, give us -- give us some administrative support, as

well as just a heads up and communication as to dates, times, where we need to be, would be greatly appreciated on my behalf.

I know that March 23 seems to be a date coming up here pretty quick for House Resources, Senate Resources, but again, just that whole process over the next six or eight weeks is.....

BAKER: Sure.

SHORT: Yeah, happening real time.

BAKER: Sure.

BURNS: Yeah. Miles, before -- Fred.

PARADY: I just wanted to offer Mikayla Fowler is DCCED's Legislative liaison. She's in Juneau. She's intently involved with the process in confirmation hearings and giving that AGDC is administratively local -- what's the word I want, located.

FAUSKE: Located.

PARADY: Thank you. In our department, I'd like to offer her assistance. She's particularly helpful in chasing your schedule. The normal process -- well, Miles can elaborate, but you've got a lot of meetings in your future.

BAKER: Sure. Mr. Chairman, to Mr. Short's question. The new appointees of the Board have been referred to two committees. In the House.....

FAUSKE: You need to speak up, Miles.

BAKER: In the House they were referred to the Resources Committee and the Labor and Commerce Committee. In the Senate they were referred to the Resources Committee and the Finance Committee. Neither of the first two committees have publicly posted yet the schedule, but through conversations I know individually and I've had conversations with the Chairman's office for both House and Senate Resources Committee, that there was at least -- currently the intent is to start that process the week of the 23rd. Monday the 23rd.

I believe the House Resources Committee plan currently is to ask all three, Mr. Short, Mr. Halford and Mr. Paskvan to be prepared to testify at the confirmation hearing on Monday the 23rd at 1:00 o'clock. Their intent -- my understanding is that if they can't conclude that on Monday, they would pick up again at Wednesday's hearing.

So I know -- I know Mr. Paskvan has some scheduling challenges with Wednesday and so I've expressed that to the Committee. And I'm perfectly willing to offer my services to help coordinate any or all of that. I could step away and let individual members deal directly with the Committees on that at your choice.

On the Senate side right now Senator Giessel has

talked to Mr. Short about testifying on the 23rd and the Senate Resource Committee has not confirmed whether they want the other two appointees on that same agenda.

I have communicated a request from Mr. Paskvan to also testify that day since he will be in Juneau, so I spoke with her Committee aide this afternoon and they're still considering that request along with the rest of the stuff they've got scheduled for that date.

I believe I for- -- if I didn't I apologize, but I had prepared, sort of, a brief, like, one pager that I had given the previous Board Members -- the first slate of Board Members on just the confirmation process in general. I don't know if I forw- -- I think I forwarded that. And beyond that, we're happy to prepare, you know, any background information you might need or if we get any indication on the types of questions they expect to ask, we'll be happy to pass that along.

BURNS: So, Miles, I guess I would just ask, if you could keep the three regularly updated.....

BAKER: Absolutely.

BURNS: And likewise, to the extent that you have any questions or need information run it through Miles and Miles will coordinate with Dan.

BAKER: And the ques-.....

FAUSKE: We will -- we'll follow-up tomorrow because we will be in Juneau tomorrow.....

BAKER: Yes.

FAUSKE: .....and we'll do a little follow-up tomorrow on that.

BAKER: And the question that had come up also whether the Corporation would cover travel expenses for those appointees to go to those hearings and we will do that.....

BURNS: Yeah.

BAKER: .....so Gwen can coordinate how that works in terms of reimbursement.

FAUSKE: Yeah, and 604 in the Baranof is the room that we'll get you in.

BURNS: Gwen, the other thing is from some housekeeping matters, if you could send the reimbursement, the financial reimbursement.....

GRAHAM: Expense report.

BURNS: .....expense report out, circulate it to everybody, so everybody knows how to provide the data and in the format which we landed on to make sure that it crosses the T's. All receipts to the extent that you have, taxi fare or something, everything has got to be accompanied by receipts, airplane, everything. So there are no -- there are no exceptions to it.

So are there any other administrative things that we need to deal with before.....

HALFORD: Yeah.

BURNS: .....we move on? Yeah, Rick.

HALFORD: Just a question on, we all have a conflict of interest obligation and there's -- March 15th is annual report and then it says 15 da- -- 30 days after either, you know, accept the first payment for anything or you take the Oath of Office. I don't know -- and somebody has also said that it depends on the date of appointment. What is governing of all those choices just to make sure that we get those in on time obviously?

PARADY: Question.

BURNS: Great question. Yeah, Frank.

PARADY: Well, Mr. Chairman, I have some unfortunate personal experience with this. I -- my appointment letter was signed July 17th, but I didn't come to work till August 25th and APOC recommended a fine to me. And I ended up not hitting September 25th. I wasn't aware of this. I submitted October 3rd or something, so I missed it by eight or 10 days. They wanted to go back to my date of appointment letter and I objected saying I wasn't a State employee till August 25th. And they ended up using a date, August 8th, when I stopped into the

office and signed -- signed up for my coming start date. So I just urge you to get the report filed the sooner the better because I have reduced the fine, but it's still $227 and it's no end of irksome 'cause I --.....

BURNS: Yeah.

PARADY: .....I don't believe there was any -- there was certainly no intent on my part to avoid reporting. I was happy to do so, but I just wasn't aware of it.

BAKER: Well, we can -- I can work with Mr. Vassar and we can make the request of the APOC to just clarify those dates.

FAUSKE: We can deal with it on our end is what I'm.....

BURNS: Yeah. And I guess, Gwen, if you would just send out to every Board Member, we need to know what our obligations are. We have to sign a Conflict of Waiver -- don't we all have to sign a Conflict of Waiver report, AGDC?

CRUZ: You have an annual due the 15th.

BURNS: Yeah.

CRUZ: You got yours done, didn't you?

BURNS: Yeah.

HALFORD: Then you have an individual, too.

CRUZ: So that's due.....

BAKER: That's in three days.

BURNS: Three days, yeah.

HALFORD: Well, yeah, the 15th is one date, that's if you don't have to file a new one. If you have to file a new one, that may be overridden by the 30 days from sign -- we signed an Oath of Office today, so that's obviously one point. My appointment was, I think, the 19th of February, that's another point you would take 30 days. And the other thing is if none of those applied then -- then first payment would apply and the regulation is pretty clear, but those three things are not exactly the same thing.

BURNS: Well, just cut a check for 255 like Fred did. Okay. Yeah.

PASKVAN: Well, my preference is, is that they try to solicit from, like, myself -- in other words, from APOC that we have 30 days, for example, from today to get this information in.

BURNS: When do the new Board Members -- when do the newly appointed Board Members have to submit it? That's the simple question to ask.

PASKVAN: Yeah.

BURNS: Yeah.

DRYGAS: One more?

BURNS: Yes, Ma'am.

DRYGAS: Can we get a copy of the Resolution that the -- I

guess the two, but I was thinking the first one as amended by Commissioner Parady, can we get a copy of that even --.....

BURNS: Yup.

DRYGAS: .....at the.....

PARADY: Just to clarify,.....

DRYGAS: .....close of business today?

PARADY: .....Mr. Chairman, we.....

BURNS: Yes.

PARADY: .....didn't -- we adopted a Resolution and then we made a motion. It didn't amend the Resolution. It was a separate motion.

DRYGAS: Okay.

GRAHAM: But you can get a copy.

DRYGAS: Thank you.

BURNS: Yeah, if you can just shoot an e-mail to (ph).....

GRAHAM: Sure.

BURNS: .....everybody. I just signed 'em (ph). Okay. Board comments, let's start with our newest member, Joe.

PASKVAN: I'm just looking forward to working hard and I -- it's very apparent to me that the other Committee Members are wanting to work hard to get this work done, so that's why I want to be here.

BURNS: Good.

PASKVAN: I want to work hard.

BURNS: Commissioner?

DRYGAS: There's a lot of passion, not just at this table, but in this room on this project and, you know, there's some difference of opinion, but there's so much more that we have in common that it's exciting. I mean, this could actually -- this should happen. This needs to happen and I feel pretty fortunate that I get to be a part of this and I want to make it happen.

BURNS: Good. Rick?

HALFORD: A lot to learn and a lot at stake.

BURNS: Yeah, boy that's true. Dave?

CRUZ: I just, again, want to welcome all the new members here. We've got a real good breadth of knowledge that's coming in and I really appreciate you guys jumping in and getting right in the middle of it, so that's all I have.

BURNS: Fred?

PARADY: Mr. Chairman, I just wanted to speak to -- I don't think any of us are unaware of the current back ad forth between the branches and the temporary tension that might exists in different perspectives on this project, but what unites everyone around the project is far greater than what divides them.

I mean, there's nothing that's been brought up that

can't be sorted out and the ultimate goal of building the pipeline is shared by every person that gives voice to their thoughts and their passions. And I just want to stay focused on what can be accomplished by harnessing that passion and sort through all these details. They're vital, critical and important. Devil's in the details, but I don't want to let us get derailed by some -- again, some of the temporary tensions that might exists.

We can get this done and I'm just honored to be joining this team in the sense of trying to get there. Alaska has been at this a long time and we're not going to get there except by pulling together.

BURNS: Um-hum. Huge?

SHORT: You know, I sat -- I sat there listening to the Chairman and a reporter talk during our break and the reporter made the comment that stories about LNG put people to sleep, that people don't read 'em. And the gentleman spent most of the day here.

But I think -- I think one of the things that I'm hoping to do is raise the profile of this project. I don't think people realize the pressure we have on the State budget. That fact that our education system could crumble in the next five years. The fact that an income tax or a sales tax or your PFD being capped.....

PARADY: Or all of the above (ph).

SHORT: Or all of the above happening if we don't figure out a new revenue source. And the best revenue source we have and the best time in the history of the State is gas and we've got to get it to market and we've got to put our differences aside. And people in the public need to understand that as interesting as someone getting shot or some celebrity getting in trouble, that LNG is the future of the State for our education and for our State government to provide the services.

And I'm honored to be here. Honored to be in this process and look forward to serving.

BURNS: Good. Well, I just want to say welcome to everybody. It's -- you know, Dave and I have been at it for a while and the amount of work is enormous, but the reward is incredible because, you know, if you look back at House Bill 4 and I think, you know, Rick made a comment earlier, it's probably the most expansive, enabling legislation that Alaska put out, you know, maybe ever. And it speaks to one objective and that is to get a gasline done.

And so when you couple House Bill 4 with 138, it's not -- it really is not if we are going to get a gasline. I think it's when. And it's incumbent upon AGDC's Board to really focus and ensure that -- you

know, that we do the business that's necessary for the State of Alaska.

And it troubles me, you know, frankly that there's this friction between this AKLNG and the ASAP because, you know, there's going to be convergence as Dave -- I mean, as Dan had said repeatedly. And there's a point where either the -- you know, one project moves forward or it doesn't, but, you know, we can't as a State allow ourselves to be left without an option if the AKLNG does not move forward.

And I am confident with the effort that everybody has put forward on the AKLNG -- I mean, I -- I've had the opportunity to speak with Steve in the past and -- Steve Butts and that the producer group and our group and -- you know, I'm very optimistic and hopeful regarding the AKLNG, but, you know, Alaska can't wait any more.

I mean, we are facing $3.5 billion deficit. You know, the horror stories that you just alluded to, I mean, might happen unless we find alternative revenues. And, you know, we can't let this opportunity fail. And so Dan, when you go to Juneau, make it happen.

FAUSKE: Yes, sir.

PARADY: Make it so.

BURNS: Yeah, make it so. And, you know, I want to

compliment the Staff, I mean, it's -- as you guys got the sense that -- the Board Members, it's incredible. It's a -- we're very, fortunate to have the caliber of the people that we do, so thanks guys.

SHORT: Mr. Chairman?

BURNS: We're off?

GRAHAM: Well, no, you didn't adjourn.

BURNS: Oh. So I.....

SHORT: Move to adjourn.

BURNS: .....would entertain a motion to adjourn.

SHORT: Move to adjourn.

CRUZ: Motion to.....

PARADY: Second.

BURNS: Moved, seconded and unanimously.....

PARADY: Agreed to.

BURNS: .....accepted. All right.

(Adjourned - 3:17 p.m.)

C E R T I F I C A T E

UNITED STATES OF AMERICA)
) ss
STATE OF ALASKA)

I, Suzan K. Olson, Notary Public in and for the State of Alaska, residing at Anchorage, Alaska, and Electronic Reporter, do hereby certify:

THAT the annexed and foregoing ALASKA GASLINE DEVELOPMENT CORPORATION, BOARD OF DIRECTORS REGULAR MEETING was taken before Suzan Olson on the 12th day of March, 2015, commencing at the hour of 9:00 o'clock a.m., and recorded at the offices of Alaska Gasline Development Corporation, 3200 C Street, Anchorage, Alaska, pursuant to Notice;

THAT this Transcript, as heretofore annexed, is a true and correct transcription of said Public Meeting taken by and thereafter transcribed by Suzan K. Olson to the best of her ability;

THAT the original of the Transcript will be lodged with the Alaska Gasline Development Corporation;

THAT I am not a relative, employee or attorney of any of the parties, nor am I financially interested in this action.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal this 23rd day of March, 2015.

Notary Public in and for Alaska
My Commission Expires: 08/01/15