

ALASKA LEGISLATURE

1571

HOUSE and SENATE FINANCE COMMITTEE FILES, 1995-1996

MEMORANDUM
DEPARTMENT OF NATURAL RESOURCES**State of Alaska**
DIVISION OF OIL AND GASTO: Ken Boyd
Director

DATE: April 16, 1996

THRU:

FILE NO:

TELEPHONE: 269-8799

FROM: Kevin Banks

SUBJECT: Northstar—Response to
Senate Resources Committee

You received a letter from Senator Loren Leman on April 12, 1996, which asked that the division provide to the Senate Resources Committee forecasts of state revenues using the "illustrative" Northstar model. The Senator's letter specifically requested model results assuming a peak rate of 80,000 barrels per day, assuming reserves of 190, 160, and 115 million barrels, and assuming capital expenditures and processing fees associated with facility sharing. The impact of these assumptions on State, federal, and BPXA revenues are attached. I did not analyze a facility sharing alternative, instead, I asked BPXA to provide their own analysis. I also asked BPXA what they felt would be the capital expenditure requirements for the various reserve assumptions and discussed their numbers with Bill Van Dyke.

These tables provide a forecast of revenues from a calculation of both supplemental royalties and net profit shares. Revenues including net profit shares are estimated assuming a full production start-up in 2002 and 1999. To be consistent, supplemental royalties should be compared to the net profit shares forecasted under the delayed development scenario.

The first table assumes that peak production of 80,000 barrels per day is achieved in 1999 for the estimate of supplemental royalties or 2002 for the estimate of net profit shares. Capital expenditures of \$139 million are added to the "most likely" case in order to achieve these rates. Production rates decline precipitously and the field shuts-in eight years after start-up.

The next three tables illustrate the effect of changing reserve assumptions. The 190 million barrel case assumes the same capital expenditures and peak production rates as above, but the production decline is less. The field life is the same as the "most likely" case. The 160 million barrel reserve case is achieved with capital expenditures of an additional \$48 million over the "most likely" case. The peak production rate is also 80,000 barrels per day. The last table illustrates the 115 million barrel case. No additional capital expenditures are assumed. The peak production rate and field life is the same as the "most likely" case.

Bill Van Dyke has also prepared a "per barrel" analysis of the cash flows in response to the questions asked by Senator Frank during the hearing on April 11, 1996. His analysis is also attached.

Senator Leman also wrote on April 15, 1996 requesting details about what I dubbed the "Marginal Lease Method," a system that calculates state take on the basis of cash flow.

This is the "formula" that Commissioner Shively referred to in his testimony. In a nutshell, the MLM approach allows for a reduction in state "take" so that the lessee can attain a rate of return necessary to develop an oil field. If, in any year, the cash flow (calculated from price, production, allowable operating and capital costs) actually received by the lessee exceeds the cash flow predicted to achieve the lessee's rate of return, the excess is paid to the state. The lessee pays this excess to the point that the state is made whole for the amount that the state's take was reduced. If the field earns additional revenues beyond this point, this excess is split between the lessee and the state. I have attached the spreadsheet that we shared with BPXA that shows how the MLM works. As you know, BPXA rejected the MLM approach stating that it was not interested in a "tax scheme," that it had "very little negotiating room," and that it wished to continue "discussion on the Supplemental Royalty approach."

Attachment.

Northstar Economic Evaluation



Estimated Total Revenues

Senate Resources Committee
Letter--rec'd 4/12/96
80,000 Barrels/Day Peak Rate

Supplemental Royalty and 1999 Development	Net Profit Share and 2002 Development	Net Profit Share and 1999 Development
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(Real 1996 Dollars)

State Revenues

State Royalty	261	262	261
State Supplemental Royalty	16	0	0
NPSL	0	0	0
State Share of Federal Royalty	17	17	17
Severance Tax	94	109	94
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	34	37	34
Income Tax	11	11	11
Total	435	438	420

Federal Revenues

Royalty (Net of State Share)	45	45	45
Income Tax	180	181	185
Total	225	226	230

BPXA Cash Flow

After Tax Funds Flow	275	277	285
Real Rate of Return	20.1%	20.1%	20.6%

Totals may not add due to rounding.

Northstar Economic Evaluation



Estimated Total Revenues

Senate Resources Committee
Letter--rec'd 4/12/86
190 MMBO Reserves

Supplemental Royalty and 1999 Development	Net Profit Share and 2002 Development	Net Profit Share and 1999 Development
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(Real 1996 Dollars)

State Revenues

State Royalty	372	373	372
State Supplemental Royalty	49	0	0
NPSL	0	217	286
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.

(This table is based on the illustrative Northstar model
discussed in Senate Resources Committee Hearings--April 11, 1986.)

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
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(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.

(This table is based on the illustrative Northstar model
described in Senate Resources Committee hearing - April 11, 1996.)

Northstar Economic Evaluation



Estimated Total Revenues

Senate Resources Committee
Letter--rec'd 4/12/86
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.

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

MILM Royalty Reduction System Real 1995's

STATUS QUD

(Includes Carry Forward Provisions)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total	
State Revenue-Status Quo	0	0	5	61	59	58	47	38	30	24	37	50	41	34	22	12	12	(1)	516
State Revenue-Real Disc	0	0	4	46	41	38	29	23	16	12	18	22	17	13	8	4	4	(0)	200
NPV(P)= \$148 NPV(AQ)= \$200 State Tax = 44.7%																			

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	59	58	47	38	30	24	30	17	14	12	8	5	5	(1)	308
State Revenue-Real Disc	0	0	4	46	41	38	29	23	16	12	20	8	6	5	3	2	2	(0)	242
NPV(P)= \$688 NPV(AQ)= \$442 State Tax = 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	69	66	66	57	46	38	31	27	14	11	17	12	7	7	(1)	472
State Revenue-Real Disc	0	0	5	55	51	49	39	31	23	18	15	7	5	8	5	3	3	(0)	313
NPV(P)= \$308 NPV(AQ)= \$313 State Tax = 33.2%																			

MILM

	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	9	10	10	9	8	7	7	(9)	(3)	5	4	2	0	0	0
State Revenue-Actual	0	0	1	13	14	19	19	19	18	18	17	(6)	(7)	14	10	5	0	0	0
ATFF-Real-Delta	0	0	1	33	36	19	39	19	16	18	17	0	0	14	10	8	0	0	0
ATFF-Real-Delta Available for Lost State Revenue Payment	(120)	(120)	(120)	(106)	(106)	(90)	(71)	(52)	(33)	(15)	0	0	0	0	0	0	0	0	0
Lost State Revenue Accr Beginning Balance	0	0	1	13	14	19	19	19	18	15	0	0	0	0	0	0	0	0	0
Payments made to Lost State Revenue Accr	(120)	(120)	(119)	(105)	(104)	(71)	(52)	(33)	(15)	0	0	0	0	0	0	0	0	0	0
Lost State Revenue Accr Ending Balance	0	0	0	0	0	0	0	0	0	3	17	0	0	14	10	6	0	0	0
ATFF-Real Delta Available for Carry Forward	0	0	0	0	0	0	0	0	0	0	0	(6)	(7)	0	0	0	0	0	0
ATFF Carry Forward	0	0	0	0	0	0	0	0	0	0	0	(6)	(5)	(15)	(1)	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	0
Credits made to Carry Forward	0	0	0	0	0	0	0	0	0	0	0	0	0	14	1	0	0	0	0
ATFF Carry Forward Ending Balance	0	0	0	0	0	0	0	0	0	0	0	(6)	(5)	(1)	0	0	0	0	0
ATFF-Real/Order Available for Split	0	0	0	0	0	0	0	0	0	3	17	0	0	0	0	0	0	0	0
State Revenue-Additional Split	0	0	0	0	0	0	0	0	0	0	2	0	0	0	1	1	0	0	0
ATFF-Real-Additional Split	0	0	0	0	0	0	0	0	0	3	15	0	0	0	8	3	0	0	0
State Tax = Application + NPRL Make-Up + Additional Split	0	0	7	82	84	67	78	67	58	46	29	14	11	17	15	8	3	(1)	566
State Tax-Real Disc	0	0	6	66	64	62	61	63	64	27	15	7	5	8	6	3	3	(0)	306
NPV(P)= \$251 NPV(AQ)= \$251 State Tax = 42.5%																			



Alaska State Legislature

Senate Resources Committee

State Capitol
Juneau AK 99801

Official Business

April 15, 1996

Mr. Ken Boyd, Director
Division of Oil and Gas
Department of Natural Resources
via facsimile: 562-3852 this page only

Dear Mr. Boyd:

During testimony Saturday, April 13 on Senate Bill 318 Commissioner Shively mentioned that a formula which would have had the effect of adjusting the state's future revenues, should the Northstar field prove to be larger than it is currently estimated to be, had been developed by the Division of Oil and Gas during its negotiations to amend the Northstar Unit leases. Please fax the committee a copy of the language which was under consideration.

I would also appreciate your summarizing how the formula would have worked in terms that a layman is likely to understand (fax number is (907) 465-3810). Thank you again for your assistance in expediting the Resources Committee's review of SB 318 and in furthering its understanding of the agreement between BPXA and the Department of Natural Resources.

Sincerely

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

Senator Loren Leman
Chairman



BP EXPLORATION

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 198612
Anchorage, Alaska 99519-8612
(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:

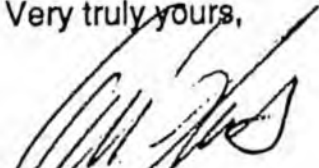
In response to the letter by Annette Kreitzer of your staff on April 5 regarding SB 318, BP provides the following information on the Northstar project and lease Agreement.:

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 Lease 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 black ink, appearing to read 'E.M. Luttrell', written over the closing 'yours'.

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,

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

Annette E. Kreitzer, Aide to
Senate Resources Committee

NPSL Accounting Handouts

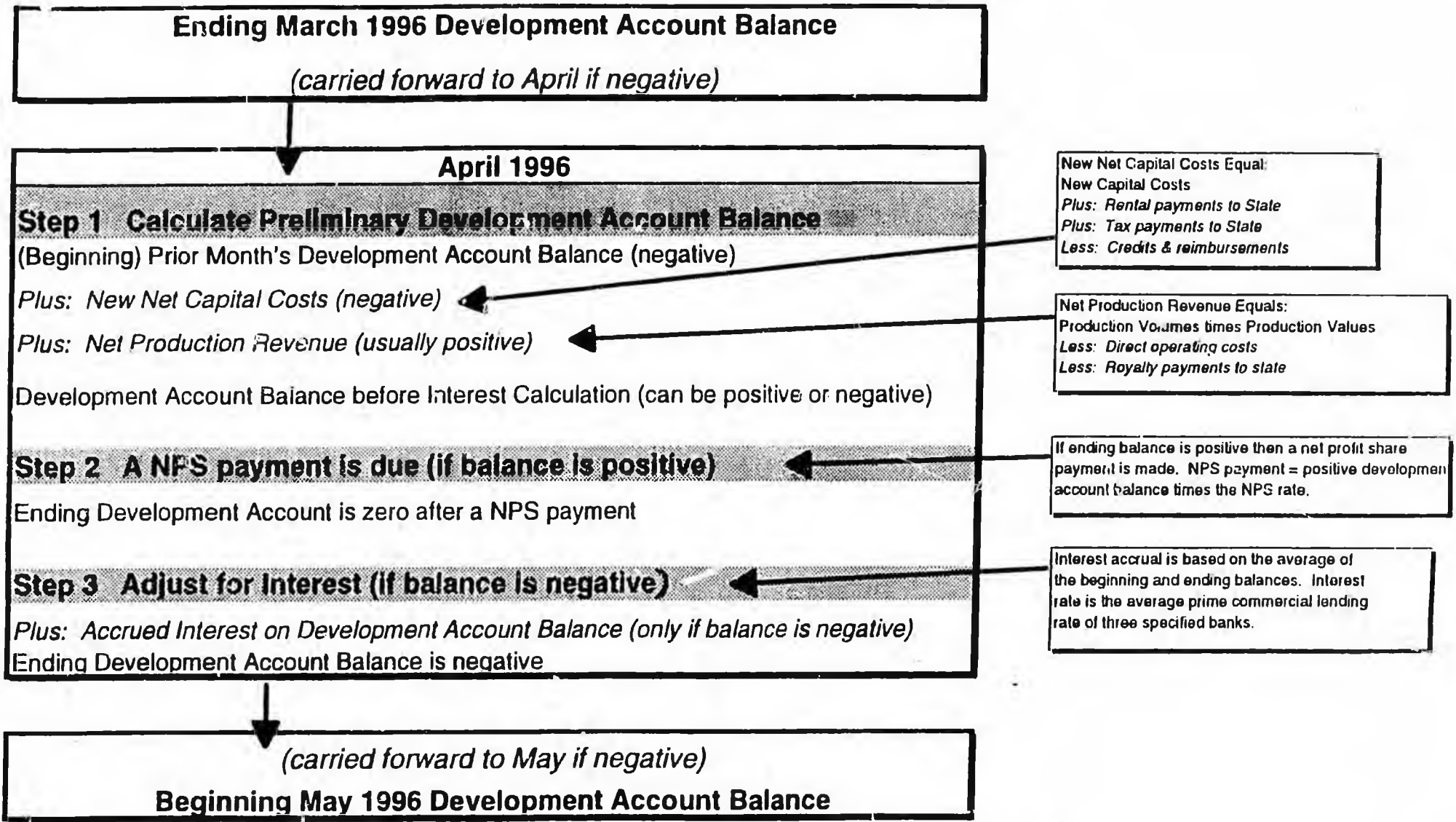
April 11, 1996

Prepared By

Alaska Department of Natural Resources

Division of Oil and Gas

NPSL ACCOUNTING FLOW DIAGRAM



Ending March 1996 Development Account Balance

(carried forward to April if negative)

April 1996

Step 1 Calculate Preliminary Development Account Balance

(Beginning) Prior Month's Development Account Balance (negative)

Plus: New Net Capital Costs (negative)

Plus: Net Production Revenue (usually positive)

Development Account Balance before Interest Calculation (can be positive or negative)

Step 2 A NPS payment is due (if balance is positive)

Ending Development Account is zero after a NPS payment

Step 3 Adjust for Interest (if balance is negative)

Plus: Accrued Interest on Development Account Balance (only if balance is negative)

Ending Development Account Balance is negative

(carried forward to May if negative)

Beginning May 1996 Development Account Balance

New Net Capital Costs Equal:
New Capital Costs
Plus: Rental payments to State
Plus: Tax payments to State
Less: Credits & reimbursements

Net Production Revenue Equals:
Production Volumes times Production Values
Less: Direct operating costs
Less: Royalty payments to state

If ending balance is positive then a net profit share payment is made. NPS payment = positive development account balance times the NPS rate.

Interest accrual is based on the average of the beginning and ending balances. Interest rate is the average prime commercial lending rate of three specified banks.

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.

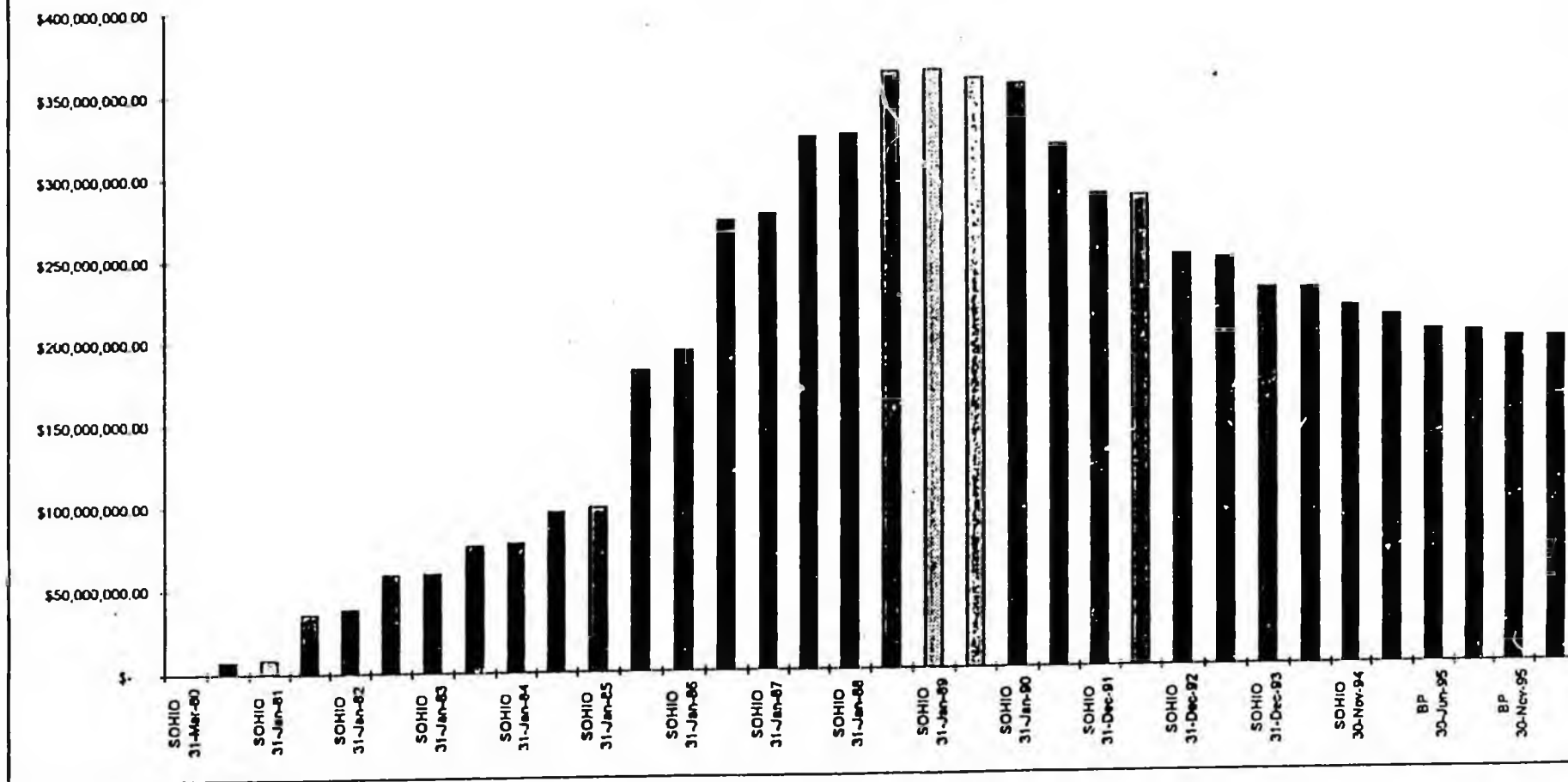
D. NET PROFIT PAYMENT ACCOUNT

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

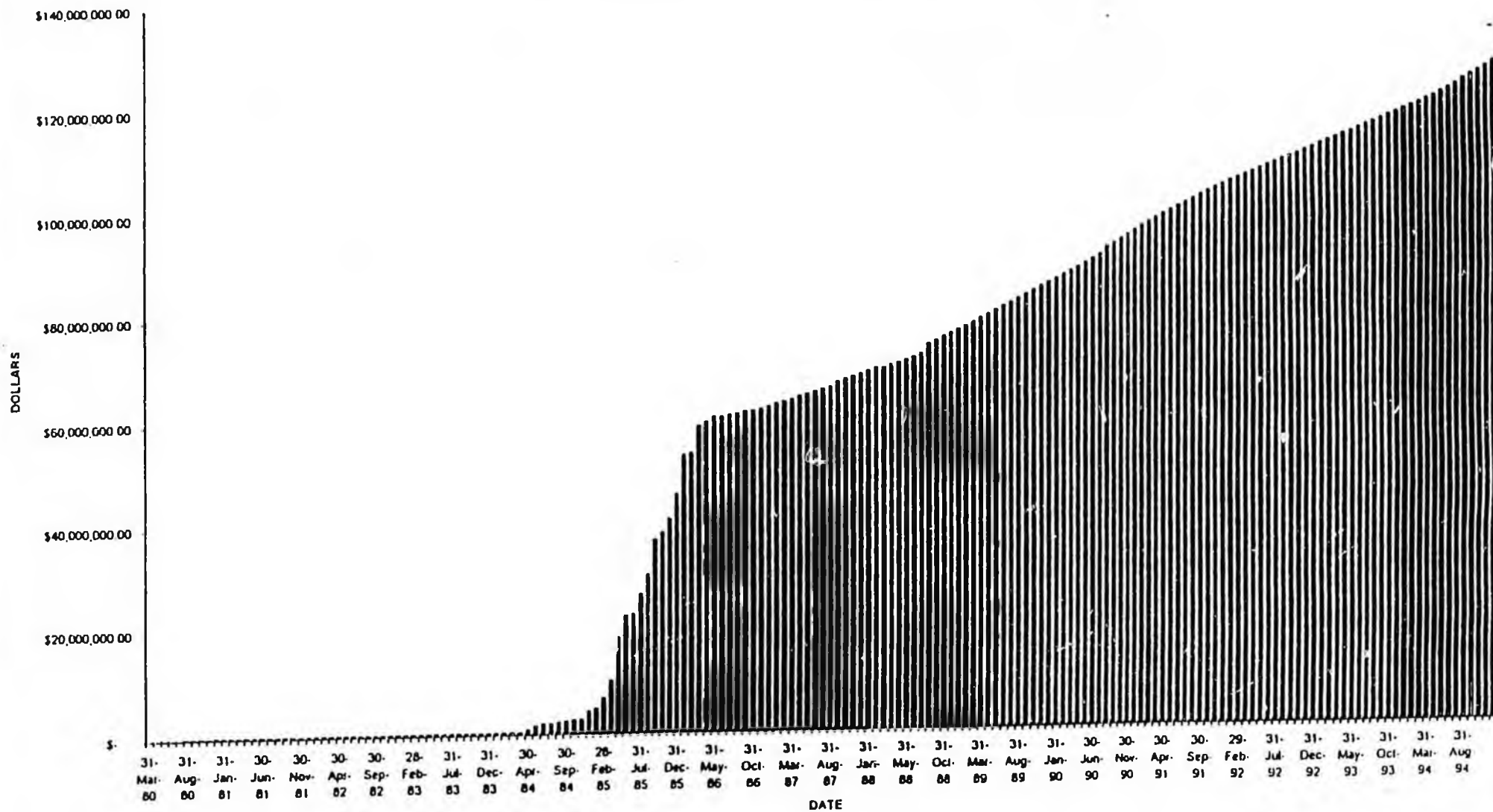
Listing of Current NPS Development Account
Balances by Field

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 Petroleum Engineer)
10% Drilling Capex	
- 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%				

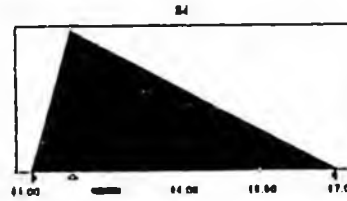
Assumptions

Assumption: S4

Cell: 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

Cell: 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

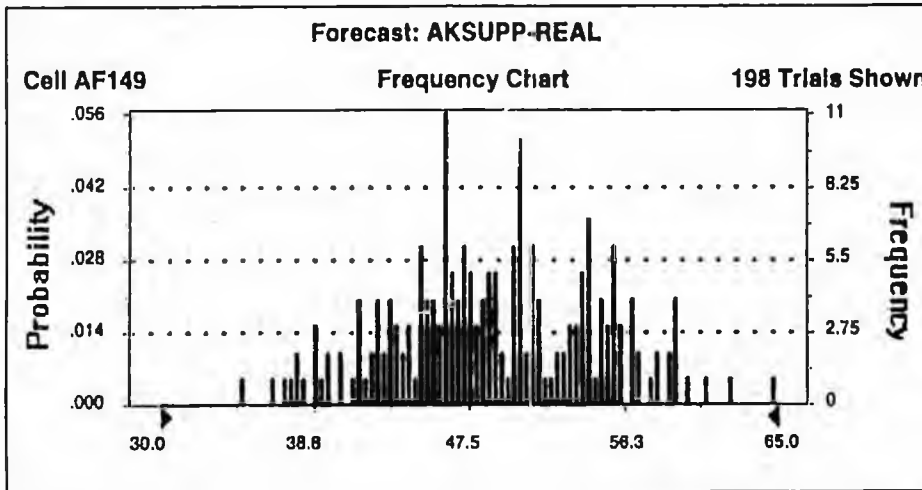
Cell: AF149

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:

	<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 1996 Base Price Forecast. Totals may not add due to rounding.

Inputs

NPSLs: ON				Supplemental Royalty: OFF			Monte Carlo Simulation: OFF	
Working Interest	98%			State			Monthly Oil Price Std Dev	
Royalty Interest	19%			312798	20.0%	93.20%	Range	Low % High %
Spill/Conservation Tax (\$/bbl)	0.034			312799	20.0%	91.20%	Drilling Capex	0.899 1.283
AVT Tax Rate	2%			312808	20.0%	85.26%	Facilities Capex	0.864 1.172
Field Lifetime	2017			312809	20.0%	85.26%	Pipeline Capex	0.882 1.893
Reservac(mmbbls)	130			355001	20.0%	40.00%	Reservac	0.808 1.231
		'98-'02	'03-'07	'08-'12	Federal		Lifting Costs	0.925 1.325
Lifting Costs(\$/bbl, Real)	1.50	1.50	1.50	Y181	0.1867	0		
State Income Tax Rate	-	2.00%	(DOR est. avg corp. rate)	Y0179	0.1867	0		
Federal Tax Rate	34.3%	(effective after AK Tax)						
Inflation Rate*	3.0%	*Used if cum inflation input blank						
Real Discount Rate	7.0%							
Prime Interest Rate NPSL	-	8.25%	(ADN 4/8/98)					
Beginning Balance(\$m)	-202							
Oil Production Multiplier	1							
Oil Price Multiplier	1							
Drilling Cost Multiplier	1							
Facility Cost Multiplier	1							
Abandonment Costs % (real)								
Starting Abandon Liability (\$MM)	23.9							
Facilities %	-	5%	(DNR Petroleum)					
Drilling Wells %	-	10%	(Engineer Est.)					

NPSLs and Supplemental Royalty Control Panel	
NPSLs ON/OFF	ON
Supplemental Royalty ON/OFF	OFF
NYMEX - AK Base MOO Price Differential	10.00

DOA Information	
Starting Wellbore Assets (\$MM)	0
Starting Field Assets (\$MM)	0
Starting Purchase Price Balance (\$MM)	0

	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	
Gross Oil(Mbd) - Produced	0.0	0.0	8.4	49.9	49.8	48.7	41.2	34.7	28.7	23.8	20.0	18.7	13.8	11.5	7.8	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	130.0	
Gross Water(Mbd)-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	0.0	0.0	0.0	0.0	0.0	
Gross Gas(MMscfd)-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	0.0	0.0	0.0	0.0	0.0	
Sales NGLs (Mbd) - 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	0.0	0.0	0.0	0.0	0.0	
Return Seawater-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	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	0.0	0.0	0.0	0.0	0.0	0.0
PS#1 NB Oil Price(\$/bbl, mod)	111.45	112.28	112.72	113.88	114.48	114.61	115.44	115.87	116.48	116.89	117.52	118.10	118.70	118.48	120.08	120.55	121.33	121.83	122.83	123.23	123.93	124.64	125.38	126.15	126.91	127.74	128.57	129.43	130.31	131.22	22.19	
Pipeline Tariffs (\$/bbl, mod)	13.42	12.77	12.59	12.58	12.88	12.87	12.99	13.13	13.31	13.53	13.78	14.01	14.24	14.35	14.55	14.81	15.03	15.34	15.58	15.98	16.14	16.32	16.51	16.71	16.91	17.12	17.33	17.55	17.78	18.01	6.25	
Marine Costs (\$/bbl, mod)	11.48	11.38	11.38	11.42	11.47	11.55	11.63	11.71	11.79	11.87	11.93	11.99	12.08	12.12	12.19	12.28	12.33	12.41	12.48	12.58	12.64	12.72	12.80	12.88	12.97	13.08	13.15	13.25	13.34	13.44	1.00	
NGL Value as % of Oil Price(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)	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	
Producing Wells(#)	0	0	5	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 Sev. Rate	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	16.00%	15.00%	18.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	
Gas Sev. Rate	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	
Abandonment(\$m real)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Costs(\$m, Real)																																
Drilling	14.0	0.0	14.0	28.0	28.0	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	
Facility	38.0	85.1	83.0	47.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Cum Inflation Rate*	1.00	1.03	1.06	1.10	1.13	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	1.78	1.82	1.87	1.93	1.98	2.04	2.11	2.17	2.23	2.30	2.37	2.44		

	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	Total
Supplemental Royalty Rate																															
Trigger Price (\$/ANS WCI)	17.35	17.61	17.88	18.18	18.47	18.78	19.08	19.37	19.68	19.99	20.31	20.64	20.97	21.31	21.65	21.98	22.34	22.70	23.07	23.43	23.81	24.19	24.58	24.97	25.37	25.78	26.18	26.61	27.03	27.47	
Linear Slope (%/ANS WCI)	1.5%																														
Supplemental Royalty Cap	7.5%																														

Caution - Only change inputs on this page

Summary Output

Development Summary				Montecarlo			
			M.L.	MIN	MAX	MONTE	
Reserves	Gross Oil (MMBbl)		130	105	180	142	
	Gross NGLs (MMBOE)		0	0	0	0	
Capex	Oil (9m USD)		99	69	124	108	
	Facility (9m USD)		251	217	294	250	
	Pipelines (9m USD)		26	25	53	34	
	Total (9m USD)		376	331	471	392	
Dev Costs (9Abbl)		2.9				2.9	
Lifting Costs (9Abbl)		1.50	1.40	2.00	1.74		

State Revenues (9m, MOD)	
Royalty (incl. supplemental)	317.4
State Share of Federal Royalty	20.3
Severance Tax	67.2
Spill & Conservation Tax	3.5
Ad Valorem Tax	52.8
NPSL	78.0
Income Tax	16.0
Total (9 m MOD)	555.1
Total (9 m real)	438.4

Federal Revenues (9m, MOD)	
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	273.6
Total (9 m MOD)	328.5
Total (9 m real)	260.9

	1.00	1.03	1.06	1.10	1.13	1.17	1.21	1.25	1.28	1.33	1.37	1.41	1.46	1.50	1.55	1.60	1.65	1.70	1.78	1.82	1.87	1.93	1.98	2.04	2.11	2.17	2.23	2.30	2.37	2.44
Cumulative Inflation	1.00	1.03	1.06	1.10	1.13	1.17	1.21	1.25	1.28	1.33	1.37	1.41	1.46	1.50	1.55	1.60	1.65	1.70	1.78	1.82	1.87	1.93	1.98	2.04	2.11	2.17	2.23	2.30	2.37	2.44
PS#1 Oil Price (\$/bbl, real)	11.45	11.90	11.97	12.75	12.79	12.77	12.81	12.83	12.84	12.82	12.81	12.82	12.84	12.95	12.94	12.84	12.81	12.88	12.88	12.79	12.79	12.79	12.78	12.79	12.79	12.79	12.78	12.79	12.79	12.79
AK WC Oil Price (\$/bbl, MOD)	16.36	16.41	16.69	17.97	18.84	19.34	20.06	20.81	21.59	22.39	23.23	24.10	25.00	25.93	26.82	27.74	28.69	29.69	30.70	31.75	32.70	33.69	34.70	35.74	36.81	37.91	39.05	40.27	41.43	42.67

Do not touch

ANS WC Oil Price Random generated around mean price forecast		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		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
Jan		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
Feb		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
Mar		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
Apr		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
May		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
Jun		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
July		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
Aug		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
Sep		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
Oct		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
Nov		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
Dec		18.34	18.39	18.58	17.39	18.33	18.02	19.73	20.47	21.23	22.02	22.84	23.70	24.59	25.50	26.41	27.32	28.25	29.22	30.23	31.27	32.27	33.24	34.23	35.28	36.32	37.41	38.53	39.69	40.88	42.10
Monthly MonteCarlo Price		18.35	18.04	18.14	18.00	17.80	18.31	26.85	21.48	18.43	25.25	23.87	25.44	20.49	26.70	27.43	26.22	31.78	30.87	28.08	28.11	38.15	38.38	32.85	35.98	34.04	37.30	38.71	31.68	40.88	42.00
Jan		18.35	18.04	18.14	18.00	17.80	18.31	26.85	21.48	18.43	25.25	23.87	25.44	20.49	26.70	27.43	26.22	31.78	30.87	28.08	28.11	38.15	38.38	32.85	35.98	34.04	37.30	38.71	31.68	40.88	42.00
Feb		18.03	17.87	17.54	18.70	21.49	21.03	17.43	23.13	26.24	17.86	24.04	23.84	24.22	24.28	25.81	28.85	28.13	28.68	30.38	30.85	28.15	30.98	34.17	31.68	39.27	39.83	36.58	39.24	40.88	40.74
Mar		18.03	17.87	17.54	18.70	21.49	21.03	17.43	23.13	26.24	17.86	24.04	23.84	24.22	24.28	25.81	28.85	28.13	28.68	30.38	30.85	28.15	30.98	34.17	31.68	39.27	39.83	36.58	39.24	40.88	40.74
Apr		18.03	17.87	17.54	18.70	21.49	21.03	17.43	23.13	26.24	17.86	24.04	23.84	24.22	24.28	25.81	28.85	28.13	28.68	30.38	30.85	28.15	30.98	34.17	31.68	39.27	39.83	36.58	39.24	40.88	40.74
May		18.03	17.87	17.54	18.70	21.49	21.03	17.43	23.13	26.24	17.86	24.04	23.84	24.22	24.28	25.81	28.85	28.13	28.68	30.38	30.85	28.15	30.98	34.17	31.68	39.27	39.83	36.58	39.24	40.88	40.74
Jun		18.03	17.87	17.54	18.70	21.49	21.03	17.43	23.13	26.24	17.86	24.04	23.84	24.22	24.28	25.81	28.85	28.13	28.68	30.38	30.85	28.15	30.98	34.17	31.68	39.27	39.83	36.58	39.24	40.88	40.74
July		18.03	17.87	17.54	18.70	21.49	21.03	17.43	23.13	26.24	17.86	24.04	23.84	24.22	24.28	25.81	28.85	28.13	28.68	30.38	30.85	28.15	30.98	34.17	31.68	39.27	39.83	36.58	39.24	40.88	40.74
Aug		18.03	17.87	17.54	18.70	21.49	21.03	17.43	23.13	26.24	17.86	24.04	23.84	24.22	24.28	25.81	28.85	28.13	28.68	30.38	30.85	28.15	30.98	34.17	31.68	39.27	39.83	36.58	39.24	40.88	40.74
Sep		18.03	17.87	17.54	18.70	21.49	21.03	17.43	23.13	26.24	17.86	24.04	23.84	24.22	24.28	25.81	28.85	28.13	28.68	30.38	30.85	28.15	30.98	34.17	31.68	39.27	39.83	36.58	39.24	40.88	40.74
Oct		18.03	17.87	17.54	18.70	21.49	21.03	17.43	23.13	26.24	17.86	24.04	23.84	24.22	24.28	25.81	28.85	28.13	28.68	30.38	30.85	28.15	30.98	34.17	31.68	39.27	39.83	36.58	39.24	40.88	40.74
Nov		18.03	17.87	17.54	18.70	21.49	21.03	17.43	23.13	26.24	17.86	24.04	23.84	24.22	24.28	25.81	28.85	28.13	28.68	30.38	30.85	28.15	30.98	34.17	31.68	39.27	39.83	36.58	39.24	40.88	40.74
Dec		18.03	17.87	17.54	18.70	21.49	21.03	17.43	23.13	26.24	17.86	24.04	23.84	24.22	24.28	25.81	28.85	28.13	28.68	30.38	30.85	28.15	30.98	34.17	31.68	39.27	39.83	36.58	39.24	40.88	40.74
ANS WC Mean Annual Value		18.36	18.44	18.82	17.90	18.64	19.34	19.60	19.85	19.77	20.93	19.52	20.93	19.20	27.34	30.94	28.02	27.98	28.85	33.07	32.22	37.89	38.34	34.37	35.59	34.07	39.07	35.89	42.52	40.98	39.79
PS#1 Mean Annual Value		11.45	12.79	12.85	13.91	14.48	14.82	15.44	15.97	16.49	16.99	17.52	18.10	18.71	19.45	20.08	20.55	21.33	21.94	22.83	23.22	23.93	24.65	25.39	26.15	26.93	27.74	28.57	29.43	30.31	31.08
Quarterly Supplemental State Royalty %		0.00%	0.00%	0.00%	0.00%	0.00%	0.38%	1.00%	1.84%	2.33%	3.04%	3.50%	4.59%	5.42%	6.30%	7.15%	7.80%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%
Jan		0.00%	0.00%	0.00%	0.00%	0.00%	0.38%	1.00%	1.84%	2.33%	3.04%	3.50%	4.59																		

	1994	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 Royalty	0.0	0.0	3.8	36.1	40.5	40.8	35.7	31.1	28.6	22.7	18.7	17.0	14.8	8.8	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
State Supplemental Royalty	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
State Share of Federal Royalty	0.0	0.0	0.2	2.5	2.6	2.6	2.3	2.0	1.7	1.5	1.2	1.1	0.8	0.5	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	0.0	0.0	0.0	0.0
Severance Tax	0.0	0.0	17.7	18.0	15.3	18.0	8.8	8.8	2.4	0.6	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	0.0
Spill & Conservation Tax	0.0	0.0	0.1	0.5	0.5	0.5	0.4	0.2	0.2	0.2	0.2	0.2	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	0.0
Ad Valorem Tax	0.0	0.0	0.8	2.5	4.3	5.4	5.2	4.8	4.5	4.1	3.7	3.3	2.8	2.3	1.8	1.2	0.8	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
Income Tax	-0.28	-0.47	-0.70	1.85	1.85	2.22	2.18	1.95	1.78	1.69	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	0.00
Total (fm, MOD)	-0.3	0.2	3.8	36.7	44.1	44.1	40.7	35.1	32.1	27.2	23.2	21.2	18.1	12.1	8.1	4.1	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
Federal Royalty (Net of State Share)	0.0	0.0	0.7	6.8	7.0	7.0	6.2	5.4	4.8	3.8	3.4	2.8	2.6	2.2	1.6	1.0	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
Income Tax	-4.7	-7.88	-11.88	28.24	31.75	38.08	37.35	33.48	30.70	28.83	27.08	24.23	20.33	15.88	12.18	8.38	5.88	0.00	0.00	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 (fm, MOD)	-4.4	-8.0	-11.3	36.0	38.7	45.1	43.8	39.8	35.3	32.8	30.6	27.2	23.8	18.0	13.8	9.7	6.7	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
BP Exploration	-8.2	-81.4	-84.5	38.7	82.8	101.8	102.8	90.4	77.8	64.8	54.2	45.8	38.0	30.0	21.0	14.0	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	0.0
Funds Flow (f/BI) (MOD)	N/A	N/A	53.98	2.75	8.44	7.21	8.81	8.08	8.35	8.41	8.36	8.45	8.42	8.16	7.1	6.0	5.21	3.16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Income (f/BI) (MOD)	4.7	7.7	20.8	78.6	71.7	90.8	51.4	47.3	42.4	35.8	30.0	25.8	21.5	15.0	10.0	6.0	3.0	-0.88	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Income (f/BI) (MOD)	N/A	N/A	13.33	5.51	4.88	4.31	4.30	4.70	5.10	5.20	5.19	5.34	5.32	5.19	5.12	5.02	4.88	4.70	4.50	4.30	4.10	3.90	3.70	3.50	3.30	3.10	2.90	2.70	2.50	2.30	2.10

	1994	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 Royalty	0.0	0.0	3.5	35.8	35.7	34.8	29.6	25.0	20.7	17.1	14.4	12.0	10.0	8.4	5.5	3.1	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
State Supplemental Royalty	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
State Share of Federal Royalty	0.0	0.0	0.2	2.3	2.3	2.2	1.8	1.6	1.3	1.0	0.8	0.6	0.5	0.4	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
Severance Tax	0.0	0.0	16.1	13.5	13.5	12.8	9.1	5.2	3.0	2.2	1.7	1.4	1.2	0.9	0.6	0.4	0.3	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
Spill & Conservation Tax	0.0	0.0	0.3	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Ad Valorem Tax	0.0	0.0	0.6	2.3	3.8	4.8	4.8	4.3	3.8	3.5	3.1	2.7	2.3	1.8	1.2	0.8	0.5	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	0.0
Income Tax	0.0	0.0	-0.7	1.5	1.6	1.8	1.8	1.8	1.4	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Total (fm, REAL)	-0.3	0.3	5.8	58.9	58.4	56.8	48.0	37.5	28.0	23.2	18.4	16.2	14.8	13.1	10.0	6.1	3.1	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
Federal Royalty (Net of State Share)	0.0	0.0	0.2	29.4	27.6	25.3	20.1	16.0	12.4	9.6	7.8	6.8	4.8	3.8	2.3	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	0.0
Income Tax	-4.4	-7.8	-11.3	25.7	28.0	32.8	32.8	26.8	23.8	21.8	18.8	17.2	14.0	10.0	6.0	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	0.0	0.0	0.0
Total (fm, REAL)	-4.4	-7.8	-10.7	31.8	34.2	38.6	38.1	31.2	27.2	24.7	22.3	19.2	16.7	13.2	9.2	4.2	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
Royalty (Net of State Share) - Real Dec.	0.0	0.0	0.6	5.1	4.8	4.4	3.5	2.8	2.1	1.7	1.3	1.0	0.8	0.6	0.4	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
Income Tax - Real Dec.	4.4	7.3	9.8	21.2	21.7	23.0	21.1	17.2	14.3	12.2	10.4	8.5	6.5	4.5	2.5	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
Total - Real Dec.	-4.4	-7.3	-9.4	28.3	28.5	28.0	24.8	19.8	15.5	13.0	11.8	9.5	7.3	5.5	3.5	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
BP Exploration	-8.2	-88.7	-78.5	36.2	82.1	87.2	85.3	72.6	60.6	48.0	38.7	32.5	26.1	19.0	12.0	7.0	2.1	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
Funds Flow (f/BI) (REAL)	N/A	N/A	50.8	2.5	5.7	6.2	7.1	7.2	7.3	7.1	6.8	6.7	6.5	6.3	6.1	5.9	5.7	5.5	5.3	5.1	4.9	4.7	4.5	4.3	4.1	3.9	3.7	3.5	3.3	3.1	2.9
Net Income (REAL)	4.7	7.4	19.8	72.8	63.3	51.1	42.8	38.0	33.1	27.1	22.0	18.3	14.7	10.0	6.0	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	0.0	0.0	0.0
Net Income (f/BI) (REAL)	N/A	N/A	12.5	5.0	4.4	3.7	3.8	3.8	4.0	3.9	3.8	3.8	3.7	3.6	3.5	3.4	3.3	3.2	3.1	3.0	2.9	2.8	2.7	2.6	2.5	2.4	2.3	2.2	2.1	2.0	1.9

BPX INDICATORS
MMV
RINDM

1722 MM
2052%

BPX
BPX

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%	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%	100%
NPSL State Rate	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	89.38%	
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%	
Revenue Account																																
Prod. Revenue	0.0	0.0	15.6	158.3	183.9	185.1	144.3	125.8	107.5	81.9	78.8	88.7	88.1	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	(2.4)	(23.0)	(23.7)	(23.8)	(20.8)	(18.2)	(18.5)	(13.3)	(11.5)	(9.8)	(8.5)	(7.3)	(5.0)	(2.8)	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	0.0	
Production Taxes	0.0	0.0	(0.0)	(14.2)	(12.4)	(12.1)	(8.0)	(5.4)	(2.1)	(0.8)	(0.2)	(0.1)	(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	
Ad Valorem Tax	0.0	10.8	(2.0)	(3.4)	(4.2)	(4.2)	(4.1)	(3.8)	(3.5)	(3.2)	(2.8)	(2.6)	(2.2)	(1.8)	(1.4)	(1.0)	(0.8)	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	
UDP Aban. Costs	0.0	0.0	(0.4)	(1.8)	(3.7)	(5.3)	(8.0)	(3.8)	(3.0)	(2.3)	(1.8)	(1.4)	(1.0)	(0.7)	(0.4)	(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	
Closing Balance	0.0	(0.0)	10.8	115.8	118.8	118.5	108.8	94.7	83.4	72.4	63.2	54.7	47.2	41.0	27.9	18.1	(0.8)	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	
Dev. Account																																
Beginning Balance	(282.0)	(327.8)	(435.4)	(551.0)	(541.8)	(488.8)	(418.8)	(340.0)	(280.4)	(204.8)	(148.3)	(82.8)	(42.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Capital Expend.	(42.2)	(77.8)	(87.3)	(83.2)	(24.3)	(13.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	108.8	94.7	83.4	72.4	63.2	54.7	47.2	41.0	27.9	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	0.0	
Prelim Closing Bal.	(304.2)	(405.2)	(512.0)	(488.3)	(448.1)	(380.8)	(310.0)	(245.3)	(186.1)	(132.4)	(83.1)	(37.8)	3.8	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	
Average Annual DA Balance	(283.1)	(359.4)	(473.7)	(524.7)	(493.9)	(433.8)	(383.3)	(292.8)	(227.8)	(188.8)	(114.7)	(85.3)	(18.7)	20.5	13.8	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	0.0	0.0	
Accrued Interest	(23.4)	(30.2)	(38.1)	(43.3)	(40.7)	(35.8)	(30.0)	(24.1)	(18.8)	(13.8)	(9.5)	(5.4)	(1.8)	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	0.0	0.0	0.0	0.0	
DA Closing Balance	(327.8)	(435.4)	(551.0)	(541.8)	(488.8)	(418.8)	(340.0)	(280.4)	(204.8)	(148.3)	(82.8)	(42.3)	2.3	41.0	27.9	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	
NPSL Payment Acc.																																
Profile 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	2.3	41.0	27.9	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 Payment*	0.0	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	38.8	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	

* Payment will be NPSL ON/OFF switch in control box turned to "OFF"

Northstar Reserves, Royalty and NPBL Tract Allocations

Lease	NPBL Acft	% of Total Reserves	of NPS Reserves	BP Ownership	NPSE State Rat	Working Interest	NPBL Tract Ret	royalty Ret by Lease	Weighted Royalty	NRI	
312798	81.20%	64,000	8.72%	9%	100%	8.18%		20%	1.344%		
312799	81.20%	555,000	44.40%	58%	100%	52.73%		20%	8.890%		
312808	85.28%	102,000	8.18%	11%	100%	8.08%		20%	1.832%		
312809	85.28%	218,000	17.52%	23%	100%	18.48%		20%	3.804%		
355001	40.00%		0.00%	0%	100%	0.00%		20.0%	0.000%		
		980,000	78.80%	100%	100%	89.39%	88%	78%	15.38%		
Effective State Royalty with 27% of Federal Take									16.38%		
Y181	228,000	18.08%							18.87%	3.014%	
Y0179	64,000	5.12%							18.87%	0.854%	
	1,250,000	100%							3.837%		
Effective Federal Royalty with 27% of Federal Take									2.885%		
									Total	19.00%	81.00%

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2008	2008	2010	2011	2012	2013	2014	2015	2016	2016	2017	2018	2018	2020	2021	2022	2023	2024	2026	Total
BTFF																																	1641
BP Revenue	0.0	0.0	18.9	202.0	209.1	210.7	184.4	180.7	137.2	117.2	101.6	87.8	75.4	64.9	44.2	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	0.0	0.0	67
- Severance Tax	0.0	0.0	0.0	17.7	15.3	15.0	8.8	8.5	2.4	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4
- Split & Concess.	0.0	0.0	0.1	0.5	0.5	0.5	0.4	0.3	0.2	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	0.0	0.0	53
- AVT	0.0	0.8	2.5	4.3	5.4	5.4	5.2	4.8	4.5	4.1	3.7	3.3	2.8	2.3	1.8	1.2	0.8	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	0.0	78
- NPFL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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
- opex	0.0	0.0	3.1	29.3	30.3	30.5	28.7	23.2	19.8	18.8	14.7	12.7	10.9	8.3	6.3	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	0.0	0.0	39
- 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	1162
Gross Profit	0.0	-0.11	14.3	150.2	157.8	159.3	142.4	125.8	110.3	95.4	82.8	71.5	58.5	48.5	31.1	18.3	-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	0.0	0.0	0
+ other income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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
- capex	53.9	99.0	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	75
BTFF	-83.8	-99.8	-97.2	-89.8	-128.5	-142.1	-142.4	-128.8	-110.3	-95.4	-82.8	-71.5	-58.5	-48.5	-31.1	-18.3	-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	0.0	0.0	290
- Inter. Drift Depr.	7.3	0.8	8.3	17.2	19.0	12.3	3.9	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	0.0	0.0	365
- Tan. Drift/Fac Depr.	5.8	21.8	40.9	50.7	48.1	38.0	29.8	24.9	18.7	10.7	3.9	0.9	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	798
Total	12.9	22.5	49.2	87.9	85.0	48.3	33.5	28.2	20.8	11.4	3.9	0.9	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
Fed. Tax Income	-12.8	-23.3	-35.0	82.3	92.8	111.0	108.9	97.6	89.5	84.0	78.0	70.7	59.3	48.6	31.1	18.3	-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	0.0	0.0	0.0
UOP Abandonment	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2008	2008	2010	2011	2012	2013	2014	2015	2016	2017	2018	2018	2020	2021	2022	2023	2024	2026	Total	
Rate (\$/bbl)	0.00	0.00	0.76	0.38	0.42	0.44	0.43	0.40	0.37	0.35	0.32	0.29	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	0.00	0.00	39
Total(\$m)	0.0	0.0	0.5	2.3	4.7	8.8	8.4	5.0	3.9	3.0	2.3	1.7	1.3	0.9	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	0.0	0.0	0.0
DD&A	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2008	2008	2010	2011	2012	2013	2014	2015	2016	2017	2018	2018	2020	2021	2022	2023	2024	2026	Total	
Rate (\$/bbl)	0.00	0.00	3.59	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	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	0.00	365
Total(\$m)	0.0	0.0	5.6	38.4	47.7	51.3	45.1	38.0	31.4	28.1	21.8	18.3	15.2	12.6	8.3	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	0.0	0.0
Income Tax	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2008	2008	2010	2011	2012	2013	2014	2015	2016	2017	2018	2018	2020	2021	2022	2023	2024	2026	Total	
State	-0.26	-0.47	-0.70	1.85	1.85	2.22	2.18	1.95	1.79	1.88	1.58	1.41	1.18	0.33	0.22	0.17	-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	0.00	0.00	16
Federal	-4.43	-7.99	-11.99	28.24	31.75	38.08	37.35	33.48	30.70	28.83	27.00	24.73	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	0.00	0.00	274
Total	-4.69	-8.45	-12.69	29.88	33.80	40.30	38.53	35.44	32.49	30.51	28.87	25.85	21.51	6.01	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	0.00	0.00	290
Funds Flow	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2008	2008	2010	2011	2012	2013	2014	2015	2016	2017	2018	2018	2020	2021	2022	2023	2024	2026	Total	
ATFF - MOD	-49.2	-91.4	-84.5	39.7	92.9	101.8	102.9	90.4	77.8	84.9	54.3	45.9	38.0	10.8	7.1	4.0	-25.5	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	480
ATFF - Real	-49.2	-89.7	-79.5	36.2	82.1	87.2	85.3	72.8	80.8	49.0	39.7	32.5	26.1	7.0	4.8	2.5	-15.4	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	0.0	172
ATFF - Real Dec	-49.2	-83.0	-69.8	29.8	83.5	83.2	58.1	48.4	38.3	27.5	20.9	18.1	12.1	3.1	1.9	1.0	-5.8	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	0.0	0.0
ATFF - Cum NPV	-49.2	-132.3	-202.1	-172.2	-108.8	-55.6	12.5	58.9	95.2	122.7	143.7	159.7	171.8	174.9	178.8	177.7	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	172.2	0.0
Nat Income	4.7	7.7	20.8	79.8	71.7	80.9	51.4	47.3	42.4	35.9	30.0	25.8	21.5	-3.0	-1.7	-0.8	13.9	0.0	0.0	0.0	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

	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	
DD&A (\$MM)																															
Reserve (MMBOE NRY)																															491.60
Opening Balance	0.0	0.0	0.0	101.7	87.2	72.8	58.7	46.7	36.7	28.4	21.5	15.7	10.8	8.8	3.5	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	103.25
Additions (BPX Net After Royalty MMB)	0.0	0.0	103.2	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	103.25
BPX Net Production (MMB)	0.0	0.0	1.9	14.4	14.4	14.1	11.8	10.1	8.3	6.8	5.8	4.8	4.0	3.3	2.2	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	491.60
Closing Balance	0.0	0.0	101.7	87.2	72.8	58.7	46.7	36.7	28.4	21.5	15.7	10.8	8.8	3.5	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	0.0	0.0
Wellbore Assets																															
Beginning Balance (Net \$MM)	0.0	13.7	13.7	27.7	51.7	71.8	73.3	66.3	46.8	35.4	26.8	19.5	13.5	8.5	4.3	1.8	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	106.64
Additions (BPX Net \$MM MOD)	13.7	0.0	14.8	30.1	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	15.18
DD&A Rate (\$/BBL)	0.00	0.00	0.41	0.42	0.77	1.10	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	106.64
DD&A (BPX Net \$MM MOD)	0.0	0.0	0.8	6.1	11.1	15.8	14.9	12.6	10.4	8.8	7.2	6.0	5.0	4.2	2.8	1.8	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	465.38
Carry Forward (BPX Net \$MM MOD)	13.7	13.7	27.7	51.7	71.8	73.3	66.3	45.6	35.4	26.8	19.5	13.5	8.5	4.3	1.8	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	0.0	0.0
Fieldwide Assets																															
Beginning Balance (Net \$MM)	0.0	35.3	121.2	202.7	220.8	184.3	148.5	118.3	82.8	71.8	54.3	39.8	27.4	17.2	8.7	3.2	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	1348.00
Additions (BPX Net \$MM MOD)	35.3	85.9	88.5	50.5	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	258.17
DD&A Rate (\$/BBL)	0.00	0.00	3.18	2.24	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	258.17
DD&A (BPX Net \$MM MOD)	0.0	0.0	5.0	32.4	36.6	35.7	30.2	25.5	21.1	17.5	14.7	12.3	10.2	8.4	5.8	3.2	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	1348.00
Carry Forward (BPX Net \$MM MOD)	35.3	121.2	202.7	220.8	184.3	148.5	118.3	92.8	71.8	54.3	39.8	27.4	17.2	8.7	3.2	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
BPX Purchase Price Allocation																															
Beginning Balance (Net \$MM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Additions (BPX Net \$MM 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
DD&A Rate (\$/BBL)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DD&A (BPX Net \$MM 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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carry Forward (BPX Net \$MM 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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total DD&A Rate \$/BBL	0.0	0.0	3.8	2.7	3.3	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	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	364.81
Total DD&A \$MM MOD	0.0	0.0	5.8	38.4	47.7	51.3	45.1	38.0	31.4	26.1	21.9	18.3	15.2	12.8	8.3	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
UOP ABANDONMENT (\$MM)																															
Beginning Balance (Net \$MM)	39.4	38.1	39.4	38.9	38.8	31.8	25.1	18.7	13.7	9.8	8.8	4.5	2.8	1.5	0.3	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
Additions (BPX Net \$MM 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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DD&A Rate (\$/BBL)	0.00	0.00	0.78	0.38	0.42	0.44	0.43	0.40	0.37	0.35	0.32	0.29	0.28	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	0.00
DD&A (BPX Net \$MM MOD)	0.0	0.0	0.5	2.3	4.7	8.8	8.4	6.0	3.9	3.0	2.3	1.7	1.3	0.9	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	0.0
Carry Forward (BPX Net \$MM MOD)	39.4	38.4	38.9	38.8	31.8	25.1	18.7	13.7	9.8	8.8	4.5	2.8	1.5	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



Forecast: AKSUPP-REAL

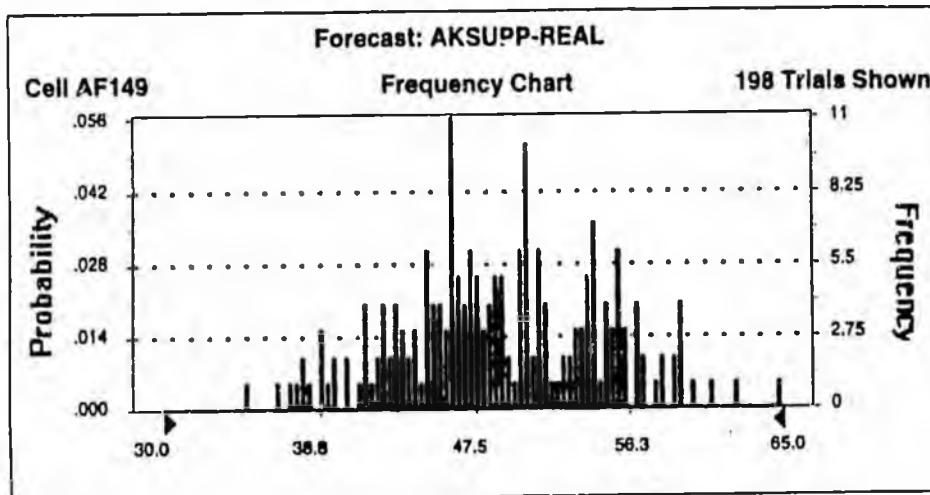
Cell: AF149

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.

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES

State of Alaska

DIVISION OF OIL AND GAS

TO: Ken Boyd
Director

DATE: April 12, 1996

THRU:

FILE NO:

FROM: Bill Van Dyke
Kevin Banks

TELEPHONE: 269-8799

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 effect 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.

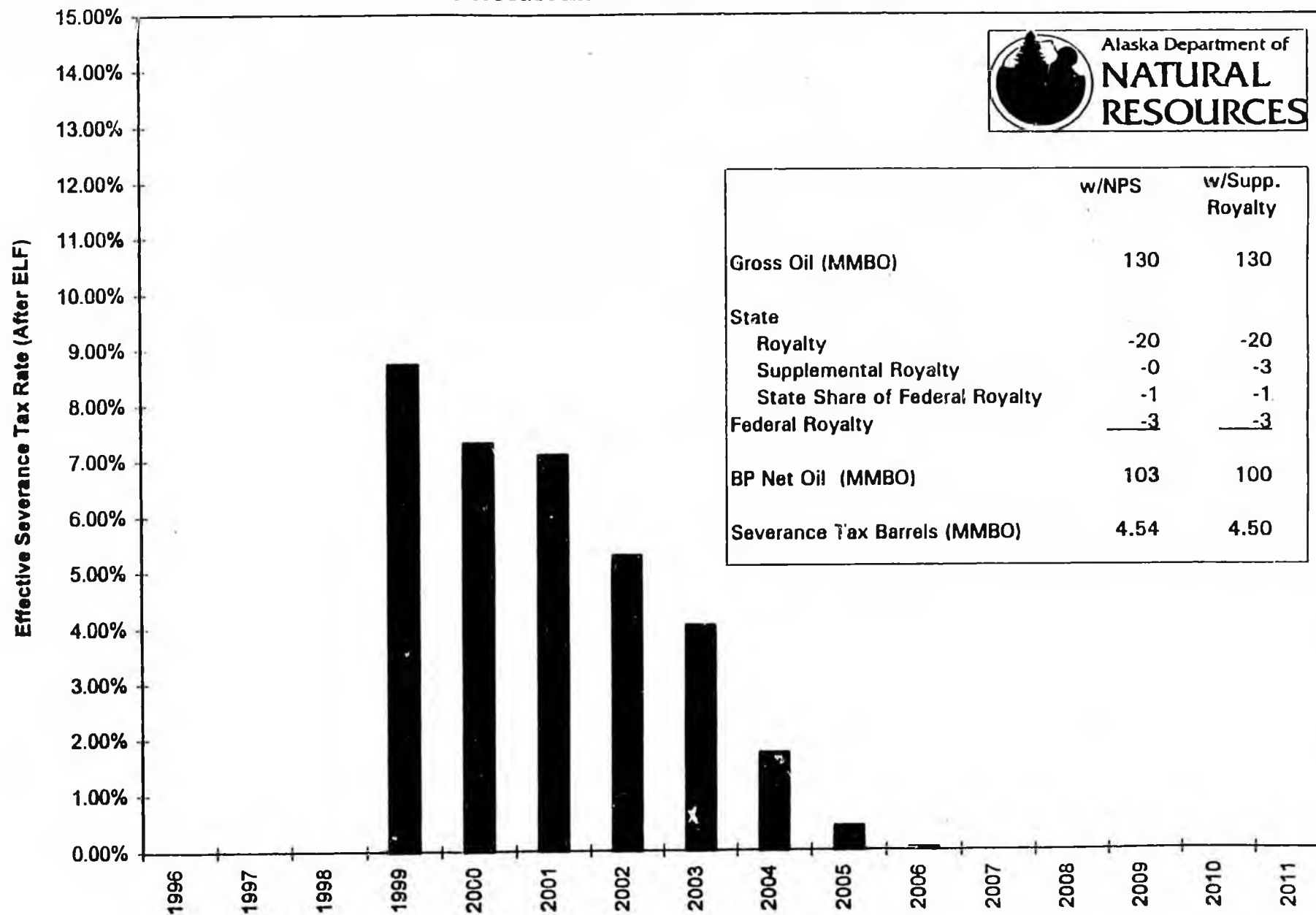
Kevin Banks will prepare a response to Senator Leman's letter received this morning, using the "Illustrative Northstar Model," as requested. These results should be available early next week.

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



	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 Petroleum Engineer)
10% Drilling Capex	
- **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

Inputs

NPSLs: OFF

Supplemental Royalty: ON

ON

MonteCarlo Simulation: OFF

Working Interest	98%
Royalty Interest	18%
Split/Conservation Tax (\$/bbl)	0.034
AVT Tax Rate	2%
Field Life(yr)	2012
Reserve-Commission	130
	'99-'02 '03-'07 '08-'12
Lifting Costs (\$/bbl, Real)	1.50 1.50 1.50
State Income Tax Rate	2.90% (DOR est. avg corp rate)
Federal Tax Rate	34.3% (after state income tax)
Inflation Rate*	3.0% *Used if cum Inflation Input Blank
Real Discount Rate	7.8% (AD Unit Report)
Prime Interest Rate NPSL	9.25% (AD Unit Report)
Beginning Balance (\$m)	-282
Oil Production Multiplier	1
Oil Price Multiplier	1
Drilling Cost Multiplier	1
Facility Cost Multiplier	1
Abandonment Costs (\$/bbl)	
Starting Abandon Liability (\$MM)	23.8
Footnote %	8% (DOR Premium)
Drilling/Water%	16% (Enghart est.)

Lease	Royalty	NPSL
312798	20.0%	83.20%
312799	20.0%	81.20%
312808	20.0%	85.28%
312809	20.0%	85.28%
385001	20.0%	40.00%
Federal		
Y181	0.1867	0
Y6178	0.1867	0

Monthly Oil Price Std Dev	
Range	Low % High %
Drilling Capex	0.889 1.253
Facilities Capex	0.884 1.172
Pipeline Capex	0.887 1.893
Reserves	0.808 1.231
Lifting Costs	0.825 1.305

NPSLs and Supplemental Royalty Control Panel	
NPSLs ON/OFF	OFF
Supplemental Royalty ON/OFF	ON
NYMEX - AX Base MOD Price Off/On/End	60.00

DDA Information	
Starting Wellbore Assets (\$MM)	0
Starting Field Assets (\$MM)	0
Starting Purchase Price Balance (\$MM)	0

	1998	1997	1996	1995	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
Gross Oil (Mbd) - Produced	0.0	0.0	5.4	49.8	49.8	49.7	41.2	34.7	28.7	23.8	20.0	18.7	13.8	11.5	7.8	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	130.0
Gross Water (Mbd) - 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	0.0	0.0	0.0	0.0	
Gross Gas (MMscfd) - 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	0.0	0.0	0.0	0.0	
Sales NGLs (Mbd) - 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	0.0	0.0	0.0	0.0	
Return Seawater-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	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	0.0	0.0	0.0	0.0	
PSF1 NB Oil Price (\$/bbl, mod)	\$11.45	\$12.26	\$12.72	\$12.99	\$14.48	\$14.92	\$15.44	\$15.87	\$16.48	\$16.99	\$17.52	\$18.10	\$18.70	\$18.48	\$20.08	\$20.55	\$21.03	\$21.83	\$22.83	\$23.22	\$23.83	\$24.64	\$25.38	\$26.15	\$26.83	\$27.74	\$28.57	\$29.43	\$30.31	\$31.22	\$348.0
Pipeline Tariffs (\$/bbl, mod)	\$3.42	\$2.77	\$2.59	\$2.56	\$2.88	\$2.87	\$2.99	\$3.12	\$3.31	\$3.53	\$3.77	\$4.01	\$4.24	\$4.38	\$4.55	\$4.83	\$5.03	\$5.34	\$5.59	\$5.88	\$6.14	\$6.32	\$6.51	\$6.71	\$6.81	\$7.12	\$7.33	\$7.55	\$7.78	\$8.01	\$8.24
Marine Costs (\$/bbl, mod)	\$1.18	\$1.28	\$1.28	\$1.42	\$1.47	\$1.55	\$1.63	\$1.71	\$1.78	\$1.87	\$1.97	\$2.07	\$2.18	\$2.28	\$2.38	\$2.48	\$2.53	\$2.61	\$2.68	\$2.74	\$2.81	\$2.88	\$2.94	\$3.01	\$3.08	\$3.15	\$3.25	\$3.34	\$3.44	\$3.54	\$3.64
NGL Value as % of Oil Price (\$/m)	0%	0%	0%	0%	0%	0%	0%	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)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Producing Wells (#)	0	0	5	10	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Oil Sev. Rate	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Gas Sev. Rate	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Abandonment (\$/m real)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	89.0
Capex (\$/m, Real)	14.0	0.0	14.0	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	251.1
Drilling	14.0	0.0	14.0	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	28.0
Facility	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cum Inflation Rate*	1.00	1.03	1.08	1.10	1.13	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	1.78	1.82	1.87	1.93	1.98	2.04	2.11	2.17	2.23	2.30	2.37	2.44	2.44

	1998	1997	1996	1995	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
Supplemental Royalty Rate	Maximum NYMEX Prices for Supplemental Royalty, e.g. If (AR Base Oil price - NYMEX Differential) > 0% table price and < 5% table price, then apply 0.5% supplemental royalty.																														
Trigger Price (\$/ANS WCI)	\$ 17.35	\$ 17.61	\$ 17.89	\$ 19.18	\$ 18.47	\$ 18.76	\$ 19.06	\$ 18.37	\$ 19.88	\$ 19.89	\$ 20.31	\$ 20.64	\$ 20.97	\$ 21.31	\$ 21.65	\$ 21.99	\$ 22.34	\$ 22.70	\$ 23.07	\$ 23.43	\$ 23.81	\$ 24.19	\$ 24.58	\$ 24.97	\$ 25.37	\$ 25.78	\$ 26.18	\$ 26.61	\$ 27.03	\$ 27.47	\$ 27.47
Linear Slope (%/ANS WCI)	1.5%																														
Supplemental Royalty Cap	7.5%																														

Caution - Only change inputs on this page

Northstar Reserves, Royalty and NPBL Tract Allocations											
Leases	NPBL	Acft	% of Total Reserves	% of NPBL Reserves	OP Ownership	NPBL Share Rate	Working Interest	NPBL Tract Rate	Royalty Pct by Lease	Weighted Royalty	NW
312786	83.20%	84,800	6.72%	8%	100%	8.18%			20%	1.344%	
312788	81.70%	585,000	44.40%	58%	100%	52.73%			20%	8.880%	
312808	85.28%	102,000	8.18%	11%	100%	8.08%			20%	1.632%	
312809	85.78%	218,000	17.52%	23%	100%	18.47%			20%	3.504%	
185001	40.00%	-	0.00%	0%	100%	0.00%			20.0%	0.000%	
		880,000	78.80%	100%	100%	86.38%	88%	78%		15.34%	
Effective State Royalty with 27% of Federal Tax										18.342%	
Y181		228,000	18.08%						18.87%	3.814%	
Y0178		64,000	5.12%						18.87%	0.964%	
		1,380,000	100.00%							3.837%	
Effective Federal Royalty with 27% of Federal Tax										2.695%	
Total										18.00%	81.00%

	1988	1987	1986	1985	1984	1983	1982	1981	1980	1979	1978	1977	1976	1975	1974	1973	1972	1971	1970	1969	1968	1967	1966	1965	1964	1963	1962	1961	1960	Total	
STFF																													1581		
BP Revenue	0.0	0.0	18.8	202.0	279.3	208.4	181.0	158.4	132.4	112.0	88.1	62.0	39.7	19.3	49.3	23.2	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	87	
Savannah Tax	0.0	0.0	0.0	17.7	15.3	14.8	9.8	8.3	2.3	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	0.0	0.0	0.0	0.0	31	
Split & Conserv	0.0	0.0	0.1	0.5	0.5	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	1.2	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	53	
AVT	0.0	0.8	2.5	4.3	5.4	8.4	8.2	4.8	4.5	4.1	3.7	3.2	2.8	2.3	1.8	1.2	0.8	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	
NPSI	0.0	0.0	0.0	0.8	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	237	
oper	0.0	0.0	3.1	28.2	30.3	30.5	28.1	23.2	18.8	16.8	14.7	12.7	10.8	8.2	6.3	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	38	
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	1182	
Gross Profit	0.0	-0.8	14.3	150.2	154.8	157.2	138.2	121.7	105.5	80.2	77.5	56.8	55.2	47.8	32.0	-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	0	
other income	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	383	
capex	53.8	98.0	111.5	80.6	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	78	
STFF	-63.8	-98.8	-97.3	68.1	128.8	148.8	158.2	121.7	108.8	88.2	77.8	58.8	58.8	49.8	32.8	18.2	-48.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	290	
Intan. Dbl. Depr.	7.3	0.8	8.3	17.2	18.0	12.3	2.8	2.3	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	286
Tan. Dbl/Fac. Depr.	5.8	21.8	48.8	80.7	48.1	38.0	28.8	24.8	18.7	18.7	3.8	0.8	0.2	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	0.0	0.0	0.0	827
Total	12.8	22.3	48.2	87.8	65.0	48.2	33.5	28.2	20.8	11.4	2.8	0.8	0.2	8.8	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	0.0	0.0	0.0
Fed. Tax Income	-12.8	-23.3	-25.0	82.3	81.8	108.8	125.7	82.5	84.7	78.8	73.8	58.0	55.7	47.8	32.0	18.2	-48.8	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

	1988	1987	1986	1985	1984	1983	1982	1981	1980	1979	1978	1977	1976	1975	1974	1973	1972	1971	1970	1969	1968	1967	1966	1965	1964	1963	1962	1961	1960	Total	
UOP Abandonment	0.00	0.00	0.78	0.28	0.43	0.45	0.43	0.40	0.37	0.34	0.30	0.27	0.23	0.18	0.14	0.07	0.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36
Rate (\$/bbl)	0.0	0.0	0.5	2.5	4.9	7.2	8.8	5.1	3.8	2.8	2.1	1.6	1.1	0.8	0.4	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	
Total (\$m)	0.0	0.0	3.8	28.5	48.8	32.3	45.7	28.1	31.2	28.7	21.4	12.2	14.8	11.8	7.8	4.4	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	
DD&A	0.00	0.00	3.88	2.74	3.40	3.74	3.90	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	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	0.00	385
Rate (\$/bbl)	0.00	0.00	3.88	2.74	3.40	3.74	3.90	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	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	0.00	
Total (\$m)	0.0	0.0	3.8	28.5	48.8	32.3	45.7	28.1	31.2	28.7	21.4	12.2	14.8	11.8	7.8	4.4	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	

	1988	1987	1986	1985	1984	1983	1982	1981	1980	1979	1978	1977	1976	1975	1974	1973	1972	1971	1970	1969	1968	1967	1966	1965	1964	1963	1962	1961	1960	Total	
Income Tax																													17		
State	-0.28	-4.37	-0.70	1.88	1.84	3.18	2.11	1.87	1.88	1.47	1.30	1.11	0.85	0.84	0.27	-0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	284	
Federal	-4.43	-7.88	-11.88	28.22	31.81	37.27	38.25	32.87	29.87	27.08	28.21	22.31	18.18	18.24	10.87	8.27	-12.74	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	0.00	300
Total	-4.88	-8.45	-12.88	29.87	33.25	38.84	38.28	33.84	30.78	28.83	28.88	23.81	19.22	17.28	11.81	8.84	-14.84	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	0.00	

	1988	1987	1986	1985	1984	1983	1982	1981	1980	1979	1978	1977	1976	1975	1974	1973	1972	1971	1970	1969	1968	1967	1966	1965	1964	1963	1962	1961	1960	Total
Funds Flow																													488	
ATFF - MOD	-48.2	-81.4	-84.5	28.7	82.3	100.5	100.8	87.8	74.7	81.8	50.8	42.3	35.7	30.2	20.4	11.8	-25.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	382
ATFF - Real	-48.2	-86.7	-78.5	28.2	81.7	88.0	83.8	70.5	58.2	48.5	37.1	30.0	24.5	20.2	12.1	7.2	-15.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	173
ATFF - Real Disc	-48.2	-83.0	-88.8	28.8	82.2	82.4	58.8	45.0	34.9	28.1	18.8	14.8	11.4	8.8	5.4	2.8	-5.8	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
ATFF - Cum NPV	48.2	-132.3	-202.1	-172.3	-108.1	-46.7	10.2	55.3	80.1	118.3	125.8	150.7	182.1	170.8	178.2	178.0	172.4	172.4	172.4	172.4	172.4	172.4	172.4	172.4	172.4	172.4	172.4	172.4	172.4	0.0

	1988	1987	1986	1985	1984	1983	1982	1981	1980	1979	1978	1977	1976	1975	1974	1973	1972	1971	1970	1969	1968	1967	1966	1965	1964	1963	1962	1961	1960	Total
Net Income	4.7	7.7	20.7	78.4	89.7	59.2	48.8	44.8	28.7	33.1	27.2	23.1	20.1	17.7	12.2	7.1	12.8	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

Year	2026	2025	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992	1991	1990	1989	1988	1987	1986	1985	1984	1983	1982	1981	1980	1979	1978	1977	1976	1975	1974	1973	1972	1971	1970	1969	1968	1967	1966	1965	1964	1963	1962	1961	1960	1959	1958	1957	1956	1955	1954	1953	1952	1951	1950	1949	1948	1947	1946	1945	1944	1943	1942	1941	1940	1939	1938	1937	1936	1935	1934	1933	1932	1931	1930	1929	1928	1927	1926	1925	1924	1923	1922	1921	1920	1919	1918	1917	1916	1915	1914	1913	1912	1911	1910	1909	1908	1907	1906	1905	1904	1903	1902	1901	1900	1899	1898	1897	1896	1895	1894	1893	1892	1891	1890	1889	1888	1887	1886	1885	1884	1883	1882	1881	1880	1879	1878	1877	1876	1875	1874	1873	1872	1871	1870	1869	1868	1867	1866	1865	1864	1863	1862	1861	1860	1859	1858	1857	1856	1855	1854	1853	1852	1851	1850	1849	1848	1847	1846	1845	1844	1843	1842	1841	1840	1839	1838	1837	1836	1835	1834	1833	1832	1831	1830	1829	1828	1827	1826	1825	1824	1823	1822	1821	1820	1819	1818	1817	1816	1815	1814	1813	1812	1811	1810	1809	1808	1807	1806	1805	1804	1803	1802	1801	1800	1799	1798	1797	1796	1795	1794	1793	1792	1791	1790	1789	1788	1787	1786	1785	1784	1783	1782	1781	1780	1779	1778	1777	1776	1775	1774	1773	1772	1771	1770	1769	1768	1767	1766	1765	1764	1763	1762	1761	1760	1759	1758	1757	1756	1755	1754	1753	1752	1751	1750	1749	1748	1747	1746	1745	1744	1743	1742	1741	1740	1739	1738	1737	1736	1735	1734	1733	1732	1731	1730	1729	1728	1727	1726	1725	1724	1723	1722	1721	1720	1719	1718	1717	1716	1715	1714	1713	1712	1711	1710	1709	1708	1707	1706	1705	1704	1703	1702	1701	1700	1699	1698	1697	1696	1695	1694	1693	1692	1691	1690	1689	1688	1687	1686	1685	1684	1683	1682	1681	1680	1679	1678	1677	1676	1675	1674	1673	1672	1671	1670	1669	1668	1667	1666	1665	1664	1663	1662	1661	1660	1659	1658	1657	1656	1655	1654	1653	1652	1651	1650	1649	1648	1647	1646	1645	1644	1643	1642	1641	1640	1639	1638	1637	1636	1635	1634	1633	1632	1631	1630	1629	1628	1627	1626	1625	1624	1623	1622	1621	1620	1619	1618	1617	1616	1615	1614	1613	1612	1611	1610	1609	1608	1607	1606	1605	1604	1603	1602	1601	1600	1599	1598	1597	1596	1595	1594	1593	1592	1591	1590	1589	1588	1587	1586	1585	1584	1583	1582	1581	1580	1579	1578	1577	1576	1575	1574	1573	1572	1571	1570	1569	1568	1567	1566	1565	1564	1563	1562	1561	1560	1559	1558	1557	1556	1555	1554	1553	1552	1551	1550	1549	1548	1547	1546	1545	1544	1543	1542	1541	1540	1539	1538	1537	1536	1535	1534	1533	1532	1531	1530	1529	1528	1527	1526	1525	1524	1523	1522	1521	1520	1519	1518	1517	1516	1515	1514	1513	1512	1511	1510	1509	1508	1507	1506	1505	1504	1503	1502	1501	1500	1499	1498	1497	1496	1495	1494	1493	1492	1491	1490	1489	1488	1487	1486	1485	1484	1483	1482	1481	1480	1479	1478	1477	1476	1475	1474	1473	1472	1471	1470	1469	1468	1467	1466	1465	1464	1463	1462	1461	1460	1459	1458	1457	1456	1455	1454	1453	1452	1451	1450	1449	1448	1447	1446	1445	1444	1443	1442	1441	1440	1439	1438	1437	1436	1435	1434	1433	1432	1431	1430	1429	1428	1427	1426	1425	1424	1423	1422	1421	1420	1419	1418	1417	1416	1415	1414	1413	1412	1411	1410	1409	1408	1407	1406	1405	1404	1403	1402	1401	1400	1399	1398	1397	1396	1395	1394	1393	1392	1391	1390	1389	1388	1387	1386	1385	1384	1383	1382	1381	1380	1379	1378	1377	1376	1375	1374	1373	1372	1371	1370	1369	1368	1367	1366	1365	1364	1363	1362	1361	1360	1359	1358	1357	1356	1355	1354	1353	1352	1351	1350	1349	1348	1347	1346	1345	1344	1343	1342	1341	1340	1339	1338	1337	1336	1335	1334	1333	1332	1331	1330	1329	1328	1327	1326	1325	1324	1323	1322	1321	1320	1319	1318	1317	1316	1315	1314	1313	1312	1311	1310	1309	1308	1307	1306	1305	1304	1303	1302	1301	1300	1299	1298	1297	1296	1295	1294	1293	1292	1291	1290	1289	1288	1287	1286	1285	1284	1283	1282	1281	1280	1279	1278	1277	1276	1275	1274	1273	1272	1271	1270	1269	1268	1267	1266	1265	1264	1263	1262	1261	1260	1259	1258	1257	1256	1255	1254	1253	1252	1251	1250	1249	1248	1247	1246	1245	1244	1243	1242	1241	1240	1239	1238	1237	1236	1235	1234	1233	1232	1231	1230	1229	1228	1227	1226	1225	1224	1223	1222	1221	1220	1219	1218	1217	1216	1215	1214	1213	1212	1211	1210	1209	1208	1207	1206	1205	1204	1203	1202	1201	1200	1199	1198	1197	1196	1195	1194	1193	1192	1191	1190	1189	1188	1187	1186	1185	1184	1183	1182	1181	1180	1179	1178	1177	1176	1175	1174	1173	1172	1171	1170	1169	1168	1167	1166	1165	1164	1163	1162	1161	1160	1159	1158	1157	1156	1155	1154	1153	1152	1151	1150	1149	1148	1147	1146	1145	1144	1143	1142	1141	1140	1139	1138	1137	1136	1135	1134	1133	1132	1131	1130	1129	1128	1127	1126	1125	1124	1123	1122	1121	1120	1119	1118	1117	1116	1115	1114	1113	1112	1111	1110	1109	1108	1107	1106	1105	1104	1103	1102	1101	1100	1099	1098	1097	1096	1095	1094	1093	1092	1091	1090	1089	1088	1087	1086	1085	1084	1083	1082	1081	1080	1079	1078	1077	1076	1075	1074	1073	1072	1071	1070	1069	1068	1067	1066	1065	1064	1063	1062	1061	1060	1059	1058	1057	1056	1055	1054	1053	1052	1051	1050	1049	1048	1047	1046	1045	1044	1043	1042	1041	1040	1039	1038	1037	1036	1035	1034	1033	1032	1031	1030	1029	1028	1027	1026	1025	1024	1023	1022	1021	1020	1019	1018	1017	1016	1015	1014	1013	1012	1011	1010	1009	1008	1007	1006	1005	1004	1003	1002	1001	1000	999	998	997	996	995	994	993	992	991	990	989	988	987	986	985	984	983	982	981	980	979	978	977	976	975	974	973	972	971	970	969	968	967	966	965	964	963	962	961	960	959	958	957	956	955	954	953	952	951	950	949	948	947	946	945	944	943	942	941	940	939	938	937	936	935	934	933	932	931	930	929	928	927	926	925	924	923	922	921	920	919	918	917	916	915	914	913	912	911	910	909	908	907	906	905	904	903	902	901	900	899	898	897	896	895	894	893	892	891	890	889	888	887	886	885	884	883	882	881	880	879	878	877	876	875	874	873	872	871	870	869	868	867	866	865	864	863	862	861	860	859	858	857	856	855	854	853	852	851	850	849	848	847	846	845	844	843	842	841	840	839	838	837	836	835	834	833	832	831	830	829	828	827	826	825	824	823	822	821	820	819	818	817	816	815	814	813	812	811	810	809	808	807	806	805	804	803	802	801	800	799	798	797	796	795	794	793	792	791	790	789	788	787	786	785	784	7
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	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	
DDA (EMOD)																															
Reserve (EMOD NRY)																															
Opening Balance	0.0	0.0	0.0	98.8	84.4	70.0	56.1	44.3	34.5	24.5	19.9	14.4	9.8	6.2	3.1	1.1	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	
Additions (DPX Net After Royal)	0.0	0.0	100.4	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DPX Net Production (EMOD)	0.0	0.0	1.8	14.4	14.4	14.0	11.7	9.8	8.0	6.4	5.5	4.3	3.7	3.0	2.0	1.1	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	
Closing Balance	0.0	0.0	99.8	94.4	70.0	56.1	44.3	34.5	24.5	19.9	14.4	9.8	6.2	3.1	1.1	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	
Wellbore Assets																															
Beginning Balance (Net EMM)	0.0	12.7	12.7	27.8	51.5	71.2	72.4	97.3	44.8	34.3	25.7	18.7	12.8	8.0	4.0	1.5	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	
Additions (DPX Net EMM MOD)	12.7	0.0	14.6	30.1	31.1	17.2	0.0	0.0	3.8	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DDA Rate (E/BL)	0.00	0.00	0.42	0.42	0.78	1.14	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	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	
DDA (DPX Net EMM MOD)	0.0	0.0	0.7	6.2	11.4	19.8	15.1	12.8	10.4	8.5	7.1	5.8	4.8	3.9	2.8	1.5	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	
Carry Forward (DPX Net EMM)	12.7	12.7	27.8	51.5	71.2	72.4	67.3	64.8	34.3	25.7	18.7	12.8	8.0	4.0	1.5	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	
Subsidiary Assets																															
Beginning Balance (Net EMM)	0.0	26.2	121.2	202.5	219.8	182.3	148.0	119.4	88.8	68.0	51.8	37.6	26.8	18.1	9.2	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Additions (DPX Net EMM MOD)	26.2	85.8	88.8	56.5	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DDA Rate (E/BL)	0.00	0.00	2.27	2.30	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	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	
DDA (DPX Net EMM MOD)	0.0	0.0	5.1	23.3	37.5	38.4	30.5	25.5	20.9	17.2	14.3	11.8	8.7	7.8	5.2	2.8	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	
Carry Forward (DPX Net EMM)	26.2	121.2	202.5	219.8	182.3	118.0	115.4	88.8	68.0	51.8	37.6	25.0	14.1	8.2	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DPX Purchase Price Allocation																															
Beginning Balance (Net EMM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Additions (DPX Net EMM 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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DDA Rate (E/BL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
DDA (DPX Net EMM 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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Carry Forward (DPX Net EMM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total DDA Rate E/BL	0.0	0.0	2.7	2.7	3.4	3.7	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	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	
Total DDA EMM MOD	0.0	0.0	5.8	38.5	68.8	52.3	45.7	38.1	21.3	25.3	21.4	17.7	14.8	11.9	7.8	4.4	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	
LOP ABANDONMENT (EMOD)																															
Beginning Balance (Net EMM)	38.4	38.4	38.4	38.8	34.4	31.5	24.4	17.8	12.7	8.8	6.0	3.8	2.3	1.2	0.4	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	
Additions (DPX Net EMM 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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DDA Rate (E/BL)	0.00	0.00	0.78	0.38	0.42	0.45	0.43	0.40	0.37	0.34	0.30	0.27	0.23	0.19	0.14	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
DDA (DPX Net EMM MOD)	0.0	0.0	0.5	2.5	4.8	7.2	6.6	5.1	3.8	2.9	2.1	1.8	1.1	0.8	0.4	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	
Carry Forward (DPX Net EMM)	38.4	38.4	38.8	38.4	31.5	24.4	17.8	12.7	8.8	6.0	3.8	2.3	1.2	0.4	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	



Alaska State Legislature


SENATE RESOURCES COMMITTEE

Official Business

State Capitol
Juneau AK 99801

MEMO

TO: Senator Pearce, Vice Chairman
Senator Halford
Senator Frank
Senator Taylor
Senator Hoffman
Senator Lincoln

FROM: Senate Resources Committee Staff (X4907) 

DATE: April 3, 1996

RE: Requested material on SB 318: Northstar Lease Agreement

Attached are materials requested or relevant to SB 318:

- 1) Letter to Ken Boyd (4/2/96) requesting names of representatives of other companies who competed for net profit leases in Sale 30. (and reply)
- 2) Memo to BP, DNR, Law requesting responses to questions asked by Committee members at March 29 hearing and reply from BP. Some responses still pending from Law and DNR.
- 3) Response from DNK to question of who owns the other existing 39 net profit share leases. In two formats:
Format one is Ownership Within Leases
Format two is a listing by lease number
- 4) Two articles relating to oil projects in Venezuela



Alaska State Legislature

Official Business

Senate Resources Committee

State Capitol
Juneau AK 99801

April 2, 1996

Mr. Ken Boyd, Director
Division of Oil and Gas
Department of Natural Resources
via fax: 562-3852

Dear Director Boyd:

Last week you provided me with a copy of a notebook entitled "Northstar Unit Briefing Paper—March 1996" which contains several documents pertaining to the history of the leases within the Northstar Unit. Among those documents is a December 27, 1979, letter entitled "Results of the 30th Competitive Oil and Gas Lease Sale" (Tab 3) and an accompanying summary of the companies submitting bids in that sale and the amounts of those bids.

Some of the testimony and committee questions concerning Senate Bill 318 to date have centered on the litigation risk associated with renegotiating the competitively bid terms of Northstar leases as the commissioner has done in this case. For example, questions have arisen about who would have standing to litigate, whether the passage of time lessens the risk of successful litigation, whether other lessees with net profit leases are similarly situated to BPXA and whether the state would be sending the appropriate signal to other lessees by preferentially renegotiating amendments to the terms of these leases and not others.

In light of these questions, I would like to provide an opportunity for representatives of the other companies who competed for net profit leases in Sale 30 to address the committee to share their views on the policy implications and litigation risk involved with the passage of SB 318. In reviewing the list of bidders, I note that several of the companies no longer exist—Gulf Oil, for example—and that others may have new identities having been merged with other companies or simply having been renamed since 1979.

I would appreciate it if you provide committee staff with the current addresses and names for contact personnel within each of the companies that submitted net profit share bids in Sale 30. I recognize that you and your staff are quite busy, but in the interest of expediting hearings on SB 318, I ask that you provide this information by fax this afternoon if at all possible. We would like to notify these companies of their opportunity to participate in future hearings on SB 318.

Sincerely,

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

Senator Loren Leman, Chairman
Senate Resources Committee



DEPARTMENT OF NATURAL RESOURCES
 OFFICE OF THE COMMISSIONER
 400 WILLOUGHBY AVENUE
 JUNEAU, ALASKA 99801-1798
 PHONE: (907) 465-2400
 FAX: (907) 465-3886

Please deliver to: Annela

Location: _____ FAX: 3810

Date: _____ Time: _____

From: Ken BMD

Number of pages 6
 Including cover sheet

Comments: THIS IS WHAT WE CALLED
PUT TOGETHER TODAY

If you experience any problems receiving this FAX, please call Sharon or Eileen at the above phone number.

Names and Addresses of Sole SO Bidders

Original Bidder Name	Current Name	Phone Number	Address	City	State
ALBERTA WEST CORPORATION		713 682-8887	ATRE J. Y. CHESTER	HOUSTON	TX
AMOCO PRODUCTION COMPANY		713 682-8888	ATRE LAND MANAGER USA	HOUSTON	TX
AMALCO PRO-RIELD COMPANY		907 282-4204	ATRE LAND MANAGER	ANCHORAGE	AK
CHEVRON U.S.A. INC.		713 682-8889	PO BOX 1845	HOUSTON	TX
CH2M SERVICE COMPANY	CH2M USA LLC	946 682-8890	PO BOX 209	MIAMI	OK
CONOCO INC.		713 682-8891	689 NORTH DUNEY AIRPORT	HOUSTON	TX
COURTNEY/MISSION INC.		907 282-4242	PO BOX 1828	ANCHORAGE	AK
ENERGY CORPORATION		713 682-7889	LABORATORY AFFAIRS	HOUSTON	TX
ENVI OIL COMPANY	ENERCO INC	282 782-4242	PO BOX 2028	DENVER	CO
ENVI OIL CORPORATION	CHEVRON U.S.A. INC.	713 782-4242	PO BOX 1845	HOUSTON	TX
ENVI OIL INC.		907 682-8888	C/O JOHN MESSICK	ANCHORAGE	AK
ENVI OIL OIL COMPANY		713 682-8889	ATRE CONTRACT & DIVISION ORDER	HOUSTON	TX
ENVI OIL OIL COMPANY		214 682-8890	ATRE SECURITY MANAGEMENT	HOUSTON	TX
ENVI OIL OIL COMPANY		604 682-8891	ATRE LAND DEPARTMENT	DALLAS	TX
ENVI OIL OIL COMPANY	MURPHY OILFIELD & PRODUCE	907 282-4242	1000 E. BRIDGEMOUNTAIN	NEW ORLEANS	LA
ENVI OIL OIL COMPANY		713 682-8892	PO BOX 1847	ANCHORAGE	AK
ENVI OIL OIL COMPANY		648 682-8893	C/O-CITY USA INC.	HOUSTON	TX
ENVI OIL OIL COMPANY		907 282-4242	1000 E. BRIDGEMOUNTAIN	MIAMI	OK
ENVI OIL OIL COMPANY		907 682-8894	ONE SEABRICK PLACE, SUITE 409	HOUSTON	TX
ENVI OIL OIL COMPANY		713 682-8895	TWO BRICK PLAZA	JERSEY	AK
ENVI OIL OIL COMPANY		907 682-8896	E. P. ZELINSKY, JR.	HOUSTON	TX
ENVI OIL OIL COMPANY	BP EXPLORATION (ALASKA) INC.	308 782-4242	PO BOX 5789	ANCHORAGE	AK
ENVI OIL OIL COMPANY	ENVI OIL OIL CO INC.	713 682-8897	C/O ALAN B. BRUNSON	DENVER	CO
ENVI OIL OIL COMPANY		907 282-4242	8944 MICHIGAN BLVD	HOUSTON	TX
ENVI OIL OIL COMPANY		682 282-4242	PO BOX 1847	ANCHORAGE	AK

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NET PROFIT SHARE LEASE OWNERS

02-Apr-96

UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
DUCK ISLAND UNIT					
SALE 30					
	ADL	312028			
	.	.	15	COOK INLET REGION INC	907 288192
	.	.	18	BOND NATURAL RESOURCES	BP EXPLORATION (ALASKA) INC 907 981911
	.	.	19	SEALASKA CORP	907 6894612
	.	.	19	NAVA PEROMAL CORPORATION INC	907 2884100
	.	.	18	NOBAG INC	907 5012888
			9	AMOCO PRODUCTION COMPANY	715 8888235
			7	CITIB SERVICE COMPANY	OOY USA INC. 918 9812885
			7	ROWAN PETROLEUM INC	ROWAN DRILLING 907 2782448
			7	GULF OIL CORPORATION	CHEVRON U.S.A. INC 713 7547855
			7	PLACID OIL CO	918 5813885
			7	GETTY OIL COMPANY	TEXACO INC 303 7884134
			7	TEXAS GULF INC.	987 2785108
			7	CONOCO INC	713 2882706
			14	MARATHON OIL COMPANY	713 6888880
			14	AMERADA HESS CORPORATION	713 6888337
			18	MURPHY OIL CORPORATION	MURPHY EXPLOR. & PROBLD 984 9812311
			19	SHELL OIL COMPANY	713 8704314
			20	CHEVRON U.S.A. INC	713 7547855
			21	EDCON CORPORATION	718 6887008
			21	UNION OIL COMPANY OF CALIFORNIA	907 2787808
			22	ATLANTIC RICHFIELD COMPANY	907 2884834
	ADL	312034			
	.	.	21	EDCON CORPORATION	718 6887008
	.	.	21	UNION OIL COMPANY OF CALIFORNIA	907 2787808
	.	.	21	ATLANTIC RICHFIELD COMPANY	907 2884834
	.	.	21	CHEVRON U.S.A. INC	718 7547855

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UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
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NON UNITIZED PRODUCING

SALE 38

ADL 312827

14			EMERSON OIL COMPANY		713 888801
14			AMERADA HESS CORPORATION		713 801887
9			AMOCO PRODUCTION COMPANY		713 888814
7			GETTY OIL COMPANY	TEXACO INC	308 784184
7			TEXAS GULF INC.		907 2789100
7			PLACID OIL CO		918 841332
7			ROMAN PETROLEUM INC	HOWARD DRILLING	907 2788408
7			GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 754788
7			CONOCO INC		713 282736
7			CITIB SERVICE COMPANY	OKY USA INC.	918 881388
17			EDSON CORPORATION		713 888700
18			COOK INLET REGION INC		907 2828100
18			MONLAG INC		907 881288
18			SEALASKA CORP		907 5301912
18			LIANA REGIONAL CORPORATION INC		907 254188
18			SONO NATURAL RESOURCES	BP EXPLORATION (ALASKA) INC	907 8616111

NORTHSTAR UNIT

SALE 38

ADL 312798

1			AMERADA HESS CORPORATION		713 888887
2			TEXACO INC		308 784184
2			TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 888471
3			AMOCO PRODUCTION COMPANY		713 888808
4			PLACID OIL CO		918 841332
4			CONOCO INC.		
4			TEXAS GULF INC.		907 2789100
4			CITIB SERVICE COMPANY	OKY USA INC.	918 881388
5			SHELL OIL COMPANY		713 878014
6			CHEVRON U.S.A. INC		713 754788
6			PHILLIPS PETROLEUM COMPANY		713 888871

CNR OFFICE OF THE COMMISSIONER
 FAX NO. 407 560 0415

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UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
ADL	312799				
		1	AMERADA HESS CORPORATION		713 608837
		2	TEXACO INC		288 783184
		2	TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 888871
		3	AMOCO PRODUCTION COMPANY		718 988888
		7	ROMAN PETROLEUM INC	ROMAN DRILLING	987 278848
		7	TEXAS GULF INC.		987 278848
		7	GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 754785
		7	CITY SERVICE COMPANY	CITY USA INC.	818 881388
		7	CONOCO INC		713 288278
		7	GETTY OIL COMPANY	TEXACO INC	389 788484
		7	FLACID OIL CO		918 881323
		8	MURPHY OIL CORPORATION	MURPHY EXPLOR. & PROD.CO	884 881281
		8	SHELL OIL COMPANY		713 878434
		9	PHILLIPS PETROLEUM COMPANY		713 888274
		8	MOBIL OIL CORP		214 881388
		9	CHEVRON U.S.A. INC		713 754785
		10	UNION OIL COMPANY OF CALIFORNIA		987 278788
ADL	312808				
		11	TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 888871
		6	CHEVRON U.S.A. INC		713 754785
		6	PHILLIPS PETROLEUM COMPANY		713 888274
		10	UNION OIL COMPANY OF CALIFORNIA		987 278788
		12	GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 754785
		12	CITY'S SERVICE COMPANY	CITY USA INC.	818 881388
		12	ROMAN PETROLEUM INC	ROMAN DRILLING	987 278848
		12	TEXAS GULF INC.		987 278848
		12	CONOCO INC		713 288278
		12	FLACID OIL CO		918 881323
		12	SHELL OIL COMPANY		713 878434
		13	MURPHY OIL CORPORATION	MURPHY EXPLOR. & PROD.CO	884 881281
		13	ATLANTIC RICHFIELD COMPANY		987 288484

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UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
	ADL	312809			
			11 TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 688471
			3 ANCOO PRODUCTION COMPANY		713 588583
			9 CHEVRON U.S.A. INC		713 7547805
			9 MOBIL OIL CORP		214 9618938
			9 PHILLIPS PETROLEUM COMPANY		713 6853741
			16 UNION OIL COMPANY OF CALIFORNIA		807 2767888
			14 AMERADA HESS CORPORATION		713 6888887
			14 MARATHON OIL COMPANY		713 6238888
			15 TEXCO GULF INC.		807 2788100
			15 GETTY OIL COMPANY	TEXACO INC	308 7884464
			15 OILS SERVICE COMPANY	COY USA INC.	818 9813885
			15 FLACID OIL CO		818 9813885
			15 GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 7547805
			16 ROMAN PETROLEUM INC	ROMAN DRILLING	807 2782888
			16 ATLANTIC RICHFIELD COMPANY		887 2634288
			16 SHELL OIL COMPANY		713 6704314
POINT THOMSON UNIT					
SALE 30					
	ADL	312888			
			17 EXXON CORPORATION		713 6887008
			6 CHEVRON U.S.A. INC		713 7547805
			6 PHILLIPS PETROLEUM COMPANY		713 6853741

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

Fax Confirmation Phone (907)465-2400 Fax (907)465-3886

FACSIMILE TRANSMITTAL

DATE & TIME: April 3, 1996 4:20 PM

PLEASE DELIVER TO: Annetta Kreitzer
Alaska Senate Resources Committee

FAX NUMBER: 465-3810

NUMBER OF PAGES (including cover): 11

FROM: Ken Boyd

COMMENTS:

Senator Helford asked for a legal analysis regarding the conclusion that the development account on a lease is transferable by the original lessor to the lessee's assignee.

Attached is a copy of a decision by Judge Fabe, now Justice Fabe, reversing the DNR's decision that the development account could not be transferred. Justice Fabe's rationale was that the state's oil and gas leasing statute, AS 28.05.180, contemplates a lease-specific system, not a lessee-specific system and the development account is lease, not lessee, specific. Accordingly, she concluded that an assignment of the lease constitutes an assignment of the development account.

cc: Jeff Landry, DOL

Attachment

EXHIBIT C
PROJECT SCHEDULE

The Northstar Development Project ("the Project") is described in the document titled "Northstar Development Project, Conceptual Engineering Report" dated February 1996. BPXA shall comply with the following schedule for the Project and shall provide satisfactory evidence of compliance within fifteen days of the date performance is due under the schedule:

BPXA shall receive Project sanction within twelve (12) months after passage by the legislature of an Act approving the First Amendments to the Northstar Unit Leases for the Project. "Project sanction" means approval in writing by the highest appropriate authority in BPXA or its parent entity necessary for the total amount of expenditures required for the Project. Satisfactory evidence of receipt of sanction shall be tendered to the State in the form of the sanctioning entity's documents approving the expenditure of funds for the Project. If Project sanction is withdrawn for any reason whatsoever, BPXA shall notify the State within three working days by letter from an authorized officer and BPXA shall be deemed to have failed to comply with this schedule.

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA
THIRD JUDICIAL DISTRICT

BP EXPLORATION (ALASKA),
INC.,

Appellant,

vs.

STATE OF ALASKA, DEPARTMENT
OF NATURAL RESOURCES,

Appellee.

MARATHON OIL COMPANY, an
Ohio Corporation,

Appellant,

vs.

STATE OF ALASKA, DEPARTMENT
OF NATURAL RESOURCES,

Appellee.

Case No. 3AN-90-225 Civil
Case No. 3AN-90-277 Civil
(Consolidated)

DECISION

This court, having considered the parties' briefs on appeal, the record on appeal, and oral argument on January 24, 1991, hereby REVERSES the decision of the Department of Natural Resources for the following reasons:

I. FACTUAL BACKGROUND

In December, 1979, the State of Alaska conducted an oil and gas lease sale, issuing a net profit share lease

(hereafter "NPSL") to Marathon Oil Company (hereafter "Marathon") and Amerade Hess Corporation (hereafter "Amerada"), as co-lessees. The NPSL method is generally described in AS 38.05.180 as:

a fixed cash bonus with a fixed royalty share reserved to the state of not less than 12 1/2 percent in amount or value of the production removed or sold from the lease with the share of the net profit derived from the lease reserved to the state as the bid variable. AS 38.05.180(f)(5).

The relevant regulations, 11 AAC 83.201-295, detail the system, under which the lessee maintains a production revenue account, a development account, and a net profit payment account. When the lease begins to produce, the lessee applies revenue gained against the development costs expended. Only after recovering the development costs does the lessee begin to pay the state a percentage of its net profits.

In 1980, Marathon and Amerade entered into a contract with BP Exploration, Inc. (hereafter "BP") to drill a well. Surface entry was to be on land leased to BP, and the bottom hole was to be on land leased by Marathon and Amerade. Disagreements arose as to various details of the drilling, and a lawsuit resulted. In an effort to settle the case, Marathon and BP entered into a preliminary agreement by which Marathon would assign its interest in the lease to BP, retaining a future production override in return for BP's payment of an undisclosed amount. As an essential part of the agreement, Marathon and BP intend that Marathon's development account, worth \$23 million, transfer entirely to BP.

The parties wrote to the Department of Natural Resources (hereafter "DNR"), requesting DNR's interpretation of the relevant regulations as to whether the development account could transfer to BP. DNR, on April 14, 1989, responded that the development account was lessee, not lease, specific and that the account would not transfer in its entirety. Under DNR's interpretation, BP would have a development account balance that reflected its own direct costs, as well as that portion of the BP/Marathon contract that could be attributed to "acquisition of development expenses".

Marathon and BP asked DNR to reconsider its position and, on August 3, 1989, DNR confirmed its earlier interpretation, stating that the decision "comports with both the purposes of NPSL leasing and the insistency of industry that NPSL account balances be lessee-specific to account for the unique situation of each lessee". Again, on October 4, 1989, after reconsidering its earlier decisions and meeting with the parties, DNR's director affirmed DNR's position, noting that "[w]hile policy or fairness considerations arguably favor the treatment requested by Marathon and BP, 11 AAC 83.219(b)(7) precludes this treatment". The commissioner, on appeal, affirmed the director's decision on December 7, 1989.

11 AAC 83.219, entitled "Development Costs", provides as follows:

(b) The lessee's development costs for a NPSL equal direct charges, as defined in 11 AAC 83.243, that are not excluded under 11 AAC 83.217 and that are directly attributable to a NPSL for...

* * *

(7) that portion of the full consideration given by the lessee in acquiring a production interest in the NPSL that is properly attributable to the wells, facilities and equipment on or in support of the NPSL which directly result in or are necessary for continued or enhanced production from the NPSL, as opposed to the consideration given for the lease itself; the lessee transferring the production interest must credit his development account for a like amount.... 11 AAC 83.219(b)(7).

BP and Marathon presently appeal DNR's decision.

BP argues that DNR erroneously interpreted 11 AAC 83.219, asserting that the development account is lease, not lessee, specific and that an assignment of the lease constitutes an assignment of the development account. In support of this position, BP refers to the statute's language, federal interpretation of similar federal statutes, and legislative intent. BP also alleges that this interpretation violates the lease's express terms.

Marathon joins in with these arguments and adds that DNR's decision represents an unconstitutional taking, violates equal protection, unjustly enriches the state, and constitutes a restraint of alienation.

II. STANDARD OF REVIEW

The primary issue on appeal is whether DNR correctly interpreted the leasing statute and regulation, AS 38.05.180

and 11 AAC 83.219, respectively, in refusing to recognize the validity of the transfer from Marathon to BP of the development account.

The Alaska Supreme Court in Trustees for Alaska v. State DNR, 795 P.2d 805 (Alaska 1990), held:

To be valid a regulation must be consistent with the authorizing statute and reasonably necessary to carry out the statute's purpose....An administrative agency's interpretation of its own regulation is normally given effect unless plainly erroneous or inconsistent with the regulations. Id. at 812.

III. INTERPRETATION OF 11 AAC 88.219

DNR interprets the statute and, particularly, the regulation to provide that only a small portion of the expenses which Marathon incurred on developing the lease will transfer to BP, reflecting only what BP paid Marathon for "wells, facilities, and equipment". This interpretation is both unjust and unlawful and must be set aside as plainly erroneous.

In reviewing the regulation, the court's first step is to address whether 11 AAC 88.219 is both consistent with AS 38.05.180 and reasonably necessary to carry out the statute's purpose. See Trustees for Alaska v. State DNR, supra.

Because the plain language of AS 38.05.180 contemplates a lease-specific system, and 11 AAC 83.219, as interpreted by DNR, contemplates a lessee-specific system, 11 AAC 83.219 is inconsistent with the statute. Specifically, AS 38.05.180(f)(5)