

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2472 SCOMM 104 HOUSE SPEC. COMM. OIL & GAS, 1997-98

The DSC will soon be considering an environmental studies ballot (Ballot 98-2) to assess potential impacts of future development plans in the PTU area.

Integrated Development Model

After the Owners create the common technical database, develop a unit Brookian model(s), and scoping cost estimates, a generic integrated development model will be built to test development sensitivities for the Thomson and Brookian Sands. The development model can then be used to evaluate synergies and allow Unit Owners to share conclusions and enhance the understanding of development possibilities within the Unit. As noted above, completion of an integrated development model is targeted by year-end 1999.

Summary

In summary, the Owners' major emphasis for PTU development during the term of the 15th POD will be to: (a) create a common shared technical database for the PTU area, and (b) complete an evaluation of the common database in accordance with the attached PTU schedule/timeline, in an effort to look for synergies between potential oil and gas developments in the PTU area.

The Owners recognize that challenges remain in creating the shared technical database, but are committed to exploring all avenues for making this a reality. We expect to have most of the common database in place by September 1, 1998. The Owners further recognize that this shared database for the PTU area will allow all Owners to participate in the building/updating of geophysical, geological, reservoir and facility models for all reservoirs within the PTU area. A unified effort by the Owners in this regard should result in a common understanding of conclusions by year-end 1999.

EXHIBIT 1 - POINT THOMSON DEVELOPMENT WORK SCHEDULE

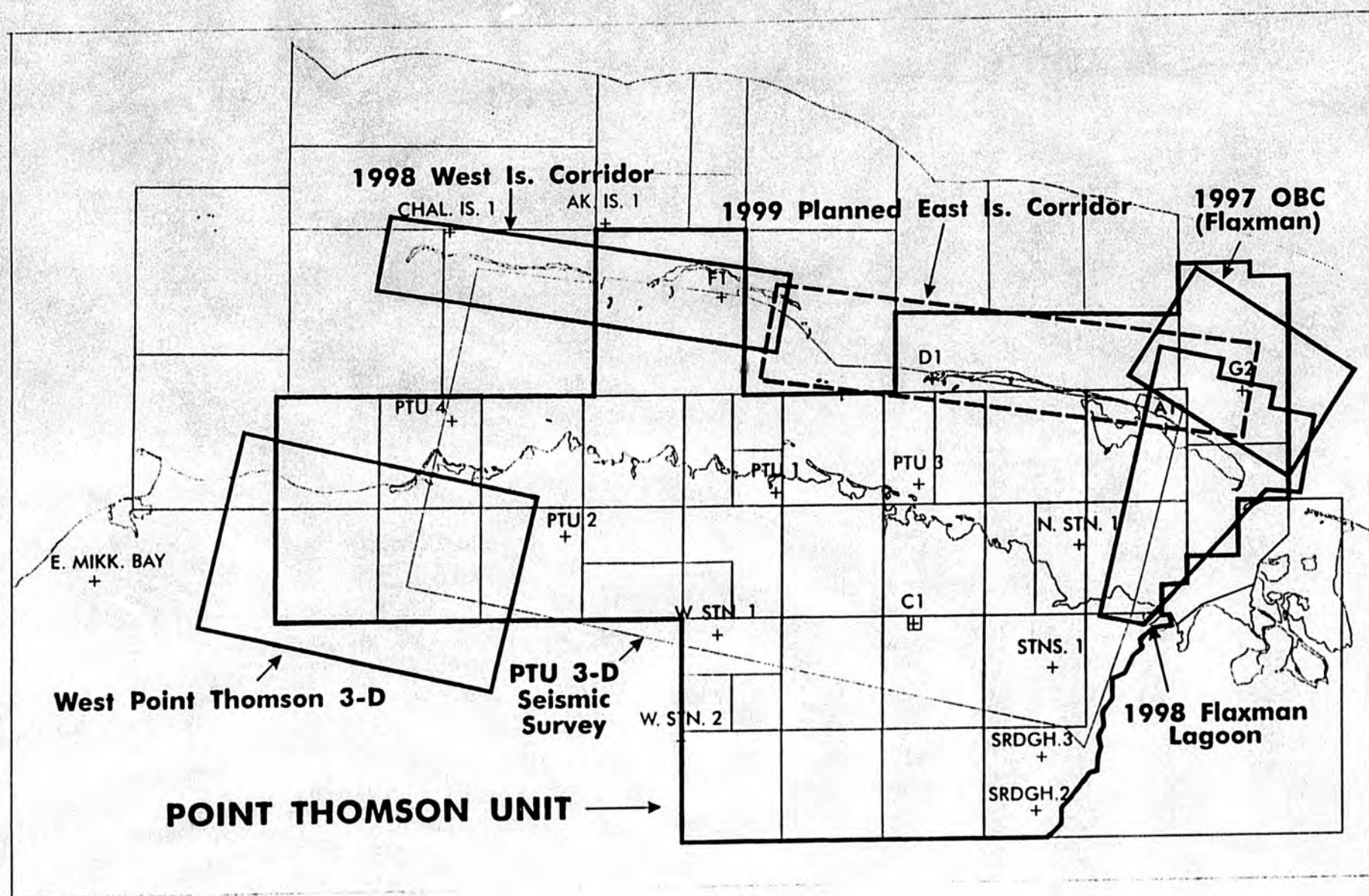
ACTIVITIES	1Q98	2Q98	3Q98	4Q98	1Q99	2Q99	3Q99	4Q99	1Q00	2Q00	3Q00	4Q00
DEVELOPMENT PLANNING												
1. PTU Other Resource Evaluation Oil Rim Geochemistry/Simulation, Flaxman Scoping Model and Basement Studies												
2. PTU Gas Resource Evaluation Scenario Upgrades (FFM), Evaluation and Economics Update, Cost Reduction (Phase II)												
3. Common Database Upgrades/Data Sharing Agreements												
4. PTU Brookian Oil Evaluation Data Trades, Seismic Process./ Interpret., Geol. Interpret. and Modeling, Simulation, Devel. Scoping												
5. Integrated Development Model												
6. Conceptual Engineering/Appraisal Planning (Phase III), if Warranted												

ACTIVITIES	1Q98	2Q98	3Q98	4Q98	1Q99	2Q99	3Q99	4Q99	1Q00	2Q00	3Q00	4Q00
POD SCHEDULE												
1. Interim POD												
2. POD 15 (Proposed)												
3. POD 16												

● Alaska DNR Reviews

Point Thomson Unit/Plan of Development 15

PTU 3D SEISMIC ACQUISITION PROGRAM



EXXON COMPANY, U.S.A.
POST OFFICE BOX 2180 • HOUSTON, TEXAS 77252-2180

PRODUCTION DEPARTMENT
ALASKA INTEREST

L. R. HOWARD
MANAGER

RECEIVED
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DIVISION OF OIL & GAS

MIKE -
ORIGINAL
FAX FILES

October 1, 1997

**Fifteenth Plan of Further Development
and Operation**
Point Thomson Unit

VIA FAX (907-562-3852) &
AIRBORNE EXPRESS

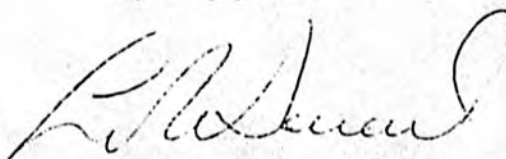
Mr. Kenneth A. Boyd, Director
Alaska Department of Natural Resources
Division of Oil and Gas
3601 "C" Street, Suite 1380
Anchorage, Alaska 99503-5948

Dear Mr. Boyd:

Exxon, as Unit Operator and on behalf of the Working Interest Owners (Owners), hereby submits the enclosed Fifteenth Plan of Further Development and Operation (15th POD) for the Point Thomson Unit for your review and approval. The 15th POD contains an update on the work activities commenced/completed under the 14th POD and a summary of the Owners' work plans for the ensuing calendar year. The work activities associated with Phase II of the Unit's development screening study will be completed during the 15th POD term.

Should you have any questions regarding the 15th POD, please do not hesitate to call me at (713) 656-7000 or Mr. Raul Huerta at (713) 656-7111.

Very truly yours,



LRH:MMM
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Enclosure
cc: PTU Working Interest Owners



Point Thomson Unit
Fifteenth Plan of Further Development and Operation
(And an Update on the Fourteenth Plan of Further Development and Operation)

This Fifteenth Plan of Development is submitted to the Commissioner of the Alaska Department of Natural Resources (DNR) pursuant to Article 10 of the Point Thomson Unit (PTU) Agreement and 11 AAC 83.343.

Overview

The 14th POD was submitted to the DNR on October 1, 1996. Under the 14th POD, the Working Interest Owners (Owners) committed to complete the activities associated with Phase I of the Point Thomson Development Screening Study (the "Study") and, if warranted by the results of Phase I, begin the Study's Phase II activities. By letter dated November 29, 1996, the DNR approved the 14th POD for a one (1) year term from January 1, 1997 to December 31, 1997, subject to the following conditions:

- A June 1997 meeting wherein the Owners would present to the DNR a progress report on the Study's Phase I activities, and
- At the earliest opportunity, a report on the results of the farmout initiative on Unit Tracts 8, 9, and 10, including the outcome of negotiations with ARCO on a 3-D Seismic Farmout Agreement affecting those tracts.

The Owners satisfied the conditions for the approval of the 14th POD as follows:

- By letter dated March 7, 1997, Exxon advised the DNR that Exxon, Mobil, and Phillips each had consummated a farmout agreement with ARCO covering their respective working interests in Unit Tracts 7, 8, 9, and 10.
- On June 18, 1997, representatives of the Owners met with the DNR and presented a progress report on the Study's Phase I activities.

During the term of the 14th POD, the Owners have continued their efforts to develop the PTU, with the focus on a screening evaluation of potential Thomson Sand reservoir development scenarios. The proposed 15th POD builds upon the 14th POD by refining certain of those development scenarios. The Owners, through their technical studies, have improved their understanding of the complex issues associated with producing a high pressure gas reservoir in a remote location. For example, the drilling and completion technologies necessary to drill and produce high throw, large-bore wells at high

production rates have been examined. Additionally, high quality geologic and reservoir simulation models have been built to enable estimation of reserves and flowstreams for various development scenarios. Well cost estimates, facility screening cost estimates, and proprietary economic models have also been updated.

While the work accomplished pursuant to 14th POD has led to an increased understanding of the Thomson Sand reservoir by the Owners, hurdles to development remain; particularly, high development costs, lack of a gas market and transportation system, and the unique challenges associated with high pressure gas cycling. Consequently, development of the Thomson Sand reservoir is not economically justified at the present time.

Three of the Owners (Exxon, BP and Phillips) have joined the State of Alaska's North Slope Gas Commercialization Team which will research and recommend changes to the State's tax and royalty structure to improve the economic feasibility of a North Slope gas project. This study may have applicability to PTU gas.

Update on the Fourteenth Plan of Development (14th POD)

Development Steering Committee (DSC) Formation

The Owners approved the formation of the DSC by an affirmative vote of 99.37% of the PTU voting interest. The DSC was charged with the coordination and completion of well design and cost estimates, facilities design and cost estimates, and selection and evaluation of development scenarios.

Fine Scale Geologic Model

A fine scale 3-D geologic model of the Thomson Sand was constructed. The model encompasses approximately 330 square miles and contains approximately 2,000,000 cells (each cell 2ft. x 600ft. x 600ft.). Each cell has been assigned a facies type (3 possible) and porosity, permeability and hydrocarbon saturation all of which are keyed to the specific facies type. Areal trend maps were generated by the Geologic and Reservoir Modeling Committee (GRMC) to control the distribution of the facies and porosity within the model, whereas the permeability values were developed using geostatistical methodologies. Hydrocarbon saturation values are capillary pressure based and linked to the porosity and facies type. The fine scale geologic model provides the foundation for the reservoir simulation models built for the Thomson Sand reservoir.

Reservoir Simulation

The reservoir simulation work was conducted by Exxon Production Research under the direction of the GRMC. Three reservoir simulation models were built: a uniform cross-

section, a finely-gridded mechanistic cross-section, and a 3-D full-field model. The uniform cross-section model was used to test the relationships between phase behavior, capillary pressure, and relative permeability. The mechanistic model was utilized to test various depletion mechanisms such as gas cycling, blowdown, and water injection. The full-field model was utilized to provide estimated flowstreams and recoveries for various development scenarios.

Well Designs and Cost Estimates

Well design work was conducted by Exxon Production Research under the direction of the DSC. Studies were performed in the following areas: wellbore stability; hole cleaning; drilling torque and drag; casing design; completion installation; workover access; and drilling days vs. depth. Screening level well cost ranges were developed by Exxon and reviewed by DSC participants.

Facilities Designs and Cost Estimates

Parsons Process Group Inc. was commissioned by the DSC to conduct a study to define "screening level" design and cost estimates for the facilities that would be required for several different Thomson Sand development scenarios. Scenarios included gas cycling and blowdown cases, with sensitivities for alternatives including condensate pipeline tie-in to the Badami project, gas injection at PBU, gas dehydration and chilling to improve condensate recovery, and water injection for pressure maintenance. The final results of this study were provided to the DSC participants on September 2, 1997.

Farmout Initiative

The farmout agreements from Exxon, Mobil and Phillips required ARCO to commence the acquisition of a 3-D seismic survey ("Survey"), covering Unit Tracts 7, 8, 9, and 10, on or before March 31, 1997. According to ARCO, Northern Geophysical completed acquisition of the Survey on March 30. The Survey was acquired as part of a larger, 3-D seismic program conducted jointly by BP and ARCO. The Survey data is currently being processed; data delivery is expected by year-end.

Exploration Activity

On March 13, 1997, BP and Chevron publicly announced that the Sourdough #3 Well had confirmed the prior oil discovery made by the Sourdough #2 Well. Both of the wells are located within the PTU. BP and Chevron believe the Sourdough prospect could contain upwards of 100 million barrels of recoverable oil. Further exploration and appraisal of the Sourdough prospect are under consideration by BP and Chevron.

Fifteenth Plan of Development (15th POD)

Work Plans

During the term of the 15th POD, the Owners plan to complete the remaining activities associated with Phase II of the Study. The tools and information developed from the 14th POD work efforts will be used to refine the gas cycling and blowdown development scenarios evaluated during Phase I of the Study. Areas of study will include: location and number of drill sites, location and number of producer and injector wells, and analysis of gas off-take vs. facility size to improve capital efficiency. Depending upon the results of this work, the Owners may undertake additional work to refine the current screening level design and cost estimates to match the upgraded scenarios.

A current work schedule for the Study is attached as Exhibit 1.

The Owners continue to monitor activity at Badami. As Badami drilling, development and pipeline construction progresses, the Owners will look for additional development and cost synergies with that project, if available.

Various owners are currently discussing possible exploration drilling in or around the PTU. At this time, no firm locations have been established. The Owners may supplement the 15th POD to address any exploration activity within the Unit that may occur during its term. Depending on the nature and extent of any such exploration activity, the Owners may request an extension to the term of the 15th POD as part of such supplement.

Requested Term

The Owners hereby request a one (1) year term for the 15th POD, January 1, 1998 through December 31, 1998.

Exhibit 1 - Point Thomson Development Screening Study Schedule

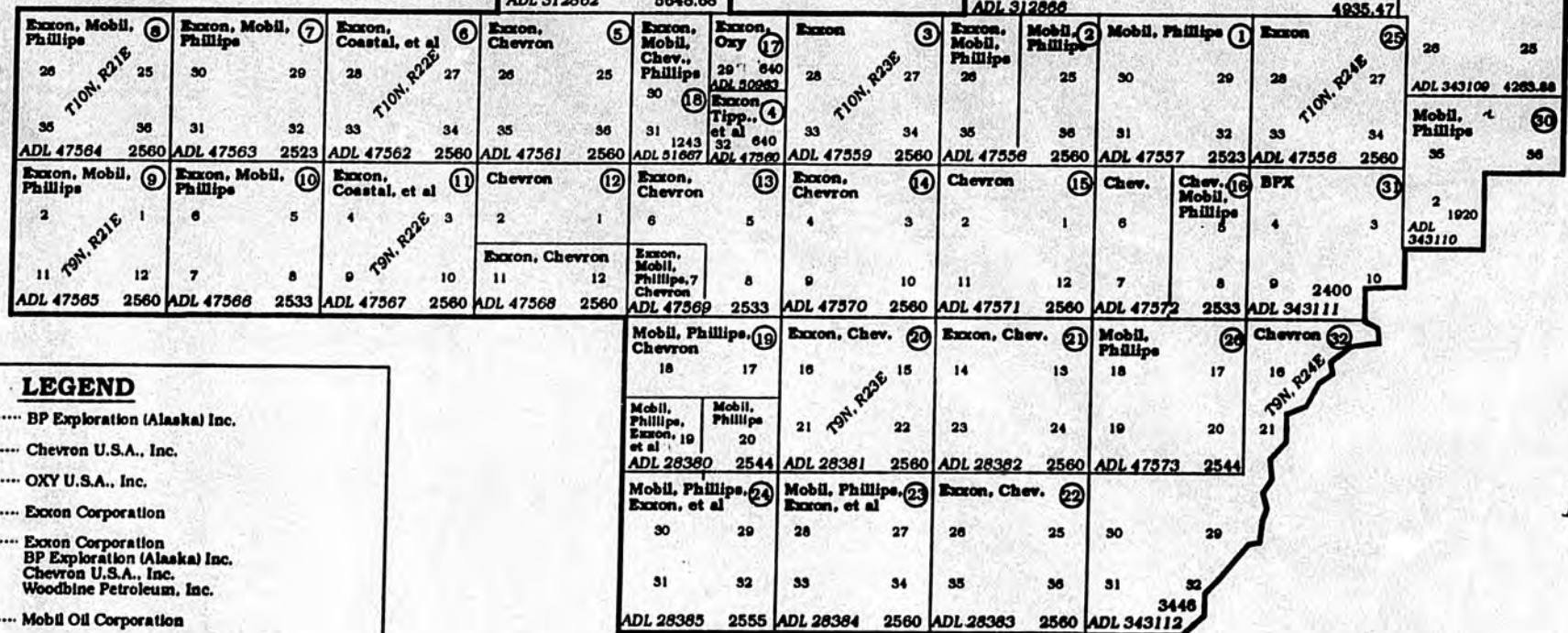
ACTIVITIES	1Q96	2Q96	3Q96	4Q96	1Q97	2Q97	3Q97	4Q97	1Q98	2Q98	3Q98	4Q98
Phase I												
1. Brainstorm development scenarios to be evaluated	■											
2. Build Thomson Sand 3-D geologic model		◆	■	■								
3. Develop well designs and cost estimates		■	■	■	■	■						
4. Build Thomson Sand reservoir simulation models & evaluate devel. scenarios				■	■	◆	■					
5. Develop cost estimates and economic models; screen development scenarios				■	■	■	■					
Phase II												
6. Upgrade cycling and blowdown development scenarios and economics								■	■	■	■	
7. Upgrade facility and pipeline screening cost estimates, if warranted										■	■	■

◆ Progress update meeting with Alaska DNR on June 27, 1996

◆ Progress update meeting with Alaska DNR on June 18, 1997

38 TRAKTS
83,820 Acres

Exxon (27)



BPX		BP Exploration (Alaska) Inc.
Chevron (Chev.)		Chevron U.S.A., Inc.
OXY		OXY U.S.A., Inc.
Exxon		Exxon Corporation
Exxon, et al		Exxon Corporation BP Exploration (Alaska) Inc. Chevron U.S.A., Inc. Woodbine Petroleum, Inc.
Mobil		Mobil Oil Corporation
Phillips		Phillips Petroleum Company
Coastal, et al		Coastal Oil and Gas Corporation Pennzoil Exploration and Production Co. Forest Oil Corporation Mobil Oil Corporation SNG Production Company Trans World Oil and Gas Ltd. Sunlite International Inc. Two-Four-Six Exploration Inc.
Tipp., et al		Tipperrary Oil and Gas Corporation Chaparral Royalty Co. Richard Donnelly Kingdon R. Hughes Edward H. Leede Pacific Lighting Gas Development Company Bernice C. Peery, Trustee Robert Searls, Jr. Jeanne Searls

① Denotes Tract Numbers, as listed on Exhibit "B"



A History of the Point Thomson Unit

Prepared by Carol Lee, Unit Manager

July 23, 1998

Summary:

DNR approved the Point Thomson Unit Agreement effective August 1, 1977, with an initial term of five years. The original unit area included 18 State of Alaska oil and gas leases comprising approximately 40,768 acres.

On November 4, 1977, DNR certified the Point Thomson Well #1 as capable of producing in paying quantities.

The following is a listing of the Plans of Development that have been approved for the Point Thomson Unit:

POD	Term	Beginning Date	Ending Date
1 st POD	1 year	1/1/78	12/31/78
2 nd POD	1 year	1/1/79	12/31/79
3 rd POD	1 year	1/1/80	12/31/80
4 th POD	1 year	1/1/81	12/31/81
5 th POD	1 year	1/1/82	12/31/82
6 th POD	1 year	1/1/83	12/31/83
7 th POD	4 years	1/1/84	12/31/88
8 th POD	3 years	1/1/89	12/31/91
9 th POD	1 year	1/1/92	12/31/92
10 th POD	1 year	1/1/93	12/31/93
11 th POD	1 year	1/1/94	12/31/94
1 st Extension of 11 th POD	16 months	12/31/94	4/30/95
2 nd Extension of 11 th POD	3 months	4/30/95	7/15/95
3 rd Extension of 11 th POD	2 months	7/15/95	9/1/95
4 th Extension of 11 th POD	5 months	9/1/95	2/1/96
13 th POD	11 months	2/2/96	12/31/96
14 th POD	1 year	1/1/97	12/31/97
Interim POD	6 months	1/1/98	6/30/98
15 th POD	15 months	7/1/98	9/30/99

On April 16, 1982, DNR approved the First Amendment to the Point Thomson Unit Agreement. Article 11 of the Point Thomson Unit Agreement was amended so that the unit owners would not be required to form a Participating Area until 90 days before production begins.

On March 14, 1984, DNR approved the First Expansion of the Point Thomson Unit Area. The expansion area included 25 additional leases comprising approximately 94,152 acres for a total unit area of approximately 134,920 acres. The expansion was

conditioned upon a well drilling commitment by March 31, 1985 and another well by February 1, 1990.

On January 17, 1985, DNR approves the Second Amendment to the Point Thomson Unit Agreement. Pertinent changes included amending Article 11 to accommodate the Net Profit Share Leases and a modification to Article 21, Rate of Prospecting, Development and Production.

On April 9, 1985 two leases contracted out of the Point Thomson Unit for failure to commence the required well by the March 31, 1985 deadline. On February 5, 1990, nine of the ten northern leases included in the First Expansion were contracted out of the unit area for failure to commence the required well by February 1, 1990. There are currently 32 leases within the Point Thomson Unit Area, comprising approximately 83,825 acres. Of these leases, six were issued in 1965, eighteen were issued in 1969, two were issued in 1970, two were issued in 1980, and four were issued in 1982. Commitment to the Point Thomson Unit extended all of the leases beyond their primary term.

The Point Thomson Unit area contains 14 wells, seven of which DNR certified as capable of producing in paying quantities. Certification of the wells extends the primary term of seven leases. If the Point Thomson Unit expired, these seven leases would continue to be held by the certified wells.

The following is the approximate ownership of the Point Thompson Sand Formation:

Exxon	41.0%
Chevron	23.1%
Mobil	16.3%
Phillips	13.5%
BP	6.1%

In three leases, with a total of 8,566 acres, the ownership is divided at depth. The ownership in those three leases above the Point Thomson Sand Formation is as follows:

Chevron	26.16%
Exxon	21.50%
BP	52.33%

The ownership in the three leases below the Point Thomson Sand Formation is as follows:

BP	46.75%
Exxon	29.89%
Chevron	23.37%

Each of the following companies or individuals holds less than 1% working interest in the Point Thomson Unit: Pennzoil, Coastal, Forest, Oxy, Grace, Sunlight, Transworld, Woodbine, Tipperary, Leede, Leede & Pine, Donnelly, Chapparal, Searls, Perry, Hughes, Pacific Lighting, Two Four Six Corp. [All percentage figures are approximated.]

Point Thomson Unit

Detailed History:

- 10/29/76 Exxon submits application for designation of a unit area and for determination of location and depth of a test well.
- 1/7/77 DNR approves application for designation of area and approval of form.
- 5/3/77 Exxon submits application for final approval of Point Thomson Unit Agreement
- 6/6/77 DNR issues Preliminary Decision and Finding approving Point Thomson Unit for an initial term of five years. Original unit area included 18 State of Alaska oil and gas leases comprising approximately 40,768 acres. Working interest owners included Atlantic Richfield (ARCO), Cities Service (Oxy), Chevron, Conoco, Exxon, Mobil, Phillips, Pennzoil, Tipperary and several individuals.
- Article 9 of the Pt Thomson Unit Agreement required the drilling of one exploratory well within six months of the date of the agreement and the unit operator to commence drilling additional wells by January 1 of each year.
- 6/7/77 Public Notice of Pt Thomson Unit Application
- 7/26/77 Final Decision and Findings approving the Pt Thomson Unit issued by J. P. Green, Director, Division of Land.
- 8/1/77 Commissioner LeResche approves Pt. Thomson Unit Agreement effective August 1, 1977.
- 11/2/77 Exxon requests Certification of the Pt Thomson #1 Well as capable of producing in paying quantities.
- 11/4/77 PT #1 Well Certified as capable of production in paying quantities.
- Article 10 of the Pt Thomson Unit Agreement required the submission of a further Plan of Development after the completion of a well capable of producing unitized substances in paying quantities.
- 1/3/78 Exxon submit its 1st Plan of Development and proposes drilling the PT #2 Well.

Point Thomson Uint
Detailed History
Page 2 of 15

- 5/28/78 DNR approves the 1st POD until 1/1/79.
- 9/6/78 Exxon requests Certification of PT #2 Well as capable of producing in paying quantities.
- 9/26/78 Exxon proposed 2nd POD which includes drilling the Exxon #3 Well in Nov/Dec 1978.
- 10/9/78 DNR approves 2nd POD through 1/1/80.
- 1/5/79 DNR Certifies PT #2 Well as capable of producing in paying quantities.
- 10/18/79 Exxon submits 3rd POD and proposed drilling the PT #4 Well in February 1980.
- 2/22/80 DNR approves the 3rd POD for the period 1/1/80 – 1/1/81.
- 5/30/80 Letter to Exxon requiring the formation of a Participating Area within sixty days after completion of the Pt. Thomson Well #4.
- 6/13/80 Exxon proposes to amend the Point Thomson Unit Agreement, Article 11. The amendment provides that a participating area (PA) need only be established before production, not immediately after completion of a discovery well.
- 10/8/80 DNR sent a letter to Exxon withdrawing the May 30, 1980 request. A participating area will be required on/or before December 8, 1982 (5 years after completion of the Unit No. 1 certified discovery well). The effective date of the PA will be December 8, 1977, the completion date of the No. 1 well. The first automatic contraction of the unit area, if necessary, will occur in January of 1983.
- 12/1/80 Exxon submits the proposed 4th POD, which includes drilling four wells outside the unit area to test the extent of the reservoir.
- 12/19/80 DNR approves the 4th POD for the period 1/1/81 – 1/1/82 and requests a presentation of the CI Well results.
- 7/22/81 DNR certifies the C1 Well as Capable of Producing in Paying Quantities.
- 8/24/81 Exxon provides C1 Well results presentation.

Point Thomson Uint
Detailed History
Page 3 of 15

- 9/14/81 Exxon submits 5th POD and proposes drilling three wells, two in Nov. 1981 and one in the 81/82 winter drilling season.
- 9/25/81 DNR approves the 5th POD for the period 1/1/82 – 1/1/83.
- 1/5/82 Letter from Exxon referring to June 13, 1980 request to amend Article 11 of the PTU Agreement and proposing amending language in Article 20(c) to delete the requirement of a PA.
- 1/20/82 Memo from Kay Brown, Acting Director to Commissioner Katz recommending approval of the requested amendments to the PTU Agreement. "The effect of this amendment could be to delay formation of a participating area for the Point Thomson Unit until production begins, probably in the late 1980's." She also recommends rescinding DNR's letter to Exxon of October 8, 1980, which required the establishment of a participating area by August 21, 1983. Memo addresses similar issues in Pt Thomson and Duck Island Units. October 8, 1980 letter on Duck Island Unit required the formation of a PA by August 21, 1983.
- 1/25/82 Commissioner Katz's letter to Exxon agreeing to amend Article 11 but not Article 20(c). Katz's decision requires all owners to ratify the amendment before DNR will approve it and rescinds DNR's letter of October 8, 1980. Katz's decision incorrectly provides August 21, 1983 as the required date to form a PA. The October 8, 1980 letter on Pt Thomson Unit required the formation of a PA by December 8, 1982.
- 4/16/82 Commissioner Katz approves and certifies amendment to the Point Thomson Unit Agreement.
- 6/18/82 DNR certifies the F1 Well as Capable of Producing in Paying Quantities.
- 7/27/82 Exxon notes that PTU Agreement is moving toward the end of the initial five-year term and they ask the commissioner for an interpretation of Article 20(c) of the PTU Agreement. Exxon argues that the PTU will be extended under Article 20(c) because there has been a valuable discovery of unitized substances and the PTU "shall remain in effect as long as unitized substances can be produced in quantities sufficient to pay for the cost of producing such substances." Exxon also says that if Article 20(c) does not extend the unit then Article 25 does. Article 25 is the PTU Agreement's force majeure provision and it specifically lists "uncontrollable delays in transportation" as a force majeure event. Exxon says that it has been prevented from developing and producing because of

"uncontrollable delays in the availability of pipeline transportation necessary to market the unitized substance."

- 7/29/82 Brown notifies Exxon that she concurs with its interpretation of Article 20(c) and the PTU is automatically extended. Under the amendment approved in April 1982, to Article 11 of the agreement, a participating area must be formed prior to production from the unit.
- 11/19/82 Exxon submits the 6th POD. The plan does not include drilling any wells but proposes a drilling and sampling program, color aerial reconnaissance photography of the Pt Thomson area, a hydrology program, and geophysics, physical oceanography and coastal processes programs during 1982. 1983 projects include a geotechnical survey, hydrology study, and an onshore environmental survey.
- 12/10/82 DNR approves the 6th POD for the period 1/1/83 – 1/1/84 and request a list of the studies and a meeting in Sept/Oct 1983 to discuss results of the studies.
- 10/28/83 Exxon submits 7th POD requesting a 5-year plan with no drilling until contracts are issued for a gas line.
- 11/29/83 DNR approves the 7th POD for the period 1/1/84 – 12/31/88. Annual progress reports are required.
- 12/7/83 Exxon gives notice of the proposed expansion of the PTU. The proposed expansion had been preliminarily approved by the director subject to a number of conditions including the condition that the state's royalty in kind share be free of cleaning and dehydration costs. Many of the companies objected to this requirement.
- 1/13/84 Exxon submits an application to expand the PTU. Not all owners had ratified the application.
- 1/20/84 Exxon submits a filing fee of \$20.00 per 11 AAC 88.105.
- 1/26/84 Public Notice of the expansion application published in the Anchorage Daily News. Thirty 30 public comment period.
- 2/15/84 Brown notifies Exxon that it is the continuing state policy that renegotiation of lease terms upon unitization constitutes a reasonable exchange of value for the benefits that the lessees obtain from the act of unitization and if the state concludes that renegotiations are necessary to

protect the public interest, the state will seek to obtain those terms. She further notified them that the state could not take action on the application until they retracted their objection.

- 2/16/84 Exxon notifies Brown that they consent to the conditions imposed on expansion of the unit area. Within weeks, the rest of the lessees consented.
- 3/14/84 DNR questions whether the northern leases are justified for inclusion in the PTU. DNR requires a well be drilled on one of the northern twelve leases before February 1, 1990, as a condition for inclusion in the PTU. If the well is not drilled by that date the acreage will contract out of the unit. Two other leases are to be excluded from the expansion application.
- 3/26/84 DNR approves the First Expansion of the Point Thomson Unit effective retroactive to January 1, 1984. Expansion area includes 25 additional leases comprising approximately 94,152 acres for a total unit area of approximately 134,920 acres. The expansion was conditioned on the lessees acceptance of specific terms and conditions for the expansion leases as follows: (a) five leases had their rental, royalty, minimum royalty, drilling and producing terms amended (State's RIV shall be free and clear of all lease expenses; (b) two leases a well drilling commitment by 3/31/85; (c) ten leases had a well drilling commitment by 2/1/90; and (d) within one year Exxon must submit an application to amend the PTU Agreement to accommodate the Net Profit Share leases.
- 8/31/84 Exxon requested amendments to Articles 2, 7, 11, 12, 18(f), 20(c), 21 and 30 of the Point Thomson Unit Agreement. Pertinent changes include amending Article 11 to accommodate the Net Profit Share Leases and a modification to Article 21, Rate of Prospecting, Development and Production. Article 21 is amended to read as follows: 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 [Fifteen (15)] thirty (3) 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, in any case, curtail rates of production to an unreasonable extent, considering unit productive capacity, transportation facilities available, and conservation objectives; or (iii) prevent this agreement from serving its purpose of adequately

protecting all parties in interest hereunder, subject to applicable conservation laws and regulations. (Brackets deleted, Underline added)

- 12/21/84 Exxon submits 1st Annual Progress Report "[Due to the]... refusal of some Unit owners to release data from wells which are still held confidential, a Unit-wide owners' technical committee has not been feasible. Exxon is continuing efforts to enlarge the data base and conduct a joint study. Meanwhile, Exxon, working with the available data base, has continued its proprietary studies of the reservoir. This phase of Exxon reservoir studies will be completed next year."
- 1/17/85 DNR accepts 1st Annual Progress Report.
- 1/21/85 DRN approves amendments to the PTU Agreement as proposed.
- 4 /85 Two leases, ADLs 28386 and 28387, were contracted out of the PTU for failure to commence the required well by the 3/31/85 deadline.
- 9/11/85 Pt Thomson Development Review Meeting held. Exxon provided confidential information to the Division of Oil and Gas regarding a gas cycling development schedule for the PTU. Start-up of the project was planned for 1991-1992.
- 12/6/85 Pt Thomson Development Review Meeting and submittal of 2nd Annual Progress Report. "Efforts during the past year have focused on two areas: 1) continued evaluation and analysis of available well and seismic data to refine knowledge of the reservoir and develop additional drilling plans, and 2) continued engineering and field studies to ascertain the viability of a potential gas cycling/condensate recovery project. To date no agreement has been reached, but the WIOs are continuing to pursue mechanisms which would yield access to the well data for purposes of common data base analyses."
- 9/29/86 Exxon submits 3rd Annual Progress Report. "In spite of the economic downturn experienced by the oil industry this past year, Exxon devoted approximately 6 man-years of technical support activity to Point Thomson development. These efforts continued to focus on improved reservoir description, well deliverability analysis, and engineering studies to more accurately assess the technical feasibility and reservoir performance of a potential gas cycling condensate recovery project."
- 9/29/87 Exxon submits 4th annual Progress Report. "Due to continued lack of a transportation system for Point Thomson gas, efforts in 1987 focused on

assessing the reservoir risk associated with a potential gas cycling development and evaluating areas to enhance its economic viability. In spite of the poor economic climate in the oil industry this past year, several man years of work were devoted toward improving the technical understanding to the reservoir and gas cycling feasibility."

- 12/16/87 Pt Thomson Development Review Meeting.
- 6/15/88 Meeting to discuss proposed well location.
- 8/9/88 DNR Letter to Exxon: PTU #5 Well location acceptable to satisfy 2/1/90 contraction date.
- 8/15/88 Letter from Exxon informing DNR that a confidential well data trade has been finalized.
- 9/27/88 Exxon submits 8th POD for 3-year term. The plan includes a 3D seismic program over 2/3 of the unit area and drilling the PT #5 Well in February 1990. In the annual progress report to the 7th POD, Exxon acknowledged that gas cycling to extract liquids was identified as the only other potential development alternative prior to major gas sales. The option is considered high risk and viewed as uneconomic by a majority of working interest owners.
- 10/6/88 DNR approves the 8th POD for the period 1/1/89 – 12/31/91.
- 6/7/89 Meeting to discuss 1989 3D Seismic program and plans for drilling the PT #5 Well.
- 8/10/89 Exxon requests later date for drilling obligation.
- 8/15/89 DNR approves revised drilling schedule. Well to be drilled during 90/91 drilling season. If well is not drilled all 10 leases contract out of the unit on 2/1/90 and penalty payment of \$9.5 million.
- 8/27/89 Exxon submits Annual Progress Report. "During the past year, PTU owners have made excellent progress toward accomplishing the goals of the Eighth POD, both in acquisition and processing of the 3-D seismic survey and in planning the PTU Well #5. ;...The survey operations were concluded on May 15, 1989, as a result of deteriorating ice conditions. A total of 83 square miles of data were collected. The completed survey covers the main portion of the Unit, including the possible gas cycling area."

- 10/10/89 DNR accepts Annual Progress Report
- 1/8/90 Exxon notifies DNR that the PT #5 well will not be drilled.
- 2/5/90 Nine of the ten northern leases included in the First PTU expansion were contracted out of the unit area for failure to commence the required well by 2/1/90. After this contraction, the PTU contains 32 leases comprising approximately 83,825 acres.
- 9/28/90 Exxon submits Annual Progress Report. "During the past year the PTU owners made substantial progress toward accomplishing the goals set out for the Eighth POD as submitted for approval on September 26, 1988. While attempts to initiate the drilling of the PTU No. 5 were unsuccessful, the owners succeeded in acquiring and processing the planned 3-D seismic survey data.
- 8/19/91 Exxon submits 9th POD for 4-year term. The proposed 9th POD includes continued efforts to more accurately assess field development potential through completion of geologic structure maps of currently known reservoirs. Exxon's preliminary work suggests reserves may be up to one-third less than the nominal 5tcf assigned to the field.
- 8/29/91 Meeting to discuss proposed Plan of Development.
- 1/3/92 DNR approves 9th POD for only one year from 1/1/92 – 12/31/92. DNR requested Exxon to expedite consensus mapping efforts in order to evaluate all PTU development opportunities.
- 8/27/92 PTU working interest owners presented consensus structure map of Thomson Sands to DNR.
- 10/1/92 Exxon submits 10th POD. The owners propose to undertake a multi-year Reservoir Characterization Study on the Thomson Sand.
- 11/27/92 DNR approves 10th POD for the period 1/1/93 – 12/31/93.
- 6/23/93 Pt Thomson Unit owners met with DNR to discuss PTU development options. The owners said that a liquid recovery program was uneconomic at this time. They had no plans to use the gas for other North Slope uses. A major gas sale from the North Slope fields was highly unlikely in the near future. They explained their plans for further geology and reservoir

studies of the Point Thomson reservoir(s). They did not propose any new exploration work.

- 9/29/93 Exxon submits the 11th POD proposing to continue the Reservoir Characterization Study. At the end of this one year term, the environmental facies analysis, petrographic analysis, petrophysics, geologic model construction, and the review of existing engineering data will be complete, and work will be well underway on the drill stem test interpretations, fluid property studies, and deliverability calculations.
- 12/17/93 DNR approves the 11th POD for the period 1/1/94 – 12/31/94 and gives notice to Exxon of intent to contract the unit boundary effective January 1, 1995. "Little exploration work has been conducted on tracts within the unit boundary in the past few years. No exploration work was conducted under the tenth plan nor is any contemplated under the eleventh plan. The tracts identified in Attachment #1 to this letter have not been shown to overlay any hydrocarbon reservoir. Absent significant and actual on-the-ground exploratory activity on the tracts identified in Attachment #1 on or before December 31, 1994, pursuant to 11 AAC 83.356(e) and 11 AAC 83.343(b), I plan at this time to contract the unit boundary effective January 1, 1995."
- 1/12/94 DNR and Dept. of Law representatives met with BP Exploration. BPX stated that it was completely surprised by the notice of intent to contract the unit area. In response to the notice letter, Exxon encouraged all other owners to make a case to the state regarding the contraction matter and the activity in the unit. BPX mentioned that they proposed farm-in agreements to Exxon to drill prospects in the south and center of the unit. Exxon rejected these proposals. BPX also noted continued problems with the sharing of information among the owners. As part of its agreement with BPX, Chevron refuses to share information with Exxon about its farmout with BPX. BPX discussed their Sourdough prospect. They noted that it may communicate with the Flaxman prospect to the north on PTU leases.
- 2/3/94 Chevron, BPX and Exxon met with DNR staff. The companies stated there would be a working interest owners meeting on February 10, 1994. Exxon read a prepared statement and asked that five tracts be deleted from the proposed contraction area because they were part of the Sourdough prospect. Director Eason responded that he was not willing to discuss the unit piecemeal and he wants a response to the State's contraction notice. Exxon had concerns about the rationale for the proposed contraction and the meaning of significant activities. Eason requested that Exxon put their

questions in writing. BPX stated that they planned two wells for the Sourdough prospect, #1 outside the unit and #2 inside the unit. The #1 well would be subject to an Exploration Incentive Credit (EIC). By drilling the #2 well inside the unit, they would be giving up any right to an EIC estimated to be worth \$2.5 MM.

- 2/16/94 Letter from Exxon questioning decision to contract the unit boundary.
- 2/25/94 DNR responded to Exxon on contraction and drilling commitments.
- 4/15/94 BPX applied for a paying quantities determination for the Sourdough #2 well.
- 4/26/94 DNR certified the Sourdough #2 well as capable of production in paying quantities. The southern half of this lease was identified as a lease subject to the division's PTU contraction notice.
- 5/11/94 Meeting for DNR to have a better understanding of known and potential reservoirs in the Pt Thomson Unit and surrounding areas.
- 9/29/94 Exxon submits 12th POD including a discussion of marketing issues. In April 1994, BPXA completed drilling the Sourdough #2 well located within the PTU. In June 1994 DNR certified the well as capable of production in paying quantities.
- BPXA conducted the Yukon Gold 3D seismic program during the 1994 winter season. This program covered all or a portion of 10 PTU leases.
- During the 12th POD the owners propose to complete the Reservoir Characterization Study including drill stem test interpretations, fluid property studies, and deliverability calculations. Engineering screening studies will be initiated during the 12th POD.
- 12/22/94 DNR agrees to extend the 11th POD until April 30, 1995 "to review the discussions and the documents exchanged to date regarding our respective views on contraction of the unit area and on diligent further exploration and development of the PTU acreage."
- 4/20/95 DNR agrees to further extend the 11th POD until July 15, 1995, to provide an opportunity for both parties to review the issues regarding our respective views on contraction of the unit area and on further diligent exploration and development of the PTU acreage.

- 7/14/95 DNR agrees to further extend the 11th POD until September 1, 1995, to provide an opportunity for Exxon, Commissioner Shively and appropriate staff to review the issues regarding our respective views on contraction of the unit area and on further diligent exploration and development of the PTU acreage.
- 8/31/95 DNR agrees to further extend the 11th POD until February 1, 1996. "The Twelfth Plan of Development will be resubmitted on or before November 1, 1995. Prior to resubmitting the Twelfth POD staff from Exxon and this division will meet to assess progress on the Eleventh POD and to consider additions to the Twelfth and subsequent Plans. I expect this meeting can take place in late September."
- 10/4/95 Meeting to review progress under the 11th POD and discuss possible work initiatives for the 12th and future PODs.
- 10/31/95 Exxon submits 13th POD for 23-month term. Owners will undertake a study aimed at evaluating potential development scenarios for the PTU. Exxon, Mobil and Phillips each plan to initiate a farmout effort targeting flank PTU acreage.
- 11/15/95 BP submits request for Lease Operations approval for Sourdough #3 Exploration Well to be drilled during the winter of 1995/96 on ADL 343112 within the PTU.
- 12/28/95 DNR approves the 13th POD for the period February 2, 1996 through December 31, 1996. Request a June meeting to evaluate the potential development scenarios.
- 1/25/96 Meeting to discuss the 13th POD farmout initiative.
- 6/27/96 Meeting to review progress under the 13th POD. Exxon has completed preliminary work on several potential development scenarios using aggressive cost and wellbore deliverability assumptions. Owners concluded that a full 3D geologic model and reservoir simulation model needed to be constructed early in the life of the study, i.e. in Phase I. A farmout proposal from ARCO was received on July 2. BP is also interested. Revised schedule: Phase II to commence late 1996 and carry into 1997.
- 10/2/96 Exxon submits the 14th POD, a continuation of the phased development study and farmout initiative begun under the 13th POD.

Point Thomson Uint
Detailed History
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- 11/29/96 DNR approves the 14th POD for the period 1/1/97 – 12/31/97. Request a meeting no later than June 1997 for a Phase 1 progress report of the PTU development screening study and a report of the farmout efforts.
- 3/7/97 Exxon, Mobil and Phillips had granted farmouts to ARCO.
- 10/2/97 Exxon submits the 15th POD. The work activities associated with Phase II of the Unit's development screening study will be completed during the 15th POD.
- 10/8/97 DNR determines the 15th POD is incomplete. The plan does not include delineation of all reservoirs in the unit area. 30 days to submit a revised POD.
- 11/6/97 Exxon submits a letter stating that the Unit's working interest owners believe the submitted 15th POD is complete.
- 11/24/97 DNR responds to Exxon as to requirements for a complete POD.
- 12/16/97 Meeting with PTU owners. DNR will entertain an interim POD for six months to allow time to develop a fully integrated unit plan of development.
- 12/19/97 Exxon submits a revised 15th POD.
- 12/24/97 DNR approves an Interim POD for the period 1/1/98 – 6/30/98. Request a meeting no later than April 15, 1998. Exxon must submit current Exhibits A and B to the Unit Agreement by January 31, 1998. By March 31, 1998, Exxon will submit: (1) a list of the studies done to date with a synopsis of each one; (2) a list of all agreements between the Point Thomson Unit owners with an explanation of each one; and (3) provide a briefing on the results of the full field modeling and Parson's Study. Exxon will also coordinate with ARCO to arrange a presentation of the 3D seismic data collected by ARCO under a farmout agreement with Exxon by March 31, 1998. The division also requested a briefing by BP and Chevron during the first quarter of 1998, on the Plan of Exploration for the Sourdough prospect.
- 1/27/98 Exxon submits new unit Exhibits A and B.
- 2/11/98 DNR meeting with Exxon on the milestones in the Interim POD.

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- 3/2/98 Chevron and BP provide a technical presentation on the Sourdough #3 well extended confidentiality.
- 3/30/98 Exxon submitted a list of the studies done to date with a synopsis of each one and a list of agreements between the PTU owners with an explanation of each one.
- 4/2/98 Pt Thomson Review attended by representatives from Exxon, BP, Chevron, Mobil, Phillips and DNR. Exxon provided a briefing on the results of the full field modeling and Parson's study.
- 4/7/98 Chevron and BP provide a technical presentation on the Sourdough prospect.
- 4/7/98 Arco presents 3D seismic data over farmout area.
- 5/14/98 Exxon submits a draft of the 15th POD.
- 5/21/98 Teleconference call with Exxon and WIOs to discuss draft 15th POD.
- 5/29/98 Teleconference call with Exxon and WIOs to discuss draft 15th POD.
- 6/5/98 Exxon submits revised draft of 15th POD.
- 6/9/98 DNR faxed comments of revised draft POD to Exxon.
- 6/16/98 Exxon submits 15th POD
- 6/19/98 Exxon submits final 15th POD.
- 6/30/98 DNR approved 15th POD for the period 7/1/98 through 9/30/99. Exxon will establish a common database, develop delineation plans, and complete development planning studies during the term of the 15th POD. Exxon also plans to explore potential synergies between development of the oil and gas reserves in the unit area. A status report is due by September 30, 1998, to demonstrate the exchange of sufficient data to map the work contemplated by the 15th POD. The owners shall create a common technical PTU database and consensus maps for all prospective reservoirs within the PTU by September 30, 1999.

FRANK H. MURKOWSKI, Alaska, Chairman

PETE V. DOMENICI, New Mexico
DON NICKLES, Oklahoma
LARRY E. CRAIG, Idaho
BEN NIGHTHORSE CAMPBELL, Colorado
CRAIG THOMAS, Wyoming
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ANDREW D. LUNDQUIST, STAFF DIRECTOR
GARY G. ELLSWORTH, CHIEF COUNSEL
THOMAS B. WILLIAMS, STAFF DIRECTOR FOR THE MINORITY
SAM E. FOWLER, CHIEF COUNSEL FOR THE MINORITY

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES

WASHINGTON, DC 20510-6150

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July 15, 1998

RECEIVED

JUL 21 1998

Mr. Kenneth A. Boyd
Director, Division of Oil and Gas
Department of Natural Resources
State of Alaska
3601 C Street, Suite 1380
Anchorage, Alaska 99503-5948

Dear Mr. Boyd:

This is to advise you that the Senate Energy and Natural Resources Committee has scheduled a hearing to conduct oversight on the results of the Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, conducted by the United States Geological Survey. The hearing will take place on Thursday, July 23, 1998 at 9:30 a.m. in room SD-366 of the Dirksen Senate Office Building, Washington, D.C.

The Committee respectfully requests you or your designee to present testimony. Specifically, the Committee would be interested in hearing your view of the results of this Assessment especially as it relates to state and private lands; how these estimates compare with previous estimates; what has been the state of Alaska's experience with use of advanced seismic technology compared with that used more than a decade ago in delineating potential fields; what has been the state's experience with economic field size; how has the advancement of technology helped in discovering new reserves and developing them while minimizing the environmental impacts, and how useful these new results may be in determining if the subsurface resources of the Arctic National Wildlife Refuge are being threatened from development on non-federal lands adjacent to ANWR.

We ask that you submit 100 copies of your testimony to the Committee by close of business on July 21, 1998. In addition, a copy of your written testimony on a computer disk in any format would be greatly appreciated. Because of time limitations, we ask that you limit your oral testimony to five to seven minutes. Your written testimony can be comprehensive, and it will be included in the official hearing record.

On behalf of the Committee, I would like to thank you in advance for your cooperation and participation in the Congressional hearing process. Your insights will considerably help the Committee and the Senate formulate sound policy. Should you have any questions, please contact Brian Malnak or Jo Meuse at (202) 224-6730.

Sincerely,

A handwritten signature in dark ink, appearing to read "Frank H. Murkowski". The signature is fluid and cursive, with a large initial "F" and a stylized "M".

Frank H. Murkowski
Chairman

**Testimony of Kenneth A. Boyd
Before the United States
Senate Energy and Natural Resources Committee**

**Arctic National Wildlife Refuge 1002 Area
July 23, 1998**

Introduction

Mr. Chairman and members of the Committee, for the record my name is Ken Boyd and I am the Director of the Alaska Division of Oil and Gas. I have B.S. and M.S. degrees in geology from the Rensselaer Polytechnic Institute. I have worked in the oil and gas business, in a variety of capacities, since 1973. Much of this time has been spent working on Alaska exploration.

I have been asked to comment on the latest U.S. Geological Survey estimates of undiscovered petroleum resources beneath the ANWR coastal plain. Because the 1998 ANWR 1002 Petroleum Assessment (conducted by the United States Geological Survey) has not been released, I cannot comment in detail on it at this time. I will be pleased to provide a review once the report is finalized.

I have seen the USGS fact sheet that summarizes some of the findings of this assessment. In very simple terms the assessment shows more oil in ANWR than in many previous assessments. However, as the USGS points out in its fact sheet, "One cannot make a meaningful comparison with previous assessments without knowledge of differences in assessment methodology, assumptions and data". Until the final report is released, I will withhold any detailed comments.

I can, however, make some general observations, and have provided a table and bar chart to show some earlier resource estimates alongside the new USGS numbers. The table shows three categories of undiscovered resources: in-place oil, technically recoverable oil and economically recoverable oil. Please note that only the 1987 USGS/BLM assessment of in-place oil is directly comparable to the new study. The new study shows an overall increase in the mean estimated in-place oil from 13.8 BBO (billion barrels of oil) in the 1987 study to 20.7 BBO today. The other categories of undiscovered oil are not directly comparable due to differences in methodology and play selection. However, gross comparisons of estimates derived from the 1995 USGS Regional Assessment indicate that the new study is generally more optimistic in its assessment of both technically recoverable and economically recoverable oil. For example, in 1995 the USGS mean estimate of risked economically recoverable oil was 0.898 BBO for the entire 1002 area. The new mean estimate is 0.6 BBO in the deformed region (eastern 1002 area) and 2.6 BBO in the undeformed (western 1002 area). Again, I must stress that the technically recoverable and economically recoverable estimates are not directly comparable.

In my opinion, the most important facts revealed so far from the USGS fact sheet are:

- 1) the estimates for finding recoverable oil are quite high, and in fact, have been increased from previous assessments;

- 2) these scientists believe the bulk of the undiscovered oil resides in the northwest part of the 1002 area rather than to the east as was assessed in previous studies;
- 3) more oil has been allocated to the younger (Brookian) reservoirs in stratigraphic traps; less oil has been allocated to the deeper Ellesmerian reservoirs in structural traps;
- 4) the assumed 512 million barrel commercially developable field size for ANWR is probably too conservative for the undeformed, western part; smaller accumulations are likely to be economic, especially if infrastructure is established in the Point Thomson, Sourdough and Flaxman areas.

As you know, a number of public estimates of the oil and gas potential of the 1002 area have been made over the last 18 years. The latest USGS estimates confirm what geoscientists have been saying for years. The 1002 area holds extremely high promise for finding commercial petroleum deposits. This is great news for Alaska and great news for the Nation.

I think it is also important to offer you some of my own observations based upon the exploration and development activity on state-owned North Slope lands west of the 1002 area.

The acquisition and interpretation of 3D seismic data has revolutionized exploration and step-out development efforts. Modern 3D data provides enhanced and incredibly accurate imaging of potential subsurface reservoirs. This reduces exploration and development risk, reduces the number of drilled wells and in turn, reduces both overall costs and environmental impacts. No 3D seismic data are yet available in the 1002 area, therefore the benefits of 3D have yet to be realized.

The Minimum Economic Field Size (MEFS)—the volume of oil required for a prospect to be economically successful—has decreased over time for the North Slope. In years past, fields of 500 million to 1 billion barrels of recoverable oil were believed to be necessary for economic success. Today, due to better technology, and lower finding and development costs, fields in the 120 to 150 million barrel range are being developed. Much smaller accumulations closer to existing infrastructure are also being developed.

Environmental impacts from development activities are being reduced. Advances in production technology continue to shrink the "footprint" of development. Computer mapping of critical habitats and wildlife use patterns has led to site-specific stipulations and regulations that can mitigate potential conflicts. The developments at Badami, Alpine and Northstar are good examples of modern, minimal impact oil fields in environmentally sensitive areas.

The last several years have been exciting times in the Alaska oil patch. The current high level of oil and gas activity in Alaska can be attributed to a favorable business climate and the use of new technology to reduce costs. This favorable climate exists, in large part, due to an ongoing series of new legislation that has improved the state's stature in the world oil marketplace. Areawide leasing is one example. On the technology side, 3D seismic and extended reach drilling have enabled the industry to drill "smarter" wells that allow substantial reductions in costs.

The industry commitment to Alaska's oil and gas future has been amply demonstrated in recent lease sales. Our Beaufort Sea Sale held last November brought in \$28 million and the state collected \$55 million from our first areawide sale held last month on the North Slope. I expect to see a further jump in exploration activity as a result of these sales. Naturally, I hope this exploration will lead to further development such as is occurring at the Badami, Tarn and Alpine fields, to name a few. Exploration and development of so-called "satellite" fields—fields in and near existing fields—is moving ahead at a rapid pace. The Tarn field, at the southwest edge of the Kuparuk field, is the latest satellite to start production. Much of this activity is made possible by new technology.

Not too far off is the construction of the first arctic, subsea oil pipeline in the world at the Northstar field. North American records for extended reach drilling have been set at Niakuk, and they continue to reach farther and farther as the technology improves. Enhanced oil recovery projects are underway in several fields. Last session, the Alaska legislature began serious debate on bringing Alaska's vast natural gas resources to market. In early August the final Environmental Impact Statement for the National Petroleum Reserve-Alaska (NPR-A) should be released. I hope to see a sale there later this year or in early 1999. And then there is ANWR.

Minimum Economic Field Size

You have also asked for my view on economic field size. For North Slope lands leased by the state, minimum economic field size has decreased dramatically over time. I believe that several factors have contributed to the decrease.

The first factor is 3D seismic technology. 3D seismic is rapidly replacing 2D as the "conventional" approach to development and exploration as costs decrease and as computer aided interpretation increases the amount of information that can be extracted from the data. All new fields currently being developed and parts of many existing fields on the North Slope have been resurveyed with 3D seismic in order to place and guide development wells. The coverage and sheer volume of data that the 3D seismic method generates leaves no blank spaces on the map to guess about and very small prospects can be delineated that could be missed or misinterpreted with 2D data. The 3D data cube is uniform and consistent so that changes in the data can more reliably be attributed to changes in the subsurface. Also, 3D seismic produces much better structure maps of the subsurface, especially in areas that are highly faulted. For these reasons, more 3D seismic will be acquired, both offshore and onshore, in the future.

In imaging the small, stratigraphic prospects currently of interest on the North Slope 3D seismic technology is definitely an improvement over 2D. Advancements in acquisition, processing and interpretation have enabled geophysicists to produce 3D visualizations of sand bodies only a few hundred feet wide at great depths. That being said, there is no guarantee that the sand will be saturated with oil in commercial quantities or that it will have good reservoir characteristics (such as sufficient permeability). These risk factors remain, even with the most sophisticated interpretation. However, the industry is working hard to get the most out of the seismic data and it would not surprise me to see these problems substantially solved in the future.

3D seismic yields such convincing results and confidence in the interpretation that companies are more willing to commit to drilling expensive, long reach wells thus minimizing surface impacts. With the advent of 3D seismic data, the State has noted an increase in drilling activity from existing pads in the Prudhoe Bay and Kuparuk River Units utilizing long offset drilling technology. 3D seismic has contributed to the industry's increased drilling success rate. For example, BP recently announced that the success rate for its North Slope exploration wells has been 1 in 2 over the past five years. About three years ago, the A.D. Little consulting firm reported the North Slope exploration success rate as 1 in 12. 3D seismic not only gives the explorationist a clearer view of the subsurface, it gives the production manager a tool to drill more efficient development wells. It allows industry to drill "smarter" wells to produce new and existing fields, substantially reducing production costs. "Smarter" means fewer wells drilled with a greater precision than could have been achieved even five years ago. 3D, in combination with computerized drill bits equipped with sensors and communication gear and other new technology, allow industry to "steer" wells to reservoir targets with previously unimagined precision. 3D seismic also assists in designing water floods and other cost-effective production enhancing techniques. In short, 3D seismic produces an interpretation that is more reliable and comprehensive than the old 2D data could generate and this results in maximizing reservoir recovery while minimizing surface disturbance.

Technology has assisted in reducing the well costs in other ways. Extended reach drilling (ERD) has pushed past 20,000 feet. Besides improving the economics, ERD helps environmentally by shrinking the "footprint" of development. Other new well technologies include through-tubing rotary drilling, coiled tubing drilling and multilateral wells. Combining these technologies allows the companies to drill so-called "designer wells". These wells, which twist and turn in some very exotic shapes, allow the drillers to target very small and difficult to reach oil deposits. Simply working smarter has let industry shorten the time to complete wells, reduce overall costs, and reduce environmental impacts.

The statistics show that with this new technology and other cost cutting measures, industry has reduced its operating costs thereby decreasing the minimum economic field size. Between 1991 and 1996, ARCO reported that its operating expenses on the North Slope were reduced from \$2.29 per barrel to \$1.54 per barrel (a 33% reduction); development well costs were reduced from \$3.0 million per well to \$2.0 million per well (a 33% reduction); and well hook-up costs were reduced from \$1.5 million per well to \$0.6 million per well (a 60% reduction). Between 1996 and 1997, development well costs were reduced another 15%. ARCO reported these cost reductions in "dollars of the day", and considering inflation over this period, these reductions are, to quote ARCO, "even more dramatic".

ARCO is not the only company that has reported a dramatic reduction in operating costs on the North Slope. In June BP reported that operating costs at the Prudhoe Bay field have been cut by 50% since 1991. Also BP reported that the well costing \$3 million in 1991, now costs \$1 million (a 67% reduction).

BP's Northstar development illustrates the effect of this dramatic reduction in production costs on minimum economic field size. In June of 1994, Amerada Hess concluded the Northstar field was uneconomic because development costs would exceed \$1.2 billion and eventually sold the

field to BP. Today, BP expects to begin production of the field's 145 million barrels of reserves in 2000. Its estimated development costs: \$350 million (a 70% reduction).

The state is also witnessing the development of very small fields near existing infrastructure as well development of fields miles away from infrastructure that several years ago would have been considered uneconomic. Fields that either have been recently developed or are moving forward with development using existing infrastructure include: Niakuk, Tarn, Sambucca, Midnight Sun, Pete's Wicked, Cascade, Eider, Sag River, and Tabasco. In addition to Northstar, other small stand-alone fields are coming on line. Those fields (with their reported reserves and estimated development costs) include: Alpine (365 million barrels of reserves with \$650 million development cost), Badami (120 million barrels with \$300 million development cost), and Liberty (120 million barrels with \$250 million development cost). The development of these smaller accumulations demonstrates that the minimum economic field size on the North Slope has been substantially reduced.

I cannot comment with specificity on what the USGS characterizes as its "rather conservatively" assumed 512 million barrel minimum commercially developable field size for ANWR reported in the USGS fact sheet because the analysis supporting that figure has not been released. I can say, however, if the known accumulations in the Point Thomson Unit area are developed, a field much smaller than 512 million barrels of reserves near the east side of the Canning River would likely be economic.

Drainage Issue

You have also asked whether new technological results are useful in determining if the subsurface resources of ANWR are being threatened by development of adjacent non-federal lands. Obviously, if better seismic data for ANWR were available, I would be in a better position to answer your question. And most of the geological and geophysical data the state possesses for adjacent state acreage is confidential. So I cannot tell you about the state's view on whether the Sourdough accumulation extends into ANWR.

What I can say is, if any of the known accumulations in the area around the Point Thomson Unit extend into ANWR, the chairman of Alaska's Oil and Gas Conservation Commission has stated that the so-called "rule of capture" controls. Our attorney general's office has told us the same thing. That means that the state believes that a state lessee could drain federal acreage. The federal government would have so-called "correlative rights", that is the right of an adjacent owner of an oil pool to produce his equitable share of the oil.

3D Seismic in ANWR

I was on the team of companies that designed the ANWR seismic program in the early 1980's. The discussions were long and complicated (helped somewhat by the fact that these meetings were held in Hawaii). My personal experience interpreting ANWR seismic data is fairly extensive. I worked as an ANWR consultant doing contract seismic interpretations. I consulted for a number of companies and my experience was always the same. I would be assigned someone from the company to work with, often someone with considerable seismic

interpretation background, but no experience in ANWR. The company interpreters always started in the undeformed area near Kavik and began moving east. It all seems so easy to start. Then you reach the deformed section near the center of ANWR and the evaluation suddenly becomes much more difficult. Using an analogy I would describe the action this way:

At first you are walking along a well-lighted hallway in an unfamiliar building. Everything is as it should be with doors leading into offices here and there. The hallway makes a turn occasionally, but you always have your bearings.

Then you come to a door marked "Central ANWR." You open the door and step into a room full of mirrors. You struggle along, making some progress until the room starts to spin. Now you are uncertain where you are, or where you came from.

Then the lights go out.

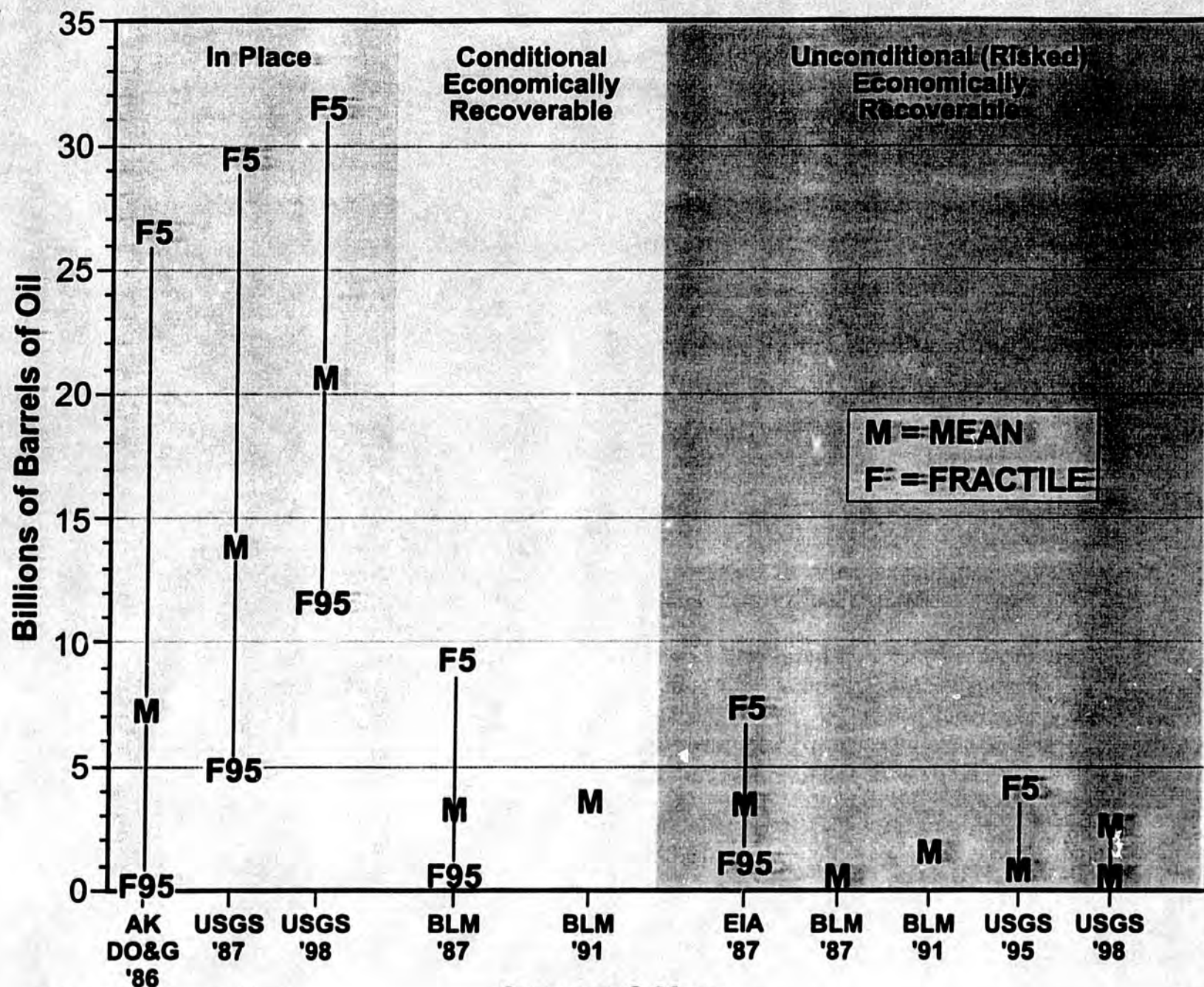
ANWR seismic data has served us well to this point, but after 15 years it is time to face the reality that we have wrung all the information out of this data that we can. 3D seismic has proved its value repeatedly. 3D seismic in ANWR would go a long way in unraveling a number of secrets that this incredibly complicated piece of real estate holds. 3D seismic coverage in the northwest quadrant of the 1002 area, especially adjacent to Sourdough and the Point Thomson Unit, would help delineate and extend known geologic trends and prospects. On the Canning River delta the old 2D seismic data set is very thin, consisting of only three seismic lines. That data is not extensive enough to adequately map and evaluate potential prospects. A comprehensive 3D seismic program east of the Canning River would go a long way toward answering the questions about the extent of known accumulations and the presence of other prospects.

Conclusion

I would like to thank the Chairman and this committee for their time and attention. The new estimates of undiscovered oil in ANWR are encouraging and should be viewed in a very positive light. It is not often that one of the Nation's premier assets—the petroleum potential beneath the ANWR coastal plain—gets upgraded so dramatically. In combination with this is other good news for every one of us that is concerned with preserving the surface values of the coastal plain. There is a heightened awareness in the petroleum industry operating in arctic Alaska to extract hydrocarbons in an environmentally safe and acceptable way. A revolution in drilling and development technology, and computer mapping applications has and will continue to dramatically reduce the footprint of development. The life of an oil field is temporary, with large fields lasting 30 to 50 years and smaller deposits depleted in 10 to 15 years. Our job is to make sure that our temporary occupation in these remote areas for petroleum extraction does not produce any long-term detrimental impacts.

Fields can be developed in sensitive areas by using the new technologies in combination with site specific stipulations and mitigation measures. I firmly believe that sound science is the necessary foundation for implementing successful development in the Arctic, both in the profitable extraction of our domestic petroleum resources and the protection of our sensitive

surface values. The Alpine oil field is being developed without gravel road access in a remote and sensitive part of the Colville River delta. The stand-alone development of this 365 million barrels of reserves will consist of two small development pads connected by a three mile long road/airstrip, and occupy only about 115 total surface acres. I believe this can be a model for remote oil field operations—what the Governor calls “Doing It Right”—and I believe we will continue to develop new techniques to minimize and mitigate environmental impact.



SOURCE: Alaska Division of Oil & Gas, July 1998

*Reflects a change in original probability from 19% to 46%.

**Estimates of Undiscovered Oil Resources in the Coastal Plain
of the Arctic National Wildlife Refuge 1986 - 1998.**

ANWR Undiscovered Oil Estimates Comparison of USGS 1998 Estimates

Total In-Place Unconditional Estimates (1) (billions of bbls)		
	1987 BLM	1998 USGS
Fractile	OIL Estimate	OIL Estimate
F95	4.8	11.6
F75	8.2	
F50, median	11.9	
F25	17.2	
F05	29.4	31.5
Mean	13.8	20.7
Mode	8.8	

(1) The in-place estimates are directly comparable.

Undiscovered, Unconditional Technically Recoverable Oil in ANWR 1002 Area (2) (billions of bbls for oil)					
1995 USGS Nat'l Assessment Northern Alaska Province		1998 USGS Assessment 1002 Area			
		1002 Area Fed Excluding State & Native	1002 Area All lands Entire asses area	Undeformed Area	Deformed Area
Fractile	OIL Estimate	OIL Estimate	OIL Estimate	OIL Estimate	OIL Estimate
F95	2.34	4.254	5.724	3.403	0.0
F5	15.43	11.799	15.955	10.224	3.185
Mean	7.41	7.668	10.322	6.420	1.248

(2) The technically recoverable estimates are NOT directly comparable; different methodology, different plays.

Undiscovered Economically Recoverable Oil Estimates (3) (billions of bbls)						
	Conditional 1987 BLM Most Likely	Conditional 1987 BLM Optimistic	Conditional 1991 BLM Update	Unconditional 1995 USGS Derived from Reg'l Assesmnt	1998 USGS Deformed	1998 USGS Undeformed
Fractile	Economic Case	Economic Case	Mean Est Only			
F99	0.49	0.18		na		
F95	0.59	0.23		0 *		
F75	1.12	0.67		na		
F50, median	2.21	1.49		0.00		
F25	4.24	3.67		na		
F5	9.24	7.65		4.129 *		
F1	17.19	15.73		na		
Mean	3.23	2.66	3.57	0.898 *	0.6	2.6
Marginal Prob	19%	26%	46%	na		
MEFS	0.44	0.15		0.40		
Risked Mean *	0.6137 *	0.6916 *	1.6422 *	0.898 *		

(3) The economically recoverable estimates are NOT directly comparable due to differences in methodology.

(3 fields) (512 MM bbls MEFS)		(1 field)
Economically Recoverable (billions of bbls)		Mean Oil
	\$/bbl	Estimate
<\$15.00		0.0
\$15.00		2.4
\$20.00		3.2

FRANK H. MURKOWSKI, Alaska, Chairman

PETE V. DOMENICI, New Mexico
DON NICKLES, Oklahoma
LARRY E. CRAIG, Idaho
BEN NIGHTHORSE CAMPBELL, Colorado
CRAIG THOMAS, Wyoming
JON KYL, Arizona
ROD GRAHAM, Minnesota
GORDON H. SMITH, Oregon
SLADE GORTON, Washington
CONRAD BURNS, Montana

DALE BUMPERS, Arkansas
WENDELL H. FORD, Kentucky
JEFF BINGAMAN, New Mexico
DANIEL K. AKAKA, Hawaii
BYRON L. DORGAN, North Dakota
BOB GRAHAM, Florida
RON WYDEN, Oregon
TIM JOHNSON, South Dakota
MARY L. LANDRIEU, Louisiana

ANDREW D. LUNDAQUIST, STAFF DIRECTOR
GARY G. ELLSWORTH, CHIEF COUNSEL
THOMAS B. WILLIAMS, STAFF DIRECTOR FOR THE MINORITY
SAM E. FOWLER, CHIEF COUNSEL FOR THE MINORITY

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES

WASHINGTON, DC 20510-6150

WWW.SENATE.GOV/~ENERGY

July 23, 1998

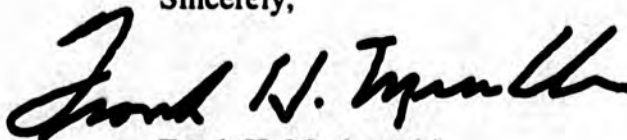
Mr. Kenneth A. Boyd
Director, Division of Oil and Gas
Department of Natural Resources
State of Alaska
3601 C Street, Suite 1380
Anchorage, Alaska 99503-5948

Dear Mr. Boyd:

I want to thank you for your recent participation in the Senate Energy and Natural Resources Committee's oversight hearing on the results of the Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998. Your testimony provided valuable insight into the work performed by the USGS and the results it produced. I especially want to thank you for your very descriptive explanations of the benefits of 3-D seismic data. Your presentation was both technically precise and easily understood, a rare combination. I am forwarding some additional questions to you and would appreciate it if you could respond to them prior to the hearing record closing on August 6.

I could not agree with you more when you stated, "ANWR seismic data has served us well to this point, but after 15 years it is time to face the reality that we have wrung all the information out of the data we can." I strongly believe that if Congress is ever to make an educated decision about the 1002 Area that this decision must be based on the best available science. I plan on moving forward with giving the USGS the authority to use their expertise to obtain this data and I would like to be able to count on you to provide the technical expertise. We simply cannot, as an oil dependent nation, ignore an area that demonstrably has the highest oil potential of any region in North America which can be produced with less environmental impact than anywhere in the world.

Sincerely,



Frank H. Murkowski
Chairman

Enclosure

QUESTIONS

1. In your testimony you referred to many dramatic examples of cost reductions in drilling and production in the past six years. For example, you quote a reduction in development costs at Northstar of 70%. Do you see these trends continuing? Are there other opportunities for cost reductions in the next 10 years?

What is your overall take on the USGS economic assumptions?

2. Your testimony presents a very clear picture of the accuracy and benefits of 3-D seismic. Any technology that reduces risk from a 1 in 12 to a 1 in 2 rate must be utilized. My question is, when is the best time to get 3-D seismic? Should it be obtained prior to leasing or should it be the responsibility of the lessee after leasing?

What Does the State do in this regard?

If we were to support 3-D seismic prior to leasing, who should pay for it, industry, the federal government?

3. What is your feeling on the 3 x 6 mile seismic grid in the light of a statement by a previous Director of the Alaska Division of Oil and Gas who testified, "Such a large grid size, when combined with the lack of well data control and the extremely complex geology, virtually guarantees that many potential oil and gas traps of significant size may not be recognized".

How has 3-D helped in understanding the Pt. Thompson unit?

Would you expect an oil company which had leases in the 1002 area to drill exploration wells on the basis of the present seismic grid?

STATE OF ALASKA

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 "C" STREET, SUITE 1380
ANCHORAGE, ALASKA 99503-5948
PHONE: (907) 269-8800

August 5, 1998

The Honorable Frank H. Murkowski, Chairman
United States Senate
Committee on Energy and Natural Resources
Washington, D.C. 20510-0150

Dear Senator Murkowski:

Thanks for your letter of July 23. Despite the long trip (not to mention the heat), I enjoyed participating in the ANWR hearing. I expect trying to get some kind of 3-D seismic legislation will, in certain quarters, cause a seismic event of its own. Your letter contained several questions that I will try to answer here.

1. **Question:** In your testimony, you referred to many dramatic examples of cost reductions in drilling and production in the past six years. For example, you quote a reduction in development costs at Northstar of 70%. Do you see these trends continuing? Are there other opportunities for cost reductions in the next 10 years?

What is your overall take on the USGS economic assumptions?

Answer: I cannot be sure that the companies will be able to continue the dramatic reductions in drilling and production costs that they have achieved over the past few years. I am sure that they will continue to focus on ways to reduce those costs. There is some information suggesting the companies are continuing cost reductions. The companies reduced the average cost for new and sidetracked wells in the Prudhoe Bay Unit between 1996 and 1997 (the most recent numbers). Moreover, I do see other opportunities for cost reductions on the horizon because Alaska has become a laboratory for applying new technology. The State certainly hopes this trend of cost reductions continues because it allows optimism despite low oil prices.

The division has not had an opportunity to review the USGS final economic report. The division's economists did review a draft, but were asked not to share its contents until the report was final. They offered several comments and suggestions to the USGS on the report, and we will withhold judgment until we have seen the final report.

2. **Question:** Your testimony presents a very clear picture of the accuracy and benefits of 3-D seismic. Any technology that reduces risk from a 1 in 12 to a 1 in 2 rate must be utilized. My question is, when is the best time to get 3-D seismic? Should it be obtained prior to leasing or should it be the responsibility of the lessee after leasing?

What does the State do in this regard?

If we were to support 3-D seismic prior to leasing, who should pay for it-- industry, the federal government?

Answer: There is no hard-and-fast rule regarding the timing of acquisition of 3-D seismic. For example, several companies were shooting massive 3-D programs in NPR-A last winter in anticipation of an upcoming sale. But the shooting was concentrated in an area presumed to need that type of data. The best time to get 3-D seismic is when you think you need it. In the case of areas that have good 2-D coverage, 3-D is often used after the sale to evaluate specific plays or prospects. However, because of the complexity of the geology in ANWR, in my opinion, the government and industry could use 3-D seismic now. It is needed in both the "undeformed" western portion and in the structurally complex eastern portion of the coastal plain. "Undeformed" does not mean "uncomplicated" or "easy"; to the contrary, these types of reservoirs have an internally complex geometry that cannot be unraveled with 2-D data. Unlike the previous ANWR 2-D surveys, which were shot in what is called a "regional" program (i.e., it covered the whole region), 3-D would be targeted to specific plays or prospects. The State does not shoot its own seismic data but does have the right to obtain all seismic data shot on State lands.

There is no simple answer to "who pays" if 3-D seismic is shot prior to leasing. The original ANWR 2-D survey (actually there were two years of acquisition) was a "group shoot" whereby a group of companies share the cost of acquisition and initial processing. Then the data is shared by only that group (although there is almost always a provision for companies that did not participate to "back-in" and get the data later by paying a premium for the data. This premium is then split among the original participants). The disadvantage of late participation (besides having to pay the premium) is that the company has no input in parameter selection for the survey. I expect you will get a number of opinions on the "best" way to obtain (and pay for) the data.

3. Question: What is your feeling on the 3 x 6 mile seismic grid in the light of a statement by a previous Director of the Alaska Division of Oil and Gas who testified, "Such a large grid size, when combined with the lack of well data control and the extremely complex geology, virtually guarantees that many potential oil and gas traps of significant size may not be recognized".

How has 3-D helped in understanding the Pt. Thomson unit?

Would you expect an oil company which had leases in the 1002 area to drill exploration wells on the basis of the present seismic grid?

Senator Frank H. Murkowski
August 5, 1998
Page 3 of 3

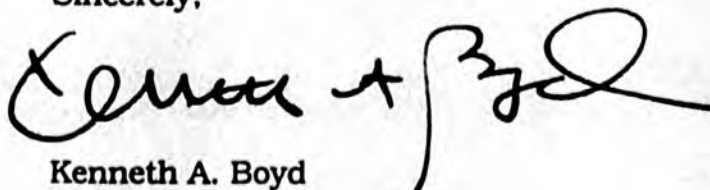
Answer: The grid size in ANWR is fairly typical of older, regional 2-D surveys shot all over the world. Simply stated, the grid size is so coarse that some plays and prospects will be missed, overlooked or misidentified. The existing seismic data set—actually two sets, one dynamite, one Vibroseis—is technologically obsolete as well as incomplete. While useful for determining gross structural and stratigraphic patterns, it simply cannot compete with modern 3-D seismic technology. 3-D data has helped Pt. Thomson in the same way it has helped every other area to which it has been applied. It has helped the Unit owners better understand the complex geology present in this area. Some of the Pt. Thomson Unit Working Interest Owners have been, and will continue to, acquire 3-D data in the area. 3-D seismic certainly played a very large role in the Sourdough discovery, as well as the discoveries at Alpine, Badami, Tarn and a number of the new "satellite" discoveries around the Prudhoe and Kuparuk fields. 3-D seismic is clearly the exploration tool of choice for the present and the foreseeable future.

It is important to realize that 3-D seismic does not make the rocks "better" (in the same way that having a CAT scan won't necessarily make you healthier). 3-D is simply a tool to help geoscientists make better informed decisions about the subsurface of the earth, just as CAT scans help doctors make better informed decisions about the interior of the human body. Not every field that has been shot with 3-D has increased in size or gone on to be produced. Arco's Sunfish field in Cook Inlet is an example of this. After shooting 3-D over Sunfish, Arco dramatically downgraded the field and ultimately sold it to Phillips Petroleum. Phillips is trying to make a go of the field (now called Tyonek Deep) this year.

I doubt very much that companies would want to risk a lot of money in ANWR without having 3-D data in hand. I do believe companies would bid at a sale without 3-D if this were the only alternative. Given the geological complexity, I suspect these bids would be conservative and the revenues from the sale would be reduced for both the state and federal governments. Successful bidders would move quickly to shoot 3-D over their leases prior to drilling. I sincerely doubt that many wells will be committed in ANWR prior to acquiring 3-D seismic over the prospect to be drilled.

I hope I have answered most of your questions. The "who pays" question will take a lot of discussion to resolve. I hope the debate can start soon.

Sincerely,

A handwritten signature in black ink, appearing to read "Ken A. Boyd", followed by a large, stylized flourish or scribble.

Kenneth A. Boyd
Director

SCOMM

104:5

4/8/97.

Purpose

to establish potential -
Reserves

BID

Hepco Carbon →

Thompson Sands →

Western Side / →

3 D surveillance program →



Jinn Branch

Unique /

High pressure gas

2x

Gas - 445 million
Condensate

Jinn
Branch

Hydro
Carbon

04/08/97

LEGISLATIVE TELECONFERENCE NETWORK SYSTEM

LTN1150

08:32:41

PARTICIPANT LIST (ALL PARTICIPANTS)

BY:ANC

TCN:70579

SCHEDULED FOR:04/08/97 08:30 TO 10:00

FOR:ANC

PUBLIC HEARING

HOUSE SPECIAL COMMITTEE ON OIL & GAS

LOCATION:ANCHORAGE

PT. THOMSON LE

PAT

KOTOWSKI

DNR-OIL & GAS

TESTIFY

04/08/97 08:33:55 LEGISLATIVE TELECONFERENCE NETWORK SYSTEM
MESSAGE FROM: LIOCJEN IN ANCHORAGE

LTN1120
JNU

RE TCN: 70579 SCHEDULED FOR: 04/08/97 08:30 TO 10:00
SPONSOR: HOUSE SPECIAL COMMITTEE ON OIL & GAS PURPOSE: PUBLIC HEARING

MESSAGE TEXT: OF1, PAUL ROBERTSON IS ON LINE FROM TEX
AND IS IN LO

PH/1/PS Petro - Wants to listen only

AGENDA

GOOD MORNING

TODAYS MEETING OF THE HOUSE SPECIAL COMMITTEE ON OIL AND GAS. TODAY IS APRIL 8TH, 1997. THIS MEETING IS CALLED TO ORDER AT 8:30AM

**FOR THE RECORD THE OIL & GAS COMMITTEE MEMBERS PRESENT ARE
- ROLL CALL -**

ON TODAYS CALENDAR WE HAVE A PRESENTATION ON THE OIL & GAS FIELD AT POINT THOMSON.

DIVISION OF OIL & GAS

■ MICHAEL KATOWSKI

EXXON

■ JIM BRANCH

THANK YOU FOR YOUR PRESENTATION - QUESTIONS FROM COMMITTEE MEMBERS?

OUR NEXT MEETING WILL BE ON THURSDAY APRIL 10, AT 8:00AM WHEN WE WILL BE HEARING FROM THE DEPARTMENT OF REVENUE. COMMISSIONER CONDON – WILL BE PRESENTING THE ADMINISTRATIONS RECOMMENDATIONS FOR LEGISLATIVE ACTION REGARDING THE TRANS ALASKA GAS LINE. WE WILL ALSO BE HEARING FROM SOME OF THE PARTIES INTERESTED IN PARTICIPATING IN THE PROJECT.

EXXON COMPANY, U.S.A.

POST OFFICE BOX 2180 • HOUSTON, TEXAS 77252-2180

PRODUCTION DEPARTMENT
ALASKA INTEREST

L. R. HOWARD
MANAGER

October 1, 1996

**Fourteenth Plan of Further Development
and Operation
Point Thomson Unit**

**VIA FAX (907-562-3852) &
AIRBORNE EXPRESS**

Mr. Kenneth A. Boyd, Director
Alaska Department of Natural Resources
Division of Oil and Gas
3601 "C" Street, Suite 1380
Anchorage, Alaska 99503-5948

Dear Mr. Boyd:

Exxon, as Unit Operator and on behalf of the Working Interest Owners (Owners), hereby submits the enclosed Fourteenth Plan of Further Development and Operation (14th POD) for the Point Thomson Unit for your review and approval. The 14th POD contains an update on the work activities commenced/completed under the 13th POD and a summary of the Owners' work plans for the ensuing calendar year. As you will note, the 14th POD work activities represent a continuation of the phased development study and farmout initiative begun under the 13th POD.

Should you have any questions regarding the 14th POD, please do not hesitate to call me at (713) 656-7000 or Mr. Raul Huerta at (713) 656-7111.

Very truly yours,



LRH:MMM

Enclosure

cc: PTU Working Interest Owners



Point Thomson Unit
Fourteenth Plan of Further Development and Operation
(And an Update on the Thirteenth Plan of Further Development and Operation)

This Fourteenth Plan of Development is submitted to the Commissioner of the Alaska Department of Natural Resources (DNR) pursuant to Article 10 of the Point Thomson Unit (PTU) Agreement and 11 AAC 83.343.

Update on the Thirteenth Plan of Development (13th POD)

General

The 13th POD was submitted to the DNR on October 30, 1995. Thereunder, the Working Interest Owners (Owners) committed to undertake a phased study aimed at evaluating potential development scenarios for the Unit. Development options previously evaluated on a proprietary basis, and found to be uneconomic, were to be considered for inclusion in the study. Originally, BP's proposed development of the nearby Badami Field was an impetus for initiating the study. The Owners desired to determine whether there were any potential synergies between the PTU and Badami which could impact the Unit's near-term development chances. However, the study has now taken on a broader focus. A current work schedule for the development study is attached hereto as Exhibit 1. The work activities associated with Phases I and II have been restructured and expanded considerably over those originally proposed in the 13th POD. Most of the work originally planned for Phase II has been incorporated into Phase I.

As part of the 13th POD, Exxon, Mobil and Phillips agreed to solicit farmout offers on flank Unit acreage, specifically, Unit Tracts 8, 9 and 10. This farmout initiative was in direct response to the DNR's desire for additional exploration work within the Unit.

The Owners requested a 23-month POD period in which to accomplish the above work initiatives. By letter dated December 28, 1995, the DNR approved the 13th POD for an 11-month POD period (February 2, 1996 to December 31, 1996). The DNR's approval was subject to the following conditions: 1) a June 1996 meeting wherein the Owners would present Phase I results, discuss the anticipated scope of Phase II, and report on the status of the farmout initiative, 2) the DNR's receipt of the Reservoir Characterization Study Committee (RCSC) final work products, 3) the DNR's receipt of a report, either on a proprietary or Unit consensus basis, on the latest estimate of gross reserves of gas, condensate and oil attributable to the Thomson Sand within the Unit, and 4) by the end of 1996, the Unit's view of the potential for gas sales and/or gas storage to the Prudhoe Bay Unit and any gas liquid sales which might result therefrom.

On June 27, 1996, representatives of the PTU met with Mr. Kenneth A. Boyd, Director, and his staff to discuss the Unit's work progress and future plans, in fulfillment of condition 1 above. A copy of the RCSC final study work products was delivered to the DNR on February 29, 1996 in satisfaction of condition 2. In compliance with condition 3, Exxon's proprietary estimate of the gross reserves for the Thomson Sand will be submitted to the DNR, on a confidential basis, on or before December 31, 1996. As to condition 4 above, the outlook for gas sales and/or storage to the Prudhoe Bay Unit, and gas liquid sales resulting therefrom, remains unchanged from prior evaluations, that is, these development scenarios are not currently viewed as economically viable. However, these scenarios will be carefully evaluated as part of the Unit's on-going development study.

3D Geologic Model

In advance of the phased development study, Exxon completed preliminary work on a number of development scenarios using aggressive cost and reservoir performance assumptions. As part of a working interest owners meeting held March 3, 1996, Exxon presented the above work to the other Owners and made certain follow-up recommendations. It was concluded that a 3D geologic model (facies, porosity and permeability inputs) and a full-field reservoir simulation model for the Thomson Sand should be constructed during Phase I of the study to ensure that the reservoir performance assumptions are supportable. The benefit of these models is two-fold: first, a full range of development scenarios can be evaluated for potential viability, and secondly, the confidence level associated with preliminary screening results will be considerably enhanced over results based on single well performance estimates. Detailed project descriptions for both models were provided to the DNR during the June 27 meeting.

In April of this year, the Owners held a workshop to develop a consensus facies model for the Thomson Sand Reservoir, a critical component of the 3D geologic model. The sequence stratigraphic work developed by the RCSC was used in the development of the facies model.

A Geologic and Reservoir Modeling Committee (GRMC) has been formed to coordinate and oversee the construction of the 3D geologic model and the reservoir simulation model; actual construction is being done by Exxon Production Research Company (EPRCo). As indicated on Exhibit 1, the 3D geologic model should be completed by year-end. Upon completion, the model will be scaled-up for input into Exxon's proprietary Multiple Application Reservoir Simulator. Exxon, Chevron, Mobil, Phillips and BP, along with eight other Owners, have elected to participate in the GRMC. The participating parties represent 98.16% of the PTU working interest.

Well Design and Cost Estimates

Well design activities have been divided into two task groups, one which focuses on drilling, the other on completions, workovers and wellbore hydraulics. The drilling component consists of days vs. depth analysis, wellbore stability, hole cleaning analysis, and torque/drag studies. The drilling-related tasks are nearly completed. The completion, workover and hydraulic tasks are scheduled for completion in the fourth quarter of 1996. Well cost estimating work should begin in the fourth quarter of 1996 and be completed in the first quarter of 1997.

Reservoir Simulation Models

Subsequent to the June 27 meeting with the DNR, the scope of this work effort was expanded to include a cross-sectional process model and a finely-gridded mechanistic or element model. Originally, only a full-field reservoir model was to be constructed. The process model will test phase behavior and relative permeability impacts. The mechanistic model will be used to evaluate potential displacement processes such as gas cycling and water injection. Construction of these models should be completed in the first quarter of 1997. Development scenarios will then be simulated to yield estimated recoveries and flowrates.

Farmout Initiative

In February of this year, Exxon contacted sixteen (16) companies to solicit their interest in farming in Unit Tracts 8, 9 and 10. Only BP and ARCO expressed interest in the offered acreage. Both companies were given a technical review of the farmout area via meetings in Exxon's downtown Houston office. On July 2, 1996, ARCO offered to enter into a 3D Seismic Farmout Agreement with Exxon, as to Unit Tracts 7 - 10 (ADLs 47563, 47564, 47565 and 47566). The offer provided for the commencement of a 3D survey over the western portion of the PTU with the option to drill a Test Well on the farmout acreage. Mobil and Phillips, each owners of a 25% working interest in the above four tracts, received similar offers from ARCO. Exxon has sent ARCO a farmout counterproposal covering the requested tracts. Trade negotiations with ARCO are continuing. Exxon, Mobil and Phillips are hopeful that mutually-acceptable farmout agreements with ARCO can be negotiated.

Exploration Activity

An exploratory well was drilled within the PTU during the 13th POD term. BP and Chevron jointly drilled the Sourdough #3 well in the SW/4 of Section 29, T9N-R24E, Umiat Meridian (ADL 343112). The well was commenced on February 1, 1996 and reached TD (12,415' MD) on March 6, 1996. Operations have been suspended. The results of the well are proprietary.

Fourteenth Plan of Development (14th POD)

Work Plans

During the term of the 14th POD, the Owners plan to complete the remaining activities associated with Phase I. Phase II work activities will be commenced only in the event one or more development scenarios screened during Phase I merit additional evaluation. Planning activities associated with cost estimating and economic modeling tasks (Activity #5, Phase I) should commence in the fourth quarter of 1996. As the necessary inputs become available from the other work efforts, appropriate models will be generated. Phase II, if commenced, would likely start in the fourth quarter of 1997 and consist of: 1) upgrading selected development scenarios, economic modeling, and case-specific facility/pipeline cost estimating. Additional reservoir simulation work will likely be required for Phase II development scenarios. If warranted by the results of Phase II, Phase III activities (securing contractor cost estimates; re-evaluation of economics) will be undertaken, pursuant to a 15th POD.

The Owners will continue to monitor the development status of BP's Badami Field and consider its impact as part of the Unit's development study.

Requested Term

The Owners hereby request a one (1) year term for the 14th POD, January 1, 1997 through December 31, 1997.

EXXON COMPANY, U.S.A.
POST OFFICE BOX 2180 • HOUSTON, TEXAS 77252-2180

PRODUCTION DEPARTMENT
ALASKA INTEREST

L. R. HOWARD
MANAGER

October 1, 1996

**Fourteenth Plan of Further Development
and Operation
Point Thomson Unit**

**VIA FAX (907-562-3852) &
AIRBORNE EXPRESS**

Mr. Kenneth A. Boyd, Director
Alaska Department of Natural Resources
Division of Oil and Gas
3601 "C" Street, Suite 1380
Anchorage, Alaska 99503-5948

Dear Mr. Boyd:

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Should you have any questions regarding the 14th POD, please do not hesitate to call me at (713) 656-7000 or Mr. Raul Huerta at (713) 656-7111.

Very truly yours,



LRH:MMM

Enclosure
cc: PTU Working Interest Owners



Point Thomson Unit
Fourteenth Plan of Further Development and Operation
(And an Update on the Thirteenth Plan of Further Development and Operation)

This Fourteenth Plan of Development is submitted to the Commissioner of the Alaska Department of Natural Resources (DNR) pursuant to Article 10 of the Point Thomson Unit (PTU) Agreement and 11 AAC 83.343.

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General

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As part of the 13th POD, Exxon, Mobil and Phillips agreed to solicit farmout offers on flank Unit acreage, specifically, Unit Tracts 8, 9 and 10. This farmout initiative was in direct response to the DNR's desire for additional exploration work within the Unit.

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On June 27, 1996, representatives of the PTU met with Mr. Kenneth A. Boyd, Director, and his staff to discuss the Unit's work progress and future plans, in fulfillment of condition 1 above. A copy of the RCSC final study work products was delivered to the DNR on February 29, 1996 in satisfaction of condition 2. In compliance with condition 3, Exxon's proprietary estimate of the gross reserves for the Thomson Sand will be submitted to the DNR, on a confidential basis, on or before December 31, 1996. As to condition 4 above, the outlook for gas sales and/or storage to the Prudhoe Bay Unit, and gas liquid sales resulting therefrom, remains unchanged from prior evaluations, that is, these development scenarios are not currently viewed as economically viable. However, these scenarios will be carefully evaluated as part of the Unit's on-going development study.

3D Geologic Model

In advance of the phased development study, Exxon completed preliminary work on a number of development scenarios using aggressive cost and reservoir performance assumptions. As part of a working interest owners meeting held March 3, 1996, Exxon presented the above work to the other Owners and made certain follow-up recommendations. It was concluded that a 3D geologic model (facies, porosity and permeability inputs) and a full-field reservoir simulation model for the Thomson Sand should be constructed during Phase I of the study to ensure that the reservoir performance assumptions are supportable. The benefit of these models is two-fold: first, a full range of development scenarios can be evaluated for potential viability, and secondly, the confidence level associated with preliminary screening results will be considerably enhanced over results based on single well performance estimates. Detailed project descriptions for both models were provided to the DNR during the June 27 meeting.

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A Geologic and Reservoir Modeling Committee (GRMC) has been formed to coordinate and oversee the construction of the 3D geologic model and the reservoir simulation model; actual construction is being done by Exxon Production Research Company (EPRCo). As indicated on Exhibit 1, the 3D geologic model should be completed by year-end. Upon completion, the model will be scaled-up for input into Exxon's proprietary Multiple Application Reservoir Simulator. Exxon, Chevron, Mobil, Phillips and BP, along with eight other Owners, have elected to participate in the GRMC. The participating parties represent 98.16% of the PTU working interest.

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Subsequent to the June 27 meeting with the DNR, the scope of this work effort was expanded to include a cross-sectional process model and a finely-gridded mechanistic or element model. Originally, only a full-field reservoir model was to be constructed. The process model will test phase behavior and relative permeability impacts. The mechanistic model will be used to evaluate potential displacement processes such as gas cycling and water injection. Construction of these models should be completed in the first quarter of 1997. Development scenarios will then be simulated to yield estimated recoveries and flowrates.

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In February of this year, Exxon contacted sixteen (16) companies to solicit their interest in farming in Unit Tracts 8, 9 and 10. Only BP and ARCO expressed interest in the offered acreage. Both companies were given a technical review of the farmout area via meetings in Exxon's downtown Houston office. On July 2, 1996, ARCO offered to enter into a 3D Seismic Farmout Agreement with Exxon, as to Unit Tracts 7 - 10 (ADLs 47563, 47564, 47565 and 47566). The offer provided for the commencement of a 3D survey over the western portion of the PTU with the option to drill a Test Well on the farmout acreage. Mobil and Phillips, each owners of a 25% working interest in the above four tracts, received similar offers from ARCO. Exxon has sent ARCO a farmout counterproposal covering the requested tracts. Trade negotiations with ARCO are continuing. Exxon, Mobil and Phillips are hopeful that mutually-acceptable farmout agreements with ARCO can be negotiated.

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Fourteenth Plan of Development (14th POD)

Work Plans

During the term of the 14th POD, the Owners plan to complete the remaining activities associated with Phase I. Phase II work activities will be commenced only in the event one or more development scenarios screened during Phase I merit additional evaluation. Planning activities associated with cost estimating and economic modeling tasks (Activity #5, Phase I) should commence in the fourth quarter of 1996. As the necessary inputs become available from the other work efforts, appropriate models will be generated. Phase II, if commenced, would likely start in the fourth quarter of 1997 and consist of: 1) upgrading selected development scenarios, economic modeling, and case-specific facility/pipeline cost estimating. Additional reservoir simulation work will likely be required for Phase II development scenarios. If warranted by the results of Phase II, Phase III activities (securing contractor cost estimates; re-evaluation of economics) will be undertaken, pursuant to a 15th POD.

The Owners will continue to monitor the development status of BP's Badami Field and consider its impact as part of the Unit's development study.

Requested Term

The Owners hereby request a one (1) year term for the 14th POD, January 1, 1997 through December 31, 1997.

EXXON COMPANY, U.S.A.
POST OFFICE BOX 2180 • HOUSTON, TEXAS 77252-2180

PRODUCTION DEPARTMENT
ALASKA INTEREST

L. R. HOWARD
MANAGER

October 1, 1996

**Fourteenth Plan of Further Development
and Operation
Point Thomson Unit**

**VIA FAX (907-562-3852) &
AIRBORNE EXPRESS**

Mr. Kenneth A. Boyd, Director
Alaska Department of Natural Resources
Division of Oil and Gas
3601 "C" Street, Suite 1380
Anchorage, Alaska 99503-5948

Dear Mr. Boyd:

Exxon, as Unit Operator and on behalf of the Working Interest Owners (Owners), hereby submits the enclosed Fourteenth Plan of Further Development and Operation (14th POD) for the Point Thomson Unit for your review and approval. The 14th POD contains an update on the work activities commenced/completed under the 13th POD and a summary of the Owners' work plans for the ensuing calendar year. As you will note, the 14th POD work activities represent a continuation of the phased development study and farmout initiative begun under the 13th POD.

Should you have any questions regarding the 14th POD, please do not hesitate to call me at (713) 656-7000 or Mr. Raul Huerta at (713) 656-7111.

Very truly yours,



LRH:MMM

Enclosure
cc: PTU Working Interest Owners

Point Thomson Unit
Fourteenth Plan of Further Development and Operation
(And an Update on the Thirteenth Plan of Further Development and Operation)

This Fourteenth Plan of Development is submitted to the Commissioner of the Alaska Department of Natural Resources (DNR) pursuant to Article 10 of the Point Thomson Unit (PTU) Agreement and 11 AAC 83.343.

Update on the Thirteenth Plan of Development (13th POD)

General

The 13th POD was submitted to the DNR on October 30, 1995. Thereunder, the Working Interest Owners (Owners) committed to undertake a phased study aimed at evaluating potential development scenarios for the Unit. Development options previously evaluated on a proprietary basis, and found to be uneconomic, were to be considered for inclusion in the study. Originally, BP's proposed development of the nearby Badami Field was an impetus for initiating the study. The Owners desired to determine whether there were any potential synergies between the PTU and Badami which could impact the Unit's near-term development chances. However, the study has now taken on a broader focus. A current work schedule for the development study is attached hereto as Exhibit 1. The work activities associated with Phases I and II have been restructured and expanded considerably over those originally proposed in the 13th POD. Most of the work originally planned for Phase II has been incorporated into Phase I.

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20th Alaska State Legislature

First Session, 1997

R. Thompson



High Gas Pressure Field. - makes REINJECTION
OF GAS DIFFICULT.

Exxon	45%	Surface Acreage	
Chevron	20%	"	"
MOBIL	14%	"	"
Phillips	12%	"	"
BP	6%	"	"

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CS FOR HOUSE BILL NO. 51()
IN THE LEGISLATURE OF THE STATE OF ALASKA
TWENTIETH LEGISLATURE - FIRST SESSION

BY

Offered:
Referred:

Sponsor(s): REPRESENTATIVES ROKEBERG AND KELLY

A BILL

FOR AN ACT ENTITLED

1 **"An Act relating to the Department of Environmental Conservation."**

2 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

3 *** Section 1. FINDINGS AND INTENT.** The legislature confirms that it is the policy of
4 the state to implement water quality laws based on scientific and technical evidence. The
5 legislature specifically requests that state agencies possessing the necessary expertise to
6 implement AS 46.03.085 - 46.03.087, enacted by sec. 4 of this Act, coordinate their efforts
7 to enable cost efficiencies in adopting regulations that encourage the creation and retention
8 of jobs for Alaskans and the economic development of the state's natural resources consistent
9 with the public interest.

10 *** Sec. 2.** AS 46.03.020 is amended by adding new subsections to read:

11 (b) The department may not adopt a regulation under (a)(10) of this section
12 unless

13 (1) the department considers whether compliance with the regulation
14 is economically feasible for the persons governed by the regulation; and

15 (2) the regulation is based on science.

(c) In regulations of the department, "background condition" means the biological, chemical, and physical conditions of a body of water outside the area of influence of the discharge under consideration. When the department performs background sampling to determine a background condition during an enforcement action, the department shall measure conditions that are upslope or outside the area of influence of the discharge. If several discharges to a body of water exist and an enforcement action is being taken, the department's background sampling shall measure conditions immediately upslope from each discharge. If the department is assessing the background condition of a disturbed watershed, the department may use the background condition of a similar watershed as the reference condition.

* Sec. 3. AS 46.03.050 is amended by adding a new subsection to read:

(b) The department shall seek and maintain federal approval under 33 U.S.C. 1342(b) of the state's permit program for discharges into navigable water so that the department has authority to administer the national pollutant discharge elimination system in the state in lieu of the federal permit program otherwise applicable to the state under 33 U.S.C. 1342(a). If, at any time, the department determines that statutory or budgetary changes are necessary to obtain or maintain federal approval of the state's program under this subsection, the department shall notify the legislature through the governor.

* Sec. 4. AS 46.03 is amended by adding new sections to read:

Sec. 46.03.085. Water quality standards. (a) In adopting and applying water quality standards, the department, consistent with 33 U.S.C. 1251 - 1376 (Clean Water Act),

(1) shall ensure that the standards are sufficient to protect human health and propagation of fish and wildlife;

(2) shall consider the background condition of bodies of water, including the presence of naturally occurring pollutants, such as arsenic;

(3) shall use scientific justification to develop water quality standards that can be reliably measured;

(4) may not require water discharged by a user to be of a higher quality than the background condition of the water received by the user; and

1 (5) shall provide procedures for permitting mixing zones in state bodies
2 of water under regulations adopted by the department.

3 (b) Except when setting standards under AS 03.05.011(a) for shellfish growing
4 areas, as defined in the national shellfish sanitation program manual of operations
5 published by the Food and Drug Administration, the department may adopt a water
6 quality standard or other regulation related to water quality that is more restrictive than
7 applicable federal water quality criteria or regulations only after following the
8 procedures in AS 46.03.087(b).

9 (c) Within 90 days after receiving a written request to amend the state's water
10 quality standards to incorporate a reduction in, or elimination of, federal water quality
11 criteria, or by another date mutually agreed on by the applicant and the department,
12 the department shall either propose regulations that amend the state's water quality
13 standards to incorporate the reduction or elimination or initiate the procedure required
14 under AS 46.03.087(b). If, following the procedure under AS 46.03.087(b), the
15 department is unable to make the written findings required under AS 46.03.087(b)(3),
16 the department shall propose regulations that amend the state's water quality standards
17 to incorporate the reduction in or elimination of the federal water quality criteria or
18 regulations.

19 (d) Except as otherwise provided in AS 46.03.087, the measurement of
20 constituents other than sediment to determine whether a permittee is in compliance
21 with permit limitations based on water quality shall be by methods approved in writing
22 by the United States Environmental Protection Agency or by substantially equivalent
23 methods approved by the department.

24 (e) The measurement of sediment to determine whether a permittee is in
25 compliance with permit limitations based on water quality shall be by the volumetric
26 Imhoff cone method for settleable solids. However, this subsection may not be
27 construed to limit the department's authority to adopt water quality criteria for total
28 suspended solids to meet United States Environmental Protection Agency requirements.

29 (f) In this section, "background condition" has the meaning given in
30 AS 46.03.020(c).

31 **Sec. 46.03.087. Special procedures for certain water quality regulations.**

1 (a) The department may, after following the procedures in this section, adopt a

2 (1) water quality standard or discharge standard that is more restrictive
3 than applicable federal water quality criteria or discharge standards;

4 (2) water quality standard or discharge standard for which there is no
5 corresponding federal water quality criteria or discharge standard; or

6 (3) regulation that allows the use of a method that is not substantially
7 equivalent to methods approved by the United States Environmental Protection Agency
8 for the measurement of constituents to determine whether a permittee is in compliance
9 with permit limitations related to water quality.

10 (b) Before adopting a standard or regulation governed by (a) of this section,
11 the department shall

12 (1) make available to the public, at convenient locations, copies of the
13 proposal and the findings of the department that describe the basis for the proposal;

14 (2) consider the economic and technological feasibility of the proposal
15 and prepare written findings; and

16 (3) find in writing, as applicable, that

17 (A) hydrologic conditions or discharge characteristics in the area
18 of the state or at the particular site where the standard or regulation applies
19 reasonably require the water quality standard, discharge standard, or method of
20 measurement to protect human health and welfare or propagation of fish and
21 wildlife; and

22 (B) hydrologic conditions or discharge characteristics are
23 significantly different in that area of the state or at that particular site from
24 those upon which the corresponding federal criteria or regulations are based.

25 * Sec. 5. TRANSITIONAL REVIEW OF REGULATIONS. (a) The Department of
26 Environmental Conservation shall, during the triennial review process of regulations that is
27 required under 33 U.S.C. 1313(c) (Clean Water Act), review its water quality regulations that
28 are in effect on the effective date of this Act in order to determine if they comply with federal
29 requirements and are not more stringent than applicable federal regulations. If the review
30 indicates that there are state regulations that are more stringent than applicable federal
31 regulations, the department shall determine whether it could justify those regulations under the

1 requirements of AS 46.03.087(b)(3), enacted by sec. 4 of this Act. If the department
2 determines that it cannot meet the requirements of AS 46.03.087(b)(3), the department shall
3 adopt the necessary revisions to the regulations. It is the legislature's intent that the
4 department complete its review of all regulations governed by this subsection and its adoption
5 of all necessary revisions required under this subsection within four years after the effective
6 date of this section.

7 (b) The Department of Environmental Conservation shall, by January 31, 1999, and
8 annually thereafter until all of the state water quality regulations in effect on the effective date
9 of this Act are reviewed, prepare a written report on the status of the department's review and
10 revisions required under (a) of this section. The department shall submit the report to the
11 governor and notify the legislature that the report is available.

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Copies of minutes listed below were originally included in this file. The minutes are available on the legislative computer database. In order to save space copies of minutes have not been left in the files.

Mary Pagenkopf

House Special Oil + Gas	2-20-96
" " " "	3-21-96
House Resources	3-27-96
" "	4-01-96
" "	4-17-96
" "	4-19-96
Senate Resources	5-02-96
" "	5-03-96



Official Business

COMMITTEE:

HOUSE SPECIAL COMMITTEE ON OIL AND GAS

DATE: January 23, 1997

SIGN-IN

Subject of meeting:

~~REDACTED~~
~~REDACTED~~

~~PLEASE PRINT:~~
NAME

ADDRESS

PHONE

REPRESENTING

DO YOU WANT
TO TESTIFY?

JANICE ADAIR			DEC	YES
MIKE CONWAY	410 Willoughby Ave., Juneau	465-5298	DEC	YES
Ceron Bruce	P.O. Box 25526 Juneau, 99802	465-6143	DF+G	YES
Irene Alexakos	325 4th St Juneau 99801	586-2751	Alaska Clean Water Alliance	Y
Marie Sansone	Ct. House 6 th Flr MS0300	465-6726	Attorney Gen. Office	ans. questions
Douglas Mertz	319 Seaview, Juneau		PLS REAC	Yes

FISCAL NOTE

STATE OF ALASKA
1997 LEGISLATIVE SESSION

BILL NO. CSHB 51(O&G)

Revision Date: _____	Dept. Affected: <u>Fish and Game</u>
Title: <u>An Act Relating to the Department of</u>	BRU: <u>Habitat and Restoration</u>
<u>Environmental Conservation</u>	Component: <u>Habitat</u>
Sponsor: <u>Rokeberg and Kelly</u>	
Requester: <u>House Oil and Gas Committee</u>	COMPONENT SERIAL NO. <u>486</u>

Expenditures/Revenues

(Thousands of Dollars)

OPERATING EXPENDITURES	FY 98	FY 99	FY 100	FY 01	FY 02	FY 03
PERSONAL SERVICES	150.0	150.0	112.5	112.5	112.5	112.5
TRAVEL	18.0	18.0	13.0	13.0	13.0	13.0
CONTRACTUAL	12.0	12.0	9.0	9.0	9.0	9.0
SUPPLIES	8.0	8.0	6.0	6.0	6.0	6.0
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	188.0	188.0	140.5	140.5	140.5	140.5

CAPITAL EXPENDITURES						
-----------------------------	--	--	--	--	--	--

CHANGE IN REVENUES ()						
-------------------------------	--	--	--	--	--	--

FUND SOURCE

(Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF	188.0	188.0	140.5	140.5	140.5	140.5
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other						
TOTAL	188.0	188.0	140.5	140.5	140.5	140.5

Estimate of any current year (FY97) cost: \$ _____

POSITIONS

FULL-TIME	2	2	1	1	1	1
PART-TIME			1	1	1	1
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

Additional expenditures stem from the increased workload that will occur as the department is required to increase the scope, substance, and specificity of its AS 16.05.840, 16.05.870, and 16.20 permit application reviews and significantly increase field inspections and site-specific water quality data collection (background conditions) in lieu of complete reliance on the Department of Environmental Conservation's water quality standards and wastewater discharge permitting program. Additional expenditures will occur assisting ADEC in developing a NPDES program that will be approved by EPA. Estimate that five reviews requiring ADF&G participation will be conducted annually to adopt regulations under AS 46.03.087(b).

Prepared by: [Signature]
Division: Habitat and Restoration

Approved by Commissioner: Frank Rue
Agency: Fish and Game

Phone: 465-4105
Date: 1/29/97
Date: 1/29/97

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ADF&G Fiscal Note Assumptions on CSHB 51(O&G)

Page 2

One additional permitting position will be needed to increase the scope of AS 16.05.870 and AS 16.20 permit reviews for activities previously afforded full protection under ADEC's wastewater permit program. This is largely due to the significantly increased field presence that will be required to collect and evaluate background conditions under AS 46.03.085(a)(4) and concerns that AS 46.03.085(e) will preempt retention of the Aquatic Life Standard's numerical turbidity and stream substrate sediment accumulation criteria. The corresponding federal narrative sediment criteria lumps settleable solids, turbidity, and total suspended solids together and does not include numeric limitations. Under a best case scenario, it would still require readoption of these criteria under AS 46.03.087, potentially on a site-specific basis. Greater statutory assurance that ADEC could retain its Aquatic Life turbidity and sediment accumulation criteria would significantly reduce this cost estimate.

Estimate five reviews will be conducted annually under AS 46.03.087(b) to adopt water quality regulations for which there is no corresponding federal criteria, a more restrictive criteria is proposed, or for methods that are not substantially similar to methods approved by EPA. Difficult to estimate cost because it is highly dependent on availability of site-specific water quality and hydrologic data; however, estimate it may range a low of \$10,000 per review to a maximum of \$62,000 each (this is the actual annual cost recently incurred assisting ADEC in development of site-specific criteria for Ikalukruk Creek (Red Dog Mine).

Estimate 0.5 FTE Habitat Biologist will be needed in Years 1 and 2 to assist in developing a state-run NPDES program that will be approved by the EPA.

Increased AS 16.05.870 and AS 16.20 Permit Review and Compliance Inspections

	<u>Annually</u>	
Line 100	75.0	1 - Habitat Biologist
Line 200	7.0	
Line 300	5.0	
Line 400	3.0	
TOTAL	90.0	

AS 46.03.087(b) Evaluations (5 annually) (Assume low-range estimate of \$10,000 each)

	<u>Annually</u>	
Line 100	37.5	0.5 - Habitat Biologist
Line 200	6.0	
Line 300	4.0	
Line 400	3.0	
TOTAL	50.5	

NPDES Program Assumption (Years 1 and 2 Only)

	<u>Year 1 and 2</u>	
Line 100	37.5	0.5 - Habitat Biologist
Line 200	5.0	
Line 300	3.0	
Line 400	2.0	
TOTAL	47.5	

FISCAL NOTE

STATE OF ALASKA
1997 LEGISLATIVE SESSION

BILL NO.

HB 51

Revision Date: 1/22/97 5:00 P.M.

Title: An Act relating to the Department of Environmental Conservation

Department Affected: Environmental Conservation

Sponsor: Reps Rokeberg and Kelly

BRU: Department-wide

Requestor: House Special Committee on Oil and Gas

Component: All

COMPONENT SERIAL NO.

633

Expenditures/Revenues:

(Thousands of Dollars)

OPERATING EXPENDITURES	FY 98	FY 99	FY 00	FY 01	FY 02	FY 03
PERSONAL SERVICES	2,597.0	2,597.0	2,597.0	2,597.0	2,597.0	2,597.0
TRAVEL	208.0	208.0	208.0	208.0	208.0	208.0
CONTRACTUAL	681.0	681.0	681.0	681.0	681.0	543.0
SUPPLIES	204.0	204.0	204.0	204.0	204.0	204.0
EQUIPMENT	212.0	212.0	212.0	212.0	212.0	212.0
LAND&STRUCTURES	0.0	0.0	0.0	0.0	0.0	0.0
GRANTS,CLAIMS	0.0	0.0	0.0	0.0	0.0	0.0
MISCELLANEOUS	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPERATING	3902.0	3902.0	3902.0	3902.0	3902.0	3764.0

CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
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CHANGE IN REVENUES ()	0.0	0.0	0.0	0.0	0.0	0.0
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FUND SOURCE

1002 Federal Receipts	0.0	0.0	0.0	0.0	0.0	0.0
1003 GF Match	0.0	0.0	0.0	0.0	0.0	0.0
1004 GF	3,902.0	3,902.0	3,902.0	3,902.0	3,902.0	3,902.0
1005 GF/Program Receipt	0.0	0.0	0.0	0.0	0.0	0.0
1006 GF/MHTIA	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	3,902.0	3,902.0	3,902.0	3,902.0	3,902.0	3,902.0

Estimate of any current year (FY97) cost: \$ 0.0

POSITIONS:

FULL-TIME	29	29	29	29	29	29
PART-TIME	0	0	0	0	0	0
TEMPORARY	0	0	0	0	0	0

ANALYSIS: (Attach a separate page if necessary.)

See attached.

Prepared by: Susan Braley
 Division: Air & Water Quality

Phone: 907-465-5308
 Date: 1/22/97

Approved by Commissioner: Frank Tilton Acting Comm.
 Agency: Department of Environmental Conservation

Date: 1-22-97

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Attachment to Fiscal Note, HB 51 -- 1/22/97

The break out of the fiscal note for HB 51 is shown by pertinent sections of the bill.

All Sections.

There will be significant legal issues associated with several sections of this bill, including obtaining delegation of the NPDES program from EPA as directed by Section 3. Per the Department of Law, they anticipate a full time attorney will be required.

Line 300 (Department of Law RSA)

\$138,000

Section 2.

This section prohibits the adoption of any environmental regulation by DEC unless the requirements are economically feasible for the persons governed by the regulations without any consideration of the public health impacts. The department administers 29 sets of regulations through Title 18 (Environmental Conservation). In a given year, approximately 15 regulatory packages are developed, revised, or amended by the department, some of which are complex and comprehensive amendments to existing law or are mandated by recent changes to federal law. The requirement to determine the economic feasibility of compliance with all DEC regulations cannot be met solely by DEC technical and scientific staff whose training is in areas other than economics.

Based on the level of regulatory activity in the department, funding for three Economists would be required:

Line 100	2 FTE (Economist II)	\$190,000
	1 FTE (Economist III)	\$107,600
	Total Line 100	\$297,600
Line 200	Travel	\$5,000
Line 300	Contractual	\$3,000
Line 400	Supplies	\$3,000
Line 500	Equipment	\$9,000

TOTAL COSTS SECTION 2 PER YEAR = \$317,600

Section 3.

This section requires the department to seek and maintain primacy of the federal National Pollutant Discharge Elimination System (NPDES) program from the USEPA. The major components of the NPDES program include permitting, compliance monitoring, and enforcement. This section represents the most substantive part of the proposed legislation from a fiscal perspective. In 1987 the department analyzed the viability of gaining primacy for the NPDES program and estimated at that time it would cost approximately \$2.3 million to administer the minimum effort required by EPA to

maintain the NPDES program.

The Division of Air and Water Quality is currently in the process of awarding a \$25,000 contract to conduct a new feasibility study on state primacy of the NPDES program. Unfortunately, the results of that study will not be available until June 1997. Therefore, for purposes of this fiscal note, the 1987 analysis has been used as the basis for determining the costs of assuming the NPDES program, taking into account current costs estimates.

Line 100	21 FTE professional staff (Envir. Specialists/Engineers)	\$1,994,700
	4 FTE clerical staff (Admin. Clerk II)	\$209,800
	(to implement NPDES related functions in permitting, monitoring, compliance monitoring, and enforcement)	
	Total Line 100	\$2,204,500
Line 200	Travel (compliance monitoring, enforcement)	\$200,000
Line 300	Contractual	\$400,000
Line 400	Supplies	\$200,000
Line 500	Equipment	\$200,000
TOTAL COSTS SECTION 3		\$3,204,500

Section 4 & 5.

To achieve the requirements under these sections, one additional full time staff position would be required to handle the requests to change a State water quality standard allowed in Sec. 46.03.085© and Section 36.03.087(b), as well as a full review of the regulations required in Section 5 of the bill. The timelines required in 46.03.085(c) would mean a staff person would have to give immediate and full time attention to the requested change.

Because of the contentious nature of making changes to the state water quality standards, it is vital that we seek, and have available for the public, third party expertise on the water quality standard in question. Past experience with contractual funding for third party expertise shows that costs run from \$20,000 to \$75,000 depending on the complexity of the issue. For example, an initial review done just on settling velocities of sediment for the A-J Mine's tailing impoundment cost the Department \$20,000 in 1994. Given the estimate of four changes requested per year, it is estimated that \$100,000 in contractual expenses will be incurred per year to gather third party expertise on the issues. Public notice and hearing costs run approximately \$10,000 per regulatory change. Therefore, the fiscal note includes:

Line 100	1 FTE professional staff(Envir. Specialist III)	\$95,100
Line 200	Travel (hearings, research)	\$3000

Line 300	Contractual Costs for 3rd party expertise	\$100,000
	Public Notice costs	\$40,000
Line 400	Supplies	\$1000
Line 500	Equipment	\$3000

TOTAL SECTION 4 & 5 PER YEAR = \$242,100

TOTAL COSTS OF HB 51 FOR ALL SECTIONS:

Line 100 (personal services)	\$2,597,200
Line 200 (travel)	\$208,000
Line 300 (contractual)	\$681,000
Line 400 (supplies)	\$204,000
Line 500 (equipment)	\$212,000
TOTAL GF	\$3,902,200

HOUSE COMMITTEE REPORT

(7)

Date Referred to Committee: January 13, 1997

FURTHER REFERRALS:

Finance

Date of Committee Action: 1/30/97

The HOUSE SPECIAL COMMITTEE ON OIL AND GAS Committee considered:

HB 51

HOUSE BILL NO. 51

REGULATIONS OF DEPT OF ENV. CONSERVATION

"An Act relating to the Department of Environmental Conservation."

recommends it be replaced

with the following committee substitute CS For HB No. 51 K

☒ the same title
☐ a new title

☐ additional referral to _____ Committee

☐ attached amendment(s)

ADOPTS: _____ Letter of Intent

ATTACHES NEW FISCAL NOTE(s): (Dept)

APPROVES PREVIOUS: (Dept/Date)

☒ fiscal note(s) D.E.C. 1/22/97

☐ fiscal note(s) _____

ADF&G 1/29/97

☐ zero fiscal note(s) _____

☐ zero fiscal note(s) _____

SIGNING WITH RECOMMENDATIONS	DP	DNP	NR	AM
<u>Car Bender</u>	☒			
<u>Mike H...</u>	☒			
<u>Tom T...</u>	☒			
<u>Scott W...</u>			☒	
<u>John J...</u>		☒		
<u>John R...</u>				

CHAIR'S SIGNATURE

Matthew...

1/30/97

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(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

130 Seward Street, Suite 409
Juneau, Alaska 99801-2105

MEMORANDUM

January 21, 1997

SUBJECT: Sectional Summary of HB 51. (An Act relating to the Department of Environmental Conservation)

TO: Representative Norman Rokeberg
Attn: Shirley Armstrong

FROM: Terri Lauterbach 
Legislative Counsel

You have requested a sectional summary of the above-described bill.

As a preliminary matter, note that a sectional summary of a bill should not be considered an authoritative interpretation of the bill and the bill itself is the best statement of its contents. If you would like an interpretation of the bill as it may apply to a particular set of circumstances, please advise.

Section 1. Gives findings and intent of the legislature.

Section 2. Places feasibility and measurability limits on all regulations of the Department of Environmental Conservation.

Section 3. Directs the DEC to seek and maintain authority from the federal government ("primacy") so that the state can administer the national pollutant discharge elimination system (NPDES) in Alaska instead of the federal government.

Section 4. Adds two new sections to the Alaska Statutes that affect the adoption and application of water quality standards. Requires special procedures for state standards that are different in specified ways from related federal standards.

Section 5. Requires DEC to review all current water quality regulations to determine if they comply with federal requirements and are not more stringent than applicable federal regulations. Requires rejustification or revision of regulations that fail the review criteria.

TML:jdr
97-028.jdr

ALASKA STATE LEGISLATURE

House of Representatives

COMMITTEE ASSIGNMENTS:

LABOR & COMMERCE COMMITTEE, CHAIRMAN
SPECIAL COMMITTEE ON OIL & GAS, MEMBER
JUDICIARY COMMITTEE, MEMBER
CORRECTIONS FINANCE SUBCOMMITTEE, MEMBER



INTERIM:
716 WEST 4TH AVENUE, SUITE 640
ANCHORAGE, AK 99501
PHONE: (907) 258-8191
FAX: (907) 258-2916

SESSION:
STATE CAPITOL
JUNEAU, AK 99801-1182
PHONE: (907) 465-4968
FAX: (907) 465-2040

Representative Norman Rokeberg

MEMORANDUM

TO: Representative Mark Hodgins, Chairman
House Special Committee On Oil & Gas

FROM: Representative Norman Rokeberg */NR*

DATE: January 21, 1997

SUBJECT: HB 51 - "An Act relating to DEC water quality."

Attached is committee packet for HB 51. As of this date I have not received the fiscal notes from the Departments of Fish and Game or Environmental Conservation. My office has contacted each department and they have assured me that the fiscal notes will be made available to the committee before the public hearing on Thursday.

In addition Representative Kelly and I met with Mr. Al Ewing, Deputy Commissioner of DEC today to discuss DEC's current position on the bill. DEC's staff have made some recommendations for word changes and we have contacted legal to prepare a blank CS for presentation to the Oil and Gas Committee.

Thank you for scheduling HB 51 and I am looking forward to working with you on this bill.

FISCAL NOTES

State of Alaska
Office of the Governor

TONY KNOWLES
Governor
P.O. Box 110001
Juneau, Alaska 99811-0001
NEWS RELEASE



Bob King
Press Secretary
Claire Richardson
Deputy Press Secretary
907-465-3500
FAX: 907-465-3533

FOR IMMEDIATE RELEASE: January 24, 1997

97-027

KNOWLES APPLAUDS STRONG GROWTH IN MINING
Receives Alaska Minerals Commission's 1997 Report

Governor Tony Knowles underscored his commitment to the state's mining industry today when he received the 1997 Alaska Minerals Commission report highlighting a third consecutive year of strong growth since he took office.

"New mines are coming on line around the state, especially in rural Alaska, and Alaskans are filling lots of new jobs," Knowles said. "My priority is creating public-private partnerships that improve the economic and regulatory climate for environmentally sound mining efforts that result in more and better jobs for Alaskans."

The mining year was highlighted by the commissioning of a new mine at Fort Knox near Fairbanks and the construction of the Illinois Creek Mine near Galena. Together the mines will employ about 485 workers and are expected to produce about 420,000 ounces of gold each year.

Alaska Minerals Commission chairwoman Irene Anderson thanked Knowles for taking action on recommendations made by the commission last year. "The continued funding of the airborne geophysical surveys is just one of the legislative and administrative actions that have contributed significantly to continued strong growth of the mining industry," Anderson said.

Some of the commission's recommendations for 1997 include the state assuming control of a federal program monitoring the discharge of pollutants into streams, continued investment in aerial mapping of Alaska's mineral resources, and support of the Alaska Mineral and Energy Resource Education Fund.

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