

ALASKA LEGISLATURE COMMITTEE FILES 1995-1996 8672

8986 SENATE RESOURCES

Northstar Economic Evaluation



Estimated Total Revenues

Senate Resources Committee
Letter--rec'd 4/12/96
190 MMBO Reserves

Supplemental Royalty
and
1999 Development

Net Profit Share
and
2002 Development

Net Profit Share
and
1999 Development

(Real 1996 Dollars)

State Revenues

State Royalty	372	373	372
State Supplemental Royalty	49	0	0
NPSL	0	217	288
State Share of Federal Royalty	24	24	24
Severance Tax	115	133	116
Spill & Conserv. Tax	4	4	4
Ad Valorem Tax	57	62	57
Income Tax	19	15	14
Total	639	827	873

Federal Revenues

Royalty (Net of State Share)	64	65	64
Income Tax	322	258	240
Total	386	323	304

BPXA Cash Flow

After Tax Funds Flow	539	421	386
Real Rate of Return	25.8%	24.3%	23.7%

Totals may not add due to rounding.

Northstar Economic Evaluation



Estimated Total Revenues

Senate Resources Committee
Letter-rec'd 4/12/96
160 MMBO Reserves

Supplemental Royalty
and
1999 Development

Net Profit Share
and
2002 Development

Net Profit Share
and
1999 Development

(Real 1996 Dollars)

State Revenues

State Royalty	316	317	316
State Supplemental Royalty	60	0	0
NPSL	0	131	201
State Share of Federal Royalty	20	20	20
Severance Tax	41	46	41
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	44	49	44
Income Tax	17	16	14
Total	501	581	641

Federal Revenues

Royalty (Net of State Share)	55	55	55
Income Tax	292	266	243
Total	348	320	297

BPXA Cash Flow

After Tax Funds Flow	490	441	399
Real Rate of Return	20.7%	20.5%	20.0%

Totals may not add due to rounding.

Northstar Economic Evaluation



Estimated Total Revenues

Senate Resources Committee
Letter--rec'd 4/12/96
115 MMBO Reserves

Supplemental Royalty
and
1999 Development

Net Profit Share
and
2002 Development

Net Profit Share
and
1999 Development

(Real 1996 Dollars)

State Revenues

State Royalty	226	227	226
State Supplemental Royalty	32	0	0
NPSL	0	0	0
State Share of Federal Royalty	14	15	14
Severance Tax	44	50	44
Spill & Conserv. Tax	3	2	3
Ad Valorem Tax	42	46	42
Income Tax	11	11	11
Total	371	350	340

Federal Revenues

Royalty (Net of State Share)	39	39	39
Income Tax	183	192	194
Total	223	231	233

BPXA Cash Flow

After Tax Funds Flow	291	307	310
Real Rate of Return:	17.7%	18.0%	18.2%

Totals may not add due to rounding.

(This table is based on the Bureau of Minerals and Geology
developed in Senate Resources Committee hearings--April 11, 1996)

MEMORANDUM

State of Alaska

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS

TO: Ken Boyd
Director

DATE: April 16, 1996

FROM: Bill Van Dyke 
Petroleum Manager

TELEPHONE NO: 269-8786

FAX NO: 562-3852

SUBJECT: Net Profit Share Accounting

Enclosed for your review is the example west coast oil price net back calculation we discussed last Thursday night at the Senate Resources Committee hearing. If you have any questions please give me a call.

Enclosure

Example Net Back Calculations for Determination of Net Profit Share and Royalty

Listed below are the calculation methodologies that one would use to determine the net back value (the LACT meter value for the oil at North Star) beginning with a west coast oil price. As was stated at the hearing last Thursday, not all deductions allowed for purposes of net profit share accounting are allowable deductions against royalty or taxes. For your information, both a net profit share net back and a royalty net back calculation are shown. For consistency, we used the assumptions shown in the North Star model for the year 2000 for these two examples.

Example Net Profit Share Calculation (for the year 2000)

\$18.64 west coast oil price in the year 2000 (\$/bbl)

-\$ 1.47 marine (tanker) transportation deduction

-\$ 2.69 TAPS tariff--Pump Station #1 to Valdez

-\$ 0.75 North Star pipeline tariff--North Star to PS#1

-\$ 2.74 royalty payment

-\$ 0.84 production tax payment

-\$ 2.26 direct operating cost (includes lifting costs)

\$7.89 per barrel production revenue that would be credited against any remaining monies in the development account

Example Royalty Calculation (for the year 2000)

\$18.64 west coast oil price in the year 2000 (\$/bbl)

-\$ 1.47 marine transportation deduction

-\$ 2.69 TAPS tariff

-\$ 0.75 North Star pipeline tariff

\$13.73 per barrel net back amount--20% of this amount (\$2.75/bbl) would be owed as the base royalty on each barrel of produced oil. The supplemental royalty as proposed would be \$0.04 per barrel at the given west coast oil price.

WVD 4/16/96

STATUS QUD

MLM Royalty Reduction System Real 1995 \$

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
State Revenue-Status Qud	0	0	5	61	58	58	47	38	30	24	37	50	41	34	22	12	12	518
State Revenue-Real Disc	0	0	4	46	41	38	29	23	16	12	16	22	17	13	8	4	4	293
Total	0	0	9	107	99	96	76	61	46	36	53	72	58	47	30	16	16	811

NPV(BP) = \$148 NPV(AQ) = \$393 State Take = 48.4%

APPLICATION

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
State Revenue-Application	0	0	5	61	58	58	47	38	30	24	37	50	41	34	22	12	12	368
State Revenue-Real Disc	0	0	4	46	41	38	29	23	18	12	10	8	6	5	3	2	2	242
Total	0	0	9	107	99	96	76	61	48	36	47	58	47	39	25	14	14	610

NPV(BP) = \$183 NPV(AQ) = \$342 State Take = 37.1%

Annual Projected Lost State Revenue = 120
Lost State Revenue = 120

ACTUAL Assume DOR High Prices and Base Case Inflation

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
State Revenue-Actual	0	0	6	60	64	68	57	48	38	31	27	14	11	17	12	7	7	472
State Revenue-Real Disc	0	0	5	55	51	49	39	31	23	18	15	7	5	8	5	3	3	313
Total	0	0	11	115	115	117	96	79	61	49	42	21	16	25	17	10	10	785

NPV(BP) = \$308 NPV(AQ) = \$313 State Take = 33.2%

MLM

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
State Revenue Calculation	0	0	1	8	8	10	10	9	8	7	7	7	7	7	7	7	7	0
State Revenue Delta-Status Qud-Application	0	0	1	13	16	19	19	19	15	18	17	17	17	14	10	8	8	0
ATFF-Real Delta-ATFF-Real-Actual - ATFF-Real-Application	(120)	(120)	(120)	(109)	(106)	(109)	(71)	(52)	(33)	(15)	0	0	0	0	0	0	0	0
ATFF-Real Delta Available for Lost State Revenue Payment	0	0	1	13	16	19	19	19	18	18	17	17	17	14	10	8	8	0
Lost State Revenue Acct Beginning Balance	0	0	1	13	16	19	19	19	18	15	0	0	0	0	0	0	0	0
Payments made to Lost State Revenue Acct	0	0	1	13	16	19	19	19	18	15	0	0	0	0	0	0	0	0
Lost State Revenue Acct Ending Balance (120)	(120)	(120)	(109)	(106)	(109)	(71)	(52)	(33)	(15)	0	0	0	0	0	0	0	0	0
ATFF-Real Delta Available for Carry Forward	0	0	0	0	0	0	0	0	0	3	17	0	0	14	10	6	6	0
ATFF Carry Forward	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ATFF Carry Forward Beginning Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Onside made to Carry Forward	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ATFF Carry Forward Ending Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ATFF-Real Delta Available for Split	0	0	0	0	0	0	0	0	0	3	17	0	0	0	0	0	0	0
State Revenue Additional Split	0.1	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0
ATFF-Real Additional Split	0.9	0	0	0	0	0	0	0	0	3	15	0	0	0	0	0	0	0
State Take = Application + NPRL Make-up + Additional Split	0	0	7	82	84	87	78	67	56	45	29	14	11	17	13	8	8	596
State Take-Real Disc	0	0	6	58	64	62	51	43	34	27	16	7	5	8	6	3	3	306
Total	0	0	13	164	150	149	129	110	90	72	41	17	11	22	16	11	11	602

NPV(BP) = \$521 NPV(AQ) = \$326 State Take = 62.2%



Alaska State Legislature

SENATE RESOURCES COMMITTEE

Official Business

State Capitol
Juneau AK 99801

Mr. Ken Boyd, Director
Division of Oil and Gas
Department of Natural Resources
via facsimile: X3886 3 pages including this one

Dear Mr. Boyd:

Will you please provide the Committee the results of the department's modeling of the anticipated revenue distribution between the State, BPXA and the federal government if the assumptions used in the "Illustrative Northstar Model" are changed to relate to peak production, reserves and capital costs in the following manner:

Peak production rate: 80,000 bbls/day

Reserves:

P(90) = 190 MMBO

Mean = 160 MMBO

P(10) = 115 MMBO

Capital Expenditures (real 1996 dollars):

Adjust facilities capital cost to reflect assumption that off-site processing facilities are used instead of constructing new production facilities.

A short narrative summary of your estimate of the state revenue losses resulting from amendment of the Northstar leases under these circumstances would be appreciated.

Also, in this transmittal is a copy of BPXA's response to specific Committee questions regarding rate of return on late field life that may be useful to you in responding to the question last night regarding the rate of return during recoupment of the capital account costs.

Sincerely,

A handwritten signature in cursive script, appearing to read "Loren".

Senator Loren Leman
Chairman



BP EXPLORATION

APR 16 1996

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
PO. Box 186612
Anchorage, Alaska 99519-0612
(907) 561-5111

April 16, 1996

The Honorable Loren Leman, Chair
Senate Resources Committee
Alaska State Legislature
State Capitol
Juneau, AK 99801

Dear Senator Leman:

In response to your letter of April 12, the Department of Natural Resources has requested BP to provide capital costs and economic analysis for off site facility sharing of Northstar production.

The analysis is based on the following assumptions:

- Total project costs are still \$378 million (same as stand alone costs);
Conceptual engineering work has indicated that capital costs for facility sharing are substantially the same or higher than a stand alone production facility. The island expansion, drilling, subsea pipeline, environmental studies, and engineering costs are the same with facility sharing. The facility on the island would still require partial processing and water/gas re-injection capability. Therefore, the slightly reduced island facility cost is offset by higher pipeline and facility modifications costs.
- Reserves are 130 million barrels with a plateau rate of 50,000 barrels per day;
- A processing fee of \$2.50 per barrel of oil is required to access the facilities.
The assumed processing fee is consistent with fees currently charged on the North Slope.

The impact on State, Federal, and BP revenues is attached for the following three scenarios (1) supplemental royalty and early development, (2) net profit share and delayed development, and (3) net profit share and early development.

If you require additional information, please do not hesitate to call me (907-564-4892) or Daryl Kleppin (907-564-5418) on my staff.

Very truly yours,

A handwritten signature in cursive script that reads "Daryl Kleppin".

for E.M. Luttrell
Vice President, Exploration and Development
BP Exploration (Alaska), Inc.

Northstar Economic Evaluation

4/16/96

Estimated Total Revenues: Facility Sharing Case, Evaluated by BPXA

	With Supplemental Royalty and Early Development	With Not Profit Share and Delayed Development (Real 1996 Dollars)	With Not Profit Share and Early Development
<u>State Revenues</u>			
State Royalty	256	257	256
State Supplemental Royalty	37	-	-
NPSL	-	-	-
State Share of Federal Royalty	16	16	16
Severance Tax	58	58	58
Spill & Conservation Tax	3	3	3
Ad Valorem Tax	42	46	42
Income Tax	8	9	9
Total	419	389	384
<u>Federal Revenues</u>			
Royalty (Net of State Share)	44	44	44
Income Tax	133	150	145
Total	177	194	189
<u>BPXA Cash Flow</u>			
After Tax Funds Flow	197	229	220
Real Rate of Return	12%	14%	13%

State of Alaska
Department of Natural Resources
Division of Oil and Gas
3601 C Street, Suite 1380, Anchorage, Alaska 99503

Fax Confirmation Phone (907)762-2549 Fax (907)562-3852

FACSIMILE TRANSMITTAL

DATE & TIME: April 15, 1996 3:41 PM

PLEASE DELIVER TO: Senator Loren Leman

FAX NUMBER: 465-3810

NUMBER OF PAGES (including cover): 2

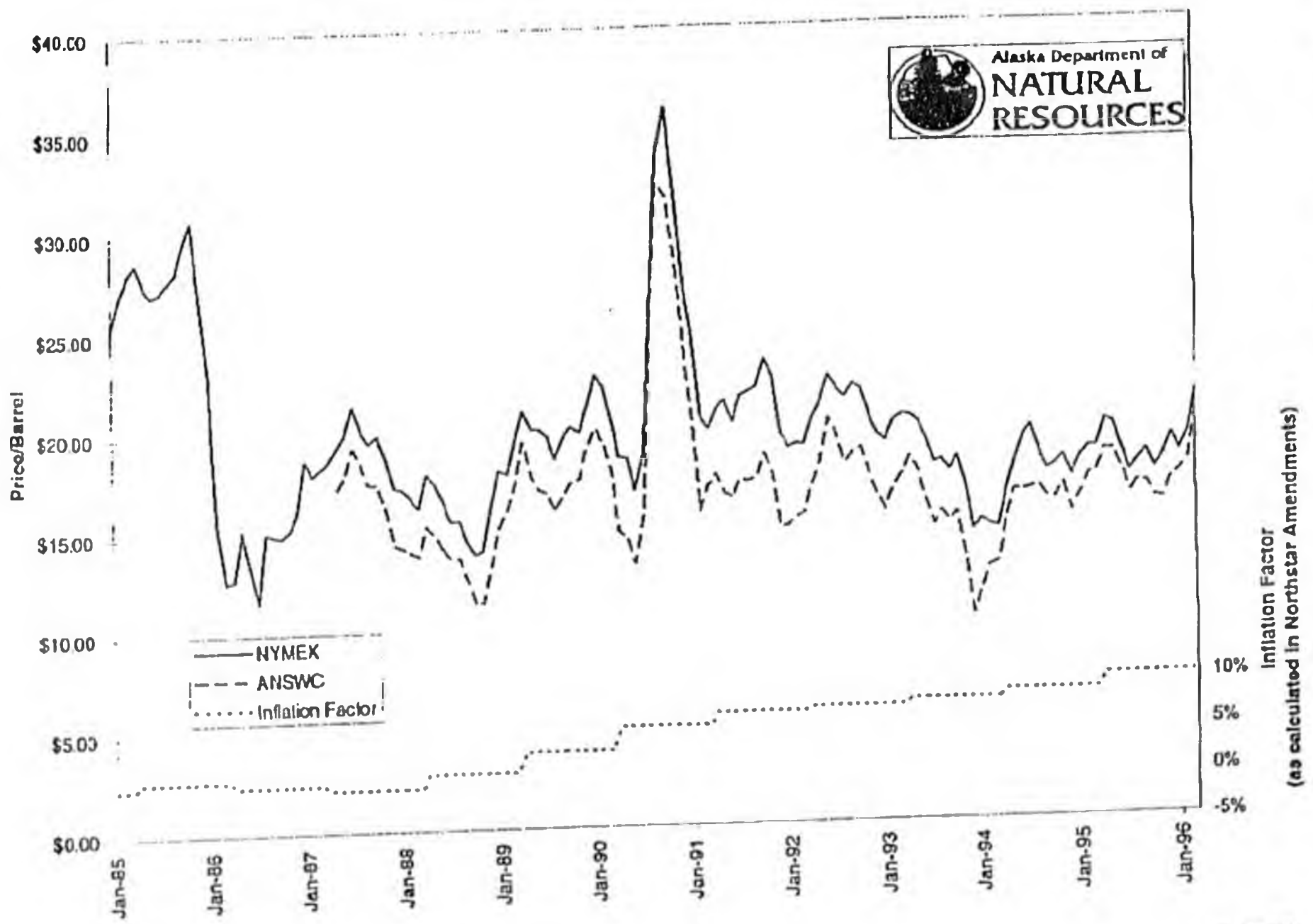
FROM: Kevin Banks
269-8799

COMMENTS:

Attached is the chart that illustrates historical oil prices and inflation. Prices are nominal (money-of-the-day), i.e., no adjustment for inflation. The inflation factor is calculated from the PPI (for industrial commodities) as indicated in the Northstar Lease Amendments, replacing December 1995 with December 1984 to show how the factor would have been calculated over the 1985-1996 period.

Attachment.

Historical Monthly NYMEX Oil Price and "Inflation Factor"



— NYMEX
- - - ANSWC
... Inflation Factor



Alaska State Legislature

SENATE RESOURCES COMMITTEE

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Chairman



Alaska State Legislature

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Sincerely,

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Senator Loren Leman
Chairman

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES

State of Alaska

DIVISION OF OIL AND GAS

TO: Ken Boyd
Director

DATE: April 12, 1996

FILE NO:

THRU:

TELEPHONE: 269-8799

FROM: Bill Van Dyke
Kevin Banks

SUBJECT: Senate Resources Hearing--
April 11, 1996

Several questions were raised at last night's Senate Resources Committee hearing on SB 318 (Northstar Lease Amendments). Senator Halford asked about the ultimate recovery expected for the Prudhoe Bay reservoir. As he observed, early recovery estimates were in the range of 9.6 billion barrels. We all know that this number has grown significantly over time. As of today the expected recovery at Prudhoe Bay is estimated to be 13 billion barrels.

Almost all this growth can be attributed to gas cycling and enhanced oil recovery benefits. The 9.6 billion barrel estimate did not include long-term high-volume gas cycling, nor did it include a miscible gas injection and NGL project. The benefits of gas cycling, miscible injection, and enhanced oil recovery, however, were not achieved without cost. The lessees have spent in excess of \$2 billion on these projects. The estimates of original-oil-in-place (OOIP) have changed very little since production start-up. The OOIP for the Prudhoe Bay reservoir is still about 23 billion barrels. As with the Northstar reservoir, the overall geology is pretty straight forward and the early seismic did a good job at defining the size and shape of the container. What has changed over time at Prudhoe Bay have been the estimates of how well the given container can be drained. Likewise, we do not believe that the size of the container at Northstar will change. Moreover, we believe that it is highly unlikely that the recovery rate at Northstar will exceed the recovery rate at Prudhoe Bay of 55 percent which was achieved after over \$2 billion of incremental investments.

We also discussed the 3-D seismic that will be shot at Northstar this summer season. That data will be used to target specific bottom-hole locations for each production and injection well. The 3-D data will allow BPXA to optimally place each wellbore, avoiding small faults and localized anomalies. I do not expect the 3-D data to significantly change the size or the shape of the overall container at Northstar.

Senator Frank asked during the hearing what the real rate of return would be to BPXA if it were to shut-in the field before the net profit share began to pay out to the state. Realistically, our assumption that development of the Northstar Unit under a net profit share system will be delayed should be used to examine this effect. Assuming that full production begins in 2002, the development account reaches zero in 2011, and net profit shares are paid to the state beginning in

2012. If the field produces for its full life, BPXA's RROR is 20.4%. If we cut off the calculation of the RROR at the year 2011, it drops slightly to 19.9%.¹ This demonstrates that there is still a positive cash flow, though discounted, to BPXA after 2011 which contributes to the RROR estimate.

After the hearing, Senator Halford asked about the effective severance tax rates applicable to the Northstar development as forecasted in the most likely case. The attached chart addresses his question and shows the annual effective severance tax rate after adjusting for the economic limit factor. This chart also shows the number of overall severance tax barrels based on these percentage rates. The timing of development has no affect on these figures; early development is shown.

Also attached is a second copy of the model that was presented last night to the committee. In this version of the model, the supplemental royalty is calculated. We have also included a revised copy of the "Assumptions Used in the Illustrative Northstar Model" handout that has the "Nominal Discount Rate 10%" in boldface type.

Kevin Banks will prepare a response to Senator Leman's letter received this morning, using the "Illustrative Northstar Model," as requested. These results should be available early next week.

Attachments.

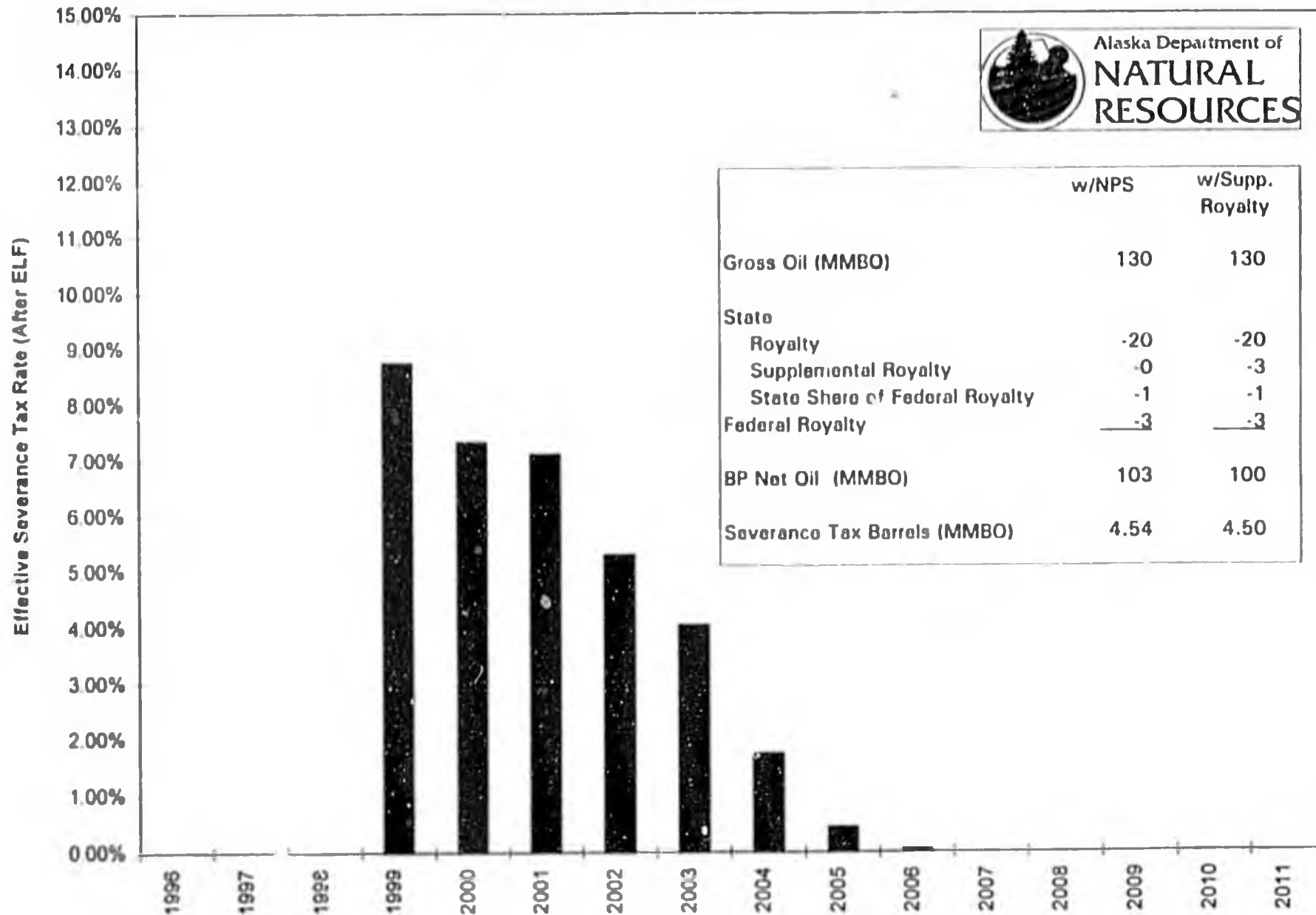
¹ This assumes delayed development. Senator Frank was looking at this question as if there would be no delay under the net profit share. The results are similar. Full field life RROR is 19.9. If the field were shut-in in 2007, the RROR is 19.4%.

Northstar Proposal

Forecast Effective Severance Tax Rates



Alaska Department of
**NATURAL
RESOURCES**



	w/NPS	w/Supp. Royalty
Gross Oil (MMBO)	130	130
State		
Royalty	-20	-20
Supplemental Royalty	0	-3
State Share of Federal Royalty	-1	-1
Federal Royalty	<u>-3</u>	<u>-3</u>
BP Net Oil (MMBO)	103	100
Severance Tax Barrels (MMBO)	4.54	4.50

Assumptions Used in the Illustrative Northstar Model

- **Project Life:** Production ramp-up in 4th Quarter 1998; full production in 1999; end of field life in 2012.
- **Wells:** 15 producers.
- **Original Oil in Place (OOIP):**

P(90)	=	310 MMBO
Mean	=	260 MMBO
P(10)	=	210 MMBO
- **Reserves:**

P(90)	=	160 MMBO
Mean	=	130 MMBO
P(10)	=	105 MMBO
- **Peak Production rate:** 50,000 bbl/day
- **Capital Expenditures (real 1996 dollars):**

Facilities:	Low	=	\$205	MM
	Base	=	\$237	MM
	High	=	\$278	MM
Drilling	Low	=	\$75	MM
	Base	=	\$85	MM
	High	=	\$110	MM
Pipeline	Low	=	\$25	MM
	Base	=	\$28	MM
	High	=	\$53	MM
Total	Low	=	\$305	MM
	Base	=	\$350	MM
	High	=	\$441	MM
- **Appraisal Costs**

Low	=	\$25	MM
Base	=	\$28	MM
High	=	\$30	MM
- **Operating Costs**

Low	=	\$1.40/bbl
Base	=	\$1.50/bbl
High	=	\$2.00/bbl
- **Initial Abandonment Costs:**

5% Facility Capex	(estimate provided by DNR
10% Drilling Capex	Petroleum Engineer)
- **BPXA's Working Interest:** 98 % (Murphy Oil owns 10% of OCS Y-181)

- **Tract Allocation:** 76.8% State (No production allocated to ADL 355001)
23.2% Federal
- **State royalty rate:** 20%
- **Supplemental royalty:** As proposed.
- **Federal royalty rate:** 16.67% (sliding scale not calculated; state receives 27% share of Federal royalty)
- **Net profit share:** 89.4% (average of the five state leases)
- **Development Account beginning balance (1996):** \$262 MM
- **Severance Tax:** 12.25% for first five years production, 15% thereafter; subject to ELF.
- **Conservation and oil spill tax:** \$0.034/bbl
- **Ad valorem tax rate:** 2%
- **State income tax rate:** 2% (estimate provided by DOR Petroleum Economist)
- **Federal income tax rate:** 35%
- **Oil Price Forecast:** DOR's Fall 1995 Base Price Forecast .
PS-1 price = Northstar wellhead and derived from DOR's forecast of TAPS tariffs and marine costs. No adjustment made for quality, pumpability, infrastructure charges, or upstream tariffs.
- **Inflation Rate:** DOR's Fall 1995 Base Price Forecast
3.0% in 1997; 3.2% thereafter.
- **Real Prime Rate:** 8.25% (Anchorage Daily News, 4/8/96)
- **Nominal Discount Rate:** 10% (A.D. Little Report)
- **General:** Stand-alone project, no facility sharing. Involves water flood and gas injection; process sales quality crude for delivery to TAPS. Expansion of the existing man-made Seal Island exploration island. Undersea, buried 12" pipeline to shore, 5 miles offshore/11 miles onshore; tie-in to Kuparuk Pipeline just west of TAPS Pump Station #1

Kevin Banks, ADNR
April 12, 1996

Summary Output

Development Summary		Months			
		MIN	MAX	MONTE	
Reserve	Gross CR (MM\$)	130	105	160	142
	Gross NGLR (MM\$)	0	0	0	0
Capex	DM (MM\$)	99	96	124	109
	Facility (MM\$)	251	211	244	250
	Hydro (MM\$)	28	25	33	34
	Total (MM\$)	378	331	471	393
Dev Costs	(MM\$)	23			28
Living Costs	(MM\$)	130	140	230	174

State Revenue (M. MOD)	
Royalty and Supplemental	108.0
State Share of Federal Royalty	20.3
Severance Tax	66.5
Gift & Conservation Tax	3.4
Ad Valorem Tax	0.0
NPRI	0.0
Income Tax	10.5
Total (M. MOD)	208.7
Total (M. real)	428.3

Federal Revenue (M. MOD)	
Royalty Port of State Share	64.8
Severance Tax	0.0
Gift & Conservation Tax	0.0
Ad Valorem Tax	0.0
NPRI	0.0
Income Tax	222.9
Total (M. MOD)	287.7
Total (M. real)	288.1

	1.00	1.02	1.04	1.10	1.12	1.17	1.21	1.24	1.28	1.32	1.37	1.41	1.48	1.50	1.55	1.60	1.65	1.70	1.75	1.80	1.85	1.90	1.95	2.00	2.05	2.10	2.15	2.20	2.25	2.30	2.35	2.40	2.44	2.48
Commodities Index	1.00	1.02	1.04	1.10	1.12	1.17	1.21	1.24	1.28	1.32	1.37	1.41	1.48	1.50	1.55	1.60	1.65	1.70	1.75	1.80	1.85	1.90	1.95	2.00	2.05	2.10	2.15	2.20	2.25	2.30	2.35	2.40	2.44	2.48
PS11 Oil Price (18/01, real)	11.45	11.00	11.07	12.75	12.78	12.77	12.81	12.82	12.86	12.82	12.81	12.82	12.84	12.85	12.84	12.84	12.81	12.86	12.84	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78
All WCC Oil Price (18/01, MOD)	18.34	18.41	18.00	17.01	18.04	18.34	18.00	17.01	17.50	17.38	17.21	17.10	17.09	17.07	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04

All WCC Oil Price (Random generated annual mean price forecast)		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Monthly Forecast Price	1992	18.24	18.28	18.58	17.20	18.32	19.00	19.73	20.47	21.23	22.00	22.80	23.70	24.50	25.50	26.41	27.20	28.25	29.27	30.23	31.27	32.27	33.24	34.23	35.28	36.20	37.28	38.20	39.28	40.21	41.50	42.62	43.78	44.88	45.91
Monthly MonteCarlo Price	1992	14.36	16.00	16.14	18.00	17.00	18.01	19.00	20.00	21.00	22.00	23.00	24.00	25.00	26.00	27.00	28.00	29.00	30.00	31.00	32.00	33.00	34.00	35.00	36.00	37.00	38.00	39.00	40.00	41.00	42.00	43.00	44.00	45.00	
ANS WCC Mean Annual Value	1992	18.34	18.41	18.00	17.01	18.04	18.34	18.00	17.01	17.50	17.38	17.21	17.10	17.09	17.07	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04
PS11 Mean Annual Value	1992	11.45	11.00	11.07	12.75	12.78	12.77	12.81	12.82	12.86	12.82	12.81	12.82	12.84	12.85	12.84	12.81	12.86	12.84	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78

Country Supplemental State Royalty %		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Country Supplemental State Royalty %	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Jan	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Feb	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mar	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Apr	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
May	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Jun	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Jul	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Aug	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Sep	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Oct	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nov	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Dec	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total (All Supplemental Tax %)	1992	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Monthly Receipts, Royalty and NPFL Tract Allocations											
Lease	NPFL	As-Is	% of Total Reserves	% of NPFL Reserves	Operating	NPFL	Working	NPFL	NPFL	Royalty Fee	NPFL
	%	\$	%	%	Days	Interest	Front	Front	by Lease	Front	NPFL
					Rate	Rate	Rate	Rate		Rate	NPFL
3112789	82.20%	84,000	8.77%	8%	100%	8.10%			70%	1,244%	1,244%
3112789	81.20%	85,000	44.00%	54%	100%	57.75%			70%	8,000%	8,000%
3112808	85.28%	102,000	8.18%	11%	100%	9.04%			70%	1,821%	1,821%
3112808	85.28%	218,000	17.57%	22%	100%	18.45%			70%	3,504%	3,504%
3514001	80.00%	9,000,000	0.00%	0%	100%	0.07%			70%	0.000%	0.000%
			78.80%	100%	100%	89.21%	88%			15,242%	15,242%
Effective State Royalty with 27% of Federal Tax											
V181		224,000	19.08%						18.87%	2,014%	2,014%
V0178		84,000	3.12%						18.87%	2,014%	2,014%
		1,700,000	100.00%							2,837%	2,837%
Effective Federal Royalty with 27% of Federal Tax											
										19.00%	19.00%
										81.00%	81.00%
										Total	

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025			
BP Revenue	0.0	0.0	19.8	202.0	208.3	208.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	158.4	
- Success Fee	0.0	0.0	0.0	17.7	15.3	14.8	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
- Spill & Conserv	0.0	0.0	0.0	0.1	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	
AVT	0.0	0.8	2.5	4.2	5.4	5.4	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	
NPIS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Other	0.0	0.0	3.1	29.2	30.3	30.5	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1		
- Abandonment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
- other income	0.0	0.0	11.2	150.2	158.8	157.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2	128.2			
- Expenses	52.8	89.0	111.5	80.8	31.1	17.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
Inter. Debt Exp	7.2	0.8	8.2	12.2	18.0	12.2	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8			
Tax, Depr/As Depr.	5.6	21.8	40.8	50.3	48.1	38.0	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8			
Total	12.8	22.5	48.2	87.8	85.0	48.2	32.5	28.2	20.0	11.4	3.8	0.8	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				
Fed. Tax Income	12.8	22.5	48.2	87.8	85.0	48.2	32.5	28.2	20.0	11.4	3.8	0.8	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
UOP Abandonment	0.00	0.00	0.78	0.26	0.43	0.45	0.48	7.2	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Rate (18/20)	0.00	0.00	0.78	0.26	0.43	0.45	0.48	7.2	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Total (nd)	0.00	0.00	0.78	0.26	0.43	0.45	0.48	7.2	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
State	0.76	0.47	-0.10	1.06	1.04	2.18	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	
Federal	4.47	-7.89	-11.99	28.22	31.51	27.37	34.25	32.01	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	34.25	
Total	-4.80	-8.45	-12.09	28.01	32.55	29.19	36.12	33.82	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12	36.12		
Foreign Price	-49.8	81.4	64.1	26.7	62.5	100.3	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	
ATIF - MOD	-49.8	81.4	64.1	26.7	62.5	100.3	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	
ATIF - Prod	-40.2	60.7	78.5	24.2	61.7	94.0	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8		
ATIF - Prod Elec	-40.2	60.7	78.5	24.2	61.7	94.0	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8		
ATIF - Comp NPV	-40.2	60.7	78.5	24.2	61.7	94.0	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8	93.8		
Net Income	-4.1	1.7	10.1	18.4	49.1	58.7	44.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8		

NPSL Accounting Handouts

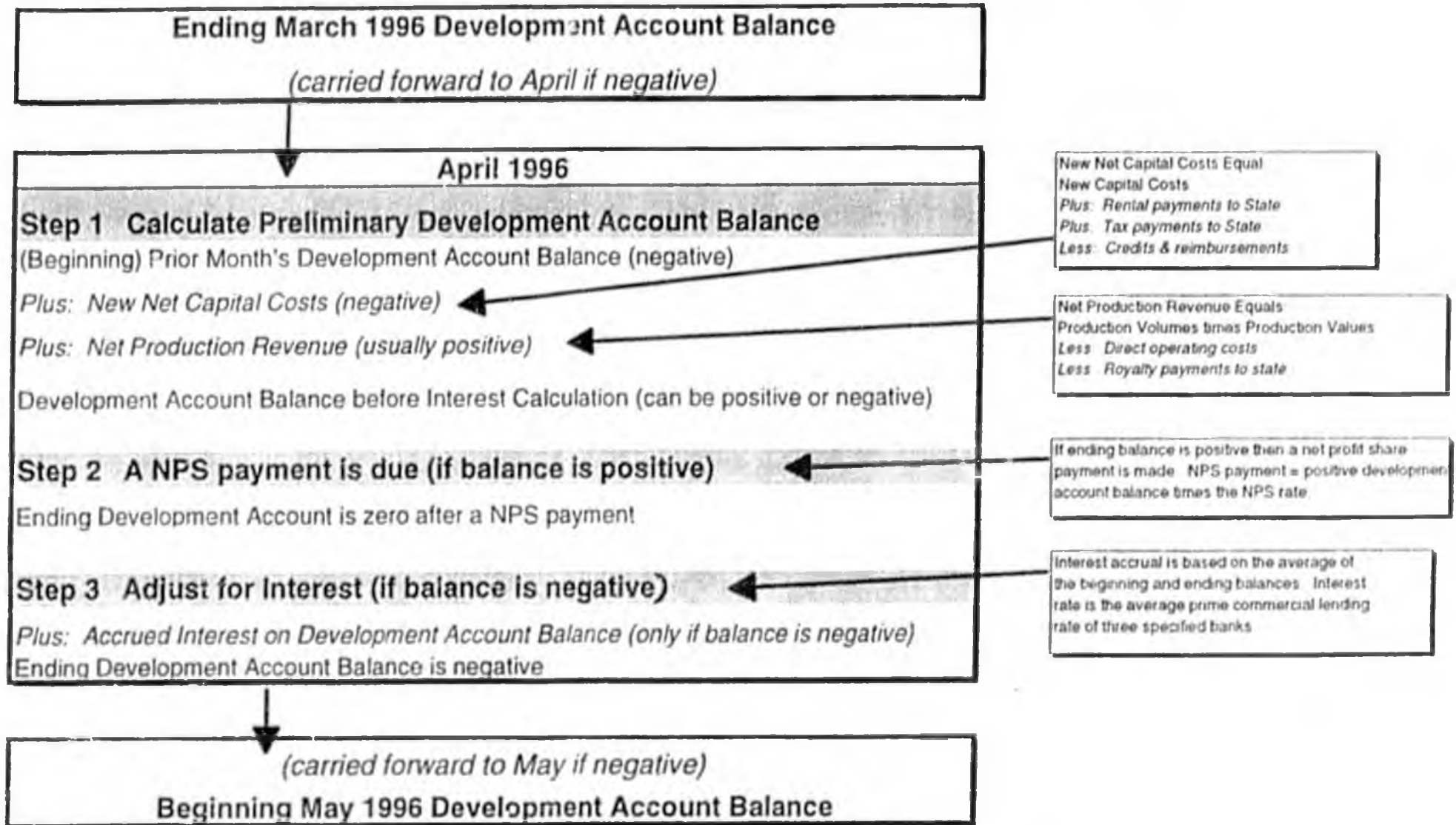
April 11, 1996

Prepared By

Alaska Department of Natural Resources

Division of Oil and Gas

NPSL ACCOUNTING FLOW DIAGRAM



NET PROFIT SHARE LEASE ACCOUNTING

1. OVERVIEW

The State's Net Profit Share Lease (NPSL) regulations define an accounting system and procedures to follow in the administration of NPSLs. The regulations' purpose is to allow a lessee to recover all appropriate development costs, with interest, and operating costs from production revenue before any net profit share becomes due the state from the lessee. These regulations provide for the monthly accumulation of certain costs in three accounts: the development account, the production revenue account, and the net profit payment account. 11 AAC 83.201-.295

In simple terms the system works as follows: Any positive balance remaining in the production revenue account (revenues minus operating costs and royalties) at the end of the month is used to reduce any accumulated costs in the development account. Any positive balance remaining in the development account is carried forward to the net profit payment account. The net profit payment account is shared with the State at the net profit share rate specified in the lease.

2. DEVELOPMENT ACCOUNT

The development account includes development costs which are generally capital expenditures. Rental payments to the State or taxes payable are an appropriate charge to the NPSL's development account for that month. Positive balances from the production revenue account are transferred monthly into the development account and reduce the accumulated costs in the development account to be carried forward.

The development account accumulates costs that are primarily capital in nature. These costs are defined in 11 AAC 83.219 subject to exclusions identified in 11 AAC 83.217. Development costs for NPSL generally consists of the following:

- 1) Cost of geological, geophysical, geotechnical and geochemical work performed on or adjacent to the NPSL relating to pre- or post-drilling operations. Such costs incurred prior to the inception of the lease (i.e. before the lease sale) are to be excluded.
- 2) Cost of design of construction projects as defined in the approved "Plan of Operations."

- 3) Cost of capital work in progress in support of the NPSL on or adjacent to the NPSL or on a contractor's premises.
- 4) Lease costs incurred to maintain an interest in the NPSL.
- 5) Cost of wells located on the NPSL.
- 6) Cost of facilities and equipment on or in support of the NPSL that are required for continued or enhanced production.
- 7) Cost of acquiring a production interest in the NPSL.
- 8) Capitalized ad valorem taxes.
- 9) General overhead and administrative expenses at the rate of three percent of the costs defined in 1), 2), 3), 5) and 6) above.

All costs are accounted for on an accrual basis and are limited by the definition of direct charges as established in 11 AAC 83.243. Further, only the reimbursable (from co-owners) portion of those costs of the lessee may be used in calculating the charge to the development account.

Development account balances are carried forward from month to month and interest is earned on these balances. The interest rate is specified in the lease sale terms, typically the average of the prime rates of three large banks. The interest that is earned on these balances further increases the total development costs to be carried forward until net production revenue is sufficient to recover the cumulative development costs plus interest to date. When the development account has a positive balance at month end, the positive balance is transferred to the net profit payment account, leaving a zero balance in the development account.

C. PRODUCTION REVENUE ACCOUNT

The production revenue account captures production revenue, direct operating costs, and royalty payments (the net profit share payment to the state is excluded). The NPSL production revenue is a positive amount credited to the account for each month's production. NPSL direct operating costs and royalty payments are charges (negative amounts) to the account.

Production Revenue generally consists of:

- 1) The value at point of production of lessee's gross share of oil and gas

produced from the NPSL, excluding fuel consumed, and volumes flared for safety or unavoidably lost or reinjected for conservation purposes.

- 2) All extraordinary production revenue or loss.

Direct Operating Costs generally consists of:

- 1) Direct charges incurred for wells, facilities, and equipment on or in support of the NPSL after commencement of commercial production that are in support of development or production operations that are not excluded or charged as development costs.
- 2) General overhead and administrative expenses not to exceed nine percent (9%) of allowable direct operating costs defined in item 1 above.
- 3) Accrual of abandonment costs amortized on unit-of-production basis.
- 4) Liability for taxes imposed on the value of production or sales from an NPSL incurred by a lessee.
- 5) Ad valorem taxes paid which are based on the value of lessee's properties used directly in the production, gathering, or treatment of production from an NPSL.

When the month-end account balance in the production revenue account is negative, the amount is carried over to the following month. When the month-end balance is positive, the amount is transferred to the development account, leaving an ending balance of zero in the production revenue account.

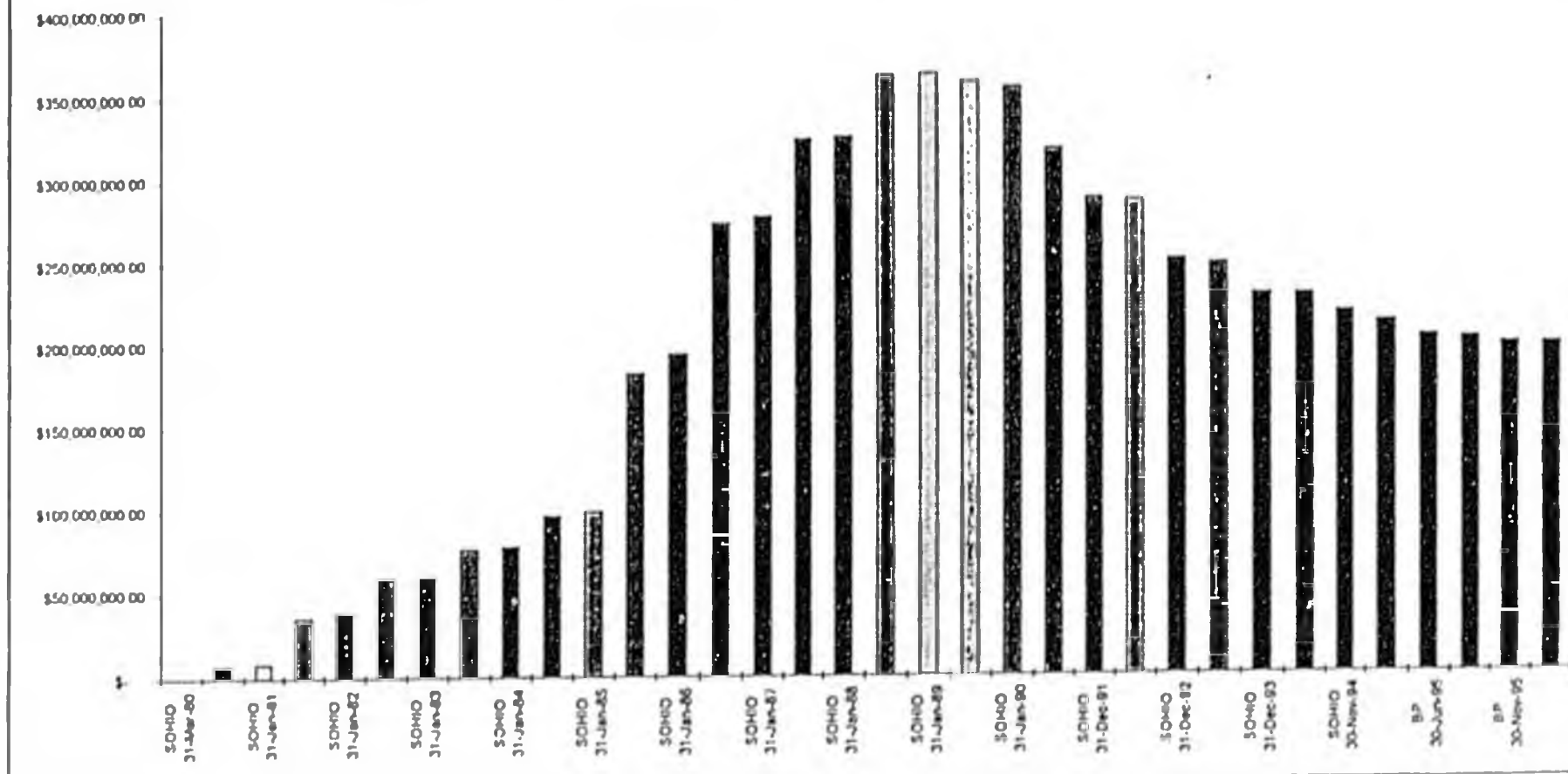
D. NET PROFIT PAYMENT ACCOUNT

The net profit payment account equals the positive amount, if any, transferred from the development account. The net profit share payment due the State equals the balance in the net profit payment account multiplied by the net profit share rate. This rate is a fixed percentage determined either through competitive bidding or by the Commissioner of Natural Resources prior to the lease sale. Further details about NPSL reporting and payment are contained in 11 AAC 83.201-295.

Two Examples of Actual NPS Development
Account Balances--One Producing Lease and
One Explored But Undeveloped Lease

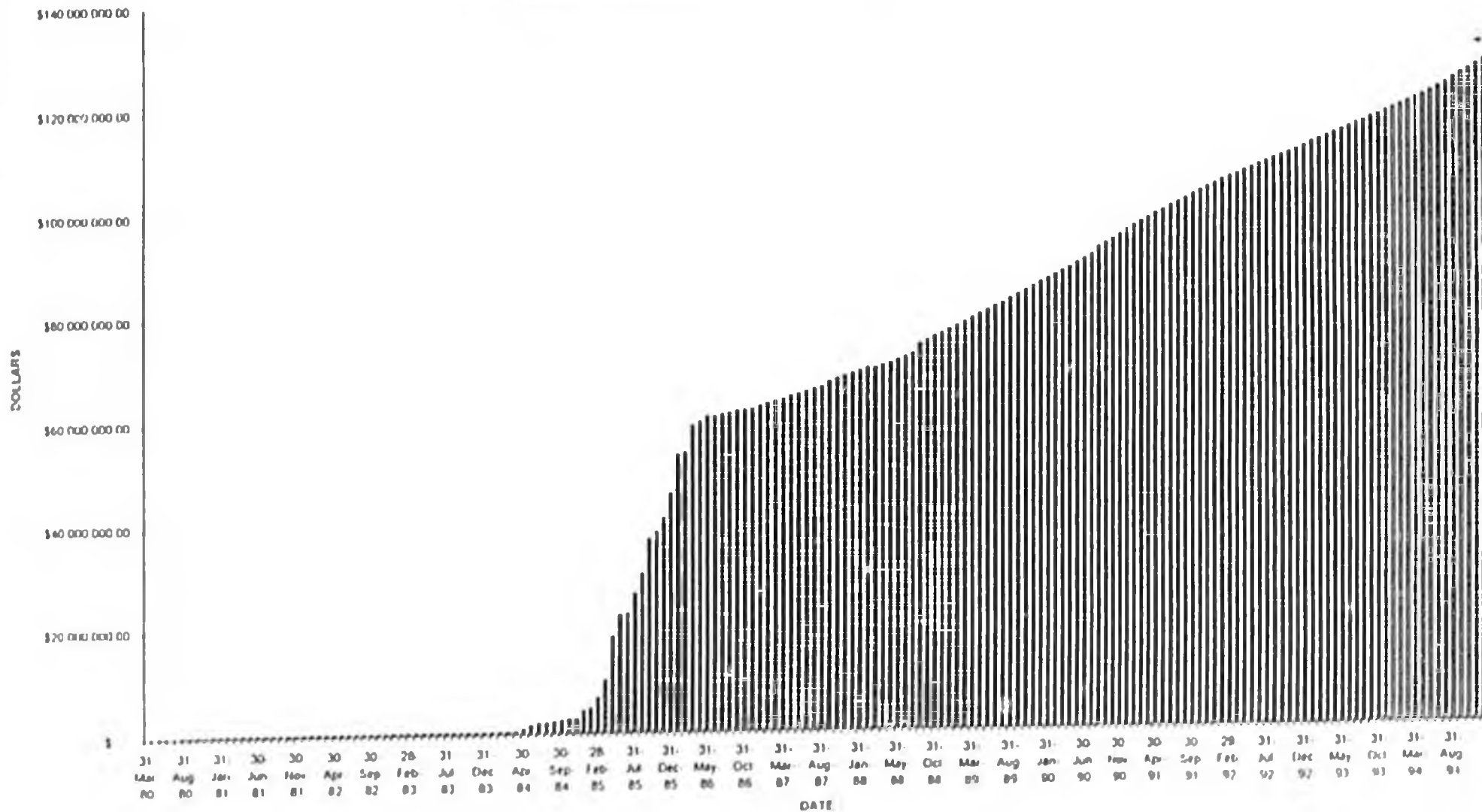
Listing of Current NPS Development Account
Balances by Field

ADL 312828 SOHIO & BP DEVELOPMENT ACCOUNT ENDING BALANCES



NPS Lease
 Duck Island Unit
 Endicott Pool
 Production Start Up Late 1987

ADL 312798 NPSL DEVELOPMENT ACCOUNT ENDING BALANCES



NPS Lease
 North Star Unit
 No Commercial Production to Date

NET PROFIT SHARE ACCOUNT
BALANCES BY FIELD

DUCK ISLAND UNIT--TWO NPS LEASES
\$203 MILLION

KUPARUK RIVER UNIT--FOUR NPS LEASES
\$123 MILLION

MILNE POINT UNIT--FOUR NPS LEASES
\$35 MILLION

NORTH STAR UNIT--FIVE NPS LEASES
\$259 MILLION

KUUKPIK UNIT--18 NPS LEASES
\$73 MILLION

POINT THOMSON UNIT--FIVE NPS LEASES
\$93 MILLION

NORTH NIAKUK AREA--ONE NPS LEASE
\$42 MILLION

GRAND TOTAL-- \$828 MILLION

Assumptions used in Illustrative Northstar Model

- **Project Life:** Production ramp-up in 4th Quarter 1998; full production in 1999; end of field life in 2012.
- **Wells:** 15 producers.
- **Original Oil in Place (OOIP):**

P(90)	=	310 MMBO
Mean	=	260 MMBO
P(10)	=	210 MMBO
- **Reserves:**

P(90)	=	160 MMBO
Mean	=	130 MMBO
P(10)	=	105 MMBO
- **Peak Production rate:** 50,000 bbl/day
- **Capital Expenditures (real 1996 dollars):**

Facilities:	Low	=	\$205	MM
	Base	=	\$237	MM
	High	=	\$278	MM
Drilling	Low	=	\$75	MM
	Base	=	\$85	MM
	High	=	\$110	MM
Pipeline	Low	=	\$25	MM
	Base	=	\$28	MM
	High	=	\$53	MM
Total	Low	=	\$305	MM
	Base	=	\$350	MM
	High	=	\$441	MM
- **Appraisal Costs**

Low	=	\$25	MM
Base	=	\$28	MM
High	=	\$30	MM
- **Operating Costs**

Low	=	\$1.40/bbl
Base	=	\$1.50/bbl
High	=	\$2.00/bbl
- **Initial Abandonment Costs:**

5% Facility Capex	(estimate provided by DNR
10% Drilling Capex	Petroleum Engineer)
- **BPXA's Working Interest:** 98 % (Murphy Oil owns 10% of OCS Y-181)

- **Tract Allocation:** 76.8% State (No production allocated to ADL 355001)
23.2% Federal
- **State royalty rate:** 20%
- **Supplemental royalty:** As proposed.
- **Federal royalty rate:** 16.67% (sliding scale not calculated; state receives 27% share of Federal royalty)
- **Net profit share:** 89.4% (average of the five state leases)
- **Development Account beginning balance (1996):** \$262 MM
- **Severance Tax:** 12.25% for first five years production, 15% thereafter; subject to ELF.
- **Conservation and oil spill tax:** \$0.034/bbl
- **Ad valorem tax rate:** 2%
- **State income tax rate:** 2% (estimate provided by DOR Petroleum Economist)
- **Federal income tax rate:** 35%
- **Oil Price Forecast:** DOR's Fall 1995 Base Price Forecast .
PS-1 price = Northstar wellhead and derived from DOR's forecast of TAPS tariffs and marine costs. No adjustment made for quality, pumpability, infrastructure charges, or upstream tariffs.
- **Inflation Rate:** DOR's Fall 1995 Base Price Forecast
3.0% in 1997; 3.2% thereafter.
- **Real Prime Rate:** 8.25% (Anchorage Daily News, 4/8/96)
- **Nominal Discount Rate:** 10%
- **General:** Stand-alone project, no facility sharing. Involves water flood and gas injection; process sales quality crude for delivery to TAPS. Expansion of the existing man-made Seal Island exploration island. Undersea, buried 12" pipeline to shore, 5 miles offshore/11 miles onshore; tie-in to Kuparuk Pipeline just west of TAPS Pump Station #1

Kevin Banks, ADNR
April 11, 1996

"SIMPLE" Discounted Cash Flow Model					
Year	1	2	3	4	5
Gross Oil (MMBO/Y)	0	5	10	6	2
State Royalty Rate	12.5%	12.5%	12.5%	12.5%	12.5%
Royalty Oil	0	0.625	1.25	0.75	0.25
WIO Oil	0	4.375	8.75	5.25	1.75
Oil Price	12.00	12.10	12.15	12.20	12.25
WIO Revenue	0.00	52.94	106.31	64.05	21.44
Capex	100.00	75.00	0.00	0.00	0.00
Opex	0.00	7.50	15.00	9.00	3.00
Total Cost	100.00	82.50	15.00	9.00	3.00
Net Revenue	-100.00	-29.56	91.31	55.05	18.44
Income Tax Rate	0.35	0.35	0.35	0.35	0.35
Income Tax	-35.00	-10.35	31.96	19.27	6.45
After Tax Cash Flow	-65.00	-19.22	59.35	35.78	11.98
NPV @10% =	\$1.50				
ROR =	11%				

Report2

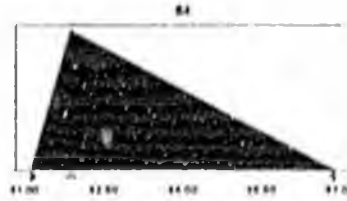
Assumptions

Assumption: S4

Coll: S4

Triangular distribution with parameters:

Minimum	\$1.00
Likeliest	\$1.80
Maximum	\$7.00



Selected range is from \$1.00 to \$7.00

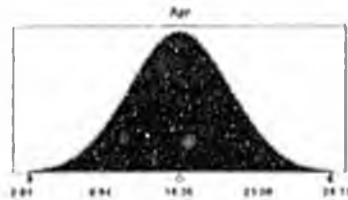
Assumption: Apr

Coll: B93

Normal distribution with parameters:

Mean	16.35	(= B80)
Standard Dev.	4.47	(= \$S\$4)

Selected range is from -21.51 to 402.42



End of Assumptions



Forecast: AKSUPP-REAL

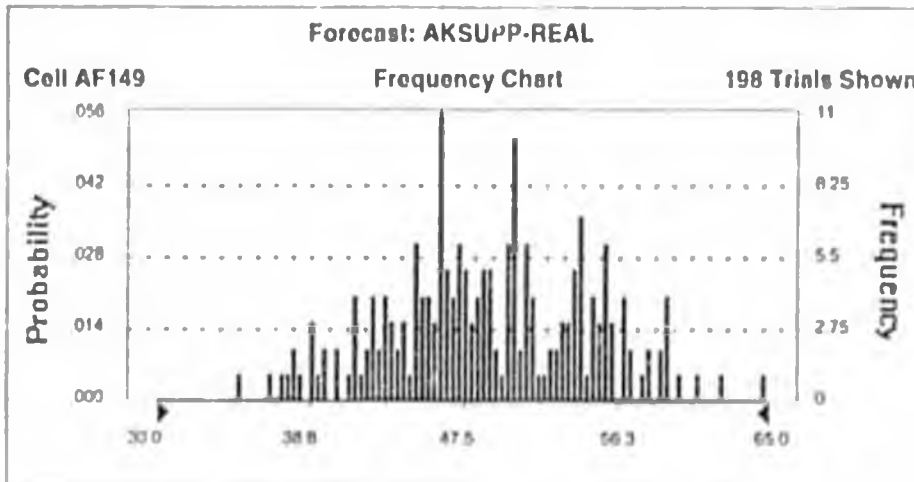
Cell: AF149

Summary:

Display Range is from 30.0 to 65.0
 Entire Range is from 34.7 to 67.8
 After 200 Trials, the Std. Error of the Mean is 0.4

Statistics:

Statistics:	Value
Trials	200
Mean	48.2
Med'ian (approx.)	48.8
Mode (approx.)	50.4
Standard Deviation	6.0
Variance	35.8
Skewness	0.23
Kurtosis	3.00
Coeff. of Variability	0.12
Range Minimum	34.7
Range Maximum	67.8
Range Width	33.2
Mean Std. Error	0.42





Forecast: AKSUPP-REAL (cont'd)

Cell: AF149

Percentiles.

<u>Percentile</u>	<u>Value (approx.)</u>
0%	34.7
10%	41.6
20%	44.2
30%	46.1
40%	47.2
50%	48.8
60%	50.5
70%	52.1
80%	54.4
90%	56.7
100%	67.8

End of Forecast



Northstar Economic Evaluation

Estimated Total Revenues

Accounting for the effects of "Price Volatility"	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
(Real 1996 Dollars)			
State Revenues			
State Royalty	255	256	257
State Supplemental Royalty	50	0	0
NPSL	0	107	41
State Share of Federal Royalty	16	16	16
Severance Tax	56	58	59
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	40	40	46
Income Tax	24	22	23
Total	444	502	444
Federal Revenues			
Royalty (Net of State Share)	44	44	44
Income Tax	218	198	213
Total	262	242	258
BPXA Cash Flow			
After Tax Funds Flow	355	319	346
Real Rate of Return	20.8%	21.1%	20.4%

*Assuming 3.2 percent inflation rate from DOR Fall 1995 Base Price Forecast. Totals may not add due to rounding.

Inputs

NPSLs: ON Supplemental Royalty: OFF

Working Interest	80%
Royalty Interest	10%
Split Conversion Fee (\$/bbl)	0.034
AVT Tax Rate	2%
Field Label(s)	2012
Recovery (months)	120
<hr/>	
Lifting Costs (\$/bbl, fixed)	1.50
State Income Tax Rate	- 2.00% (DOE set - no comp. rate)
Federal Tax Rate	34.2% (effective after AB Fee)
Inflation Rate*	3.0% *Use if sum inflation and base
Real Discount Rate	7.0%
Prime Interest Rate NPSL	- 6.25% (MCM 6/6/08)
Beginning Balance (\$M)	202
Oil Production Multiplier	1
Oil Prod Multiplier	1
Lifting Cost Multiplier	1
Facility Cost Multiplier	1
<hr/>	
Abandonment Costs (\$/bbl)	
Starting Abandonment Liability (\$MM)	77.8
Factor %	- 5% (O&A Percentage)
Timing (days)	- 10% (Expense Est.)

Lease	Royalty	NPSL
State		
212788	20.0%	83.20%
212789	20.0%	81.20%
212808	20.0%	85.28%
212809	20.0%	85.28%
255001	20.0%	80.00%
Federal		
V181	0.1887	0
V0179	0.1887	0

Monte Carlo Simulation:		Off
Monthly Oil Price End Date		12/31/2012
Range:	Low %	High %
Oil Price Cases	0.898	1.263
Gas Price Cases	0.864	1.172
Water Price Cases	0.997	1.092
Reserve Cases	0.808	1.231
Lifting Costs	0.935	1.375

NPSLs and Supplemental Royalty Control Panel	
NPSLs ON/OFF	On
Supplemental Royalty ON/OFF	Off
AVT/AVT - All Basin MOO Price Estimation	88.00

DOA Information	
Starting Oil Reserve Assets (\$MM)	0
Starting Well Assets (\$MM)	0
Starting Purchase Price Balance (\$MM)	0

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total							
Gross Oil (MMbbl) Produced	0.0	0.0	5.4	48.8	48.8	48.7	41.2	34.7	29.7	25.8	20.0	16.7	13.8	11.5	9.6	8.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	130.0							
Gross Water (MMbbl) Produced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							
Gross Gas (MMbbl) Produced	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							
Sales NGLs (MMbbl) Produced	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							
Return Gas (MMbbl) Purchased	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							
Return Gas Purchased	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							
<hr/>																																	
PS&T All Oil Prod (\$/bbl, mod)	811.45	812.28	812.72	813.88	814.48	814.87	815.88	815.87	816.48	816.88	817.52	818.10	818.78	818.88	820.08	820.88	821.33	821.81	822.82	823.25	823.83	824.84	825.38	826.18	826.81	827.74	828.57	829.43	830.31	831.22	82.18		
Pipeline Fees (\$/bbl, mod)	43.42	42.77	42.54	42.54	42.88	42.87	42.88	42.12	43.21	43.53	43.78	44.01	44.24	44.38	44.18	44.83	45.82	46.34	46.68	46.84	46.14	46.32	46.81	46.71	46.81	47.12	47.33	47.58	47.78	48.01	48.23		
Market Costs (\$/bbl, mod)	11.48	11.28	11.28	11.42	11.47	11.55	11.83	11.71	11.78	11.87	11.83	11.88	12.04	12.12	12.18	12.78	12.23	12.41	12.48	12.54	12.84	12.77	12.88	13.08	13.07	13.08	13.18	13.25	13.34	13.44	13.60		
NGL Value as % of Oil Prod (mod)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%		
Other Income (\$/bbl, mod)	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00		
Producing Water \$/bbl	0	0	0	10	15	15	15	15	15	15	15	15	15	15	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
Oil Ser. Fee	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%		
Gas Ser. Fee	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	
Abandonment Fee cost		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Capital, fixed																																	
Oil	14.8	0.0	14.8	28.0	28.0	15.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Facility	28.0	0.0	28.0	47.6	47.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Pipeline	5.0	13.0	18.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Cost Index Base*	1.00	1.03	1.08	1.15	1.12	1.17	1.21	1.24	1.28	1.33	1.37	1.41	1.48	1.50	1.55	1.60	1.65	1.70	1.75	1.8	1.85	1.93	1.98	2.04	2.11	2.17	2.23	2.29	2.37	2.44	2.48		

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total							
Supplemental Royalty Rate																														
Trigger Price (\$/Bbl WCI)	17.25	17.01	17.00	18.18	18.87	19.78	18.00	18.37	18.00	18.88	19.21	20.00	20.07	21.21	21.85	21.88	22.34	22.79	22.87	23.43	23.81	24.18	24.64	24.87	25.37	25.78	26.18	26.81	27.83	27.87
Linear Slope (% \$/Bbl WCI)	1.0%																													
Supplemental Royalty Cap	1.0%																													

Caution - Only change inputs on this page

Summary Output

Development Summary			Monte Carlo			
		M.L.	MIN	MAX	MONTE	
Reserves	Crude Oil	MMBBL	130	105	180	142
	Gas NGLs	MMBOE	0	0	0	0
Costs	Oil	(\$/bbl)	88	88	124	109
	Facility	(\$/m well)	251	217	284	250
	Pipeline	(\$/m well)	28	21	53	34
	Total	(\$/m well)	378	331	411	343
Dev Costs	(\$/MM)		2.8			2.8
Initial Costs	(\$/MM)		1.50	1.40	2.00	1.74

State Revenue (\$m. MOE)	
Royalty (incl. supplemental)	217.4
State Share of Federal Royalty	20.3
Severance Tax	87.2
Spill & Conservation Tax	3.5
Ad Valorem Tax	52.8
NPSL	78.0
Income Tax	18.0
Total (\$ m MOE)	555.1
Total (\$ m well)	438.4

Federal Revenue (\$m. MOE)	
Royalty (Net of State Share)	54.9
Severance Tax	0.0
Spill & Conservation Tax	0.0
Ad Valorem Tax	0.0
NPSL	0.0
Income Tax	272.8
Total (\$ m MOE)	328.5
Total (\$ m well)	260.8

	1 00	1 03	1 04	1 10	1 12	1 17	1 21	1 24	1 29	1 33	1 37	1 41	1 48	1 50	1 55	1 60	1 65	1 70	1 75	1 82	1 87	1 93	1 98	2 04	2 11	2 17	2 27	2 30	2 37	2 44	
Cumulative Inflation																															
PE&I Oil Price (\$/bbl, real)	11.48	11.80	11.97	12.78	13.79	13.77	12.81	12.83	12.94	12.92	12.81	12.92	12.84	12.95	12.84	12.84	12.81	12.80	12.80	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78
Ad. W.C. Oil Price (\$/bbl MOE)	18.28	18.41	18.69	17.87	18.84	18.24	20.04	20.81	21.59	22.30	21.23	24.18	25.00	25.07	26.87	27.74	28.88	29.88	32.28	31.71	32.70	33.88	34.70	35.74	31.81	37.81	38.88	40.27	41.43	42.87	42.87

ANS WC Oil Price (Random generated around mean price forecast)		1998	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Monthly Forecast Price		18.34	18.39	18.84	17.38	18.33	18.82	18.73	20.47	21.23	22.82	23.84	23.70	24.51	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.24	36.23	37.41	38.63	38.88	40.08	42.10
Monthly Monte Carlo Price		18.36	18	18.14	18.00	17.80	18.21	20.88	23.48	18.42	25.05	22.17	25.44	26.70	27.43	28.23	21.78	28.87	29.88	29.81	29.11	28.15	28.38	22.88	25.88	24.84	27.20	28.71	28.88	40.88	42.88
ANS WC Mean Annual Value		18.38	18.44	18.82	17.80	18.34	18.84	18.27	20.81	21.58	22.38	23.23	24.18	25.00	25.81	26.82	27.74	28.70	29.68	30.71	31.74	32.71	33.88	34.70	35.74	38.81	37.82	38.88	40.27	41.43	42.87
PE&I Mean Annual Value		11.48	12.29	12.87	13.81	14.81	14.82	15.81	18.87	18.48	18.88	17.87	19.10	18.71	18.45	20.08	20.55	21.33	21.84	22.87	23.22	23.87	24.81	25.88	26.15	28.87	27.74	28.81	29.43	31.41	31.84

Quarterly Supplemental Oil Revenue %		1 00	1 03	1 04	1 10	1 12	1 17	1 21	1 24	1 29	1 33	1 37	1 41	1 48	1 50	1 55	1 60	1 65	1 70	1 75	1 82	1 87	1 93	1 98	2 04	2 11	2 17	2 27	2 30	2 37	2 44	
Jan	0.00%	0.00%	0.00%	0.00%	0.00%	0.38%	1.00%	1.84%	2.23%	3.04%	3.80%	4.54%	5.23%	6.30%	7.15%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	
Feb	0.00%	0.00%	0.00%	0.00%	0.00%	0.47%	1.09%	1.74%	2.43%	3.14%	3.80%	4.70%	5.54%	6.41%	7.24%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Mar	0.00%	0.00%	0.00%	0.00%	0.00%	0.54%	1.18%	1.83%	2.52%	3.24%	3.81%	4.81%	5.88%	6.53%	7.37%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Apr	0.00%	0.00%	0.00%	0.00%	0.00%	0.64%	1.27%	1.87%	2.67%	3.34%	4.11%	4.92%	5.78%	6.46%	7.48%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
May	0.00%	0.00%	0.00%	0.00%	0.13%	0.73%	1.38%	2.02%	2.73%	3.44%	4.22%	5.03%	5.87%	6.76%	7.60%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Jun	0.00%	0.00%	0.00%	0.00%	0.21%	0.82%	1.45%	2.11%	2.82%	3.54%	4.22%	5.14%	6.09%	7.00%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Jul	0.00%	0.00%	0.00%	0.00%	0.39%	0.91%	1.64%	2.31%	3.02%	3.75%	4.54%	5.39%	6.10%	7.16%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Aug	0.00%	0.00%	0.00%	0.00%	0.39%	0.90%	1.63%	2.31%	3.02%	3.75%	4.54%	5.39%	6.10%	7.16%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Sep	0.00%	0.00%	0.00%	0.00%	0.49%	1.06%	1.73%	2.40%	3.12%	3.84%	4.68%	5.47%	6.33%	7.23%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Oct	0.00%	0.00%	0.00%	0.00%	0.54%	1.18%	1.82%	2.50%	3.23%	3.84%	4.78%	5.64%	6.48%	7.32%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Nov	0.00%	0.00%	0.00%	0.00%	0.64%	1.27%	1.81%	2.60%	3.32%	3.84%	4.78%	5.70%	6.54%	7.44%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Dec	0.00%	0.00%	0.00%	0.15%	0.74%	1.36%	2.01%	2.70%	3.42%	4.17%	4.81%	5.81%	6.88%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Annual & Avg Supplemental Oil Rev %		0.00%	0.00%	0.00%	0.38%	0.77%	1.50%	2.17%	2.87%	3.50%	4.38%	5.39%	6.48%	7.80%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	

NPSL Calculation	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Tract Alloc. Factor	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%
Tract Ownership	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
NPSL State Rate	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%
Prime Interest Rate	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Reversal Amount																															
Prod. Revenue	0.0	0.0	19.8	198.2	183.8	186.1	144.5	128.8	107.8	91.8	79.8	68.7	59.1	50.8	34.7	20.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Costs	0.0	0.0	12.41	123.01	123.71	123.81	120.81	118.21	116.51	113.31	111.51	108.91	106.51	103.21	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11
Production Taxes	0.0	0.0	10.01	110.21	112.41	112.11	108.01	106.41	103.11	101.01	100.21	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11	101.11
Ad Valorem Tax	0.0	10.81	12.01	13.41	14.21	14.21	14.11	13.81	13.51	13.21	12.81	12.51	12.21	11.81	11.41	11.01	10.51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
UOP Alloc. Costs	0.0	0.0	10.41	11.81	12.71	13.21	13.91	13.91	13.01	12.21	11.81	11.41	11.01	10.71	10.41	10.11	10.51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing Balance	0.0	10.81	10.8	118.8	118.8	118.8	104.8	84.7	82.4	72.4	63.2	54.7	47.2	41.0	27.8	18.1	10.51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Debt Account																															
Beginning Balance	1242.01	1327.81	1438.41	1581.01	1641.81	1488.81	1418.81	1340.01	1288.41	1204.81	1148.31	1082.81	1023.21	959.01	888.01	800.01	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital Expend	143.21	177.81	187.31	183.21	124.31	113.51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Prod Rev Acc Credit	0.0	0.0	10.8	118.8	118.8	118.8	104.8	84.7	82.4	72.4	63.2	54.7	47.2	41.0	27.8	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Prism Closing Bal	1304.21	1405.21	1513.01	1688.31	1648.11	1380.81	1310.01	1248.31	1188.11	1122.41	1053.11	977.81	908.01	833.01	752.01	661.01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Average Annual DA Balance	1282.11	1388.41	1473.71	1624.71	1483.81	1423.81	1383.31	1323.81	1272.81	1208.81	1148.71	1083.31	1023.21	959.01	888.01	800.01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accrued Interest	123.41	130.21	138.11	143.31	140.71	138.81	130.01	124.11	118.81	113.81	108.51	103.41	98.41	93.41	88.41	83.41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DA Closing Balance	1327.81	1438.41	1561.01	1688.81	1688.81	1418.81	1340.01	1288.41	1204.81	1148.31	1082.81	1023.21	959.01	888.01	800.01	711.01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NPSL Payment Acc																															
Prime Sub. NPSL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	41.0	27.8	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NPSL Payments*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	28.8	24.8	14.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

* Payments null if NPSL ONA11 switch in control box is set to "OFF"

Northstar Reserves, Royalty and NPBL Tract Allocations												
Leases	NPBL	Ac/Ft	% of Total Reserves	% of NPBL Reserves	NPBL Ownership	NPBL Share Rate	Working Interest	NPBL Tract Ret	NPBL Royalty by Lease	Weighted Royalty	NPBL	
312798	83.20%	84,000	8.73%	8%	100%	8.18%			20%	1.244%		
312799	81.20%	555,000	44.40%	56%	100%	32.73%			20%	8.881%		
312800	89.28%	102,000	8.16%	11%	100%	8.08%			20%	1.432%		
312809	84.24%	218,000	17.52%	23%	100%	18.46%			20%	3.504%		
35800'	40.00%		0.00%	0%	100%	0.00%			20.0%	0.000%		
		880,000	78.80%	100%	100%	80.39%	88%	78%		15.28%		
Effective State Royalty with 27% of Federal Tax										10.67%	3.014%	
V181		228,000	18.06%							10.67%	3.014%	
Y0178		84,000	7.52%							10.67%	0.994%	
		1,250,000	100.0%								2.827%	
Effective Federal Royalty with 27% of Federal Tax											2.865%	
										Total	18.00%	81.00%

0177		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
BP Revenue		0.0	0.0	19.8	203.0	209.1	210.7	184.4	180.3	137.2	117.2	101.8	87.8	75.4	64.8	44.2	29.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1641
Severance Tax		0.0	0.0	0.0	17.7	16.3	16.0	8.8	8.5	2.4	0.8	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	87
Upm & Corros		0.0	0.0	0.1	0.6	0.6	0.6	0.4	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4
AVI		0.0	0.8	2.8	4.3	5.4	5.4	5.2	4.8	4.5	4.1	3.7	3.3	2.8	3.3	1.8	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	53
NPSL		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	78
Upes		0.0	0.0	3.1	26.3	20.2	20.8	28.7	27.2	19.8	18.8	14.7	12.7	10.8	8.3	8.2	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	237
Abandonment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39
Other income	Other income	0.0	-0.8	14.3	150.2	157.8	158.3	142.4	129.8	110.3	95.4	82.8	71.8	58.8	48.8	31.1	8.3	-40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1182
Capex	Capex	53.8	89.0	111.5	80.8	31.1	17.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	283
Inten Drill Dep.	Inten Drill Dep.	-53.8	-89.0	-111.5	-80.8	-31.1	-17.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	769
Ten. Drill Dep.	Ten. Drill Dep.	7.3	0.8	8.3	17.3	18.0	12.3	3.8	3.3	2.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75
Ten. Drift Dep.	Ten. Drift Dep.	8.8	21.8	40.8	50.7	48.1	38.0	28.8	24.8	18.7	10.7	3.8	0.8	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	290
Total	Total	12.8	22.5	49.2	87.8	85.8	48.2	23.8	28.2	20.8	11.4	3.8	0.8	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	385
Fed Tax Income	Fed Tax Income	-12.8	-27.3	25.0	82.2	82.8	111.0	108.8	87.8	88.8	84.0	78.0	70.7	58.2	48.8	31.1	8.3	-40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	798

UOP Abandonment		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total	
Rate (\$/bbl)	Rate (\$/bbl)	0.00	0.00	0.78	0.38	0.42	0.44	0.43	0.40	0.37	0.35	0.32	0.28	0.26	0.22	0.17	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29	
Total (\$M)	Total (\$M)	0.0	0.0	0.8	2.3	4.7	8.8	9.4	8.0	3.9	3.0	2.3	1.7	1.3	0.8	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29	
DD&A																																	
Rate (\$/bbl)	Rate (\$/bbl)	0.00	0.00	3.88	2.88	3.30	3.83	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	385	
Total (\$M)	Total (\$M)	0.0	0.0	5.8	28.4	47.7	51.3	45.1	38.0	21.4	28.1	21.8	18.2	12.8	9.3	4.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	385	

Income Tax		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
State	State	-0.28	-0.47	-0.70	1.88	1.85	2.22	2.18	1.95	1.78	1.88	1.88	1.41	1.18	0.33	0.22	0.13	-0.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16
Federal	Federal	-4.43	7.88	11.88	28.24	31.75	38.08	37.38	33.48	20.70	28.83	27.08	24.23	20.33	5.88	3.81	2.18	-13.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	274
Total	Total	-4.69	6.45	12.88	28.88	33.80	40.30	39.53	35.44	12.48	30.51	28.87	25.85	21.81	8.01	4.04	2.28	-14.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	290

Funds Flow		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total	
ATFF - MOD	ATFF - MOD	-48.2	-81.4	-84.5	38.2	82.8	101.8	102.8	80.4	77.8	84.8	84.3	45.8	38.0	10.8	7.1	4.1	-25.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	480	
ATFF - Real	ATFF - Real	-48.2	-81.4	-84.5	38.2	82.8	101.8	102.8	80.4	77.8	84.8	84.3	45.8	38.0	10.8	7.1	4.1	-25.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	353
ATFF - Real Disc	ATFF - Real Disc	-48.2	-81.4	-84.5	38.2	82.8	101.8	102.8	80.4	77.8	84.8	84.3	45.8	38.0	10.8	7.1	4.1	-25.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	172
ATFF - Cum NPV	ATFF - Cum NPV	-48.2	-132.3	-202.1	-172.2	108.8	-45.8	12.1	88.8	85.2	122.7	143.2	158.2	171.8	174.8	178.8	177.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	

Net Income		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Net Income	Net Income	4.7	7.7	20.8	28.8	31.2	80.8	81.4	47.3	42.4	25.8	20.0	25.8	21.8	-3.0	-1.2	-0.8	13.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	508

Forecast: AKSUPP-REAL

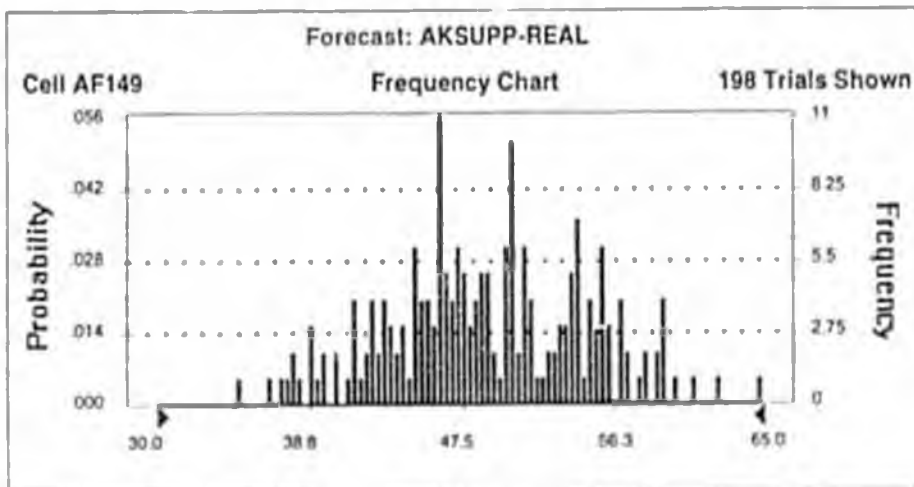
Cell: AF149

Summary:

Display Range is from 30.0 to 65.0
 Entire Range is from 34.7 to 67.8
 After 200 Trials, the Std. Error of the Mean is 0.4

Statistics:

	<u>Value</u>
Trials	200
Mean	49.2
Median (approx.)	48.8
Mode (approx.)	50.4
Standard Deviation	6.0
Variance	35.8
Skewness	0.23
Kurtosis	3.00
Coeff. of Variability	0.12
Range Minimum	34.7
Range Maximum	67.8
Range Width	33.2
Mean Std. Error	0.42





Forecast: AKSUPP-REAL (cont'd)

Cell: AF149

Percentiles:

<u>Percentile</u>	<u>Value (approx.)</u>
0%	34.7
10%	41.6
20%	44.2
30%	46.1
40%	47.2
50%	48.8
60%	50.5
70%	52.1
80%	54.4
90%	56.7
100%	67.8

End of Forecast

Northstar Economic Evaluation



Estimated Total Revenues

Accounting for the effects of "Price Volatility"	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
	(Real 1996 Dollars)		
State Revenues			
State Royalty	255	256	257
State Supplemental Royalty	50	0	0
NPSL	0	107	41
State Share of Federal Royalty	16	16	16
Severance Tax	56	58	59
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	40	40	46
Income Tax	24	22	23
Total	444	502	444
Federal Revenues			
Royalty (Net of State Share)	44	44	44
Income Tax	218	198	213
Total	262	242	258
BPXA Cash Flow			
After Tax Funds Flow	355	319	346
Real Rate of Return	20.8%	21.1%	20.4%

*Assuming 3.2 percent inflation rate from DOR Fall 1995 Base Price Forecast. Totals may not add due to rounding.

STATE OF ALASKA

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

400 WILLOUGHBY AVENUE
JUNEAU, ALASKA 99801-1796
PHONE: (907) 465-2400
FAX: (907) 465-3886

April 11, 1996

Senator Loren Leman
Chairman, Senate Resources Committee
Alaska State Legislature
State Capitol
Juneau, AK 99801

Dear Senator Leman:

The Division of Oil and Gas responds to your list of questions dated April 5, 1996, as follows:

1. BPXA currently estimates that 76.8% of the recoverable reserves underlie the state's leases in the Northstar Unit (NSU). The Division's Resource Evaluation Group has reviewed this estimate and other confidential estimates, and believes that 75 to 80% is a reasonable range. This range could be slightly higher if BPXA develops the known reserves to the Northwest.
2. The Division does not possess the necessary information to estimate the bonus that the state would have received in 1979 if the NSU leases had been offered with a 12.5% royalty and no net profit share. In order to make such an estimate, the Division would need to know, among other things, the 1979 estimates (or ranges of estimates) of capital expenditures, operating costs, oil prices, dry hole risk, oil in place, recoverable reserves, TAPS wells, tanker costs, and federal tax rates. The Division employee responsible for such a pre-sale analysis is no longer employed by the state and the Division has been unsuccessful in locating a file containing a pre-sale analysis of the NSU leases.

If one is willing to make many assumptions, the most important of which are that the bidders would bid on all tracts in proportion to the reserves they believe underlie a tract and in 1979 and 1983 bidders believed that recoverable reserves were split between the state and federal leases as they have been estimated in 1996, then one can estimate the bid based upon the actual bids on the federal leases. The two federal leases received a combined winning bid of \$81,080,995. If that is assumed to be 23.2% of the total bid amount, then the state total bid for the state NSU unit would be \$268,406,052. One could also assume that the bid might be higher because the federal leases were leased at 16.67% sliding scale royalty and your hypothetical stipulates a 12.5% fixed royalty. Conversely, the state leases would pay severance tax while the federal leases would not and this might result in lower bids on the state leases.

3. If one assumes that 50% of the \$268,406,052 would have been deposited into the Permanent Fund, then based upon the annual realized rate of returns reported by the Permanent Fund in its 1995 annual report, then the balance for the year ending 1995 would be \$704,588,494.

4. The Division does not ordinarily calculate the bonuses that the state could expect to receive from a lease sale. Nor does it possess a model to estimate bonuses. In the usual pre-sale analysis, the Division does prepare an estimate of the net present value of the projected discounted cash flow (NPV or EMV) for a prospect to assist in setting the lease terms to offer in the sale. Terms which the Division considers include the royalty rate, net profit share rate, and whether to offer an exploration incentive credit. In attempting to maximize the revenue to the state, the NPV represents how much bidders may have available to bid. As part of that evaluation, the Division considers many factors including: prospectivity, company interest, development costs, operating costs, and oil prices. These factors are very important in deciding the balance to strike between the bonus bid and the size of the state's future royalty or net profit share ("state take").

In a world of certainty and competition, the amount of a bid should equal the "economic rent." Economic rent is the difference between the value of production and the total necessary cost of exploration, development, and production including a reasonable rate of return to the lessee. In this idealized world, the most efficient firm with the lowest hurdle rate would win the bid. Oil and gas competitive bidding, however, is often conducted under conditions of uncertainty and limited competition. It is widely believed that the winner tends to be the bidder who most overestimates reserve potential, although other factors such as underestimating costs can lead to the same result, particularly in frontier areas. It should be noted, however, that if the NSU leases were rebid, much of the uncertainty about reserves would have been resolved.

Bidders employ various strategies, ranging from intuition to formal models, for bidding in such high risk situations. Although profit maximization remains the object, bidders will examine the tradeoff between reducing the bid and reducing the probability of winning. In general, bidders will bid some fraction of the project's "expected mean value (EMV)."

To do an EMV calculation, an appropriate discount rate must be selected. Various hurdle rates for oil and gas companies have been reported in the literature, ranging from 5% to 15% (real). In addition, the Division has access to confidential information regarding hurdle rates for several companies. For purposes of this analysis, the Division has used discount rates of 10 and 15% (real).

Next, certain assumptions must be made regarding oil prices, production rates, capital expenditures, operating costs, taxes, and the like. For purposes of this analysis, the Division has used the same assumptions used in the Northstar model, as requested by you, except outcomes were varied over certain ranges: (1) the recoverable reserves from

105 MMBO to 160 MMBO; (2) capital expenditures from \$330 to \$471 MM; (3) operating costs from \$1.40/bbl to \$2.00/bbl; and (4) oil prices varied over an average of a normal distribution whose standard deviation is between \$1.00 to \$7.00 around the DOR mid-price forecast. The Division did 200 Monte Carlo trials to calculate an EMV at the 10 and 15% discount rates. The results under the various discount rates and royalty rates are presented in Table 1.

The results presented in attached Table represent the most a bidder, who believed that the Northstar project could be developed for about \$380 MM, including appraisal costs, would bid assuming the bidder's discount rate was 10% or 15% respectively. Because the results are the discounted value of real cash flows to the bidder, delaying the sale by one year, two years, or three years would only slightly increase the EMV if you assume DOR's projection of slight real growth in oil prices to be true. A bidder who believed that Northstar could be developed for \$380 MM, however, would attempt to develop a bidding strategy to obtain the NSU leases for less than the EMV.

An examination of the competition would suggest that the leases could be obtained for less than the EMV. If a prospective competing bidder determined that the project could not be developed for less than \$1.4 Billion (such as Amerada Hess did), then the project would have a negative EMV at either discount rate and the prospective competing bidder would not likely bid at the sale. Indeed, if Amerada Hess had turned the NSU leases back to the state for releasing, the Division would have expected the bonus bids to be very small at any royalty rate. Only because BPXA had the opportunity to work the project after acquiring information from Amerada Hess was BPXA able to reduce the development costs to the \$380 MM range. In sum, if a sale of the NSU leases were conducted in the future, the Division would expect bonus bids to range from a nominal amount to something less than \$225 MM depending on the royalty rate and discount rate. See attached Table.

I hope that this information is helpful to you. Please call me if you have any questions.

Sincerely,



Kenneth A. Boyd

Director

Division of Oil and Gas

Northstar Economic Evaluation



Expected Mean Value

	12.5% Royalty			20.0% Royalty		
	P(90)	Mean	P(10)	P(90)	Mean	P(10)
Discounted at 10%	\$173	\$225	\$281	\$137	\$182	\$231
Discounted at 15%	\$92	\$130	\$166	\$63	\$98	\$136



Alaska State Legislature

SENATE RESOURCES COMMITTEE

State Capitol
Juneau AK 99801

Official Business

April 5, 1996

Mr. Ken Boyd, Director
Division of Oil and Gas
Department of Natural Resources

via facsimile: (907) 562-3852

Dear Mr. Boyd:

So we may better understand the relationships between the selection of lease sale bidding terms available to the Commissioner under the statutes and the size and timing of anticipated state revenues that may result, I would appreciate your written reply to the following questions before the presentation Mr. Banks is scheduled to make before the Resources Committee next Thursday.

1) What proportion of the Northstar oil reserves is estimated to underlie the State's leases in the unit?

2) According to Table 1 (Northstar Leases Information) of BP's document entitled "Northstar Project BP Exploration (Alaska) Proposal for Modified Lease Terms" (Proposal), the total bonuses received for the state's leases in the Northstar unit was \$15,469,000.

Based upon the division's ability to model bidding strategy as a function of the bidding variable selected for each sale, what would be its best estimate of the bonuses it would have received in 1979 had the leases been offered with the bonus as the bid variable, and with a 12.5 percent royalty and no net profit share instead of under the terms which the department selected?

3) Based upon the historical performance of the Permanent Fund, and your best estimate of total bonuses which would have been received under the circumstances outlined in question #2, please contrast for the committee the Permanent Fund revenues that would have resulted versus those which have occurred from the initial deposit of 50 percent of the bonuses actually received for the state leases.

4) Finally, as BP has noted on page 8 of its Proposal, in evaluating the alternative revenue stream which the state might expect were it to re-lease the Northstar leases, "[t]otal state revenues in this scenario would have to include the revenue from bonus bids on the leases." Using the model you have developed for evaluating the economics of the Northstar Agreement - or another model if you believe it would be more appropriate - please provide the committee your estimate of the bonuses you would anticipate under the following sets of circumstances:


- Bonus as the bid variable
- 12.5 percent royalty; not net profit share; 20 percent, no net profit share

- Recoverable oil reserves of 130 mmbbls; recoverable oil reserves of 160 mmbbls
- Capital and operating expenses as estimated for Northstar development and used in your existing model
- Timing of production delayed by one year, two years and three years, respectively, from the earliest date of production anticipated under the Northstar Agreement.

In addition to being prepared to discuss the state's modeling of revenues under the Northstar Agreement, I would appreciate it if Mr. Banks would be prepared to answer any follow-up questions the committee may have based on your responses to these questions.

Thank you once again for your cooperation, and that of your staff in providing this information.

Sincerely,


Senator Loren Lemman
Chairman



BP EXPLORATION

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
PO. Box 1966.2
Anchorage, Alaska 99519-0612
(907) 561-5111

April 10, 1996

The Honorable Loren Leman, Chair
Senate Resources Committee
Alaska State Legislature
State Capitol
Juneau, AK 99801

Dear Senator Leman:

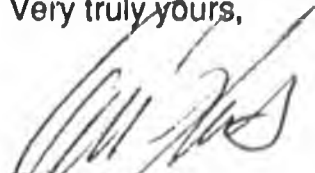
In response to the letter by Annette Kreitzer of your staff on April 5 regarding SB 318, BP provides the following information on the Northstar project and lease Agreement.:

1. Common Carrier Status of Northstar Pipeline and Estimated Tariff. The Northstar pipeline from Seal Island which will deliver sales oil to TAPS will be a regulated common carrier line. The tariff is estimated to be between \$.25- \$1.00 per barrel depending upon actual pipeline construction costs, throughput volumes, and operating expenses.
2. Acreage of Fabrication Yard. The estimated size of the required fabrication yard at the port area in Anchorage is approximately 5-10 acres.
- 3&4. Rate of Return on Late Life Field Investment with and without NPSL terms. A hypothetical incremental investment later in field life (2007) would have a rate of return of 21% without NPSL terms versus 10% with NPSLs in effect.
- 5&6. BP Comments on Net Profit Leasing Regulations (1979) and Net Profits Lease Sales (1979 and 1982) In response to your question, BP talked with parties involved in the initial NPSL legislation and regulations who recall that Sohio/BP and other companies almost uniformly opposed net profit share leasing. The industry did work with the state in drafting regulations to be workable from an accounting standpoint. They recall that while industry may not have been in supportive about the new NPSL statutory scheme, they worked with the state in order to have the regulations in place for the joint state-federal lease sale in 1979. We are continuing to review BP's files and will be happy to request the State of Alaska Department of Law for copies of comments and testimony which BP/Sohio may have provided.

April 10, 1996
Page 2

We look forward to working with you and other members of the Senate on the Northstar legislation.

Very truly yours,

A handwritten signature in dark ink, appearing to read "E.M. Luttrell", written over a light-colored background.

E.M. Luttrell
Vice President, Exploration and Development
BP Exploration (Alaska), Inc.



Alaska State Legislature

SENATE RESOURCES COMMITTEE

Official Business

State Capitol
Juneau AK 99801

April 5, 1996

Mr. Eric Luttrell
BP Exploration (Alaska) Inc.
via facsimile: 564-5900

Mr. Luttrell:

During the April 3, 1996 Senate Resources Committee hearing several questions were asked and you responded that you would like to get back to the committee with the requested information.

I have listed the questions below:

- 1) Regarding the description of the island and facilities, the question was whether the pipeline would be a common carrier pipeline. Members sought additional confirmation that it is proposed to be a common carrier pipeline and the estimated dollars per barrel tariff. (You replied that Daryl Clipin could answer the question, and that you'd be able to supply the answer to the committee.)
- 2) Senator Taylor wanted to know the acreage necessary for your assembly. (This followed a discussion between Chairman Leman and you on fabrication.)
- 3) Senator Frank wanted to know if the rate of return on additional investment would always be prime. This was in reference to a discussion between you and Senator Frank on net profit leases. You clarified the question to "what would be the rate of return of late life investments in the field", and said you would "get back with a precise number".
- 4) Senator Frank wanted an example from BP of the rate of return on additional investment. (You said "we can go back and get a very simple calculation and bring it in and show it to you...")
- 5) Senator Leman wanted to know did BP participate in the rulemaking process or comment on the draft net profit leasing regulations when they were proposed by DNR.
- 6) Senator Leman wanted to know if BP ever provided testimony or formally communicated with DNR its view that the leasing provisions were not profit related before 1979 and 1982 when it successfully bid on the net profit sharing leases it owns in the Duck Island and Pt. Thomson units.

Sincerely,


Annette E. Kreitzer, Aide to
Senate Resources Committee



BP EXPLORATION

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

April 8, 1996

The Honorable Loren Leman, Chair
Senate Resources Committee
Alaska State Legislature
State Capitol
Juneau, AK 99801

Dear Senator Leman:

In response to your letter of April 3, 1996, BP has provided and will provide certain non-confidential and confidential information to the Alaska State Legislature in support of the negotiated agreement between BP and the Department of Natural Resources (DNR). Although a privilege of confidentiality could be asserted for much of the information, BP has willingly provided most of the information in order to facilitate a full and candid discussion of the agreement.

In addition to the substantial amount of information provided to DNR on a non-confidential basis, BP provided certain additional information (see attached list) for which it requested confidentiality pursuant the statutory provisions you noted, namely AS 38.05.035(a)(9)(C) and (D). BP has consented to the disclosure of the following information to legislators on a confidential basis as outlined below :

1. Purchase price paid by BP for its acquisition of Northstar from Amerada Hess. The purchase agreement between BP and Amerada Hess requires confidentiality. However, we have requested permission from Amerada Hess to disclose the purchase to the Alaska State Legislature on a confidential basis in executive session. BP will disclose this information when we have written authorization from Amerada Hess.
2. BPXA's Economic Model. DNR and/or BP will demonstrate BP's confidential economic model, which involves cost data and financial information, in an executive session. Either DNR or BP can run and Interrogate the model during the session with various scenarios requested by the legislators. However, we do not plan to leave a copy of the model with the legislature. BP is willing to work individually with any legislator to review the model and answer any questions.
3. BPXA's Approval and Sanction Process (GIAAPS) and BP's Economic Criteria (price forecasts). This is sensitive financial information which we are willing to disclose only to Alaska legislators on a confidential basis, without further disclosure to legislative advisors, consultants or staff members.

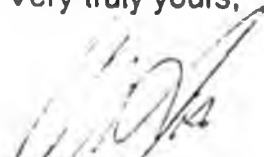
April 8, 1996

Page 2

4. BP's NPSL Development (Investment) Account Review. BP has made an internal assessment of the NPSL Development Account which was provided to the DNR on a confidential basis. While we are willing to share that review with the Legislature, it may be more appropriate for you to ask the DNR for their review of the Development Account.

We look forward to working with you and other members of the Senate on the Northstar legislation.

Very truly yours,



E.M. Luttrell
Vice President, Exploration and Development
BP Exploration (Alaska), Inc.

attachment
cc: Shively, Boyd

NORTHSTAR PROJECT
Negotiation of Modified Lease Terms
BPXA Data Transmitted to DNR

<u>Item</u>	<u>Date to DNR</u>	<u>Data for Public Release</u>
1) Northstar Project - Economic Evaluation Supplement to DNR	1/3/96	
A. Agreement for Purchase & Sale of Amerada Northstar Interest	1/11/96	NO
B. BP Preliminary Pre-acquisition Appraisal (GEM #59) See "F" below.	1/3/96	Not relevant
C. Development (Investment) Account Review	1/3/96	NO
D. BP Northstar AFEs	1/3/96	YES
E. BP Expenditures	1/3/96	YES
F. Draft Conceptual Eng. Report and Geology Final report issued in February, 1996	1/3/96	YES
G. Tract Allocation	1/3/96	YES
H. BP Approval and Sanction Process (GIAAPS)	1/9/96	NO
I. BP Economic Criteria (Price forecasts)	1/9/96	NO
J. BP/DNR Economic Model (Excel ss)	1/3/96	NO
K. Partner Economics	Not supplied	
L. Early Assessment of Risks and Reserves	1/3/96	Not relevant
M. Federal Royalty Relief Efforts	No data available	
N. Alaska Expenditures	No data available at the time	
2) Various BP and DNR Proposals on Modified Lease Terms and Draft Agreements	12/95-3/96	Not relevant



Alaska State Legislature

Senate Resources Committee

Official Business

State Capitol
Juneau AK 99801

April 3, 1996

Commissioner John Shively
Department of Natural Resources
via fax: 465-3886

Dear Commissioner Shively:

I anticipate BPXA may ask that part of our review of the economics supporting the negotiated agreement between BPXA and the administration be conducted in executive session. Rule 22(b)(1)-(3) of the Uniform Rules of the Alaska State Legislature provides that:

A legislative body may call an executive session at which members of the general public may be excluded for the following reasons:

- (1) discussion of matters, the immediate knowledge of which would adversely affect the finances of a government unit;
- (2) discussion of subjects that tend to prejudice the reputation and character of a person;
- (3) discussion of a matter that may, by law, be required to be confidential.

Similarly, the Open Meetings Guidelines adopted by the Senate provide parallel provisions and requirements for executive sessions.

Testimony before this committee has established that the Department of Natural Resources is not opposed to public discussion of any of the material supporting its negotiations to amend the net profit share provisions of the Northstar leases.

BPXA, however, may decide to claim the privilege of confidentiality for certain of the information, and may ask that the committee review the information in executive session. Presumably BPXA would base its entitlement to confidentiality on the provisions of AS 38.05.035(a)(9)(C) and (D) which provide:

- (a) The director shall....
 - (9) maintain such records as the commissioner considers necessary, administer oaths and do all things incidental to the authority imposed; the following records and files shall be kept confidential upon request of the person supplying the information:
 - (C) all geological, geophysical and engineering data supplied, whether or not concerned with the extraction or development of natural resources;
 - (D) except as provided in AS 38.05.036, cost data and financial information submitted in support of applications, bonds, leases and similar items;

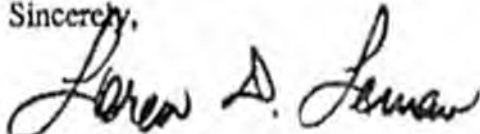
You, Governor Knowles, and BPXA President John Morgan have all said that you support full and candid discussion of the negotiations and the policy implications behind the legislature's decision of whether or not to ratify the agreement. To assure that the review is public, yet thorough, only that information which must be kept confidential by law will be treated as confidential.

Accordingly, before the committee votes to go into executive session, BPXA's representative should confirm that BPXA is indeed requesting confidentiality, and ~~to~~ state the statutory basis for the request.

DNR's representative should be prepared to certify that the information to be discussed is entitled to confidentiality under the department's statutes and regulations.

Thank you for your participation in these hearings.

Sincerely,

A handwritten signature in cursive script that reads "Loren A. Leman".

Senator Loren Leman
Chairman