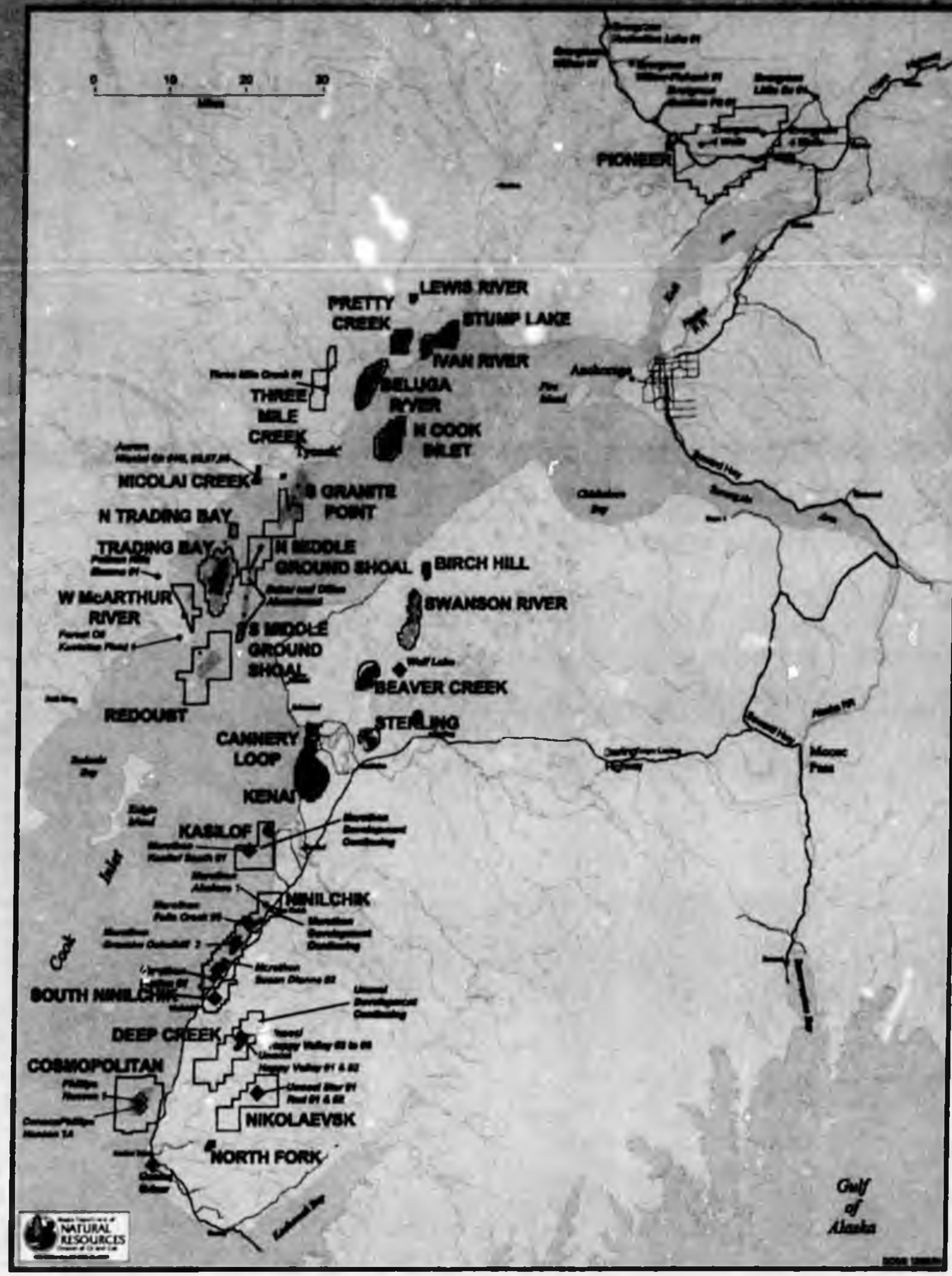
ALASKA LEGISLATURE COMMITTEE FILES, 2005-2006 0092
11944 SENATE RESOURCES

Cook Inlet Oil & Gas Activities & Discoveries December 2004

Map Legend

- Units
- Oil Accumulations*
- Gas Accumulations*
- Recent Oil Discoveries
- Recent Gas Discoveries
- *2004 Active and Proposed Exploration Wells*
- *2003 Exploration Wells*
- Platforms
- Road
- Alaska Railroad

*Oil and Gas Accumulations are Approximate



jrc/cjb 12/04

Cook Inlet Drilling Summary – 2004 (1)

- Cosmopolitan Unit – Conoco Phillips (Oil discovered in 1967 by Pennzoil)
  - Hansen #1 well P&Aed, Forest reported successful results, no word from Conoco Phillips yet
  - Hansen #1A well completed as oil producer, test production is being trucked to Nikisiki refinery.
- Iliamna Prospect – Pelican Hill
  - Iliamna #1 drilled and suspended, now converting to disposal well
- Kasilof Unit – Marathon (Gas)
  - Unit approved in October 2002
  - Kasilof South #1 and #1L drilled, evaluating
- Middle Ground Shoals Field – Unocal & XTO
  - While XTO continues operations at two platforms, Unocal has ceased operations at this field and placed its two platforms (Dillon and Baker) in lighthouse mode.
  - Decision on "decommissioning" platforms still to come
  - XTO drilling C31-26RD in progress
- Nicolai Creek Unit – Aurora Gas
  - NCU #3 production of gas ended March 2004
  - NCU #2, 1B, 9 completed, producing gas since November 2003
- Nikolaevsk Unit – Unocal
  - -- Red #1 drilled, results confidential. First of a 5-year 3 well commitment
  - -- Results Confidential
- Ninilchik Unit – Marathon
  - G.O. #1 well completed as gas well, tested at 11.2 MMCF/D from one zone
  - G.O. #2 well completed as gas well, tested at 11.9 MMCF/D from three zones between 8,048 and 9,440 ft. (MD).
  - Falls Creek #1RD completed as gas well, tested at 6.8 MMCF/D from a depth of 8,714 ft. (<D).
  - Susan Dionne #3 (SDPA) completed as gas well; Falls Creek #3 (FCPA) active, no details available.
  - Abalone #1 well drilled in 2003 at north end of unit, not completed, currently shut down, no other details available.
  - Plans to drill Susan Dionne #2 (SDPA), Ninilchik State #1 (GOPA).
  - Production started at GOPA in Septmeber 2003, currently about 15 MMCF/D rate.

MMCF/D = million cubic feet per day

db/jrc 12/04

Cook Inlet Drilling Summary – 2004 (2)

- North Fork Unit and Deep Creek Unit – Unocal
  - Unit getting renewed interest from small investor group
  - Non-Binding pipeline contract with ENSTAR signed in September 2003
  - Development drilling will begin 2005
- Redoubt Unit – Forest Oil (Oil discovered in 1968 by Pan Am)
  - Production began Dec. 9, 2002
  - Recent drilling results indicate field is more complicated than previously thought; reserves probably to be reduced
  - Waterflood most likely to come online soon (end of 2005?)
  - RU#3 well began producing fuel gas on 7/28/2003
- South Ninilchik Unit and Deep Creek Unit – Unocal
  - Pearl #1 and Deep Creek NNA #1 wells completed as gas producers in 2002, Unocal reported disappointing results.
  - Nine wells drilled to date, two more in progress. Some of these wells have been successful, some not.
  - Unocal built gas pipeline connecting Happy Valley pad to KKPL. Start-up Nov. 1, 2004.
- Three Mile Creek Unit
  - Unit approved March 26, 2004.
  - Objective is Beluga Formation gas zones bypassed by early opener.
  - Additional 2-D seismic acquired
  - Three mile Creek #1 well drilled
- Trading Bay Unit/McArthur River Field – Unocal
  - T.B.U. #K-13 came on production at 7,100 BOPD, highest rate of any well in Cook Inlet
  - Unit and PA expansions approved to bring boundaries into agreement with producing areas

BOPD = barrels of oil per day; MMBO = millions of barrels of oil

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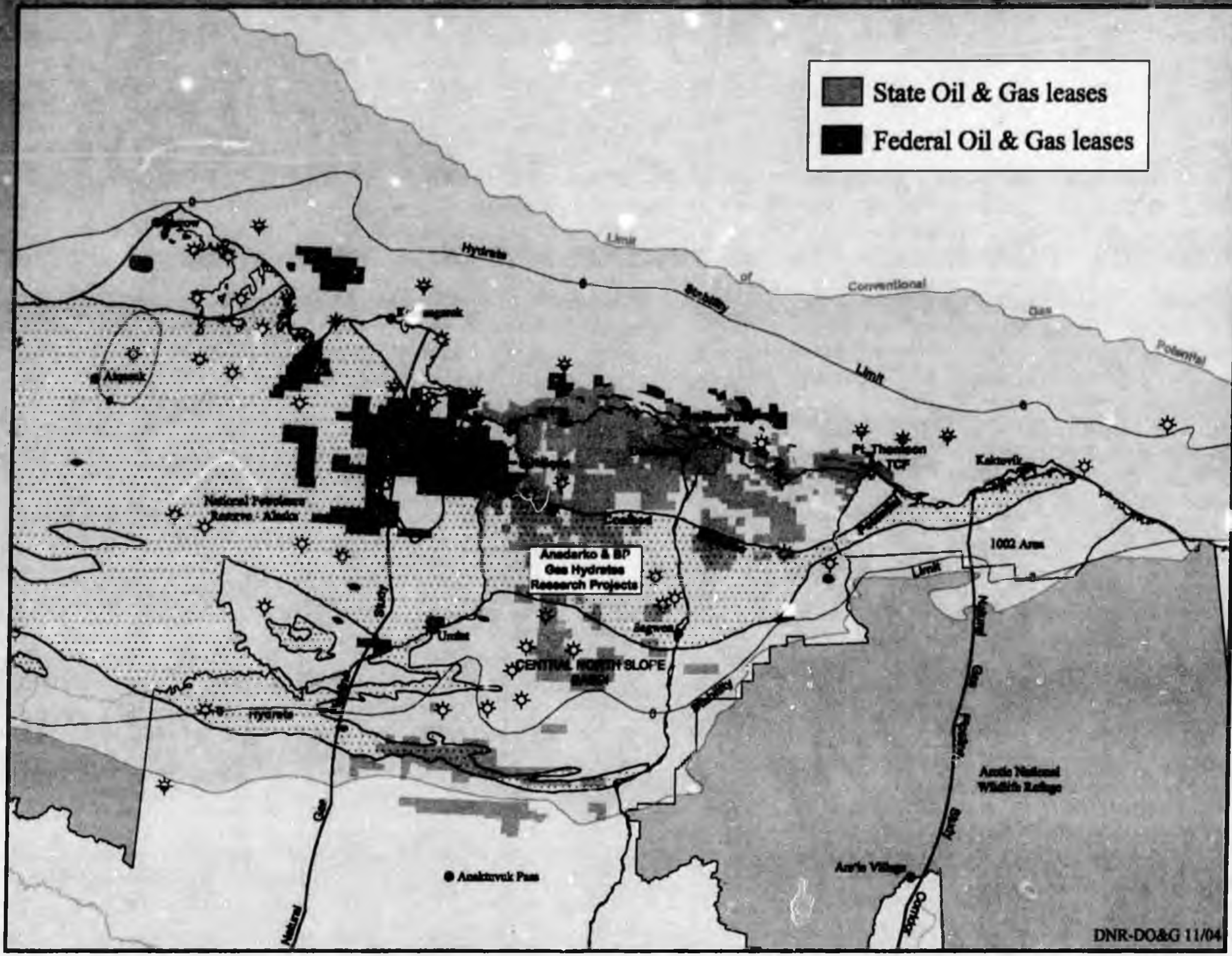
Gasline Update

- Stranded Gas Negotiations (Producers / Transcanada)
- MOU discussions (ANGDA/Port Authority)
- Economic Modeling
- Regulatory discussions (FERC)
- Right-of-Way Permitting
- Resource Assessments

Resource Assessments

- Alaska's gas can make a huge contribution to reducing our nations dependence on foreign sources of energy.
- Federal and state geologists believe that the 35 TCF of gas from Prudhoe Bay and Pt. Thomson is just the tip of the iceberg.
- North Slope and offshore conventional mean technically recoverable undiscovered resource potential exceeds 236 TCF.
- Gas hydrate resource in the Prudhoe/Kuparuk Milne Pt. field area alone is 100 TCF.

Gas Potential – North Slope Area with Oil & Gas Leasing Activity



Mean Value, Total Natural Gas Reserve and Resource Basis for Gas Pipeline Supply Report

All Values Trillions of Cubic Feet (TCF)
Alaska Division of Oil and Gas (01/12/05)

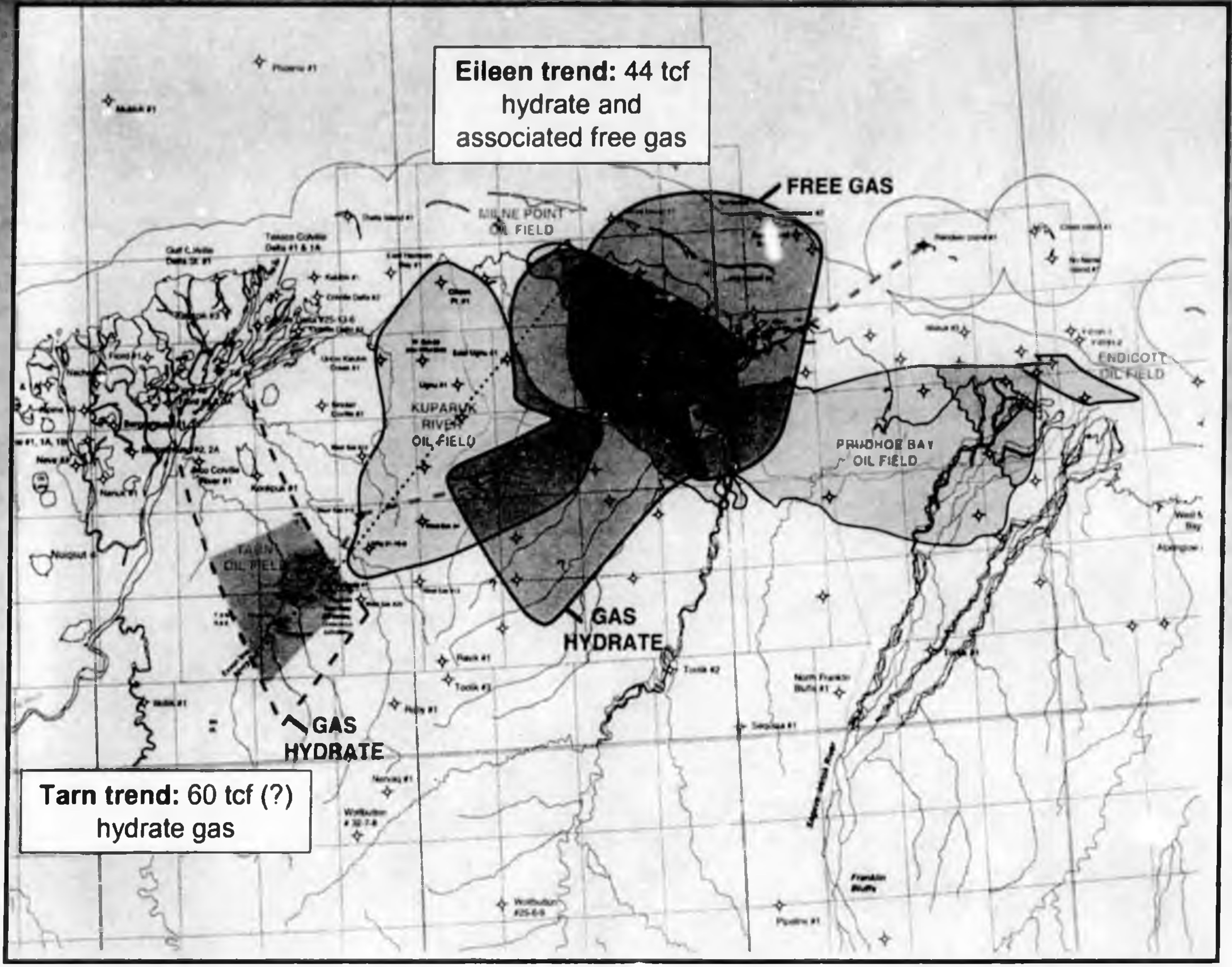
BASIN	KNOWN RESERVES	RISKED UNDISCOVERED CONVENTIONALLY RECOVERABLE RESOURCE	*RISKED UNDISCOVERED CONVENTIONALLY RECOVERABLE DEEP GAS RESOURCE*[2]	GAS HYDRATES IN PLACE RESOURCE[6]	COALBED METHANE IN PLACE RESOURCE	BASIN TOTAL
NORTH ALASKA (onshore)	35.000[1]	141.700[8]	*17.700*[2]	590.000[6]	800.000[7]	1,566.700
NORTH ALASKA (Beaufort shelf)[2]	0.000	32.070	*N/A*	32,325.000[3]	N/A	32,357.070
NORTH ALASKA (Chukchi shelf)[2]	0.000	60.110	*N/A*	50.000[3]	N/A	110.110
CENTRAL ALASKA[4]	0.000	2.760	*N/A*	N/A	N/A	2.760
YUKON FLATS[9]	0.000	5.460	*N/A*	N/A	N/A	5.460
KANDIK[5]	0.000	0.116	*N/A*		N/A	0.116
NENANA/TANANA	0.000	N/A	*N/A*	N/A	N/A	N/A
COPPER RIVER	0.000	N/A	*N/A*	N/A	N/A	N/A
TOTAL BY GAS TYPE	**35.000**[1]	**242.216**	***17.700***[2]	**32,965.000**	**800.000**[7]	**34,042.216**

After Craig, J., and Sherwood, K.,Prospects for development of Alaska natural gas: a review as of January 2001, Minerals Management Service, Alaska Region. tbl. 9, p. 76.
Modified to include only North and Central Alaska basins and updated to include new information as footnoted.
N/A = Not Assessed

[1] Current estimate of known "stranded" recoverable North Slope conventional gas reserves in Prudhoe Bay, Point Thomson and smaller fields.
[2] *Subcategory of and included in "Undiscovered Technically Recoverable Conventional Reserves". Represents Basin Deep or Basin Centered component > 15,000' depth.*
[3] Craig and Sherwood arbitrarily split offshore hydrate resource estimates between Beaufort and Chukchi Sea shelves. Total North Alaska offshore gas hydrate potential remains 32,375 tcf.
[4] 1995 National Assessment of United States Oil and Gas Resources, U.S. Geological Survey, Open File Report , Digital Data Series-30, pub. 1995. For all central Alaska basins except the Kandik Basin. Other basins not evaluated individually.
[4,5] Geological Survey of Canada estimated mean undiscovered gas in place ~ 0.489 - 0.800 TCF. Alaska component estimated as 0.116 Tcf.
[6] Collett, personal communication, 11/26/04.
[7] Barker, C.E., Clough, J.G., Roberts, S.B., and Fisk, R., Coalbed methane in Northern Alaska: potential resources for rural use and added supply for the proposed trans-Alaska gas pipeline; AAPG-SPEM Joint Technical Conference, Anchorage, AK, May 2002.
[8] Includes nonassociated and associated gas. State and Native lands are estimated to be approximately 60 TCF and are included in this total.
[9] Oil and Gas Assessment of Yukon Flats, East-Central Alaska, 2004, USGS Fact Sheet 2004-3121, December 2004.

jrc 01/12/05

Known Gas Hydrate Acccumulations
(shown in blue)

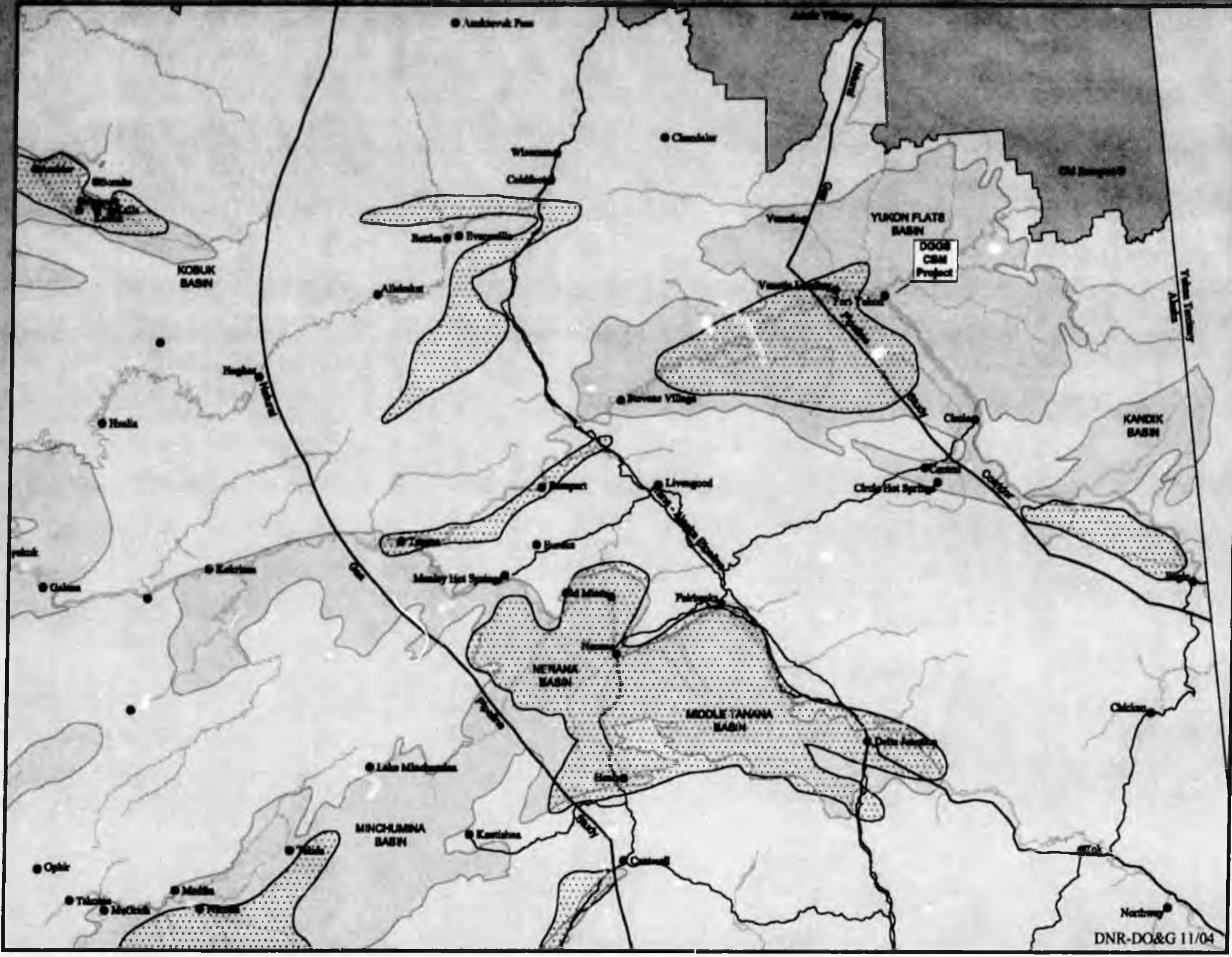


Modified from T.S. Collett, USGS 10/4/01

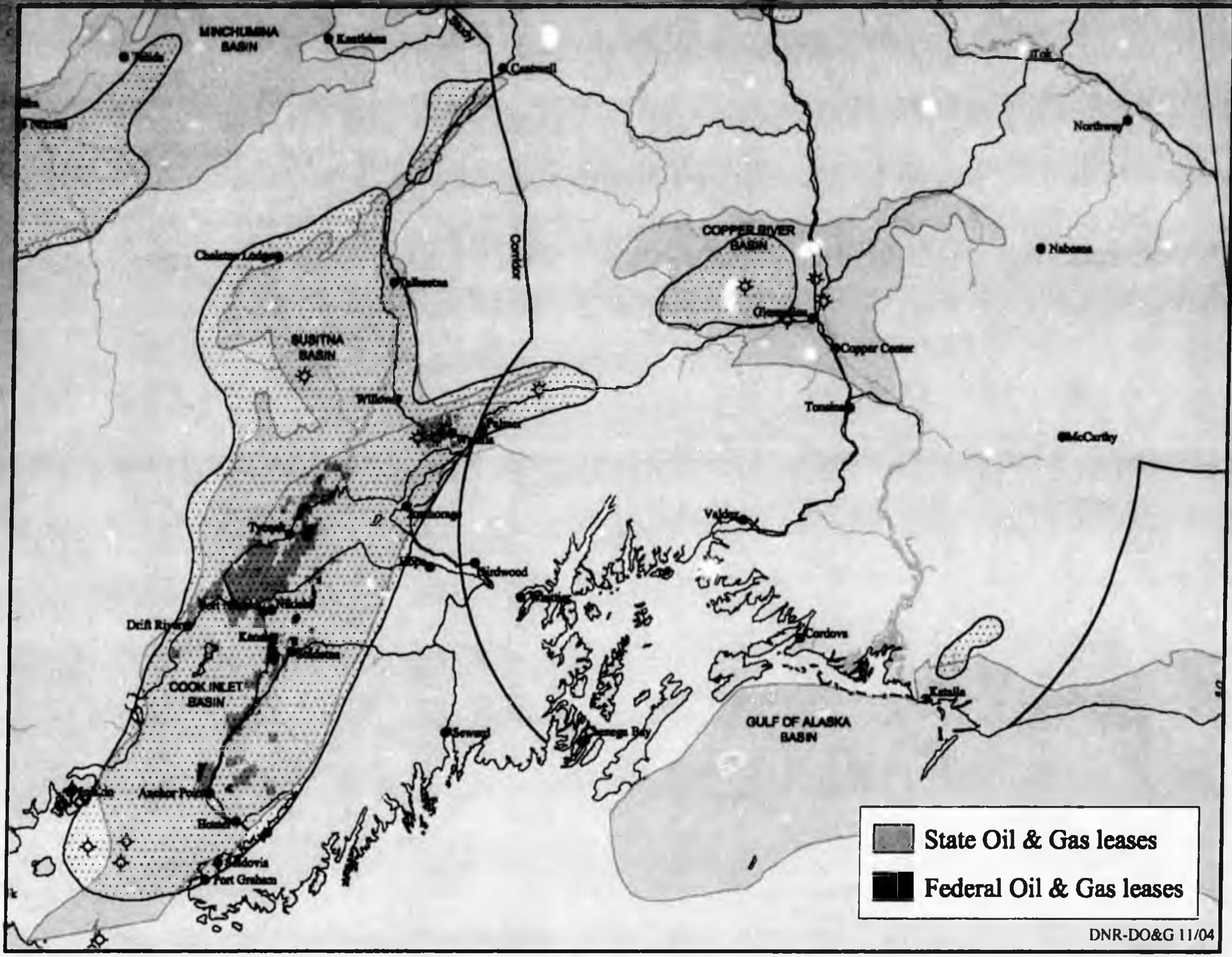
Useful Life of a Gas Pipeline

[illegible]	36	21.9	17.6
	40	24.36	19.6
Undiscovered Resources	60	36.5	29.4
	100	61.5	48.9
	150	91.3	73.4

Gas Potential – Interior Area



Gas Potential – Southcentral Area with Oil & Gas Leasing Activity



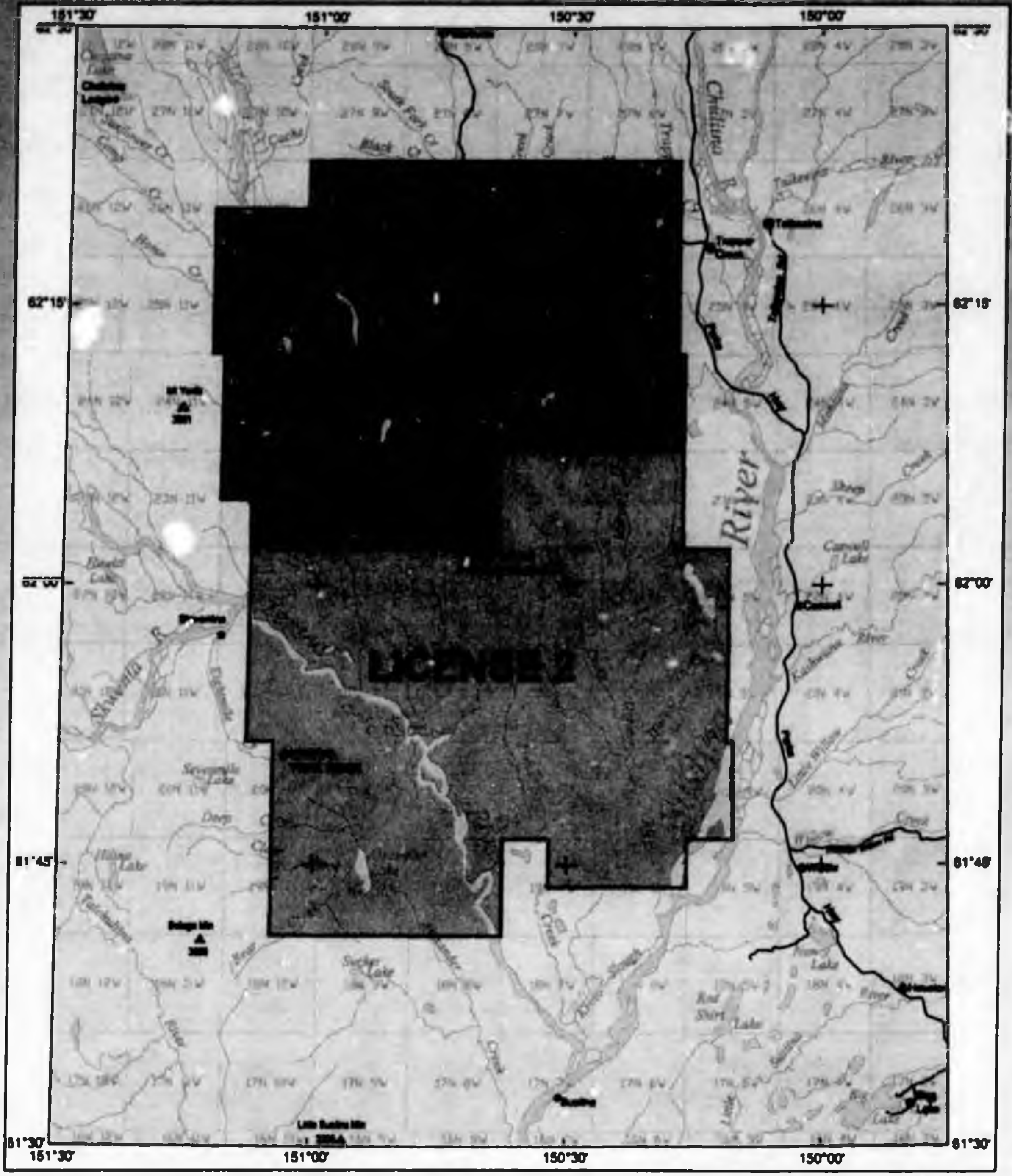
Promoting New Investments

- Leasing / Licensing New Areas
- Data Integration
- DOE Grant
- Governor's meetings with the Independents
- Streamlined Permitting
- Maximizing the Use of Existing Facilities
- Development of New Infrastructure

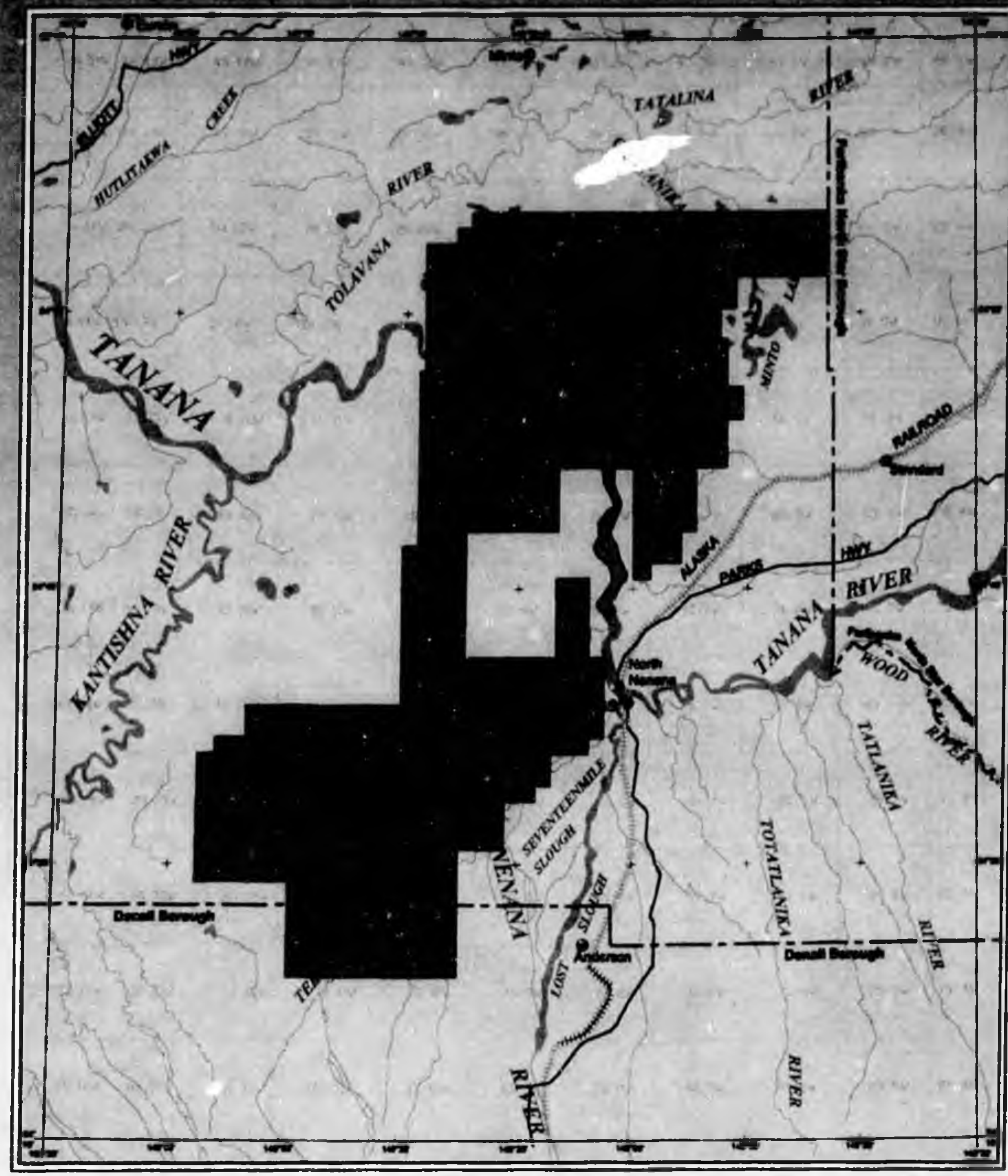
Susitna Basin Exploration License Area

Susitna Basin License 1:
Licensee - Forest Oil Corp.
386,207 Acres
Work Commitment - $2,520,000
Effective Date – 11/1/03
Term – 7 years

Susitna Basin License 2:
Licensee - Forest Oil Corp.
471,474 Acres
Work Commitment - $3,000,000
Effective Date – 11/1/03
Term – 7 years



Nenana Basin Exploration License Area



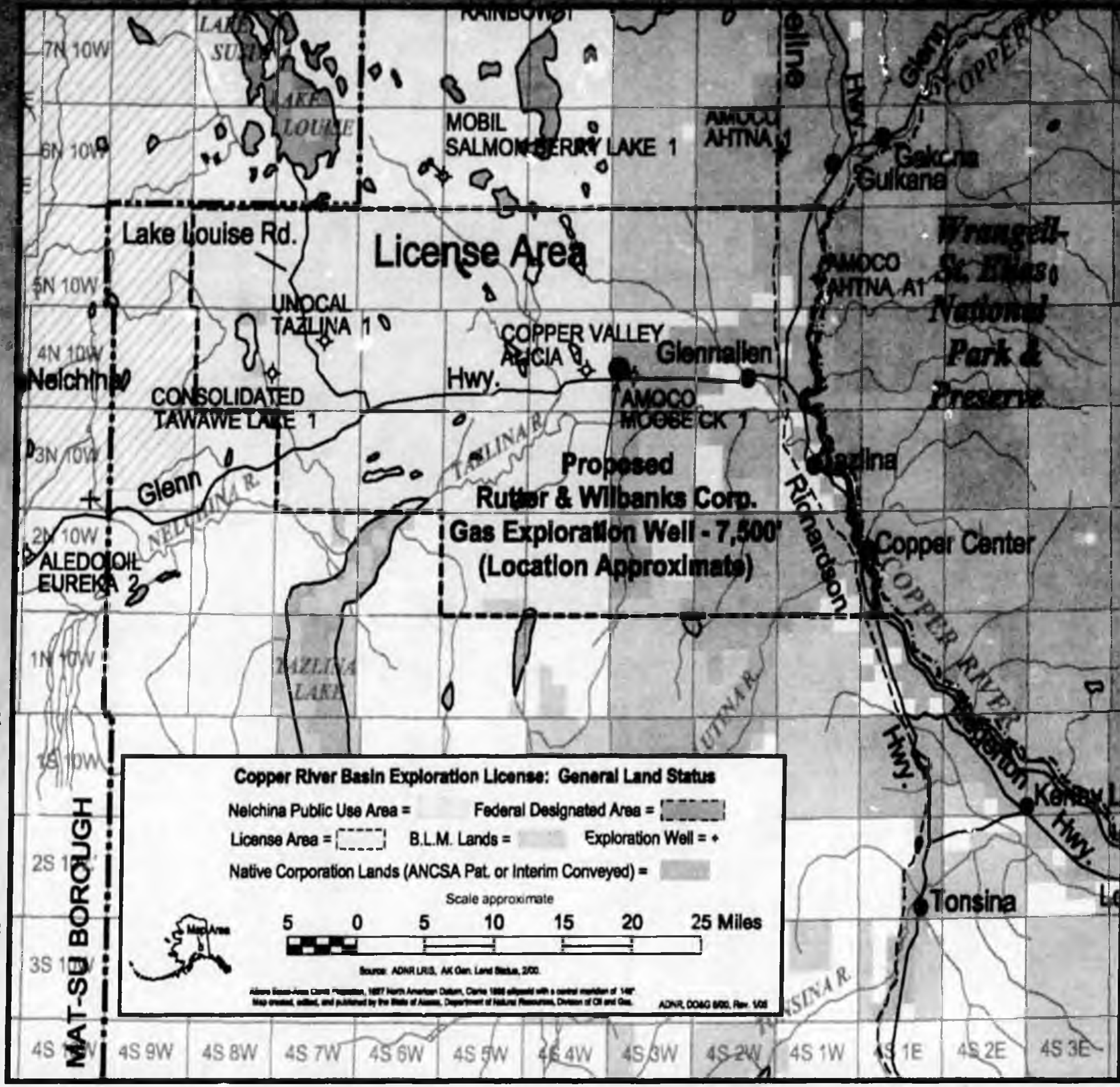
PGS is conducting a 2D seismic survey on behalf of Andex Resources, L.L.C.

- Geophysical exploration permit issued from Dec. 1, 2004 to April 30, 2005.
- Approximately 200 2D line miles proposed.

Copper River Basin Exploration License Area

Proposed Rutter & Wilbanks Corp. Gas Exploration Well

- Plans to drill in February 2005 to 7500 feet.
- The first gas exploration well in the Copper River basin in more than 20 years.
- The Exploration License expires Oct. 2005. It may be converted to leases at licensee's option.



Well location from Dwight's Alaska Report; Section 19, Twp. 4N, Rge. 3W, Copper River Meridian.

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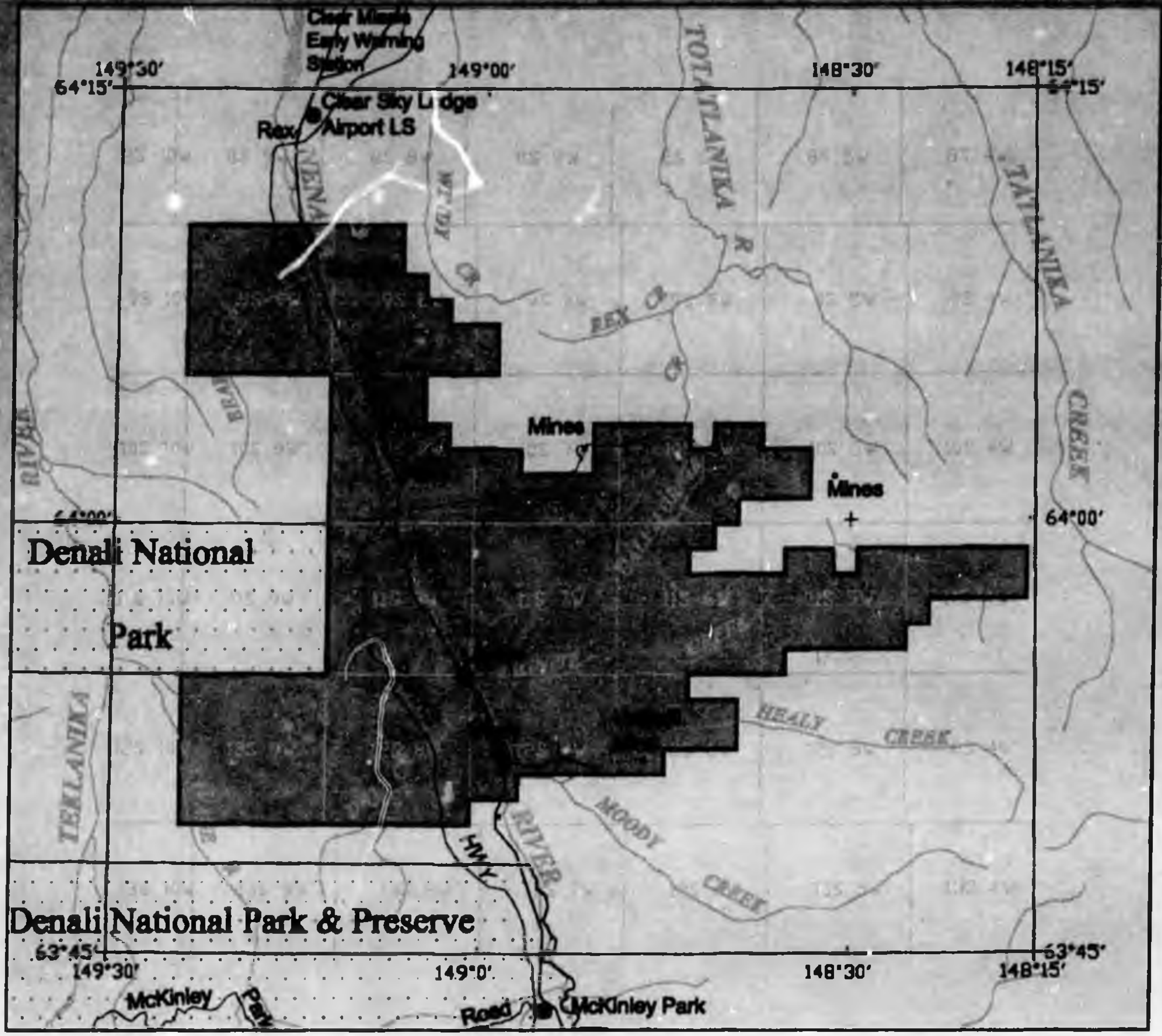
Proposed Healy Basin Exploration License Area

- Usibelli Coal Mine Inc. proposed a work commitment of $500,000 with a 10 year term.
- Solicitation of Competing Proposals ended Dec. 9 (none received).
- Solicitation of Public Comments (Deadline March 11).
- Public Meeting in Healy (Jan. 19).
- Preliminary Best Interest Finding (April 2005).
- Final Best Interest Finding (Summer 2005).



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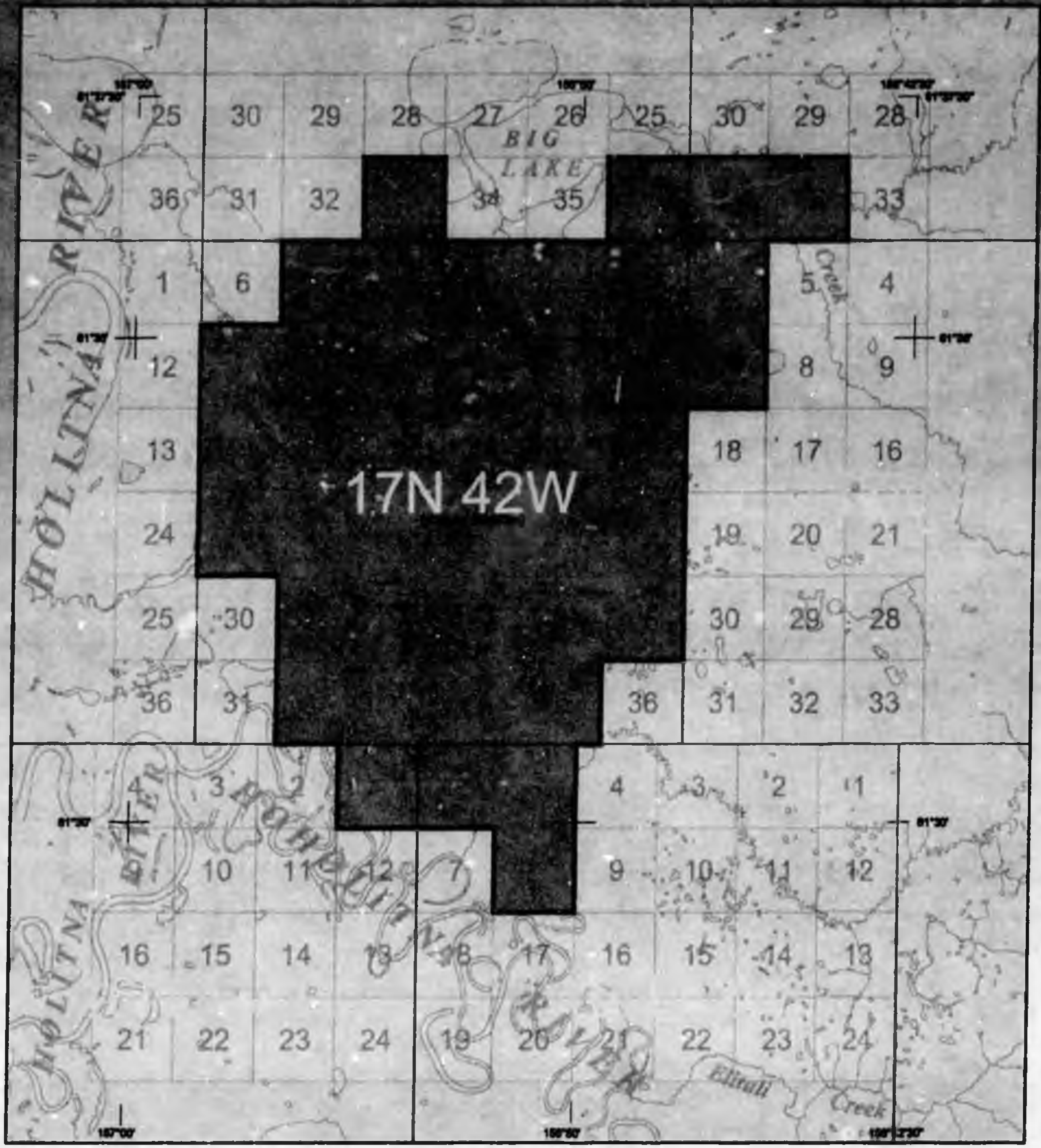
Proposed Holitna Basin Exploration License Area

•Holitna Energy Co. converted from Shallow Natural Gas applications (Under HB 531).

•Solicitation of Public Comments (Ended Dec. 21).

•Preliminary Best Interest Finding (March/April 2005).

•Final Best Interest Finding (Summer 2005).



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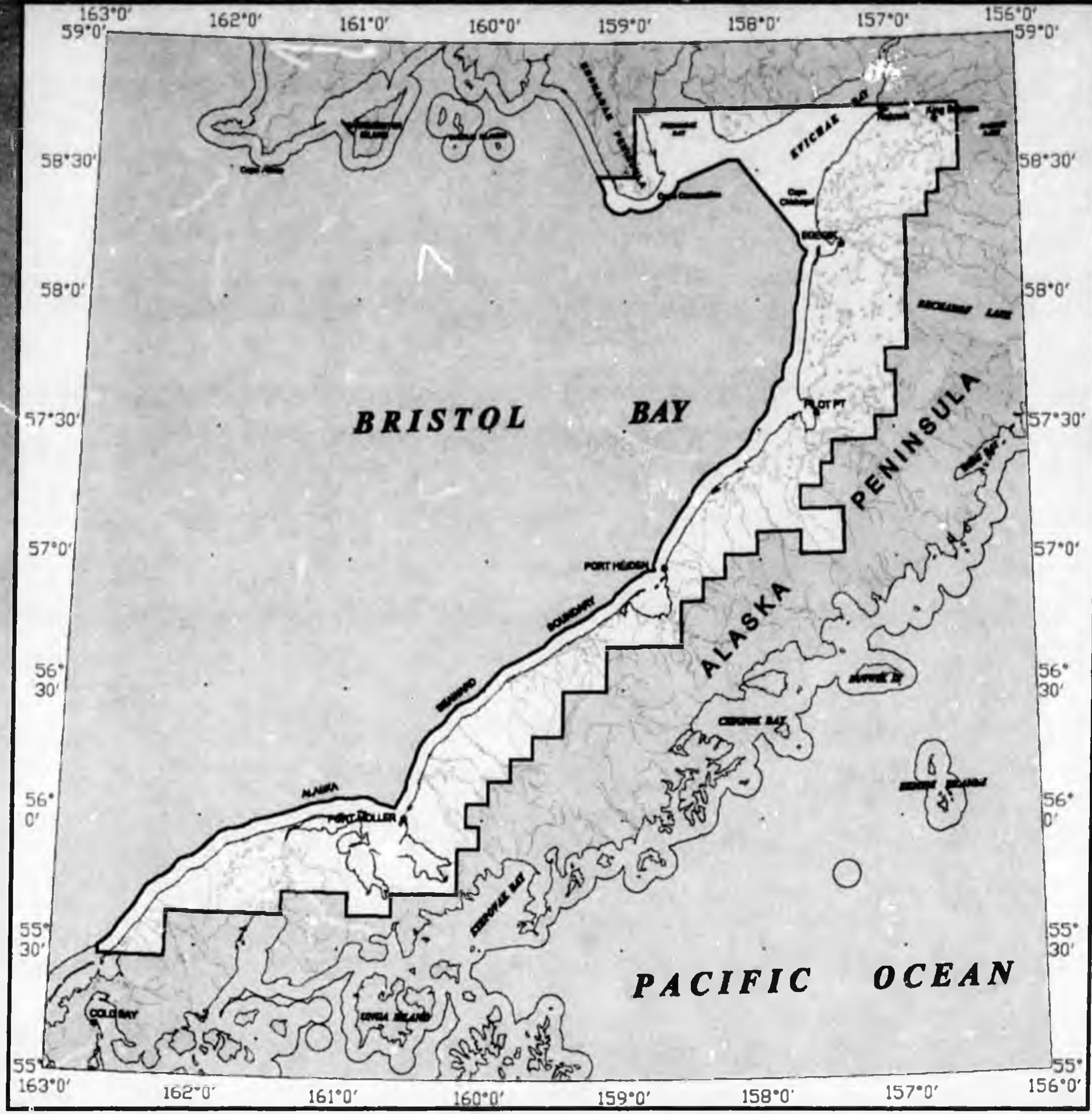
Proposed Alaska Peninsula Areawide Oil and Gas Lease Sale Area



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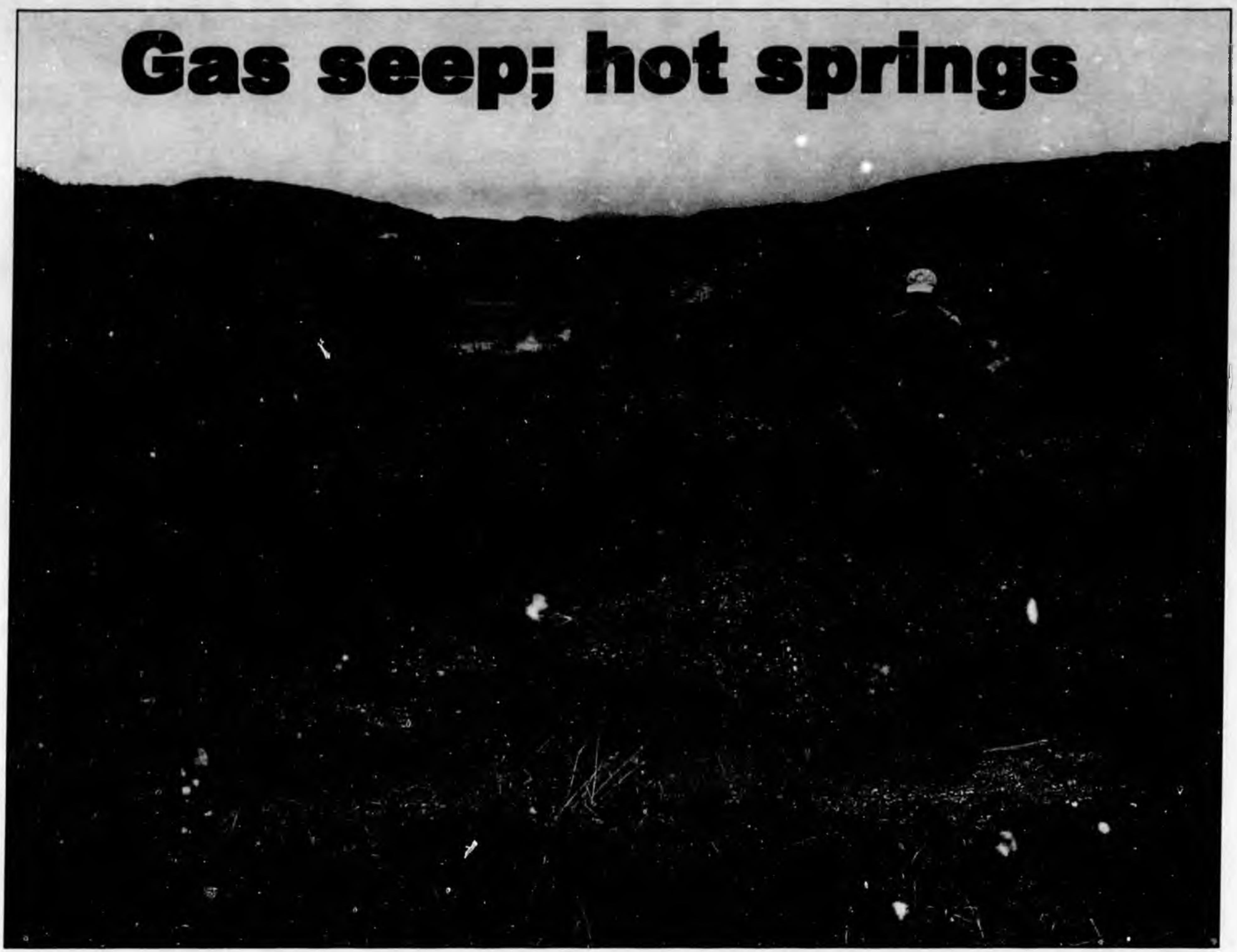
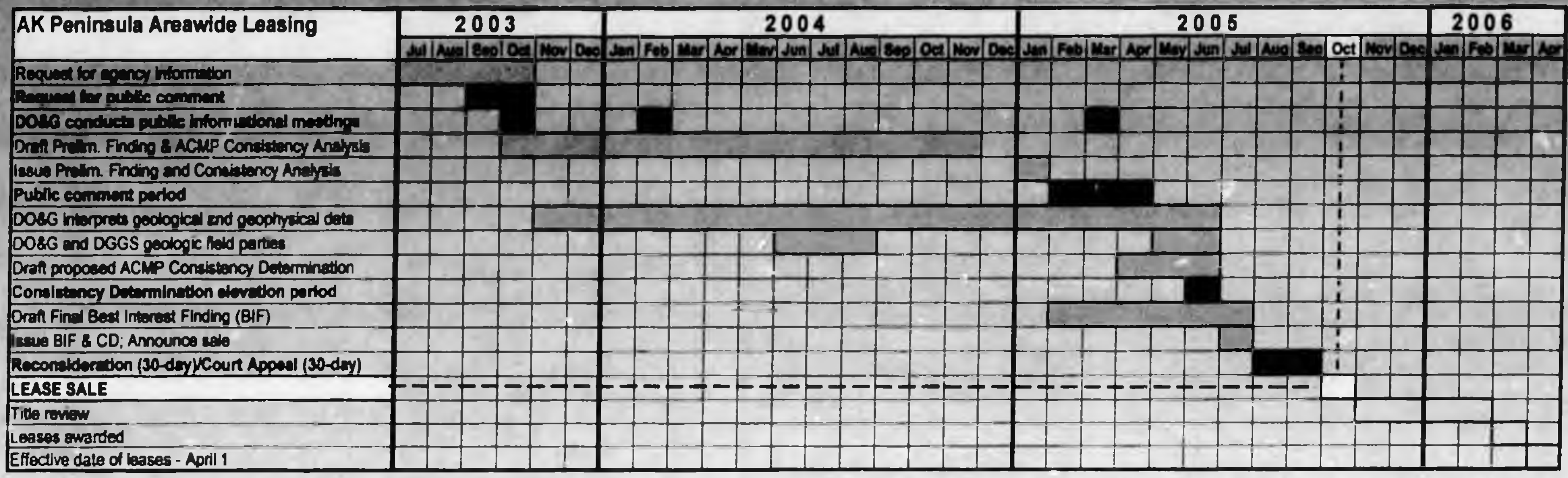
Oil Seeps
along
Oil Creek - Alaska Peninsula

Gas seep; hot springs



Alaska Peninsula Areawide Oil and Gas Lease Sale Timeline



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Promoting New Investments

- Data Integration
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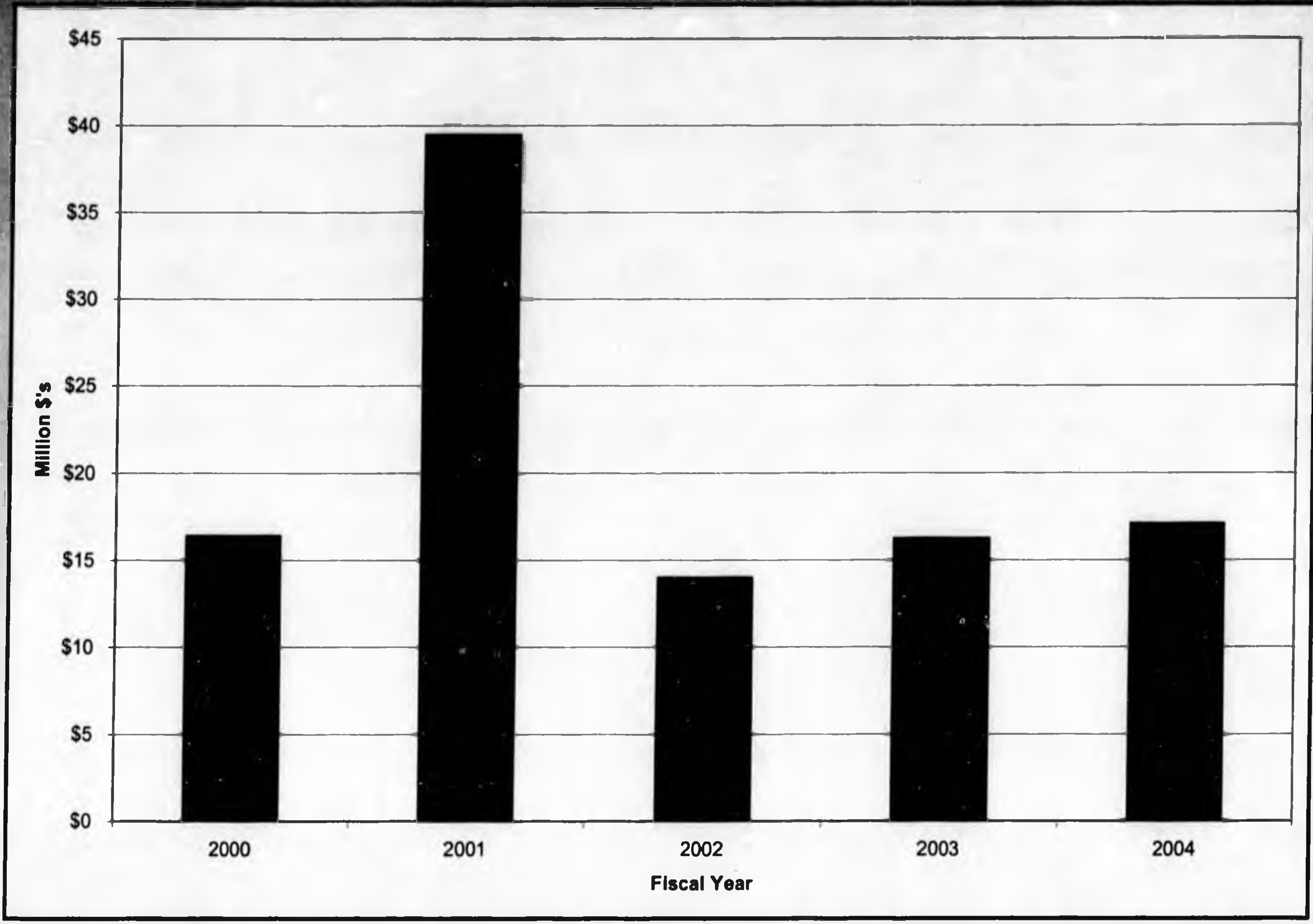
Commercial Issues

- Royalty Settlement Reopeners
- Pipeline Tariffs
- RIK Progress Report
- Audits (next slide)

Audit Section

Royalty Revenue Recovered in Audit



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Coalbed Methane

- HB 531 – Shallow Natural Gas / Coalbed Methane
- Mat-Su Valley Coalbed Methane Enforceable Standards

HB 531 – Shallow Natural Gas / Coalbed Methane

- Repeals existing over-the-counter shallow gas leasing program and replaces it within current exploration licensing and conventional competitive leasing programs.
  - Both these programs require the Department of Natural Resources to do a Best Interest Finding (BIF) prior to leasing. The BIF process includes extensive public noticing and public input and requires the Commissioner to balance interests prior to holding a lease sale or issuing a license.
- Gives the Commissioner the discretion to issue either oil and gas or gas only leases.
- Limits the discretion of DNR to extend the existing shallow gas leases.
- Gives a one-time opportunity for pending lease applicants to apply for a noncompetitive exploration license with a Best Interest Finding and a work commitment.
- On a gas-only-lease allows for the lessee to make a showing to DNR that can result in lower rentals and royalties if the gas doesn't compete with other gas and the lease has only non-conventional gas potential.

HB 531 – Shallow Natural Gas / Coalbed Methane (Cont.)

- Repeals the HB 69 provisions allowing the Commissioner of DNR to override authority over local zoning ordinances.
- Requires the DNR Commissioner to establish setbacks and noise mitigation measures for compressor stations prior to approving coalbed methane operations on any state leases.
- Includes additional ground water protections involving the production of non-conventional gas through requiring the AOGCC to regulate:
  - Hydraulic fracturing
  - Disposal of wastes
  - Reinjection of produced water
  - Prohibiting the production of gas from aquifers that serve as a source of water for human consumption or agricultural purposes unless it can be demonstrated that it will not adversely affect the aquifer.
- Requires the operator design and implement a water well testing program to provide baseline data on water quality and quantity as a condition for approval of an AOGCC permit to drill a coalbed methane well for production or production testing.
- Specifies bonding requirements on gas-only leases.
- DNR, AOGCC, AOGA, Tech Cominco, and Usibelli worked on this bill. HB 531 goes a long way to fixing the issues raised by the public with respect to the shallow natural gas program.

Matanuska-Susitna Valley
Coalbed Methane Enforceable Standards

- **These standards will be implemented by DNR when making decisions related to coalbed methane development in the Mat-Su Borough.**

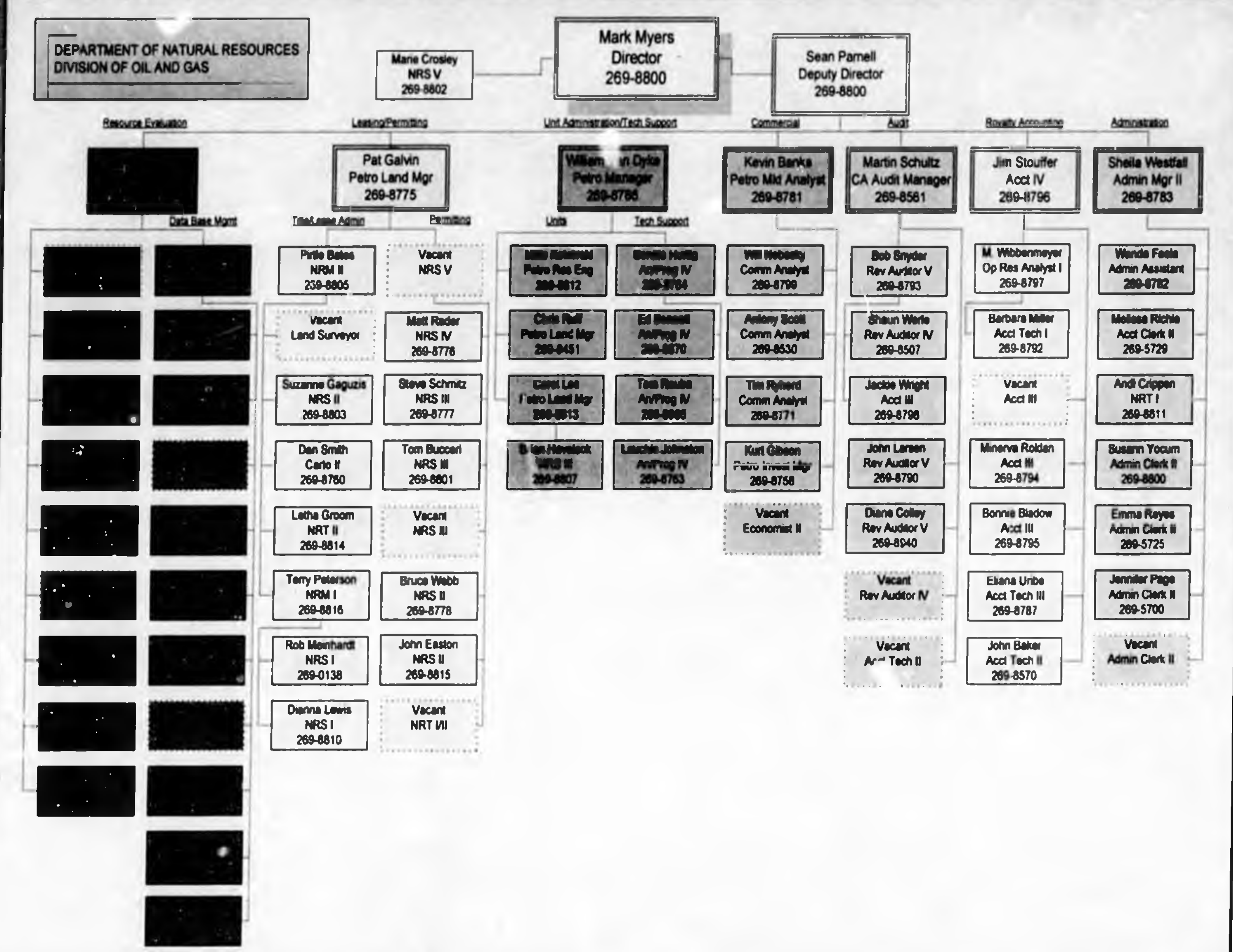
  Types of decisions:
  - Issuing oil and gas leases or licenses.
  - Reviewing proposed plans of operations.
  - Reviewing applications for the formation or alteration of oil and gas units.

- **Public Participation**
  - Public workshops were held in the Mat-Su Borough in January and February 2004.
  - A draft of these standards was released in April 2004 for public review with a 60-day comment period.
  - During the comment period, three public meetings were held in the Mat-Su Borough to review the draft document and take public comment.
  - The public comments were used to develop the final enforceable standards.

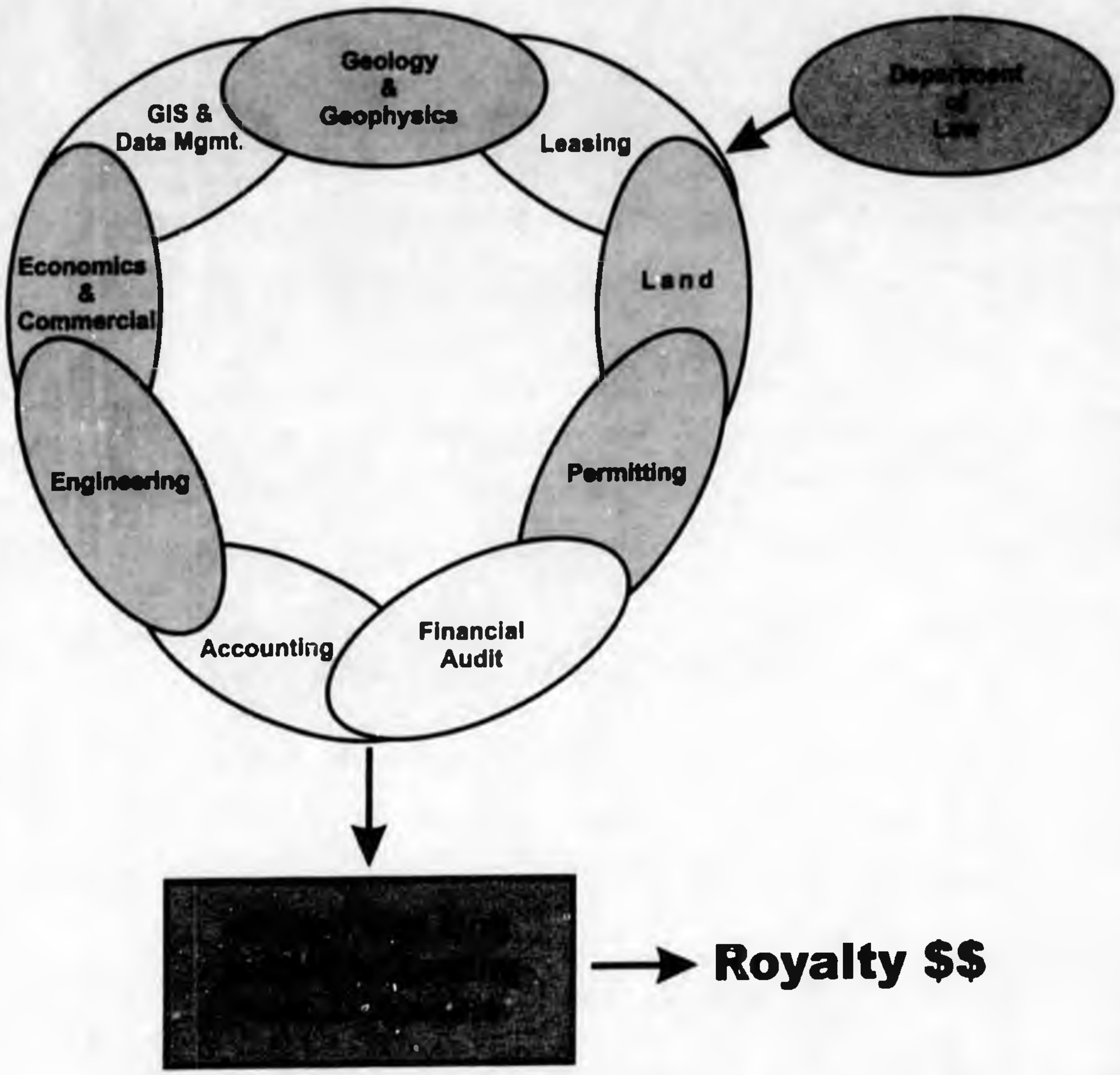
Enforceable Standards

- **Public Notice**
- **Public Information**
- **Setbacks**
- **Surface Impacts**
  - Noise Mitigation
  - Visual Mitigation
  - Light Shielding
  - Solid Waste Storage
  - Erosion Control Plan
  - Permanent Erosion Control
  - Timber Harvesting
- **Split Estate**
- **Water Management**
- **Hydraulic Fracturing**
- **Roads and Pipelines**
- **Public Access**
- **Monitoring**
- **Well Spacing**
- **Geophysical Hazards**
- **Dismantlement, Removal, and Rehabilitation**

Division of Oil and Gas
Organization Chart



Division of Oil & Gas Organization Links Affect the Bottom Line



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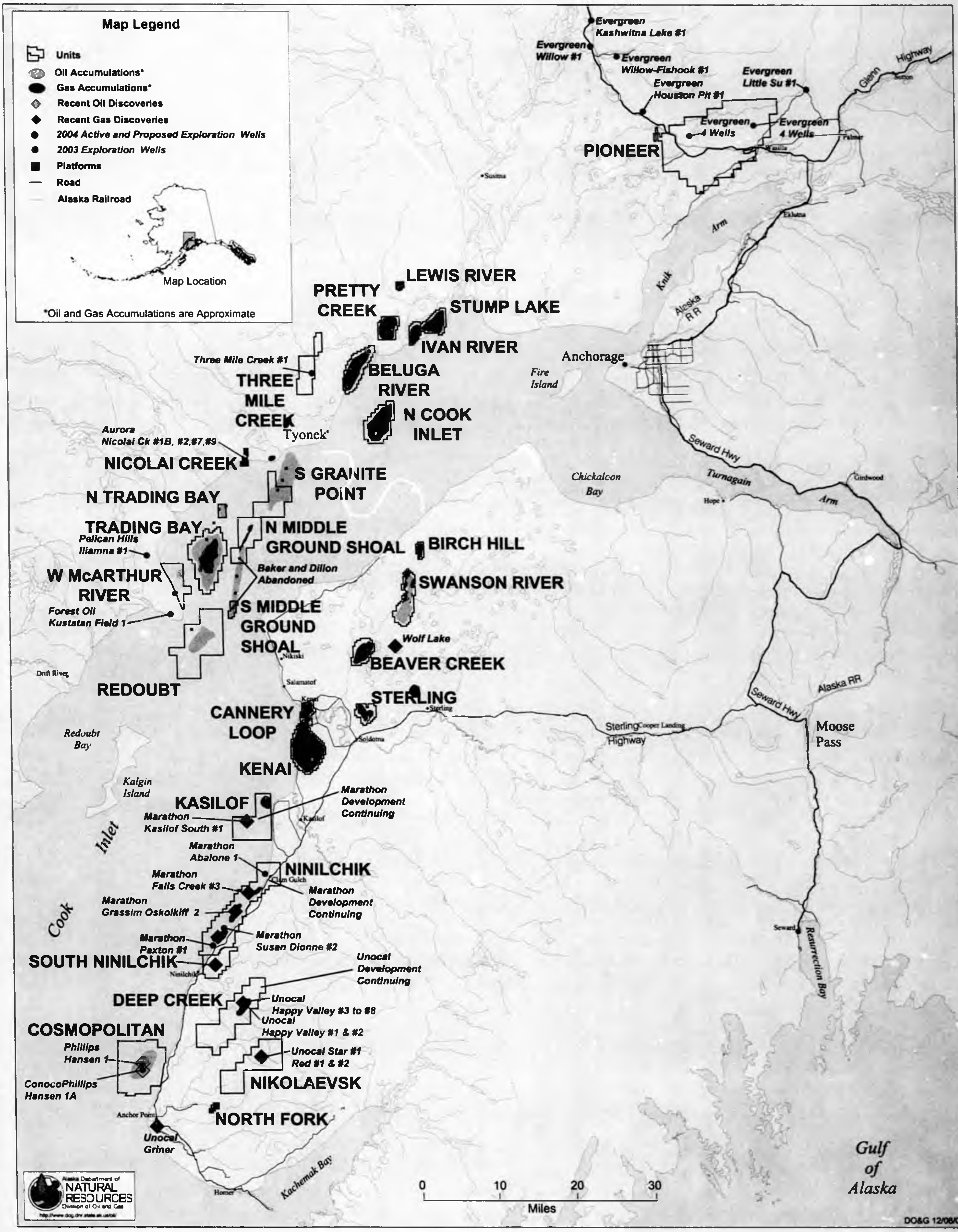
End

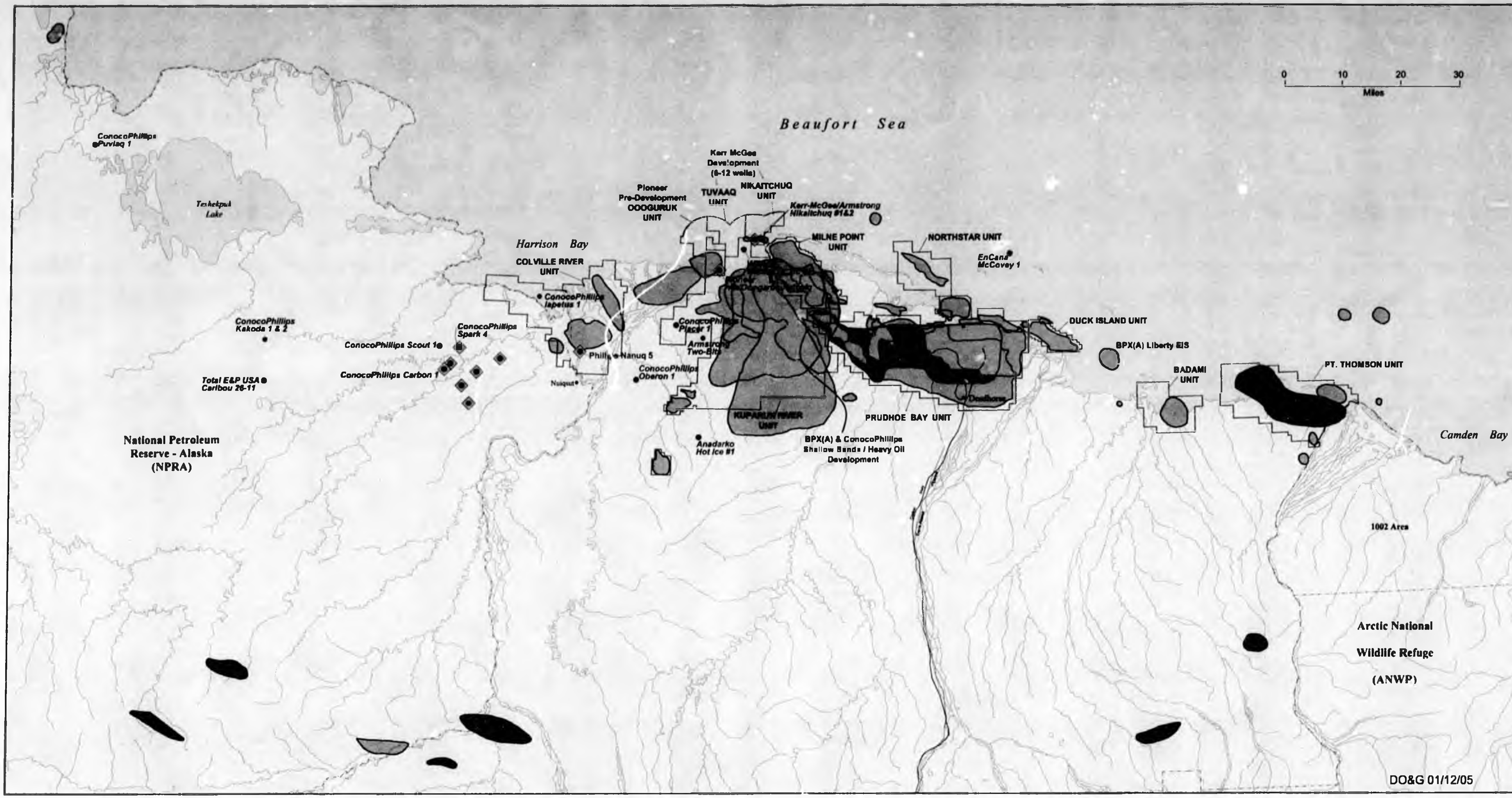
CURRENT INCENTIVES	CONVENTIONAL LEASES	UNLEASED STATE LAND	LICENSED LAND	SNG LEASES	FEDERAL & PRIVATE LAND
Exploration Incentive Credits (EIC)					
AS38.05.180(I)	up to 50% of drilling costs	up to 50% of seismic costs	N/A	up to 50% of drilling costs	N/A
AS41.09.010 -- expires 7-1-2007	N/A	up to 50% of drilling & seismic costs	up to 50% of drilling & seismic costs	N/A	up to 25% of drilling & seismic costs
Exploration Tax Credit					
AS43.55.025 -- expires 7-1-2007 (S 185)	20% of drilling costs or 40% of drilling costs if >25 mi of a unit plus 40% of seismic costs	20% of drilling costs or 40% of drilling costs if >25 mi of a unit plus 40% of seismic costs	20% of drilling costs or 40% of drilling costs if >25 mi of a unit plus 40% of seismic costs	20% of drilling costs or 40% of drilling costs if >25 mi of a unit N/A	20% of drilling costs or 40% of drilling costs if >25 mi of a unit plus 40% of seismic costs
AS43.20.043 -- expires 1-1-2013 **(HB61)** for below 68° latitude*** (see note at bottom)	10% of capital investment 10% of annual cost	10% of capital investment 10% of annual cost	10% of capital investment 10% of annual cost	10% of capital investment 10% of annual cost	10% of capital investment 10% of annual cost
Royalty Reduction					
AS38.05.180(j) (HB28)	as low as 5% if new production as low as 3% if producing or shut-in	N/A	(Applies after conversion to Lease) (Applies after conversion to lease)	as low as 5% if new production as low as 3% if producing or shut-in	N/A
AS38.05.180(f)(5) **(SB185)**	As low as 5% for oil production from CI platforms if production falls below specified levels	N/A	N/A	N/A	N/A
Discovery Royalty					
AS38.05.180(f)(4) for Cook Inlet only	5% royalty for 10 yrs	N/A	(In limited area after conversion: T18N)	(Applies to limited area: T18N)	N/A
for pre-1969 leases only, statewide	5% royalty for 10 yrs	N/A	N/A	N/A	N/A
AS38.05.180(f)(5) for following fields only: Falls Creek, Nicolai Creek, Starichkof, North Fork, Redoubt Shoals, & West Foreland field must be in production by 1-1-2004	5% on 1st 25 MM bbls for 10 yrs 5% on 1st 35 BCF for 10 yrs	N/A	N/A	N/A	N/A
Economic Limit Factor -- AS43.55.013	Yes	N/A	(Applies after conversion to Lease)	Yes	Yes
Contract Gas Price With a Utility vs Royalty Value -- AS38.05.180(aa)	Value of state's royalty share equals gas contract price	N/A	(Applies after conversion to Lease)	Value of state's royalty share equals gas contract price	Value of state's royalty share equals gas contract price
Value of state's royalty gas used for ag products -- AS38.05.180(ee) (HB57)	Negotiated Value	N/A	(Applies after conversion to Lease)	Negotiated Value	Negotiated Value

***** If requesting this credit, not eligible for any other tax credits or royalty modifications**

INCENTIVES AS PART OF A PROGRAM		CONVENTIONAL LEASES	UNLEASED STATE LAND	LICENSED LAND	SNG LEASES	FEDERAL & PRIVATE LAND
Exploration Licensing	AS38.05.132	N/A	N/A	Up to 500,000 acres per license	N/A	N/A
				One-time $1/acre license fee		
				No bonus bid		
				No annual rental		
				sole right to covert to O & G leases		

Cook Inlet Oil & Gas Activity & Discoveries
December 2004





North Slope Oil & Gas Activity & Discoveries

January 2005

Alaska Department of NATURAL RESOURCES
Division of Oil and Gas
http://www.dog.dnr.state.ak.us/oil

Map Legend

- Oil Accumulations*
- Gas Accumulations*
- Recent Discoveries
- *2003 Exploration Wells*
- *2004 Exploration Wells*
- *2005 Exploration Wells & Activities*
- Units
- Road
- Trans-Alaska Pipeline

*Oil and Gas Accumulations are Approximate

Map Location

POINT THOMPSON UNIT, 4/28/06

Senate Resources **April 28, 2006**

Pt. Thomson Unit Agreement Update

Cover Sheet ______________________________ 1 page

1st Denial, September 30, 2005 ______________________ 24 pages

2nd Denial, October 27, 2005 (revised version) ____________ 31 pages

(Note: there is also a denial, titled "Amended Decision" dated 10/27/05)

Total Pages: ______________________________ 56 pages

I. SUMMARY OF DECISION

This is the final Decision of the Alaska Department of Natural Resources, Division of Oil and Gas (the Division) on the Twenty-second Plan of Development (22nd POD) for the Point Thomson Unit (PTU) submitted by the PTU Operator, Exxon Mobil Corporation (Exxon), on August 31, 2005. The Division finds that the PTU Agreement is in default for Exxon's failure to submit an acceptable unit plan of development.

The PTU is underlain by a massive undeveloped gas and gas condensate reservoir that was discovered nearly 30 years ago, but the PTU oil and gas lessees have determined that production of the unitized substances is, in their view, not commercially viable. The 22nd POD proposes additional studies to determine if the PTU lessees can design a commercially viable production project.

The 22nd POD states that PTU development is not possible without modifying the current laws regarding the State's right to taxes and royalties on oil and gas production and on construction of a North Slope gas pipeline. The PTU Operator proposed integrating the lessees' PTU development obligations into negotiations for a fiscal contract with the State and proposed a two year delay of the development commitments made by the lessees in connection with an expansion of the PTU in 2001, both of which would make PTU development uncertain. The current fiscal contract negotiations may or may not lead to construction of a North Slope gas pipeline.

The premise that the PTU can only be developed if a North Slope gas pipeline is built is inappropriate. In addition to dry gas, the unit contains 100s of millions of barrels of hydrocarbon liquids. These hydrocarbon liquids could be produced using mostly existing oil pipelines without construction of a North Slope gas pipeline. Therefore, potential PTU development is not, in fact, limited to dry gas production. In addition, the PTU Agreement, which requires timely exploration, delineation, development, and production of unitized substances, does not guarantee the lessees' commercial success or provide for indefinite extension of the leases.

1. The 22nd POD is disapproved because it does not set out a plan to bring the PTU into commercial production within a reasonable time frame.

2. Exxon has 90 days to cure the defect in the 22nd POD by submitting a unit plan that commits to timely development and production of unitized substances.

3. This decision provides notice under Article 21 of the PTU Agreement that Exxon must initiate development operations within the PTU by October 1, 2007. The Division will contact Exxon to schedule a hearing on this issue, which will be held not less than 30 days from the date of this decision.

4. This decision also provides notice under the individual lease agreements that the PTU leases containing certified wells must commence production in paying quantities by October 1, 2009.

5. In addition, the Division denies Exxon's request for a one-year deferral of the Expansion Agreement commitments. If Exxon does not commence drilling

CORRECTION

THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION

Senate Resources April 28, 2006

Pt. Thomson Unit Agreement Update

(Note: there is also a denial, titled "Amended Decision" dated 10/27/05)

Total Pages: ______________________________ 56 pages

DENIAL OF THE PROPOSED PLANS FOR DEVELOPMENT OF THE

POINT THOMSON UNIT

September 30, 2005

Findings and Decision of the Director, Division of Oil and Gas
Under Delegation of Authority from the
Commissioner, Department of Natural Resources, State Of Alaska

I. SUMMARY OF DECISION

This is the final Decision of the Alaska Department of Natural Resources, Division of Oil and Gas (the Division) on the Twenty-second Plan of Development (22nd POD) for the Point Thomson Unit (PTU) submitted by the PTU Operator, Exxon Mobil Corporation (Exxon), on August 31, 2005. The Division finds that the PTU Agreement is in default for Exxon's failure to submit an acceptable unit plan of development.

The PTU is underlain by a massive undeveloped gas and gas condensate reservoir that was discovered nearly 30 years ago, but the PTU oil and gas lessees have determined that production of the unitized substances is, in their view, not commercially viable. The 22nd POD proposes additional studies to determine if the PTU lessees can design a commercially viable production project.

The 22nd POD states that PTU development is not possible without modifying the current laws regarding the State's right to taxes and royalties on oil and gas production and on construction of a North Slope gas pipeline. The PTU Operator proposed integrating the lessees' PTU development obligations into negotiations for a fiscal contract with the State and proposed a two year delay of the development commitments made by the lessees in connection with an expansion of the PTU in 2001, both of which would make PTU development uncertain. The current fiscal contract negotiations may or may not lead to construction of a North Slope gas pipeline.

The premise that the PTU can only be developed if a North Slope gas pipeline is built is inappropriate. In addition to dry gas, the unit contains 100s of millions of barrels of hydrocarbon liquids. These hydrocarbon liquids could be produced using mostly existing oil pipelines without construction of a North Slope gas pipeline. Therefore, potential PTU development is not, in fact, limited to dry gas production. In addition, the PTU Agreement, which requires timely exploration, delineation, development, and production of unitized substances, does not guarantee the lessees' commercial success or provide for indefinite extension of the leases.

1. The 22nd POD is disapproved because it does not set out a plan to bring the PTU into commercial production within a reasonable time frame.

2. Exxon has 90 days to cure the defect in the 22nd POD by submitting a unit plan that commits to timely development and production of unitized substances.

3. This decision provides notice under Article 21 of the PTU Agreement that Exxon must initiate development operations within the PTU by October 1, 2007. The Division will contact Exxon to schedule a hearing on this issue, which will be held not less than 30 days from the date of this decision.

4. This decision also provides notice under the individual lease agreements that the PTU leases containing certified wells must commence production in paying quantities by October 1, 2009.

5. In addition, the Division denies Exxon's request for a one-year deferral of the Expansion Agreement commitments. If Exxon does not commence drilling

within the PTU by June 15, 2006, the PTU boundary will contract and the contracted leases will no longer be held by unitization.

II. BACKGROUND

The details of the PTU history set out below can be summarized as follows: Some of the PTU leases were issued over 40 years ago and the unit has been in existence for 28 years. The Division certified 7 exploration wells within and around the unit area as capable of producing hydrocarbons in paying quantities, but it has been 20 years since the last well was drilled. The Thomson Sand Reservoir is known to contain at least 8 trillion cubic feet of gas and 200 million barrels of gas condensate and oil. The PTU also contains 100s of millions of barrels of oil in the shallower Brookian reservoirs. The PTU lessees have not yet determined whether they can commercially produce PTU resources, and they have not committed to timely explore, delineate, or develop PTU oil, gas, or gas condensate. The unit operator has consistently proposed that more studies or workshops are needed before putting the PTU into production and, since 1983, has periodically asserted that production cannot begin until a North Slope gas pipeline is built.

The PTU is located on the North Slope of Alaska. The western unit boundary is approximately 3 miles east of the Badami Unit and 30 miles east of the Prudhoe Bay Unit (PBU), and the eastern unit boundary lies west of the western boundary of the Arctic National Wildlife Refuge (ANWR). The southern PTU boundary is onshore, and the northern boundary is offshore in the Beaufort Sea, adjacent to or near the three-mile territorial sea boundary that separates state from federal Outer Continental Shelf (OCS) lands. The PTU consists of 45 state oil and gas leases encompassing approximately 106,200.55 acres. The state owns the entire subsurface estate within the unit area.

Twenty-five lessees hold working interest ownership in the PTU (PTU Owners), and Exxon is the designated Unit Operator. Ownership is calculated based on a lessee's percent of working interest ownership in each lease multiplied by the lease acreage, as a percentage of the total unit acreage. On a surface acreage basis, the Major PTU Owners hold 98.9056% of the PTU: Exxon 52.5779%[1], BP Exploration (Alaska) Inc. (BPXA) 29.1943%, Chevron U.S.A. Inc. (Chevron) 14.3125%, and ConocoPhillips Alaska, Inc. (CPAI) 2.821%. The Minor PTU Owners include twenty entities that hold the remaining 1.0944% interest in the PTU.

The Division approved the PTU Agreement effective August 1, 1977, with a five-year Initial Plan of Exploration. The original unit area included 18 state oil and gas leases comprising approximately 40,768 acres. The PTU Owners drilled 11 wells in and around the unit area between 1978 and 1983, and the Division certified six of those wells as capable of producing hydrocarbons in paying quantities under the regulations[2] and the PTU Agreement[3].

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[1] Exxon Mobil Corporation holds 43.2361% working interest ownership in the PTU and ExxonMobil Oil Corporation holds 9.3418%, jointly referred to as Exxon.

[2] 11 AAC 83.361. Certification of Well Test Results. "For the purposes of 11 AAC 83.301 – 11 AAC 83.395, a well will be considered capable of producing hydrocarbons in paying quantities, as defined in 11 AAC 83.395, when so certified by the commissioner following application by the lessee or unit operator. The commissioner will require the submission of data necessary to make the certification, including all results of the flow test or tests, supporting geological data, and cost data reasonably necessary to show that the production capability of the well satisfies the economic requirements of the paying quantities definition." 11 AAC 83.395. Definitions. "Unless the context clearly requires a different meaning, in 11 AAC 83.301 – 11 AAC 83.395 and in the applicable unit agreements, ... (4) 'paying quantities' means quantities sufficient to yield a return in excess of operating costs, even

On March 26, 1984, the Division approved an application to expand the unit area on condition that the PTU Owners drill a well on one of the two southern expansion leases by March 31, 1985, and a well on one of the ten northern expansion leases by February 1, 1990. The expansion added approximately 94,152 acres within 25 leases to the PTU. The PTU Owners failed to meet both drilling commitments; therefore, the two southern expansion leases and nine northern expansion leases contracted out of the PTU.[4]

In 1998, the Division denied a unit expansion application, which was submitted by Exxon as the owner of the proposed expansion lease, rather than as the PTU Operator; because it was not supported by the other PTU Owners. The Division found that adding a lease to a unit where the owners have demonstrated a lack of cooperation may discourage, rather than encourage, unit development. The Division's denial of Exxon's 1998 PTU expansion application instigated negotiations between the Division and the PTU Owners to redefine the unit boundary. Supporting technical data indicated that the Thomson Sand Reservoir extended beyond the existing unit boundary and that other portions of the unit were not underlain by known hydrocarbons.

On February 2, 2001, Exxon applied to simultaneously expand and contract the PTU boundary. On July 31, 2001, the Division and the PTU Owners entered into an agreement in which the Division approved an expansion of the unit area in return for the PTU Owners' commitment to do certain items of work. This agreement also provided that the expansion leases would contract out of the unit and the PTU Owners would pay the State certain sums of money if the work was not done. This "*Agreement Resolving All Pending Point Thomson Unit Expansion/Contraction Matters and Proceedings*" (Expansion Agreement) identified seven Expansion Areas and one Work Commitment Area (WCA) outside of the preexisting PTU (All together referred to as "Expansion Acreage"). The Expansion Agreement included the following work commitments by the PTU Owners:

1. WCA Drilling Commitment: Drill a well through the Thomson Sand interval within the Work Commitment Area by June 15, 2003, or the WCA acreage would automatically contract out the PTU on that date. Drilling a new well or deepening the Red Dog #1 Well would have fulfilled the WCA Drilling Commitment

2. 2006 Development Drilling Commitment: Commence development drilling in the PTU by June 15, 2006, or all of the Expansion Acreage would automatically contract out of the unit effective that date, and the PTU

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if drilling and equipment costs may never be repaid and the undertaking considered as a whole may ultimately result in a loss; quantities are insufficient to yield a return in excess of operating costs unless those quantities, not considering the costs of transportation and marketing, will produce sufficient revenue to induce a prudent operator to produce those quantities;"

[3] PTU Agreement, Article 9, Drilling to Discovery. "Within 6 months after the effective date hereof, the Unit Operator shall begin to drill an adequate test well at a location approved by the Director, ... and thereafter continue such drilling diligently until the top 100 feet of the Pre-Mississippian formation has been tested or until at a lesser depth unitized substances shall be discovered which can be produced in paying quantities (to wit: quantities sufficient to repay the costs of drilling, and producing operations, with a reasonable profit) ..."

[4] One of the northern expansion leases remained committed to the PTU because a well drilled on that lease in 1982 was certified as capable of producing in paying quantities.

Owners would pay the State $20,000,000 by July 1, 2006, to compensate for the unrealized bonus payments during the period that the Expansion Acreage was withheld from leasing.

3. 2008 Development Drilling Commitment: Complete drilling seven development wells in the PTU by June 15, 2008, or all of the Expansion Acreage would automatically contract out of the unit effective that date, and the PTU Owners would pay the State $27,500,000 by July 1, 2008, to compensate for the unrealized bonus payments during the period that the Expansion Acreage was withheld from leasing.

4. Participating Area Commitment: Allocate production to the Expansion Acreage within a participating area approved by the Division by certain deadlines. The participating area commitment date is June 15, 2008, for Expansion Acreage primarily underlain by the Thomson Sand Reservoir; and June 15, 2010, for Expansion Acreage primarily underlain by a Brookian prospect.

In addition, the Expansion Agreement imposed contraction provisions and charges of up to $27,500,000 if the PTU Owners failed to meet the drilling commitments. The Agreement also increased royalty rates on eight of the twelve expansion leases; from 12.5% to 16.66667% on one lease, and from 16.66667% to 20% on the other seven leases.

The May 24, 2002 Findings and Decision contains the Division's evaluation of the Expansion Agreement, which resulted in the Second Expansion and Third Contraction of the PTU. The Expansion Agreement added approximately 40,353 acres within 12 leases to the PTU, and excluded all or portions of 4 leases, containing approximately 7,572 acres; an overall increase in the unit area of 39 percent. The revised unit area encompassed approximately 116,607 acres within 46 leases.

The PTU Owners based the Expansion Agreement on their assumption that they could engineer and develop a commercially viable gas cycling project. In a gas cycling project natural gas is produced, gas condensates are removed, and the dry gas is re-inject back into the reservoir for later production. The PTU Owners would need to build a pipeline from the PTU to connect with the Badami Unit pipeline to ship the gas condensates through the existing Trans-Alaska oil pipeline for sale. However, the PTU Owners recognized that until they completed a full technical evaluation of the gas cycling project, commercially viability the project was uncertain. Therefore, the Expansion Agreement provided that if PTU Owners found, in their view, the project to be uneconomic by June 15, 2003 (the Contraction Election Deadline), the PTU Owners could elect to contract all of the Expansion Acreage out of the PTU, pay the State $8,000,000 to compensate for the unrealized bonus payments during the period that the acreage was withheld from leasing, and be released from the remaining obligations in the Expansion Agreement.

The Division approved subsequent unit plans that described the PTU Owner's proposed plans for development of a gas cycling project including: facility design, preliminary engineering, updating the PTU geologic model, and initiating the permitting process. However, in the Nineteenth POD, approved effective October 1, 2002, Exxon stated that the PTU Owners could not justify drilling an exploration well in the WCA, the first drilling commitment in the Expansion Agreement, due to their findings that the costs would be higher and the potential accumulation smaller than they had previously anticipated.

On January 29, 2003, the Division found that the geological and geophysical data supported Exxon's proposal to transfer ADL 389728 from the WCA to Expansion Area #1. This amendment of the Expansion Agreement increased the applicable royalty rate for ADL 389728 from 16.66667% to 20% and the PA Extension Charge for Expansion Area #1 from $17,031,000 to $21,289,000.

Under the terms of the Expansion Agreement, the two remaining leases in the WCA contracted out of the PTU and the PTU Owners relinquished their interest in the leases effective January 21, 2003 and the PTU Owners paid the State $940,000 because they failed to fulfill the first drilling commitment.

On April 24, 2003, Exxon requested a two-year extension of the next three deadlines in the Expansion Agreement: the Contraction Election Deadline, the 2006 Development Drilling Commitment, and the 2008 Development Drilling Commitment.

On May 15, 2003, the Division approved a one-month extension of the Contraction Election Deadline, but the Development Drilling Commitments were unchanged. On June 20, 2003, the PTU Owners requested an additional six-month extension of the Contraction Election Deadline. On July 14, 2003, the Division approved the Twentieth POD for the period October 1, 2003 through September 30, 2004, during which time, Exxon planned to acquire the necessary permits and approvals for the gas cycling project while evaluating the Thomson reservoir structure and reserve estimates to move the gas cycling project toward the next phase of funding approval. This decision also extended the Contraction Election Deadline until January 15, 2004 as follows:

a) On or before July 15, 2003, the Working Interest Owners may elect to contract all of the Expansion Acreage out of the PTU, pay the State of Alaska $8,000,000 to compensate for the unrealized bonus payments during the period that the acreage was withheld from leasing (Extension Charge), and be released from the remaining obligations imposed in the Decision. The Extension Charge will be due on August 1, 2003.

b) Notwithstanding the foregoing, the above described deadline for election is hereby extended for a period of six months, until January 15, 2004, in exchange for an increase of the Extension Charge by the sum of $2,000,000, provided that, at any time during such six-month extended period, the PTU Owners may provide notification of their election hereunder, in which event the total Extension Charge of $10,000,000 shall be reduced by an amount equal to 1/12 of $4,000,000 for each full month of such six-month period remaining.

The Division agreed to extend the Contraction Election Deadline on May 15 and again on July 14, 2003, to allow additional time for the PTU Owners to further evaluate their proposed gas cycling project. The PTU Owners presented their current interpretation of the PTU geologic model and updated in-place and recoverable hydrocarbons estimates to the Division on October

16, 2003. Unfortunately, the PTU Owners' assessment of their proposed gas cycling project indicated higher costs and lower liquid recovery than they had previously estimated.

In a letter dated December 18, 2003, Exxon stated that engineering and resource evaluation work confirmed that, in their view, development of the resource at PTU is challenged. The resource evaluation work resulted in a significant reduction in condensate recovery under the PTU Owners' conceptual design for a gas cycling project. In addition, they found that their engineering design, along with permitting and environmental requirements added significant cost to the gas cycling project. After evaluating potential cost reduction measures and alternate development plans, Exxon concluded "that a standalone project prior to gas sales is not economically viable under the current fiscal system." Exxon's letter went on to request a further extension of the Contraction Election Deadline, until June 15, 2006. The Division's denial of Exxon's requested extensions provides in part:

> "Over the past year, the Owners reviewed the geologic model, recalculated the recoverable liquid hydrocarbons, refined the engineering design to better estimate the cost of development, began evaluating the environmental impacts through the federal permitting process, and considered alternate development scenarios. Through these activities, the Owners determined that the gas cycling project is currently uneconomic and suspended the permitting process indefinitely. Representatives from ExxonMobil met with division staff on December 2, 2003, to discuss possible revisions to the State's current fiscal system that might make the gas cycling project commercially viable. However, the Owners have not made any specific proposals that would warrant a further extension of the Contraction Election Deadline.
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> Without a commercially viable project, the Owners may surrender the expansion acreage, pay the $10 million Extension charge, and be released from the remaining obligations in the Decision. If the Owners do not exercise this option, they must begin development drilling in the PTU by June 15, 2006, or all of the Expansion Acreage will automatically contract out of the PTU and the Owners will pay $20 million to the State of Alaska. We trust that the Owners will continue to evaluate options to economically produce the known hydrocarbon resources underlying the PTU, and look forward to reviewing the proposed PTU Twenty-First Plan of Development in July 2004."

Although the PTU Owners found the gas cycling project to be uneconomic, they did not exercise their option to contract the Expansion Acreage out of the PTU prior to the January 15, 2004 Contraction Election Deadline.

The Twenty-first POD, dated August 31, 2004, stated that the PTU Owners were unable to identify a viable gas cycling project under the current fiscal terms and they planned to focus on gas sales rather than gas cycling. The Twenty-first POD included a proposal to share with the Division the results of the PTU studies including reserve estimates, distributions, and mapping for the Thomson Sand Reservoir as well as the Brookian and Pre-Mississippian reservoirs within the unit area and provide financial and technical information so the Division could conduct an independent economic evaluation of the PTU Owners' gas cycling project. But the WIOs would only provide this information if the Division executed an extraordinary confidentiality agreement.

North Slope producers Exxon, BPXA, and CPAI (Sponsor Group), three of the Major PTU Owners, submitted an application to the State under the Stranded Gas Development Act (SGDA), which proposed a fiscal contract that may or may not lead to construction of a major North Slope gas pipeline. The Sponsor Group does not officially represent the PTU, the PBU or any other unitized area on the North Slope. During the Twenty-first POD, the PTU Owners planned to evaluate the technical and commercial issues necessary for the PTU Owners to participate in a future open season for major gas sales from the North Slope.

On September 23, 2004, the Division approved the Twenty-first POD, on condition that Exxon provide the Division with existing technical information, costs, and other fiscal assumptions necessary for the Division to conduct an economic analysis of the PTU Owners' gas cycling project. The Division reminded Exxon of the statutory and regulatory confidentiality protections accorded sensitive information, and notified Exxon that the Division would not execute the proposed confidentiality agreement. The Division requested that Exxon provide copies of all of the requested data no later than November 15, 2004. In addition, the Division's approval of the Twenty-first POD required that the 22nd POD contain specific plans to fulfill the 2006 drilling commitment set forth in the Expansion Agreement.

Exxon appealed the Division's decision on the Twenty-first POD to the Commissioner of the Department of Natural Resources (the Commissioner). But on November 15, 2004, Exxon hand delivered a set of technical data to the Division. The Commissioner affirmed the Division's Twenty-first POD decision on November 24, 2004.

On June 21, 2005, Exxon proposed amending the Expansion Agreement such that the Expansion Acreage leases would remain within the PTU while the State and Sponsor Group continue negotiations over a fiscal contract and for the duration of any resulting fiscal contract. On July 1, 2005, the Division received Exxon's proposed 22nd POD, which included an update on activities during the term of the Twenty-first POD and planned activities during the one-year term of the 22nd POD. Exxon reported that the PTU Owners had incorporated the results of the prior geologic model, updated reservoir simulation, facility design, and cost estimates into a conceptual depletion plan for the PTU gas sales project. Under that plan, the PTU Owners would produce PTU gas and send it to the PBU for further processing before shipping it via a North Slope gas pipeline for sale, but did not specify a time-frame for development.

The 22nd POD did not commit to timely development or production of unitized substances. Instead, it proposed further development of the gas sales conceptual depletion plan so the PTU Owners would be prepared to participate in some future open season for nominations to a North Slope gas pipeline. The 22nd POD provides that the exact timing of the open season will be dependent, in part, upon the successful completion of a fiscal contract under the SGDA. During the term of the 22nd POD, the PTU Owners planned to monitor the progress of the negotiations under the SGDA and adjust the PTU work schedule as necessary to participate in an open season. The 22nd POD included the items of work summarized as follows:

1. Incorporate geologic modeling of the Thomson Sand aquifer uncertainty and the Pre-Mississippian bedded facies in the reservoir simulation model to form the basis of a major gas sales depletion plan.

2. Initiate more detailed facility design or Conceptual Engineering.

3. Determine optimum drillsite and well locations and update drilling and completion plan costs to estimate total project costs and timing.

4. Share the results of the above tasks with the Division.

5. Begin planning the permitting process for the PTU gas sales project.

6. Continue working to obtain all PTU Owners' approval of a new PTU Operating Agreement.

7. Assist the Division with its independent assessment of the commercial viability of the gas cycling project.

The Division's July 27, 2005 response indicated that it would not accept Exxon's proposal to amend the Expansion Agreement by tying it to the SGDA negotiations or relieve the PTU Owners of the work commitments they made in return for including the Expansion Acreage in the PTU. However, the Division indicated that it would be willing to extend the 2006 and 2008 Development Drilling Commitments, if the PTU Owners agreed to drill an exploration/delineation well, in lieu of a development well, by June 15, 2006 that could provide pertinent information pertaining to appropriate development of the western portion of the Thomson Sand Reservoir. The Division gave Exxon ten days to submit an acceptable plan, which should include the following items:

1. ExxonMobil shall drill an exploration/delineation well within the PTU by June 15, 2006.

2. The well must be drilled to the Mississippian basement and located to
   a. delineate the Thomson Reservoir west of the PTU #1 well,
   b. evaluate connectivity and continuity within the Thomson Reservoir, and
   c. evaluate the extent of and the hydrocarbon properties within the oil rim.

3. ExxonMobil shall apply to the Alaska Oil and Gas Conservation Commission for Pool Rules and a depletion plan for the Thomson Reservoir.

4. ExxonMobil shall prepare a schedule of activities to obtain the necessary permits for construction of the PTU facilities and pipelines.

5. ExxonMobil shall compare core samples from the Badami wells with the appropriate PTU wells to evaluate the Brookian reservoirs within the PTU.

Division staff discussed the requested modifications to the 22nd POD with the PTU Owners on July 27, 2005, and on August 1, Exxon indicated that they would respond to the Division by the end of the month.

On August 31, 2005, Exxon submitted a revised 22nd POD and a letter requesting a one-year deferral of both the 2006 and 2008 Development Drilling Commitments, rather than an indefinite extension under the SGDA. The 22nd POD stated that the PTU Owners could not justify drilling an exploration well, but Exxon offered to hold a workshop with Division staff to evaluate whether drilling exploration/delineation wells could provide valuable information that would reduce the uncertainty associated with the western portion of the Thomson Sand Reservoir. Other than a commitment to drill an exploration/delineation well by June 15, 2006, the revised 22nd POD included the other modifications that the Division had requested. However, without a commitment to drill an exploration/delineation well within the PTU while requesting deferral of the Development Drilling Commitments and tying development activities in the 22nd POD to the SGDA, the PTU Owners' plans for development of the PTU are unacceptable.

III. STATE STATUTES, REGULATIONS, AND PTU AGREEMENT PROVISIONS RELEVANT TO EVALUATION OF THE PTU OWNERS' PLANS FOR DEVELOPMENT OF THE PTU

The standards and criteria for approval of unit plans are set out in the State statute and regulations, and the applicable unit agreement.

A. State Statute and Regulations

The Commissioner, or his designee, may approve a unit plan if he determines it is necessary or advisable in the public interest.[5] The following statutes and regulations govern approval of unit plans:

AS 38.05.180(p) provides, in part:

> To conserve the natural resources of all or part of an oil or gas pool, field, or like area, the lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or unit plan of development or operation of the pool, field, or like area, or part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest. . . . The commissioner may require oil and gas leases issued under this section to contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and may prescribe a plan under which the lessee must operate. The plan must adequately protect all parties in interest, including the state. "

AS 38.05.180 (q) provides, in part,

> A plan authorized by (p) of this section, which includes land owned by the state, may contain a provision vesting the commissioner, or a person, committee, or

[5] By memorandum dated September 30, 1999, the Commissioner approved a revision of Department Order 003 that delegated this authority to the Director of the Division of Oil and Gas.

state agency, with authority to modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan.

Under State regulation 11 AAC 83.303(a), the Director will approve a unit plan of development upon finding that it will: 1) promote the conservation of all natural resources; 2) promote the prevention of economic and physical waste; and 3) provide for the protection of all parties of interest, including the State. Subsection .303(b) sets out six factors that the Director will consider in evaluating a proposed unit plan.

11 AAC 83.343, Unit Plan of Development, provides as follows:

> (a) A unit plan of development must be filed for approval as an exhibit to the unit agreement if a participating area is proposed for the unit area under 11 AAC 83.351, or when a reservoir has become sufficiently delineated so that a prudent operator would initiate development activities in that reservoir. All development operations must be conducted under an approved plan of development. A unit plan of development must contain sufficient information for the commissioner to determine whether the plan is consistent with the provisions of 11 AAC 83.303. The plan must include a description of the proposed development activities based on data reasonably available at the time the plan is submitted for approval as well as plans for the exploration or delineation of any land in the unit not included in a participating area. The plan must include, to the extent available information exists:
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> > (1) long-range proposed development activities for the unit, including plans to delineate all underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established;
> > (2) plans for the exploration or delineation of any land in the unit not included in a participating area;
> > (3) details of the proposed operations for at least one year following submission of the plan; and
> > (4) the surface location of proposed facilities, drill pads, roads, docks, causeways, material sites, base camps, waste disposal sites, water supplies, airstrips, and any other operation or facility necessary for unit operations.
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> (b) The commissioner will approve the unit plan of development if it complies with the provision of 11 AAC 833.303. If the proposed unit plan of development is disapproved, the commissioner will, in his discretion, propose modifications which, if accepted by the unit operator, would qualify the plan for approval.
> (c) The unit plan of development must be updated and submitted to the commissioner for approval at least 90 days before the expiration date of the previously approved plan, as set out in that plan. The update must describe the extent to which the requirements of the previously approved pan were achieved; if actual operations deviated from or did not comply with the previously approved pan, an explanation of the deviation or noncompliance must be included in the update. ... After the commissioner has determined that an updated unit plan of

development is complete as submitted, or as modified by the unit operator following the commissioner's suggestions, the commissioner will have an additional 60 days in which to approve or disapprove the plan; if no action is taken by the commissioner, the update of the unit plan of development is approved.

(d) The unit operator shall submit an annual report to the commissioner describing the operatons conducted under the unit plan of development during the preceding year.
(e) The unit operator may, with the approval of the commissioner, amend an approved pan of development.

B. The PTU Agreement Provisions

The following PTU Agreement provisions are relevant to the Division's evaluation of the PTU Owners' plans for development of the PTU.

Article 10, Plan of Further Development and Operation, provides as follows:

> Within six months after completion of a well capable of producing unitized substances in paying quantities, the Unit Operator shall submit for the approval of the Director an acceptable plan of development and operation for the unitized land which, when approved by the Director, shall constitute the further drilling and operating obligations of the Unit Operator under this agreement for the period specified therein. Thereafter, from time to time before the expiration of any existing plan, the Unit Operator shall submit for the approval of the Director a plan for an additional specified period for the development and operation of the unitized land. The Unit Operator expressly covenants to develop the unit area as a reasonably prudent operator in a reasonably prudent manner.
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> Any plan submitted pursuant to this section shall provide for the exploration of the unitized area and for the diligent drilling necessary for determination of the area or areas thereof capable of producing unitized substances in paying quantities in each and every productive formation and shall be as complete and adequate as the Director may determine to be necessary for timely development and proper conservation of oil and gas resources of the unitized area, and shall:
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> (a) specify the number and location of any wells to be drilled and the proposed order and time for such drilling; and,
> (b) to the extent practicable, specify the operating practices regarded as necessary and advisable for the proper conservation of natural resources.
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> Separate plans may be submitted for separate productive zones, subject to the approval of the Director.
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> Said plan or plans shall be modified or supplemented when necessary to meet changed conditions, or to protect the interests of all parties to this agreement. Reasonable diligence shall be exercised in complying with the obligations of the approved plan of development. ...

Article 16, Conservation, states:

> Operations hereunder and production of unitized substances shall be conducted to provide for the most economical and efficient recovery of said substances without waste, as defined by or pursuant to state law or regulation.

Article 20, Effective Date and Term, provides in part:

> This agreement shall become effective upon approval by the Commissioner or his duly authorized representative as of the date of approval by the Commissioner and shall terminate five (5) years from said effective date unless:
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> (a) such date of expiration is extended by the Commissioner, or
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> (b) it is reasonably determined … that the unitized land is incapable of production of unitized substances in paying quantities … or
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> (c) a valuable discovery of unitized substances has been made or accepted on unitized land during the said initial term or any extension thereof, in which event the agreement shall remain in effect for such term and so long as unitized substances can be produced in quantities sufficient to pay for the cost of producing same from wells on unitized land and, should production cease, so long thereafter as diligent operations are in progress for the restoration of production or discovery of new production and so long thereafter as the unitized substances so discovered can be produces as aforesaid, or
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> (d) it is terminated as heretofore provided in this agreement. …

Article 21, Rate of Prospecting, Development and Production, provides in part:

> … the Director is also hereby vested with authority to alter or modify from time to time at his discretion the rate of prospecting and development and the quantity and rate of production under this agreement when such alteration or modification is in the interest of attaining the conservation objectives stated in this agreement and is not in violation of any applicable state law.
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> Powers in this section vested in the Director shall only be exercised after notice to Unit Operator and opportunity for hearing to be held not less than thirty (30) days from notice, and shall not be exercised in a manner that would (i) require any increase in the rate of prospecting, development or production in excess of that required under good and diligent oil and gas engineering and production practices; or (ii) alter or modify the rates of production from the rates provided in the approved plan of development and operations then in effect …; or (iii) prevent this agreement from serving its purpose of adequately protecting all parties in interest hereunder, subject to applicable conservation laws and regulations.

IV. ANALYSIS OF THE PTU OWNERS' PLANS FOR DEVELOPMENT OF THE PTU

A discussion of the subsection 11 AAC 83.303(b) criteria, as they apply to the PTU Owners' plans for development of the PTU, is set out directly below, followed by the Director's findings relevant to the subsection .303(a) criteria; and the Director's decision.

1. Prior Exploration Activities and Geological and Engineering Characteristics of the PTU

The Thomson Sand Reservoir is the primary reservoir in the PTU, consisting of the Lower Cretaceous Thomson Sand interval trending generally west-northwest across the unit, and between approximately –12,780' and –13,128' tvdss[6] in the Point Thomson Unit #1 discovery well (PTU1) drilled by Exxon in 1977. Exxon estimates that the Thomson Sand Reservoir contains approximately 8 trillion cubic feet (TCF) of gas and over 200 million barrels (MMB) of recoverable gas condensate with a discontinuous heavy-oil rim. The reservoir pressure is extremely high, around 13,000 pounds per square inch (psi). Other potentially productive reservoirs present in the PTU include Brookian Lower Tertiary turbidite sands and what are informally referred to as the "Pre-Mississippian" carbonates. Although the Sourdough well data remain confidential, in 2001 BPXA disclosed that the wells encountered recoverable reserves of approximately 200 MMB in the Brookian section. All three reservoirs are, or may be, over-pressured throughout much of the PTU.

A subsurface ridge-like structural feature constrains the northern edge of the Thomson Sand accumulation. While Thomson Sand presence, hydrocarbon charge, and thickness are uncertain on the north flank of the feature, it is possible that the Thomson Sand Reservoir is present north of the feature within Expansion Area #6.

Eighteen exploration wells have been drilled within and around the PTU. At the request of the Unit Operator, the Division certified seven PTU wells as capable of producing hydrocarbons in paying quantities and granted five wells extended confidentiality[7]. The public PTU well data is summarized in Attachment 1 to this decision.

The available well data allows the Thomson Sand Reservoir to be described as very fine-grained sand along the southern margin of the unit coarsening northward to a conglomeratic facies and exhibiting an average porosity of about 16%. Permeability within the reservoir varies from 10 millidarcies (md) to more than 1,000 md.

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[6] Total vertical depth subsurface (below sea level).

7 20 AAC 25.537. Public and Confidential Well Information. "(d) Except as provided by (a) of this section, the reports and information required by this chapter to be filed by the operator will be kept confidential by the commission for 24 months following the 30-day filing period after well completion, suspension, or abandonment unless the operator gives written and unrestricted permission to release all of the reports and information at an earlier date. Upon notification that the commissioner of the Department of Natural Resources has made a finding that the required reports and information from a well contain significant information relating to the valuation of unleased land in the same vicinity, the commission will hold the reports and information confidential beyond the 24-month peiior and until notified by the commissioner of the Department of Natural Resources to release the reports and information."

The PTU Owners also acquired extensive seismic data over the unit. They merged and began prestack depth migration processing of four 3D seismic surveys, which cover essentially the entire unit area: the Point Thomson Unit, Flaxman Lagoon, Island Corridor West, and Challenge Island surveys. Merging the seismic data sets produced a more unified interpretation of the extent of the Thomson Sand Reservoir over the greater unit area. The well and geophysical data indicate that much of the PTU is underlain or is potentially underlain by oil, natural gas and gas condensate deposits in the Thomson Sand Reservoir, and by Brookian oil deposits. There also appears to be a thin and potentially discontinuous oil leg at the bottom of the Thomson Sand Reservoir. The PTU owners incorporated the well and seismic data into a common database, which is the basis for the PTU Owners' Thomson Sand Geologic and Reservoir Simulation Models.

The Sixteenth POD, submitted by Exxon on July 30, 1999, included a commitment to conform the unit boundary to consensus maps of the potential reservoirs. During the term of the Sixteenth POD, the PTU Owners developed consensus structure and isochore maps of the Thomson Sand Reservoir and five potential Brookian accumulations; and initiated unit expansion discussions with adjacent leaseholders. On July 31, 2001, the Division and the PTU Owners executed the Expansion Agreement, which restructured the unit boundary in exchange for the PTU Owners' exploration and development commitments.

The Eighteenth POD, approved effective October 1, 2001, included activities toward fulfilling the Expansion Agreement, including selecting a location and contracting for a rig to drill an exploration/delineation well in the WCA. During the term of the Eighteenth POD, the PTU Owners completed prestack depth migration of the combined PTU 3D data set (Point Thomson Unit, Challenge Island, Island Corridor West and Flaxman Lagoon) over the redefined unit area. Exxon continued to pursue facility design, engineering and geological studies, and environmental analysis toward development of the Thomson Sand Reservoir, and initiated the federal permitting process for a gas cycling project, which moved from conceptual engineering to front-end engineering and facility design during the Eighteenth POD.

In the Nineteenth POD, dated August 8, 2002, Exxon notified the Division that the PTU Owners would not drill an exploration well prior to the WCA Drilling Commitment deadline of June 15, 2003. The State and Exxon executed a Memorandum of Understanding to facilitate the State permitting process for the gas cycling project and Exxon proceeded with engineering design of the surface facilities during the term of the Nineteenth POD. On June 24, 2003, the PTU Owners presented their updated stratigraphic and structural interpretation of the Thomson Sand Reservoir, based on the merged PTU seismic data, to Division staff.

During the term of Twentieth POD, October 1, 2003 through September 30, 2004, the PTU Owners completed a number of technical studies to evaluate Thomson Reservoir quality, fault seal, and structural framework; which, to the PTU Owners, indicated a chance of greater compartmentalization and a higher risk of sand production. The PTU Owners also studied alternative facility designs and identified cost reduction measures for their proposed gas cycling project. The PTU Owners stated that, in their view, their proposed gas cycling project is not commercially viable. Exxon suspended all permitting activities for their proposed gas cycling project and deferred evaluation of the Pre-Mississippian formation that underlies the Thomson Sand Reservoir. The PTU Owners incorporated the results of the prior geologic model, updated reservoir simulation, facility design, and cost estimates into a depletion plan for a conceptual PTU gas sales project.

Despite rigorous analyses of seismic data, the depth of the subsurface geological structure of the Thomson Sand Reservoir west of the PTU1 well remains suspect and introduces substantial uncertainty about reservoir connectivity and continuity, fluid contacts, and the character of the underlying oil rim between the eastern and western areas of the PTU. An exploration/delineation well in this area would provide geologic and reservoir data that could confirm or reduce the structural uncertainty and aid the subsequent determination of recoverable reserves and development options for the PTU.

The PTU Owners' prior exploration activities identified several hydrocarbon accumulations within the unit area that are capable of production in paying quantities. The geological and engineering data indicate that the PTU is underlain by the Thomson Sand Reservoir, which contains significant oil, gas, and gas condensate reserves, and several Brookian oil reservoirs. However, there has been no further delineation of the known accumulations or exploration within the PTU since BPXA drilled the Sourdough #3 well in 1996. The PTU Owners have not yet begun development or production of the known hydrocarbon resources within the unit, and the 22nd POD does not contain any commitments to do so. Therefore, the criteria in 11 AAC 83.303(b)(2) and .303(b)(3), do not support approval of the 22nd POD.

2. The PTU Owners' Plans for Development of the PTU

Although the Thomson Sand Reservoir was discovered in 1977 and the PTU contains several known hydrocarbon accumulations that are capable of producing in paying quantities, the PTU Owners have not committed to put the unit into commercial production. Instead, the PTU Owners propose that more studies are needed and a fiscal contract changing the State's royalty and tax share is required before they can begin development of the PTU.

According to Exxon, the focus of the 22nd POD is on preparing for a potential open season for major gas sales from the North Slope. The 22nd POD states

> The timing of the open season process will be dependent upon successful completion of a fiscal contract between the Sponsor Group and the SoA under the Stranded Gas Development Act (SGDA). During the next year, the Owners will monitor progress of the contract negotiations under the SGDA and be prepared to adjust the work schedule to ensure the necessary work is conducted in sufficient time to allow the Owners to prepare for an open season for an Alaska gas pipeline while maximizing the efficiency of the work processes and sequence.

The Sponsor Group consists of only three of the Major PTU Owners: Exxon, BPXA, and CPAI, and does not officially represent the PTU lessees. The State is also negotiating with two other applicants that submitted proposals to build a North Slope gas pipeline. Depending on the progress of the negotiations, it is unlikely that a North Slope gas pipeline will be in operation before 2012, and the Sponsor Group has not yet made a public commitment to ever build a North Slope gas pipeline. However, regardless of the status of those negotiations, the PTU Owners have an obligation to diligently explore, delineate, and develop the hydrocarbon resources underlying the unit area.

The 22nd POD states that field activities associated with development drilling should begin three to three and one-half years before field startup, but it does not indicate when, if ever, an open season might occur or when, if ever, Exxon anticipates the commencement of development or production. At this point in time, the PTU Owners do not control if or when a North Slope gas pipeline will ever be operational. Reliance on third parties, beyond the control of the PTU Owners, is not grounds for the delay of PTU development and production.

While previous plans focused on developing unitized substances through a gas cycling project, the PTU Owners stated that project was not commercially viable and redirected their efforts to evaluate PTU development through gas sales. The 22nd POD describes several activities that the PTU Owners plan to execute during the next year to evaluate a conceptual PTU gas sales project, but those activities are all contingent on the Sponsor Group successfully negotiating a fiscal contract with the State under the SGDA.

The 22nd POD outlines the unit operator's plans for one year beginning October 1, 2005. Exxon plans to update the PTU geologic model and incorporate the results in the reservoir simulation to identify potential upside gas production from the Pre-Mississippian section. The technical studies will be the basis for a gas sales depletion plan followed by conceptual engineering for detailed facility design. The 22nd POD anticipates completing the depletion plan in April 2006 and initiating conceptual engineering, a 9 to 12 month process that must be completed in time for the PTU Owners to be prepared to nominate gas in an open season, should one occur. During the conceptual engineering process, the PTU Owners plan to determine optimum drillsites and well locations, and update drilling and completion costs to estimate total project costs and timing. PTU conceptual engineering will also include provisions for Brookian development, which Exxon anticipates will occur after it develops the Thomson Sand Reservoir. However, the 22nd POD did not identify a firm date for the start of production.

During the 22nd POD, the PTU Owners plan to assess the permitting requirements for PTU gas sales. They will review the previous permitting activities undertaken for the gas injection project, evaluate the need for additional data and studies, and assess the interrelationship between permitting for PTU development and for the Alaska gas pipeline project. The PTU Operator will also apply to the AOGCC for a conservation order that addresses gas offtake and depletion plans for the Thomson Sand Reservoir and discuss other conservation orders needed for PTU development. Based on the permitting assessment, Exxon will update the project timeline and prepare a schedule of activities to obtain the permits and conservation orders needed to drill the PTU wells and to construct and operate the facilities and pipelines.

To address the Division's concern about reservoir uncertainty in the western unit area, the 22nd POD includes Exxon's offer to hold a workshop to evaluate whether drilling delineation wells could provide valuable information that would reduce the uncertainty associated with the western Thomson Sand Reservoir. The 22nd POD also includes plans to compare core samples from PTU and Badami wells to evaluate potential development of Brookian prospects within the PTU.

While there is some benefit to the proposals in the 22nd POD, it does not contain sufficient plans or commitments to timely develop and produce unitized substances. The PTU Owners are not entitled to condition development of the PTU on the construction of a pipeline by a third party or on modification of the state's royalty and tax rights. PTU Owners' plans for delineation and development of the unit area do not justify approval of the 22nd POD or the PTU Owners' request for extension of the 2006 and 2008 Development Drilling Commitments. The 22nd POD does not meet the criteria in section 11 AAC 83.303(b)(4).

3. Economic Costs and Benefits of the PTU Owners' Plans for Development of the PTU.

The cost to the state and the public of approving the 22nd POD is that the known underlying hydrocarbons will not be timely delineated and produced and the remainder of the unit area will not be timely explored. Moreover, the 22nd POD conditions PTU development on amending the State's existing tax and royalty structure in the Sponsor Group's fiscal contract and construction of a North Slope gas pipeline, which are an inappropriate basis upon which to condition PTU development.

In the short-term, development of the PTU could create additional jobs and in the long-term, development would create additional employment and income to State residents. The State and the public are primarily interested in timely oil and gas production from State leases. Every year that production is delayed costs the State millions of dollars in unrealized interest on production revenue and delays the secondary benefits associated with PTU development. If the PTU Owners developed and began production from the PTU, the State would earn royalty and tax revenues over the long-term life of the field. Royalties, corporate income taxes, property taxes, and severance taxes would benefit the local and state economy, and provide revenue to the State's general, school, and permanent funds. The PTU Owners may reinvest revenues from PTU production in new exploration and development in the State.

Development of the PTU would also increase demand for goods and services supplied by local businesses, retailers, and service providers. An increased property tax base would benefit the residents and communities within the North Slope Borough and along the Trans-Alaska Pipeline corridor. Timely development and production from the PTU will lead to additional development and production from other reservoirs in the unit area and could provide an infrastructure base for exploration, development, and production outside of the unit area.

The Division's May 24, 2002 evaluation of the Expansion Agreement, found that the economic benefits of including the Expansion Acreage in the PTU outweighed the costs because the PTU owners made meaningful commitments to explore and develop the Thomson Sand Reservoir by drilling adequate exploration and development wells by dates certain, and agreed to increased royalty rates for some of the leases to compensate the state for lost opportunities to re-lease the acreage. If the Applicants fail to follow through with those commitments as scheduled, the Expansion Acreage will automatically contract out of the unit, and the PTU Owners must compensate the State for the lost opportunity to receive bonus payments in past lease sales. However, the PTU Owners have requested a one-year deferral of the Development Drilling Commitments. The 22nd POD, unlike the Eighteenth POD and subsequent plans, does not contain activities toward fulfilling the commitments in the Expansion Agreement.

In addition to the Development Drilling Commitments, the Expansion Agreement also contains the PTU Owners commitments to allocate production under an approved participating area by June 15, 2008, for Expansion Areas primarily underlain by the Thomson Sand Reservoir; and by June 15, 2010, for Expansion Areas underlain by Brookian prospects. If the PTU Owners ultimately fail to drill the required development wells, approval of a one-year deferral of the Development Drilling Commitments would delay receipt of any payments to compensate for withholding the Expansion Acreage from leasing, and if they do ultimately develop the PTU, deferral would delay receipt of facility and production related payments,.

There are currently 45 state oil and gas leases committed to the PTU Agreement.[8] Most of the PTU leases had a 10-year primary term, except the four most recent leases, which were issued with 7-year primary terms. All but two of the PTU leases are beyond their primary term, but under Article 18 (d) of the PTU Agreement they are all extended for the duration of the unit term.[9]

In addition, the primary terms of seven PTU leases are extended because the Division certified wells located on those leases as capable of production in paying quantities. The PTU leases with certified wells are: ADL 28382, ADL 47556, ADL 47560, ADL 47567, and ADL 47473, which were issued on lease form DL-1 revised October 1963; ADL 312862 issued on DMEM-1-79B (Sliding Scale Royalty) revised November 5, 1979; and ADL 343112, issued on DMEM 1-82 (Net Profit Share) revised April 7, 1982. The primary term of these leases are extended under the individual lease agreements and State regulation. Paragraph 7 of the DL-1 lease form states:

> Extension by Shut-in Production. If, upon the expiration of the primary term or at any time or times thereafter, there is on said land a well capable of producing oil or gas in paying quantities, this lease shall not expire because Lessee fails to produce the same unless Lessor gives notice to Lessee allowing a reasonable time, which shall not be less than sixty days, after such notice to place the well on a producing status, and Lessee fails to do so; provided, that after such status is established such production shall continue on the said land unless and until suspension of production is allowed by Lessor.

Lease forms DMEM-1-79B (Sliding Scale Royalty) and DMEM 1-82 (Net Profit Share) contain similar extension provision under Paragraph 5 (d) and Paragraph 4(d), respectively. However, these two lease forms specify that the lessor must give the lessee at least six months notice to place the well on production. State regulation 11 AAC 83.135, Shut-in Production contains similar language.

The lessees have had twenty to thirty years to delineate, develop, and commence production from the hydrocarbon accumulations underlying these leases, which contain wells that are certified as capable of production in paying quantities. If the Division notifies the lessees that they must commence production, and they fail to do so within the time allowed, the leases will no longer be held by shut-in production, although the primary terms may continue to be extended by unitization or other extension provisions in the lease agreements.

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[8] Six of the PTU leases were effective in 1965, nineteen in 1969, three in 1970, two in 1979, four in 1982, one in 1988, eight in 1991, one in 1993, two in 1997, and one each in 2000 and 2002.

[9] PTU Agreement, Article 18 (d) states "Each lease, sublease or contract relating to the exploration, drilling, development or operation for oil or gas of lands, committed to this agreement, which, by its terms might expire prior to the termination of this agreement, is hereby extended beyond any such term so provided therein so that it shall be continued in full force and effect for and during the term o this agreement."

If the PTU Agreement terminates and the leases expire, the Division could re-offer the acreage for lease in future lease sales and impose work commitments in the new leases.[10] Re-offering the PTU acreage would also replace older lease forms with a more modern updated lease form. The Division received bonus bids totaling nearly $146 million when the State originally issued the current PTU leases, and could attract significantly higher bid bonuses today.

Another benefit the state could realize by re-offering the unit acreage is the potential for increased royalty rates. Most of the leases in the core unit area have royalty rates of 12.5%. If the Division were to re-offer the acreage, it could impose higher royalty rates. The PTU Owners agreed to increased royalty rates for some leases in the Expansion Areas, ensuring that the State would receive the benefit of higher royalties on production from those leases without releasing the acreage. The royalty rate increased from 16.66667% to 20% for seven of the leases and from 12.5% to 16.66667% for one lease.

If the PTU is terminated and the Division re-offered the PTU acreage for bid, it might attract new lessees who may bring new ideas and energy as well as new geologic interpretations, engineering, development timelines, and marketing perspectives to develop the area. At this point, the current PTU Owners have had the leases for far beyond their primary term, and their conclusion today is simply that they cannot make enough money to justify development. It is time for the PTU Owners to develop and produce or give new lessees had a chance to develop the known hydrocarbon resources within the PTU.

In summary, the economic costs outweigh the benefits that might be gained by approving the 22nd POD. Therefore, the Division's evaluation of the section .303(b)(5) economic criteria does not support approval of the 22nd POD.

4. Environmental Costs and Benefits of the PTU Owners' Plans for Development of the PTU.

The PTU Owners do not propose any exploration, delineation, or development operations within the PTU. Therefore, the section 11 AAC 83.303(b)(1) environmental criteria neither supports nor condemns approval of the PTU Owners' plans for development of the PTU.

5. Other Relevant Factors to Protect the Public Interest

The PTU contains wells certified as capable of production in paying quantities. Considering the facts, it is now time to develop and produce the underlying hydrocarbons. If the PTU Owners have been unable to identify a commercial project in nearly 30 years, it is time to terminate the unit and re-offer the acreage to new lessees who will have the opportunity to develop the State's resources in a timely manner.

The Division has given the PTU Owners many opportunities over many years to develop the PTU. It is not in the public interest to grant a state lessee an indefinite extension on development merely because development in their view is not currently profitable enough or is too risky.

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[10] "The Commissioner may include terms in any oil and gas lease imposing minimum work commitment on the lessee. These terms shall be made public before the sale, and may include appropriate penalty provisions to take effect in the event the lessee does not fulfill the minimum work commitment." AS 38.05.180 (h).

The intent of oil and gas leases is to give producers an opportunity to explore, develop, and produce within the primary term of the lease. That intent has been met and exceeded in this case. It is not in the public interest to change leasehold intent by allowing a lessee's parochial interests to supersede the State interest for orderly and reasonably prompt development.

The state's primary interest in oil and gas leases is development of hydrocarbons which yield oil and gas revenue. The state's interest is not met by allowing the producers to delay production until such time as the lessee determines that it is the lessee's optimum time to develop a known resource or the State agrees to compromise its tax and royalty system.

It is not fair to the public or other potential lessees to allow the current PTU Owners to continue to hold the leases, thereby precluding others from the opportunity to develop the resource.

V. FINDINGS

The PTU Owners' Plans for Development of the PTU fail to meet the criteria in 11 AAC 83.303(a) as follows:

A. Promote the Conservation of All Natural Resources.

If the Unit Operator proposed any operations under the 22nd POD, there would be environmental impacts associated with reservoir development. However, unitized development of the unit area would reduce the disruption of land and fish and wildlife habitat that would occur under individual lease development. This reduction in environmental impacts and preservation of subsistence access would, when taken in isolation, be in the public interest. While unitized operations conserve natural resources when compared to lease-by-lease development, development on a lease basis maybe preferable to no development at all. However, development of the Thomson Sand Reservoir is possible under a new unit agreement.

Additionally, before undertaking any specific operations, the unit operator must submit a unit plan of operations to the Division and other appropriate state and local agencies for review and approval, and the lessees may not commence exploration or development operations until all agencies have granted the required permits. The Division may condition its approval of a unit plan of operations and other permits on performance of mitigation measures in addition to those in the leases, if necessary or appropriate. Compliance with the mitigation measures would minimize, reduce or completely avoid adverse environmental impacts. Lease-by-lease operations would also require agency approvals, including mitigation measures.

B. Promote the Prevention of Economic and Physical Waste.

Exxon submitted geological, geophysical, and engineering data to support its interpretation of the hydrocarbon accumulations underlying the unit area. The available data indicates the PTU encompasses all or part of one or more hydrocarbon accumulations, but the PTU Owners' plans do not provide for delineation and timely development of those resources.

The PTU Owners stated that a gas cycling project was not commercially viable and the 22nd POD focuses on evaluating gas sales, but does not commit to produce and sell PTU gas. There is uncertainty regarding continuity of the reservoir in the western unit area, which could be addressed by drilling additional delineation wells. The Unit Operator has not adequately considered alternate development scenarios that incorporate both gas sales and gas cycling. Nor has Exxon evaluated the cumulative benefits of simultaneously developing the multiple hydrocarbon accumulations within the unit area. Timely development and production from the PTU does not preclude PTU gas sales at a later date. Focusing on gas sales at the exclusion of all other development options may result in waste of natural resources.

Gas cycling theoretically allows the recovery of significantly more liquids than would be recovered in a pure gas blow down project. In a gas blow down scenario, oil and gas condensates that remain in the field following gas sales may be largely unrecoverable. In addition, delaying timely production also constitutes waste. The Division and AOGCC must determine whether the proposed development will promote the conservation of oil and gas, but the Unit Operator has yet to apply to AOGCC for conservation orders and to the Division for approval of a depletion plan. The Director has the authority to modify the rate of development to achieve the conservation objectives under the PTU Agreement, and I find that increasing the rate of development in the PTU is necessary and advisable.

C. Provide for the Protection of All Parties of Interest, Including the State

A majority of the State's general fund revenue is derived from North Slope oil and gas operations in the form of royalty, net profit shares, production tax, property tax, and corporate income tax. Failure to develop and produce known hydrocarbon accumulations deprives the State of incremental revenue, economic activity and jobs. Should the PTU terminate, the area could be re-leased and unitized again under an acceptable unit plan of development that includes commitments to develop and produce the underlying hydrocarbon accumulations.

Continuing this 30-year record of non-development and delay of an oil and gas lessee's obligations to develop and produce its oil and gas leases makes a mockery of the statutory, regulatory and contractual protections for the State as owner of the oil and gas estate. Therefore, the 22nd POD is unacceptable.

VI. DECISION

The 22nd POD fails to meet the requirements of 11 AAC 83.303 and .343 because it does not provide for the reasonable delineation and timely development of the hydrocarbon accumulations in the unit area. Nearly 30 years ago, lessees discovered the Thomson Sand Reservoir underlying the PTU, which to date has not been developed or put into commercial production. The PTU contains significant gas condensate and oil resources. Eighteen wells have been drilled within and around the PTU, but the most recent PTU well was drilled by BPXA nearly 20 years ago. Although some of the leases are more than 40 years old, and several hydrocarbon accumulations within the unit area contain wells that are certified as capable of producing in paying quantities, the Unit Operator has not stated that production from the PTU is economic and has not committed to development and commercial production. To the contrary, the Unit Operator has stated the production from the unit is not economic.

1. The 22nd POD makes no commitment to timely develop and produce PTU oil, gas, or gas condensate. The 22nd POD is hereby denied.

2. Failure to obtain approval of the unit plan is grounds for default under the PTU Agreement and the State oil and gas regulations. The PTU Owners are hereby notified that effective October 1, 2005, the PTU Agreement is in default.

3. To cure the default, the Unit Operator shall submit an acceptable POD within 90 days, by Thursday, December 29, 2005.

    a) An acceptable unit plan must contain specific commitments to timely delineate the hydrocarbon accumulations underlying the PTU and develop the unitized substances. The following commitments represent an acceptable PTU plan of development:

        - Development activities for the unit, including plans and deadlines to delineate the Thomson Sand Reservoir, bring the reservoir into commercial production, maximize oil, condensate, and gas recovery, and maintain and enhance production once established; and plans for the exploration or delineation and production of other hydrocarbon accumulations and lands that lie stratigraphically above or below the Thomson Sand Reservoir;

        - The PTU Owners shall sanction a commercial PTU development project by October 1, 2006, and provide the Division with evidence of corporate approval and commitment of project funding.

        - The PTU Operator shall begin commercial production of unitized substances from the PTU by October 1, 2009.

        - Details of the proposed operations to fulfill the 2006 Development Drilling Commitment, including the proposed surface location of the drill pad, bottom-hole location for the well, testing plan, and schedule of activities. The consequences of failure to fulfill the 2006 drilling commitment are specified in the Expansion Agreement.

4. Failure to submit an acceptable plan of development is grounds for termination of the PTU.

5. The PTU Operator shall commence development operations within the PTU by October 1, 2007. The PTU Owners shall have an opportunity for hearing regarding this notice to modify the rate of PTU development.

6. Oil and gas leases ADL 28382, ADL 47556, ADL 47560, ADL 47567, ADL 47473, ADL 312862, and ADL 343112, must commence production in paying quantities, as defined in 11 AAC 83.105, from by October 1, 2009. The Division shall also provide notice to the notification lessees, Exxon Mobil Corporation, ExxonMobil Oil Corporation, Chevron U.S.A., Inc., and Devon Energy Production Company, LP under separate cover.

A person affected by this decision may appeal it, in accordance with 11 AAC 02. Any appeal must be received within 20 calendar days after the date of "issuance" of this decision, as defined in 11 AAC 02.040 (c) and (d), and may be mailed or delivered to Thomas E. Irwin, Commissioner, Department of Natural Resources, 550 W. 7th Avenue, Suite 1400, Anchorage, Alaska 99501; faxed to 1-907-269-8918; or sent by electronic mail to dnr_appeals@dnr.state.ak.us. This decision takes effect immediately. If no appeal is filed by the appeal deadline, this decision becomes a final administrative order and decision of the department on the 31st day after issuance. An eligible person must first appeal this decision in accordance with 11 AAC 02 before appealing this decision to Superior Court. A copy of 11 AAC 02 may be obtained from any regional information office of the Department of Natural Resources.

Original signed by Mark D. Myers, Director *September 30, 2005*

Mark D. Myers, Director
Division of Oil and Gas

Date

cc: Thomas E. Irwin, Commissioner DNR
John Norman, Chair AOGCC
Richard Todd, Senior Assistant Attorney General

AMENDED DECISION

DENIAL OF THE PROPOSED PLANS FOR DEVELOPMENT OF THE POINT THOMSON UNIT

October 27, 2005

Findings and Decision of the Director, Division of Oil and Gas
Under Delegation of Authority from the
Commissioner, Department of Natural Resources, State Of Alaska

Revision Version

The Division of Oil and Gas (the Division) hereby amends the decision entitled *Denial of the Proposed Plans for Development of the Point Thomson Unit* dated September 30, 2005 (the Decision). The Decision included notice that the Division would hold a hearing under Article 21 of the Point Thomson Unit Agreement. The Decision is amended to remove certain items of work and all references to Article 21 because they do not apply to the Division's evaluation of the Unit Operator's proposed plans for development of the Point Thomson Unit.

Additions are shown in **bold and underlined** and deletions are shown [IN ALL CAPS IN BRACKETS].

I. SUMMARY OF DECISION

This is the final Decision of the Alaska Department of Natural Resources, Division of Oil and Gas (the Division) on the Twenty-second Plan of Development (22nd POD) for the Point Thomson Unit (PTU) submitted by the PTU Operator, Exxon Mobil Corporation (Exxon), on August 31, 2005. The Division finds that the PTU Agreement is in default for Exxon's failure to submit an acceptable unit plan of development.

The PTU is underlain by a massive undeveloped gas and gas condensate reservoir that was discovered nearly 30 years ago, but the PTU oil and gas lessees have determined that production of the unitized substances is, in their view, not commercially viable. The 22nd POD proposes additional studies to determine if the PTU lessees can design a commercially viable production project.

The 22nd POD states that PTU development is not possible without modifying the current laws regarding the State's right to taxes and royalties on oil and gas production and on construction of a North Slope gas pipeline. The PTU Operator proposed integrating the lessees' PTU development obligations into negotiations for a fiscal contract with the State and proposed a two year delay of the development commitments made by the lessees in connection with an expansion of the PTU in 2001, both of which would make PTU development uncertain. The current fiscal contract negotiations may or may not lead to construction of a North Slope gas pipeline.

The premise that the PTU can only be developed if a North Slope gas pipeline is built is inappropriate. In addition to dry gas, the unit contains 100s of millions of barrels of hydrocarbon liquids. These hydrocarbon liquids could be produced using mostly existing oil pipelines without construction of a North Slope gas pipeline. Therefore, potential PTU development is not, in fact, limited to dry gas production. In addition, the PTU Agreement, which requires timely exploration, delineation, development, and production of unitized substances, does not guarantee the lessees' commercial success or provide for indefinite extension of the leases.

1. The 22nd POD is disapproved because it does not set out a plan to bring the PTU into commercial production within a reasonable time frame.

2. **Failure to obtain approval of the unit plan is grounds for default under the PTU Agreement and the State oil and gas regulations. Effective October 1, 2005, the PTU Agreement is in default.** Exxon has 90 days**,**

until December 29, 2005 to cure the **default** by submitting a unit plan that commits to timely development and production of unitized substances.

[3. THIS DECISION PROVIDES NOTICE UNDER ARTICLE 21 OF THE PTU AGREEMENT THAT EXXON MUST INITIATE DEVELOPMENT OPERATIONS WITHIN THE PTU BY OCTOBER 1, 2007. THE DIVISION WILL CONTACT EXXON TO SCHEDULE A HEARING ON THIS ISSUE, WHICH WILL BE HELD NOT LESS THAN 30 DAYS FROM THE DATE OF THIS DECISION.]

[4. THIS DECISION ALSO PROVIDES NOTICE UNDER THE INDIVIDUAL LEASE AGREEMENTS THAT THE PTU LEASES CONTAINING CERTIFIED WELLS MUST COMMENCE PRODUCTION IN PAYING QUANTITIES BY OCTOBER 1, 2009.]

[5.]3. In addition, the Division denies Exxon's request for a one-year deferral of the Expansion Agreement commitments. If Exxon does not commence drilling within the PTU by June 15, 2006, the PTU boundary will contract and the contracted leases will no longer be held by unitization.

II. BACKGROUND

The details of the PTU history set out below can be summarized as follows. Some of the PTU leases were issued over 40 years ago and the unit has been in existence for 28 years. The Division certified 7 exploration wells within and around the unit area as capable of producing hydrocarbons in paying quantities, but it has been 20 years since the last well was drilled. The Thomson Sand Reservoir is known to contain at least 8 trillion cubic feet of gas and 200 million barrels of gas condensate and oil. The PTU also contains 100s of millions of barrels of oil in the shallower Brookian reservoirs. The PTU lessees have not yet determined whether they can commercially produce PTU resources, and they have not committed to timely explore, delineate, or develop PTU oil, gas, or gas condensate. The unit operator has consistently proposed that more studies or workshops are needed before putting the PTU into production and, since 1983, has periodically asserted that production cannot begin until a North Slope gas pipeline is built.

The PTU is located on the North Slope of Alaska. The western unit boundary is approximately 3 miles east of the Badami Unit and 30 miles east of the Prudhoe Bay Unit (PBU), and the eastern unit boundary lies west of the western boundary of the Arctic National Wildlife Refuge (ANWR). The southern PTU boundary is onshore, and the northern boundary is offshore in the Beaufort Sea, adjacent to or near the three-mile territorial sea boundary that separates state from federal Outer Continental Shelf (OCS) lands. The PTU consists of 45 state oil and gas leases encompassing approximately 106,200.55 acres. The state owns the entire subsurface estate within the unit area.

Twenty-five lessees hold working interest ownership in the PTU (PTU Owners), and Exxon is the designated Unit Operator. Ownership is calculated based on a lessee's percent of working interest ownership in each lease multiplied by the lease acreage, as a percentage of the total unit acreage. On a surface acreage basis, the Major PTU Owners hold 98.9056% of the PTU: Exxon