

SB

318

SFIN

FILE

FISCAL NOTE

STATE OF ALASKA
1996 LEGISLATIVE SESSION

BILL NO. CSSB318(RES)

Revision Date: Original Dept Affected Natural Resources
 Title: An Act authorizing, approving, and ratifying BRU: Resource Development
the amendment of Northstar Unit oil and gas leases ... Component: Pipeline Coordinator
 Sponsor: Senate Rules Committee
 Requestor: Senate Finance Component Serial No. 1191

Expenditures/Revenues	(Thousands of Dollars)					
OPERATING EXPENDITURES	FY97	FY98	FY99	FY00	FY01	FY02
PERSONAL SERVICES	147.3	147.3	125.0			
TRAVEL	25.0	25.0	25.0			
CONTRACTUAL	243.3	243.3	75.0			
SUPPLIES	12.0	12.0	6.0			
EQUIPMENT	3.5	3.5				
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	431.1	431.1	231.0	****	****	****
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES ()						

FUND SOURCE	(Thousands of Dollars)					
1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
1091 Designated Program Rcpts	431.1	431.1	231.0			
TOTAL	431.1	431.1	231.0	****	****	****

Estimate of any current year (FY96) cost: \$ none

POSITIONS	FY97	FY98	FY99	FY00	FY01	FY02
FULL-TIME	0	0	0	0	0	0
PART-TIME	0	0	0	0	0	0
TEMPORARY	0	0	0	0	0	0

ANALYSIS: (Attach a separate page if necessary)

This request is an industry funded project under AS 38.35.140(b) for the development of a common carrier pipeline for the Northstar project near Prudhoe Bay.

The budget is based on the Lease Application moving forward from mid-April 1996 through September 1997 and construction beginning in November 1997. The Leasing Process and Statute require that the Commissioner of DNR make a decision that the Applicant is financially and technically FIT, WILLING and ABLE to construct, operate, maintain and terminate the pipeline. The funds for FY97 and some of the funds for FY98 will be expended on determining if the applicant has proposed a project that meets this requirement. The remainder of the funding will be expended for oversight of the construction of the pipeline by ADNDR, ADEC, ADF&G and ADLabor. The FY99 funds will be used for conformation and oversight of the operational aspects of the project, such as Quality Assurance, Quality Control, and operational processes. *Continued on next page...*

Prepared by: Jerry Brossia, State Pipeline Coordinator Phone: 271-3601
 Division: State Pipeline Coordinator's Office Date: 30-Apr-96
 Approved by Commissioner: *[Signature]* Date: 30-Apr-96
 Agency: Natural Resources

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Fiscal Analysis Continued...

**** Beyond FY99 there will be a request for additional funds for the administration and oversight of the Leases that cannot be determined at this time. These funds will be based on the outcome of the previous years activities and findings. The State Pipeline Coordinator's Office will promptly notify the Governor's Office should this project schedule change.

FISCAL NOTE

STATE OF ALASKA
1996 LEGISLATIVE SESSION

BILL NO. CSSB318(RES)

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 Sponsor: Senate Rules Committee
 Requestor: Senate Finance Component Serial No. 1191

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CONTRACTUAL	243.3	243.3	75.0			
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EQUIPMENT	3.5	3.5				
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	431.1	431.1	231.0	****	****	****
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES ()						

FUND SOURCE	(Thousands of Dollars)					
1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
1091 Designated Program Rcpts	431.1	431.1	231.0			
TOTAL	431.1	431.1	231.0	****	****	****

Estimate of any current year (FY96) cost: \$ none

POSITIONS	FY97	FY98	FY99	FY00	FY01	FY02
FULL-TIME	0	0	0	0	0	0
PART-TIME	0	0	0	0	0	0
TEMPORARY	0	0	0	0	0	0

ANALYSIS: (Attach a separate page if necessary)

This request is an industry funded project under AS 38.35.140(b) for the development of a common carrier pipeline for the Northstar project near Prudhoe Bay.

The budget is based on the Lease Application moving forward from mid-April 1996 through September 1997 and construction beginning in November 1997. The Leasing Process and Statute require that the Commissioner of DNR make a decision that the Applicant is financially and technically FIT, WILLING and ABLE to construct, operate, maintain and terminate the pipeline. The funds for FY97 and some of the funds for FY98 will be expended on determining if the applicant has proposed a project that meets this requirement. The remainder of the funding will be expended for oversight of the construction of the pipeline by ADNDR, ADEC, ADF&G and ADLabor. The FY99 funds will be used for conformation and oversight of the operational aspects of the project, such as Quality Assurance, Quality Control, and operational processes. *Continued on next page...*

Prepared by: Jerry Brossia, State Pipeline Coordinator Phone: 271-3601
 Division: State Pipeline Coordinator's Office Date: 30-Apr-96
 Approved by Commissioner: [Signature] Date: 30-Apr-96
 Agency: Natural Resources

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Fiscal Analysis Continued...

**** Beyond FY99 there will be a request for additional funds for the administration and oversight of the Leases that cannot be determined at this time. These funds will be based on the outcome of the previous years activities and findings. The State Pipeline Coordinator's Office will promptly notify the Governor's Office should this project schedule change.

FISCAL NOTE

STATE OF ALASKA
1996 LEGISLATIVE SESSION

BILL NO. CSSB318(RES)

Revision Date: 26-Apr-96 Dept Affected: Natural Resources
 Title: An act authorizing, approving, and ratifying the BRU: Resource Development
amendment of the Northstar Unit oil and gas leases... Component: Oil and Gas Development
 Sponsor: Rules by request of the Governor
 Requestor: Senate Finance Component Serial No. #439

Expenditures/Revenues	(Thousands of Dollars)					
OPERATING EXPENDITURES	FY97	FY98	FY99	FY00	FY01	FY02
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES (1002,1004)	0.0	1,900.0	20,900.0	38,400.0	36,900.0	15,650.0

FUND SOURCE	(Thousands of Dollars)					
1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
Other						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY96) cost: \$ _____

POSITIONS	FY97	FY98	FY99	FY00	FY01	FY02
FULL-TIME	0	0	0	0	0	0
PART-TIME	0	0	0	0	0	0
TEMPORARY	0	0	0	0	0	0

ANALYSIS: (Attach a separate page if necessary)

The state will realize a significant increase in revenues from royalties and taxes from the Northstar Unit development over the next six years if this bill is passed. Without the bill, the Department of Revenue predicts in its Fall 1995 Base Price forecast that the Northstar Unit will not commence full production until 2002. If this is the case, DNR predicts that the state might receive about \$36 million in royalty and tax revenues over the next six years.

With passage of this bill, early the development of the Northstar field is possible. Full oil production is anticipated by 1999. Within this same six-year period, state revenues could be \$130 million more, including \$12 million from "supplemental royalties."

SEE ATTACHED TABLE FOR A FULL FINANCIAL ANALYSIS.

Prepared by: Ken Boyd, Director Phone: 267-8800
 Division: Oil and Gas Date: 26-Apr-96
 Approved by Commissioner: [Signature] Date: 26-Apr-96
 Agency: Natural Resources

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Updated #1 for CS(RES) 4/30/96

SB318 FISCAL NOTE ATTACHMENT

Year	State Revenues (without Northstar Lease Amendments)									
	State Royalty	State Supplemental Royalty	State Share of Federal Royalty	DNR Revenues	Severance Tax	Spill & Conserv. Tax	Property Tax	Corporate Income Tax	DOR Revenues	Total State Revenues
	(Thousands of 1996 Dollars)									
1997	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
1998	00.0	00.0	00.0	00.0	00.0	00.0	00.0	00.0	00.0	00.0
1999	00.0	00.0	00.0	00.0	00.0	00.0	00.0	(200.0)	(200.0)	(200.0)
2000	00.0	00.0	00.0	00.0	00.0	00.0	400.0	(700.0)	(300.0)	(300.0)
2001	1,900.0	00.0	100.0	2,000.0	00.0	00.0	1,700.0	(1,000.0)	700.0	2,700.0
2002	<u>19,800.0</u>	<u>00.0</u>	<u>1,250.0</u>	<u>21,050.0</u>	<u>8,100.0</u>	<u>200.0</u>	<u>3,400.0</u>	<u>800.0</u>	<u>12,500.0</u>	<u>33,550.0</u>
	\$21,700.0	\$0.0	\$1,350.0	\$23,050.0	\$8,100.0	\$200.0	\$5,500.0	(\$1,100.0)	\$12,700.0	\$35,750.0

Year	State Revenues (with Northstar Lease Amendments)									
	State Royalty	State Supplemental Royalty	State Share of Federal Royalty	DNR Revenues	Severance Tax	Spill & Conserv. Tax	Property Tax*	Corporate Income Tax	DOR Revenues	Total State Revenues
	(Thousands of 1996 Dollars)									
1997	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$400.0	(\$700.0)	(\$300.0)	(\$300.0)
1998	1,800.0	00.0	100.0	1,900.0	00.0	00.0	1,600.0	(100.0)	1,500.0	3,400.0
1999	19,600.0	00.0	1,300.0	20,900.0	8,100.0	200.0	3,100.0	800.0	4,100.0	25,000.0
2000	35,700.0	400.0	2,300.0	38,400.0	14,800.0	400.0	4,300.0	2,900.0	7,600.0	46,000.0
2001	35,300.0	1,300.0	2,300.0	38,900.0	13,100.0	400.0	4,700.0	3,200.0	8,300.0	47,200.0
2002	<u>32,200.0</u>	<u>2,400.0</u>	<u>2,100.0</u>	<u>36,700.0</u>	<u>10,300.0</u>	<u>400.0</u>	<u>4,400.0</u>	<u>3,300.0</u>	<u>8,100.0</u>	<u>44,800.0</u>
	\$124,600.0	\$4,100.0	\$8,100.0	\$136,800.0	\$46,300.0	\$1,400.0	\$18,500.0	\$9,400.0	\$29,300.0	\$166,100.0

Year	Change in State Revenues (with Northstar Lease Amendments)									
	State Royalty	State Supplemental Royalty	State Share of Federal Royalty	DNR Revenues	Severance Tax	Spill & Conserv. Tax	Property Tax*	Corporate Income Tax	DOR Revenues	Total State Revenues
	(Thousands of 1996 Dollars)									
1997	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$400.0	(\$700.0)	(\$300.0)	(\$300.0)
1998	1,800.0	0.0	100.0	1,900.0	0.0	0.0	1,600.0	(100.0)	1,500.0	3,400.0
1999	19,600.0	0.0	1,300.0	20,900.0	8,100.0	200.0	3,100.0	1,000.0	4,300.0	25,200.0
2000	35,700.0	400.0	2,300.0	38,400.0	14,800.0	400.0	3,900.0	3,600.0	7,900.0	46,300.0
2001	33,400.0	1,300.0	2,200.0	36,900.0	13,100.0	400.0	3,000.0	4,200.0	7,500.0	44,500.0
2002	<u>12,400.0</u>	<u>2,400.0</u>	<u>850.0</u>	<u>15,650.0</u>	<u>2,200.0</u>	<u>200.0</u>	<u>1,000.0</u>	<u>2,500.0</u>	<u>(4,400.0)</u>	<u>11,250.0</u>
	\$102,900.0	\$4,100.0	\$6,750.0	\$113,750.0	\$38,200.0	\$1,200.0	\$13,000.0	\$10,500.0	\$16,600.0	\$130,350.0

FISCAL NOTE

STATE OF ALASKA

BILL NO. CSSB318(RES)

1996 LEGISLATIVE SESSION

Revision Date: <u>26-Apr-96</u>	Dept Affected: <u>Natural Resources</u>
Title: <u>An act authorizing, approving, and ratifying the amendment of the Northstar Unit oil and gas leases...</u>	BRU: <u>Resource Development</u>
Sponsor: <u>Rules by request of the Governor</u>	Component: <u>Oil and Gas Development</u>
Requestor: <u>Senate Finance</u>	Component Serial No. <u>#439</u>

Expenditures/Revenues (Thousands of Dollars)

OPERATING EXPENDITURES	FY97	FY98	FY99	FY00	FY01	FY02
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES (1002,1004)	0.0	1,900.0	20,900.0	38,400.0	36,900.0	15,650.0

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 MHTIA						
Other						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY96) cost: \$ _____

POSITIONS

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

ANALYSIS: (Attach a separate page if necessary)

The state will realize a significant increase in revenues from royalties and taxes from the Northstar Unit development over the next six years if this bill is passed. Without the bill, the Department of Revenue predicts in its Fall 1995 Base Price forecast that the Northstar Unit will not commence full production until 2002. If this is the case, DNR predicts that the state might receive about \$36 million in royalty and tax revenues over the next six years.

With passage of this bill, early the development of the Northstar field is possible. Full oil production is anticipated by 1999. Within this same six-year period, state revenues could be \$130 million more, including \$12 million from "supplemental royalties."

SEE ATTACHED TABLE FOR A FULL FINANCIAL ANALYSIS.

Prepared by: <u>Ken Boyd, Director</u>	Phone: <u>269-8800</u>
Division: <u>Oil and Gas</u>	Date: <u>26-Apr-96</u>
Approved by Commissioner:	Date: <u>26-Apr-96</u>
Agency: <u>Natural Resources</u>	

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(Thousands of 1996 Dollars)										
1997	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
1998	00.0	00.0	00.0	00.0	00.0	00.0	00.0	00.0	00.0	00.0
1999	00.0	00.0	00.0	00.0	00.0	00.0	00.0	(200.0)	(200.0)	(200.0)
2000	00.0	00.0	00.0	00.0	00.0	00.0	400.0	(700.0)	(300.0)	(300.0)
2001	1,900.0	00.0	100.0	2,000.0	00.0	00.0	1,700.0	(1,000.0)	700.0	2,700.0
2002	<u>19,800.0</u>	<u>00.0</u>	<u>1,250.0</u>	<u>21,050.0</u>	<u>8,100.0</u>	<u>200.0</u>	<u>3,400.0</u>	<u>800.0</u>	<u>12,500.0</u>	<u>33,550.0</u>
	\$21,700.0	\$0.0	\$1,350.0	\$23,050.0	\$8,100.0	\$200.0	\$5,500.0	(\$1,100.0)	\$12,700.0	\$35,750.0

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1998	1,800.0	00.0	100.0	1,900.0	00.0	00.0	1,600.0	(100.0)	1,500.0	3,400.0
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	\$124,600.0	\$4,100.0	\$8,100.0	\$136,800.0	\$46,300.0	\$1,400.0	\$18,500.0	\$9,400.0	\$29,300.0	\$166,100.0

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1998	1,800.0	0.0	100.0	1,900.0	0.0	0.0	1,600.0	(100.0)	1,500.0	3,400.0
1999	19,600.0	0.0	1,300.0	20,900.0	8,100.0	200.0	3,100.0	1,000.0	4,300.0	25,200.0
2000	35,700.0	400.0	2,300.0	38,400.0	14,800.0	400.0	3,900.0	3,600.0	7,900.0	46,300.0
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2002	<u>12,400.0</u>	<u>2,400.0</u>	<u>850.0</u>	<u>15,650.0</u>	<u>2,200.0</u>	<u>200.0</u>	<u>1,000.0</u>	<u>2,500.0</u>	<u>(4,400.0)</u>	<u>11,250.0</u>
	\$102,900.0	\$4,100.0	\$6,750.0	\$113,750.0	\$38,200.0	\$1,200.0	\$13,000.0	\$10,500.0	↓16,600.0	\$130,350.0

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(Thousands of Dollars)

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LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	431.1	431.1	231.0	****	****	****

CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
-----------------------------	-----	-----	-----	-----	-----	-----

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

(Thousands of Dollars)

FUND SOURCE	FY97	FY98	FY99	FY00	FY01	FY02
1002 Federal Receipts						
1003 GF Match						
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1005 GF/Program Receipts						
1006 GF/MHTIA						
1091 Designated Program Rcpts	431.1	431.1	231.0			
TOTAL	431.1	431.1	231.0	****	****	****

Estimate of any current year (FY96) cost: \$ none

POSITIONS

	FY97	FY98	FY99	FY00	FY01	FY02
FULL-TIME	0	0	0	0	0	0
PART-TIME	0	0	0	0	0	0
TEMPORARY	0	0	0	0	0	0

ANALYSIS: (Attach a separate page if necessary)

This request is an industry funded project under AS 38.35.140(b) for the development of a common carrier pipeline for the Northstar project near Prudhoe Bay.

The budget is based on the Lease Application moving forward from mid-April 1996 through September 1997 and construction beginning in November 1997. The Leasing Process and Statute require that the Commissioner of DNR make a decision that the Applicant is financially and technically FIT, WILLING and ABLE to construct, operate, maintain and terminate the pipeline. The funds for FY97 and some of the funds for FY98 will be expended on determining if the applicant has proposed a project that meets this requirement. The remainder of the funding will be expended for oversight of the construction of the pipeline by ADNDR, ADEC, ADF&G and ADLabor. The FY99 funds will be used for conformation and oversight of the operational aspects of the project, such as Quality Assurance, Quality Control, and operational processes. *Continued on next page...*

Prepared by: Jerry Brossia, State Pipeline Coordinator Phone: 271-3601
 Division: State Pipeline Coordinator's Office Date: 29-Mar-96
 Approved by Commissioner: [Signature] Date: 29-Mar-96
 Agency: Natural Resources

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Fiscal Analysis Continued...

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BILL NO. SB318

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the amendment of Northstar Unit oil and gas leases ... Component: Oil & Gas Development
 Sponsor: Senate Rules Committee
 Requestor: Senate Resources Component Serial No. 439

Expenditures/Revenues (Thousands of Dollars)

	FY97	FY98	FY99	FY00	FY01	FY02
OPERATING EXPENDITURES						
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES (1004)	0.0	3,857.1	37,952.1	38,700.6	34,975.4	(3,686.3)

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
Other						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY96) cost: \$ none

POSITIONS

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

ANALYSIS: (Attach a separate page if necessary)

The state will likely realize a significant increase in revenues from royalties and taxes from the Northstar Unit development over the next six years if this bill passes. Without the bill, the Department of Revenue predicts in its Fall 1995 Base Price forecast that the Northstar Unit will not commence full production until 2002. Assuming full production in 2002 (and some preliminary production starting in 4th quarter 2001), DNR predicts that the state will receive only \$5.5 million in tax revenues over the next six years, mostly from property taxes.

With passage of this bill, early development of the Northstar field is possible. Full oil production is anticipated by 1999. Within this same six-year period, state revenues will likely be an additional \$180 million over the \$5.5 million amount. These revenues will be in the form of royalties and "supplemental royalties," and severance, conservation, property, and corporate income taxes. The state will also receive nearly \$7 million as its share of federal royalties from the federal lease tracts in the Northstar Unit. **SEE ATTACHED TABLE FOR FULL FINANCIAL ANALYSIS...**

Prepared by: Ken Boyd, Director Phone: 269-8800
 Division: Oil & Gas Date: 28-Mar-96
 Approved by Commissioner: [Signature] Date: 28-Mar-96
 Agency: Natural Resources

State Revenues (without Northstar Lease Amendments)

State	State Royalty	State Supplemental Royalty	State Share of Federal Royalty	Severance Tax	Spill & Conserv. Tax	Property Tax*	Corporate Income Tax	Total State Revenues
(Thousands of 1996 Dollars)								
1996	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
1997	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1998	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1999	0.0	0.0	0.0	0.0	0.0	0.0	(477.1)	(477.1)
2000	0.0	0.0	0.0	0.0	0.0	828.3	(835.9)	(7.6)
2001	3,868.9	0.0	247.4	0.0	45.6	2,547.2	(1,173.8)	5,535.3
2002	35,778.5	0.0	2,287.7	16,171.7	407.2	4,245.3	2,784.3	61,674.6
	<u>\$39,647.4</u>	<u>\$0.0</u>	<u>\$2,535.1</u>	<u>\$16,171.7</u>	<u>\$452.8</u>	<u>\$7,620.8</u>	<u>\$297.5</u>	<u>\$66,725.2</u>

State Revenues (with Northstar Lease Amendments)

State	State Royalty	State Supplemental Royalty	State Share of Federal Royalty	Severance Tax	Spill & Conserv. Tax	Property Tax*	Corporate Income Tax	Total State Revenues
(Thousands of 1996 Dollars)								
1996	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$477.1)	(\$477.1)
1997	0.0	0.0	0.0	0.0	0.0	761.4	(834.1)	(72.7)
1998	3,625.3	0.0	231.8	0.0	50.1	2,343.9	(1,213.4)	5,037.7
1999	35,631.3	42.5	2,278.2	16,101.5	447.4	3,914.3	2,767.6	61,182.8
2000	35,735.8	680.0	2,284.9	13,487.8	432.1	4,771.2	2,994.3	60,386.1
2001	34,891.8	1,969.0	2,231.0	12,682.7	406.5	4,586.5	3,440.7	60,208.2
2002	29,599.9	2,887.4	1,892.6	7,949.5	330.6	4,293.8	3,234.1	50,187.9
	<u>\$139,484.1</u>	<u>\$5,578.9</u>	<u>\$8,918.5</u>	<u>\$50,221.5</u>	<u>\$1,666.7</u>	<u>\$20,671.1</u>	<u>\$9,912.1</u>	<u>\$236,452.9</u>

Change in State Revenues (with Northstar Lease Amendments)

State	State Royalty	State Supplemental Royalty	State Share of Federal Royalty	Severance Tax	Spill & Conserv. Tax	Property Tax*	Corporate Income Tax	Total State Revenues
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2000	35,735.8	680.0	2,284.9	13,487.8	432.1	3,942.9	3,830.2	60,393.7
2001	31,022.9	1,969.0	1,983.6	12,682.7	361.0	2,039.3	4,614.5	54,673.0
2002	(6,178.6)	2,887.4	(395.1)	(8,222.2)	(76.5)	48.5	449.9	(11,486.7)
	<u>\$99,836.7</u>	<u>\$5,578.9</u>	<u>\$6,383.4</u>	<u>\$34,049.8</u>	<u>\$1,214.1</u>	<u>\$13,050.3</u>	<u>\$9,614.7</u>	<u>\$169,727.8</u>

*Approximately 75 percent of this amount may go to the North Slope Borough.

FISCAL NOTE

No. 1

Bill Version: SB 318

(S) Publish Date: 3-28-96

STATE OF ALASKA 1996 LEGISLATIVE SESSION

Revision Date: Original Dept Affected Natural Resources
 Title: An Act authorizing, approving, and ratifying BRU: Resource Development
the amendment of Northstar Unit oil and gas leases ... Component: Oil & Gas Development
 Sponsor: House Rules Committee
 Requestor: Governor Component Serial No. 439

Expenditures/Revenues		(Thousands of Dollars)					
	FY97	FY98	FY99	FY00	FY01	FY02	
OPERATING EXPENDITURES							
PERSONAL SERVICES							
TRAVEL							
CONTRACTUAL							
SUPPLIES							
EQUIPMENT							
LAND & STRUCTURES							
GRANTS, CLAIMS							
MISCELLANEOUS							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0	
CHANGE IN REVENUES (1004)	0.0	3,857.1	37,952.1	38,700.6	34,975.4	(3,686.3)	

FUND SOURCE		(Thousands of Dollars)					
	FY97	FY98	FY99	FY00	FY01	FY02	
1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1006 GF/MHTIA							
Other							
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	

Estimate of any current year (FY96) cost: \$ none

POSITIONS		FY97	FY98	FY99	FY00	FY01	FY02
FULL-TIME		0	0	0	0	0	0
PART-TIME		0	0	0	0	0	0
TEMPORARY		0	0	0	0	0	0

ANALYSIS: (Attach a separate page if necessary)

The state will likely realize a significant increase in revenues from royalties and taxes from the Northstar Unit development over the next six years if this bill passes. Without the bill, the Department of Revenue predicts in its Fall 1995 Base Price forecast that the Northstar Unit will not commence full production until 2002. Assuming full production in 2002 (and some preliminary production starting in 4th quarter 2001), DNR predicts that the state will receive only \$5.5 million in tax revenues over the next six years, mostly from property taxes.

With passage of this bill, early development of the Northstar field is possible. Full oil production is anticipated by 1999. Within this same six-year period, state revenues will likely be an additional \$180 million over the \$5.5 million amount. These revenues will be in the form of royalties and "supplemental royalties," and severance, conservation, property, and corporate income taxes. The state will also receive nearly \$7 million as its share of federal royalties from the federal lease tracts in the Northstar Unit.

SEE ATTACHED TABLE FOR FULL FINANCIAL ANALYSIS...

Prepared by: Ken Boyd, Director Phone: 269-8800
 Division: Oil & Gas Date: 26-Mar-96
 Approved by Commissioner: _____ Date: 26-Mar-96
 Agency: Natural Resources

PREPARER TO PROVIDE ALL DISTRIBUTION COPIES TO GOVERNOR'S LEGISLATIVE OFFICE

State Revenues (without Northstar Lease Amendments)								
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1999	0.0	0.0	0.0	0.0	0.0	0.0	(477.1)	(477.1)
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*Approximately 75 percent of this amount may go to the North Slope Borough.

Letter of Intent for SB318

The legislature sets forth its intent regarding the meaning of certain words and phrases used in the "Amendment to the Northstar Unit Leases between the State of Alaska and BP Exploration (Alaska) Inc. ("Amendment")". Specifically, the legislature sets forth its intent regarding Paragraph 41 of the 1980 Leases entitled "Employment of Alaskan Residents" and Paragraph 31 of the 1983 Lease entitled "Employment of Alaskan Residents" in the Amendment (collectively "Employment Paragraphs"). The legislature intends that the Alaska residents and contractors discussed in the Employment Paragraphs are truly Alaskan and that Alaska residents throughout the state be given an opportunity to obtain employment on the Northstar project.

The legislature believes that its findings made in AS 36.10.005(a)(1)c(8) and (11)c(18), (c), and (d), regarding an employment preference for Alaska residents on state construction projects are equally applicable to the Amendment. The legislature believes that the state has a compelling interest in reducing the level of unemployment among its residents.

For purposes of Employment Paragraphs, the legislature intends that the phrases "Alaska resident," "residents of Alaska," and "resident personnel" mean an individual who is physically present in the state with the intent to remain in the state indefinitely and to make a home in the state. An individual demonstrates that intent by maintaining a residence in the state for one year before the date of hire. Other acceptable proof of that intent includes evidence that the individual: (1) was registered to vote in Alaska for the year previous to the date of hire; (2) attended school in Alaska within the year previous to the date of hire; (3) possessed an Alaska driver's, fishing, trapping, or hunting license for at least one year before the date of hire; or (4) received an Alaska permanent fund dividend for the year previous to the date of hire. The hiring entity may also require that the individual state under oath that the individual is not claiming residency outside of the state or obtaining benefits under a claim of residency outside of the state.

For purposes of the Employment Paragraphs, the legislature intends that the word "available" means Alaska residents who are located anywhere in the state, not just residents located in the area of the

state where the work is to be performed. The legislature further intends that the word "qualified" means an individual who either currently possesses the requisite education, training, skills, or experience to perform the work necessary for a particular position or is capable of performing such skills after completing one of the job training programs that are contemplated in the Employment Paragraphs.

The legislature understands that nonresidents will be hired only if there is no available and qualified Alaska resident to perform the work. For purposes of the Employment Paragraphs, the legislature intends that the requirement to "advertise for available positions locally" includes advertising in newspapers and other publications located throughout the state, including rural areas, not just in the location where the work is to be performed. The legislature further intends that the requirement to "use Alaska job service organizations" includes those offices maintained by the Department of Labor whose functions are to aid the unemployed in finding employment and any job service organization located throughout the state, not just the location where the work is to be performed.

For purposes of the Employment Paragraphs, the legislature intends that the phrases "Alaska contractors" and "Alaska firms" mean a firm or contractor that:

(1) has held an Alaska business license for one year before performing any work in connection with the Northstar leases; and

(2) has maintained for one year a place of business within the state that deals in the supplies, services or construction of the nature required for the project before performing any work in connection with the Northstar leases; and

(3) is

(a) a sole proprietorship and the proprietor is an Alaska resident;

(b) a partnership and more than fifty percent of the partners are Alaska residents;

(c) a corporation that has been incorporated in the state; or

(d) is a joint venture composed entirely of ventures that

qualify under (1), (2), and (3), (a), (b) or (c) above.

For purposes of the Employment Paragraphs, the legislature intends that the requirements that the lessee "furnish the Department of Labor a quarterly report regarding the Alaska residents on the leased area in compliance with regulations by the Commissioner of Labor" and "[t]he report must also include statistical data concerning the number of resident personnel hired within the past year for this lease" comply with the reporting requirements of 8 AAC 30.062 and shall include information regarding the number of nonresidents hired within the past year, and the number of Alaska contractors and non-Alaska contractors hired within the past year. The legislature intends that the provisions of the Employment Paragraphs be enforced to the greatest extent permissible under the constitutions of the United States and the State of Alaska.

FINDINGS OF FACT OF THE SENATE RESOURCES COMMITTEE REGARDING SB 318, DATED APRIL 24, 1996. Based upon extensive public testimony, as well as the review of the written documents and presentations made by BP Exploration (Alaska) Inc. (BPXA), the Department of Law, and the Department of Natural Resources related to the proposal of BP Exploration (Alaska) Inc. and the Department of Natural Resources to amend certain of the lease terms of State of Alaska oil and gas leases within the Northstar Unit (NSU), the Senate Resources Committee makes the following findings of fact:

ARTICLE 1. THE STATE'S NET PROFIT SHARE AND HISTORY OF THE NORTHSTAR LEASES BEFORE UNITIZATION.

(1) The net profit share provision of four of the five state leases now included in the Northstar Unit was the competitively bid variable when the leases were originally offered for lease. The leases were offered with a fixed per acre cash bonus and a fixed royalty of 20 percent, and bidders were asked to submit sealed competitive bids based upon the percentage of net profits that the bidder would share with the state. According to the Department of Natural Resources, the average of the winning net profit share bids for these leases was "about 89 percent." As to the fifth state lease, the net profit share and royalty were fixed by the Department of Natural Resources at 40 percent and 12 1/2 percent, respectively, and the competitively bid variable was the amount of bonus offered by the bidders.

(2) The leases for which the net profit share was the bid variable, ADL Nos. 312798, 312799, 312808, and 312809, were offered for lease in State of Alaska Competitive Oil and Gas Lease Sale 30, that was held in December 1979. These four leases were issued in 1980 for a primary term of 10 years. The fifth lease, ADL 355001, was offered in State of Alaska Competitive Oil and Gas Lease Sale 39 in May 1983, and was issued in June 1983. The primary term of ADL 355001 was also 10 years.

(3) The original lessees of the Northstar leases included Amerada Hess Co., Shell Oil Co. (Shell), Enterprise Oil Co. (Enterprise), and Murphy Oil Co. In 1990, Amerada

Hess Co. bought Enterprise's interest in the leases for \$2,000,000.

(4) Three years after the initial four state leases were issued, Shell Oil Co. discovered the Northstar oil field while drilling the Seal Island No. 1 Well. Thereafter, during the period 1984 - 1986 additional wells were drilled to delineate the Northstar field. Those wells included Shell Seal Island No. 2 (1984); Shell Seal Island No. 3 (1985); Shell Seal Island No. 4 (1985); Amerada Hess Co. Northstar No. 1 (1985); and Amerada Hess Co. Northstar No. 2 (1986).

(5) Near the end of the 10-year primary term for the initial four state leases and the two Outer Continental Shelf (OCS) leases that later came to be included in the Northstar Unit, Amerada Hess Co. and its partners approached the Department of Natural Resources and the federal Minerals Management Service with a proposal to form the Northstar Unit.

ARTICLE 2. FORMATION OF THE NORTHSTAR UNIT AND ACTIVITIES UNDER THE INITIAL PLAN OF DEVELOPMENT.

(1) Instead of attempting to take back the four leases that were due to expire so that they could be competitively leased again, division director James Eason of the Department of Natural Resources along with the Minerals Management Service approved formation of the Northstar Unit and its initial Plan of Development, thereby extending the ten-year primary term of the leases committed to the unit. The Department of Natural Resources' action in approving this exploratory unit which effectively extended all four state leases beyond their primary term (and effectively precluding competitively releasing them) without any certainty of production was consistent with the department's actions on a multitude of units including: Prudhoe Bay/Niakuk deferral, Prudhoe Bay/Pt. McIntyre deferral, Milne Point formation, Milne Point expansion, Duck Island, Point Thomson, Point Thomson expansion, Thetis Island, Hemi Springs, Big River, Astosch, Badami, Kuukpuk, Northstar formation, North Fork, Nicolai Creek, Kavik, Jones Island, Falls Creek, West McArthur River, and Gwydyr Bay. There has been no evidence that the Department of Natural Resources sought the Department of Law's advice about taking back the leases without certified wells and forcing the leases with certified wells into production in connection with its 1990 decision.

(2) The term of the Northstar Unit was five years, from January 24, 1990, until

January 23, 1995.

(3) According to the Department of Natural Resources, as a condition of its approval of the initial five-year Plan of Development for the unit, "[t]he state lessees were permitted to make progressively larger annual payments to the state in lieu of drilling a well in the Plan of Development. The extension fee payments were to be paid by the State lessees to the State under the following schedule: January 31, 1991—\$1 million; January 31, 1992—\$2 million; January 31, 1993—\$2 million; January 31, 1994—\$3 million and January 31, 1995—\$4 million, unless the fee obligation was extinguished by the drilling of a well in the unit area." As further conditions of its approval, the Department of Natural Resources also required Amerada Hess Co. and its partners to conduct certain petrological and petrophysical analyses, to gather an additional 250 line-miles of geophysical (seismic) data over the unit area, and to complete facilities design and reservoir engineering studies (pre-production studies) during the initial Plan of Development. The Plan of Development did not require Amerada Hess and its partners to begin production during the five-year initial term.

(4) Amerada Hess Co. and its partners made the scheduled "in lieu of drilling" payments for the first three years of the five-year Plan of Development period, with payments totaling \$5 million. Amerada Hess Co. then elected to drill the Amerada Hess Co. Northstar No. 3 Well in 1994, extinguishing its remaining financial obligations to the state under the terms of the Plan of Development for the Northstar Unit. Amerada Hess Co. and its partners also timely complied fully with each of the other conditions set out by the Department of Natural Resources in its approval of the initial Plan of Development. The Plan of Development had succeeded in getting one well drilled and in Amerada Hess Co. and its partners' completing certain other work commitments including petrological/petrophysical studies, production facilities design, seismic surveys, seismic analysis and interpretation, and reservoir engineering studies. However, no production from the unit occurred during the five-year period of the initial Plan of Development.

(5) Following the drilling of the Amerada Hess Co. Northstar No. 3 Well earlier in 1994, Amerada Hess Co. met with representatives of the Department of Natural Resources and the Minerals Management Service in June 1994, to inform the agencies of its decision not to proceed with development of the Northstar Unit. The Department of Natural

Resources has indicated that Amerada Hess Co. believed that the development costs for the Northstar Unit leases would exceed \$1,400,000,000. Assuming that the state could have gotten the leases back, because of their \$1,400,000,000 development cost, the Department of Natural Resources believes that the leases would have had little value and would most likely have been re-leased for a nominal bonus bid.

(6) Under the terms of the Northstar Unit Agreement, Amerada Hess Co. and its partners were required to submit a proposed Plan of Development to the Department of Natural Resources late in October 1994, 90 days before the expiration of the first Plan of Development, or the unit, which had already extended the Northstar Unit leases five years beyond their initial primary term, would terminate.

(7) Having made the decision not to proceed with development of the unit, Amerada Hess Co. did not submit a proposed second Plan of Development, and under the terms of the unit agreement and the department's regulations, the Department of Natural Resources issued a Notice of Default to Amerada Hess Co. and its partners on November 3, 1994.

(8) By subsequent letter dated December 12, 1994, the Department of Natural Resources amended its November 3, 1994, Notice of Default to provide that Amerada Hess Co. could cure the default either by providing an updated Plan of Development within 90 days or by voluntarily agreeing to terminate the Northstar Unit Agreement. The Department of Natural Resources' December 12, 1994, letter concluded "[f]inally, if the NSU terminates, three State of Alaska leases will continue beyond their primary term pursuant to paragraph 5(d) of the lease. The three leases are ADLs 312798, 312799 and 312809. This is further notice that within 90 days of termination of the NSU the lessees shall file a Plan of Development in compliance with the requirements set forth in paragraph 17 of the lease."

(9) Amerada Hess Co. and Shell began efforts to sell their respective interests in the Northstar Unit leases. Neither the exact timing nor the details of Amerada Hess Co.'s and Shell's efforts to market the leases are a matter of public record.

(10) Amerada Hess Co. and Shell subsequently sold their interests in the Northstar Unit leases to BP Exploration (Alaska) Inc. early in 1995. BP Exploration (Alaska) Inc. has characterized the terms of its purchase of the Northstar Unit lease interests as a "competitive process." However, BP Exploration (Alaska) Inc. has declined to make public

the terms of its purchase or the identity of its competitors for the purchase of Amerada Hess Co.'s and Shell's interest in the Northstar Unit leases, citing a confidentiality agreement between the parties that prohibits its doing so. The state played no role in the offering or selling of Amerada Hess Co.'s and Shell's interest in the Northstar Unit leases to BP Exploration (Alaska) Inc. Lessees commonly sell interests in leases without the state's involvement other than approving assignments resulting from the sale.

(11) In its purchase of the Northstar Unit leases from Amerada Hess Co. and its partners, BP Exploration (Alaska) Inc. acquired the net profit share development accounts for those leases. The amount of accrued costs in the Northstar Unit net profit share development accounts has been estimated by BP Exploration (Alaska) Inc. to be \$262,000,000. Under the terms of the leases and the Department of Natural Resources' regulations, although BP Exploration (Alaska) Inc. did not actually spend the \$262,000,000 in the development accounts, it would be entitled to recover those costs, plus its actual future costs of development, with interest, before it would be obligated to pay the state a share of net profits from the development of the Northstar Unit leases.

(12) Department of Natural Resources Commissioner Shively has testified that "[T]he implications for the state in that is the longer the development is delayed, the less money the state is going to get in net profits leasing. And so timing was critical to me as we negotiated this deal with BP."

(13) BP Exploration (Alaska) Inc.'s president, Mr. John Morgan, has testified "[I]n making that acquisition (purchase of the Northstar leases) we did understand and it was clear to us that the issue of net profit leases represented a problem, and a problem that would need to be overcome with the state, if development was to proceed."

(14) BP Exploration (Alaska) Inc.'s president, Mr. Morgan, also has testified that ". . . part of the risk we took when we acquired the leases was that the State of Alaska may not agree to a modification of the terms that would allow us to go forward with development, and we did that knowingly and clearly."

ARTICLE 3. BP EXPLORATION (ALASKA) INC.'S SUCCESSION
AS NORTHSTAR UNIT OPERATOR AND THE DEPARTMENT OF
NATURAL RESOURCES' APPROVAL OF THE 2ND PLAN OF
DEVELOPMENT FOR THE NORTHSTAR UNIT.

(1) On January 13, 1995, BP Exploration (Alaska) Inc. wrote the Department of Natural Resources and the Minerals Management Service to request that the agencies approve a 90-day extension to the Department of Natural Resources' earlier Notice of Default for the Northstar Unit.

(2) Effective January 19, 1995, then-director Eason approved assignment of the state Northstar Unit leases to BP Exploration (Alaska) Inc. as had been requested earlier, and on January 20, 1995, both then-director Eason of the Department of Natural Resources and the Minerals Management Service approved BP Exploration (Alaska) Inc. as the successor operator of the Northstar Unit.

(3) On January 23, 1995, the day the Northstar Unit was scheduled to terminate under the Department of Natural Resources' Notice of Default for failure of the operator to provide a proposed Plan of Development, BP Exploration (Alaska) Inc., in its capacity as the new unit operator, submitted a proposed two-year Plan of Development for the Northstar Unit. According to documents in the Department of Natural Resources' unit files, BP Exploration (Alaska) Inc. indicated "that with more time it could submit a more detailed and decisive plan."

(4) The following day, on January 24, 1995, then-director Eason of the Department of Natural Resources approved BP Exploration (Alaska) Inc.'s request for a 90-day extension to submit a new plan of development because, according to director Eason, it was "in everyone's best interest to allow BP additional time to conclude its acquisition and to formulate a new Plan of Development." On January 24, 1995, the Minerals Management Service also approved BP Exploration (Alaska) Inc.'s request for an extension to file a more detailed Plan of Development until April 30, 1995.

(5) On March 30, 1995, BP Exploration (Alaska) Inc. submitted a revised and more comprehensive Plan of Development and a request to extend the Northstar Unit Agreement for a three-year term coincident with its revised Plan of Development. Importantly, the revised plan included sanction within the last year. The plan included the following specific activities: (A) data gathering and project development including environmental data gathering and studies, promulgation of marine mammal incidental take regulations, and a cooperative agreement with the Alaska Eskimo Whaling Commission; (B) 3-D seismic acquisition, including the appropriate government permits and seismic processing,

pipeline and facility engineering and reservoir descriptions; (C) project sanction including project construction permits, integrated 3-D seismic and reservoir descriptions, permit approvals, and finally, sanction by BP Exploration (Alaska) Inc.'s headquarters. The revised Plan of Development added the steps required by BP Exploration (Alaska) Inc. to take the Northstar development to project sanction. The estimated cost of these activities was \$12,000,000. In the two-year plan, the estimated cost was \$10,000,000.

(6) The term of the second Plan of Development was increased from the originally proposed two-year term to a three-year term because of increased commitments by BP Exploration (Alaska) Inc.

(7) On May 1, 1995, the Minerals Management Service approved the revised plan concluding that the "new schedule of activities are deemed necessary to bring the unit into production." On June 2, 1995, the Department of Natural Resources "conditionally" approved BP Exploration (Alaska) Inc.'s revised three-year Plan of Development. Division director Ken Boyd approved the plan because, "in his judgment, it was a reasonable one that allowed the new operator, BP Exploration (Alaska) Inc., adequate time to interpret the existing geological, geophysical, and engineering data, shoot what he considered important 3-D seismic data, begin work on development options, define the scope of reservoir/conceptual engineering, and submit permits with the ultimate goal of getting internal BP Exploration (Alaska) Inc. sanction in the fourth quarter of 1997." It was director Boyd's belief that "[t]he plan was tailored to the shortest deadlines that an operator could reasonably be expected to meet." The plan explicitly stated that sanction would "depend on economic competitiveness of the project compared to other BP Exploration (Alaska) Inc. projects worldwide, the business climate (oil price, etc.), and the status of the external permitting processes." It also noted that the risks included "[d]evelopment and production economics."

(8) According to the Department of Natural Resources, "[a]s part of the conditional approval, BPXA was required to submit annual program reports and a final report to the agencies that synthesizes the data and studies performed by BPXA during the extension period and BPXA's conclusions and recommendations regarding the development of the NSU. The POD does not require BPXA to start production during the three year term. Assuming BPXA complies with the conditions of the second POD, the unit will not expire until April 30, 1998."

ARTICLE 4. BP EXPLORATION (ALASKA) INC.'S
INITIAL EFFORTS TO AMEND THE NET PROFIT
SHARE LEASE TERMS.

(1) Both BP Exploration (Alaska) Inc.'s President, Mr. Morgan, and Department of Natural Resources Commissioner Shively have testified that at sometime between January and April 1995, before the Department of Natural Resources' approval of BP Exploration (Alaska) Inc.'s revised Plan of Development and extension for the Northstar Unit, BP Exploration (Alaska) Inc. approached the administration, asking that it support the incorporation of provisions that would allow the commissioner of the Department of Natural Resources to modify net profit share terms of oil and gas leases in the royalty modification legislation that the administration requested last session (HB 207). Mr. Patrick Coughlin, petroleum investment manager for the division of oil and gas, testified that BP Exploration (Alaska) Inc. requested incorporation of the net profit provisions sometime in late January or early March (1995) during the drafting of the original version of HB 207.

(2) Testimony before the committee by both BP Exploration (Alaska) Inc. and the Department of Natural Resources reflects that the parties decided, however, not to pursue authority to amend the terms of net profit share leases in that legislation. According to Commissioner Shively, ". . . I felt, and ultimately I think BP felt, that adding another issue to the mix was probably not appropriate."

(3) Commissioner Shively testified that, after having decided not to pursue incorporation of the net profit share amendment provisions within the framework of HB 207, "he committed to BP at the time to discuss Northstar, but under the conditions that I believed, at the time, that I probably did not have the legal authority to make a deal with them on Northstar. And so therefore, that the individual deal itself would have to come to the legislature. That was always part of the discussions."

(4) Based upon testimony by both Commissioner Shively and BP Exploration (Alaska) Inc.'s Mr. Morgan, it is clear that even had HB 207 been amended to include explicit authority for the commissioner to reduce the state's net profit share under the same circumstances as the commissioner was ultimately authorized to reduce the state's royalty share under the terms of HB 207, to encourage production that otherwise would not be economically feasible, the commissioner could not have done so in this instance because

production from the Northstar Unit is forecast to be economic without amendments to the net profit share provisions.

ARTICLE 5. THE ECONOMICS OF DEVELOPING THE
NORTHSTAR LEASES UNDER THEIR
EXISTING TERMS.

(1) The director of the division of oil and gas, Ken Boyd, has testified that "BPXA currently estimates that 76.8% of the recoverable reserves underlie the state leases in the Northstar Unit (NSU). The Division's Resource Evaluation Group has reviewed this estimate and other confidential estimates, and believes the 75 to 80% is a reasonable range. This range could be slightly higher if BPXA develops the known reserves to the Northwest."

(2) Both the Department of Natural Resources and BP Exploration (Alaska) Inc., have testified that BP Exploration (Alaska) Inc.'s development of the Northstar Unit leases under the original lease terms would be economic. According to BP Exploration (Alaska) Inc.'s President, Mr. Morgan, "[W]e have never argued that the development of Northstar could not be profitable under the terms including the net profit arrangements. In profitability in terms of return on capital, this would be possible. This is not a marginal oil field."

(3) The Department of Natural Resources' independent analysis of the Northstar Unit economics comes to a similar conclusion. Commissioner Shively has testified "[t]oday both we, and I think British Petroleum, estimate that around 135 mm barrels of oil could be recovered from this field. It is not a marginal field; it is not the kind of field we talked about last year with HB 207. It is a field fully capable of carrying its own under the appropriate economic conditions."

(4) BP Exploration (Alaska) Inc.'s President, Mr. Morgan, has testified ". . . that with the net profit arrangement in place, at the level that it exists, BP would not be prepared to go ahead with the development of a Northstar project, even though, if you run the economics, you can show that the return on investment for the project is a sound sort of return on investment."

(5) Based upon BP Exploration (Alaska) Inc.'s own analysis, development of the Northstar project "would have an estimated BP Net Revenue of approximately \$485 million and a full project Rate of Return (ROR) of around 21%."

(6) BP Exploration (Alaska) Inc. has testified that its rate of return for a "hypothetical incremental investment" later in field life (2007) would be 21 percent without the net profit share lease terms versus 10 percent with the net profit share lease terms.

(7) In its September 1995 report to the Governor's Oil and Gas Policy Council entitled "Review of International Competitiveness of Alaska's Fiscal System" (Little Report), the Arthur D. Little Co. concluded "[Oil] companies generally look for a rate of return of about 15% . . . Projects with lower returns usually do not generate enough profits to encourage companies to commit time and resources to their development."

(8) Commissioner Shively testified "I do not believe that no oil company in the world could develop this field under the current provisions. When we did the economic analysis, we believe the rate of return is sufficient for somebody to want to do it. On the other hand, BP has told us that they would not do it, and therefore, I cannot make a finding that under the current situation the development of the field is not economically feasible. It, in my mind, is economically feasible under both considerations. Both of the considerations of the net profits and using the supplemental royalty. BP has said for them it is not developable under the net profit conditions."

(9) Based upon BP Exploration (Alaska) Inc.'s estimates of the recoverable reserves and project development costs, the Northstar Unit has a per barrel development cost of \$2.90. For comparison, other North Slope projects which BP Exploration (Alaska) Inc. has sanctioned (approved and committed the funding to develop), the year in which the developments were sanctioned and BP Exploration (Alaska) Inc.'s estimated per barrel cost of developing each are: Kuparuk (1982) - \$6.65 per barrel; Endicott (1985) - \$5.40 per barrel; Prudhoe Bay Unit: GHX-2 (1992) - \$4.45 per barrel; Pt. McIntyre (1992) - \$2.30 per barrel; and Niakuk (1992) - \$2.50 per barrel.

(10) BP Exploration (Alaska) Inc. estimates the per barrel development costs for both the Milne Point Unit - Schrader Bluff development and the Northstar project, neither of which have yet been sanctioned by BP Exploration (Alaska) Inc. management, to be \$1.80 per barrel, and \$2.90 per barrel, respectively.

ARTICLE 6. REVENUE TRADE-OFFS FROM
THE LEASING OF THE NORTHSTAR LEASES
WITH THE NET PROFIT SHARE AS THE

COMPETITIVE BID VARIABLE.

(1) The decision by the commissioner of natural resources to offer the Northstar Unit leases with the net profit share as the competitive bid variable in 1979 resulted in a trade-off of larger immediate bonus payments for the speculative potential to receive a share of the lessees' net profits from the development of any field subsequently discovered. Since oil and gas exploration is inherently risky, with commercial discoveries occurring far less frequently than dry holes, the commissioner's bid strategy entailed risk sharing with the lessees. Compared to other bidding terms available to the commissioner, the selection of net profit share terms allowed successful bidders to obtain the leases for less cash than would otherwise have been required.

(2) Interpolating revenue received for the federal leases within the Northstar Unit, which were leased with a $16 \frac{2}{3}$ percent sliding scale royalty and the bonus as the bid variable and making many speculative assumptions, the Department of Natural Resources estimates the state's Northstar Unit leases could have brought \$268,406,052, as opposed to the \$15,469,000 actually received, had the leases been offered with a $12 \frac{1}{2}$ percent royalty, no net-profit share and with the bonus as the bid variable.

(3) Assuming the Department of Natural Resources' estimate of bonuses is correct and based upon the annual realized rate of returns reported by the Alaska Permanent Fund Corporation in its 1995 report, the balance of the 50 percent of the \$268,406,052 that would have been deposited to the permanent fund would have been \$704,588,494 at year-end 1995.

(4) The Department of Natural Resources has provided estimates of the expected mean value to a bidder of the Northstar Unit leases. If the Northstar Unit leases were returned at one time to the state for reoffering in a competitive sale with bonus as the bid variable, with royalty set at $12 \frac{1}{2}$ percent or 20 percent, with no net profit share and with estimated recoverable reserves, capital and operating costs as estimated in its economic modeling of the agreement with BP Exploration (Alaska) Inc., the estimated expected mean value, in the view of the Department of Natural Resources, would represent the most a bidder would bid. The Department of Natural Resources further qualifies its estimates by noting that the bidder would have had to make the same economic assumptions about the Northstar Unit leases as were used by BP Exploration (Alaska) Inc. Further, the division of oil and gas has

testified that "if a sale of the Northstar Unit leases were conducted in the future, the division would expect bonus bids to range from a nominal amount to something less than \$225,000,000, depending upon the royalty rate and the discount rate." For a 12 1/2 percent royalty and at discount rates of 10 percent and 15 percent, the Department of Natural Resources estimates that the expected mean value to a bidder would be \$225,000,000 and \$130,000,000, respectively. For a 20 percent royalty and at discount rates of 10 percent and 15 percent, the Department of Natural Resources estimates the mean value of anticipated bonuses would be \$182,000,000 and \$98,000,000, respectively.

ARTICLE 7. BP EXPLORATION (ALASKA) INC.'S
REFUSAL TO DEVELOP THE NORTHSTAR
UNIT LEASES UNLESS THE NET PROFIT
SHARE PROVISIONS ARE AMENDED.

(1) Notwithstanding the acknowledged forecasted profitability of developing the Northstar field under its existing lease terms, BP Exploration (Alaska) Inc.'s President, Mr. Morgan, has testified that BP Exploration (Alaska) Inc. will not develop the Northstar Unit leases unless the State of Alaska agrees to eliminate the net profit share provisions of the leases.

(2) There is no precedent, nor is there explicit legislative authority for the commissioner of natural resources to retroactively change the competitively bid variable of a state oil and gas lease.

(3) The Department of Natural Resources has testified that BP Exploration (Alaska) Inc. did not inform the state of its unwillingness to develop the Northstar Unit leases without amendment of the net profit share terms until some time after the department had approved the current Plan of Development and the three-year extension of the unit term.

(4) The Department of Natural Resources has testified that there is an implied covenant for lessees of Alaska's oil and gas leases to diligently explore and develop their leases. The Department of Natural Resources also has testified, however, that since the department has approved a three-year Plan of Development for the Northstar Unit leases that does not explicitly require development of the field, it believes that so long as BP Exploration (Alaska) Inc. meets the requirements of that plan, it would be seen as fulfilling its obligation to develop, and cannot be forced to proceed with production during the term of the current

plan which does not expire until April 30, 1998.

(5) The Department of Natural Resources has testified that BP Exploration (Alaska) Inc.'s refusal to develop the Northstar Unit leases represents the first occasion in which a state oil and gas lessee has confirmed that it could develop an oil field economically, but that it is unwilling to do so unless the state renegotiates the competitively bid terms of the leases.

(6) The Department of Natural Resources has testified that if the department had not approved a further three-year extension for the Northstar Unit in June 1995, the two leases within the unit that did not have wells upon them certified to be capable of production in paying quantities would have reverted to the state, becoming available for releasing. Under the lease provisions and the regulations, the department could then have given notice to BP Exploration (Alaska) Inc. to begin production from the three leases that did have wells certified as capable of production in paying quantities within a reasonable time to do so, that could not have been less than six months. The department has indicated that it has never previously given such a notice to any lessee and there could be litigation over what constitutes "reasonable time" on the North Slope to put a well into production. Furthermore, the leases provide that the leases with certified wells cannot be terminated without "an appropriate judicial proceeding."

(7) As to why the Department of Natural Resources did not insist on a firm commitment from BP Exploration (Alaska) Inc. last year that it would develop the Northstar Unit leases before the department agreed to extend the Northstar Unit for three years, Commissioner Shivley has testified ". . . [I]f we had all the information in the spring of last year that we had today, we might have made another decision; we did not have that information."

(8) The Department of Natural Resources' approval of the second Plan of Development, and the resulting three-year extension, effectively eliminated any short-term leverage the department might have had otherwise to expedite BP Exploration (Alaska) Inc.'s development of the Northstar Unit leases without amendment of the leases. The Department of Natural Resources believes its approval was in keeping with the department's approval of other Plans of Development in the recent past.

(9) Both the Department of Natural Resources and the Department of Law

have testified that the Department of Natural Resources did not consult with the Department of Law regarding whether the state might have any legal basis for moving earlier than 1998 to force production under the lease terms. The Department of Natural Resources has indicated that it saw nothing unique about this case that would have justified consulting the Department of Law.

ARTICLE 8. THE DEPARTMENT OF NATURAL RESOURCES' AND
BP EXPLORATION (ALASKA) INC.'S NEGOTIATIONS TO AMEND
THE NORTHSTAR UNIT LEASES.

(1) Based upon BP Exploration (Alaska) Inc.'s representation that it would not develop the Northstar Unit leases under their existing terms, the Department of Natural Resources entered into confidential negotiations with BP Exploration (Alaska) Inc. in the fall of 1995 to amend the state's oil and gas lease terms.

(2) As its principal reason for proceeding with the negotiations to amend the leases, the Department of Natural Resources cited its desire to assure that production begins earlier than it otherwise would under the timeline estimated by the Department of Revenue. The Department of Natural Resources maintains that, if the legislature does not pass SB 318, the department could not force BP Exploration (Alaska) Inc. to develop the field until after the expiration of the current Plan of Development.

(3) Department of Natural Resources' Commissioner Shively has testified that, "[t]he negotiations were long--longer than I had hoped. I had hoped to have this agreement to the legislature earlier; they were at times very difficult, but I believe that we have negotiated a deal that is in the best interests of the state."

(4) BP Exploration (Alaska) Inc.'s President, Mr. Morgan, has testified that ". . . I can't stress enough, that from BP's perspective, this was a long and very formal negotiating process, that I don't see the agreement contained in this bill as in any way being an incentive to BP; I see it as a very balanced agreement coming out of that negotiation."

(5) Under the terms of the agreement negotiated by BP Exploration (Alaska) Inc. and the Department of Natural Resources, the state agrees to waive its net profit interest in the leases, and in return is to receive an increased royalty rate on one of the five leases, from 12 1/2 percent to 20 percent, as well as the potential to receive a "supplemental royalty" on all of the leases, depending upon whether oil prices rise sufficiently in the future beyond

a specified threshold (trigger) price. In addition, BP Exploration (Alaska) Inc. has made certain nonbinding commitments to increases in state employment, conditional commitments to construct certain undefined modules, and facilities necessary to develop the Northstar Unit within Alaska and has agreed to relinquish the Northstar Unit leases if BP Exploration (Alaska) Inc.'s management does not sanction the project within one year after the effective date of legislation ratifying amendment of the leases.

ARTICLE 9. LEGAL ANALYSIS BY THE DEPARTMENT OF LAW.

(1) As to whether the commissioner has the authority to amend the state's net profit share lease terms in a situation where those terms were the competitive bid variable in a sale, the Attorney General has testified that "Clearly what we are faced here is with a diminution of revenues that would come to the state . . . and that would require the commissioner in order to make the changes to make a finding that this project otherwise would not be economically feasible. And that was a conclusion which the commissioner would not and could not make. And once again, whether 180 (AS 38.05.180) would apply, in this instance it could not apply. And again, our reasoning supports the need to put this matter before the legislature."

(2) As to whether legislative ratification of a negotiated agreement between the commissioner of the Department of Natural Resources and BP Exploration (Alaska) Inc. to modify the terms of the Northstar Unit leases would violate the Constitution of the State of Alaska's prohibition against local or special legislation, the Department of Law representative has testified that "[I]t will be the department's responsibility to carefully articulate the state's interest during legislative hearings on the bill proposing the net profit share reduction. This must be done with the goal in mind of establishing a detailed legislative history supporting the interests of the state. The legislative history will be important because the ultimate decision 'whether a general act can be made applicable' rests with the Alaska Supreme Court."

(3) The Department of Law representative has testified that "[i]f there is valuable consideration received by both the state and the leaseholder, the benefit to the state may be characterized as direct."

(4) The Department of Law representative has also testified that "[b]ecause the State leased the oil rights at the Northstar field pursuant to the constitutional mandate to obtain the maximum public benefit, an effort to expedite production vitally affects the public

interest."

(5) The Department of Law has also testified "[w]e believe that a compelling case can be made that there is adequate consideration to support a finding of a direct and substantial public benefit flowing from the reduction of the net profit share."

(6) As to whether the promises of local manufacture and assembly of facilities must be binding terms of the Northstar Agreement in order to meet the "statewide significance" test, the Department of Law representative has testified "[t]hat there needs to be a record made here in the legislature of the State interests that are behind this very narrowly focused piece of legislation. As far as the promises to be binding I think it is enough that there's some good and sound reason for this kind of legislation."

(7) The Department of Law representative has testified that "[w]hether the agreement bears fruit I don't think is as important as the fact that you are doing it in good faith belief that it will happen. I don't know if I can tell you that it has to be binding. That's not a consideration of our opinion. It's merely a fact that there must be some sound reasonable basis for making this legislation as narrow as it is."

(8) The Department of Law representative has testified "[w]e think this transaction has state-wide significance because of the amount of revenue that's involved, the fact the major population center of the railbelt area would be the beneficiary of some of the economic activity connected with the development of the Northstar Unit, that fact that petroleum revenues form such a large percentage of the total revenues to the State. It makes this a very good case for being a matter of state-wide significance."

(9) As to whether the expenditures (loss of state revenues) under the Northstar Agreement meet the "public purposes" test under art. IX, sec. 6, of the Alaska Constitution, the Department of Law representative has testified "[i]t's been our opinion in the past that the courts will generally find a public purpose if the legislature declares it to be a public purpose. That's been the reasoning of the courts. From our side, analyzing it even further than that, because we don't like to stop there sometimes being the executive branch. We also analyze it as this mutually of consideration that there has to be some equal exchange in order for there to be a public purpose."

(10) As to the consideration which the state must receive under the Northstar Agreement, the Department of Law representative has testified "[t]here has to be, in order to

satisfy the public purpose doctrine, a direct public benefit and not an indirect public benefit-- when you're giving up public revenues or foregoing some debt that's owed you by some third party. There has to be a direct public benefit and not an indirect benefit. The direct benefit cannot only flow to the other interest and there appears to be direct public benefit here in connection with the way this agreement is structured."

(11) As to whether the consideration which the State expects to receive under the Northstar Agreement actually must be received, the Department of Law representative has testified "[n]o, I don't think so, not under the public purpose doctrine. The public purpose doctrine is the one legal issue that worries me the least. I think this transaction easily passes the public purpose doctrine test. The courts have been very deferential to legislative determinations of what is in the best interests of the State to expend its money on or to forego its revenues on or to receive additional revenues on. The courts have been very deferential in that regard and I don't see that as being a major factor influencing the validity of this particular transaction."

(12) As to whether an aggrieved bidder may have standing to challenge the Department of Natural Resources' negotiated amendments to the competitively bid lease terms, the Department of Law representative has testified "We note that the issue is present, that someone can raise this as a means of attacking the validity of the lease amendments. What we conclude is that if the legislature were to enact specific authorization, both ratifying and approving the contract, and authorizing the department to undertake the lease change, that, we think, would overcome the competitive bidding argument."

(13) The Department of Law representative has testified that "[o]ther persons who competed for the leases may claim that since the net profit share was the sole variable in the lease sale, it is such a material term that a change cannot be made without violating the competitive bidding statute. Uncertainty concerning the state's prospects for prevailing on any litigation on this issue gives an additional basis for our advice that the department seek independent statutory authority for the Northstar transaction."

(14) As to whether the legislature's passage of SB 318 will effectively shield the Department of Natural Resources' negotiated amendments to the Northstar Unit leases from legal challenge, the attorney general has testified "I guess my own judgment on this . . . we can't give you the certainty that absent this kind legislation, we would prevail on the

argument. That's precisely, again, I think one of the reasons we brought this to the legislature, and Jim's (Assistant Attorney General Jim Baldwin) comments earlier about seeing legislative action as being an effective vaccination, as it were, against that kind of challenge."

(15) The attorney general has testified that "[w]ith legislative action, I think we have a high degree of confidence that we would prevail on this issue."

ARTICLE 10. THE DEPARTMENT OF NATURAL RESOURCES' AND
BP EXPLORATION (ALASKA) INC.'S VIEW OF THE LEGISLATURE'S ROLE
IN RATIFICATION AND PASSAGE OF SB 318.

(1) Although both BP Exploration (Alaska) Inc.'s President, Mr. Morgan, and Commissioner Shively have testified that they believe legislative approval of the amendments is necessary, both have confirmed their intent that the legislature's role in reviewing the negotiated amendments should be limited to voting for or against ratification of the agreement that they have negotiated, and should not include amending the terms of the agreement. Commissioner Shively testified "[w]ell, Mr. Chairman, as John Morgan just said, we have presented this as an up or down vote. And we did it for a variety of reasons. One, the negotiations we went through were long and complex. It is late in the session. On the other hand, if there are things that BP believes that they would like to agree to, we will certainly look at them."

(2) BP Exploration (Alaska) Inc.'s President, Mr. Morgan, testified "I have to say that from our perspective, we have in good faith reached a negotiated agreement with the administration, and I believe that any variation of those terms would cast that whole negotiating process into doubt. So it's both my belief that that was the intent of the administration in introducing the bill, and it would certainly be my very strong preference that this should be handled essentially on an approval or disapproval basis, without the introduction of any significant or material changes."

ARTICLE 11. THE EFFECTS OF THE AMENDMENTS ON THE STATE'S SHARE
OF REVENUE FROM THE DEVELOPMENT OF THE NORTHSTAR UNIT.

(1) The Department of Natural Resources cannot precisely define the state's future revenue losses. Commissioner Shively noted that "the only thing we know about all these numbers (the DNR's economic modeling of the effects of amending the NSU leases), is since they are projections, is that they are wrong, we just don't know how wrong."

(2) The Department of Natural Resources' Mr. Coughlin has testified regarding potential state revenue loss that "[i]f you look at it as if they (BP Exploration (Alaska) Inc.) would go ahead and develop it because it's, they say, an economic field, the state loses, in essence, \$48 million by trading a net profit share for the supplemental royalty." Mr. Coughlin has noted on the other hand, if full production does not begin until after 2002, the state could lose money if the amendments are not accepted.

(3) The Department of Natural Resources' representative has testified that its evaluation of the economic consequences to the state of amending the Northstar Unit leases to remove the net profit provisions is based upon the assumption that the "mean" recoverable oil reserves from the Northstar Unit are likely to be 130,000,000 barrels, and that there is a 90 percent probability that recoverable reserves will be greater than 105,000,000 barrels and a 90 percent probability that recoverable reserves will be less than 160,000,000 barrels."

(4) The Department of Natural Resources has testified that its analysis of the economic consequences to the state of amending the Northstar Unit lease terms to remove the net profit provisions is based upon an assumed peak production rate from the field of 50,000 barrels per day.

(5) As to whether the Department of Natural Resources, in the course of its negotiations with BP Exploration (Alaska) Inc. had considered whether to add some sort of corrective factor to the agreement to compensate if the reserves ultimately prove to be considerably larger than estimated, Commissioner Shively has testified "[w]e did have a proposal at one time on the table that would have taken that into account. That's not where we ended up. It was part of a more complicated formula that was developed by our division of oil and gas that was part of one of our counter-offers."

(6) The Department of Natural Resources' petroleum economist, Mr. Kevin Banks, who was responsible for evaluating the economic effects of the Northstar Unit lease amendments, has testified that the negotiated agreement is an "okay" deal rather than a "good" deal for the state. In response to the question of why he characterized the deal as "okay" rather than "good", Mr. Banks, testified "I think it has to do with the fact that the net profit share has considerable up-side for the state. If there's any change in the economics of the field that improves, if prices are considerably higher, for example, or if production is any higher. As some of the materials we sent over to you earlier would indicate, the net profit

share really pours in. By the same token, it's exactly the problem that BP has with it: that for any increase in the "benefits" that might be associated with the higher production rates or higher prices, or some other economic feature, the state gets all of it, virtually all of it. And it has a fairly serious impact on the economics and the incentives for incremental kinds of projects for the company. And that's why I say it's "okay." There is a high side to this that I think we can't ignore." Additionally, Mr. Banks has provided the committee with information that under low side cases, the state's revenues from the net profit share are substantially reduced while the supplemental royalty may still pay something, and the longer the project is delayed, the more likely the payout from the net profit share will be reduced.

ARTICLE 12. THE NONMONETARY TERMS OF THE DEPARTMENT OF
NATURAL RESOURCES/BP EXPLORATION (ALASKA) INC. NEGOTIATED
AMENDMENTS TO THE NORTHSTAR UNIT LEASES AND THE
ENFORCEABILITY OF THOSE TERMS.

(1) As to whether the terms in the negotiated agreement between the Department of Natural Resources and BP Exploration (Alaska) Inc. regarding local hire and local contracting are enforceable, Commissioner Shively has testified "I do not believe we could--that that language allows us to enforce to the extent BP is morally committed to do, and I don't think you can write language to do that."

(2) Although the agreement to amend the Northstar Unit leases purportedly provides for automatic termination of the leases, making them available for releasing under the state's competitive oil and gas leasing program, should BP Exploration (Alaska) Inc. not sanction the project within 12 months, Commissioner Shively has testified that the agreement contains a provision that allows the state to waive the obligation by prior written consent.

(3) The Department of Law has testified that any waiver of BP Exploration (Alaska) Inc.'s commitment to perform under the sanction schedule would have to be done "reasonably and not arbitrarily," and Commissioner Shively has testified "I have no intention of waiving that. I mean that's a very important part of the arrangement, and I mean, I think that if we cannot get this project going, then we need to reassess those leases and get them back out onto the public market."

(4) In response to the question of how would the administration, or a court if the need should arise, measure compliance given the number of disclaimers and qualifiers, and

the lack of any specific performance measures in the agreement, Commissioner Shively has testified "I think we have stated this before. What we are asking BP to do, and what they have committed to do, I do not believe is enforceable by law."

ARTICLE 13. POLICY IMPLICATIONS OF THE PASSAGE OF SB 318.

(1) As to where the state ultimately ends up if, as a matter of precedent, it has to negotiate against itself in other instances to encourage its existing lessees to honor the terms of their competitively bid contracts, Commissioner Shively has testified "[A]ny of these things puts the state in a difficult position. We've, on the other hand, there have been provisions that allow the state to modify lease terms in the law and in the lease since Statehood. This is not a new concept. I was actually just reading an article the other day about the recent leases or arrangements that were made between the Venezuelan government and a number of private companies, and one of the conclusions of that article was that the first thing the companies were going to do down there was go back in and renegotiate their terms. And so, it does put the government in a difficult position. It's why I think in things like this and also like heavy oil, we need to do some economic and other analyses, which we did. But I think in this day and age this is part of how the government manages its resources. But it is not new. We've made changes to the leases before. We have not made changes in this particular way, but we have done these before, and once you start down that road, which we started down years ago, yes, the state does put itself in a difficult position, but not an impossible position."

(2) In response to the question of how the commissioner can test whether, and to what extent the state must give up public resources to promote the development of the state's resources, if, as here, there are no standards and no rules, Commissioner Shively has testified "When you make these decisions, it's like anything else, you have to use your best judgment. I happen to believe that one of the problems with government is that we try to set all of these sorts of rules and guidelines, and it's what makes government unworkable. What you need is people that can make judgments, that can look at difficult situations, assess the information, and say this is a good idea or a bad idea. I see nothing wrong with that. I think that's better government, but this idea that we have now that if you just have enough rules and enough regulations, everything is going to be perfect is nuts. I mean, even the bidding process doesn't necessarily guarantee the state that you get your full value for your resources. You get the most somebody wants to pay for it. That may or may not be full value."

FIRST AMENDMENT TO THE NORTHSTAR UNIT LEASES BETWEEN THE STATE
OF ALASKA AND BP EXPLORATION (ALASKA) INC.

The State of Alaska ("State") and BP Exploration (Alaska) Inc. ("BPXA") are parties to the following leases in the Northstar Unit: ADL 312798, effective February 1, 1980; ADL 312799, effective February 1, 1980; ADL 312808, effective February 1, 1980; and ADL 312809, effective February 1, 1980 (collectively the "1980 Leases"); as well as ADL 355001, effective August 1, 1983 (the "1983 Lease"). The parties agree to amend the 1980 Leases and the 1983 Lease as set forth in this first amendment to the Northstar Unit leases.

1980 Leases

1) Paragraph 6(b) is replaced in its entirety as follows:

(b) Annual rental paid in advance is a credit on the royalty or supplemental royalty due under this lease for that year.

2) Paragraph 7 is replaced in its entirety as follows:

7. SUPPLEMENTAL ROYALTY. (a) In addition to the royalty paid and computed under paragraphs 8, 10, and 11 below, Lessee shall pay to the State a supplemental royalty ("supplemental royalty"). Lessee shall pay the supplemental royalty, if owed, upon the same production volume for which royalty is paid ("production volume"). The supplemental royalty payment for a given month equals the supplemental royalty value times the supplemental royalty percentage rate ("percentage rate") times the production volume for that month. The percentage rate shall be calculated monthly by reference to: (1) an ANS West Coast spot price ("spot price"); and (2) a supplemental royalty trigger price ("trigger price"). If the spot price is equal to or less than the trigger price, then the percentage rate equals zero. If the spot price is greater than the trigger price, then the percentage rate equals [the spot price per barrel minus the

trigger price per barrel] times 1.5 per cent per dollar per barrel. The percentage rate may never exceed 7.5 per cent.

(b) The spot price is the price per barrel calculated in Article 3.3 of and Exhibit 4 to the ANS Royalty Litigation Settlement Agreement ("ANS Agreement"), dated December 31, 1991, between the State and BPXA, for the crude oil referred to as "ANS (USWC)" in the ANS Agreement. The trigger price is \$17.35 per barrel through April 30, 1997. On May 1, 1997, and each May 1 thereafter, the trigger price shall be adjusted by an inflation factor equal to fifty percent of the "inflation rate" defined as the Producer Price Index for Industrial Commodities ("PPI") for December of the previous year, as reported by April 30 of the current year, divided by the PPI for December of 1995, as reported by April 30, 1996. The supplemental royalty value for oil, gas, natural gas liquids and associated substances is defined in paragraphs 10 and 11 below. Exhibit B is a sample calculation to demonstrate the method of calculating supplemental royalty for oil.

3) Paragraph 9 is replaced in its entirety as follows:

9. REDUCTION OF ROYALTY. Except as provided in paragraph 7 above, Lessee shall not be entitled to any reduction of royalty paid under paragraph 8 above or supplemental royalty paid under paragraph 7 above based on any current or future agreement, State statute, or State regulation.

4) Paragraph 10 is replaced in its entirety as follows:

10. ROYALTY IN VALUE. Unless the State elects to receive all or a portion of its royalty or supplemental royalty in kind as provided in paragraph 12 below, Lessee shall pay to the State the value of all royalty and supplemental royalty oil, gas and associated substances as determined under paragraph 11 below. Royalty and supplemental royalty paid in value shall be free and clear of all lease expenses (and any portion of such expenses which is incurred away from the leased area), including, but not limited to, expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area. All royalty and supplemental royalty that may become payable in money to the State shall be paid on or before the last day of the calendar month following the month in which the oil, gas or associated substances are produced. Royalty and supplemental royalty payments shall be accompanied by copies of run tickets or such other information relating to valuation of royalty and supplemental royalty as the State may require, which may include, but is not limited to, evidence of sales, shipments, and amounts of gross oil, gas and associated substances produced.

- 5) Paragraph 11 is replaced in its entirety as follows:

11. VALUE. For purposes of computing supplemental royalty due under this lease, the value of supplemental royalty oil, gas, natural gas liquids and associated substances shall be the value used in computing royalty on said substances.

(a) To compute the value of oil for royalty and supplemental royalty purposes, this lease shall be deemed an "ANS Lease" under the terms of the ANS Agreement, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(b) To compute the value of gas and natural gas liquids for royalty and supplemental royalty purposes, this lease shall be deemed a "Lease" under the terms of the 1995 ANS Gas Royalty Litigation Settlement Agreement between BPXA and the State dated as of April 1, 1995, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(c) To compute the value of associated substances (which shall be deemed to exclude oil, gas, and natural gas liquids) for royalty and supplemental royalty purposes, the value of such associated substances shall not be less than the highest of:

(1) the field price actually received by Lessee for such associated substances;

(2) Lessee's posted price in the field for such associated substances;

(3) the volume weighted average field price actually received by other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area; or

(4) the volume weighted average posted price in the field of other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area.

If associated substances are sold away from the leased or unit area, the term "field price" above shall be the actual price for such associated substances received from the purchaser thereof less the actual cost of transportation away from the leased or unit area to the point of delivery.

Minimum Value Determinations. The State may establish minimum values for purposes of computing royalties on associated substances obtained from this lease, with consideration being given to the price actually received by Lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by Lessee and/or other producers from

sales occurring away from the leased area, and to other relevant matters. Each such determination will be made only after Lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty associated substances under this lease may not necessarily equal the price of such associated substances.

- 6) The following provision shall be added to the end of paragraph 12:

(e) Supplemental royalty under paragraph 7 above may be taken in kind under the same terms and conditions as royalty may be taken in kind under this paragraph 12.

- 7) Paragraph 14 is replaced in its entirety as follows:

14. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The landowner's royalty and supplemental royalty share of the unit production allocated to each separately owned tract shall be regarded as royalty to be distributed to and among, or the proceeds of it paid to, the landowners, free and clear of all unit expense and free of any lien for it. Under this provision, the State's royalty and supplemental royalty share of any unit production allocated to the leased area shall be regarded as royalty to be distributed to, or the proceeds of it paid to, the State, free and clear of all unit expenses (and any portion of such expenses which is incurred away from the unit area), including, but not limited to, expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing oil, gas or associated substances for transportation off the unit area, and free of any lien for it.

- 8) Paragraph 28 (c) is added as follows:

(c) Notwithstanding any other provisions of this lease, the Northstar Unit Agreement, State statute, or State regulation, this lease shall terminate automatically without notice, an opportunity to be heard, or judicial proceeding, if the Lessee fails to comply with the project schedule set forth in Exhibit C ("project schedule"), attached and incorporated by reference. Automatic termination shall occur whether or not there is a well on the leased area capable of producing oil or gas in paying quantities, the lease is committed to a unit agreement, or the Lessee is drilling or conducting reworking operations, on the date performance under the schedule is due. Furthermore, upon termination BPXA shall promptly file of record appropriate lease relinquishments. The automatic termination shall occur at 11:59 P.M., Alaska Time, on the day performance of an obligation under the project schedule is due. The State may waive performance of an obligation required under the project schedule by prior written consent. The performance of any obligation

required under the project schedule is subject to the provisions of paragraph 32.

- 9) Paragraph 32 is replaced in its entirety as follows:

32. **FORCE MAJEURE.** If the State determines that Lessee has been prevented, after diligent efforts made in good faith, from complying with any express or implied promise, term, condition or covenant of this lease, from conducting drilling operations, or from producing or marketing oil or gas from the leased area, by reason of war, riots, acts of God, unusually severe weather, or any other cause beyond Lessee's reasonable ability to foresee or control (including delays caused by judicial decision or lack thereof or inability to obtain local, State, or federal permits or environmental impact statements), whether similar to those enumerated or not, Lessee's obligation to comply with such provision shall be suspended, but not voided, and Lessee shall not be liable for damages for failure to comply therewith. If Lessee's obligations to conduct drilling or reworking operations are suspended under this paragraph and the continuation of such operations without suspension would have had the effect of preventing the expiration or termination of this lease, this lease shall not terminate during the period which the obligation to perform such operations is suspended. Nothing in this paragraph shall be construed to suspend the obligation to pay rentals, or to suspend the obligation to pay royalties, supplemental royalties or other production payments from operations on the lease area which are not suspended or from operations which are not affected by any such suspension, to the State.

- 10) Paragraph 41 is replaced in its entirety as follows:

41. **EMPLOYMENT OF ALASKAN RESIDENTS.** Lessee shall comply with all valid federal, State and local laws in hiring Alaska residents and contractors and shall not discriminate against Alaska residents or contractors. Within the constraints of law, Lessee shall employ Alaska residents and contractors to the extent they are available and qualified. Subject to the foregoing:

Lessee voluntarily agrees to adopt a program to hire residents of Alaska. Lessee shall advertise for available positions locally and use Alaska job service organizations to notify the Alaskan public. For work in connection with this lease, Lessee shall use best efforts to contract with Alaska firms and fabricate modules in Alaska, whenever feasible. Lessee shall encourage its contractors to employ and train, when necessary, residents of Alaska. In determining feasibility, Lessee shall consider commercial, health, safety, and environmental conditions and requirements to ensure maintenance of Lessee's operational standards. Lessee shall submit annually to the Director, Division of Oil and Gas, for transmission to the Department of

Labor, a report that details the specific measures Lessee and its contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, describes on-the-job training opportunities, and describes Lessee's efforts to hire Alaska firms for work in connection to this lease. Lessee shall furnish the Department of Labor a quarterly report regarding the employment of Alaska residents on the leased area in compliance with regulations by the Commissioner of Labor. The report must also include statistical data concerning the number of resident personnel hired within the past year for this lease.

1983 Lease

1) Paragraph 4(f) and paragraph 34(7) are deleted and replaced in their entirety with the following paragraph 4(f):

(f) FORCE MAJEURE. If the state determines that lessee has been prevented, after diligent efforts made in good faith, from complying with any express or implied promise, term, condition or covenant of this lease, from conducting drilling operations, or from producing or marketing oil or gas from the leased area, by reason of war, riots, acts of God, unusually severe weather, or any other cause beyond lessee's reasonable ability to foresee or control (including delays caused by judicial decision or lack thereof or inability to obtain local, state, or federal permits or environmental impact statements), whether similar to those enumerated or not, lessee's obligation to comply with such provision shall be suspended, but not voided, and lessee shall not be liable for damages for failure to comply therewith. If lessee's obligations to conduct drilling or reworking operations are suspended under this paragraph and the continuation of such operations without suspension would have had the effect of preventing the expiration or termination of this lease, this lease shall not terminate during the period which the obligation to perform such operations is suspended. Nothing in this paragraph shall be construed to suspend the obligation to pay rentals, or to suspend the obligation to pay royalties, supplemental royalties or other production payments from operations on the lease area which are not suspended or from operations which are not affected by any such suspension, to the state.

2) Paragraph 5(b) is replaced in its entirety as follows:

(b) Annual rental paid in advance is a credit on the royalty or supplemental royalty due under this lease for that year.

- 3) Paragraph 7 is replaced in its entirety as follows:

7. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The state's royalty and supplemental royalty share of the unit production allocated to each separately owned tract must be regarded as royalty to be distributed to or among, or the proceeds of it paid to, the state, free and clear of all unit expenses and free of any lien for them. Under this provision, the state's royalty and supplemental royalty share of any unit production allocated to the leased area will be regarded as royalty to be distributed to, or the proceeds of it paid to, the state, free and clear of all unit expenses (and any portion of those expenses incurred away from the unit area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, and preparing oil, gas, or associated substances for transportation off the unit area, and free of any lien for them.

- 4) A new paragraph 20(c) is added as follows:

(c) Notwithstanding any other provisions of this lease, the Northstar Unit Agreement, state statute, or state regulation, this lease shall terminate automatically without notice, an opportunity to be heard, or judicial proceeding, if the lessee fails to comply with the project schedule set forth in Exhibit C ("project schedule"), attached and incorporated by reference. Automatic termination shall occur whether or not there is a well on the leased area capable of producing oil or gas in paying quantities, the lease is committed to a unit agreement, or the lessee is drilling or conducting reworking operations, on the date performance under the schedule is due. Furthermore, upon termination BPXA shall promptly file of record appropriate lease relinquishments. The automatic termination shall occur at 11:59 P.M., Alaska Time, on the day performance of an obligation under the project schedule is due. The state may waive performance of an obligation required under the project schedule by prior written consent. The performance of any obligation required under the project schedule is subject to the provisions of paragraph 4(f).

- 5) Paragraph 31 is replaced in its entirety as follows:

31. EMPLOYMENT OF ALASKAN RESIDENTS. Lessee shall comply with all valid federal, state and local laws in hiring Alaska residents and contractors and shall not discriminate against Alaska residents or contractors. Within the constraints of law, lessee shall employ Alaska residents and contractors to the extent they are available and qualified. Subject to the foregoing:

Lessee voluntarily agrees to adopt a program to hire residents of Alaska. Lessee shall advertise for available positions locally and use Alaska job

service organizations to notify the Alaskan public. For work in connection with this lease, lessee shall use best efforts to contract with Alaska firms and fabricate modules in Alaska, whenever feasible. Lessee shall encourage its contractors to employ and train, when necessary, residents of Alaska. In determining feasibility, lessee shall consider commercial, health, safety, and environmental conditions and requirements to ensure maintenance of lessee's operational standards. Lessee shall submit annually to the Director, Division of Oil and Gas, for transmission to the Department of Labor, a report that details the specific measures lessee and its contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, describes on-the-job training opportunities, and describes lessee's efforts to hire Alaska firms for work in connection to this lease. Lessee shall furnish the Department of Labor a quarterly report regarding the employment of Alaska residents on the leased area in compliance with regulations by the Commissioner of Labor. The report must also include statistical data concerning the number of resident personnel hired within the past year for this lease.

6) Paragraph 35 is replaced in its entirety as follows:

35. ROYALTY ON PRODUCTION. Except for oil, gas, and associated substances used on the leased area for development and production or unavoidably lost, the lessee shall pay to the state as a royalty 20 percent in amount or value of the oil, gas, and associated substances saved, removed, or sold from the leased area and of the gas used on the leased area for extraction of natural gasoline or other products from the leased area.

7) Paragraph 36 is replaced in its entirety as follows:

36. VALUE. For purposes of computing supplemental royalty due under this lease, the value of supplemental royalty oil, gas, natural gas liquids, and associated substances shall be the value used in computing royalty on said substances.

(a) To compute the value of oil for royalty and supplemental royalty purposes, this lease shall be deemed an "ANS Lease" under the terms of the ANS Agreement, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(b) To compute value of gas and natural gas liquids for royalty and supplemental royalty purposes, this lease shall be deemed a "Lease" under the terms of the 1995 ANS Gas Royalty Litigation Settlement Agreement between BPXA and the State dated as of April 1, 1995, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(c) To compute the value of associated substances (which shall be deemed to exclude oil, gas, and natural gas liquids) for royalty and supplemental royalty purposes, the value of such associated substances shall not be less than the highest of:

(1) the field price actually received by lessee for such associated substances;

(2) Lessee's posted price in the field for such associated substances;

(3) the volume weighted average field price actually received by other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area; or

(4) the volume weighted average posted price in the field of other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area.

If associated substances are sold away from the leased or unit area, the term "field price" above shall be the actual price for such associated substances received from the purchaser thereof less the actual cost of transportation away from the leased or unit area to the point of delivery.

Minimum Value Determinations. The state may establish minimum values for purposes of computing royalties on associated substances obtained from this lease, with consideration being given to the price actually received by lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by lessee and/or other producers from sales occurring away from the leased area, and to other relevant matters. Each such determination will be made only after lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty associated substances under this lease may not necessarily equal the price of such associated substances.

8) Paragraph 37 is replaced in its entirety as follows:

37. ROYALTY IN VALUE. Unless the state elects to receive all or a portion of its royalty or supplemental royalty in kind as provided in paragraph 38, lessee shall pay to the state the value of all royalty and supplemental royalty oil, gas and associated substances as determined under paragraph 36. Royalty and supplemental royalty paid in value shall be free and clear of all lease expenses (and any portion of such expenses which is incurred away from the leased area), including, but not limited to, expenses for separation, cleaning

dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area. All royalty and supplemental royalty that may become payable in money to the state shall be paid on or before the last day of the calendar month following the month in which the oil, gas or associated substances are produced. Royalty and supplemental royalty payments shall be accompanied by copies of run tickets or such other information relating to valuation of royalty and supplemental royalty as the state may require, which may include, but is not limited to, evidence of sales, shipments, and amounts of gross oil, gas and associated substances produced.

- 9) The following provision shall be added to the end of paragraph 38:

(f) Supplemental royalty under this lease may be taken in kind under the same terms and conditions as royalty may be taken in kind under this paragraph 38.

- 10) Paragraph 39 is replaced in its entirety as follows:

39. REDUCTION OF ROYALTY. Except as provided in paragraph 40 below, lessee shall not be entitled to any reduction of royalty paid under paragraph 35 above or supplemental royalty paid under paragraph 40 below based on any current or future agreement, state statute, or state regulation.

- 11) Paragraph 40 is replaced in its entirety as follows:

40. SUPPLEMENTAL ROYALTY. (a) In addition to the royalty paid and computed under paragraph 35, 36, 37 above, lessee shall pay to the state a supplemental royalty ("supplemental royalty"). Lessee shall pay the supplemental royalty, if owed, upon the same production volume for which royalty is paid ("production volume"). The supplemental royalty payment for a given month equals the supplemental royalty value times the supplemental royalty percentage rate ("percentage rate") times the production volume for that month. The percentage rate shall be calculated monthly by reference to: (1) an ANS West Coast spot price ("spot price"); and (2) a supplemental royalty trigger price ("trigger price"). If the spot price is equal to or less than the trigger price, then the percentage rate equals zero. If the spot price is greater than the trigger price, then the percentage rate equals [the spot price per barrel minus the trigger price per barrel] times 1.5 per cent per dollar per barrel. The percentage rate may never exceed 7.5 per cent.

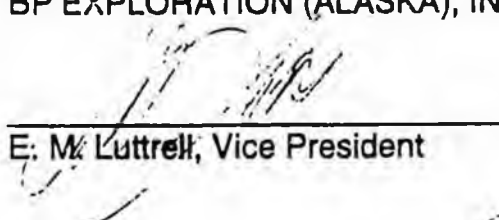
(b) The spot price is the price per barrel calculated in Article 3.3 of and Exhibit 4 to the ANS Royalty Litigation Settlement Agreement ("ANS Agreement"), dated December 31, 1991, between the State and BPXA, for the crude oil referred to

as "ANS (USWC)" in the ANS Agreement. The trigger price is \$17.35 per barrel through April 30, 1997. On May 1, 1997, and each May 1 thereafter, the trigger price shall be adjusted by an inflation factor equal to fifty percent of the "inflation rate" defined as the Producer Price Index for Industrial Commodities ("PPI") for December of the previous year, as reported by April 30 of the current year, divided by the PPI for December of 1995, as reported by April 30, 1996. The supplemental royalty value for oil, gas, natural gas liquids and associated substances is defined in paragraphs 36 and 37 above. Exhibit B is a sample calculation to demonstrate the method of calculating supplemental royalty for oil.

These amendments do not affect: (1) any future agreements which may be reached for the handling of outside substances as that term is used in the Northstar Unit Agreement effective January 24, 1990 or (2) the current valuation methodology for royalty for any other Alaska Net Profit Share leases between the State and BPXA or any affiliates or any future agreements which may be reached regarding a future valuation methodology for Alaska Net Profit Share leases. These amendments take effect when and if an Act(s) substantially similar to the act, attached as Exhibit D and incorporated by reference, takes effect. This amendment is dated for reference purposes as of March 22, 1996.

LESSEE: —

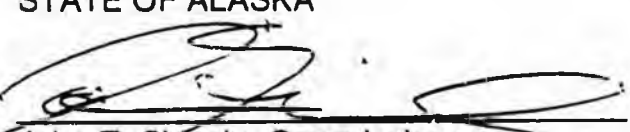
BP EXPLORATION (ALASKA), INC.



E. M. Luttrell, Vice President

LESSOR:

STATE OF ALASKA



John T. Shively, Commissioner
Department of Natural Resources

STATE OF ALASKA)
) ss.
Third Judicial District)

On March 22, 1996, before me appeared John T. Shively, Commissioner, State of Alaska, Department of Natural Resources, and who executed this lease and acknowledged voluntarily signing it on behalf of the State of Alaska, as lessor.

Dianne A. Pitts
Notary Public in and for the State of Alaska
My Commission Expires: 1/16/99



STATE OF ALASKA)
) ss.
Third Judicial District)

On March 22, 1996, before me appeared E. M. Lutrell, Vice President of BP Exploration (Alaska), Inc., and who executed this lease and acknowledged voluntarily signing it on behalf of the BP Exploration (Alaska), Inc., as lessee.

Dianne A. Pitts
Notary Public in and for the State of Alaska
My Commission Expires: 1/16/99



Exhibit B
Calculation of the Supplemental Royalty Payment for Oil

1) The calculation of the ANS West Coast spot price is derived from Platt's "Oilgram Price Report" Spot Crude Price Assessments:

Date	Platt's Reported Daily Assessment (\$/barrel)		ANSWC Daily Average	ANSWC Daily Average (After Rounding) ¹
	ANSWC Low	ANSWC High		
01/02/96	\$17.97	\$18.06	\$18.015	\$18.02
01/03/96	\$17.94	\$18.03	\$17.985	\$17.98
01/04/96	\$17.96	\$18.03	\$17.995	\$18.00
01/05/96	\$18.60	\$18.64	\$18.620	\$18.62
01/09/96	\$18.23	\$18.29	\$18.260	\$18.26
01/10/96	\$17.99	\$18.05	\$18.020	\$18.02
01/11/96	\$17.10	\$17.17	\$18.135	\$17.14
01/12/96	\$16.64	\$16.71	\$18.675	\$16.68
01/15/96	\$16.75	\$16.83	\$16.690	\$16.79
01/16/96	\$16.60	\$16.66	\$16.730	\$16.63
01/17/96	\$16.91	\$16.97	\$16.940	\$16.94
01/18/96	\$17.46	\$17.54	\$17.500	\$17.50
01/19/96	\$17.28	\$17.37	\$17.325	\$17.32
01/22/96	\$17.02	\$17.08	\$17.050	\$17.05
01/23/96	\$17.10	\$17.16	\$17.150	\$17.13
01/24/96	\$17.35	\$17.41	\$17.380	\$17.38
01/25/96	\$16.76	\$16.81	\$17.785	\$16.78
01/26/96	\$16.43	\$16.53	\$17.480	\$16.48
01/29/96	\$16.16	\$16.24	\$16.200	\$16.20
01/30/96	\$16.30	\$16.38	\$16.340	\$16.34
01/31/96	\$16.46	\$16.56	\$16.510	\$16.51

Monthly Average calculated from ANSWC Daily Average (After Rounding) = \$17.2271 per barrel

ANS West Coast spot price for the January 1996 month of production = \$17.23 per barrel

2) The inflation factor shall be calculated as follows: Assume that by April 30, 1996, the U.S. Department of Labor reports a PPI for December 1995 as 126.2. Assume that by April 30, 1998, the PPI for December 1997 is 134.2. The inflation factor for 1998 is calculated according to the following formula:

¹ All source and calculated numbers shall be rounded as required in the ANS Agreement.

Inflation Factor for May 1, 1998 through April 30, 1999

$$= [(PPI \text{ December of the previous year} \div PPI \text{ December 1995}) - 1] \times 0.5$$

$$= [(134.2 \div 126.2) - 1] \times 0.5 = 0.0317 = 3.17 \text{ percent}$$

3) The trigger price for May 1, 1998 through April 30, 1999 is calculated by adjusting \$17.35 per barrel by the inflation factor as follows:

$$\text{Trigger price for the current year} = \$17.35 \text{ per barrel} \times (1 + \text{inflation factor})$$

$$= \$17.35 \text{ per barrel} \times (1 + 3.17 \text{ percent})$$

$$= \$17.35 \times 1.0317$$

$$= \$17.90 \text{ per barrel}$$

4) Assuming the current month ANSWC spot price is \$21.40, the supplemental royalty percentage rate is calculated as:

$$\text{Supplemental royalty percentage rate} = (\text{ANSWC spot price} - \text{trigger price for the current year}) \times (1.5 \text{ percent per dollar per barrel})$$

$$= (\$21.40 \text{ per barrel} - \$17.90 \text{ per barrel}) \times 1.5 \text{ percent per dollar per barrel}$$

$$= (21.40 - 17.90) \times 0.015$$

$$= 0.05250 = 5.25 \text{ percent}$$

5) The calculation of the supplemental royalty payment for the current month is the product of the production volume times the royalty value and the supplemental royalty percentage rate. Assume that 1,550,000 barrels of oil were produced in the Northstar unit in the current month and that the royalty value is \$17.71. The supplemental royalty is:

$$\text{Supplemental royalty payment} = \text{production volume} \times \text{royalty value} \times \text{supplemental royalty percentage rate}$$

$$= 1,550,000 \text{ barrels} \times \$17.71 \text{ per barrel} \times 5.25 \text{ percent}$$

$$= \$1,441,151.25$$

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.

TONY KNOWLES
GOVERNOR



F. O. Box 110001
Juneau, Alaska 99811-0001
(907) 465-3500
Fax (907) 465-3532

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

March 25, 1996

The Honorable Drue Pearce
President of the Senate
Alaska State Legislature
State Capitol
Juneau, AK 99801-1182

Dear President Pearce:

Under the authority of art. III, sec. 18, of the Alaska Constitution, I am transmitting a bill providing for legislative authorization, approval, and ratification of the "First Amendment to the Northstar Unit Leases Between the State of Alaska and BP Exploration (Alaska) Inc."

This project is the beginning of a new era in the development of Alaska's oil resources. It requires a new commitment to Alaska hire, expands opportunities for Alaskan companies, introduces efficient and safe technological innovations and brings new revenues to Alaskans.

The Northstar Unit leases currently require BP Exploration (Alaska) Inc. to make net profit share payments to the state which average about 88% of "net profits." BP Exploration (Alaska) Inc. maintains that it can not develop the Northstar Unit unless the net profit share requirements are eliminated from the leases. The Department of Natural Resources believes that 2002 is the earliest the state might achieve development of Northstar. The longer it takes to develop the leases, the less the state receives because of the development account provisions of the net profit share leases. The incentives provided in this amendment would bring the Northstar Unit into full production by 1999.

The amendment has three main components. First, it eliminates the net profit share payments. In place of the net profit provision a supplemental royalty is required, payable on a sliding scale based on the price of oil, partially adjusted for inflation. This supplemental royalty, which can be as much as 7½%, is in addition to the 20% base royalty required under the leases. Development of these leases will generate an estimated \$430 million or more to the state treasury from royalties and taxes, including an estimated \$37 million in supplemental royalties.

Second, the amendment commits BP Exploration (Alaska) Inc. to an ambitious project schedule that requires construction start-up by 1997. If BP Exploration (Alaska) Inc. fails to perform its obligations under the project schedule the leases terminate automatically, thereby allowing the state to lease the tracts to another company.

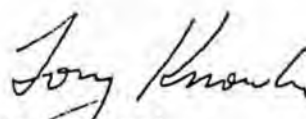
And third, the amendment replaces the current Alaska hire provisions in the leases with more forceful provisions that require BP Exploration (Alaska) Inc. to hire Alaskans, within the constraints of the law, and to contract with local construction and fabrication companies to build the project facilities. It is anticipated that enactment of this bill will generate 500 construction jobs and 50 permanent jobs in the state. It will result in Alaska companies fabricating production modules, including one or more of the first sealift modules ever constructed in Alaska.

I am requesting legislative approval of the Northstar amendment for two reasons. First, the terms of this amendment involve issues of statewide interest and impact that deserve a thorough and open public review and discussion.

Second, the bill would remove any legal cloud which may exist over the Administration's authorities in this matter by providing the commissioner of the Department of Natural Resources with sufficient express authority to amend the leases in the way we have amended them here. This will ensure that the project can proceed expeditiously and maximize the benefits to the state and the people of Alaska.

I urge your prompt and favorable action on the bill.

Sincerely,


Tony Knowles
Governor

SENATE COMMITTEE REPORT

First Committee of Referral

DATE: 3/28/96

FURTHER: Finance

Date of 5-Day Notice: 3-28-96
(in accordance with Uniform Rule 23)

DATE TURNED INTO OFFICE: 4-25-96

The Resources Committee considered SB 318

Authorizing, approving, and ratifying the amendment of Northstar Unit oil and gas leases between the State of Alaska and BP Exploration (Alaska) Inc.; efd.

and recommends:

- be replaced with SR 318 CS SR 318 (RET)
- adopt previous _____ CS _____ (_____)
- attached amendment(s)
- adopt Letter of Intent by _____ Committee
- further referral to the _____ Committee

- Senate Bill:**
- same title
 - new title
- House Bill:**
- same title
 - technical title
 - new: SCR# _____

SIGNING DO PASS	DP	OTHER RECOMMENDATIONS	NR	DNP	AM
		<i>Kirk Halford</i>	✓		
		<i>Demetrius</i>		✓	
		<i>Adrian Frank</i>	✓		
		<i>Robert Taylor</i>		✓	
		<i>Irue</i>	✓		
CHAIR: <i>Tom A. Luman</i>	✓	CHAIR:			

NEW FISCAL NOTE(S):

Department	Date	Zero	Fiscal

PREVIOUS FISCAL NOTE(S):*

Department	Date	Zero	Fiscal

APPROPRIATION -- no fiscal note

*include fiscal notes accompanying Governor's bill

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

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


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

MEMORANDUM

April 23, 1996

SUBJECT: Ripeness for litigation of Senate Bill 318, approving modification of Northstar Unit leases between the State and B.P. Exploration (Alaska)

TO: Senator Loren Leman, Chair
Senate Resources Committee

FROM: Jack Chenoweth
Legislative Council 

The second paragraph of Jim Eason's April 22 letter relates:

I believe that litigation ratifying the agreement to amend the leases with a delayed effective date would be ripe for litigation when signed by the governor. . . .

His conclusion that a challenge to a law may properly be brought and maintained once the bill is enacted--that is, once the final act has been taken by which a measure becomes law--is supported by the weight of case law in other jurisdictions,^{1/} and the Alaska Supreme Court has not concluded otherwise.^{2/}

In this jurisdiction, under AS 01.10.070(f)(4):

^{1/} State ex rel. Richards v. Whisman, 154 N.W. 707 (S.Dak. 1915), error dismissed, 241 U.S. 643, 36 S.Ct. 449, 60 L.Ed. 1218 (1916), Anderson v. Byrne, 242 N.W. 687, 692 - 693 (N.Dak. 1932), Drockton v. Board of Elections, 240 N.E.2d 896, 901 (Ohio Common Pleas, 1968), citing City of Cincinnati v. Hillenbrand, 132 N.E. 556, 558 - 560 (Ohio 1921), City of North Las Vegas v. Cluff, 452 P.2d 461, 462 (Nev. 1969).

^{2/} In ARCO Alaska, Inc. v. State of Alaska, 824 P.2d 708 (Alaska 1992), a challenge to retroactive amendment of the ELF (economic limit factor) used in the calculation of oil production taxes was filed July 28, 1989, challenging legislation that had been enacted May 8, 1989, but which was not due to become effective until August 6, 1989. The litigation, filed by plaintiff oil companies after the bill's enactment but before its actual effective date, proceeded through to final resolution.

Senator Loren Lemman

April 23, 1996

Page 2

"becomes law" means is enacted; "enactment" occurs when any one of the following takes place:

(A) a bill which is passed by the legislature is signed by the governor;

(B) the period specified in article II, section 17 of the Alaska Constitution expires without gubernatorial action;

(C) the legislature overrides the governor's veto of a bill.

JBC:pl:klb

96-134.plm



Alaska State Legislature


Senate Resources Committee

Official Business

Memo

State Capitol
Juneau AK 9

TO: Tam Cook, Director
Legal Services

FROM: Annette Kreitzer, Aide to 
Senate Resources Committee

DATE: April 22, 1996

RE: Written Opinion re: SB 318

Please provide written confirmation of the time when you believe an aggrieved party would be able to file litigation challenging the legislature's ratification of an agreement to amend the Northstar Unit leases under the terms of CSSB 318. Would a party have to wait until the delayed effective date, or would the Act be ripe for challenge after signing by the governor?

To assist in answering this question I've attached a memo from Jim Eason to Senator Leman and a letter from E.M. Luttrell of BP addressing the subject.

James E. Eason

Oil and Gas Operations, Management and Policy

3611 Leeper Circle • Anchorage, AK 99504-4209
Phone: (907) 337-3515 • Fax: (907) 333-9087

April 22, 1996

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

Dear Senator Leman:

By letter dated April 20, 1996, Mr. Eric Luttrell reconfirmed that BP Exploration (Alaska) Inc. (BPXA) is unwilling to reopen the negotiations of the Northstar Unit lease amendments as contemplated in CSSB 318. In your decision of whether or not to require amendments of the agreement, particularly any amendments of the effective date, you should be aware that Mr. Luttrell's concern, that delaying the effective date will delay the opportunity to defend the agreement against any lawsuits that may result, may be unfounded.

I believe that legislation ratifying the agreement to amend the leases with a delayed effective date would be ripe for litigation when signed by the governor. If that is the case, an aggrieved party would not have to delay filing of a lawsuit until "the first day following delivery of a letter from the commissioner of natural resources to the revisor of statutes, with copies to the president of the senate and the speaker of the house of representatives confirming that BP Exploration (Alaska) Inc. or its parent entity has made an irrevocable commitment of full funding (project sanction) to develop the Northstar Oil Field."

What does change, under the original effective date and the language allowing force majeure events, including litigation, to delay sanction, is the sharing of risk if litigation is filed. With the combination of an immediate effective date and the ability to claim force majeure, BPXA will have the right to the amended lease terms—no net profit share obligation—and a contractual defense against the one year "take it or leave it" provision of the agreement. If there is delay from litigation, the principal benefit which the state has supposedly bargained for—expedited development—is lost. More to the point, it would be lost because of litigation challenging the very action supposedly necessary to secure the benefit—legislative ratification.

Sincerely,



James E. Eason

**BP EXPLORATION**

Luttrell
Vice President
Exploration, Alaska

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-5812
(907) 564-4892

April 20, 1996

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

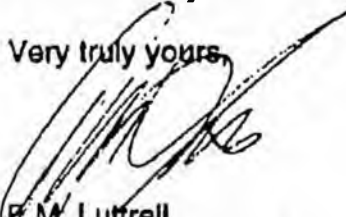
Dear Senator Lemman:

I appreciate the opportunity to comment further on the Senate Resources Committee Substitute for Senate Bill 318. For the reasons explained in my letter and testimony of April 18, 1996, BP will not reopen the negotiations of the agreement and cannot agree to the changes.

With respect to the 21-page findings of fact, BP believes the inclusion of such findings in the act itself is unprecedented. Although many portions of the findings are apparently quotations from testimony and evidence before the committee, we do not believe the findings are a complete or balanced reflection of this testimony and evidence. In addition, the findings describing the history of the leases and unitization are incomplete and seem largely irrelevant to the committee's decision. If the committee desires to make findings of fact such as those in CS 318, it seems more appropriate to include them in the committee record or in a separate committee report rather than in the act itself.

BP also requests that the effective date of the act not be delayed. There has been public testimony from at least one witness regarding a possible legal challenge to the legislation, and we would not want a challenge to be delayed due to a delayed effective date of the act.

Very truly yours,



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

APR 16 1996

**BP EXPLORATION**

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

April 16, 1996

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

Dear Senator Leman:

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

The analysis is based on the following assumptions:

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

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

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

Very truly yours,

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

Northstar Economic Evaluation

4/16/96

Estimated Total Revenues: Facility Sharing Case, Evaluated by BPXA

	<u>With Supplemental Royalty and Early Development</u>	<u>With Net Profit Share and Delayed Development (Real 1996 Dollars)</u>	<u>With Net Profit Share and Early Development</u>
State Revenues			
State Royalty	256	257	256
State Supplemental Royalty	37	-	-
NPSL	-	-	-
State Share of Federal Royalty	16	16	16
Severance Tax	58	58	58
Spill & Conservation Tax	3	3	3
Ad Valorem Tax	42	46	42
Income Tax	8	9	9
Total	419	389	384
Federal Revenues			
Royalty (Net of State Share)	44	44	44
Income Tax	133	150	145
Total	177	194	189
BPXA Cash Flow			
After Tax Funds Flow	197	229	220
Real Rate of Return	12%	14%	13%

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

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

FACSIMILE TRANSMITTAL

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

PLEASE DELIVER TO: Senator Loren Leman

FAX NUMBER: 465-3810

NUMBER OF PAGES (including cover): 2

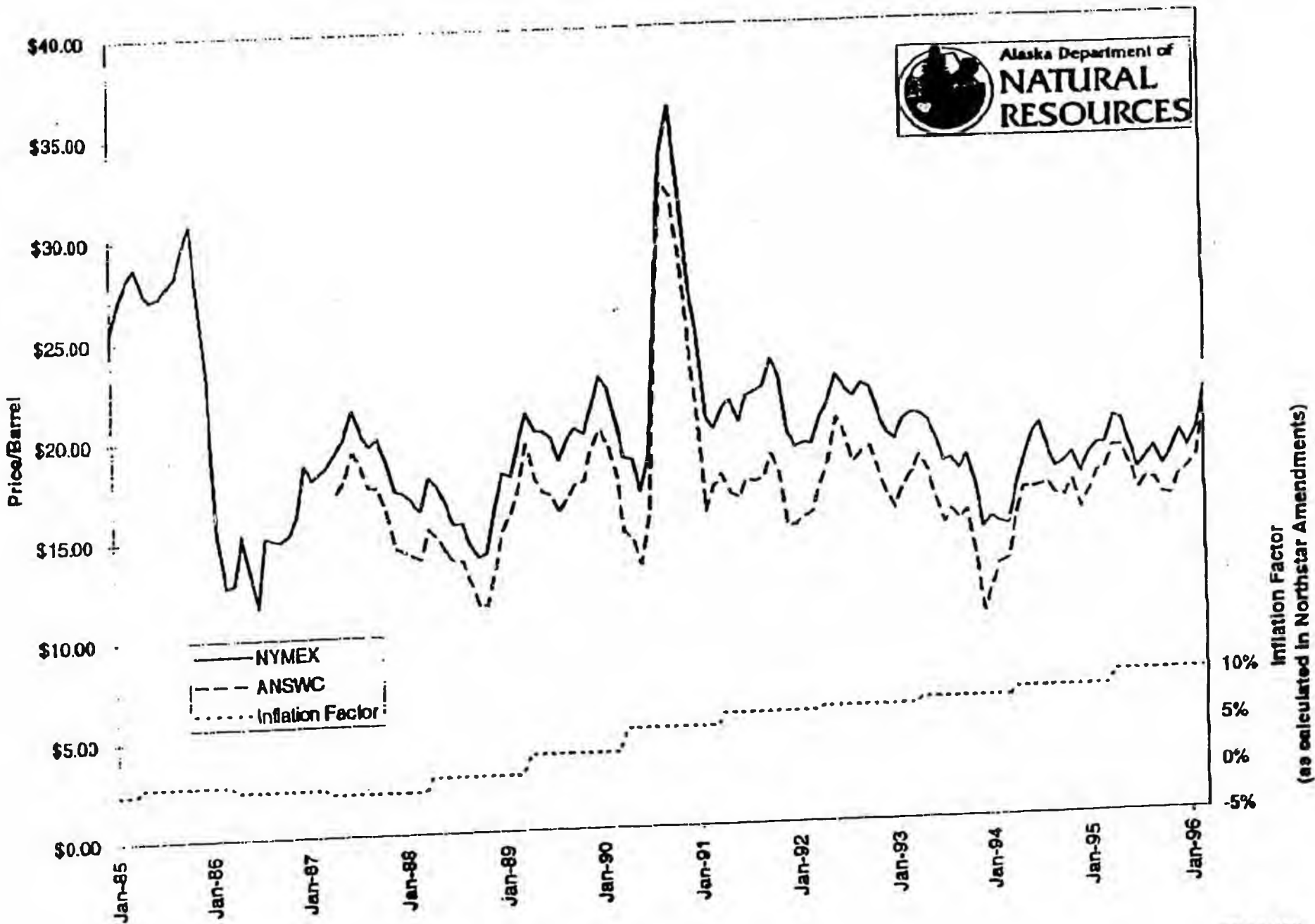
FROM: Kevin Banks
269-8799

COMMENTS:

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

Attachment.

Historical Monthly NYMEX Oil Price and "Inflation Factor"



PRICE X .5 NYMEX

4/15/96, 2:34 PM



Alaska State Legislature

SENATE RESOURCES COMMITTEE

Official Business

State Capitol
Juneau AK 99801

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

Dear Mr. Boyd:

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

Peak production rate: 80,000 bbls/day

Reserves:

P(90) = 190 MMBO

Mean = 160 MMBO

P(10) = 115 MMBO

Capital Expenditures (real 1996 dollars):

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

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

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

Sincerely,

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

Senator Loren Leman
Chairman

STATE OF ALASKA

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

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

April 11, 1996

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

Dear Senator Leman:

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

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

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

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

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

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

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

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

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

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

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

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

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

Sincerely,



Kenneth A. Boyd

Director

Division of Oil and Gas

Northstar Economic Evaluation



Expected Mean Value

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



Alaska State Legislature

SENATE RESOURCES COMMITTEE

Official Business

State Capitol
Juneau AK 99801

April 5, 1996

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

via facsimile: (907) 562-3852

Dear Mr. Boyd:

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

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

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

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

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

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

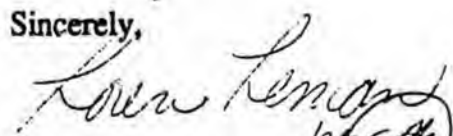
- Bonus as the bid variable
- 12.5 percent royalty; not net profit share; 20 percent, no net profit share

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

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

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

Sincerely,


Senator Loren Leman
Chairman

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

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

FACSIMILE TRANSMITTAL

DATE & TIME: April 17, 1996 10:25 AM

PLEASE DELIVER TO: Senator Loren Leman

FAX NUMBER: 465-3810

NUMBER OF PAGES (including cover): 10

FROM: Ken Boyd
269-8800

COMMENTS:

Attached is our response to your request for Northstar model forecasts assuming various production rates and reserve estimates. Please call if you have any questions

Attachment.

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

DATE: April 16, 1996

FILE NO:

THRU:

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
---	---	---

(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
---	---	---

(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
---	---	---

(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

MLM Royalty Reduction System Real 1995's

STATUS QID

(Includes Carry Forward Provision)

		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total	
State Revenue: Status Quo	net	0	0	5	61	59	56	47	38	30	24	37	50	41	34	22	12	(1)	518	
State Revenue-Real Disc	1	0	0	4	46	41	38	29	23	16	12	18	22	17	13	8	4	(0)	293	
																				314
																				149
		IRR= 22.3%		NPV(BP)= \$148				NPV(AQ)= \$293				State Take = 48.4%								

APPLICATION

		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total	
State Revenue: Application	net	0	0	5	61	59	56	47	38	30	24	30	17	14	12	8	5	(1)	308	
State Revenue-Real Disc	2	0	0	4	46	41	38	29	23	16	12	20	8	6	5	3	2	(0)	242	
																				394
																				163
		IRR= 24.1%		NPV(BP)= \$163				NPV(AQ)= \$342				State Take = 37.1%								

Annual Projected Lost State Revenue	0	0	0	0	0	0	0	0	0	0	0	17	33	27	22	14	7	0	123
Lost State Revenue = 120																			

ACTUAL Assume DOR High Price and Base Case Inflation

		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2011	Total	
State Revenue: Actual	net	0	0	6	60	58	56	47	48	38	31	27	14	11	17	12	7	(1)	472	
State Revenue-Real Disc	4	0	0	5	55	51	49	39	31	23	18	15	7	5	8	5	3	(0)	313	
																				549
																				306
		IRR= 30.8%		NPV(BP)= \$308				NPV(AQ)= \$313				State Take = 33.2%								

MLM

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2011	Total		
State Revenue Calculation																				
State Revenue Delta--State Revenue:Actual--State Revenue:Application	0	0	1	8	9	10	10	9	8	7	7	(5)	(3)	5	4	2	0	0		
ATFF-Real Delta--ATFF-Real/Actual - ATFF-Real/Application	0	0	1	13	16	19	19	19	18	18	17	(6)	(7)	14	10	6	0	0		
ATFF-Real Delta Available for Lost State Revenue Payment	0	0	1	13	16	19	19	19	18	18	17	0	0	14	10	6	0	0		
Lost State Revenue Acct Beginning Balance	(120)	(120)	(120)	(119)	(108)	(90)	(71)	(52)	(33)	(15)	0	0	0	0	0	0	0	0		
Payments made to Lost State Revenue Acct	0	0	1	13	16	19	19	19	18	15	0	0	0	0	0	0	0	0		
Lost State Revenue Acct Ending Balance (120)	(120)	(120)	(118)	(106)	(89)	(71)	(52)	(33)	(15)	0	0	0	0	0	0	0	0	0		
ATFF-Real Delta Available for Carry Forward	0	0	0	0	0	0	0	0	0	3	17	0	0	14	10	6	0	0		
ATFF Carry Forward	0	0	0	0	0	0	0	0	0	0	0	(6)	(7)	0	0	0	0	0		
ATFF Carry Forward Beginning Balance	0	0	0	0	0	0	0	0	0	0	0	(6)	(15)	(15)	(1)	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		
ATFF Carry Forward Ending Balance	0	0	0	0	0	0	0	0	0	0	0	(6)	(16)	(1)	0	0	0	0		
ATFF-Real Delta Available for Bill	0	0	0	0	0	0	0	0	0	3	17	0	0	0	9	6	0	0		
State Revenue: Additional Spills	0.1	0	0	0	0	0	0	0	0	0	2	0	0	0	1	1	0	0		
ATFF-Real: Additional Spills	0.9	0	0	0	0	0	0	0	0	3	15	0	0	0	8	5	0	0		
State Take = Application + NPBL Make-up + Additional Spill	0	0	7	82	84	87	76	67	58	46	29	14	11	17	13	8	(1)	586		
State Take-Real Disc	0	0	6	66	64	62	61	63	54	27	15	7	5	8	6	3	(0)	398		
																				441
																				231
		IRR= 24.7%		NPV(BP)= \$231				NPV(AQ)= \$338				State Take = 42.2%								



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 Lemman, Chair
Senate Resources Committee
Alaska State Legislature
State Capitol
Juneau, AK 99801

Dear Senator Lemman:

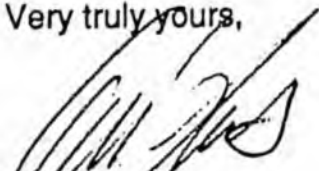
In response to the letter by Annette Kreitzer of your staff on April 5 regarding SB 318, BP provides the following information on the Northstar project and lease Agreement.:

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

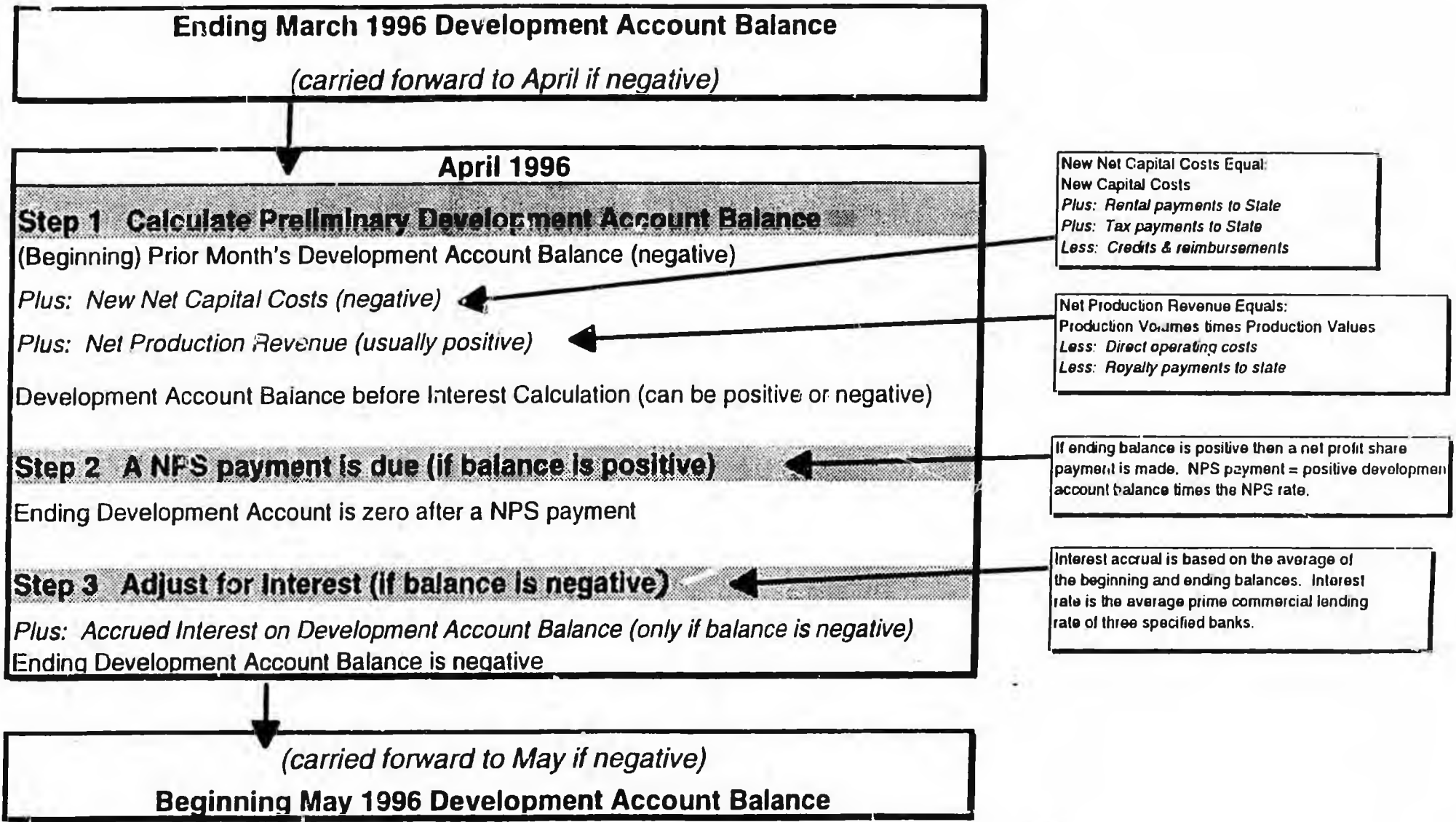
April 11, 1996

Prepared By

Alaska Department of Natural Resources

Division of Oil and Gas

NPSL ACCOUNTING FLOW DIAGRAM



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.

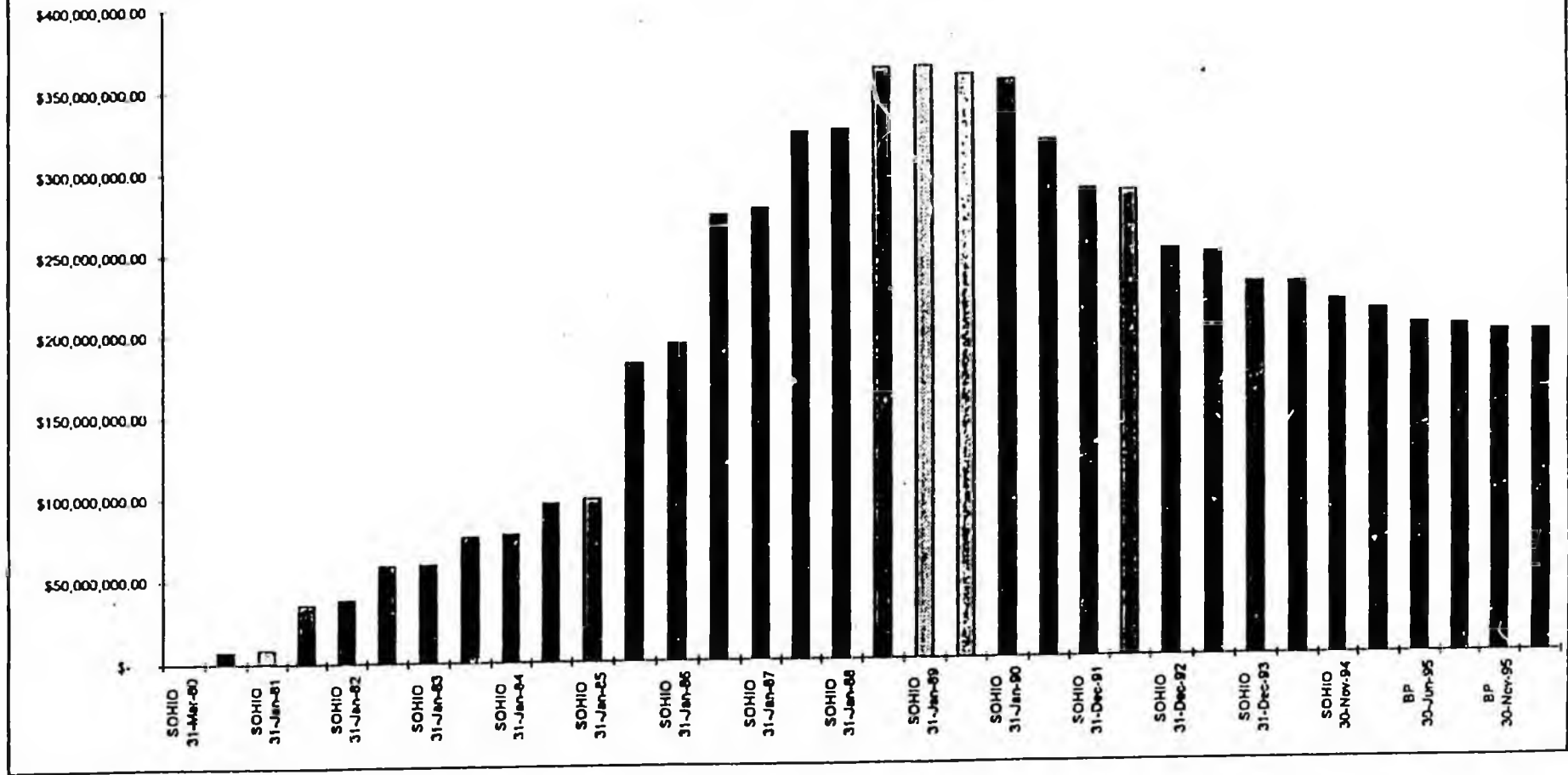
D. NET PROFIT PAYMENT ACCOUNT

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

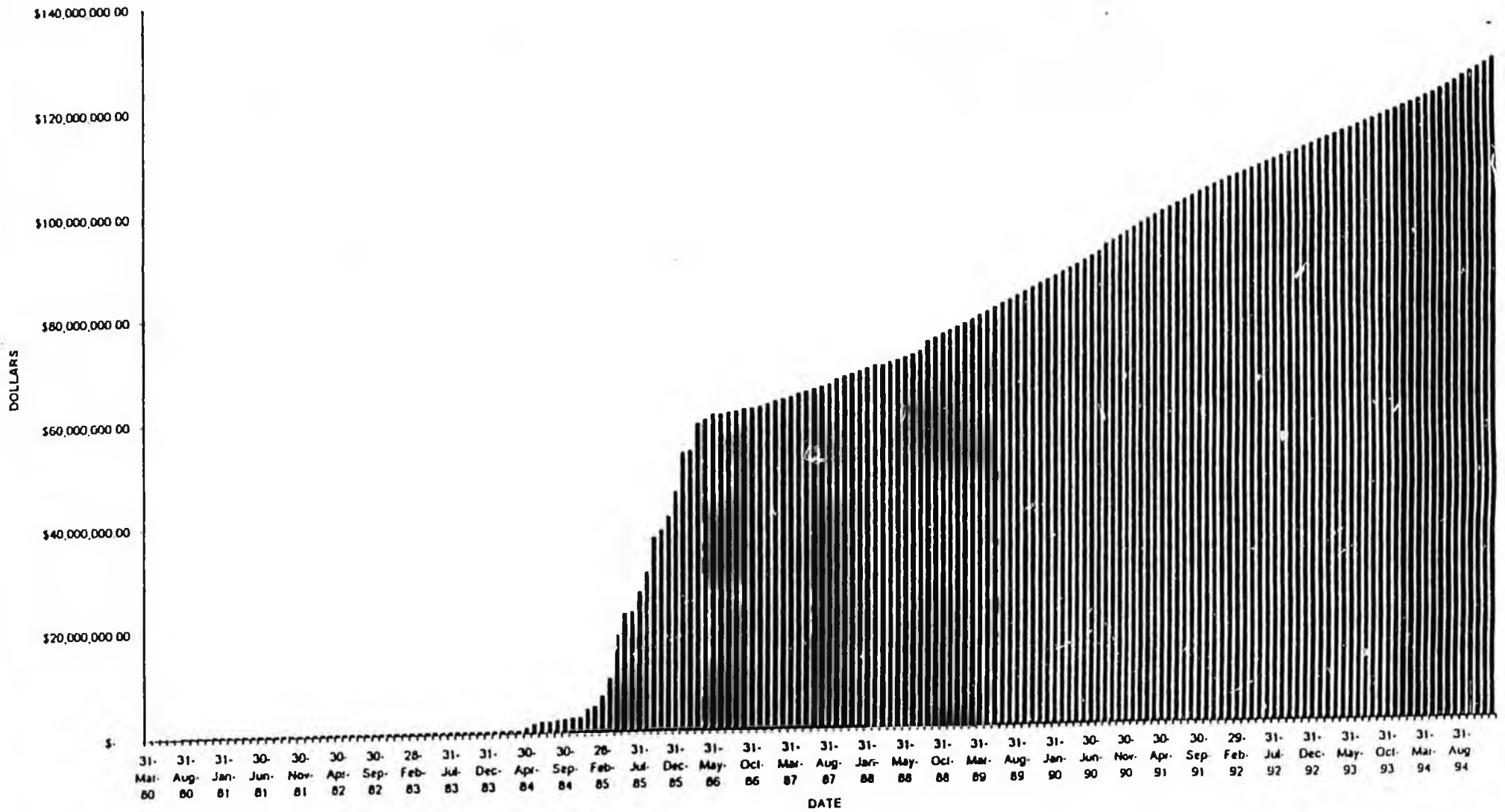
Listing of Current NPS Development Account
Balances by Field

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%				

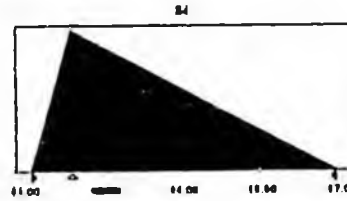
Assumptions

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

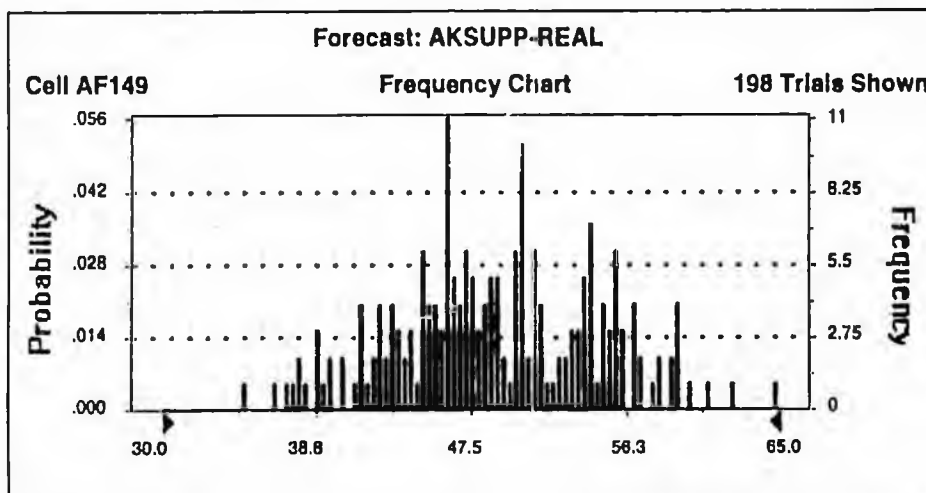
Cell: AF149

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	0.862 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	0.1667	0		
State Income Tax Rate	- 2.00%	(DOR est. avg corp. rate)			Y0179	0.1667	G	
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	

	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
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
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
PS#1 NB Oil Price(\$/bbl, mod)	\$11.45	\$12.28	\$12.72	\$13.89	\$14.48	\$14.61	\$15.44	\$15.87	\$16.48	\$16.99	\$17.52	\$18.10	\$18.70	\$19.44	\$20.08	\$20.55	\$21.33	\$21.93	\$22.83	\$23.23	\$23.93	\$24.64	\$25.38	\$26.15	\$26.91	\$27.74	\$28.57	\$29.43	\$30.31	\$31.22	\$22.19
Pipeline Tariffs (\$/bbl, mod)	\$3.42	\$2.77	\$2.59	\$2.58	\$2.88	\$2.87	\$2.99	\$3.13	\$3.31	\$3.53	\$3.78	\$4.01	\$4.24	\$4.35	\$4.55	\$4.83	\$5.03	\$5.34	\$5.59	\$5.98	\$6.14	\$6.32	\$6.51	\$6.71	\$6.91	\$7.12	\$7.33	\$7.55	\$7.78	\$8.01	\$6.25
Marine Costs (\$/bbl, mod)	\$1.49	\$1.38	\$1.38	\$1.42	\$1.47	\$1.55	\$1.63	\$1.71	\$1.79	\$1.87	\$1.93	\$1.99	\$2.08	\$2.12	\$2.19	\$2.28	\$2.33	\$2.41	\$2.48	\$2.58	\$2.64	\$2.72	\$2.80	\$2.88	\$2.97	\$3.08	\$3.15	\$3.25	\$3.34	\$3.44	\$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	23.9	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
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	28.0	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	(\$m real)	99	69	124	108
	Facility	(\$m real)	251	217	294	250
	Pipelines	(\$m real)	28	25	53	34
	Total	(\$m real)	378	331	471	392
Dev Costs	(\$Abbl)					2.8
Lifting Costs	(\$Abbl)	1.50	1.40	2.00	1.74	

State Revenue (\$m, 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 (\$ m MOD)	555.1
Total (\$ m real)	438.4

Federal Revenue (\$m, 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 (\$ m MOD)	328.5
Total (\$ m real)	260.9

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	12.79	12.78	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	29.66	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

2.44
12.78
42.67

ANS WC Oil Price Random generated around mean price forecast																															
Monthly Forecast Price	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	
Jan	18.34	18.39	18.58	17.39	18.33	19.02	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	18.59	17.48	18.39	19.08	19.78	20.53	21.30	22.09	22.91	23.77	24.66	25.58	26.49	27.39	28.33	29.31	30.32	31.38	32.35	33.32	34.32	35.36	36.41	37.50	38.62	39.78	40.98	42.21	
Mar	18.35	18.40	18.61	17.60	18.45	19.14	19.85	20.59	21.38	22.18	22.98	23.85	24.73	25.66	26.56	27.47	28.41	29.38	30.40	31.45	32.43	33.40	34.40	35.43	36.50	37.59	38.72	39.89	41.08	42.31	
Apr	18.35	18.40	18.63	17.71	18.50	19.19	19.91	20.65	21.43	22.22	23.05	23.92	24.81	25.74	26.63	27.55	28.49	29.47	30.49	31.53	32.51	33.48	34.49	35.52	36.59	37.69	38.81	39.96	41.14	42.34	
May	18.35	18.40	18.66	17.81	18.58	19.25	19.97	20.72	21.49	22.29	23.12	23.98	24.86	25.81	26.71	27.62	28.57	29.55	30.57	31.62	32.59	33.58	34.57	35.61	36.69	37.77	38.89	40.04	41.22	42.42	
Jun	18.38	18.41	18.68	17.92	18.81	19.51	20.03	20.78	21.58	22.38	23.19	24.07	24.98	25.89	26.79	27.70	28.65	29.63	30.68	31.71	32.67	33.65	34.65	35.69	36.77	37.87	39.00	40.17	41.38	42.62	
July	18.38	18.42	18.74	18.00	18.87	19.37	20.09	20.84	21.62	22.42	23.27	24.14	24.99	25.89	26.78	27.70	28.65	29.63	30.68	31.71	32.67	33.65	34.65	35.69	36.77	37.87	39.00	40.17	41.38	42.62	
Aug	18.37	18.45	18.65	18.08	18.73	19.43	20.15	20.91	21.69	22.49	23.34	24.21	25.11	26.04	26.93	27.86	28.81	29.80	30.83	31.87	32.83	33.81	34.83	35.87	36.95	38.06	39.20	40.37	41.58	42.87	
Sep	18.37	18.47	18.98	18.11	18.79	19.49	20.22	20.97	21.78	22.66	23.41	24.29	25.18	26.12	27.01	27.94	28.90	29.89	30.92	31.95	32.91	33.90	34.91	35.95	37.02	38.12	39.25	40.42	41.63	42.87	
Oct	18.37	18.48	17.06	18.17	18.84	19.55	20.28	21.04	21.82	22.63	23.48	24.38	25.27	26.19	27.09	28.02	28.98	29.98	31.01	32.03	32.99	33.98	35.00	36.06	37.13	38.25	39.38	40.57	41.78	42.87	
Nov	18.38	18.52	17.17	18.22	18.90	19.81	20.34	21.10	21.89	22.70	23.58	24.44	25.35	26.28	27.16	28.10	29.08	30.08	31.10	32.11	33.07	34.07	35.08	36.14	37.22	38.34	39.48	40.68	41.90	42.87	
Dec	18.38	18.54	17.28	18.28	18.98	19.87	20.40	21.17	21.98	22.77	23.63	24.51	25.42	26.34	27.24	28.18	29.14	30.15	31.18	32.19	33.15	34.15	35.17	36.23	37.32	38.44	39.59	40.78	42.00	42.87	
Monthly MonteCarlo Price	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	
Jan	18.35	18.04	18.14	18.00	17.80	18.31	26.85	21.48	18.43	25.35	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	36.98	34.04	37.30	38.71	31.68	40.88	40.74	
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	24.38	25.81	28.85	26.13	28.68	30.38	30.85	28.15	30.98	38.17	31.68	39.27	39.83	36.84	39.24	40.88	40.74	
Mar	18.07	15.18	14.01	20.55	22.84	18.28	18.78	21.98	17.33	23.20	25.14	28.74	23.88	20.81	24.85	25.98	29.10	24.84	35.22	33.70	35.42	30.16	33.54	36.80	33.88	36.89	35.47	43.78	38.57	43.98	
Apr	18.70	14.74	14.14	18.41	22.02	18.38	18.69	20.98	20.04	18.48	22.88	25.24	27.88	21.04	28.88	27.29	28.88	29.42	31.81	28.99	31.42	32.58	31.64	38.23	28.38	41.31	38.08	41.87	38.81	38.81	
May	19.88	18.80	18.94	18.57	27.71	20.27	17.47	20.71	18.13	26.51	21.90	28.51	22.83	28.88	23.82	25.05	27.75	28.68	27.94	30.75	32.88	31.89	37.23	32.35	41.28	37.87	40.48	38.08	38.81	38.81	
Jun	22.16	15.89	17.55	17.77	14.13	23.43	18.78	18.99	21.85	22.32	24.88	26.28	21.84	24.78	27.19	28.81	26.05	30.70	28.77	28.50	34.80	36.43	36.54	34.18	36.78	38.88	40.54	38.81	38.81	38.81	
July	17.87	15.70	15.88	17.71	21.38	-2.38	18.82	18.88	18.95	18.89	19.85	21.40	24.74	28.22	28.53	28.58	29.09	29.81	32.15	32.27	34.47	28.53	33.27	31.88	37.14	38.95	38.87	44.88	43.72	44.84	
Aug	15.43	20.33	15.87	18.01	18.43	18.08	18.56	22.32	22.21	26.82	20.21	23.27	20.40	25.89	28.90	28.18	30.09	29.81	32.15	32.27	34.47	28.53	33.27	31.88	37.14	38.95	38.87	44.88	43.72	44.84	
Sep	18.88	13.57	18.75	18.85	18.83	21.85	23.13	23.57	18.27	24.74	22.81	28.84	25.39	28.98	32.05	23.95	30.24	31.40	33.01	31.88	38.23	32.87	34.48	38.95	39.28	39.22	48.84	41.88	38.45	42.08	
Oct	18.82	18.82	15.83	18.42	18.76	18.82	19.61	18.90	25.57	23.68	28.87	24.18	28.36	27.89	26.08	30.58	28.45	30.46	30.44	34.86	28.38	31.22	34.38	34.95	39.28	39.22	48.84	41.88	38.45	42.08	
Nov	20.25	18.24	15.89	18.56	14.78	17.24	18.48	21.86	18.83	23.93	20.03	23.51	29.10	29.38	25.85	28.27	31.15	30.07	28.80	32.87	35.03	31.70	32.84	36.05	36.48	39.42	40.88	43.70	44.32	44.32	
Dec	14.83	18.55	13.78	17.90	19.34	18.60	18.85	19.77	20.93	18.52	25.25	28.93	29.20	27.34	30.94	28.02	27.98	28.85	33.07	32.22	37.89	28.44	34.37	25.59	34.87	38.87	42.82	40.98	38.79	38.79	
ANS WC Mean Annual Value	18.38	18.44	18.82	17.90	18.84	19.34	20.08	20.81	21.59	22.39	23.23	24.10	25.00	25.93	26.82	27.74	28.70	29.68	30.71	31.74	32.71	33.69	34.70	35.74	36.81	37.82	38.98	40.23	41.43	42.52	
PS#1 Mean Annual Value	11.45	12.78	12.85	13.91	14.48	14.82	15.44	15.97	16.48	16.99	17.52	18.10	18.71	19.45	20.08	20.65	21.33	21.94	22.63	23.22	23.82	24.45	25.38	26.15	28.83	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%	0.47%	1.08%	1.74%	2.43%	3.14%	3.90%	4.70%	5.54%	6.41%	7.28%	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%	
Feb	0.00%	0.00%	0.00%	0.00%	0.00%	0.58%	1.18%	1.83%	2.52%	3.24%	4.01%	4.81%	5.65%	6.53%	7.37%	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%	7.60%	
Mar	0.00%	0.00%	0.00%	0.00%	0.00%	0.64%	1.27%	1.93%	2.62%	3.34%	4.11%	4.92%	5.78%	6.65%	7.48%	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%	7.60%	
Apr	0.00%	0.00%	0.00%	0.00%	0.13%	0.73%	1.38%	2.07%	2.72%	3.44%	4.22%	5.03%	5.87%	6.78%	7.60%	7.6															

	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		
Production (mbbl)																															130		
Gross Oil	0.0	0.0	5.4	49.8	48.8	48.7	41.2	34.7	28.7	23.8	20.0	16.7	13.9	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	20		
State Royalty Oil	0.00	0.00	0.83	7.85	7.85	7.48	6.33	5.33	4.41	3.88	3.07	2.57	2.14	1.77	1.17	0.88	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	0		
State Suppl Royalty Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1		
State Share of Federal Royalty Oil	0.00	0.00	0.05	0.49	0.49	0.48	0.40	0.34	0.28	0.22	0.20	0.18	0.14	0.11	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3		
Federal Royalty Oil (Net of State Share)	0.00	0.00	0.14	1.32	1.32	1.29	1.09	0.92	0.78	0.63	0.53	0.44	0.37	0.31	0.20	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0		
Backout Loss	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103		
Net BP Oil	0.00	0.00	4.29	39.53	39.53	39.88	32.71	27.55	22.78	18.99	15.88	13.28	11.03	9.13	6.03	3.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0		
Oil Price (\$/bbl, mod netback)	\$11.45	\$12.28	\$12.72	\$13.99	\$14.48	\$14.92	\$15.44	\$15.87	\$16.49	\$16.99	\$17.52	\$18.10	\$18.70	\$19.48	\$20.08	\$20.85	\$21.33	\$21.93	\$22.63	\$23.23	\$23.93	\$24.84	\$25.38	\$26.15	\$26.93	\$27.74	\$28.57	\$29.43	\$30.31	\$31.22	0		
Gross NGLs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0		
State Royalty NGLs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0		
State Suppl Royalty NGLs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0		
State Share of Federal Royalty NGLs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0		
Federal Royalty NGLs (Net of State Share)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0		
Backout Loss	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0		
Net BP NGLs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0		
NGL Price (\$/bbl, mod netback)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	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	\$1.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	0		
Revenue (\$m, mod)																															1641		
BP Net Revenue	0.0	0.0	19.9	202.0	209.1	210.7	184.4	180.7	137.2	117.2	101.6	87.8	75.4	64.8	44.2	26.8	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		
BP Net Revenue for Oil Severance	0.0	0.0	19.9	202.0	209.1	210.7	184.4	180.7	137.2	117.2	101.6	87.8	75.4	64.8	44.2	26.8	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		
BP Net Revenue for Gas Severance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0		
Royalty (\$m, mod)																															317		
State	0.0	0.0	3.8	39.1	40.6	40.8	35.7	31.1	28.8	22.7	19.7	17.0	14.8	12.8	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		
State Supplement 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		
State Share of Federal Royalty	0.0	0.0	0.2	2.5	2.8	2.8	2.3	2.0	1.7	1.5	1.3	1.1	0.9	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		
Federal Royalty (Net of State Share)	0.0	0.0	0.7	8.8	7.0	7.0	6.2	5.4	4.8	3.9	3.4	2.9	2.5	2.2	1.5	0.9	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	55		
Total	0.0	0.0	4.8	48.3	50.0	50.4	44.1	38.5	32.8	28.1	24.3	21.0	18.0	15.5	10.8	6.1	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	393		
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		
Tax (\$m, mod)																																	
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%		
Oil ELF	0.00	0.00	0.00	0.71	0.80	0.58	0.43	0.27	0.12	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0		
Gas Sev. Rate	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%		
Gas ELF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	4		
Total Severance	0.0	0.0	0.0	17.7	18.3	15.0	9.8	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			
Spill & Cont.	0.0	0.0	0.1	0.5	0.5	0.5	0.4	0.3	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	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		
Capex (\$m, mod, net)																																	
Drilling Tang	4.1	0.0	4.4	9.0	9.3	5.2	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	32		
Drilling Intang	9.8	0.0	10.2	21.1	21.7	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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		
Facility Capital	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	28		
Pipeline Capital	4.9	13.1	10.4	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	393		
Total	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		
Opex (\$m, mod, net)																																	
Field ON/OFF Req	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	237	
-Northern Direct O&M	-	-	3.1	29.3	30.3	30.5	2																										

NPSL Calculation		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2008	2010	2011	2012	2013	2014	2015	2016	2017	2018	2018	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	27.8	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	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	27.8	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	
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	27.8	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NPSL 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	18.00%	81.00%

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2008	2008	2010	2011	2012	2013	2014	2015	2016	2017	2018	2018	2020	2021	2022	2023	2024	2025	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	87.6	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	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	4	
- Spill & Contain.	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	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	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	2.0	38.6	24.9	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	0.0	237	
- opex	0.0	0.0	3.1	29.3	30.3	30.5	28.7	23.2	19.8	18.9	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	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	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	8.3	-40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	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	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	-8.3	-40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	365	
- Tan. Drift/Fac Depr.	5.8	21.9	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	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	
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	48.5	31.1	8.3	-40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	2025	Total	
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	0.26	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	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	
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	2025	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	365	
Total(\$m)	0.0	0.0	5.6	38.4	47.7	51.3	45.1	38.0	31.4	28.1	21.9	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	
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	2025	Total	
State	-0.28	-0.47	-0.70	1.85	1.85	2.22	2.18	1.95	1.79	1.88	1.58	1.41	1.19	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	18	
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	274	
Total	-4.89	-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	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	2025	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	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	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	
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	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	508	

DO&A (\$MOD)	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		
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	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	
DO&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	0.00	106.64
DO&A (BPX Net \$MM MOD)	0.0	0.0	0.8	8.1	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	0.0	
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	18.5	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	
DO&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	0.00	258.17
DO&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	0.0	
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	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DO&A Rate (\$/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
DO&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	0.0
Total DO&A Rate \$/BBL	0.0	0.0	3.6	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	0.0	364.81
Total DO&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 (\$MOD)																																
Beginning Balance (Net \$MM)	39.4	39.4	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	
DO&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	
DO&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	39.4	38.9	38.8	31.8	25.1	18.7	13.7	9.8	8.8	4.5	2.8	1.5	0.8	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

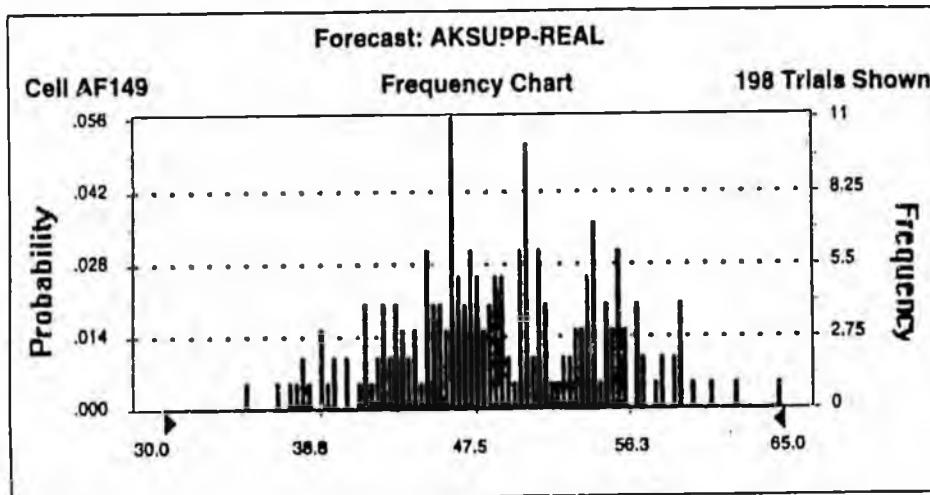
Cell: AF149

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 affect on these figures; early development is shown.

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

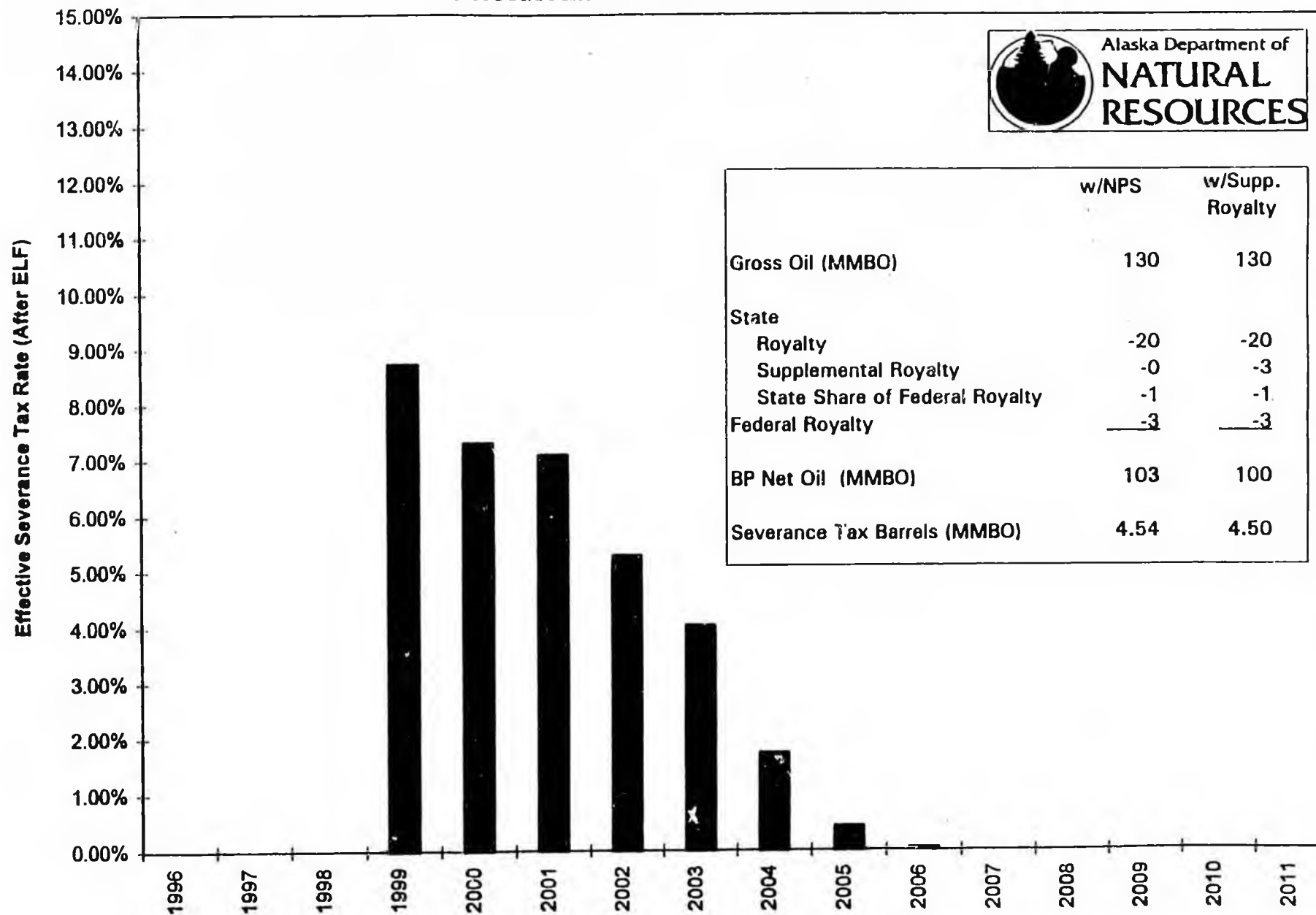
Kevin Banks will prepare a response to Senator Leman's letter received this morning, using the "Illustrative Northstar Model," as requested. These results should be available early next week.

Attachments.

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

Northstar Proposal

Forecast Effective Severance Tax Rates



	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/acre(ft)	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 NPBL	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%	18% (Enghart est.)		

Lease	Royalty	NPBL
312798	20.0%	83.20%
312799	20.0%	81.20%
312808	20.0%	85.28%
312809	20.0%	85.28%
355001	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

NPBLs and Supplemental Royalty Default Period	
NPBLs ON/OFF	OFF
Supplemental Royalty ON/OFF	ON
NYMEX - AK Base MOD Price Offset (\$/bbl)	40.00

DORA 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	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	
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	
PSF1 NB Oil Price (\$/bbl, mod)	\$11.45	\$12.28	\$12.72	\$12.99	\$14.48	\$14.92	\$15.44	\$15.87	\$16.48	\$18.99	\$17.52	\$18.10	\$18.70	\$18.48	\$20.08	\$20.55	\$21.33	\$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	\$32.16	
Pipeline Tariffs (\$/bbl, mod)	\$3.42	\$2.77	\$2.59	\$2.56	\$2.88	\$2.87	\$2.99	\$3.12	\$3.31	\$2.53	\$2.77	\$4.01	\$4.24	\$4.38	\$4.55	\$4.83	\$5.03	\$5.34	\$5.48	\$5.58	\$5.88	\$6.14	\$6.32	\$6.51	\$6.71	\$6.81	\$7.12	\$7.33	\$7.55	\$7.78	\$8.01	
Marine Costs (\$/bbl, mod)	\$1.18	\$1.28	\$1.28	\$1.42	\$1.47	\$1.55	\$1.83	\$1.71	\$1.78	\$1.87	\$1.99	\$1.99	\$2.08	\$2.12	\$2.18	\$2.28	\$2.33	\$2.41	\$2.48	\$2.58	\$2.64	\$2.72	\$2.80	\$2.88	\$2.87	\$2.98	\$3.15	\$3.25	\$3.34	\$3.44	\$3.48	
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	0.0	
Capex (\$/m, Real)																																
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	0.0	
Facility	36.0	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	1.08	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	1.76	1.82	1.87	1.93	1.98	2.04	2.11	2.17	2.23	2.30	2.37	2.44	2.48	

Supplemental Royalty Rate	
Trigger Price (\$/ANS WCI)	\$ 17.35
Linear Slope (%/ANS WCI)	1.5%
Supplemental Royalty Cap	7.5%

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

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
22.70	23.07	23.43	23.81	24.19	24.58	24.97	25.37	25.78	26.19	26.61	27.03	27.47					

Caution - Only change inputs on this page

Summary Output

Development Summary		Montecarlo			
		M.L.	MIN	MAX	MONTE
Reserves	Grass Oil (MBOE)	130	105	170	142
	Grass NGLs (MBOE)	0	0	0	0
Capex	DW (1m cost)	83	88	124	106
	Facility (1m cost)	251	217	284	250
	Pipeline (1m cost)	29	25	57	34
	Total (1m cost)	378	331	471	385
Dev Costs	(1MBO)	2.8			
Utility Costs	(1MBO)	1.50	1.40	2.00	1.74

State Revenue (\$m, MOD)	
Royalty (incl. supplemental)	388.0
State Share of Federal Royalty	20.3
Severance Tax	66.6
Split & Conservation Tax	3.4
Ad Valorem Tax	52.8
NPFL	0.0
Income Tax	18.5
Total (\$m MOD)	527.6
Total (\$m real)	424.3

Federal Revenue (\$m, MOD)	
Royalty Net of State Share	54.9
Severance Tax	0.0
Split & Conservation Tax	0.0
Ad Valorem Tax	0.0
NPFL	0.0
Income Tax	238.8
Total (\$m MOD)	293.8
Total (\$m real)	206.1

	1.00	1.02	1.04	1.10	1.13	1.17	1.21	1.24	1.29	1.33	1.37	1.41	1.44	1.50	1.55	1.60	1.65	1.70	1.74	1.82	1.87	1.93	1.98	2.04	2.11	2.17	2.23	2.30	2.37	2.44	2.44
Commutative Inflation	1.00	1.02	1.04	1.10	1.13	1.17	1.21	1.24	1.29	1.33	1.37	1.41	1.44	1.50	1.55	1.60	1.65	1.70	1.74	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 (1984 real)	11.45	11.90	11.97	12.75	12.78	12.77	12.81	12.83	12.84	12.82	12.81	12.82	12.84	12.95	12.84	12.84	12.81	12.86	12.86	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	
AR WC Oil Price (1984 MOD)	18.24	18.41	18.85	17.87	18.84	18.34	20.08	20.81	21.58	22.38	22.23	24.10	25.08	25.82	26.82	27.74	28.88	29.88	30.70	31.75	32.70	33.88	34.70	35.74	36.81	37.81	38.05	40.22	41.43	42.87	

ANS WC Oil Price (Random generated around mean price (constant))		Monthly Forecast Price																													
		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
Jan	18.24	18.24	18.28	18.58	17.28	19.23	18.02	18.72	20.47	21.23	22.02	22.84	23.70	24.58	25.48	26.41	27.38	28.39	29.43	30.50	31.60	32.73	33.89	35.08	36.29	37.53	38.80	40.10	41.43	42.87	
Feb	18.24	18.28	18.58	17.49	19.28	18.08	18.78	20.53	21.29	22.08	22.90	23.78	24.68	25.60	26.54	27.51	28.51	29.54	30.60	31.69	32.81	33.96	35.14	36.35	37.59	38.86	40.16	41.49	42.87		
Mar	18.25	18.40	18.61	17.80	19.45	18.14	18.85	20.58	21.34	22.13	22.96	23.84	24.74	25.66	26.61	27.59	28.60	29.64	30.71	31.81	32.93	34.08	35.26	36.47	37.71	38.98	40.28	41.61	42.97		
Apr	18.25	18.40	18.62	17.71	19.50	18.19	18.91	20.66	21.42	22.21	23.04	23.92	24.82	25.74	26.69	27.67	28.68	29.72	30.79	31.89	33.01	34.16	35.34	36.55	37.79	39.06	40.36	41.69	43.05		
May	18.25	18.40	18.62	17.81	19.58	18.25	18.97	20.72	21.48	22.27	23.12	23.99	24.88	25.81	26.77	27.82	28.87	29.94	31.03	32.14	33.27	34.42	35.60	36.81	38.05	39.32	40.62	41.95	43.31		
Jun	18.24	18.41	18.68	17.92	19.61	18.31	20.00	20.78	21.58	22.38	23.18	24.07	24.98	25.90	26.84	27.80	28.79	29.80	30.83	31.87	32.93	34.01	35.11	36.23	37.37	38.53	39.72	40.94	42.18	43.44	
Jul	18.24	18.42	18.74	18.00	19.67	18.41	20.11	20.81	21.60	22.40	23.24	24.11	25.01	25.94	26.89	27.86	28.85	29.86	30.89	31.93	33.00	34.09	35.20	36.33	37.48	38.65	39.85	41.07	42.31	43.57	
Aug	18.27	18.45	18.85	18.04	19.72	18.42	20.15	20.81	21.60	22.40	23.24	24.11	25.01	25.94	26.89	27.86	28.85	29.86	30.89	31.93	33.00	34.09	35.20	36.33	37.48	38.65	39.85	41.07	42.31	43.57	
Sep	18.27	18.47	18.86	18.11	19.78	18.48	20.22	20.87	21.66	22.46	23.30	24.17	25.07	25.99	26.93	27.89	28.87	29.87	30.89	31.93	33.00	34.09	35.20	36.33	37.48	38.65	39.85	41.07	42.31	43.57	
Oct	18.27	18.48	18.86	18.17	19.84	18.55	20.29	21.04	21.88	22.73	23.60	24.50	25.42	26.36	27.32	28.30	29.30	30.31	31.34	32.39	33.46	34.55	35.66	36.78	37.92	39.08	40.26	41.46	42.67	43.90	
Nov	18.28	18.52	18.91	18.22	19.89	18.61	20.34	21.10	21.98	22.87	23.78	24.72	25.68	26.66	27.66	28.68	29.71	30.76	31.82	32.90	34.00	35.11	36.24	37.38	38.54	39.72	40.92	42.14	43.37	44.61	
Dec	18.28	18.54	18.92	18.28	19.95	18.67	20.40	21.17	22.06	22.97	23.90	24.85	25.82	26.81	27.82	28.85	29.90	30.96	32.04	33.13	34.24	35.36	36.50	37.66	38.84	40.03	41.24	42.46	43.69	44.93	
Monthly Monte-Carlo Price																															
Jan	18.28	18.84	14.14	19.80	17.80	14.31	25.88	23.43	19.41	25.88	23.87	20.84	28.88	26.34	27.88	29.38	31.78	33.88	36.88	39.88	42.88	45.88	48.88	51.88	54.88	57.88	60.88	63.88	66.88	69.88	
Feb	18.80	17.82	17.54	18.70	21.48	21.02	17.43	23.24	23.24	17.88	23.88	23.84	24.22	24.29	28.81	24.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	
Mar	18.81	15.28	14.01	20.95	21.84	19.29	18.29	21.88	21.88	20.84	20.84	20.84	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	
Apr	18.38	14.14	14.14	18.81	22.82	18.38	18.88	20.88	20.88	20.84	20.84	20.84	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	21.88	
May	18.80	18.80	18.84	18.37	22.71	20.27	17.47	20.71	18.12	28.51	21.88	22.42	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	
Jun	22.11	18.88	17.35	17.27	24.12	23.42	18.78	18.88	21.88	22.28	24.88	24.88	21.18	24.24	28.22	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	
Jul	17.87	15.70	15.88	22.71	23.28	22.58	28.42	19.48	19.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	
Aug	15.43	20.20	18.80	18.01	18.43	21.88	18.88	22.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	
Sep	18.88	13.87	18.75	18.88	18.88	18.88	21.88	22.12	23.87	24.27	24.28	24.84	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	28.88	
Oct	18.88	18.88	18.88	18.42	18.78	18.33	18.51	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	
Nov	18.25	18.24	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	18.84	
Dec	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	18.88	
ANS WC Mean Annual Value		18.24	18.44	18.82	17.80	18.84	18.34	20.08	20.81	21.58	22.38	23.23	24.10	25.08	25.82	26.82	27.74	28.88	29.88	30.70	31.75	32.70	33.88	34.70	35.74	36.81	37.81	38.05	40.22	41.43	
PS#1 Mean Annual Value		11.45	12.28	12.85	12.21	12.48	14.82	15.44	15.82	18.48	18.88	17.82	18.10	18.71	18.85	20.88	20.88	21.84	22.88	23.22	24.85	25.28	26.15	26.82	28.15	28.82	29.74	30.31	31.01		

Quarterly Supplemental State Royalty %		Monthly Forecast Price																												
		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
Jan	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.47%	1.08%	1.74%	2.43%	3.14%	3.90%	4.70%	5.54%	6.41%	7.30%	8.21%	9.14%	10.09%	11.06%	12.05%	13.06%	14.08%	15.11%	16.15%	17.20%	18.26%	19.33%	20.41%	21.50%
Feb	0.00%	0.00%	0.00%	0.00%	0.00%	0.47%	1.08%	1.74%	2.43%	3.14%	3.90%	4.70%	5.54%	6.41%	7.30%	8.21%	9.14%	10.09%	11.06%	12.05%	13.06%	14.08%	15.11%	16.15%	17.20%	18.26%	19.33%	20.41%	21.50%	22.60%
Mar	0.00%	0.00%	0.00%	0.00%	0.00%	0.58%	1.18%	1.83%	2.52%	3.24%	4.01%	4.81%	5.65%	6.53%	7.45%	8.40%	9.38%	10.39%	11.42%	12.47%	13.54%	14.62%	15.71%	16.81%	17.92%	19.04%	20.17%	21.31%	22.46%	23.62%
Apr	0.00%	0.00%	0.00%	0.00%	0.																									

(\$m, MOD)	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total	
State	0.0	0.0	3.8	38.1	40.5	40.8	39.7	31.1	21.6	22.7	16.7	17.0	14.8	12.4	6.8	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	317.4	
State Royalty	0.0	0.0	0.0	0.0	0.8	2.3	3.5	4.4	5.0	5.3	5.8	5.7	5.7	5.7	4.1	2.4	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	60.8	
State Supplemental Royalty	0.0	0.0	0.0	0.0	0.8	2.3	3.5	4.4	5.0	5.3	5.8	5.7	5.7	5.7	4.1	2.4	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	20.3	
State Share of Federal Royalty	0.0	0.0	0.3	2.3	2.9	2.8	2.3	3.0	1.7	1.5	1.3	1.1	0.8	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	64.6	
Severance Tax	0.0	0.0	0.0	17.7	15.3	14.6	9.8	6.3	2.3	2.3	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.4	
Spill & Conserv. Tax	0.0	0.0	0.1	0.5	0.5	0.5	0.4	0.3	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	62.8	
Ad Valorem Tax	0.0	0.8	2.5	4.3	5.4	5.4	6.2	4.8	4.5	4.1	3.7	3.3	2.8	2.3	1.8	1.3	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	
NPSL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.5	
Income Tax	-0.26	-0.47	-0.70	1.08	1.84	2.18	2.11	1.87	1.88	1.98	1.47	1.30	1.11	0.95	0.64	0.37	-0.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	527.5	
Total (\$m, MOD)	-0.2	9.2	8.8	65.7	69.9	68.5	66.7	60.8	48.8	38.9	32.0	29.8	25.8	22.4	15.8	8.2	-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	263.8	
Federal	0.0	0.0	0.7	6.8	7.0	7.6	8.3	5.4	4.8	3.9	3.4	2.9	2.5	2.2	1.5	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	54.9	
Royalty (Net of State Share)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	263.8	
Income Tax	-4.43	-7.89	-11.89	28.22	31.31	37.37	38.28	22.07	29.07	27.05	29.21	22.31	18.10	16.34	10.97	8.27	-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	338.6	
Total (\$m, MOD)	-4.4	-8.0	-11.2	35.0	38.3	44.9	46.5	32.4	33.7	31.9	29.6	25.2	21.6	18.9	12.9	7.1	-12.7	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	486.2	
BP Exploration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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 (MOD)	-48.2	-91.4	-84.5	28.7	82.5	100.5	100.8	87.8	74.7	81.8	50.8	42.3	35.7	30.3	20.4	10.97	8.27	-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	
Funds Flow \$/bbl (MOD)	N/A	N/A	-52.86	2.75	8.43	7.19	8.60	8.18	9.21	9.25	8.28	8.34	8.57	8.95	10.18	10.20	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Net Income (MOD)	4.7	7.7	20.7	78.4	88.7	98.2	88.6	44.8	38.7	33.1	27.3	20.1	20.1	17.7	12.2	7.1	13.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Net Income \$/bbl (MOD)	N/A	N/A	13.21	5.13	4.85	4.17	4.14	4.55	4.84	5.02	4.87	5.09	5.28	5.81	6.11	6.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	528.7

(\$m, REAL)	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total		
State	0.0	0.0	3.8	38.1	39.7	34.8	28.6	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	765.8		
State Royalty	0.0	0.0	0.0	0.0	0.7	2.0	2.8	3.5	3.8	4.0	4.1	4.1	3.8	3.8	2.7	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	37.0		
State Supplemental Royalty	0.0	0.0	0.0	0.0	0.7	2.0	2.8	3.5	3.8	4.0	4.1	4.1	3.8	3.8	2.7	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	18.3	
State Share of Federal Royalty	0.0	0.0	0.3	2.3	2.3	1.8	1.6	1.2	1.1	0.8	0.8	0.8	0.8	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	57.5	
Severance Tax	0.0	0.0	0.0	18.1	10.5	12.7	7.8	5.1	1.8	0.4	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	2.8		
Spill & Conserv. Tax	0.0	0.0	0.1	0.4	0.4	0.4	0.3	0.2	0.2	0.1	0.1	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	42.0	
Ad Valorem Tax	0.0	0.8	2.3	3.8	4.8	4.8	4.3	3.8	3.5	3.1	2.7	2.3	1.9	1.5	1.2	0.8	0.4	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	
NPSL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.8	
Income Tax	-0.3	-0.5	-0.7	1.5	1.8	1.8	1.8	1.5	1.2	1.2	1.1	0.8	0.8	0.8	0.4	0.2	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	434.3	
Total (\$m, REAL)	-0.2	9.2	8.8	65.8	68.8	68.2	66.7	60.8	48.8	38.9	32.0	29.8	25.8	22.4	15.8	8.2	-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	188.8	
State Royalty - Real Disc.	0.0	0.0	0.2	2.4	2.6	2.3	2.0	1.8	1.4	1.2	1.2	1.2	1.1	1.0	0.8	0.4	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	20.1	
Supp Royalty - Real Disc.	0.0	0.0	0.0	0.0	0.5	1.4	2.0	2.2	2.3	2.3	2.0	1.8	1.8	1.8	1.1	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	0.0	10.8	
State Share of Federal Royalty	0.0	0.0	0.2	1.8	1.8	1.3	1.0	0.8	0.8	0.5	0.4	0.3	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	42.1	
Severance Tax - Real Disc.	0.0	0.0	0.0	10.3	10.4	8.2	5.4	3.2	1.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	
Spill & Conserv. Tax - Real Disc.	0.0	0.0	0.0	0.4	0.3	0.3	0.2	0.1	0.1	0.1	0.1	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	27.1	
Ad Valorem Tax - Real Disc.	0.0	0.7	2.1	3.2	3.7	3.3	2.8	2.5	2.1	1.7	1.4	1.2	0.9	0.7	0.5	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	0.3	
NPSL - Real Disc.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.8	
Income Tax - Real Disc.	-0.3	-0.4	-0.6	1.2	1.3	1.4	1.2	1.0	0.8	0.7	0.8	0.5	0.4	0.3	0.2	0.1	-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	279.7
Total - Real Disc.	-0.3	-0.3	-0.6	1.2	1.3	1.4	1.2	1.0	0.8	0.7	0.8	0.5	0.4	0.3	0.2	0.1	-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	
NPSL for Chart BBAE(12)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.6	6.2	6.2	6.0	5.1	4.3	3.8	3.0	2.5	2.1	1.7	1.4	1.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.2	
Royalty (Net of State Share)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	221.8	
Income Tax	-4.4	-7.8	-11.2	25.7	27.8	32.0	30.1	25.8	22.9	20.4	18.4	15.8	13.1	10.9	7.1	3.8	-3.3	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	288.1	
Total (\$m, REAL)	-4.4	-7.8	-10.7	31.9	34.0	38.0	35.2	30.1	28.2	22.4	20.8	17.8	14.8	12.7	8.0	4.5	-3.3</																

	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
NPSL Calculation																															
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%	
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%	
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%	
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%	
Revenue Account																															
Prod. Revenue	0.0	0.0	15.8	158.3	183.3	183.3	141.8	122.8	103.7	87.8	75.3	84.3	54.7	46.5	31.5	18.2	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	
Operating Costs	0.0	0.0	(2.4)	(23.0)	(23.7)	(23.8)	(20.8)	(18.2)	(15.8)	(11.7)	(11.5)	(9.8)	(8.5)	(7.2)	(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	
Production Taxes	0.0	0.0	(0.0)	(14.2)	(17.3)	(12.0)	(7.8)	(6.3)	(2.0)	(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	
Ad Valorem Tax	0.0	(0.8)	(2.0)	(2.4)	(4.3)	(4.2)	(4.1)	(3.8)	(3.5)	(2.2)	(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	
UOP Alen. Costs	0.0	0.0	(0.4)	(1.8)	(3.9)	(5.8)	(5.2)	(4.0)	(3.0)	(2.2)	(1.7)	(1.2)	(0.8)	(0.8)	(0.7)	(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	
Closing Balance	0.0	(0.8)	10.8	115.8	118.1	117.8	103.8	81.4	79.7	88.5	59.0	50.4	42.8	36.7	24.8	14.3	(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	
Dev. Account																															
Beginning Balance	(282.0)	(327.8)	(428.4)	(551.1)	(541.8)	(487.8)	(418.8)	(348.0)	(279.4)	(219.5)	(186.2)	(118.5)	(79.8)	(27.2)	(2.2)	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	
Capital Expend.	(47.2)	(77.8)	(87.2)	(83.2)	(74.3)	(113.5)	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	
Prod Rev And Credit	0.0	0.0	10.8	115.8	119.1	117.8	103.8	81.4	79.7	88.5	59.0	50.4	42.8	36.7	24.8	14.3	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	
Prinm Closing Bal.	(204.2)	(408.3)	(512.0)	(498.3)	(447.0)	(383.7)	(319.7)	(254.4)	(198.7)	(151.0)	(107.2)	(68.1)	(32.8)	(8.8)	(2.8)	7.1	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	
Average Annual DA Balance	(282.1)	(384.4)	(473.7)	(524.8)	(494.4)	(435.7)	(367.7)	(300.2)	(238.3)	(186.2)	(136.7)	(83.2)	(54.2)	(18.0)	10.2	7.1	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	
Accrued Interest	(23.4)	(20.2)	(28.1)	(42.2)	(40.8)	(35.0)	(28.2)	(24.8)	(18.8)	(15.2)	(11.2)	(7.7)	(4.5)	(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	
DA Closing Balance	(227.8)	(425.4)	(551.1)	(541.8)	(487.8)	(418.8)	(348.0)	(279.4)	(219.5)	(186.2)	(118.5)	(79.8)	(27.2)	(2.2)	22.8	14.3	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	
NPSL Payment Acc.																															
Profit 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	0.0	0.0	22.8	14.3	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	
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	0.0	0.0	0.0	0.0	0.0	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 nil if NPSL ON/OFF switch in central box turned to "OFF"

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 Take										18.342%	
Y181		228,000	18.08%						18.87%	3.014%	
Y0178		64,000	5.12%						18.87%	0.964%	
		1,380,000	100.00%							3.837%	
Effective Federal Royalty with 27% of Federal Take										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	1959	1958	1957	1956	1955	1954	1953	1952	1951	1950	Total	
BTFF																																								1591	
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	49.7	38.3	27.2	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	87	
Saverance 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	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	63	
AVT	0.0	0.8	2.5	4.3	5.4	8.4	8.2	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	237	
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38	
oper	0.0	0.0	3.1	29.3	30.3	30.5	28.1	23.2	18.8	16.8	14.7	12.7	10.8	8.3	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1182	
Abandonment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	
Gross Profit	0.0	-0.8	14.3	150.2	154.8	157.2	138.2	121.7	105.5	90.2	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	383	
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	798	
capex	53.9	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	76		
BTFF	-63.9	-98.8	-97.3	69.1	128.8	146.8	158.2	121.7	108.8	98.2	77.8	68.8	88.8	49.8	32.8	18.3	-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	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	19.0	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	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	29.8	24.8	18.7	19.7	3.8	0.8	0.2	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	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	3.8	0.8	0.2	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	827
Fed. Tax Income	-12.9	-23.3	-25.0	82.3	81.8	108.8	125.7	82.5	84.7	78.8	73.8	68.0	85.7	47.8	32.0	18.3	-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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
UOP Abandonment	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	Total	
Rate (\$/bbl)	0.00	0.00	0.78	0.38	0.43	0.43	0.43	0.40	0.37	0.34	0.30	0.27	0.23	0.19	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36	
Total (\$/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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DD&A	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	Total	
Rate (\$/bbl)	0.00	0.00	3.00	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	0.80	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	0.00	0.00	0.00	0.00	385	
Total (\$/bbl)	0.0	0.0	3.8	28.5	48.8	57.2	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	0.80	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	0.00	0.00	0.00	0.00		
Income Tax	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	Total	
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	0.37	-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	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.00	17	
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	-13.74	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	0.00	284
Total	-4.88	-8.45	-12.88	29.87	33.25	38.84	38.28	33.84	28.78	28.83	28.88	22.81	19.22	17.29	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	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	0.00	300
Funds Flow	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	Total	
ATFF - MOD	-49.2	-81.4	-84.5	28.7	82.3	100.5	100.8	87.8	74.7	81.8	50.8	42.3	35.7	30.3	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	498	
ATFF - Real	-49.2	-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	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 Disc	-49.2	-83.0	-88.8	29.8	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	173
ATFF - Cum NPV	49.2	-132.3	-202.1	-172.3	-109.1	-46.7	10.2	55.3	80.1	118.3	125.8	150.7	182.1	170.8	178.2	178.0	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	173.4	0.0	627	
Net Income	4.7	7.7	20.7	78.4	89.7	59.2	48.8	44.8	29.7	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Ad Valorem Tax	1.00	1.03	1.06	1.09	1.12	1.15	1.18	1.22	1.28	1.30	1.34	1.38	1.42	1.46	1.50	1.55	1.60	1.65	1.70	1.75	1.80	1.85	1.91	1.97	2.03	2.09	2.15	2.21	2.28	2.35	Total			
Inflation Rates	1998	1997	1996	1995	2001	2001	2001	2002	2004	2005	2006	2007	2008	2008	2009	2010	2011	2012	2012	2014	2015	2016	2017	2018	2020	2021	2022	2023	2024	2025	Total			
1998	1.0000																																	
1997		0.8375																																
1996			0.8750																															
1995				0.8333																														
2001					0.8231																													
2002						0.8187																												
2003							0.8333																											
2004								0.8889																										
2005									0.7778																									
2006										0.7500																								
2007											0.8671																							
2008												0.8333																						
2009													0.8000																					
2010														0.8000																				
2011															0.8000																			
2012																0.8000																		
2013																	0.8000																	
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2021																									0.8000									
2022																										0.8000								
2023																											0.8000							
2024																												0.8000						
2025																													0.8000					
Gross Field AVT	0.00	0.80	2.54	4.38	5.51	5.47	5.28	4.93	4.69	4.21	3.80	3.20	2.88	2.37	1.83	1.25	0.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
BP Net AVT	0.00	0.78	2.49	4.28	5.40	5.36	5.18	4.83	4.49	4.13	3.72	3.29	2.92	2.32	1.79	1.23	0.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		

	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	13.7	13.7	27.8	51.5	71.2	72.4	57.3	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)	13.7	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	0.00	0.00	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	15.8	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)	13.7	13.7	27.8	51.5	71.2	72.4	57.3	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	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)	35.3	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	0.27	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	0.00	0.00	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	23.5	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)	35.3	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	0.7	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	0.0	0.0	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 EMM MOD	0.0	0.0	5.8	38.5	68.8	52.3	45.7	38.1	31.3	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 Bidder

Original Bidder Name	Current Name	Phone Number	Address	City	State
AMERADA HESS CORPORATION		713 699-0287	ATtn: J. Y. CHESTNUT	880 DALLAS ST	HOUSTON TX
AMOCO PRODUCTION COMPANY		713 693-6938	ATtn: LAND MANAGER/USA	PO BOX 2897	HOUSTON TX
ARLINC FIO FIELD COMPANY		907 285-4231	ATtn: LAND MANAGER	P.O. BOX 10000	ANCHORAGE AK
CHEVRON USA, INC.		713 694-2885	PO BOX 1465	ATtn: P.J. WALKER	HOUSTON TX
CRIS SERVICE COMPANY	CRIS USA INC.	916 894-2885	PO BOX 308		TULSA OK
CONOCO INC.		713 228-8706	688 NORTH DAWY ABERFORD	ATtn: WILLIAM DAUGHERTY	HOUSTON TX
COOK INLET ENERGY INC.		907 288-8948	PO BOX 98838		ANCHORAGE AK
EDCON CORPORATION		713 694-7889	LAND REGULATORY AFFAIRS	PO BOX 2886	HOUSTON TX
GATF OIL COMPANY	TRALCO INC.	388 776-4144	PO BOX 2638	ATtn: LAND DEPARTMENT	DENVER CO
GULF OIL CORPORATION	CHEVRON USA, INC.	713 784-7665	PO BOX 1465	ATtn: P.J. WALKER	HOUSTON TX
NOVAG INC.		907 693-6468	C/O JOHN MERRICK	608 S ST 407	ANCHORAGE AK
MARTIN OIL COMPANY		713 623-4408	ATtn: CONTRACT & DIVISION ORDER	P.O. BOX 2049	HOUSTON TX
MORL OIL CORP.		214 981-8888	ATtn: PROPERTY MANAGEMENT	PO BOX 68822	DALLAS TX
MURPHY OIL CORPORATION	MURPHY EXPLOR & PROD CO	604 881-8911	ATtn: LAND DEPARTMENT	P.O. BOX 61781	NEW ORLEANS LA
NANA REGIONAL CORPORATION INC.		907 285-4789	1088 E. SIMPSON BLVD.	ATtn: VICE PRESIDENT MEMBERS	ANCHORAGE AK
PHILIPS PETROLEUM COMPANY		713 489-8741	PO BOX 7167	ATtn: ALASKA REGIONAL MANAGER	HOUSTON TX
PLACID OIL CO		916 844-2885	C/O CRIS USA INC.	P.O. BOX 288	TULSA OK
ROSWAY PETROLEUM INC.	ROSWAY OIL INC.	907 294-6665	TWO POST OAK TOWER	608 WILKINSON	HOUSTON TX
SEALASKA CORP.		907 696-1612	ONE SEALASKA PLAZA, SUITE 408	DR WILLIAM M HOWE, PRESIDENT	JUREAU AK
SHELL OIL COMPANY		713 678-8214	TWO SHELL PLAZA	PO BOX 2897	HOUSTON TX
SONO NATURAL RESOURCES	SP EXPLORATION (ALASKA) INC.	907 661-6211	E. P. ZELICNY, JR.	PO BOX 77442/PO BOX 18, DENSON BL	ANCHORAGE AK
TEXACO INC.		303 778-4144	PO BOX 2789	ATtn: LAND DEPARTMENT	DENVER CO
TEXAS EASTERN EXPLORATION COMPANY	EMERSON OIL & CO INC.	713 696-8471	C/O ALAN R. BRILLINGTON	4201 FM 190 WEST, STE. 310	HOUSTON TX
TEXAS GULF INC.		987 274-6180	894 MONROE STREET		GOLDEN CO
UNION OIL COMPANY OF CALIFORNIA		907 276-7380	PO BOX 17807	ATtn: LAND MANAGER	ANCHORAGE AK

34-02-1-155 17:23
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 ADNR/DIV OIL & GAS
 FAX NO. 478-7504
 STATE OF ALASKA

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 689612
	.	.	19	NANA PERSONAL CORPORATION INC	907 2884100
	.	.	18	NORAS INC	907 5012888
			9	AMOCO PRODUCTION COMPANY	715 888823
			7	CITIB SERVICE COMPANY	OOY USA INC. 918 9812885
			7	ROWAN PETROLEUM INC	ROWAN DRILLING 907 278248
			7	GULF OIL CORPORATION	CHEVRON U.S.A. INC 713 754785
			7	PLACID OIL CO	918 5813885
			7	GETTY OIL COMPANY	TEXACO INC 303 7884134
			7	TEXAS GULF INC.	987 2785108
			7	CONOCO INC	713 2882786
			14	MARATHON OIL COMPANY	713 6888880
			14	AMERADA HESS CORPORATION	713 6888337
			18	MURPHY OIL CORPORATION	MURPHY EXPLOR. & PROD. CO 984 9812311
			19	SHELL OIL COMPANY	713 8704314
			20	CHEVRON U.S.A. INC	713 754785
			21	EDCON CORPORATION	718 6887008
			21	UNION OIL COMPANY OF CALIFORNIA	907 2787008
			22	ATLANTIC RICHFIELD COMPANY	907 2884834
	ADL	312034			
	.	.	21	EDCON CORPORATION	718 6887008
	.	.	21	UNION OIL COMPANY OF CALIFORNIA	907 2787008
	.	.	21	ATLANTIC RICHFIELD COMPANY	907 2884834
	.	.	21	CHEVRON U.S.A. INC	718 754785

24-02-1336 17:33
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 ADNR/DIV OIL & GAS
 FAX NO. 515015030415

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 888366
7			GETTY OIL COMPANY	TEXACO INC	308 784184
7			TEXAS GULF INC.		907 2789100
7			PLACID OIL CO		918 8613325
7			ROMAN PETROLEUM INC	HOWARD DRILLING	907 2788408
7			GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 7547885
7			CONOCO INC		713 2832736
7			CITIB SERVICE COMPANY	OKY USA INC.	918 8813885
17			EDSON CORPORATION		713 8887000
18			COOK INLET REGION INC		907 2838188
18			MONLAG INC		907 8812888
18			SEALASKA CORP		907 5381912
18			LIANA REGIONAL CORPORATION INC		907 2541888
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 8884471
3			AMOCO PRODUCTION COMPANY		713 888366
4			PLACID OIL CO		918 8613325
4			CONOCO INC.		
4			TEXAS GULF INC.		907 2789100
4			CITIB SERVICE COMPANY	OKY USA INC.	918 8813885
5			SHELL OIL COMPANY		713 8780514
6			CHEVRON U.S.A. INC		713 7547885
6			PHILLIPS PETROLEUM COMPANY		713 8883741

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 FAX NO. 407 560 0415

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 ADNR/DIV OIL & GAS

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UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
ADL	312799				
		1	AMERADA HESS CORPORATION		713 698837
		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 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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APR 1988
 APR 1988
 APR 1988

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 9618838
			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	COX 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 38.05.180, 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 Amerada 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 Amerada 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 Amerada. 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)

discusses "production removed or sold from the lease" and the "share of the net profit derived from the lease" when describing the NP&L bidding method. (Emphasis added.) A plain reading of this language indicates that calculations are based on the money expended upon and earned from the lease. The statute does not suggest an intent to link these accounts to a particular lessee.

BP's analysis of the legislative history, the analogous federal statute, and other regulations support this reading, which is also apparent from the statute's face. For example, BP points to various reports contemplated by the Legislature when discussing the Alaska Land Act's 1976 amendments. Of particular interest is a 1977 report by Mason Gaffney, "Oil & Gas Leasing Policy: Alternatives for Alaska in 1977 (A Report to the State of Alaska, Jay S. Hammond, Governor, Department of Natural Resources, Guy Martin, Commissioner, and to the Alaska State Legislature, Interim Committee on Oil and Gas Taxation and Leasing Policy, Chancy Croft, Chairman)" (Feb. 1, 1977) (Microfiche No. 511-517, Anchorage Law Library). In this report, Gaffney discusses the net profit share in terms of a "net proceeds tax", and notes that this tax "is in rem: it is levied on the income and expenses attributable to a particular 'thing', in this case the leasehold". Id. at 52-53. He clearly distinguishes it from the example of an income tax, which is levied "in personam". Id.

The analogous federal statute and regulations, found in 43 U.S.C. § 1337(a)(1)(D), (E), (F) (West 1986) and 30 C.F.R. 220, also aid interpretation. In answer to a question about the assignability of the development account (called a "capital recovery account", in the federal scheme), the federal Minerals Management Service stated:

Because the NPSSL capital account is maintained by lease and includes all costs incurred during the term of the NPSSL, any costs incurred by the lessee would be carried forward to the assignee in the case of a farmout. That is, the assignee would begin NPSSL operation with the same balance in the NPSSL capital account as that remaining at the time of the farmout. December 3, 1985 letter from William S. Goldmiller, Chief, Royalty Valuation & Standards Division, United States Department of the Interior, Minerals Management Service, to Daniel Mills, Landman, Texaco U.S.A. (Doc. Supp. at 93.)

The federal statute, like the state statute, has language describing the NPSSL system in terms of profits derived "from the lease". Thus, the federal government's interpretation of the NPSSL as lease-specific, provides support for reading Alaska's NPSSL system in the same manner.

The three-fold purpose of AS 38.05.180 has been discussed in Kelly v. Zamarelio, 486 P.2d 906 (Alaska 1971), and includes an intent "to insure that leases on valuable oil and gas producing state lands will be made available to the public on a fair and equitable basis, that the state will be adequately compensated for its natural resources, and that the state's resources are developed in an orderly fashion".

Id. at 912. The purposes of the NPBL system specifically include avoiding premature lease abandonment, allowing less well financed operators to compete, and enabling payments to correspond with benefits. University of California, Walter J. Mead, Professor of Economics, "Comments From an Economic Perspective on House Bill No. 854 in the Legislature in the State of Alaska, Tenth Legislature -- Second Session", May 15, 1978. (Doc. Supp. at 415-416.)

11 AAC 83.219, as interpreted by DNR, furthers none of these aims and specifically detracts from some. For example, the fact that some of Marathon's expenses would be lost runs counter to the general purpose of fair and equitable availability of leases. Also, although the statute intends to insure adequate compensation of the state, DNR's interpretation would give the state, in this instance, more compensation than it would have had if Marathon had not transferred its interest. Thus, the regulation is not reasonably necessary to further the statute's purpose.

The correct interpretation of 11 AAC 83.219(b)(7) is that it pertains only to partial assignments of leasehold interests and would not apply to the complete assignment contemplated by BP and Marathon. This interpretation is consistent with the statute and furthers the statutory purposes by preventing double deductions of development costs.

Specifically, it prevents a development cost that is included in the assignor's development account from also being included in the assignee's development account. This interpretation gives effect to the regulation's requirement that "the lessee transferring the production interest must credit his development account for a like amount". 11 AAC 83.219(b)(7). This sentence would have no meaning under DNR's interpretation that the regulation applies to total assignments, as the assignor would have no development account to credit.

The effect of applying this regulation to a partial assignment is that there is no net change in the total amount of development costs that will be used to calculate net profits from the lease. It merely results in a reallocation of the total development costs.

The state alternatively argues that BP and Marathon are effectuating a partial assignment, because Marathon plans to retain an overriding royalty interest. The court finds that the agreement assigns all of Marathon's interests as lessee to BP, particularly given the fact that the regulation defines a lessee as someone who holds a "working interest" which, by definition, differs from a "royalty interest". See 11 AAC 83.295(27) and 11 AAC 83.295(30). Consequently, because this is a total assignment and the regulation, properly interpreted, applies to partial assignments, DNR's decision must be REVERSED.

DATED at Anchorage, Alaska this 25 day of July,

1991.

Dana Fabe
DANA FABE
SUPERIOR COURT JUDGE

I certify that on 7/25/91,
a copy of the above was mailed to each
of the following at their address of
record:

Mason / Maasera / Johnson
J. Jensen
Secretary / Deputy Clerk



Alaska State Legislature

Official Business

SENATE RESOURCES COMMITTEE

State Capitol
Juneau AK 99801

FAX MEMO

TO: ~~Mr. John Morgan/BP Exploration~~ (564-5514)
~~Commissioner John Shively, DNR~~ (269-8918)
~~Attorney General Bruce Botelho~~ (465-2075)

5900

FROM: Annette Kreitzer, Aide to
Senate Resources Committee 

DATE: April 1, 1996

RE: Requests for information from March 29 Resources meeting

Attached is the list of requests for information from the March 29 meeting of the Senate Resources Committee. Please provide the information to me as soon as possible. Information regarded by the state as confidential should be gathered to be disseminated during a confidential session of the committee. Please advise me, though, when the information is ready for the committee, so that the chairman can schedule a confidential session.

Thank you for your assistance.



Alaska State Legislature

Senate Resources Committee
Information Requests from Committee Members
re: SB 318: Northstar Lease Agreement
March 29, 1996 Hearing

State Capitol
Juneau AK 99801

Official Business

FIRST REQUEST:

- Halford: How much did BP pay Amerada Hess for the leases? (Available to Legislature under confidentiality measure).

SECOND REQUEST:

In response to question from Senator Pearce, Senator Leman requested BP provide details on what BP agreed to in BP's successful January bid on leases in Venezuela that are similar or the same as net profit share leases.

THIRD REQUEST:

Halford:

Want an analysis from Law re: conclusion as to whether development fund carries forward.

- ✓ Want list of other bidders on these parcels/leases in the sale (where BP acquired Amerada Hess leases).

If there is a lawsuit that stops development because of a change in the bid variable, what happens to the economic benefits (in the BP agreement)?

Want economic module to be run on 135 million barrels and on double that.

- ✓ Want to know what the projected severance tax rates will be.

FOURTH REQUEST:

- ✓ Pearce: Federal definition of net profit share. (Patrick Coughlin verbalized at 3/30/96 hearing, but this was not passed out to members for context of where the definition appears. Mr. Coughlin needs to provide the definition and its context to the committee.)

FIFTH REQUEST:

Leman: Wants list of how many and locations of employees from BP, CIRI, VECO and Arctic Slope and their subsidiaries. (after testimony from these companies regarding local hire)

SIXTH REQUEST:

- ✓ Leman: Wants BP to provide the committee comparable numbers for BP's decisions to proceed with other North Slope developments. Estimated per barrel development costs which BP management considered before committing to develop: 1) Kuparuk, 2) shallow oil deposits at Milne Point (Schrader Bluff), 3) Niakuk, 4) Pt. McIntyre and any other North Slope fields BP has developed.



BP EXPLORATION

Alaska Exploration & Developments

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

April 2, 1996

Hon. Loren Lemam
Chairman, Senate Resources Committee
Alaska State Legislature
State Capitol
Juneau, AK 99801

Dear Senator Lemam:

Per the request by Annette Kreitzer of your staff on April 1, I have enclosed responses to your six requests regarding SB 318 on the Northstar Lease Agreement. If you require additional information, please do not hesitate to call me (907-564-4892) or Daryl Kleppin (907-564-5418) on my staff.

Very truly yours,

A handwritten signature in black ink, appearing to read 'E. M. Luttrell', written over a horizontal line.

E. M. Luttrell
Vice President
BP Exploration, Alaska Inc.

BP Exploration, Alaska (Inc.)
Response to Requests by Senate Resources Committee
SB 318 - Northstar Lease Agreement

- 1.) How much did BP pay Amerada Hess for the leases?

The terms of the purchase agreement between Amerada Hess and BP for the Northstar leases are confidential. BP did not secure permission from Amerada to release that information under confidentiality agreements to specific staff within the Department of Natural Resources. We have requested permission from Amerada to provide that information to the Alaska Legislature under a similar confidentiality agreement.

- 2.) Please provide details on what BP agreed to in BP's successful bid on leases in Venezuela that are similar or the same as net profit share leases.

Both Alaska and Venezuela derive their oil income from a combination of taxes and royalties. In addition, Venezuelan law allows the State Oil Company (PDVSA) to participate in the new E&P ventures up to 35% by paying full proportionate costs including any historical costs which are inflated at the prime interest rate. Reporting in the recent press assumes that PDVSA will do so.

Assuming that PDVSA takes its 35% share, the total government take in Venezuela (taxes, royalty, PDVSA) equals about 92% of profits. A comparable value for Northstar in Alaska is about 62% (State royalty, severance, and income tax; Federal royalty and income tax).

Venezuela can take a higher proportion of the benefits since the costs of developing, operating and transportation are substantially lower. In Venezuela, BP's cost per barrel (F&D, lifting, transportation) is about \$2.00 per barrel. Comparable costs in Alaska are about \$7.00 per barrel. In Venezuela, BP looks to make a profit of about \$1.20 per barrel from a capital investment (F&D) of about \$1.00 per barrel (a 1.2 ratio). In Alaska, we look to make about \$3.25 per barrel on a capital investment of about \$3.50 per barrel (a .94 ratio).

Economically (and from a view of simple capital efficiency), both of these ventures look attractive to BP, although BP's profit per barrel in Alaska is higher than in Venezuela. We also expect a much greater reserve potential in Venezuela (up to possibly 1 billion barrels).

- 3.) a) Please provide analysis from Law re: conclusion as to whether development fund carries forward.

To be provided by Alaska Department of Law

- b) Please provide a list of other bidders on these parcels/leases in the sale (where BP acquired Amerada leases).

See attachment #1.

c) If there is a law suit that stops development because of a change in the bid variable, what happens to the economic benefits (in the BP agreement)?

To be provided by DNR staff.

d) Please provide economic model runs on 135 million barrels and on double that.

The DNR will provide for an upside development case with reserves of 160 million barrels.

e) What is the projected severance tax rates?

The ELF at field startup (1999) is .7 and goes to .03 in 2005 and zero there after. Therefore, the severance rate varies from 8.7% in 1999 to zero in 2006.

4.) Please provide Federal definition of net profit share.

DNR and Department of Law to provide.

5.) Please provide list of how many and location of employees from BP, CIRI, Veco, and Arctic Slope and their subsidiaries.

At year end 1995, BP employed 1,077 in Alaska of which 917 or 85.1% were Alaska residents. BPX would encourage it's Northstar Alliance contractors to provide similar data to the committee.

6.) Please provide to the committee a comparable number for BP's decisions to proceed with other North Slope developments. Estimate per barrel development costs which BP management considered before committing to develop: 1)

Kuparuk; 2) shallow oil deposits at Milne Point (Schrader Bluff); 3) Niakuk; 4) Pt. McIntyre and other North fields BP has developed.

Field	Sanction Year	Development Cost (\$/bbl)	ANS WC (\$/bbl) (MOD)	ANS WC (1996\$) (real)
Kuparuk	1982	6.65	30	40
Endicott	1985	5.40	25	33
PBU: GHX-2	1992	4.45	18	19
Pt McIntyre	1992	2.30	18	19
Niakuk	1993	2.50	16	17
Not sanctioned				
MPU-Schrader Bluff	1996-97??	1.80	17	17
Northstar	1996-97??	2.90	17	17

Attachment #1

Sale 30 (12/79) Northstar Bidding

The following table outlines the sale 30 results (NPSL) showing the successful bidder and parties that bid unsuccessfully.

ADL 312798		
Bid Group/Co.	Co. Interest	NPS Bid
Amerada Hess	100%	93.20000%
Texas Eastern	50%	80.58789%
Texaco	50%	
Amoco	100%	71.12500%
Texas Gulf	10%	61.87000%
Conoco	48%	
Placid	22%	
Cities Service	20%	
Murphy	10%	40.79133%
Shell	90%	
Phillips	50%	34.48464%
Chevron	50%	

ADL 312808		
Bid Group/Co.	Co. Interest	NPS Bid
Texas Eastern	100%	85.25978%
Texas Gulf	6%	38.12530%
Gulf Oil	25%	
Conoco	25%	
Placid	16%	
Rowan	3%	
Cities Service	25%	
Unocal	100%	25.50000%
Phillips	50%	10.14550%
Chevron	50%	
Atlantic Richfield	40%	2.11111%
Murphy	10%	
Shell	50%	

ADL 312799		
Bid Group/Co.	Co. Interest	NPS Bid
Amerada Hess	100%	91.20000%
Amoco	100%	82.59999%
Texas Eastern	50%	80.56789%
Texaco	50%	
Rowan	2%	71.62539%
Conoco	20%	
Texas Gulf	5%	
Getty	0.2	
Placid	13%	
Gulf	20%	
Cities Service	20%	
Murphy	10%	56.77133%
Shell	90%	
Phillips	33%	43.26273%
Mobil	33%	
Chevron	34%	
Unocal	100%	32.00000%

ADL 312809		
Bid Group/Co.	Co. Interest	NPS Bid
Texas Eastern	100%	35.25978%
Amoco	100%	71.25009%
Marathon	50%	53.83000%
Amerada	50%	
Gulf	25%	46.37549%
Placid	16%	
Getty	25%	
Texas Gulf	6%	
Rowan	3%	
Cities Service	25%	
Unocal	100%	38.00000%
Mobil	34%	34.23333%
Phillips	33%	
Chevron	33%	
Atlantic Richfield	45%	31.89117%
Shell	55%	

Oil and Indian Oil
MMS
for reporting and paying

Oil and Indian Gas

gas
produced gas
for reporting and paying

Minerals, General—
Reserved

Oil—Cool

royalty interest

Other Solid Minerals—
Reserved

Subsided Resources

Leads,
in geothermal resources,
royalty,
for standards for report-
royalties.

Subpart—Reserved

field in the lease, unless the Secretary, pursuant to the provisions of the applicable mineral leasing laws, reduces, or in the case of OCS leases, reduces or eliminates, the royalty rate or net profit share set forth in the lease.

(b) For purposes of this subpart, the use of the term royalty(ies) includes the term net profit share(s).

§ 202.105 Minimum royalty.

For leases that provide for minimum royalty payments, the lessee shall pay the minimum royalty as specified in the lease.

Subpart C—Federal and Indian Oil

§ 202.106 Royalty on oil.

(a) Royalties due on oil production from a lease are subject to the requirements of this part, including conditions separated from gas without processing, shall be at the royalty rate established by the terms of the lease. Royalty shall be paid in advance unless MMS requires payment in kind. When paid in value, the royalty due shall be the value, for royalty purposes, determined pursuant to part 206 of this title multiplied by the royalty rate in the lease.

(b)(1) All oil (except oil unavoidably lost or used on, or for the benefit of, the lease, including that oil used offshore for the benefit of the lease when such off-lease use is permitted by the MMS or BLM, as appropriate) produced from a Federal or Indian lease to which this part applies is subject to royalty.

(2) When oil is used on, or for the benefit of, the lease at a production facility handling production from more than one lease with the approval of the MMS or BLM, as appropriate, or at a production facility handling method or communitization production, only that proportionate share of each lease's production (actual or allocated) necessary to operate the production facility may be used royalty-free.

(3) Where the terms of any lease are inconsistent with this section, the lease terms shall govern to the extent of that inconsistency.

(c) If BLM determines that oil was unavoidably lost or wasted from an offshore lease, or that oil was drained from an onshore lease for which compensatory royalty is due, or if MMS de-

termines that oil was unavoidably lost or wasted from an offshore lease, then the value of that oil shall be determined in accordance with 30 CFR part 206.

(d) If a lessee receives insurance compensation for unavoidably lost oil, royalties are due on the amount of that compensation. This paragraph shall not apply to compensation through self-insurance.

(e)(1) In those instances where the lessee of any lease committed to a federally approved unitization or communitization agreement does not actually take the proportionate share of the agreement production attributable to its lease under the terms of the agreement, the full share of production attributable to the lease under the terms of the agreement nonetheless is subject to the royalty payment and reporting requirements of this title. Except as provided in paragraph (e)(2) of this section, the value, for royalty purposes, of production attributable to unitized or communitized leases will be determined in accordance with 30 CFR part 206. In applying the requirements of 30 CFR part 206, the circumstances involved in the actual disposition of the portion of the production to which the lessee was entitled but did not take shall be considered as controlling in arriving at the value, for royalty purposes, of that portion as though the person actually selling or disposing of the production were the lessee of the Federal or Indian lease.

(2) If a Federal or Indian lessee takes less than its proportionate share of agreement production, upon request of the lessee MMS may authorize a royalty valuation method different from that required by paragraph (e)(1) of this section, but consistent with the purposes of these regulations, for any volumes not taken by the lessee but for which royalties are due.

(3) For purposes of this subchapter, all persons actually taking volumes in excess of their proportionate share of production in any month under a unitization or communitization agreement shall be deemed to have taken royalty-free all persons actually taking less than their proportionate share of the agreement production for that month.

(4) If a lessee takes less than its proportionate share of agreement produc-

tion for any month but royalties are paid on the full volume of its proportionate share in accordance with the provisions of this section, no additional royalty will be owed for that lease for prior periods when the lessee subsequently takes more than its proportionate share to balance its account or when the lessee is paid a sum of money by the other agreement participants to balance its account.

(f) For production from Federal and Indian leases which are committed to federally approved unitization or communitization agreements, upon request of a lessee MMS may establish the value of production pursuant to a method other than the method required by the regulations in this title if: (1) The proposed method for establishing value is consistent with the requirements of the applicable statutes, lease terms, and agreement terms; (2) persons with an interest in the agreement, including, to the extent practical, royalty interests, are given notice and an opportunity to comment on the proposed valuation method before it is authorized; and (3) to the extent practical, persons with an interest in a Federal or Indian lease committed to the agreement, including royalty interests, must agree to use the proposed method for valuing production from the agreement for royalty purposes.

(30 FR 1717, Jan. 11, 1969)

§ 202.107 Standards for reporting and paying royalties.

Oil volumes are to be reported in barrels of clean oil of 61 standard U.S. gallons (21 cubic inches each) at 60°F. When reporting oil volumes for royalty purposes, corrections must have been made for Gas, Sediment and Water (GS&W) and other impurities. Reported American Petroleum Institute (API) oil gravities are to be those determined in accordance with standard industry procedures after correction to 60°F.

(30 FR 1717, Jan. 11, 1969)

Subpart D—Federal and Indian Gas

Source: 30 FR 1717, Jan. 11, 1969, unless otherwise noted.

From Patrick Conner	
Co. DNR	
445-2400	
445-3810	

AUTHORITY: 5 U.S.C. 551 et seq.; 30 U.S.C. 206 et seq.; 25 U.S.C. 2201 et seq.; 30 U.S.C. 2202 et seq.; 30 U.S.C. 2203 et seq.; 30 U.S.C. 2204 et seq.; 30 U.S.C. 1701 et seq.; 30 U.S.C. 1702 et seq.; 30 U.S.C. 1703 et seq.; 43 U.S.C. 1201 et seq.; 43 U.S.C. 1202 et seq.; 43 U.S.C. 1203 et seq.

Subpart A—General Provisions—
(Reserved)

Subpart B—Oil, Gas, and OCS
Sulfur, General

Source: 30 FR 1317, Jan. 11, 1969, unless otherwise noted.

§ 202.61 Scope and definitions.

(a) This subpart is applicable to Federal and Indian (Tribal and allotted) oil and gas leases (except leases on the Ogea Indian Reservation, Ogea County, Oklahoma) and OCS sulfur leases.

(b) The definitions in subparts C, D, and E of part 206 of this title are applicable to subparts B, C, D, and E of this part.

§ 202.63 Royalties.

(a) Royalties on oil, gas, and OCS sulfur shall be at the royalty rate speci-

245-3810
Royalty including NP

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 2:35 PM

PLEASE DELIVER TO: Annette Kreitzer
Alaska Senate Resources Committee

FAX NUMBER: 465-3810

NUMBER OF PAGES (including cover): 9

FROM: Ken Boyd

COMMENTS:

Attached is Kevin Banks' analysis of 1) the effect of a delay on the Northstar development and 2) an increase in the reserve estimates. Please call if you have any questions.

Attachment

MEMORANDUM
DEPARTMENT OF NATURAL RESOURCES

State of Alaska
DIVISION OF OIL AND GAS

TO: Ken Boyd
Director

DATE: April 3, 1996

FILE NO:

THRU:

TELEPHONE: 269-8799

FROM: Kevin Banks *K. Banks*
Petroleum Economist

SUBJECT: Northstar Unit - Senate
Resource Committee
Requests

In response to Senator Halford's request about the effect on the economic benefits if a lawsuit delays development of the Northstar Unit, I analyzed the effect on economic benefits caused by a delay for any reason. In short, any delay increases the economic benefits to the state while decreasing the economic benefits to BPXA. The attached graph and table illustrate this point.

The graph shows that, as full production start-up is delayed beyond 1999, the net profit share falls and the supplemental royalty rises. The net profit share declines because the development account accrues interest at the prime rate. The supplemental royalty increases as the start-up date is delayed because of the effect of inflation, i.e., the supplemental royalty is triggered by a price that rises at just one-half the rate of inflation.

The first table shows in greater detail the effects of delaying full production start-up until 2002. This table is similar to one that was supplied in the DNR Northstar Briefing Paper, but includes a column to show the revenues from the supplemental royalty if the project is delayed.

I also considered Senator Halford's request to run the model at double BPXA's "most likely" reserve estimate of 130 million barrels. Following the hearing, I spoke to Senator Halford and he said I should be "realistic." Based on conversations with BPXA and DNR's resource evaluation staff, I do not believe that recovery of double the 130 million barrel estimate is realistic. Instead, I have run the model based on an assumption of 180 million barrels, which is the highest number put forward by either BPXA or DNR staff.

The four tables labeled "Reserves of 180+ Million Barrels" and "Reserves of 105+ Million Barrels" illustrate what happens to revenues if the reserves are much higher (though not doubled as Senator Halford suggested) and much lower than BPXA's "most likely" case. In the first two tables, I assume that reserves are 180 million barrels. This reserve estimate represents a 70 percent recovery rate—an unusually high number.¹ I also assumed that this recovery estimate is

¹Doubling the reserves as requested by Senator Halford would require a 100 percent recovery of BPXA's most likely original-oil-in-place estimate. The initial recovery rate for the Prudhoe Bay field was estimated at 40 percent. After substantial investment, the current recovery estimate has changed to 55 percent. A 70 percent recovery might be possible but only after extraordinary expense. Furthermore, the field would have to produce for many years before attaining this level.

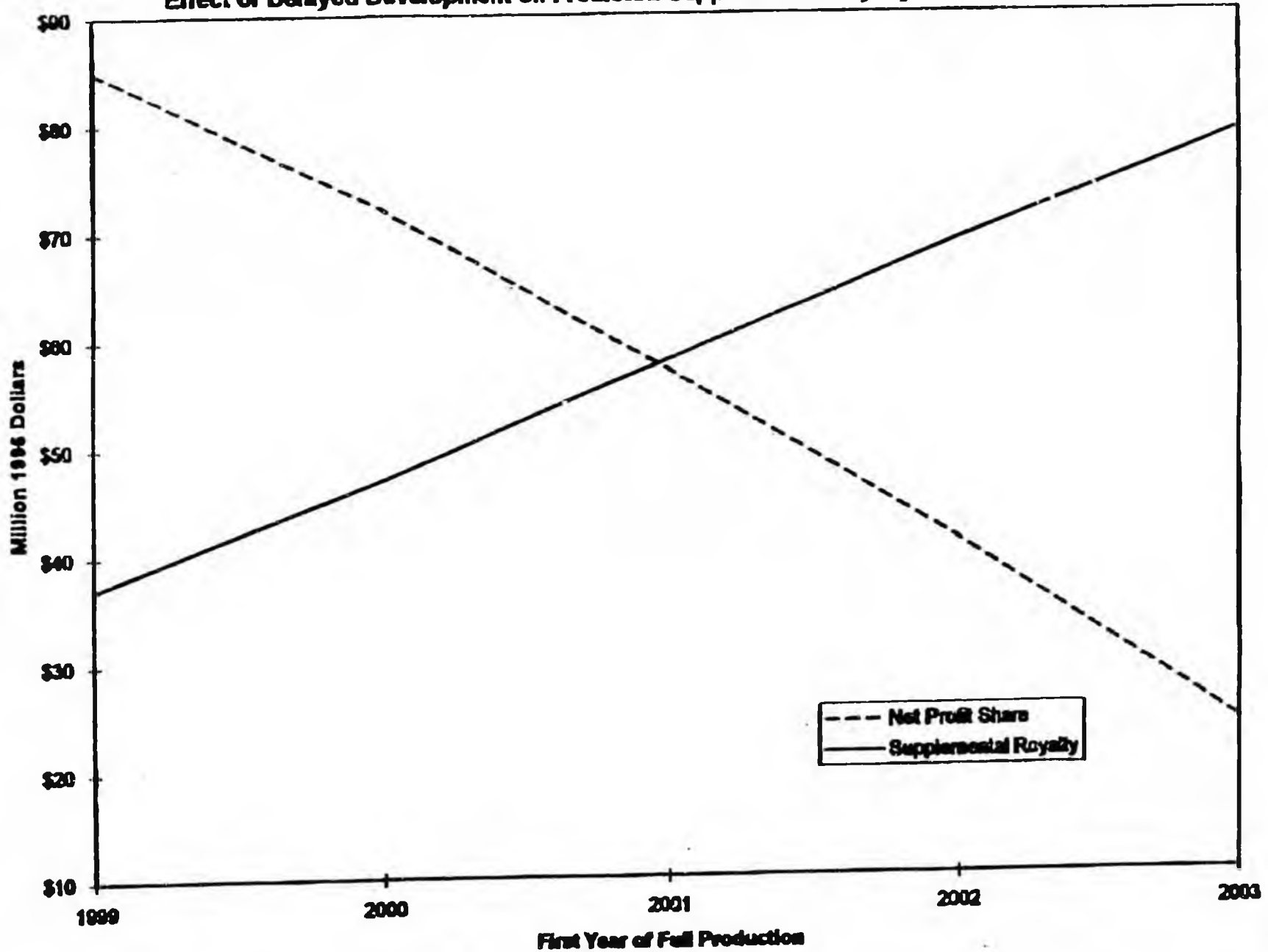
achieved by adding capital expenditures of only \$28 million to the most likely case for more drilling. BPXA's "upside" case envisions an additional \$91 million in capital expenditures to achieve reserves estimated at 160 million barrels. Other assumptions are held constant.

The second two tables show the downside, i.e., if reserves are only 105 million. In this case, I assume that the capital expenditures estimated for the most likely case are spent and the field never attains the most likely case production rates. Other assumptions are held constant.

04-03-1996 15:07 907 465 3886 DNR OFFICE OF THE COMMISSIONER

Northstar Proposal

Effect of Delayed Development on Predicted Supplemental Royalty and Net Profit Share



(This chart is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

Northstar Economic Evaluation



Estimated Total Revenues

Effect of Delay

Supplemental
Royalty and
1999 Development

Net Profit Share
and
1999 Development

Supplemental
Royalty and
2002 Development

Net Profit Share
and
2002 Development

(Real 1998 Dollars)

State Revenues

State Royalty	258	258	257	257
State Supplemental Royalty	██████████	0	██████████	0
NPSL	0	██████████	0	██████████
State Share of Federal Royalty	16	16	16	16
Severance Tax	58	58	56	59
Spill & Conserv. Tax	3	3	3	3
Ad Valorem Tax	42	42	46	46
Income Tax	24	22	22	23
Total	485	481	469	444

Federal Revenues

Royalty (Net of State Share)	44	44	44	44
Income Tax	215	198	205	213
Total	259	243	249	258

BPXA Cash Flow

After Tax Funds Flow	349	318	331	348
Real Rate of Return	20.0%	19.9%	19.2%	20.4%

Totals may not add due to rounding.

(This table is based on BPXA's most likely estimate of reserves, original and operating costs, and DNR's Full 700 Base Price Payment.)

4/29/98, 1:01 PM

04-03-1998 15:07 907 465 3886 DIST OFFICE OF THE COMMISSIONER

Northstar Economic Evaluation

Estimated Total Revenues

At Reserves of
 180+ Million Barrels.*

With Supplemental
 Royalty

With Net Profit Share

(Real 1996 Dollars**)

State Revenues

State Royalty	363	363
State Supplemental Royalty	██████████	0
NP&L	0	██████████
State Share of Federal Royalty	23	23
Severance Tax	89	91
Spill & Conserv. Tax	4	4
Ad Valorem Tax	52	52
Income Tax	37	26
Total	639	934

Federal Revenues

Royalty (Net of State Share)	63	63
Income Tax	341	237
Total	404	300

BPXA Cash Flow

After Tax Funds Flow	581	389
Real Rate of Return	23.9%	21.7%

*2001 assumes 180 MMBO total reserves; additional 8 production wells; a two year increase in field life, and an additional \$20 million in capital costs over BPXA's most likely case.

**Totals may not add due to rounding.

Northstar Economic Evaluation

Estimated Total Revenues

At Reserves of 180+ Million Barrels.*	With Supplemental Royalty	With Net Profit Share
	(Discounted Net Present Value**)	
State Revenues		
State Royalty	223	223
State Supplemental Royalty	[REDACTED]	0
NPSL	0	[REDACTED]
State Share of Federal Royalty	-14	14
Severance Tax	61	63
Spill & Conserv. Tax	2	3
Ad Valorem Tax	32	32
Income Tax	21	16
Total	389	524
Federal Revenues		
Royalty (Net of State Share)	39	39
Income Tax	195	149
Total	234	188
BPXA Cash Flow		
After Tax Funds Flow	281	194
Real Rate of Return	23.9%	21.7%

*DNR assumes 185 MMBO total reserves, additional \$ production wells, a two year increase in field life, and an additional \$26 million in capital costs over BPXA's most likely case.

**Assuming 10 percent nominal discount rate. Totals may not add due to rounding.

04-03-1886 15:08 907 465 3886 DNR OFFICE OF THE COMMISSIONER P.01

Northstar Economic Evaluation



Estimated Total Revenues

At Reserves of 105 Million Dollars* With Supplemental Royalty With Net Profit Share

(Real 1996 Dollars**)

State Revenues

State Royalty	206	206
State Supplemental Royalty	0	0
NPSL	0	0
State Share of Federal Royalty	13	13
Severance Tax	30	30
Spill & Conserv. Tax	2	2
Ad Valorem Tax	42	42
Income Tax	17	18
Total	340	312

Federal Revenues

Royalty (Net of State Share)	36	36
Income Tax	153	163
Total	189	199

BPXA Cash Flow

After Tax Funds Flow	234	256
Real Rate of Return	14.5%	15.1%

*DNR assumes 105 MBO total reserves, the minimum production indicated by BPXA in its "Proposal for Modified Lease Terms"

**Assuming 3.2 percent inflation rate from DOR Fall 1996 Base Price Forecast. Totals may not add due to rounding.

DNR OFFICE OF THE COMMISSIONER 907 465 3696 04-03-1998 15:08

Northstar Economic Evaluation



Estimated Total Revenues

At Reserves of 105 Million Dollars*

With Supplemental
Royalty

With Net Profit
Share

(Discounted Net Present Value**)

State Revenues

State Royalty	-136	136
State Supplemental Royalty	[REDACTED]	0
NPSL	0	[REDACTED]
State Share of Federal Royalty	-9	-9
Severance Tax	23	23
Spill & Conserv. Tax	1	1
Ad Valorem Tax	27	27
Income Tax	10	11
Total	-223	-207

Federal Revenues

Royalty (Net of State Share)	24	24
Income Tax	92	98
Total	116	121

BPXA Cash Flow

After Tax Funds Flow	92	102
Real Rate of Return	14.5%	15.1%

*DNR assumes 105 NBEDO total reserves, the minimum production indicated by BPXA in its "Proposal for Modified Lease Terms"

**Assuming 10 percent discount rate. Totals may not add due to rounding.

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DNR's Full Well Share Price Payment.)

Postnet Fax Note Date 4/25/96

To: <i>Caroline Weitzler</i>	From: <i>Patricia J. K...</i>
Co Dept: <i>Greater Leasing</i>	Co: <i>INTL</i>
Phone #: <i>405-2095</i>	Phone #: <i>209-5900</i>
Fax #: <i>465-3810</i>	Fax #:

Net Profit Share Lease Ownership

01-Apr-96

LEASE NUMBER	NAME	WORKING INTEREST %
ADL 312798	BP EXPLORATION (ALASKA) INC	100
	Total for Segment	1
ADL 312799	BP EXPLORATION (ALASKA) INC	100
	Total for Segment	1
ADL 312808	BP EXPLORATION (ALASKA) INC	100
	Total for Segment	1
ADL 312809	BP EXPLORATION (ALASKA) INC	100
	Total for Segment	1
ADL 312827	BP EXPLORATION (ALASKA) INC	50
	AMEXADA HESS CORPORATION	50
	Total for Segment	1
ADL 312828	DOYON LIMITED	0.8
	NANA REGIONAL CORPORATION	1.5
	COOK INLET REGION INC	2.5
	BP EXPLORATION (ALASKA) INC	95.5
	Total for Segment	1
ADL 312834	ARCO ALASKA, INC	33.33333
	UNION OIL COMPANY OF CALIFORNIA	33.33333
	EXXON CORPORATION	33.33334
	Total for Segment	1
ADL 312866	EXXON CORPORATION	100
	Total for Segment	1
ADL 343108	EXXON CORPORATION	50
	BP EXPLORATION (ALASKA) INC	50
	Total for Segment	1
ADL 343110	PHILLIPS PETROLEUM COMPANY	50
	MOBIL OIL CORPORATION	50
	Total for Segment	1

LEASE NUMBER	NAME	WORKING INTEREST %
ADL 343111	BP EXPLORATION (ALASKA) INC	100
	Total for Segment	1
ADL 343112	CHEVRON U.S.A. INC	33.33
	BP EXPLORATION (ALASKA) INC	66.67
	Total for Segment	1
	CHEVRON U.S.A. INC	100
	Total for Segment	A
	CHEVRON U.S.A. INC	33.33
	BP EXPLORATION (ALASKA) INC	66.67
	Total for Segment	B
ADL 355001	BP EXPLORATION (ALASKA) INC	100
	Total for Segment	1
ADL 355016	OXY USA INC	8.81
	BP EXPLORATION (ALASKA) INC	26.81
	BP EXPLORATION AND OIL COMPANY	64.38
	Total for Segment	1
	AMERADA HESS CORPORATION	50
	MIDGARD ENERGY COMPANY	50
	Total for Segment	A
ADL 355017	OXY USA INC	8.81
	BP EXPLORATION (ALASKA) INC	26.81
	BP EXPLORATION AND OIL COMPANY	64.38
	Total for Segment	1
ADL 355018	OXY USA INC	8.81
	BP EXPLORATION (ALASKA) INC	26.81
	BP EXPLORATION AND OIL COMPANY	64.38
	Total for Segment	1
ADL 355021	OXY USA INC	8.81
	BP EXPLORATION (ALASKA) INC	26.81
	BP EXPLORATION AND OIL COMPANY	64.38
	Total for Segment	1
	MIDGARD ENERGY COMPANY	50
	AMERADA HESS CORPORATION	50
	Total for Segment	A
ADL 355023	ARCO ALASKA, INC	100

LEASE NUMBER	NAME		WORKING INTEREST %
		Total for Segment	100
ADL 355024	ARCO ALASKA, INC		100
		Total for Segment	100
ADL 355029	EXXON CORPORATION		20
	ARCO ALASKA, INC		80
		Total for Segment	100
	AMERADA HESS CORPORATION		50
	EXXON CORPORATION		50
		Total for Segment	100
ADL 355030	ARCO ALASKA, INC		100
		Total for Segment	100
ADL 355031	ARCO ALASKA, INC		100
		Total for Segment	100
	HUNT PETROLEUM CORPORATION		18.80672
	ROSEWOOD RESOURCES INC		18.90756
	PLACID OIL COMPANY		64.28572
		Total for Segment	100
ADL 355032	ARCO ALASKA, INC		100
		Total for Segment	100
ADL 355034	ARCO ALASKA, INC		100
		Total for Segment	100
	HUNT PETROLEUM CORPORATION		18.80672
	ROSEWOOD RESOURCES INC		18.90756
	PLACID OIL COMPANY		64.28572
		Total for Segment	100
ADL 355035	ARCO ALASKA, INC		100
		Total for Segment	100
	ARCO ALASKA, INC		50
	TEXACO EXPLORATION & PRODUCTION		50
		Total for Segment	100
ADL 355036	UNION TEXAS PETROLEUM CORPORATION		12.5
	ARCO ALASKA, INC		87.5
		Total for Segment	100
	HUNT PETROLEUM CORPORATION		4.20168

LEASE NUMBER	NAME		WORKING INTEREST %
	ROSEWOOD RESOURCES INC		4.72880
	UNION TEXAS PETROLEUM CORPORATION		12.5
	PLACID OIL COMPANY		28.57143
	AMERADA HESS CORPORATION		50
	Total for Segment	A	100
ADL 255037			
	UNION TEXAS PETROLEUM CORPORATION		6.25
	ARCO ALASKA, INC		93.75
	Total for Segment	1	100
	HUNT PETROLEUM CORPORATION		2.10084
	ROSEWOOD RESOURCES INC		2.363445
	UNION TEXAS PETROLEUM CORPORATION		6.25
	PLACID OIL COMPANY		14.285715
	AMERADA HESS CORPORATION		25
	MIDGARD ENERGY COMPANY		25
	TEXACO INC		25
	Total for Segment	A	100
ADL 355038			
	UNION TEXAS PETROLEUM CORPORATION		6.25
	ARCO ALASKA, INC		93.75
	Total for Segment	1	100
	HUNT PETROLEUM CORPORATION		2.10084
	ROSEWOOD RESOURCES INC		2.363445
	UNION TEXAS PETROLEUM CORPORATION		6.25
	PLACID OIL COMPANY		14.285715
	MIDGARD ENERGY COMPANY		25
	TEXACO INC		25
	AMERADA HESS CORPORATION		25
	Total for Segment	A	100
ADL 355039			
	UNION TEXAS PETROLEUM CORPORATION		6.25
	ARCO ALASKA, INC		93.75
	Total for Segment	1	100
	HUNT PETROLEUM CORPORATION		2.10084
	ROSEWOOD RESOURCES INC		2.363445
	UNION TEXAS PETROLEUM CORPORATION		6.25
	PLACID OIL COMPANY		14.285715
	MIDGARD ENERGY COMPANY		25
	AMERADA HESS CORPORATION		25
	TEXACO INC		25
	Total for Segment	A	100
ADL 355040			
	ARCO ALASKA, INC		100
	Total for Segment	1	100
	TEXACO EXPLORATION & PRODUCTION		20
	ARCO ALASKA, INC		80
	Total for Segment	A	100

LEASE NUMBER	NAME	WORKING INTEREST %
ADL 364470		
	AMERADA HESS CORPORATION	11.35
	UNION TEXAS PETROLEUM CORPORATION	22
	ANADARKO PETROLEUM COMPANY	22
	ARCO ALASKA, INC	44.85
	Total for Segment	100
ADL 364471		
	AMERADA HESS CORPORATION	11.35
	ANADARKO PETROLEUM COMPANY	22
	UNION TEXAS PETROLEUM CORPORATION	22
	ARCO ALASKA, INC	44.85
	Total for Segment	100
ADL 364472		
	UNION TEXAS PETROLEUM CORPORATION	22
	ANADARKO PETROLEUM COMPANY	22
	ARCO ALASKA, INC	56
	Total for Segment	100
	ANADARKO PETROLEUM COMPANY	6.16
	ARCO ALASKA, INC	21.84
	UNION TEXAS PETROLEUM CORPORATION	22
	AMERADA HESS CORPORATION	50
	Total for Segment	100
ADL 364473		
	ANADARKO PETROLEUM COMPANY	22
	UNION TEXAS PETROLEUM CORPORATION	22
	ARCO ALASKA, INC	56
	Total for Segment	100
	ANADARKO PETROLEUM COMPANY	6.16
	ARCO ALASKA, INC	21.84
	UNION TEXAS PETROLEUM CORPORATION	22
	AMERADA HESS CORPORATION	50
	Total for Segment	100
ADL 364474		
	UNION TEXAS PETROLEUM CORPORATION	28
	ARCO ALASKA, INC	74
	Total for Segment	100
	ARCO ALASKA, INC	24
	UNION TEXAS PETROLEUM CORPORATION	26
	AMERADA HESS CORPORATION	50
	Total for Segment	100
ADL 364475		
	UNION TEXAS PETROLEUM CORPORATION	28
	ARCO ALASKA, INC	74
	Total for Segment	100
	ARCO ALASKA, INC	24
	UNION TEXAS PETROLEUM CORPORATION	26

LEASE NUMBER	NAME		WORKING INTEREST %
	AMERADA HESS CORPORATION		50
	Total for Segment	A	100
AD ¹ 354476	UNION TEXAS PETROLEUM CORPORATION		28
	ARCO ALASKA, INC		74
	Total for Segment	1	100
	ARCO ALASKA, INC		24
	UNION TEXAS PETROLEUM CORPORATION		28
	AMERADA HESS CORPORATION		50
	Total for Segment	A	100
AD ^L 364477	UNION TEXAS PETROLEUM CORPORATION		16.989
	ARCO ALASKA, INC		83.001
	Total for Segment	1	100
	ARCO ALASKA, INC		16.331
	UNION TEXAS PETROLEUM CORPORATION		16.989
	AMERADA HESS CORPORATION		66.67
	Total for Segment	A	100
AD ^L 354478	UNION TEXAS PETROLEUM CORPORATION		32
	ARCO ALASKA, INC		68
	Total for Segment	1	100
	ARCO ALASKA, INC		18
	UNION TEXAS PETROLEUM CORPORATION		32
	AMERADA HESS CORPORATION		50
	Total for Segment	A	100

Net Profit Share Leases - Ownership Within Units

01-Apr-96

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
DUCK ISLAND			
ADL	312838	BP EXPLORATION (ALASKA) INC	95.5
		COOK INLET REGION INC	2.5
		DOYON LIMITED	0.5
		NANA REGIONAL CORPORATION	1.5
		Total for Segment	100
ADL	312834	ARCO ALASKA, INC	33.3333
		EXXON CORPORATION	33.3333
		UNION OIL COMPANY OF CALIFORNIA	33.3333
		Total for Segment	100
KUPARUK RIVER			
ADL	348823	ARCO ALASKA, INC	100
		Total for Segment	100
ADL	348824	ARCO ALASKA, INC	100
		Total for Segment	100
ADL	348838	ARCO ALASKA, INC	100
		Total for Segment	100
ADL	348832	ARCO ALASKA, INC	100
		Total for Segment	100
KUUKPIK			
ADL	348828	ARCO ALASKA, INC	80
		EXXON CORPORATION	20
		Total for Segment	100
		AMBRADA HESS CORPORATION	50
		EXXON CORPORATION	50
		Total for Segment	100
ADL	348831	ARCO ALASKA, INC	100
		Total for Segment	100
		HUNT PETROLEUM CORPORATION	16.80673
		PLACID OIL COMPANY	64.28572
		ROSEWOOD RESOURCES INC	18.90756
		Total for Segment	100
ADL	348834	ARCO ALASKA, INC	100

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Annelle Kuntiger
 Director Leases
 Dept 465-2095
 Fax 465-3810

Patrick Conaghan
 on DNR
 Phone 269-8000
 Fax

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
		Total for Segment	1 100
		HUNT PETROLEUM CORPORATION	16.80673
		FLACID OIL COMPANY	64.28373
		ROSEWOOD RESOURCES INC	18.90756
		Total for Segment	A 100
ADL	14833	ARCO ALASKA, INC	100
		Total for Segment	1 100
		ARCO ALASKA, INC	90
		TEXACO EXPLORATION & PRODUCTION	90
		Total for Segment	A 100
ADL	14836	ARCO ALASKA, INC	87.3
		UNION TEXAS PETROLEUM CORPORATION	12.5
		Total for Segment	1 100
		AMERADA HESS CORPORATION	90
		HUNT PETROLEUM CORPORATION	4.30168
		FLACID OIL COMPANY	28.37149
		ROSEWOOD RESOURCES INC	4.72680
		UNION TEXAS PETROLEUM CORPORATION	12.5
		Total for Segment	A 100
ADL	14837	ARCO ALASKA, INC	93.75
		UNION TEXAS PETROLEUM CORPORATION	6.25
		Total for Segment	1 100
		AMERADA HESS CORPORATION	25
		HUNT PETROLEUM CORPORATION	2.10084
		MIDGARD ENERGY COMPANY	25
		FLACID OIL COMPANY	14.285713
		ROSEWOOD RESOURCES INC	2.363448
		TEXACO INC	25
		UNION TEXAS PETROLEUM CORPORATION	6.25
		Total for Segment	A 100
ADL	14838	ARCO ALASKA, INC	93.75
		UNION TEXAS PETROLEUM CORPORATION	6.25
		Total for Segment	1 100
		AMERADA HESS CORPORATION	25
		HUNT PETROLEUM CORPORATION	2.10084
		MIDGARD ENERGY COMPANY	25
		FLACID OIL COMPANY	14.285713
		ROSEWOOD RESOURCES INC	2.363448
		TEXACO INC	25
		UNION TEXAS PETROLEUM CORPORATION	6.25
		Total for Segment	A 100
ADL	14839	ARCO ALASKA, INC	93.75
		UNION TEXAS PETROLEUM CORPORATION	6.25

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
		Total for Segment	1 100
		AMERADA HESS CORPORATION	25
		HUNT PETROLEUM CORPORATION	210084
		MEDGARD ENERGY COMPANY	25
		PLACED OIL COMPANY	1428715
		ROSEWOOD RESOURCES INC	1363448
		TEKACO INC	25
		UNION TEXAS PETROLEUM CORPORATION	6.25
		Total for Segment	A 100
ADL	36446	ARCO ALASKA, INC	100
		Total for Segment	1 100
		ARCO ALASKA, INC	80
		TEKACO EXPLORATION & PRODUCTION	20
		Total for Segment	A 100
ADL	36447	AMERADA HESS CORPORATION	11.33
		ANADARKO PETROLEUM COMPANY	22
		ARCO ALASKA, INC	44.65
		UNION TEXAS PETROLEUM CORPORATION	22
		Total for Segment	1 100
ADL	36447	AMERADA HESS CORPORATION	11.33
		ANADARKO PETROLEUM COMPANY	22
		ARCO ALASKA, INC	44.65
		UNION TEXAS PETROLEUM CORPORATION	22
		Total for Segment	1 100
ADL	36447	ANADARKO PETROLEUM COMPANY	22
		ARCO ALASKA, INC	56
		UNION TEXAS PETROLEUM CORPORATION	22
		Total for Segment	1 100
		AMERADA HESS CORPORATION	30
		ANADARKO PETROLEUM COMPANY	6.16
		ARCO ALASKA, INC	21.84
		UNION TEXAS PETROLEUM CORPORATION	22
		Total for Segment	A 100
ADL	36447	ANADARKO PETROLEUM COMPANY	22
		ARCO ALASKA, INC	56
		UNION TEXAS PETROLEUM CORPORATION	22
		Total for Segment	1 100
		AMERADA HESS CORPORATION	30
		ANADARKO PETROLEUM COMPANY	6.16
		ARCO ALASKA, INC	21.84
		UNION TEXAS PETROLEUM CORPORATION	22
		Total for Segment	A 100
ADL	36447	ANADARKO PETROLEUM COMPANY	22
		ARCO ALASKA, INC	56
		UNION TEXAS PETROLEUM CORPORATION	22
		Total for Segment	1 100
		AMERADA HESS CORPORATION	30
		ANADARKO PETROLEUM COMPANY	6.16
		ARCO ALASKA, INC	21.84
		UNION TEXAS PETROLEUM CORPORATION	22
		Total for Segment	A 100

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
		ARCO ALASKA, INC	74
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
		AMERADA HESS CORPORATION	30
		ARCO ALASKA, INC	24
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
ADL	34475	ARCO ALASKA, INC	74
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
		AMERADA HESS CORPORATION	30
		ARCO ALASKA, INC	24
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
ADL	34476	ARCO ALASKA, INC	74
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
		AMERADA HESS CORPORATION	30
		ARCO ALASKA, INC	24
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
ADL	34477	ARCO ALASKA, INC	13.801
		UNION TEXAS PETROLEUM CORPORATION	16.999
		Total for Segment	100
		AMERADA HESS CORPORATION	66.67
		ARCO ALASKA, INC	16.331
		UNION TEXAS PETROLEUM CORPORATION	16.999
		Total for Segment	100
ADL	34478	ARCO ALASKA, INC	68
		UNION TEXAS PETROLEUM CORPORATION	32
		Total for Segment	100
		AMERADA HESS CORPORATION	30
		ARCO ALASKA, INC	18
		UNION TEXAS PETROLEUM CORPORATION	32
		Total for Segment	100
MILNE POINT			
ADL	34501	BP EXPLORATION (ALASKA) INC	26.81
		BP EXPLORATION AND OIL COMPANY	64.36
		OXY USA INC	8.81
		Total for Segment	100
		AMERADA HESS CORPORATION	50

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
		MEDGARD ENERGY COMPANY	30
		Total for Segment A	100
ADL	168017	BP EXPLORATION (ALASKA) INC	26.81
		BP EXPLORATION AND OIL COMPANY	64.38
		OXY USA INC	8.81
		Total for Segment 1	100
ADL	168018	BP EXPLORATION (ALASKA) INC	26.81
		BP EXPLORATION AND OIL COMPANY	64.38
		OXY USA INC	8.81
		Total for Segment 1	100
ADL	168021	BP EXPLORATION (ALASKA) INC	26.81
		BP EXPLORATION AND OIL COMPANY	64.38
		OXY USA INC	8.81
		Total for Segment 1	100
		AMERADA HESS CORPORATION	30
		MEDGARD ENERGY COMPANY	30
		Total for Segment A	100
NON-UNIT PRODUCTION			
ADL	312827	AMERADA HESS CORPORATION	30
		BP EXPLORATION (ALASKA) INC	30
		Total for Segment 1	100
NORTHSTAR			
ADL	312798	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
ADL	312799	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
ADL	312830	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
ADL	312840	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
ADL	312841	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
POINT THOMSON			
ADL	312844	MOCON CORPORATION	100
		Total for Segment 1	100

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
ADL	343109	BP EXPLORATION (ALASKA) INC ECONOM CORPORATION	50 50
		Total for Segment 1	100
ADL	343110	MOORE OIL CORPORATION PHILLIPS PETROLEUM COMPANY	50 50
		Total for Segment 1	100
ADL	343111	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
ADL	343112	BP EXPLORATION (ALASKA) INC CHEVRON U.S.A. INC	66.67 33.33
		Total for Segment 1	100
		CHEVRON U.S.A. INC	100
		Total for Segment A	100
		BP EXPLORATION (ALASKA) INC CHEVRON U.S.A. INC	66.67 33.33
		Total for Segment B	100

CAMBRIDGE ENERGY RESEARCH ASSOCIATES

FAX MESSAGE

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Cambridge Energy Research Associates

C E R A



LATIN AMERICA ENERGY



WORLD OIL

INSIDE

Benefits to the Economy

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CERA ALERT

FEBRUARY 1, 1996

VENEZUELA LEAPS FORWARD: THE SECOND COMING OF OIL?

January 22, 1996 marked the day that Venezuela re-opened the door to direct private investment in its oil and natural gas sectors.* Sixty of the seventy-five companies that pre-qualified for the bidding round participated in the process that ended last week. Winners were chosen twice a day for the ten blocks containing an estimated 7 billion barrels of oil. An issue for many of the private investors was the amount of the take—the government participation in royalties and taxes—but the issue was not enough to derail investor interest.

Assuming that the PDVSA affiliate takes the maximum 35 percent share of the joint venture, the final division of profits in the profit sharing agreements will be between 88 and 92 percent for the government/PDVSA, leaving only 8 to 12 percent for the private investor consortium (see Figure 1, Venezuela: Bidding Round Results). This high level of take guarantees the government will receive large oil revenues in addition to what it already receives from PDVSA (between \$5 and \$6 billion per year).

More importantly, the low percentage of profits for the private investors may be an indication of a change in the emphasis of investor strategy—from the overall return on investment to securing long-term crude supplies. One reason this change is occurring for the Venezuelan bidding round is the sheer size of their natural resource base and the expectations of large prospects. Higher risk areas in Latin America are unlikely to be able to adopt similarly difficult terms, as seen in the lack of bids for the higher risk Catatumbo and El Sombrero blocks.

Benefits to the Economy

The success of the bidding rounds will provide a much needed boost to Venezuela's economy over the long term through the expected capital investments by the private companies. More importantly, the high rate of government participation and cash bonuses pledged provides a tremendous boost to the country's confidence.

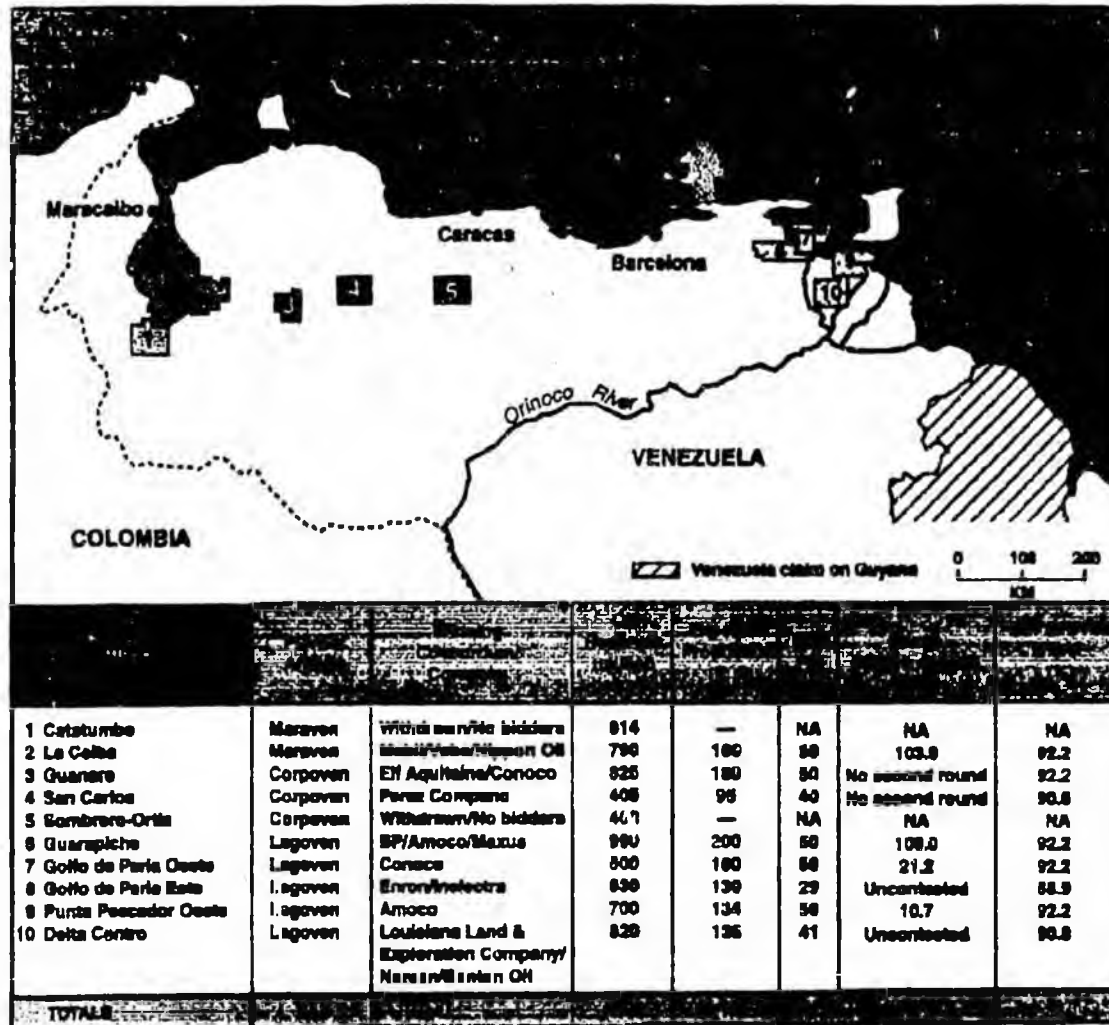
*See the upcoming CERA Private Report, *Venezuela Opens the Upstream: The Impact on Exports*, February 1996.

Cambridge Energy Research Associates

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The CERA Alert is part of CERA's Latin American Energy Retainer Advisory Service.
For more information, please contact Brian Ward at (617) 487-8446.

Figure 1
Venezuela: Bidding Round Results



Source: Cambridge Energy Research Associates, PDVSA

* CLUM = Condensates/Light/Medium
** Includes royalty, income tax, and PEG.

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After enduring a multi-year recession, a rapidly devaluing currency, weak foreign investment, and a near-collapse of its banking industry, Venezuela needed some good news. And now it is in a position to lock up a long-term tax revenue stream if estimated production levels are realized.

In addition to the state, PDVSA is also reaping a very large benefit, for it now has secured the investment capital needed to expand liquid productive capacity over the next ten years. If the ambitious estimates are realized, these private companies will help increase capacity from today's level of

approximately 3.2 million barrels per day (mbd) to over 6.07 mbd by 2003. In terms of impact on the world oil market, PDVSA's export capacity would increase from nearly 2.0 mbd to over 4.7 mbd.

The Bottom Line

Surprisingly, five bids in the first round—which determined the state's share of profits—were for an additional royalty of 50 percent (allowable bids were between 0 and 50 percent). Four of the five bids resulted in a tie among the bidders, requiring that the cash bonus envelope be opened in order to break the tie. These bonuses ranged from \$10 million to \$109 million per block, or \$244.8 million in total. Eight of the 10 blocks were successfully auctioned off, with two blocks—Catatumbo and El Sombrero—being pulled from the process due to a lack of bidders. Importantly, the winning bids for five of the blocks included the maximum level of discretionary royalty to the government (50 percent).

Initial exploratory drilling could begin as soon as late 1996 if everything goes according to plan, but production is not expected for several more years. The government hopes this program will attract over \$500 million in investments over the first two years and reach an aggregate \$11 billion in new investments over the life of the 20-year program.

The Fiscal Terms: A Review

PDVSA's Role

If a block is found to be commercially viable, the developing consortium is required to enter into a joint venture profit-sharing agreement with a PDVSA subsidiary. The subsidiary has the right to take up to a 35 percent position in the joint venture—a value of which will be determined by taking a pro-rata percentage of the exploration costs. For example, if the exploration cost were \$1 billion and the subsidiary opted for a 35 percent share, then they would be required to pay the consortium \$350 million. However,

this amount is to be paid from the profits of the joint venture. In effect, the consortium will be lending the subsidiary the capital until a profit stream is realized but will be allowed to charge a market-based interest rate for the "loan." Once the consortium has been paid back, the joint venture will split the profits according to their respective share. If the block is not commercially viable, the consortium bears the entire financial risk.

The Government's Role

There are two components to the government's fiscal take in the profit sharing agreements—*income taxes and royalties*. The combined take for the government under the current structure is considered high in both absolute terms and also relative to other South American oil and gas investment opportunities.

- **Income taxes.** Income taxes are established by law, and changes would require Congressional approval. Currently, income taxes are set at 67.7 percent with a potential investment credit reduction of 2 percent.
- **Royalties.** The royalty component can be modified without a legislative change. In the case of the proposed profit sharing agreements, the royalty payment could be in two parts. The first part is established for the industry and is generally calculated at one sixth of the market value of the hydrocarbon produced. The government has the option to take all or part of the payment in kind.
- **The "PEG."** An additional royalty was invoked in the profit sharing agreements and was by design the determining factor in the winning bids. Called the Participacion del Estado en las Ganancias (PEG), it is an additional percentage of pre-tax profit offered by the private company or consortium during the bidding round. This percentage was bid up significantly in the most sought after fields, and determined which company was chosen. ■

Please mark your calendar for CERA's 15th Annual Executive Conference in Houston on February 13 and 14, 1998. For more information, call Brian Ward at (817) 441-2647.

CERA's new multienter study, *Latin America Energy: Scenarios to 2010*, will be available soon. For more information please contact Brian Ward at (817) 441-2647.

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

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February 22, 1996

The Honorable Drue Pearce
Capitol Building
Juneau, Alaska 99801-1182

Dear Senator Pearce,


Following our conversation yesterday, we have located a couple of articles reporting the Venezuela state petroleum company's (Pdvsa) recent signing of exploration and production profit sharing contracts. As noted in the January 15, 1996 Oil and Gas Journal article (page 24), this effort represented the first offering of exploration acreage in Venezuela since 1958, and encompasses a profit sharing plan designed to boost productive capacity by pursuing solo projects, joint ventures, and private oil company ventures in marginal field reactivation, exploration and production profit sharing deals, heavy oil projects and other ventures.

In the February 12, 1996 Oil and Gas Journal article (pages 31-34), details of the bidding are reported. Briefly, the contract/licenses garnered outlays of millions of dollars on each block, high profit sharing bonuses in the 40% to 50% range, high "tiebreaker" bonus bids in the millions of dollars, and provisions to purchase a working interest by paying a pro rata share of costs in the event of a commercial discovery.

Legal concerns apparently were raised by many oil companies regarding the structure of the tender offer and aspects of the proposed joint venture tax issues (OGJ, Feb. 12, 1996, pg. 34). Also, according to the January 29, 1996 Petroleum Intelligence Weekly (PIW), the major companies complained over the fiscal terms of the tender. Neither the tax issues nor the complaints over the fiscal terms appeared to dampen the impressive bidding.

I hope this information helps. Feel free to contact me if you have further questions.

Sincerely,


Kenneth A. Boyd
Director

Oil, gas potential seen on 10 Venezuelan blocks

Gregory D. Croft Karl W. Stauffer *Panera Petroleum Inc. San Leandro, Calif.*

Venezuela's congress approved on July 4, 1995, the offering of 10 exploration blocks after several months of discussions. This is the first new offering of exploration acreage in Venezuela since 1958 (OGJ, July 24, p. 21).

Terms for the offering include a sliding-scale royalty, various taxes, a fixed work commitment, and a government participation share. This last parameter is offered by the bidder, with the largest participation share being the winning bid.

The blocks are located in different parts of the country, but all 10 are located in basins that are prolific oil and gas producers. The following is a brief summary of the petroleum geology of each block.

Block 1, Catatumbo

Located on the southwestern shore of Lake Maracaibo, this area is essentially unexplored but lies between the major Lake Maracaibo oil production and the oil producing areas along both sides of the border with Colombia.

It is certain that almost all of the oil produced from the Venezuela-Colombia border area was sourced by the prolific Cretaceous La Luna formation in the Maracaibo basin and migrated to the southwest, in part through this block. A second, lesser source rock is the shale and coal of the Paleocene Orucue formation, but that unit tends to be gas prone.

Reservoirs in this block would mostly be Tertiary sandstones, especially those of the Mirador and Carbon-



era formations. Cretaceous carbonates with sand interbeds are also likely reservoir rocks. Possible traps include stratigraphic wedges as well as anticlines related to the thrust faults formed during the Miocene to recent uplift of the Merida Andes.

Block 2, La Celia

This block is east of the southern part of Lake Maracaibo and immediately south of prolific Motatan field, which produces from Eocene Misoa sandstones. Well productivities from the Eocene sandstones at Motatan are quite variable but can exceed 5,000 b/d.

Oil seeps along the

foothills of the Merida Andes just south of this block indicate that oil migrated through the block from north to south. The source of the oil is the La Luna formation.

The most likely reservoir rocks are the Misoa formation and other Tertiary sandstones, as well as fractured carbonates and sands of the Cretaceous Cogollo group. Traps are likely to be structures associated with the Andean uplift or with earlier, left lateral strike slip faulting.

Block 3, Guarema

The block is located in the northeastern part of the Barinas basin, which is the northern extension of Colombia's prolific Llanos basin. Sedi-

ments in this block reach thicknesses of about 15,000 ft. The source of the hydrocarbons on this block is again the La Luna equivalent, principally the Cretaceous Escandalo formation.

The most likely reservoirs are sandstones of Tertiary age, particularly the Eocene Gobernador formation that produces in the older fields to the southwest. Other possible reservoirs are the sands and limestones of the Upper Cretaceous.

This relatively unexplored block (only one well has been drilled in the area) has the glamor of traps associated with large horizontal thrusts. In the foothills along this same mountain front are the

giant fields of the Furrrial trend in eastern Venezuela and the Cusiana trend in the Llanos basin of Colombia.

Block 4, San Carlos

This block is located along the southern margin of the Merida Andes near the El Baul arch, which separates the Eastern Venezuela basin from the Barinas basin.

This is a relatively unexplored block that has interesting potential. Source rock is not considered a problem as the Escandalosa formation is either on the block or nearby.

Structurally this block is very complicated: it is at the intersection of two structural trends, has sedimentary section that wedges out against the El Baul arch, and has south verging thrust faults.

Likely reservoirs in this block are the sandstones of the Tertiary, particularly the Eocene, and possibly sandstones and carbonates of the Cretaceous. Likely traps are anticlines associated with thrust faults, possibly older Tertiary fault blocks, and updip pinchouts. Late structural movement associated with the Merida Andes may have destroyed earlier traps.

Block 5, El Sombrero

El Sombrero is located about 50 miles south of Caracas. The major natural gas accumulation at Yucal-Placer is located immediately east of and on trend with this block. To the southeast is the Las Mercedes area, which has produced about 200 million bbl of oil from sands that range in age from Miocene to Cretaceous.

Sediments in this block are up to 10,000 ft thick and hydrocarbons may be either oil or gas. The bounding thrust fault of the Coastal Range is close to the northern boundary of the block.

Possible traps in this block include anticlines and thrust structures related to the uplift of the Coastal Range and sand pinchouts to the south in younger units. The major source rocks here are probably the shales of the La

THE AUTHORS



Craft

Gregory D. Craft worked 11 years for Chevron Overseas Petroleum on 2D and 3D seismic interpretation projects in West Africa and Ecuador, and also in business planning. He left Chevron in 1994 to join Dr. Stauffer in founding Pantera Petroleum, a San Leandro, Calif., consulting firm specializing in Venezuela. He has an M.S. in geophysics from Stanford University.



Stauffer

Karl W. Stauffer's early employment was with Royal Dutch/Shell and later Chevron. He was loaned from Chevron to Petrolera de Venezuela from 1977 through 1979, during which time he prepared a series of studies including a regional evaluation of the petroleum potential of the Maracaibo basin. He left Chevron in 1984 to form Pantera Petroleum. He received a PhD in geology from Stanford University.

Luna equivalent formations, although some sourcing from Tertiary shales, especially of gas, may have occurred.

Block 6, Carapiche

This area is east of the city of Maturin along the famous Furrrial trend, where many giant oil and gas fields have been discovered in the last 10 years. The recent discoveries have all been to the west of this block, but the geologic structure in the area trends east-west and continues through the block.

Source rock is not a concern in this area given the prolific nearby discoveries. The major source is again the La Luna equivalent, here called Querecual and San Antonio, although there is probably a secondary contribution from the Miocene Carapita formation.

Potential reservoirs include Miocene, Oligocene, and Cretaceous sandstones, as in the Furrrial trend, as well as Plio-Pleistocene sands such as produce in Quiriquirc and Pedernales fields. Traps are probably related to thrust-faulted structures, although there may be stratigraphic traps in

the younger Tertiary and flank traps against shale diapirs.

Reservoir quality and continuity are the principal risks associated with this block.

Blocks 7-9, Gulf of Paria

These blocks cover the southern part of the Gulf of Paria from the Venezuelan coast to the marine boundary with Trinidad. These are the only wholly offshore blocks. The blocks are located near the axis of the gravity low that marks the center of Tertiary sediment accumulation in the Eastern Venezuela basin.

Sediments here may be more than 30,000 ft thick. That there are hydrocarbons in the area is clear; Pedernales field is just onshore to the south, the Furrrial trend is to the west, and the oil fields of southern Trinidad are on trend to the east.

Geological and structural trends do appear to continue all the way from the Furrrial area into Trinidad, although facies changes of individual units also occur. Source rocks are largely the Querecual of Upper Cretaceous age, called the La Luna further west and

the Naparaima Hill in Trinidad.

The most likely reservoirs are Neogene sands and perhaps Paleogene and Cretaceous sands. Traps in these blocks may include thrust related structures as well as unconformities, stratigraphic traps, and traps against the flanks of shale diapirs.

Reservoir continuity may be a problem in these blocks.

Block 9, Punta Pescador

This block is located onshore and offshore the northernmost Amacuro delta. It is bounded to the north by the marine boundary with Trinidad and to the south shares in part a common border with Block 10.

Pedernales field to the west produces oil from stacked Pliocene and Miocene sandstone reservoirs on the flank of a shale diapir. The sedimentary section in this block is very thick, probably about 30,000 ft. The source rocks here are the Upper Cretaceous Querecual, called Naparaima Hill in Trinidad. Potential reservoirs include Neogene and perhaps Paleogene sands.

In addition to having deltaic-type structures that could serve as traps, this block may have structures related to earlier compression. Neogene submarine fan deposits could contain stratigraphic traps, and shale diapirism is also a likely trapping mechanism. A potential problem in this block is reservoir quality both due to the original facies and to compaction effects.

Block 10, Delta Centro

As its name suggests, this block is located in the middle of the Amacuro delta. In this block the sediment thickness is greater than in the productive Temblador-Tucupita trend to the southwest but less than in Block 9 to the north.

The source rock for the block would be the stratigraphic equivalent of the La Luna formation, either within the block or just beyond it. Possible reservoirs include

sandstones ranging in age from Pliocene to Cretaceous. Traps may include deltaic-type extensional structures, pre-deltaic compressional structures and stratigraphic wedges combined with faults.

This block has fewer data than any of the other blocks; no wells have been drilled within the block, and little seismic has been acquired. The unknown quality and continuity of sandstone reservoirs may be the greatest risk in this block.

A recent oil discovery at Las Piedras, just west of the block, flowed 2,700 b/d.

CONCLUSIONS

The blocks to be offered in Venezuela's upcoming exploration round include some very exciting exploration potential.

The blocks are located mostly in the deeper parts of Venezuela's two most important oil producing basins, and several of them are in structurally complex areas.

Many of the blocks are highly prospective for natural gas as well as oil, but operators will face a challenge marketing large quantities of gas in Venezuela's well-supplied gas market.

The offering also represents a watershed in Venezuelan politics in that foreign companies have not been able to obtain exploration acreage in Venezuela for many years.

NEVADA

Tide Petroleum of Nevada, Reno, staked the state's first wildcat to subthrust Palcozoics.

Permitted to 10,000 ft, it is the 2 Baseline Canyon Unit-Federal, in 21-1n-59c, Lincoln County. The spot is in Coal valley 25 miles south of Grant Canyon oil field.

N. DAKOTA

Armstrong Operating Inc., Dickinson, completed a Mississippian Lodgepole

discovery in Stark County.

The 29-1 Haller, in 29-139n-96w, 3 miles southwest of Dickinson, flowed 157 b/d of oil, 78 Mcfd of gas, and 35 b/d of water from 9,622-34 ft.

The discovery opens Ver-sippi field.

Baker Hughes Inc. reported 20 rotary rigs making hole in North Dakota in the week ended Sept. 1, compared with five in the same week in 1994.

OKLAHOMA

OXY USA Inc. staked an Ardmore basin wildcat in Johnston County.

The 1A Airport, in 21-4s-6e, 2 miles south of Tishomingo, is projected to 9,500 ft. The spot is 5 miles northeast of an abandoned one well oil field, PI reported.

PetroCorp Inc., Houston, is connecting two gas wells in the Misener Trend of Alfalfa County.

PetroCorp expects sales to start this month at 1.5 MMcfd of gas from the 19C-4 Janet. Sales started Aug. 25 from the 10C-1 Sherri, averaging 200 Mcfd.

TEXAS

South

Tesoro Petroleum Corp., San Antonio, might shoot a 3D seismic survey next year over a potentially significant discovery in Webb County.

The 1 Longoria, 40 miles east of Laredo on Tesoro's 2,200 acre South Guerra prospect, flowed 3.5 MMcfd of gas through a 3/4 in. choke with 4,090 psi wellhead pressure. The well encountered

80 ft of gross pay sand in the rested interval and three other pay sands untested behind pipe.

The discovery well is 4 miles southwest of and analogous to Guerra field, which has produced 125 bcf of gas.

Tests of the 1 Longoria continued to determine permeability and the need to fracture the pay sands. The company hopes to complete a directional delineation well by yearend to optimize contact with at least four identified prospective pay sands.

Mustang Oil & Gas Corp., a unit of Gull Resources Corp., San Antonio, and Tesoro Petroleum Corp. opened new pays in Lopeno field in Zapata County.

The 1 Palmyra, enhanced by 3D seismic data, flowed as much as 10.7 MMcfd of gas on a 3/4 in. choke with 5,443 psig wellhead pressure from multiple zones in Eocene Upper Wilcox at about 11,000 ft. CAOF is 48,849 MMcfd.

The well cut 86 ft of gross pay sand in four producing intervals within the L-13, L-18, L-21, and L-22 sands.

Lopeno field, discovered in 1952, has produced about 120 bcf from L-5 through L-27 sands. Mustang used deviated drilling technology and multiple zone completion techniques that proved successful at Bob West gas field 6 miles southeast.

Gulf Coast

Nurvu Energy Co. completed a Brookeland field well that is the third well on its 58,000 acre joint venture with Texaco Exploration and Production Inc.

The 1H Springer, in Jasper

County, flowed 15.4 MMcfd of gas with 2,880 b/d of condensate through a 3/4 in. choke with 3,375 psi FTP.

The Cretaceous Austin chalk well produces through dual laterals a combined 9,082 ft long. True vertical depth is 11,830 ft.

Patterson Energy Inc., Snyder, Tex., has boosted its holdings in the Iola area of the Cretaceous Austin chalk trend in Grimes County to 3,700 acres.

The new holdings are near Patterson's Norwood and Davis wells, which were dual lateral completions.

UTAH

Amerac Energy Corp., Houston, formerly Wolverine Exploration Co., staked a wildcat in Summit County between Pineview and Bridger Lake fields.

Projected TD is 17,000 ft at the 1 Table Top Unit, in 16-1n-10e, 18 miles east of Pineview oil field.

Barrett Resources Corp., Denver, is preparing to complete its 3 Cave Gulch well that has established the deepest production in Cave Gulch Unit in the Wind River basin.

The well was hooked to sales in mid-August at 5 MMcfd of gas and 40 b/d of oil from perforations at 8,537-8,830 ft in a previously untested section of the Upper Cretaceous Lower Lance. TD is 9,050 ft.

Barrett plans to perforate additional zones in Lance.

The company recently staked the 10 Cave Gulch Unit, in 32-37n-86w, Natrona County, as a 9,200 ft Lance test in Waltman field.

API MONTHLY U.S. WELL COMPLETIONS*

	Oil wells	Footage	Gas wells	Footage	Dry holes	Footage	Total wells†	Footage
June 1995	529	2,917,495	773	5,088,457	381	2,254,434	1,683	10,258,386
May 1995	606	2,919,998	771	4,814,814	383	2,074,481	1,758	9,809,290
June 1994	518	2,813,313	747	4,590,358	517	2,064,888	1,802	10,368,784

*Total wells reported to API during June 1995 and stratigraphic and core tests. †Includes oil, gas, and dry holes plus service wells.

Pdvsas poised to sign first E&P profit sharing

Venezuela's state petroleum company Petroleos de Venezuela SA (Pdvsas) this month will sign its first exploration and production profit sharing contracts.

The effort represents Venezuela's most extensive offering of this type for private investment since nationalization 70 years ago. It also is the first offering of exploration acreage in Venezuela since 1958.

The program is expected to generate as much as \$12 billion in added investment in Venezuela's upstream sector the next 10-15 years.

Pdvsas goals

The E&P profit sharing program falls in line with Pdvsas's goal of boosting oil productive capacity to more than 5 million b/d by 2005 from the current level of slightly more than 3 million b/d, in expectation of growing world oil demand.

Pdvsas's 10 year business plan calls for total outlay of \$60 billion to hike productive capacity to 5.691 million b/d. That breaks out as \$35 billion for Pdvsas solo projects, another \$11 billion for joint ventures, and \$16 billion from private oil companies for marginal fields reactivation projects, E&P profit sharing deals, Orinoco heavy oil projects, and other oil and gas ventures.

Meantime, Pdvsas has earmarked about \$6 billion in capital spending this year, with most of the focus on E&P to underpin production and reserves growth.

The company also is moving to consolidate its growing global role as a refiner and marketer of heavy crudes and related products.

E&P program

The long awaited E&P profit sharing program is a departure from Venezuela's other recent efforts to attract private—especially foreign—investment to its upstream sector.

Pdvsas has signed some major "strategic alliance" agreements involving major oil companies for participation in heavy oil development/upgrading ventures (see table, OGJ, Aug. 14, 1995, p. 37).

In addition, Pdvsas is making progress in a 3 year old program targeting private investment to reactivate marginal oil fields in Venezuela (OGJ, June 12, 1995, p. 38).

Further, Pdvsas has all the elements in place except for a market for its liquefied natural gas export scheme, which includes offshore natural gas field development, in cooperation with foreign oil companies (OGJ, Sept. 4, 1995, Newsletter).

VENEZUELAN E&P PROFIT SHARING BIDDERS

Agip	Luzon
Amoco	Maersk
Ampco	Marathon
Aradano	Marubeni
AARCO	Mazda
Asra Caspi	McQuarrie
Bentley Oil & Gas	Mitsui & Co.
BHP	Mitsui Oil
Box Energy	MOBIL
British Petroleum	Morgan Bros.
British Gas	Murphy Oil
Brown & Root	Nippon Oil
Canadian	Norbeco
Occidental	Norcan
Cia. Gen. de Combustibles	Norsk Hydro
Chevron	Numac
Clydesdale	OPIC
Coastal Corp	Occidental
Conoco	Petrobras
Elf Aquitaine	Perez Companc
ENAP	Petrobras
Enron	Petrolina
Esso	Polonca
Fluor	Phillips
Gulf Canada	Pluspetrol
Hess	Ranger
Husky	Repsol
Hyundai	Royal Dutch
Indenco	Shell
Inepra	Seagull
Japex	Stabil
JNOC	Talman
Louisiana Land & Exploration	Tecpetrol
	Tekoku
	Texaco
	Total

The profit sharing scheme under Pdvsas's "apertura" (opening) oil program is the first time since nationalization in 1976 that private companies will be allowed to conduct E&P programs in Venezuela as equity owners.

The profit sharing deals call for exploration of 10 undeveloped blocks earmarked for joint ventures financed totally by private companies. Minimum investment is expected to be \$40-60 million/block.

The 10 blocks are spread over an area estimated at 4.5 million acres (see map, OGJ, Sept. 18, 1995, p. 85). Potential reserves are estimated at 7 billion bbl of high quality medium and light gravity crudes.

If commercial volumes of oil and/or gas are discovered, the private companies will form joint ventures with one of Pdvsas's subsidiaries, sharing the venture's profits and being reimbursed for exploration costs.

Companies, timetable

More than 200 companies have expressed an interest in the E&P profit sharing program, and about 70 have qualified to bid (see table).

Here is the schedule for opening sealed bids under the profit sharing program:

- Jan. 22, Catarumbu Block A, Zulia

and Merida states; La Ceiba Block B, Trujillo, Menda, and Zulia states.

- Jan. 23, Guanare Block C, Portuguesa state; San Carlos Block D, Cojedes and Portuguesa states.

- Jan. 24, El Sombrero Block E, Guarico state; Guarapiche Block F, Monagas and Sucre states.

- Jan. 25, West Gulf of Paria Block C and East Gulf of Paria Block H, both Sucre state.

- Jan. 26, Punta Pescador Block I and Delta Centro Block J, both Delta Amacuro state.

Pdvsas 1996 spending

Pdvsas's 1996 budget focuses heavily on its efforts to boost Venezuela's crude oil reserves to about 66 billion bbl, which it reckons would be an increase of about 1.6 billion bbl.

Oil & Gas Journal estimated Venezuela's proved crude reserves as of Jan. 1, 1996, at 64.5 billion bbl (OGJ, Dec. 25, 1995, p. 44).

Pdvsas said its 1996 E&P program includes more funds for exploratory drilling in new areas such as the South Andean flank and North and Central Monagas state.

Increased spending also will go for development and appraisal drilling, secondary recovery, and steam injection projects.

In addition, Pdvsas expects to increase Venezuela's gas reserves by about 585 million bbl of oil equivalent (BOE) to about 25 billion BOE.

Pdvsas reported production of Orimulsion, its boiler fuel that is an emulsion of extra heavy crude, water, and a surfactant, will total about 4.8 million metric tons in 1996, up 104,000 tons from 1995. It also reported production and marketing of coal from its Carbones del Guasare joint venture will be about flat in 1996 with 1995's level of 4.3 million tons.

Downstream plans

Pdvsas is pressing a program of upgrading and modernizing its refineries while eyeing possible further investments in refining abroad. All told, the goal is to add 600,000 b/d to worldwide refining capacity.

Plans call for increasing refining capacity in Venezuela by about 200,000 b/d by 2000 at a cost of about \$5.2 billion.

Current refining capacity in Venezuela is about 1.167 million b/d. Crude throughput is pegged at 983,000 b/d for 1996.

Much of the refining investment emphasis is on processing larger vol-

lines of heavy and extra heavy crudes.

Plans call for Pdvsa subsidiary Maraven SA to complete a \$2 billion upgrade of its 286,000 b/d Cardon refinery this year.

Pdvsa also plans to expand the 195,000 b/d Puerto La Cruz and 115,000 b/d El Palito refineries operated by its Corpoven SA unit.

Amuay project

In addition, Pdvsa subsidiary Lagoven SA will increase capacity of the hydrosulfurization unit at its 571,000 b/d Amuay refinery. Plans call for expanding unit capacity to 250,000 b/d of high sulfur, heavy crudes from 190,000 b/d.

The project will allow the refinery to process feedstock from other refineries, distillates and gas oils, said Lagoven Refining Manager Heraldo Sifontes.

"That gas oil will be supplied to other refineries in the Pdvsa circuit to be used at catalytic cracking units for the production of gasoline," Sifontes said.

Amuay's expanded deep conversion capacity of 98,000 b/d breaks out as 64,000 b/d of flexicoking and 34,000 b/d of delayed coking.

During first half 1995, Amuay processed about 102,000 b/d of heavy crudes, the highest in 45 years of operation. That volume of throughput is expected to rise to about 170,000 b/d as expansion work progresses, Sifontes said.

"Refining hard to market heavy

crudes means greater operational and commercial flexibility for Lagoven," Sifontes said.

Pdvsa estimates about 73% of Venezuela's oil reserves are heavy and extra heavy crudes and 27% medium and light crudes and condensate.

Foreign refining

Pdvsa currently is negotiating the purchase of several refineries in the U.S. and possibly building another in Brazil, said Ronald Pantin, the company's strategic planning coordinator.

He did not disclose which plants are under consideration for purchase but said negotiations are based on an "association scheme" aimed at boosting Pdvsa's refining capacity by 100,000 b/d in the U.S., plus an additional 100,000 b/d of refining capacity in wholly or partly owned refineries at Lake Charles, La., Corpus Christi, Tex., Paulsboro, N.J., Savannah, Ga., Lemont, Ill., and Houston.

In addition, Pdvsa has 310,000 b/d of refining capacity at the Isla refinery in Curacao and a combined 260,000 b/d of capacity at refineries in Germany, Sweden, Belgium, and the U.K.

Heavy oil upgrading

As an adjunct to the refining expansion, Pdvsa continues to press projects with ARCO, Conoco, Mobil, and Total intended to produce a combined total of about 500,000 b/d of extra heavy crude and convert it into a more marketable synthetic crude.

Following an agreement last month setting up a \$2 billion heavy oil joint development/marketing venture be-

tween Chevron Corp. and Pdvsa unit Maraven SA (OGJ, Dec. 25 1995, p. 29), Mobil is expected to complete negotiations on a similar project involving Orinoco extra heavy crudes with Lagoven.

"The prospects for that project look very positive," said Lagoven Pres. Julius Frinkunas.

He noted the prefeasibility study for the project is complete, and the contract should get a final green light for signing in the first quarter.

Under their strategic association, Mobil and Lagoven would set up a joint venture to produce about 100,000 b/d of extra heavy crude from the Orinoco belt's Cerro Negro region. The Cerro Negro crude will be upgraded at Kening's syn-crude.

The deal is expected not only to open markets to Lagoven in the U.S. but also lead to other joint ventures involving the two companies in the U.S.

Last November, Maraven signed a 35 year, \$1.5 billion strategic association contract with Conoco Inc. to produce, transport, and upgrade 120,000 b/d of Orinoco extra heavy crude (OGJ, Nov. 13, 1995, Newsletter).

Earlier, Maraven signed a contract with Total covering a \$2.85 billion project to produce and upgrade 180,000 b/d of Orinoco crude.

A \$3.5 billion strategic association between Corpoven and ARCO to produce 165,000 b/d of Orinoco crude, upgrade that to 210,000 b/d of syn-crude, and export the syn-crude still is pending approval (OGJ, Oct. 3, 1994, Newsletter).

Protests linger over Shell Nigerian connection

Royal Dutch/Shell has come under more fire for its role in Nigerian operations.

In the latest development, London's Shell Centre buildings, U.K. headquarters for many of the company's international operations, was the starting point for a Jan. 4 protest against the company and Nigeria's military regime.

The Ogoni Community Association organized a march from Shell Centre to the Nigerian High Commission and on to St. James's Church, Piccadilly, for a memorial service for Ken Saro-Wiwa and eight other activists executed by the Nigerian government late last year (OGJ, Nov. 20, 1995, p. 37).

Also in London, members of Britain's Royal Geographical Society voted to expell Shell as one of their sponsors because of its Nigerian oper-

ations.

Meantime, Nigerian Minister of State for Petroleum Resources Kabir Chafe said threats by Britain and the U.S. to boycott Nigeria's oil won't harm his country's economy if they develop.

Chafe told Kaduna newsmen Nigeria would simply turn to other companies waiting to do business with his country if the U.K. and U.S. make good their threats.

Target Shell

Although Shell was once again the target of protests because of its supposed close links with government to facilitate its oil operations in Nigeria, the anti-Shell feeling was more muted than in recent months.

A Shell International spokesman said only about 30 protesters gathered outside Shell Centre, and there did not appear to be any reference to Shell in posters and banners they displayed.

The official said Shell had been asked to protest to Nigeria's government over 19 more Ogoni tribe protesters, currently held on the same charges, murder, as Saro-Wiwa and colleagues and due for trial at an undisclosed date.

In Kaduna, Chafe pointed out that Iran and Libya are under U.S. oil embargos but are still exporting their oil to other buyers.

He said Nigeria is bolstering its economic relations with China, Russia, and eastern European countries to forestall any embarrassment sanctions from the West might cause.

Pdvsa and lands biggest Asian supply contract for Orimulsion

Venezuela's Bitumenes Orinoco (Bitor) soon will sign a deal to sell 3.4 million tons/year of Orimulsion to Taiwan, matching its biggest sale to date.

Orimulsion is an emulsion of extra heavy crude oil, water, and a surfactant that is designed to back out coal as a low cost, environmentally preferred boiler fuel.

Bitor is a subsidiary of state owned Petroleos de Venezuela SA (Pdvsas).

Far East market push

Bitor Pres. Jorge Zemella said his company received "with great satisfaction" a report from Taiwan on the outcome of a tender by Taiwan's state owned power company to select new projects assigned to independent power producers (IPPs).

Zemella said Bitor affiliate MC Bitor Ltd. will "significantly penetrate" the Asian market with the Orimulsion sale to Taiwan.

Orimulsion will be the sole fuel of a power plant to be built by a group led by Intergerm at Lizhe in the Suao region on Taiwan's east

coast. Sales will begin in 2000.

The project is one of many proposed under a Taiwanese government initiative to solicit IPPs from the private sector to build power plants to meet Taiwan's soaring electric power demand.

Taiwan's Ministry of Economic Affairs recently chose from the first round of proposals seven groups to build a total of 7.11 million kw. Combined power capacity of 23 projects proposed under the first round totaled 30.3 million kw.

Oil products and natural gas will feed some of the other winning projects.

Lizhe project

Among the companies selected in the first round is a combine led by International Generating Co. (Intergerm), a joint venture of Bechtel Group and Pacific Gas & Electric affiliates. Other members of the group are Taiwan Synthene Rubber Corp., APED, and China Steel.

The combine's Lizhe plant will have an installed generating capacity of 1.5 million kw involving two units of 750,000 kw each.

One of the units will begin operations about mid-2000 and the second by the end of that year.

MC Bitor and Mitsubishi Corp. will supply those units about 3.4 million tons/year of Orimulsion for 25 years exported from the Jose terminal in Anzoategui state, eastern Venezuela.

It will be the largest supply contract of Orimulsion in the Asia-Pacific region. MC Bitor and Intergerm are reported to sign the agreement soon.

Zemella said, "The approval constitutes the most significant step forward in the Asia-Pacific region by Bitumenes Orinoco, through MC Bitor, in penetrating the electricity segment of the energy market in the Far East."

The market has been dominated by energy sources such as gas, coal, and conventional liquid hydrocarbon fuels.

The next step in marketing Orimulsion in the region is to prepare an environmental impact study to obtain permits from Taiwanese local and regional authorities.

Venezuela's E&D round mostly successful

Venezuela's first profit sharing exploration and development licensing round has yielded generally positive results.

Although two of the 10 blocks up for bid received no bids, some of the remaining blocks received hefty ones. State owned Petroleos de Venezuela (Pdvsas) netted about \$215 million in tiebreaker bonuses in the round, in addition to about \$15 million from the sale of data packages to prospective bidders.

The 10 blocks, covering 4.5 million acres, are believed to contain potential oil reserves of at least 7 billion bbl of medium and light grade crude in addition to substantial potential volumes of natural gas (see map, OGI, Sept. 18, 1995, p. 85). Preliminary estimates of potential oil reserves for the combined blocks ran as high as 23 billion bbl of light and medium gravity crude.

The tender marks the return of foreign companies to full equity participation in oil and gas E&D, a sector that Venezuela nationalized 20 years ago. It is expected to generate as much as \$12 billion in added investment in

Venezuela's upstream sector the next 10-15 years (OGI, Jan. 15, p. 24).

The tender was marred by litigation stemming from concerns over clauses in proposed profit sharing contracts.

The push to expand foreign investment in Venezuela's upstream oil sector underlies the government's goal of doubling oil revenues in 7 years from the current \$6 billion/year.

To meet that goal, Caracas is counting on investment by Pdvsas and private companies, especially foreign firms, to help jump productive capacity to 5.7 million b/d from today's 3.15 million b/d.

Venezuela currently claims to produce about 2.4 million b/d, close to its Organization of Petroleum Exporting Countries' quota of 2.359 million b/d. However, other sources have placed Venezuela's output considerably higher than that, exceeding quota by more than 300,000 b/d.

How the bidding went

Pdvsas voiced satisfaction with results of the E&D profit sharing license round. More than 75 companies pre-

qualified for the bidding.

"We are very pleased with the results," said Pdvsas Pres. Luis Giusti. "The most important thing is that the massive attendance of large, medium, and small companies has ratified investor confidence in the country's petroleum industry."

Beyond concerns over tax and currency issues, international oil and gas executives praised Pdvsas for a smoothly run tender.

"In some cases, we declined to submit bids simply because the risks in those areas were far too high or because we just did not have sufficient geological data to make a final decision," said one executive whose company failed to obtain a contract. "This by no means points to a lack of interest in Venezuela, which remains an attractive oil country."

Pdvsas estimates \$1 billion will be spent in the first 3 year exploration period for the profit sharing blocks and another \$10 billion the following 7 years. The contracts call for outlays of

at least \$40-60 million/block.

In the event of a commercial discovery, license terms call for a Pdvsa affiliate to have an option to purchase a working interest by paying a pro rata share of costs incurred to date.

Pdvsa is expected to hand over the signed contracts early this month to the Energy & Mines Ministry, which in turn will send the documents to the cabinet of ministers, then to

Ronald Pantin, Pdvsa strategic planning coordinator, expressed surprise that Amoco and the Total/Statoil combine each offered a 50% PEG. He noted industry sees only one major oil play in the area but added that a major natural gas strike is highly prospective there.

In addition, the swampy region poses logistical challenges.

Oil Co./Lismo plc, Petrobras Brasil-eim SA/Benton Overseas Petroleum & Investment Co., Unocal Corp./Japan Petroleum Exploration Co. Ltd., and Repsol SA/Enterprise plc.

Work commitment for the La Ceiba block in the first 5 year phase of exploration is about \$50 million. The minimum work commitment calls for drilling of three wildcats. Plans call for seismic surveys to get under way this year.

Ronald Wilson, president of Mobil Latin America business development ventures, noting Mobil is familiar with the La Ceiba area, said, "We expect to find large accumulations."

Mobil first operated in Venezuela in 1934 and, with the country's new efforts to attract foreign investment, seeks to expand its presence.

Mobil is currently negotiating a \$1.8 billion strategic association with Pdvsa subsidiary Lagoven SA to produce and upgrade 100,000 b/d of extra heavy crude from the Orinoco oil belt. In addition, Mobil recently returned to lubricant manufacturing and marketing in Venezuela last year, when it purchased 50% of local company CA Nacional de Gases & Lubricantes, the country's biggest lube plant.

Veba also has a long association with Pdvsa, dating to 1978 when it entered into a government backed accord between Germany and Venezuela for technical cooperation in the energy sector. In 1983, Veba and Pdvsa formed a joint venture, Ruhr Oel, to operate Germany's biggest refining system with throughput capacity of 440,000 b/d.

Conoco blocks

Conoco bid alone in winning the West Gulf of Paria block in shallow water off Venezuela's northeastern coast in the Caribbean Sea.

Competing against Conoco were the Canadian-South Korean group of Canadian Occidental Petroleum Ltd., Numac Energy Inc., Yukong Ltd., and Korea Petroleum Development Corp.; Agip/Norsk Hydro; and the Canadian-Argentine combine Talisman Energy Inc./Astra Capsa.

Conoco offered a 50% PEG plus a tiebreaker bonus of \$21.2 million compared with the runnerup Canadian-South Korean group's bid of \$20.2 million.

Terms call for a 4 year, \$30 million commitment to drill two wells and acquire seismic data in the western

RESULTS OF VENEZUELA'S LAZAR PROTE SHARING ROUND

Block	Area (sq km)	Estimated potential oil reserves (million bbl)	Estimated potential production (1,000 bpd)	Winning bidder(s) (%)	Profit sharing bonus (%)	Tiebreaker bonus bid (million \$)	First year projected exploration investment (million \$)	Five year projected investment (million \$)
Guarema	1,688	825	180	Elf 50, Conoco 50	50	—	55	541
San Carlos	1,171	405	95	Compagnie BP 37.5, Amoco 37.5, Maxam 25	40	—	28	698
Guarapiche	1,900	990	200	Conoco 100	50	109	162	1,583
West Gulf of Paria	1,134	600	135	Envan 90, Ineletra 10	50	21.2	144	1,146
East Gulf of Paria	1,080	630	130	LL & E 37.5, Norcen 37.5, Benton 25	29	—	121	1,201
Delta Centre	2,138	820	180	Amoco 100	41	—	107	1,393
Punta Pescador	8,046	700	134	Mobil 37.5, Veba 37.5, Nippon 25	50	10.7	98	688
La Ceiba	1,742	791	180		50	104	120	1,482

*Catatumbo and El Sombrero blocks did not receive bids.

Venezuela's congress for final approval.

Exploration generally is expected to get under way in first quarter 1997.

Amoco blocks

Attracting the most interest in the bidding was the Guarapiche block in eastern Venezuela, which is believed to hold as much as 1 billion bbl of medium and light gravity crude.

A combine of Amoco Corp., British Petroleum Co. plc, and YPF SA unit Mayra Energia Corp. won the block based on a 50% pretax profit sharing bonus (PEG) plus a tiebreaker bonus of almost \$109 million.

Amoco bid solo to win the Punta Pescador block in eastern Venezuela, just east of the Guarapiche block in which the company is a partner. Amoco offered a 50% PEG and a tiebreaker bonus of \$10.7 million.

That topped a bid of 50% PEG and tiebreaker bonus of \$5.6 million by a combine of France's Total and Norway's Den norske stats oljeselskap AS.

Amoco plans to spend at least \$40 million to explore its Punta Pescador block. The block lies just south of gas fields Amoco is developing off Trinidad.

La Ceiba block

A close second to the Guarapiche bid was the winning offer for the La Ceiba block along the southeast edge of Lake Maracaibo, thought to hold 790 million bbl of oil reserves.

Here, a Mobil Corp. led group that includes Germany's Veba Oil AG and Japan's Nippon Oil Exploration U.S.A. Ltd. made a winning bid of 50% PEG and tiebreaker bonus of almost \$104 million.

Mobil and partners shared the 1,793 sq km La Ceiba block on the western shore of Lake Maracaibo on the first day of bidding, Jan. 22 (OGJ, Jan. 29, Newsletter). Interests in the block are Mobil 50%, Veba 30%, and Nippon 20%. Their winning tiebreaker bonus bid topped bids by nine other groups that matched the 50% PEG bonus.

Closest to the winning bid was Exxon/Shell, which offered a 50% PEG bonus plus a \$57.5 million tiebreaker bonus. Other bidding for La Ceiba were Amoco, Texaco Inc./Mitsubishi Corp./Maxus, Elf Aquitaine/Conoco Inc., Agip SpA/Norsk Hydro, Total/Statoil/Petronas Carigali, Marathon

Gulf of Paria between Venezuela and Trinidad. Exploration is to get under way right after the contract is signed.

Conoco combined with Elf Aquitaine 50-50 to take the Guanare block in Portuguesa state in western Venezuela. The block is in the foothills of the Menda Andes.

The work commitment calls for a 5 year, \$30 million outlay to drill four wells and acquire seismic data. Work is to get under way immediately after the contract is signed.

Conoco also has a strong presence in Venezuela.

It formed a joint venture, Petrozuata, with Pdvs's unit Maraven SA to produce 1.5 billion bbl of Orinoco extra heavy crude and convert it to synthetic crude, most of which will be processed in Conoco's U.S. refineries. Construction on the \$1.4 billion project is to get under way early in 1997.

Conoco also is a partner with Bitumenes Orinoco SA to convert Orinoco bitumen to Orimulsion. Pdvs's proprietary heavy oil/water/surfactant emulsion is used as a boiler fuel.

LL&E group block

A group made up of Louisiana Land & Exploration Co. (LL&E), New Orleans, Norcen Energy Resources Ltd., Calgary, and Benton Oil & Gas Co., Carpinteria, Calif., won the Delta Centro block in eastern Venezuela.

Operator LL&E will hold a 35% interest in the block. Norcen will take 35% and Benton 30%.

The Delta Centro block lies in a mostly marshy region of the Orinoco River delta in Northeast Venezuela's Delta Amacuro state.

The group's work commitment calls for acquiring and processing 1,300 line km of seismic data and drilling three wells in 5 years with an option to extend the exploration period 4 years.

Work is to get under way after the contract with Pdvs is signed.

LL&E Chairman M. Leighton Savage and noted the Delta Centro block's marshy terrain is similar to marshlands in Louisiana where LL&E has long operated.

Other bidding

Perez Compana SA took the San Carlos block in Cojedes and Portuguesa states of Southwest Venezuela.

The Argentina company topped a bid by Elf by offering a 40% PEG. Perez Compana currently is involved in reviving oil production in Venezuela under the country's marginal fields participation program.

A combine of Enron Corp. and

WATCHING THE WORLD



With David Knott from London

The unequal split of British Gas

Facing competition in U.K. gas markets, restrictions by government regulations, and massive gas contract debts, British Gas plc will split into two companies.

The former U.K. gas supply monopoly, privatized in stages beginning in 1986, will split into a large company, to be known as Transco International plc, and a smaller unit, British Gas Energy plc.

Chairman Richard Giordano said, "This demerger is about the creation of two separate companies that will manage our business more effectively to the advantage of our customers, shareholders, and employees."

But some pundits say the move is designed to protect the company's profitable businesses from losses in long term take or pay gas purchase contracts.

Ahead of gas market deregulation, U.K. operators developed gas fields to support their plans to supply gas directly to end users. Trading in gas began among companies. And with the glut of new gas the spot price fell.

Assets shored up

Because of the low spot price, British Gas is said to face losses of £1.5 billion (\$2.25 billion) on long standing contracts worth a combined £40 billion (\$60 billion).

The new Transco unit will get the biggest asset, British Gas' transportation and storage business, along with most of the exploration and production assets and the potentially lucrative power generation business and international operations.

British Gas Energy will be a comparative runt, given only the parent's supply and trading business. This is where it faces intense competition from new suppliers and big losses on

gas purchase contracts.

British Gas Energy also will get U.K. Morecambe Bay producing gas fields, which a spokesman said would allow it to compete with independents in liberalized markets.

Two fields with original reserves amounting to 6.6 tcf of gas, one of which has been on stream since 1985 and one since 1994, does not seem a great deal with which to take on fierce competition—particularly when British Gas estimated its reserves in 1994 at almost 2 billion bbl of oil equivalent.

Public outcry

British Gas said the smaller company will receive no exploration assets or expertise in the transfer. So it will face an immediate problem in replacing reserves to remain competitive.

Transco is to be like a utility with steady returns, while British Gas Energy will be more like a consumer company with ups and downs in income. And everybody knows how much a consumer business can die.

The outcry has been evidenced in the British press by the news that Cedric Brown, British Gas chief executive, is to retire Apr. 30.

Following a turn over Brown's 75% pay hike in December 1994, Britons are now incensed by reports that he will get a £4 million (\$6 million) retirement package and will be retained as a consultant for the demerger.

Government's original idea in privatizing British Gas was supposed to be to make a cumbersome giant efficient and profitable. This latest move is a warning against following political dogma to the detriment of practical considerations of gas supply.

Inectra won the East Gulf of Paria block.

Catatumbo block, southwest of Lake Maracaibo, and El Sombrero block, in Central Venezuela, failed to attract bids.

Noteworthy for their absence from the list of winning bidders was a combine of Exxon Corp. and Royal Dutch/Shell Group that was expected to dominate bidding. However, the combine bid conservatively for the La Ceiba and Punta Pescador blocks and came away empty handed.

Some prospective bidders were daunted by the stiff terms Venezuela

imposed on the profit sharing deals. They call for income taxes totaling 67.7% and royalties of 16.7% in addition to the PEG and tiebreaking bonuses.

A second try

Pdvsa on Jan. 29 tried again and failed to attract bidders for the Catatumbo and El Sombrero blocks.

Representatives from several private companies said high risks, low prospects for crude oil discoveries, and lack of geological data discouraged interest in those areas.

Juan Szabo, president of Venezuelan

Petroleum Corp. (CVP), said, "The lack of interest in some areas is relatively normal because each company chooses those blocks that fit their figures and their particular strategies."

CVP, a once defunct Pdvsa subsidiary, was revived specifically for the bidding process and given the portfolio of blocks to be tendered.

Winning bidders will sign the profit sharing contracts and set up joint ventures (JVs) with CVP. The Pdvsa unit will own as much as 35% of the JV stock, with the remainder held by foreign partners.

Pdvsa is considering putting together another tender for new blocks as part of its apertura, or "oil opening" policy, which includes profit sharing contracts, operating agreements, strategic associations, and alliances. A new round of bidding could occur as early as the end of this year or early next year.

Legal concerns

The tender was held against a backdrop of optimism in government and oil industry circles and concern among many oil executives regarding aspects of the proposed joint venture tax issues and Venezuela's onerous currency control regulations.

Venezuela currently is negotiating an economic restructuring accord with the International Monetary Fund, under which it had agreed to lift currency exchange controls in first quarter 1996.

In addition, a group of intellectuals including Central University of Venezuela Rector Simon Munoz and chamber of deputies (lower house) energy and mines committee Chairman Ali Rodriguez filed two lawsuits in Venezuela's supreme court over the proposed profit sharing contracts. They claimed the proposed clauses allowing international litigation to settle differences and barring municipal authorities from exercising autonomy on tax matters violate the constitution.

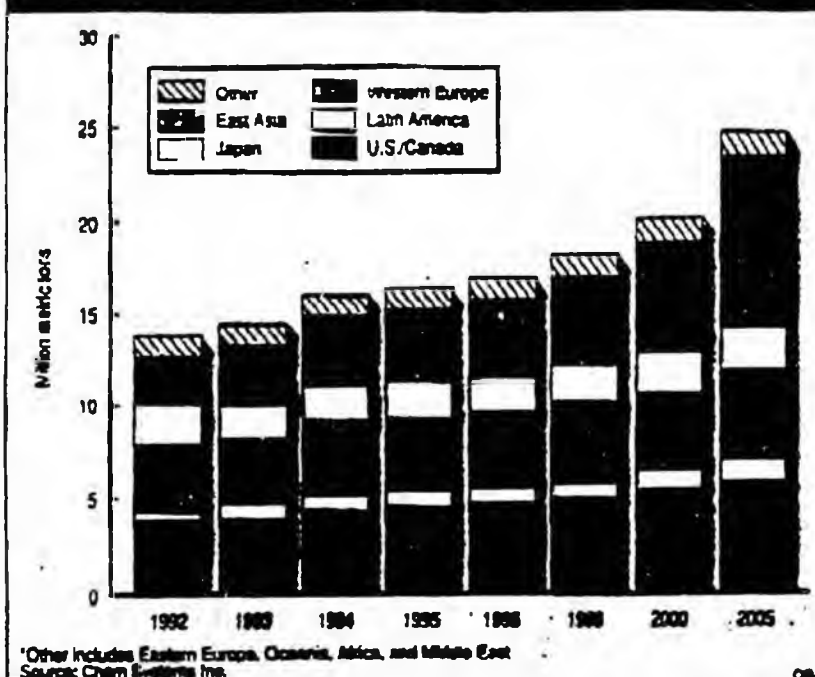
Giusti said there are no legal grounds for the lawsuits because under the constitution, municipal authorities have no autonomy to set taxes for the oil industry.

Regarding currency controls, Giusti said regulations currently allow companies to hold offshore dollar accounts and make profit remittances in foreign currency.

However, private oil companies contend issues such as municipal and other taxes and currency controls should be clarified in the contracts.

Government sources said a decree is being written to allow foreign companies operating in Venezuela to choose dollar accounting as the nation's stiff currency control system is put aside.

HOW WORLD STYRENE DEMAND WILL RISE



Strong styrene growth foreseen

Eastern Asia will lead hefty growth in world styrene demand through 2005.

Driving the region's 9.3%/year increase in styrene consumption are economic growth, improved standards of living, and increasing exports of finished products.

Those are the findings of a study by Chem Systems Inc., Tarrytown, N.Y.

The firm predicts world styrene consumption will increase at an average 4.1%/year through 2005, fueled by increased demand for polystyrene and acrylonitrile butadiene styrene (ABS).

Most styrene capacity expansion will take place in eastern Asia. Chem Systems expects additions in that region to total 2.5 million metric tons/year by 1998. This massive

capacity increase will reduce world operating rates, shift trade patterns, and squeeze profits in traditional exporting countries.

World styrene consumption increased 9.6% during 1994, making styrene one of the leaders in commodity petrochemicals' recent recovery.

Devalued growth was strong for all styrene derivatives, especially polystyrene and ABS, which combined account for 75% of world styrene consumption.

In 1995, says Chem Systems, growth in styrene demand was less than anticipated because of inventory adjustments and an unexpected slide in shipments to China after the country closed its southern border.

European gasoline prices. Furthermore, if the WTO orders Washington to relax restrictions on gasoline from foreign plants, imports from Brazil could soar to 30,000 b/d, as in 1993, instead of the meager 12,000 b/d of components state Petrobras has been selling to the US of late (p8). The loss of 110,000 b/d of gasoline supply in the East Coast — enough to cover more than 3.5% of local demand — could add 1¢ a gallon to prices, according to Houston-based Stone Bond.

An expected drop in the availability of spot barrels — as Tosco diverts gasoline from its nearby Bayway refinery into its filling stations to replace the lost barrels from Marcus Hook — could also prove a stimulant to New York Harbor prices, by weakening the heavy-selling firm's bearish influence over that market. Recent changes to the New York gasoline futures contract should further boost liquidity and price transparency.

Successful Tender Sets Stage For Next Act In Venezuela

Any remaining skepticism about the level of international company interest in Opec-member Venezuela's oil patch disappeared last week. At a licensing round for 10 exploration blocks, large foreign oil companies — led by British Petroleum, Conoco, and Mobil — bid aggressively in terms of both bonuses and proffered government take for the most prospective acreage, pushing the hemisphere's heavyweight closer to its goal of lifting burgeoning capacity from 3.1-million barrels a day to 5.5-million b/d in 2005. State Petroleos de Venezuela is now mulling over the next stage in the country's reopening, including the possibility of direct negotiations to reactivate smaller fields ahead of another competitive tender. Firms have conducted geological studies on some of Venezuela's oldest fields in PDV subsidiary Maraven's domain around Lake Maracaibo, with hopes of clinching direct service deals like the one Chevron signed for the Boscan field last month (PIW Dec.11.p8). Pennzoil has its eye on Mene Grande, and Canadian Occidental is targeting Cabimas, both of which now pump only a few thousand barrels a day. But political pressure still favors competitive bidding for most acreage awards, and PDV is already pondering which areas to offer in a third marginal-fields round at year's end.

Underscoring the majors' enthusiasm, despite complaints over fiscal terms and lingering uncertainties in the profit-sharing contract, the bidding opened with an impressive nine-way tie out of 11 participants for the prized La Ceiba block east of Lake Maracaibo. It was finally awarded to Mobil and partners Germany's Veba and Japan's Nippon Oil in a high-stakes runoff in which they posted a hefty \$104-million cash bonus. The runners-up were Exxon with Royal Dutch/Shell and Texaco with Mitsubishi and Argentine YPF. BP, Amoco, and YPF paid a \$109-million bonus in order to break a four-way tie for the coveted Guarapiche block in the swampy Delta region. Other blocks named fewer heads, and the gas-prone El Sombrero generated no bids at all. El Sombrero, which lies southwest of Caracas, is to be re-offered this week. As at La Ceiba, which holds an estimated 800-million barrels or more of reserves, the companies offered the government the maximum 50% share in pre-tax profits at offshore Gulf of Paria West and at onshore Guanara, Guarapiche, and Punta Pescador. Conoco won the first after posting a \$21.2-million bonus, and then teamed up with Elf Aquitaine as operator to win Guanara. Amoco got Punta Pescador with a \$10.6-million cash bonus. Enron with local consulting giant Inelectra was sole bidder for offshore Gulf of Paria East, offering Caracas a 29% profit share, while Argentine Perez Companc outbid Elf for the San Carlos tract in the central region, offering the state 40% of profits (PIW Jan.15.p8).

Impending changes in PDV's upper ranks, possibly even appointing savvy President Luis Giusti, probably won't shift the country's basic reopening campaign or its recession-driven grab for market share, given the gravity of the Caldera administration's domestic economic woes. Indeed, word that Giusti could take over the Finance Ministry raises the prospect of a further loosening in economic controls, a possibility that would spark even more interest in oil and gas projects. Talks with the Internacional Monetary Fund, however, seem to be faltering, as President Rafael Caldera continues to resist another hike in subsidized domestic gasoline prices. The high level of bonuses obtained in the bid round may feed opposition to an IMF deal. A PDV insider would likely replace Giusti.

LEGAL SERVICES

**DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA**

MAR 25 1996

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

MEMORANDUM

March 25, 1996

SUBJECT: Renegotiation of State Oil and Gas Lease

TO: Senator Drue Fearce
President of the Senate

FROM: Jack Chenoweth
Legislative Counsel

I am responding to three questions set out in your March 22 memo.

1. I have not found explicit statutory or regulatory authority to renegotiate an oil and gas lease as seems to be contemplated in the North Star field lease. See by way of specific example, 11 AAC 71.205 authorizing amendment of timber and materials contracts except that the amendment "may not materially affect or change the meaning or intent of the contract," 11 AAC 71.205(b). The lease documents applicable to the North Star field lease may authorize or provide for renegotiation under specific circumstances, but I don't know this.

Even absent an explicit statute or regulation or provision in the lease, as a matter of general law, negotiations may be initiated to amend a competitively bid public contract. 72 C.J.S. Supp., "Public Contracts," sec. 24. However, amendments to competitively bid contracts are prohibited if the amendments proposed are "material," that is to say, competitively bid contracts may not be materially amended. McKinnon v. Alaska, 633 P.2d 281, 287 (Alaska 1981), Kenai Lumber Company v. LeRonde, 646 P.2d 215, 221 (Alaska 1982). Amendments to a contract are "material" if they involve the alteration of factors that influence the judgment or decision on the award of the contract. Brown v. Ward, 593 P.2d 247, 250 (Alaska 1979), Cousineau v. Walker, 613 P.2d 608, 613 (Alaska 1980). Based on the pre-lease analysis, the state's choice of leasing method—including the decision to take net profit share using the amount reserved as the bid variable (which I think is what is at work in the award of the original North Star field lease)—seems to be "material" by any measure.

2. Without having a notion of what the administration may choose to offer, still, I think the administration will, in one way or another, ask the legislature to ratify or validate modifications proposed to the North Star lease.

Senator Drue Pearce
March 25, 1996
Page 2

An Act or public enactment to validate the modification of a public contract is a form of curative legislation. Yelton v. Plantz, 89 N.E.2d 540 (Indiana 1950); C. Sands, Sutherland Statutory Construction, sec. 71.07. As a general rule, curative legislation is valid (1) when the legislature originally had power to authorize the acts that were done and (2) the curative legislation does not impair a vested right in violation of constitutional provisions prohibiting impairment of contract. Fairbanks North Star Borough v. State, 753 P.2d 1158, 1160 (Alaska 1988). The legislature might have authorized renegotiation of public contracts, and, depending on what is submitted, it is more probable than not that the proposed legislation would not impair a vested right (assuming that the state administration is prepared to waive the right to receive revenue under the original lease by shifting from one choice of leasing method to another).

A validating or curative act is usually subject to the "local or special" act limitations of a state constitution. C. Sands, Sutherland Statutory Construction, secs. 41.11 - 41.13. Even if it was a consideration in this instance, there is, it seems to me, good chance that the court would find the test of Abrams v. State, 534 P.2d 91 (Alaska 1975) to control and determine that the modification of an oil and gas lease with significant potential revenue-producing capacity is a matter of common interest to the whole state, having, through the contributions to the state treasury, probable statewide interest and impact, and therefore not subject to the local and special legislation prohibition provision.

It is also possible, of course, that the legislation sponsored by the administration will be general, in that it will authorize renegotiations of all or some types of oil and gas leases. That type of legislation, potentially applying to other leases as well as the North Star lease, would avoid the "local or special act" question altogether.

3. Your memo describes legislation that addresses the possibility that the state may receive less revenue than originally anticipated. It does not propose to withdraw money from the state treasury, therefore an act addressing renegotiation of the lease is not to be regarded as an appropriation.

JBC:glc
96-177.glc

LEGAL SERVICES

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MEMORANDUM

March 11, 1996

SUBJECT: Administration revocation or amendment of "net profit" oil and gas lease without legislative approval (Work Order No. 9-LS1783\A)

TO: Senator Drue Pearce
President of the Senate
ATTN: Stephanie Szymanski

FROM: Jack Chenoweth
Legislative Counsel

You have asked whether, under AS 38.05.180(p) or 38.05.180(s), the administration may revoke or amend a "net profit" oil and gas lease without prior legislative approval.

The answer must be yes. Neither AS 38.05.180(p), relating to leases made subject to a unitization agreement, nor AS 38.05.180(s), relating to leases subject to a communitization or similar drilling arrangement, imposes a limitation on the administration's right to reform or revoke an oil and gas lease that subjects the reformation or revocation to prior legislative approval.

The legislature's involvement in oil and gas leasing is rather limited. Under AS 38.05.180(h), the legislature is entitled to receive and review the five-year oil and gas leasing program proposed by the administration. Legislative approval of anything involving oil and gas leasing appears to be limited to disagreement with a decision by the administration to take state royalty oil or gas in cash rather than in kind. See AS 38.05.182(b). The legislature may also approve the sale of royalty oil that has been taken in kind. See AS 38.05.183. Apart from those, the legislature has not asserted authority to approve a proposed oil or gas lease and, consequently, cannot assert that the administration may not reform or revoke an oil and gas lease without legislative consent.

JBC:klb
96-179.klb

April 23, 1996

APR 23 1996

Gov. Tony Knowles
Rep. Joe Green
Rep. Sean Parnell
Rep. Con Bunde
Sen. Judy Salo
Sen. Loren Leeman

Re: BP lease negotiations at Northstar

Dear Governor, Senators, and Representatives;

I would like to express my strong opposition to the recent negotiations with BP concerning renegotiation of the net profits and royalty terms of the Northstar oil field. I believe renegotiating the terms for this field is a bad deal for the Alaskan resource owner and is unfair to the larger oil industry. I work as a petroleum geologist in Alaska and my objections to the Northstar deal are these two:

1. Probable reserve growth at Northstar

The proposed terms reported in the press show Alaska losing much income from Northstar if eventual reserves are much larger than estimated and receiving more income if the field is smaller than expected. However, a typical oil field increases reserves between 2 and 3 times from the time of first discovery to last eventual production. This reserve growth occurs because of initial conservative estimates mandated by the SEC, by conservative estimates by the company itself, by application of unexpected, new technology to existing fields, and sometimes by unexplained superior performance of the reservoir. Many companies count on reserve growth and work it into their future expectation and upside, even though these are not officially booked reserves. Reserve growth of 2 to 3 times the original estimate is typical for the worldwide industry and not unusual. On the North Slope of Alaska, every field of which I am aware has experience dramatic reserve growth, with the possible exception of the Lisburne Field, discussed below.

Oil recovery from Prudhoe Bay, Kuparuk, and Endicott Fields are now far in excess of original expected recovery. Kuparuk is an example of a field that has nearly doubled the expected producible reserves and

yields more oil than reservoir parameters would predict. A "fudge factor" is used to increase expected output from wells because experience has shown that the reserves are systematically underestimated, even with very good reservoir data. These fields that perform so well are clastic (sandstone) reservoirs and Northstar is of this type. It is a reasonable, based on past experience, for the Northstar reserves to increase over its life and this increase will likely be in the range of 2 to 3 times today's estimate. This would be the expected case. It is exactly in this scenario that the State of Alaska is giving up the most value in the current renegotiation and I fear Alaska will lose much income in the long run.

The only exception to reserve growth for North Slope fields that I know of is the Lisburne field, which is a carbonate (limestone) reservoir, which is significantly different from the clastic reservoirs. So far the Lisburne Field has been a disappointment and limestone horizons have under performed. However, lower dolomite zones in the Lisburne were drilled in 1994 and the first well in these lower zones has produced far more oil from dolomites than previous wells in the limestone. This well (NK-26) has produced 1.2 million barrels of oil in about 2 years and more wells are planned for this interval. It remains to be seen if the Lisburne Field in the end will remain a disappointment.

2. Level Playing Field

Exploration in Alaska is based on all companies having an equal opportunity to bid and participate in the process. I find the process of renegotiating freely bid lease terms offensive to fair play and I fear it will in the long run tend to undermine the leasing process. Amerada and BP were both well aware of the implications of the lease terms at Northstar and willingly agreed to the lease stipulations. If these companies made a poor business decision, Alaska has no obligation to be a safety net for them.

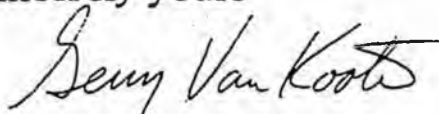
I find it particularly offensive that BP is using a political process to circumvent agreed lease terms. This approach rewards companies that can muster the most political pressure and has the sharpest negotiators. It also opens the political process to immense pressure from the oil industry. If BP is successful, I would expect every other company to come with requests for relief and the State will be hard pressed to deny these requests. We have already seen Unocal at the

table with relief requests for Cook Inlet fields. The renegotiation with BP feels like special treatment and a cozy relationship.

I feel if BP cannot develop Northstar under the very onerous lease terms, the lease should return to the State and be reoffered under new terms to all parties, including BP. This insures that everyone has equal opportunity to participate and bid the value they feel is appropriate. This system of leasing at both State and Federal levels has historically been highly successful in generating high value for lease tracts.

I appreciate the opportunity to express my views and thank you for your consideration.

Sincerely yours

A handwritten signature in cursive script that reads "Gerry Van Kooten". The signature is written in dark ink and is positioned below the typed name.

Gerry Van Kooten
4551 East 135th Ave.
Anchorage, Ak 99516
907-345-7900

April 24, 1996

An Open Letter to Mr. John C. Morgan, President BP Exploration (Alaska) Inc.

Thank you for sending me letters and brochures about BP's Northstar development. I agree with you Alaska is in a new era of oil development. This new era is causing the industry, the state and others to re-examine the business of oil development in Alaska's unique conditions. As one of the brochures points out Alaska is 39% of BP's world oil production. I believe BP is approximately 40% of Alaska's oil production. It is obvious we need each other.

I, like you, am glad the period of acrimonious attitudes between the state and the oil industry is becoming a thing of the past. As you know attitudes can shift every two or four years with elections. I have also come to notice attitudes shift with changes in the leaders of companies.

As part of the North Slope Alliancing programs and BP's efforts "to maintain an open dialogue with Alaskans" it would be good if all parties could get beyond the short term desire (like lowering the royalties on a specific oil field) and focus more on the long-term vision of our relationship. Like any relationship we each carry some history with us, or to use an American slang, we have to live with each others baggage, as well as our own.

The Dutch are using covenants between industry and government to create innovative partnerships. These agreements are being touted in some disciplines as a way to improve relationships and reduce costs. As part of our new era would the industry be willing to enter into a covenant with the people of Alaska for the development of the state's resources? These covenants could be put to a vote of the people to approve our long term relationship.

These covenants could include the new international standards on environmental management, ISO 14000. These standards are similar to the British Standard 7750 which I am sure BP staff are familiar with. The ISO 14000 standards are rapidly becoming the benchmark for leading corporate environmental programs.

In these days of partnering many streamlining steps are developed by employees. One approach used by a growing number of businesses is Open-Book Management. Open-book management is a way of running a company that gets everyone focused on helping the business make money. Simply put, employees who understand how the company makes money and how they contribute to the bottom line can then act to do so. I suggest you read the book *Open-Book Management: The Coming Business Revolution* by John Case. BP might explore using this approach to bring Alaskans and your company together so we both benefit from development of smaller fields.

One idea is to use one of the newly developing fields, such as Northstar, as a test case of open book management. As part of the "Alaska Energy Infobank" set up a Web page so all Alaskans, all the owners of the oil, can work with BP. Ideally, if BP makes money on Alaskan oil, so too will Alaskans make money on it being developed.

I know these ideas sound far fetched. As one of the brochures points out, "BP is going where no one has gone before." For BP's continued success in Alaska all of us need to go where no one has gone before. One of the ways to improve our dialogue is to get together and talk without a specific agenda, like lowering royalty shares. John Case's book provides several examples of how open-book management improves companies profit margin. This idea might help BP get the 2% more profit to make Alaska production as profitable as other parts of the world.

I agree with you that Alaskans need to get our fiscal house in order and close the "fiscal gap." Historically Alaskans have shown some financial wisdom, the Permanent Fund — our Prudhoe Bay — is one of the best run pools of wealth in the world. Though we can not rest on our laurels. This where I do not understand the wisdom of reducing Alaska's royalty shares so we decrease the money flowing into the treasury. Can't we work together so both your profit stays in the 40% range and Alaska stills receives revenue?

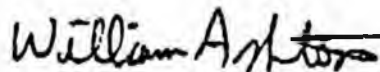
I suggest we work together though means other than advertising and direct mail to improve the relationship between the oil industry and the people of Alaska. In summary lets:

1. Develop a vision for oil development in Alaska,
2. Use innovative ideas such as covenants, ISO 14000, and open-book management, and
3. Work together to go where no oil producing province has gone before.

BP has shown time and time again it meets the challenges of oil development in Alaska. I also believe Alaskans continue to meet the challenges of oil development. This is another opportunity.

I appreciate receiving your letters and information from time to time. If you have any questions please give me a call at 345-6600.

Sincerely,



William Ashton
200 W 34th Ave., #1120
Anchorage, AK 99503

Senator Loran Leman
Juneau, Alaska
FAX # 465-3810

Several years ago in an irreverent play called "Sister Mary Agnes Answers All Your Questions" a young man asks an elderly nun if God answers all prayers. Her answer is, "Yes, but sometimes the answer is no." Governor Knowles must not have seen the play, because his answer to BP's prayer is the wrong one.

Many people are watching your struggle to do the right thing in the face of heavy opposition. All we can ask is that you do your best to protect the interests and future of the State of Alaska. The stakes are high and the deck may be stacked. But you already know that.



Sheila M. Turner

Donald. W. Ince
3121 Capstan Dr.
Anchorage, AK 99516

April 22, 1996

Senator Loren Leman
State Capitol, Room 113
Juneau, AK 99801-1182

RE: Northstar Lease Terms

Dear Honorable Loren Leman,

I am writing this letter to voice my opposition to changing the Northstar lease terms as proposed by British Petroleum and Governor Tony Knowles. I have been following closely the developments regarding the Knowles-BP deal and I am convinced this is a terrible deal for Alaskans. I read in complete disbelief the manner in which Commissioner of Natural Resources John Shively has analyzed this deal. He essentially says we should trust his analysis that this is a good deal for Alaska. Unfortunately, examination of this deal simply does not support his statement.

There are basically three scenarios put forth for analysis as summarized in the chart below.

Northstar Oil Production	State Earnings		BP Pays Alaska (\$/barrel)	
	w/net profit	w/o net profit	w/net profit	w/o net profit
Case 1=130 million	\$444 MM	\$435 MM	\$3.42	\$3.35
Case 2=105 million	\$312 MM	\$340 MM	\$2.97	\$3.24
Case 3=180 million	\$934 MM	\$639 MM	\$5.19	\$3.55

In Case 1, if BP believes Northstar will produce 130 million barrels it is not clear why they would lobby so vigorously to change the lease terms. The difference they must pay to Alaska is only \$9 million or 7¢/barrel. In case 2, where Northstar produces only 105 million barrels, BP should negotiate to keep the net profit sharing provision. They would actually pay \$28 million less (27¢/barrel less) than if net profits were removed. BP obviously does not believe Northstar will produce only 105 million barrels. So, Alaskans must ask why BP is

spending so much time, money and effort to change these lease terms? The answer is clear when Case 3 is examined. They believe Northstar will produce significantly more oil than 130 million barrels. It is not difficult to understand why BP believes Northstar will become an over-achiever considering the past forecasts for other Alaska oil fields. Prudhoe Bay reserves have increased 35% from 9.6 billion to 13 billion barrels, BP's Niakuk field has increased 85% from 54 million to 100 million barrels since production began. BP's Endicott field has increased 200% from 300 million barrels in 1987 to 600 million barrels today.

BP is fighting hard to negotiate this upside potential away from Alaskans. If they succeed, BP will earn a \$295 million profit as shown in Case 3. If their negotiations fail to remove the net profit sharing provision, they will pay \$1.64/barrel more revenues to Alaska. BP has even resorted to intimidating Alaskans by threatening not to develop Northstar unless we give up our net profit share. When our Senate Resource Committee tried to modify the agreement BP's vice-president Eric Luttrell said, "BP will not reopen the negotiations and cannot agree to the changes." I would respectfully suggest that Alaskans tell Mr. Luttrell and BP that, "Alaskans cannot agree to changing the Northstar lease terms because we believe a deal is a deal and Northstar lease terms will not be reopened for negotiations."

Some legislators and other officials may believe this upside potential at Northstar is speculative and has no value. Obviously, BP believes exactly the opposite. They are hopeful Alaska will change the lease terms in return for something like a few jobs. But look carefully at the proposal. BP makes no binding agreement to construct modules in Alaska or hire Alaskans. The fifty permanent jobs BP estimates will be created by Northstar development will be needed regardless of what the lease terms are or who develops the field. So, it is very difficult for me to understand exactly what BP is offering Alaska residents that is tangible in return for us giving away our net profit share of Northstar.

I urge you to do the right thing and vote against changing Northstar lease terms.

Very truly yours,

Donald W. Ince
via fax



APR 22 1996

21 April 1996

The Honorable Loren Leman
Alaska State Legislature
State Capitol (MS 3100)
Juneau, Alaska 99801-1182

Dear Senator Leman:

I sincerely appreciated the opportunity to discuss with you last Friday, your concerns with the Northstar project. Your desire to insure that Alaska residents will benefit from the project and long-term opportunities for Alaskan contractors will be realized is commendable, and a desire I share as well.

I am writing this letter to further clarify VECO'S position regarding the Northstar project. We see this project as a real advancement for Alaskan contractors and Alaskan workers within the oil industry. On past projects, fifty percent (50%) of the craft labor has been performed in the lower 48 on all of the oil field facility projects. On GHX2 alone, this amounted to over three million man hours. On the Northstar project it is possible that one hundred percent (100%) of the craft labor will be performed in Alaska by Alaskan contractors employing available and capable Alaskans.

For years we have had to convince the oil companies that sea lift modules could be built competitively within the State of Alaska. With your support, the Northstar project will give us the opportunity to prove our position.

I am confident that the oil companies are able to make some of these marginal projects feasible by innovative approaches to the drilling, design, construction and operating philosophy of these developments.

It is important that legislation does not unduly inhibit that freedom



The Honorable Loren Leman
Page 2
21 April 1996

and flexibility. With the Northstar project, BP Exploration has committed to making this new opportunity a reality.

I have had a long relationship with BP and have always found them to be a trustworthy client. When they give their word, a contract is not needed! BP is a major player in the oil business throughout the world, and they have significant opportunities for investment in very attractive projects. Alaska is lucky to have such a partner to be in business with, and to help us realize our Alaskan potential for building our own infrastructure for modules utilizing our skilled labor, which will be advantageous in world market competition.

Your full support of this negotiated agreement will help to make this happen.

Sincerely,

A handwritten signature in cursive script that reads "Bill J. Allen".

Bill J. Allen
Chairman & CEO

COOK INLET REGION, INC.

April 22, 1996

VIA FAX: (907) 465-3810

Honorable Loren Leman
Chairman
Senate Resources Committee
State Capitol
Juneau, Alaska 99801-3810

Dear Senator Leman:

I am writing to you today as a follow up to my earlier testimony to the Committee and my conversations with you about Senate Bill 318. As you are aware, CIRI is heavily involved in the oil industry in Alaska through our own developments on the Kenai, as a working interest owner in Endicott, and through our three subsidiary companies, PEAK Oilfield Services, Construction Machinery, Inc. and Alaska Interstate Construction. So we benefit from more than our alliances and partnerships as a contractor on Alaska's North Slope.

It is our belief that SB 318, which would allow the development of Northstar, is a most vital piece of legislation. It will do more than just put hundreds of Alaskans to work and inject millions of private sector dollars into our economy. It will maintain flow in the Trans Alaska Pipeline. Clearly, the State must continue to support these smaller field developments or we will reach a point where it is uneconomic to transport oil through the pipeline. If the pipeline shuts down we can forget any future developments such as ANWR.

We believe the Executive Branch is properly empowered under the Constitution to negotiate deals within a general statutory framework established by the Legislature. And while the Legislative Branch may read into the record what it believes should be or should have been included in a contract, it is bad constitutional precedent and poor practical policy for the Legislature to get into the business of rewriting or re-negotiating contracts carefully negotiated by the Executive Branch.

I fully understand the role of the Legislature in our system of checks and balances and your duty to review what the Administration is proposing in terms of lease amendments. You have made it clear that -- had you negotiated the deal -- it would have been somewhat different. But this is the agreement that was hammered out between the State of Alaska and BP Exploration and should be the only agreement on the table.

Senator Leman
April 22, 1996
Page 2

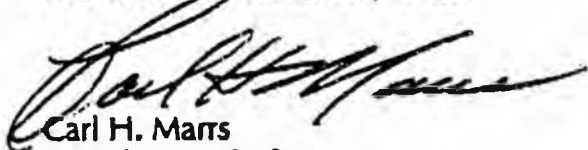
Cook Inlet Region, Inc. fully supports this negotiated agreement. For our part, we are satisfied that BP will do everything in its power to fulfill its commitments on local hire and local business participation in Northstar's development. We do not base this belief on misguided optimism, but on cold political reality. If, for any reason, BP does not live up to its commitments, they will find scarce support among Alaska businesses and public officials for any future development opportunities. Moreover, I am advised that there is a real danger, from a legal perspective, that this well-intentioned attempt to put more "teeth" into the Alaska hire and contracting provisions could amount to "throwing out the baby with the bath water." It also may substantially increase the chance that this entire piece of legislation will be ruled illegal or unconstitutional under state and federal law.

In summary, we believe BP means what they say and that the Northstar project is our best opportunity to forge a new standard for Alaskan's participation in oil development. It also sends the right message to other companies thinking about investing in Alaska. The legislature worked hard to pass HB 207 last year to send the message that Alaskans are willing to work with the industry on issues critical to the future development of Alaska's resources. This is one of those issues so let's — as Alaskans live up to the intent of HB 207 and pass SB 318 as recieved from the Administration.

Accordingly, on behalf of Cook Inlet Region, Inc., I strongly urge you to support SB 318 as it was introduced and keep this vital legislation moving forward. Thank you.

Sincerely,

COOK INLET REGION, INC.



Carl H. Marrs
President & CEO

CHM/dm
0028



arctic slope regional corp.

Fax Transmittal Cover Page

Date: April 22, 1996

To: Honorable Loren Leman

Firm: Chairman, Senate Resources Committee

Fax Number: (907) 465-3810

City & State: Juneau, Alaska

From: **Brenda I. ta-Lee, Vice President, Human Resources**

ASRC Human Resources Department Fax Number: **(907) 852-9470**

Total number of pages, including cover page: 03 (Three)

If you do not receive all the pages, please call: **(907) 852-8633**

Fax Operator/Contact Person: **Julia Kaleak**

Original: Will Will Not **Be Mailed**

Comments: _____

URGENT - SB318

WE ARE TRANSMITTING FROM A MURATA F-75



April 22, 1996

Honorable Loren Leman
Chairman,
Senate Resources Committee
State Capital
Juneau, Alaska 99801-1182

VIA Fax: 907-465-3810

Dear Senator Leman:

Arctic Slope Regional Corporation (ASRC) owns several subsidiaries directly involved in the development of Alaska's oil resources. ASRC subsidiaries now rank as some of the largest multi-disciplined construction companies on the West Coast. They serve a diverse array of clients, including the oil and gas industry, government, mining, petroleum refineries and other private industries.

The economic health of Alaska's oil industry is very important to ASRC's overall well-being. That's why I'm writing you today about SB 318 - and to encourage you to give it speedy approval.

The agreement negotiated between the state and BP Exploration is a good deal for the state. One that maximizes the state's return, nurtures an exciting new business in Alaska and comes as close as the courts will allow to guarantee new jobs for Alaskans. It is also an agreement that requires all of us - BP, the state, and contractors - to partner together for the mutual benefit of all.

BP is willing to pay a multi-million-dollar premium to help us develop the expertise and infrastructure we need to build the much larger production modules Northstar will require. But the window of opportunity to develop the capabilities we need to build these large production modules is limited. Either we move now, or a non-Alaskan company will likely take over the market. Our subsidiary, Alaska Petroleum Contractors, has already made the large capital investment we need to turn a part-time fabrication business into full-time jobs for Alaskans. And we have a commitment from BP on Northstar that goes far beyond what any other oil company has offered to date.

We are, therefore, fully committed to Northstar's development and we believe BP is equally committed to honoring the terms of the agreement negotiated with the state. On behalf of Arctic Slope Regional Corporation, I strongly urge you to support SB 318 as it was introduced and to pass it from your committee.

Thank you.

Sincerely,

ARCTIC SLOPE REGIONAL CORPORATION

Jacob Adams
Jacob Adams, President





BP EXPLORATION

E. M. Luttrell
Vice President
Exploration, Alaska

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 564-4892

April 20, 1996

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

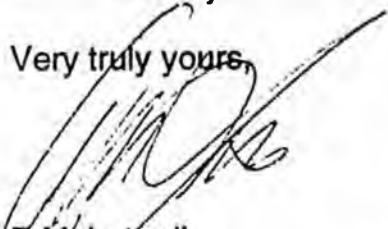
Dear Senator Leman:

I appreciate the opportunity to comment further on the Senate Resources Committee Substitute for Senate Bill 318. For the reasons explained in my letter and testimony of April 18, 1996, BP will not reopen the negotiations of the agreement and cannot agree to the changes.

With respect to the 21-page findings of fact, BP believes the inclusion of such findings in the act itself is unprecedented. Although many portions of the findings are apparently quotations from testimony and evidence before the committee, we do not believe the findings are a complete or balanced reflection of this testimony and evidence. In addition, the findings describing the history of the leases and unitization are incomplete and seem largely irrelevant to the committee's decision. If the committee desires to make findings of fact such as those in CS 318, it seems more appropriate to include them in the committee record or in a separate committee report rather than in the act itself.

BP also requests that the effective date of the act not be delayed. There has been public testimony from at least one witness regarding a possible legal challenge to the legislation, and we would not want a challenge to be delayed due to a delayed effective date of the act.

Very truly yours,



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

PETRO MARINE SERVICES

Petroleum Marketing to the Marine Industry

SB318

APR 17 1996

April 15, 1996

Senator Loren Leman
Room 113
State Capitol
Juneau, Alaska 99801-1182

Dear Senator Leman,

The Alaska Legislature is currently in the process of making a decision on the Northstar offshore oil field, located six miles north of Prudhoe Bay. According to BP Exploration (Alaska) Inc. officials, Northstar will yield about \$500 million in new government revenues and another \$500 million in direct spending in Alaska over the life of the project.

As a lifelong Alaskan and businessman, I can clearly see the benefits of this project. I consistently embrace and support projects that offer the opportunity to be a "win" for all parties. Northstar represents a creative -- and mutually beneficial -- approach to developing a field with marginal economics because of the 89-percent net profits requirements.

On the other hand, I recognize that in your position as a legislator, this may be a challenging decision. Northstar will break new ground for our traditional oil and gas policies. In any event, as I understand it, we are exchanging long-term risk for the short-term certainty of a 20-percent base royalty and the potential of another 7.5-percent supplemental royalty. While some will view this strategy as a "trade-off," from my perspective it is a symbol of a true partnering relationship between industry and the state.



P.O. Box 389 • Seward, Alaska 99664

Phone (907) 224-3190 • Fax (907) 224-3937

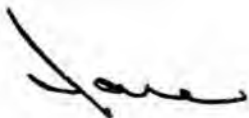
A HARBOR ENTERPRISES COMPANY

In addition, BP says that Northstar will directly create 500 construction jobs and 50 permanent jobs, as well as generate hundreds of indirect jobs. In my opinion, this is a substantial and significant step forward in positioning Alaska as an attractive state in which to conduct business.

At the present, I view the Alaska economy as being reasonably stable. While we are not experiencing dynamic growth, I have no overriding anxieties that we are facing a down cycle. If we are to maintain economic stability, I encourage the Legislature to continue to support the private sector in Alaska, which ultimately benefits all Alaskans. Accordingly, this letter is to respectfully request your support of the Northstar agreement as negotiated between BP and the Alaska Department of Natural Resources. Again, and for the record, I am squarely behind Northstar!

I appreciate your taking the time to consider my views.

Sincerely,



Dale R. Lindsey
President/Chief Executive Officer

PETRO MARINE SERVICES

Petroleum Marketing to the Marine Industry

STATE OF ALASKA

DEPARTMENT OF LAW

OFFICE OF THE ATTORNEY GENERAL

APR 22 1996

April 22, 1996

Honorable Loren Leman
Senator
Alaska State Legislature
Room 115 State Capitol
Juneau, Alaska 99801

Re: SB318 (Northstar Unit net profit
share reduction)

Dear Senator Leman:

You have requested our comments on the draft committee substitute to Senate Bill No. 318.

We recommend that the material set out beginning at page 1, line 5 through page 20, line 8 be deleted from the bill and placed in a separate committee report. The record speaks for itself, there is no need to select and insert excerpts of the record in the bill. It is sufficient that the committee investigate the facts and circumstances of the lease amendments and have a reasonable basis for the action it proposes. The technique of selecting excerpts from the record may be used by opponents of the transaction to argue that the committee placed too much, or not enough reliance on certain facts, when this was not the case. The committee will no doubt rely on the entire record in recommending a bill for passage by the Senate.

We believe that the insertion of an amended lease amendment in statute raises serious questions whether, in enacting this bill, the legislature would be violating the separation of powers doctrine implicit in the Alaska Constitution. The governor proposed a bill that would give the Department of Natural Resources the power to reduce a net profit share lease. The governor's version would also have the legislature ratify the amendments negotiated for the Northstar Unit. The draft committee substitute would enact a counteroffer to the leaseholder which differs from the agreement between the department and British Petroleum. The negotiation of lease agreements is an executive function, not a lawmaking function. Clearly the legislature may delineate the power that the department has when it acts in these matters. It is when the legislature attempts to negotiate on behalf of the state that the separation of powers doctrine has been violated.

TONY KNOWLES, GOVERNOR

PLEASE REPLY TO:

1031 WEST 4TH AVENUE, SUITE 200
ANCHORAGE, ALASKA 99501-1994
PHONE: (907) 269-5100
FAX: (907) 276-3697

KEY BANK BUILDING
100 CUSHMAN ST., SUITE 400
FAIRBANKS, ALASKA 99701-4679
PHONE: (907) 451-2811
FAX: (907) 451-2846

P.O. BOX 110300-DIMOND COURT HOUSE
JUNEAU, ALASKA 99811-0300
PHONE: (907) 465-3600
FAX: (907) 465-6735

Hon. Loren Leman

April 22, 1996

Page 2

If the committee is determined to effect changes in the present lease amendment, it should consider redrafting the bill to set out limits on the power to reduce or change the net profits aspects of the North Star leases. If the legislature defines the power in a way that is inconsistent with the lease amendments presented, the parties must return to negotiations.

The lease provisions added in the committee substitute relating to local hire may present a legal defect that will lead to litigation. Protracted litigation may frustrate the purpose of the lease amendments. On page 28 lines 10 - 29, the provision appears to mandate resident hire on module fabrication projects. The provision also requires the lessee to ensure that all subcontractors practice local hire. These requirements appear to be similar to the local hire requirements that were struck down in Robison v. Francis, 713 P.2d 259 (Alaska 1986). For this reason, the committee is urged to recede from this proposed change to the lease agreement. It probably does not violate the United States or Alaska Constitutions to require a leaseholder to fabricate modules in Alaska.

Thank-you for the opportunity to comment on the draft committee substitute.

Very truly yours,

BRUCE M. BOTELHO
ATTORNEY GENERAL

By: 

James L. Baldwin
Assistant Attorney General

JLB:clh



BP EXPLORATION

E. M. Luttrell
Vice President
Exploration, Alaska

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 190612
Anchorage, Alaska 99519-0612
(907) 564-4892

April 18, 1996

Senator Loren Leman
Alaska State Legislature
State Capitol (MS 3100)
Juneau, Alaska 99801-1182

Subject: BP position on the CS for Senate Bill 318

Dear Senator Leman:

BP has reached a negotiated agreement with the State of Alaska to amend the Northstar unit leases. The Legislature has been asked to consider and ratify that agreement. Ratification will lead to the early development of Northstar to the mutual benefit of both Alaska and BP.

The CS (Committee Substitute) has altered the agreement, attempting to reopen the negotiation. All of the areas of the original agreement which have been amended in the CS version are areas which were carefully discussed and negotiated to arrive at a balanced agreement. Both we and the DNR have sought to explain to your committee the reason for these conclusions. BP will not reopen the negotiations and can not agree to the changes.

To be clear, BP and its contractors have heard the concern of the Legislature over local hire and we reaffirm our public commitment to maximize the job opportunities for Alaskans and Alaskan contractors represented by Northstar development.

Sincerely,

Eric M. Luttrell

EML/dd

cc: President Drue Pearce
Speaker Gail Phillips
Commissioner John Shively

April 15, 1996

To: Senator Loren Leman, Chair, Senate Resources Committee
From: Thomas Cook, 1848 Kalgin Street, Anchorage, Alaska 99504
(phone (907)333-1419; fax (907)338-9792)
Subject: SB318--Northstar Beaufort Sea Net Profit Share Leases

I respectfully offer the following comments to you and your committee in support of SB 318 that would amend the terms of certain leases overlying BP's Northstar Prospect by deleting the provisions for net profit shares to the state.

Let me begin by acknowledging that, as an oil and gas industry consultant, I sometimes work for various companies in the oil industry including BP Exploration. However, I assure you and your committee that my comments are those of a concerned citizen and are offered to you at my own initiative.

From June 1, 1978 until May 31, 1980, I served as Director of the Division of Minerals and Energy Management, Department of Natural Resources. It was during my period as Director that the State prepared for and conducted the 1979 Joint State/Federal Beaufort Sea Oil and Gas Lease Sale which resulted in the net profit share leases which are now at issue.

I became Director at the same time as the State's new oil and gas leasing statute took effect. With the passage of this new law, the Division faced a major task of developing regulations to implement the law and the various new bidding provisions provided for in the revised leasing statute. The Division also faced a major task implementing a leasing program under the new law. With these responsibilities before me, I realized that I should review the legislative history of the new leasing law. More importantly, I wanted to review the studies and analytical work that I assumed had been done by the Department of Natural Resources in support of the newly enacted law. When I requested copies of these studies which I presumed had been undertaken, I learned that none had been done, or at least none had been documented.

The only study I could lay my hands on was a consultant's report prepared for the Department by Mr. Mason Gaffney. The report recommended a variety of unorthodox bidding methods and leasing strategies without much analytical support and no citations as to where these policies had been used and with what

results. Based on my past experience and knowledge, I was very skeptical about the application of contingency bidding methods, "checker-board" leasing, and "two-stage" leasing and other unproven leasing techniques which Mr. Gaffney was recommending to the Department.

As Director, I was strongly opposed to contingency bidding and net profit share bidding in particular, for the following reasons:

1. Contingency bidding methods and net profit share bidding, as a type of contingency bidding, have the effect of shifting risk from the private sector to the public sector. Under contingency bidding and net profits bidding, the State accepts a promise (higher royalty, share of profits, or a work commitment) in lieu of cash up front (bonus bid) as a criterion for awarding a lease. Reward to the State then becomes largely a function of geologic risk (is oil present or not), and business risk (will future oil prices justify and support development). Industry is in a much better position to deal with these risks. It does so through joint bidding with partners, conducting exploration and development in many areas of the world, and counting on enough successful ventures to pay for the more numerous unsuccessful ventures. The State has no significant means of spreading or lessening risk other than to accept the highest competitive cash bid as a criterion for a lease award.

2. Net profit share bidding (and some other forms of contingency bidding) can lead to unrealistic or irresponsibly high bids. There are really no factors which practically constrain a contingency bid which is a promise costing nothing and bearing little in the way of obligations. Cash bonus bidding by its nature requires that a bidder carefully evaluate its bid in terms of available cash and its desire to aggressively proceed with exploration and development. History shows that tracts receiving high bonus bids receive timely exploration and expeditious development if exploration results in a commercial discovery.

3. Net profit share leases are likely to involve excessive administrative costs and disputes as to how the net profit due the State is to be calculated. Regardless of how tightly accounting and regulatory definitions are drawn, there will still be differences of opinion as to the allocation of costs and revenues, the treatment of depreciation, and questions of fair return on investment. It is quite possible or even likely that administrative costs and disputes leading to litigation would negate the worth of a net profit share to the State.

4. Net profit share leases necessarily cause the State to be involved in business and technical decisions which are best left the responsibility of the lessee. For example, if the State became concerned that the costs of development, however necessary and prudent for a safe operation, were too high, it might pressure the lessee to cut corners and undertake less than prudent development to cut costs and thus increase profits.

These were my primary concerns in opposing the use of net profit share leasing in the 1979 Beaufort Sea Lease Sale. With this background in mind, I urge the Legislature to delete the net profit share provisions from the Northstar leases.

In choosing net profit share as the bid variable in 1979, the State chose to forgo hundreds of millions of dollars in lease bonuses which would have been forthcoming under the proven system of cash bonus bidding. The opportunity for large cash bonuses has been lost because times have changed. The late 1970's were times of extremely high oil prices. State and industry experts alike shared a general view that oil prices would remain high and many believed oil prices would increase in the future. The outlook now is considerably more sober. The state cannot recapture the opportunity it lost in 1979 by canceling and offering the leases at another sale.

The best course of action for the State is to delete the net profit share provisions and allow BP Exploration to proceed with development. This will lead to real benefits in terms of royalty payments and taxes to the State, jobs and economic opportunities for contractors and businesses across the state.

The simple fact that the Northstar leases have remained undeveloped by the original lessees for over fifteen years --in spite of promising discoveries--is ample proof that the original lessees found development to be uneconomic under net profit share obligations averaging 90 percent.

The Northstar leases are now owned by BP Exploration, a company with a demonstrated commitment to responsible and diligent development of Alaska's oil and gas resources. The State Legislature now has the opportunity to undo a past mistake in choosing net profit share lease terms by deleting the onerous and uneconomic net profit requirements. To do otherwise would be a ratification of a costly mistake and another decision to forgo the development of Northstar with its many benefits to the State and its citizens.

Thank you for the opportunity to comment on this important legislation.

Sen. Loren Leman,

4-20-96

First of all I want to compliment you on your handling of the Northstar issue.

I also want to pass on a couple thoughts/ideas to you.

In this deal with BP can we establish a review board that looks at this every year to see if both parties are living up to their end of the deal?

And on this review board could we have a couple BP north slope employees on it.

Also give this review board the power to cancel the agreement or at least halt it until agreements are met.

Keep up the good work

Mark A. Niew

p.s. We had a rally in front of the BP building on the 17th, news came out but didn't give us any air time. But we had a lot of support from cars driving by, honking their horns and giving the "thumbs up" sign!

APR 19 1996

April 16, 1996

Dear Senator Leman:

I'm very disappointed not to have heard from you regarding my concerns about BP's request for royalty and tax relief on their proposed Northstar development. I must remind you that the oil BP is proposing to develop belongs to the CITIZENS of the State of Alaska. Any deals or concessions must be for the long-term benefit of our State.

To show you where BP is putting some of its money, please read the enclosed news release. There is a service available through BP that provides current events affecting the oil production, chemical, and refining industries. As you can see, BP's CEOs both present and past, are receiving very handsome bonuses. The attached article is receiving wide circulation on the Slope at present.

We along with the present contract employees, are very concerned about BP's current and proposed job cuts in its Prudhoe Bay unit. These cuts will more than offset any gains by BP's proposed added jobs at Northstar. Their press release and other public statements contains too many "weasel clauses".

They haven't shown to my satisfaction their commitment to build, hire, or buy Alaskan goods and services. Fairmont has, since my last letter to you, even transferred their buyers to Utah. It's obvious to me, and should be to you, that you don't move your buyers to Utah if you intend to buy Alaskan good.

Again, I wish BP success, but Alaska still provides almost half their world oil production, and I see no need to "GIVE AWAY THE FARM."

BP has figuratively "spit" on OUR written contract, so I'm very apprehensive about any "gentlemen's agreements" between Alaska and BP.

I've been told by a few of your colleagues that the State has no business telling BP how to manage its affairs. However, they are the ones approaching US, wanting to re negotiate something they previously agreed to.

Also, they provide us with "Gap Rap" information regarding the State budget, and the need to cut it.

Please "jawbone" BP into dealing openly and honestly with its employees and partners, the State of Alaska, and its citizens.

Sincerely,

William F. Bocast

William F. Bocast

P.O. Box 520626

Big Lake, AK 99652

FROM: Daily Mirror 03/19

BP bosses strike gold

The top brass at oil giant BP have struck black gold.

The company yesterday revealed 109 senior managers will be given more than six million shares.

The hand-out - worth nearly £34 million last night - is for helping profits gush in over the past five years.

But they could be worth even more by the time they get them in five years.

Shares allocated to seven directors under the scheme were worth £8.5 million last night.

New chief executive John Browne is the biggest winner with a £1.75 million windfall. *£2,800,000*

FROM: Financial Times 03/19

Former Chairman Gains from BP's £10.5m. Shares Pay-Out

Nine present and former directors of British Petroleum are to share in an award of £10.5m of shares under the company's long-term performance plan.

They include Mr. Robert Horton, the former chairman ousted in a boardroom coup in 1992, a year after the plan was initiated. Mr. Horton, now chairman of Railtrack, will get shares worth £227,00 at yesterday's price. *£363,200*

According to the company's annual report released yesterday, Mr. Horton "was able to initiate certain changes ... which have benefited the performance of the company." BP said these changes included reorganisation of the company's headquarters in 1990 which had boosted efficiency.

Other former executives who qualified for the award were Mr. Norton, managing director until last year, who gets *Hugh* £1.78m, and Sir David Simon, now chairman, who received £880,00 worth of shares. The largest recipients among current directors are Mr. John Browne, chief executive, who gets shares worth £1.73m, Mr. Steve Ahearn, finance director (£1.66m), Mr. Bryan Sanderson, head of chemicals (£1.65m) and Mr. Russel Seal, head of human resources (£1.17m).

Other former executives who qualified were Mr. Hugh Norton, managing director until last year, who gets £1.75m, and Sir David Simon, now chairman, who receives shares worth £860,000.

The largest recipients among current directors are Mr. John Browne, chief executive, who gets shares worth £1.7m, Mr. Steve Aheame, the finance director (£1.6m), Mr. Bryan Sanderson, head of chemicals (£1.6m) and Mr. Russell Seal, head of human resources (£1.1m).

The long term performance plan was introduced in 1991 to replace share options.

Share are awarded after five years based on BP's returns compared with other leading oil groups. Mr. Peter Sutherland, chairman of the remuneration committee, said BP had outperformed the stock market over the period, producing a return of 15 per cent a year. Earnings had increased by 37 per cent, and return on capital went up from 9 to 14 per cent. The awards were based on a 60 per cent achievement of the targets laid down in 1991.

Newsweek

February 26, 1996 \$2.95

CORPORATE



Robert B. Palmer, Digital
Cut 20,000 jobs



Albert J. Dunlap, Scott
Cut 11,000 jobs



Robert E. Allen, AT&T
Cut 10,000 jobs



Louis V. Gerstner Jr., IBM
Cut 60,000 jobs

KILLERS

Wall Street Loves Layoffs.
But the Public Is Scared
as Hell. Is There a Better
Way? BY ALAN SLOAN

STANDARD DIME GREENS TO DS OFORMA
RENGTH AFTER

can no longer count on staying with the likes of IBM forever. But nothing has taken the place of the benevolent Big Daddy employer, and that scares the pants off us. You can practically smell the fear and anger in white-collar America, because no one in CEO-land seems to care. Where will I find another job if I get downsized? Stop whining, unemployment statistics have barely budged despite huge white-collar firings. Will my boss ruin my life to make another cent of profit on her stock options? Cheer up, you're serving the greater good by being blown away by what economist Joseph Schumpeter christened "the gale of creative destruction." Except for oddballs like the chief economist at Morgan Stanley (who has warned for years that there would be a backlash) and the president of United Technologies (who recently unveiled a nifty program to help UT workers re-educate themselves for their next jobs), Wall Street and Big Business have been in perfect harmony about how in-your-face capitalism is making America great.

Wits at AT&T Corp. quip that chairman Robert Allen will soon fire everyone but himself, and AT&T will stand for Allen & Two Temps

are debatable, though Dunlap doesn't agree. Nor is it easy to get a handle on how many firings there actually are. Layoff numbers from the Chicago outplacement firm of Challenger, Gray & Christmas, an oft-cited source, are full of holes, as the firm readily admits. They include only publicly announced cuts. I'm not sure what federal job-cut numbers actually measure, and you can argue endlessly about how to interpret figures about workers' salaries and output. What really matters is that although unemployment is relatively low and the economy is still cranking out new jobs, millions of Americans believe they're being screwed by corporate America and Wall Street.

It's unfair to blame every job cut in America on Big Business and Wall Street. The world is changing, and no matter how big and rich a company is, it has to adapt or die. (Even NEWSWEEK hasn't been immune to job-cutting.) But Wall Street and Big Business have made a bad problem worse by being greedheads. Instead of keeping payrolls lean and helping employees to prepare for their next careers, lots of CEOs have messed up big time. They let their payrolls get bloated. Then to recoup, they offer up employees as human sacrifices to Mammon, god of Wall Street, hoping to get their stock price up. When the price rises, it's like Wall Street spitting on the victims' bodies. And the CEO gets a raise. How many CEOs of big, downsizing companies sacrificed some of their pay and perks to encourage a sense of community? Did they apologize publicly to the people they fired? Did they take any personal responsibility for mistakes that helped cause the problems they're solving with layoffs? No way, that's not macho.

WELL, NOW IT MAY BE BACKLASH TIME. SUDDENLY, white-collar woes are a hot issue in the 1996 presidential campaign. Al Dunlap of Scott Paper, the loudest spokesman for corporate hardball (page 48), duked it out with Labor Secretary Robert Reich on "Nightline." Bob Dole is making antibusiness noises. And Big Media from The New York Times to The Wall Street Journal attribute Pat Buchanan's strong showing in the Iowa caucuses to his attacks on business.

We're not going to argue about whether today's mass firings make economic sense. Companies like IBM and Sears and GM had to downsize or die. Other cuts—like some of those at Scott Paper—

Of course, no matter how sensitive or smart a CEO may be, there are tides that you just can't swim against. Take banking. Thanks to money-market mutual funds, national banking, teller machines and spiffy computers, many banks, bank branches and thousands of

Louis Gerstner
CEO

IBM

Salary: \$2,625,000

July 1993

60,000 layoffs



John McDonnell
Chairman, Former CEO

McDonnell Douglas

Salary: \$775,000

July 1990

17,000 layoffs

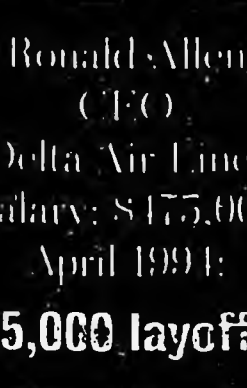
Ronald Allen
CEO

Delta Air Lines

Salary: \$175,000

April 1991

15,000 layoffs



Robert Stempel
Former CEO
General Motors
Salary: \$1,000,000
December 1991:
74,000 layoffs

Edward Brennan
Former CEO
Sears, Roebuck & Co.
Salary: \$1,075,000
January 1993:
50,000 layoffs



Robert Palmer
CEO
Digital Equipment
Salary: \$900,016
May 1991:
20,000 layoffs



bank jobs will vanish in the next few years. Electric utilities used to be great lifetime employers, too. They were regulated monopolies allowed to pass costs on to their customers. But regulators have started to let companies invade each other's turf. The result: utilities have started to combine, and will soon be zapping workers to get costs down. Ditto for local phone companies, thanks to the recent Telecommunications Act.

LOOK, YOU CANT STOP ADVANCES IN COMPUTERS AND communications and transportation. They're making national markets into global markets. Foreign companies whose names you can't even pronounce can take away your customers and kill you. Mistakes show up quickly. Product cycles are shorter than ever. Look at how IBM and Digital Equipment, once the world's two biggest computer makers, seemed to add the word troubled to their names almost overnight. (They both seem to be recovering.) A marvelous company like Motorola can have its stock smashed to smithereens, if its profits come in a hair or two below expectations. Indeed, one reason that chief executives are meaner and greedier than they used to be is the 1980s: no company was safe from raiders if its stock price was depressed. If you didn't unload your losers and fire "surplus" workers, a takeover troll would buy your company and fire everybody.

Yet while layoffs have traditionally been part of blue-collar life, the '90s is the first time white-collar workers have been slaughtered en masse. That helps account for the uproar. After all, agenda setters like politicians and we media-elite types live in a white-collar universe. Anyway, you could see why GM was firing 74,000 workers in 1991 or Sears was firing 50,000 two years later. Both companies were in desperate trouble, and

their survival was at stake. And the chairmen of GM and Sears were forced to walk the plank.

Today's layoffs are different. The symbol: AT&T. When AT&T, formerly the kindly Ma Bell, announced in January that it would fire 40,000 people as part of its breakup into three companies, the stock market went nuts. AT&T shares roared upward. Bob Allen, who I think wants to do the right thing, symbolized the clueless CEO when he talked to NEWSWEEK last month. He said he felt bad about firing people but saw no point in giving up some of his pay or perks as a shared sacrifice with the workers. And, he said, he saw no reason to apologize: "I wouldn't see any value of going on TV and crying." Allen, who had been ridiculed on Wall Street for AT&T's disastrous \$7.5 billion hostile takeover of computer maker NCR in 1991, made more than \$5 million when the value of his stock and options soared after the layoffs were announced. (He declined to talk last week.)

For another classic example of how CEOs seem to have forgotten how to deal with people, consider the recent combination of two giant New York City banks, Chase Manhattan and Chemical. Chase was pressured by Michael Price of the Mutual Series funds (whose stockholders include me) to get its stock price up and sold out to Chemical. The attraction to Chemical: the Chase name, which it's keeping, and its ability to cut 12,000 jobs from the combined banks. Those jobs would have probably vanished even without a takeover, but in a slower, more controlled way. Thousands of little people were fired to save money, while the new Chase kept all 36 outside directors, who get fat fees and dandy retirement packages.

And here's another company with no clue as to how things look to the outside world: troubled Apple Computer. Apple recently installed Gil-

The world is changing, and no matter how rich a company is, it has to adapt or die. But Wall St. and Big Business have made it worse by being greedheads.



Michael Miles
Former CEO
Philip Morris
Salary: \$1,000,000
November 1993:
14,000 layoffs



Frank Stroncz
CEO
Boeing
Salary: \$1,200,000
February 1993:
28,000 layoffs



William Johnson
Former CEO
Xerox
Salary: \$800,000
January 1993:
33,800 layoffs

bert Amelio as CEO. A company firing workers and eliminating its dividend to conserve cash is paying Amelio \$2.5 million a year of salary and bonus. At a minimum. Hello? For heaven's sake, Amelio was already on Apple's board; that makes him at least partly responsible for Apple's problems. How can you lay megabucks on him while paring workers to conserve cash? Only if you don't care about what anybody thinks. Consider Amelio's answer last week when NEWSWEEK asked him to justify his pay package: "It's a market-determined figure." Contrast that to Lee Iacocca's taking the helm of Chrysler for a dollar a year in 1978. Iacocca, who got fat stock options in addition to his dollar, has been no prize in recent years, as greed and ego overwhelmed his good sense. But he was an inspiration when Chrysler was croaking, and it really mattered.

Rather than fire workers to save a few bucks, Scherer Brothers Lumber stopped buying sports tickets and fresh flowers for receptionists' desks.

conglomerate that has cut 23,000 jobs since 1990. Last December, UT unveiled a new, expensive plan to help workers get re-educated. President George David says the United States can't stop production jobs from migrating overseas, so companies should help people upgrade their education before it's too late. "We load education into our first 21 years of life, and then think that we can leave the classroom essentially forever," he said. UT now gives employees time off to attend classes, pays for tuition and books, and will give employees who complete their studies 50 shares of UT stock, currently worth about \$5,200. You can go to nursing school or get a degree in creative writing, none of which has anything to do with UT's businesses. David hopes that 20 percent of his employees will use the plan. That would gradually increase the company's outlay to about \$50 million a year from the current \$11 million. "We're not softhearted," said David, whose face turned red when I suggested he sympathized with downsized workers. "It's in our interest to have an educated work force."

IACOCCA'S GREAT GESTURE WAS LONG AGO AND FAR AWAY. Now let's look at the behavior that convinced Stephan Roach, the chief economist at Morgan Stanley, that business is carving itself a disproportionate piece of a pie that's supposed to be shared with workers. Roach is hardly anti-business—he loved downsizing in the early 1990s. Yet a few years ago he realized something was wrong: workers' output was rising, but their incomes weren't keeping pace. "This isn't the way economics is supposed to work," he says. "It contradicted everything I was taught to believe." When he warned companies to do something before a political backlash struck, they giggled on Wall Street. I don't think they're giggling now.

There are no surefire solutions to these problems. But some companies are enlightened enough to know that helping their workers also helps them. Take United Technologies, a hard-boiled

Then there is John Grundhofer, chairman of First Bank System of Minneapolis, which recently collected a \$200 million fee for abandoning its proposed takeover of First Interstate Bank. With no fanfare, Grundhofer—who fired 2,000 employees when he joined the bank six years ago—recently gave each employee a \$750 bonus, about \$11 million in all. He wanted to show his appreciation to employees for having created a bank strong enough to bid for a company bigger than itself.

For decency, it's hard to top Malden Mills, which became famous last year when it kept 1,400 workers on the payroll after its plant in Lawrence, Mass., burned down. "What right do I have to destroy a major city just to get a few more dollars in the bank that I won't spend before I die?" said mill owner Aaron Feuerstein.

"The money would only go to my children and spoil them." Or take a company almost no one's ever heard of: Scherer Brothers Lumber Co., a building-supply company in suburban Minneapolis. President Mike Scherer said that officers don't draw bonuses until the company has given a 15 percent profit-sharing contribution to every eligible employee. And rather than firing workers to save a few bucks, the company eliminated fresh flowers for receptionists' desks, cut the top officers' pay temporarily by 25 percent and stopped buying professional sports tickets. "When you buy professional tickets, you're subsidizing people making tons more than I am, and they're still not happy," he says. "I'm not going to lay off our employees to subsidize them."

There is no magic bullet that will make the problem go away. Even eliminating short-term thinking isn't the answer. Proof: German and Japanese companies specialize in long-term thinking, and

they're more messed up than we are. The federal government can't save us. Can you see the Feds drawing up rules to define a good-jobs company in order to give it tax breaks? And we can't go back to the days of the 1950s and '60s, when big companies offered lifetime employment. Any company that tries that these days will be like an elephant in a piranha pond.

You solve this problem one company at a time, with innovative programs like United Technologies', decent behavior like Feuerstein's and Scherer's, intelligent and relatively cheap gestures like Grundhofer's. Let business act as if it cares about employees. Who knows? Business may even rediscover what many executives once knew but seem to have forgotten: that doing the right thing for your people is often the best thing you can do for your business.

With ANNE UNDERWOOD in New York, JOHN MCCORMICK in Chicago and DEBORAH BRANSCOMBE in Emeryville, Calif.

Villains? Heck No. We're Like Doctors.

Job cuts hurt, says Al Dunlap, but it keeps firms alive

ALBERT DUNLAP HAS BECOME the poster boy for the folks who say that CEOs have gone too far. The 58-year-old former CEO of Scott Paper, known to detractors as "Chain Saw Al," cut 11,000 jobs in 1994. After merging the company with Kimberly-Clark, he walked away with about \$100 million in salary, stock profits and other perks. Dunlap previously downsized seven other companies, including Diamond International and Lily-Tulip. When NEWSWEEK asked more than 50 CEOs of large American companies to discuss corporate restructuring, only Dunlap was willing to talk. Here's what he had to say:

When journalists and politicians spout off about corporate downsizing, it's the Al Dunlaps of the world who tend to get the blame. We're painted as villains; but we're not. We're more like doctors. We know it's painful to operate, but it's the only way to keep the patient from dying. Take the restructuring at Scott. We had to fire 35 percent of the work force. It was a difficult task. Coming from a working-class family (my father was a union steward), I know what

it's like when someone in the family loses a job. But while we had to cut some jobs, we were able to give 65 percent of the work force a more secure future than they might have otherwise had. And Scott's stockholders came out \$6.5 billion to the better.

So why are shareholders so important to workers? By doing a good job for them, we're encouraging them to invest, to build new plants and create new products. At the end of the day, that will mean more and better jobs down the road. And that's the point people need to remember: the only way corporate America is going to do right by its workers is to compete. And in order to compete, companies need to become efficient. That means if you have workers for whom you don't have a real job, you can't keep them on the payroll.

Let me put this in some historical perspective. In the '70s America lost its position as a leader in global business. Look at the industries we once had



that barely exist: shoes, machine tools and consumer electronics. Don't blame today's executives who are having to face up to the tough decisions—blame the executives who created bloated corporations that are noncompetitive. People are always criticizing companies that bring in record profits and then announce layoffs. What they don't realize is that if an organization doesn't make record profits, it doesn't have the money to invest in new plants and new technologies.

That's not to say that I don't

believe in CEOs' being accountable to their workers. I think a CEO has an obligation to communicate with workers and prepare them for the inevitable. Before the restructuring at Scott, I personally went around the world and talked to people on the shop floors. One of the things we told them was that we weren't keeping the

elitist tools of corporate America at the expense of workers. Our biggest cutback was to sell the 750,000-square-foot corporate headquarters and downsize 71 percent of the corporate staff. At one plant, the workers actually applauded me. People are pretty intelligent if you tell them what's going on and explain why you're doing what you're doing.

On the other hand, the politicians don't seem to be getting the message. They pander

to the public and polarize people. And they try to tell American industry how to conduct its business. The job of industry is to become competitive—not to be a social experiment. God help us if we pass legislation to make American companies less productive and compromise our global competitiveness. Then it won't be a case of a relatively small number of people losing their jobs. It will be huge numbers losing their jobs—and the death of the American free-enterprise system as we know it.

FACSIMILE COVER PAGE

To: Sen Loren Leman
From: Brad Humelsine
Pages (including cover): 1

Time: 09:55:42
Date: 04/19/96

Please find the following letter to BP. It was written in response to the direct mailing they made regarding Northstar.

This is the kind of sweet deal Alaska can do without.

Thank you,

Brad

James B. Humelsine
2553 LaHonda Drive
Anchorage, Alaska 99517
Phone (907) 276-7826

April 19, 1996

John C. Morgan President, Alaska
BP Exploration (Alaska) Inc.
900 East Benson Blvd.
P.O. Box 196612
Anchorage, Alaska 99519

Dear Mr. Morgan:

I am responding to the direct mailing you sent me regarding the Northstar oil field.

As a strong supporter of the oil industry in Alaska, but I am very disappointed in BP and its' handling of the Northstar affair. Your company purchased the field knowing full well, what the former owner had bid on the tracts. You also knew as the new owner would be bound by the same agreement. Since this tract was awarded by the competitive bid process, It should only be changed through the same bid process.

BP must feel they much to gain from this purchase and subsequent renegotiation, because in my 17 years in Alaska I have never seen such a concerted effort from an oil company to reopen a contract. In your letter you call this field "relatively small", however your PR effort is relatively large. You have spent a significant amount of money on advertising and other public relations efforts relating only to this field. Historically the themes of your advertising and PR campaigns have been the "good neighbor" or "look at we do for you Mr/ Mrs Alaskan", recently you have used increasingly more hard line themes such as "We are Alaska's biggest tax payer". But never before this have you said call you legislator and tell them "don't tinker with this deal we negotiated with the Governor". I closely follow the Ad campaigns of yours and other companies, I have witnessed your increasingly aggressive themes, and I do not approve of them, period. This another example of the bully attitude your company is pushing.

Sorry, Mr Morgan I am too smart to fall for such a ploy.

If this contract were to be successfully renegotiated, it would set a precedent that I am sure you would be happy to use many times in the future. I think this is wrong for Alaska, and should be stopped now.

Thank you for taking the time to read my response.

Respectfully,

Brad Humelsine

CC:
Rep. Cynthia Toohey
Sen Loren Leman
Gov. Tony Knowles



Executive Office
Mikera Center
Washington, PA 15301
412-223-2300

D. M. CHURCH
Director
Purchasing and Materials Management

April 10, 1996

Dear Supplier,

Effective May 1, 1996, Fairmont Supply Company will relocate and centralize its Price, Utah Western Purchasing functions into our Corporate Purchasing and Materials Management Department out of Washington, Pennsylvania.

All future correspondence should be forwarded to the following address:

Fairmont Supply Company
P. O. Box 501
Washington, PA 15301
Attn: Purchasing and Materials Management

Phone No.: 412-223-2200
Hours: 8:00 a.m. - 5:00 p.m. E.S.T.
Monday - Friday

Invoicing will remain as before.

Please update your files accordingly and notify the appropriate personnel of these changes at your company. If you have any questions or have any concerns, please contact Mr. Carl Grebner, Manager - Commodity Purchases.

Thank you,

D. M. Church
Director
Purchasing and Materials Management

Question to Alaskan Legislators
Is this where you intended for BP
Exploration to do their business?
Do we now go to Pennsylvania
to sell to the north slope oilfields?

Mr. Tom
PO Box 100648

Lakosh

*Northstar
file*

338-1606

Anchorage AK 99510
Date POM Sent Constituency Bill Number
04/09/96 N SB 318

Response
Opposes

Distribution
07

Affiliation

Reg Voter
U

PLEASE PROVIDE FOR A PUBLIC COMMENT HEARING WITH A TELECONFERENCE SITE IN ANCHORAGE. THIS BILL VIOLATES MY CONSTITUTIONAL RIGHTS, UNDER ARTICLE I SECTION 5, BY IMPAIRING A CONTRACT. PROPER PROCEDURE REQUIRES DISSOLUTION OF THE UNIT, REVERSION OF LEASES, AND RE-OFFERING OF THE LEASES PURSUANT TO COMPETITIVE BIDDING PROCEDURE THIS AUGUST.

04/15/96

LEGISLATIVE TELECONFERENCE NETWORK SYSTEM

LTN1150

15:43:23

PARTICIPANT LIST (ALL PARTICIPANTS)

BY:ANC

TCN:60744 SCHEDULED FOR:04/15/96 15:30 TO 17:00

FOR:ANC

PUBLIC HEARING

SENATE RESOURCES

LOCATION: ~~ANCHORAGE~~
SB 318 #

~~JERRY~~

~~SCOTCHON~~

~~SCOTCHON~~

DAN R. GILBERTSON
1240 GILMORE TRAIL
FAIRBANKS, ALASKA 99712
907-457-3989

POSTAGE PAID

March 26, 1996

MAR 29 1996

TO:

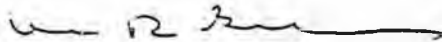
Petroleum News*Alaska
Anchorage Daily News, Fax: 907-258-2157
Fairbanks Daily News Miner, Fax: 907-452-7917
Legislative Information Office - All Legislators mailed to Juneau
Bert Sharp - Chair Interior Delegation Hand Delivered
Gene Therriault - State Representative
Mike Stepovich
Ken Boyd, Director, Division of Oil & Gas, Fax: 907-562-3852
Charlie Cole

Enclosed please find a copy of our letter to Commissioner Shively. We are copying this letter to you not only for informational purposes but for any assistance that you as representatives of the people of our State could provide. At a time when the Legislator and the Senate seem to be going in a pro-development stage, why is it that we as individuals cannot get the same considerations.

Once read, I am sure you will find the attached letter extremely self-explanatory. I am sure you can understand my frustration with this situation.

Thank you.

Sincerely,



Dan R. Gilbertson

Dan R. Gilbertson

1240 GILMORE TRAIL
FAIRBANKS, ALASKA 99712

Telephone 907-467-3889

March 26, 1996

Commissioner John Shively
Department of Natural Resources
400 Willoughby Avenue
Juneau, Alaska 99801-1724

VIA FAX TO: 1-907-465-3886

Dear Commissioner Shively,

As a small independent investor on the North Slope, one of only a handful in comparison to the major oil companies up there, I have some serious concerns as to why the Major Oil Companies and the State seem to be so bound and determined to allow only big oil on the North Slope. Specifically, this is in reference to Lease #365537, Lease Date commencing on 11/30/85 for 10 years (this lease has a 16 2/3% Royalty to the State of Alaska).

Let me provide you with some of the specifics on the above mentioned lease.

At one time this lease was part of the Badami Unit, and at the State's request, put into a separate unit (the Rheingold Exploration Unit). Obviously the Badami Unit overshadowed the Rheingold Unit, and there was no reason to have two separate units. We are still unclear as to why we were removed from the Badami Unit in the first place. We were the only lease not owned by major companies excluded from the Badami Unit. Perhaps you can shed some light on this as well.

A year ago, we negotiated with British Petroleum in good faith and thought we had consummated a deal to sell them this lease. BP was not negotiating in good faith. They would discuss the agreement with us verbally and then when we received the written agreement from them, it was not as previously discussed. To put it concisely they negotiated in bad faith.

My reason for this statement is that I suspected that BP was at their State acreage limit while they were negotiating with us. We then offered our lease to ARCO. ARCO stated they were not interested in that area, but then, one month later, at the December 5, 1995 lease sale #80, purchased the adjoining lease to ours- more than likely on BP's behalf.

As our lease was about to expire, we realized that we would not have a deal, and would need to come up with another game plan.

Since that time we have been attempting to seek a lease extension from the Division of Oil and Gas. It became glaringly apparent that we were not going to be allowed to be part of any Unit Agreement.

During the last week of November 1995, we sent our annual lease payment check in the amount of \$14,400.00 with our request for an extension of our lease which was to expire on November 30, 1995. The State subsequently cashed this check, but has yet to notify us if in fact our lease has been extended.

Is it safe to assume that since your department cashed the check, the lease is in fact extended? If so, I would appreciate some verification of this extension.

At this time it would be in the best interest of the State to provide us with an extension on the lease so we can proceed with our plans.

Currently, the Division of Oil & Gas, the Governor's Office, and the Legislators are going the extra mile to promote development on these fields in the North Slope and working directly with the Major Oil Companies. I think it would be very beneficial for the State to provide the same considerations and courtesies to the small independents that have been provided to the major oil companies. Earlier Commissioners have extended leases indefinitely with a discovery well on-site, and being that this north-slope lease has a discovery well, I think we should be given the same consideration. Eight leases previously extended were ADL #47466 for ARCO and ADL #45527 for ARCO/EXXON.

I am concerned that if you do not encourage independent leaseholders on the North Slope the same negotiating ability on lease terms and conditions as granted by ARCO, that you will never know the true quantities and value of oil.

The State has had a hand in creating a monopoly for the major oil companies on the North Slope and the people of Alaska should demand that there be some other type of mechanism structured in so that individuals and independents have equal access to Alaska's resources, so vital for the long term economic development of Alaska and its people.

As a lifelong resident of Alaska, whose family has been involved with oil and gas leases for 3 generations, I expect equal consideration be given individuals and independents that has been granted to the major oil companies.

If the State is to grant us a lease extension - there is nothing to lose, and it is a win-win situation. I feel that we could afford to pay a much higher royalty rate than what the major's say is to high. Alaska has much lower royalty rates than any other country. Our lease has a 16 2/3% royalty to the State of Alaska.

Oil and gas leasing in Alaska is open to all comers; individual, independents, and major oil companies. The State should respond to all lease owners in a consistent and fair manner and not favor just big oil in their decisions.

We feel our lease; ADL #365537 should be extended as we have previously requested and by this letter are asking your assistance and action on this request.

We would appreciate your response on this within 5 days.

Please let me know if you need anything further.

I look forward to your immediate response in the above matter. Thank you for your consideration.

Sincerely,


Dan R. Gilbertson

CC: Petroleum News*Alaska
Anchorage Daily News
Fairbanks Daily News-Miner
Legislative Information Office - All Legislators
Bert Sharp - Chair of the Interior Delegation
Charlie Cole
Cliff Burglin
Jack Sexton
Jacquie Gilber
Ken Boyd, Director, Division of Oil & Gas

ALBERS EQUAL AREA/NAD27

BEAUFORT SEA

NORTH

AND UNIT

BADAMI UNIT

(App. Filed 1/21/54)

HOMER UNIT

R17E

R18E

R19E

R20E

SHUVIYIK RIVER

(App. Filed 6/54)

135

PAY TO THE ORDER OF
FIRST NATIONAL BANK OF ANCHORAGE
FOUR THOUSAND TO THE ACCOUNT OF
THE PROFESSIONAL FEE
DEPT. OF NATURAL RESOURCES
ANCHORAGE REVENUE
ACCOUNT NO. STATE OF ALASKA, 100-001
(181) 847 6

11/29/95

NOV 29 1995

NOV 29 1995 12:00 PM
ANCHORAGE, ALASKA
FIRST NATIONAL BANK OF ANCHORAGE

12500024
08E 585074

C. SURGLIN - LAND CONSULTANT
P O BOX 13
FAIRBANKS, AK 99707

5901

PAY TO THE ORDER OF

Dept of Natural Resources \$14,412.76
fourteen thousand four hundred twelve and 76/100 DOLLARS

NOV 29 19 95

ALASKA STATE BANK

FOR A126365537

C. Surclin

12500024 08E 585074

brennan

communications

April 4, 1996

Senator Loren Leman
via fax

Dear Loren:

I hope you will support the legislation necessary to amend the lease terms allowing BP's North Star project to proceed. We in the contractor community consider North Star a vital step toward developing the potential of small fields on the North Slope. I am personally convinced that is where the future of Alaska's economy lies. Big fields are wonderful, but experience shows they are few and far between.

Net profits bidding may have been a worthwhile experiment, but the experiment failed and acknowledging that is essential to correcting its problems. Since little cash had to be advanced for net profits leases, the incentive for prospective bidders was to ratchet their estimates on potential production to the maximum and bid as though a dream field were involved. If the acreage proved not to be that rich, their investment was relatively small and they could walk away.

The problem for the state was that the lease was then prohibited from development by a contract written for a much larger field than actually exists there. The state entrapped itself. Net profits leases fail to take Murphy's Law into account. Fortunately the Legislature is in a position to correct the problem and put this vital small field into production. Thanks for the time and effort you have put into this issue.

I look forward to seeing you at the State Convention.

Sincerely,



Tom Brennan

Lauesen and Company • Anchorage • Alaska

721 Breakwater Circle • 99515-3633 • (907) 345-4060 • (907) 345-4544 (fax) • email 73244.372@compuserve.com

Thursday, April 4, 1996
(Hon.) Senator Loren Lehman
Alaska State Senate
Juneau, Alaska 99811

Via Fax

RE: BP Proposal: Big Dipper Oil: gratitude to you and Senator Taylor

I note in today's paper (ADN: 4.4.96: B1: SENATE PANEL CONSIDERS BP PROPOSAL) that BP spokesman Luttrell emphasized that the fundamental difference between the net profit share arrangement in Venezuela and Alaska is the profitability of the field. This is *prima facie* baloney! There are a myriad of other differences built into the Venezuela deal including foreign exchange benefits and equity in the project which gives a reduction of the net to the venture by allowing profit-taxing by a JV holding company...I am attempting to get more details via the internet and will pass them on to you.

You and Senator Taylor are absolutely right to question this deal. Think of Alaska as an Oil Company. Let's call it "Big Dipper Oil". Think of each Alaskan as a shareholder in that Company. Now think of yourself as a member of the Board of Directors of Big Dipper. Now consider the fiduciary responsibility of that Board AND the CEO (Governor) to ensure profit maximization. In this context, then I must ask the following: Why in the hell are we not requesting Statements of Interest from every potential development partner in the World? Why are we giving the Franchise for our State's Future to the Big Oil Triumvirate when there is a world virtual alliances and partnerships available out there. Why don't we buy back the *@#! lease if we prospect a better deal? Why don't we start acting with some *cajones* when these companies sit down at the table--this is OUR future at play!

Senator, I am a lifelong Alaskan, a lifelong Democrat, and a (former) supporter of the Governor, but as far as I can tell, you and Senator Taylor are the only ones in leadership who are asking the right questions. Thank you for exercising your fiduciary duties in this monumentally important issue.

Please pass this along to Senator Taylor with my gratitude...

March 11, 1996

Petition to:

Loran Leman
State Capitol
Juneau, Alaska 99801-1182

MAR 15 1996

I am writing as an Alaskan oil worker who is concerned about the recent turn of events with BP Exploration (Alaska).

Recently BP has taken to task to "outsource" its Alaskan workers on the North Slope. On February 19, 1996 BP Management stepped up and announced it would "outsource" five groups in the Maintenance Department, a total of about 75 people. This company is doing no this but eliminating company positions in order to turn around and fill them with Out of State workers, at lower pay and benefits. This displacement of these workers will compromise the safety of the workers as well as the Environment. This is only the beginning.

As an Alaskan legislator, you need to look into this disturbing trend and take action. When incentives are given to Alaskan oil industries to further

a stable economy, there have to be consequences when the oil companies do not follow through with their obligations

BP has entered into agreement with:
Empco Services of New Orleans (workers for overhauls on major rotation equipment)
Fairmont Supply Co of Price, Utah (parts and warehouse supplier),
Anderson Worldwide Professional Services Corp of Dallas, Texas (accounting services). As you may have noticed all of the above companies are out of state owned and operated. Other oil companies are following BP's lead. This trend will lead to an overall reduction in wages and benefits throughout Alaska's economy, as the Oil Industry workers have strongly influenced the income levels Alaskans have come to expect for their labors. Now is the time for you to take action and make them accountable for their blatant disregard of the Alaskan workers' future

BP has lobbied the State for lower taxes and fewer restrictions. They have always said if they get what they want there would be more jobs for Alaskans - we all believed them. If BP continues their plan to "outsource" the

Maintenance, accounting, and warehouse personnel, the only jobs that will come into existence will be the ones at the refineries in Japan, Korea, and Taiwan.

The oil companies need to be responsible and evaluated regularly to make sure they are not only looking out for their stockholders, but also their employees and the State of Alaska who have contributed to their success.

Please write and inform me as to how you stand on this issue and what you intend to do about it.

Sincerely,

Lucille M. Aspelund

Lucille M. Aspelund
P.O. Box 870430
Wasilla, AK 99687

907-373-7335

Konopacki

WHY IS IT...?

...that the people who make all the decisions blame everything on those of us who don't?



...that the people who really DO make too much money, keep complaining that WE make too much money?



...that government incentives for the rich means giving them MORE, while incentives for the poor means giving them LESS?



...that employers keep demanding highly educated workers, and then replace us with low-skill minimum-wage earners because we're "too expensive?"



Petition to

MAR 11 1996

Loren Leman

Legislator

State Capitol

Juneau, Alaska 99801-1182

I am writing as an oil worker in Alaska who is concerned about the recent turn of events with BP Exploration (Alaska) Inc.

Recently, BP has taken to task to "outsource" its highly trained BP employees on the North Slope. On February 19, 1996, BP management stepped up and announced it would "outsource" five groups in the Maintenance Department, a total of about 75 people. This company is doing nothing but eliminating company positions in order to turn around and fill them with inexperienced, transient workers at lower wages and benefits. This displacement of these workers will compromise the safety of the workers, as well as the environment. This is only the beginning.

As an Alaskan Legislator, you need to look into this disturbing trend and take action. When incentives are given to the Alaska Oil Industry to further a stable economy, there have to be consequences when the companies do not follow through with their obligations. Dick Olver, Deputy Chief Executive of BPX said, "Our investment in Alaska ... our risks in Alaska ... the jobs they create and the revenues they generate for state government and Alaskan companies ... are the bedrock for the bridge to Alaska's economic future." In fact, BP has entered into agreements with: Enpro Services of New Orleans (workers for overhauls on major rotating equipment), Fairmont Supply Co. of Price, Utah (parts and warehouse supplier), Andersen Worldwide Professional Services Corp. of Dallas, Texas (accounting services). Other oil companies are following BP's lead. This trend will undoubtedly lead to an overall reduction in wages and benefits throughout Alaska's economy, as the Oil Industry workers have strongly influenced the income levels Alaskans have come to expect for their labors. Now is the time for us all to take action and make them accountable for their blatant disregard of the Alaskan workers' future.

Another grave concern to you as a Legislator is the possibility of an oil spill or other environmental disaster caused by an inexperienced or transient work force. The North Slope is an unforgiving environment where experience and training prevent accidents.

MAR 11 1996

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Legislator

State Capitol

Juneau, Alaska 99801-1182

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The dedicated employees on the North Slope have worked hard for years to produce oil for BP. In return, the employees, BP and the state have all benefited from the revenues generated and spent throughout the state. The state's economy is dependent on oil, and therefore the state is dependent on competent, dedicated, trained, qualified workers to make sure the safety of the workers and the environment is not compromised. Those of us who live, work, raise our families, etc., in Alaska have a very strong investment in the future of the state, both financially and environmentally.

When BP has lobbied the state for lower taxes and fewer restrictions, they have always said if they get what they want there will be more jobs for Alaskans - we all believed them. Now we have the lifting of the Export Ban, which according to BP will add jobs in Alaska as well as on the West Coast. If BP continues their plan to "outsource" the maintenance personnel, accounting, etc., the only jobs that will come into existence will be the ones at the refineries in Japan, Korea and Taiwan. This "outsourcing" is not being done because BP cannot afford to do otherwise - the headlines in BP Today read, "95 results best in BP History." Alaska is supplying 95 percent of BP's U.S. oil and gas production and 40 percent of its worldwide total.

The oil companies need to be responsible and evaluated regularly to make sure they are not only looking out for their stockholders, but also their employees and the State of Alaska who have contributed to their success.

Please write and inform me as to how you stand on this issue and what you intend to do about it.

Sincerely;

Richard P. ...
Signature

3-6-96
Date

3018 LEXINGTON AV.
Address

ANCHORAGE AK 99502

Petition to

Larsen Larsen

Legislator

State Capitol

Juneau, Alaska 99801-1182

MAR 11 1996

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MAR 11 1996

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Loren Loman

Legislator

State Capitol

Juneau, Alaska 99801-1182

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Please write and inform me as to how you stand on this issue and what you intend to do about it.

Sincerely;

Paul E. Munn 3-5-96
Signature Date
746 Cranberry Ridge
Address
Fairbanks, AK 99712



BP EXPLORATION

John C. Morgan
President, Alaska

MAR 24 1996

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 564-5422

March 22, 1996

Senator Loren Leman
Alaska State Legislature
State Capitol Rm. 113
Juneau, AK 99801-1182

Dear Senator Leman,

It has been brought to my attention that some employees of BP Exploration may have raised their concerns to you about our business decision to outsource certain functions on the North Slope and in Anchorage. Because this matter may have been brought before you, I feel that it is important for us to give you information on what we are doing and the reasons behind it.

In the face of Prudhoe Bay's continuing production decline, it is essential that we structure our business so that it will remain profitable into the next century, while not sacrificing our ability to use the best practices and technology available to us. We are continuously examining how to achieve significant cost savings in order to reduce our per barrel operating costs since this is key to keeping the Prudhoe Bay field and Alaska an attractive and competitive option. That is the primary motivation behind the outsourcing decisions we have made and those that we are currently considering. These changes allow us to be more efficient and ensure access to the most current technology at a cost that takes into account the economies of scale which are only available to us through outsourcing.

Recently proposed changes in four areas of our Prudhoe Bay Maintenance and Projects department appear to be fueling considerable concern. These changes include telecommunications, the toolroom, the welding shop, and the paint/carpenter shop. The largest impact would be felt in telecommunications where 15 BP and contractor employees would be affected if a planned study shows that it would be both feasible and beneficial to outsource this function, most likely to an Alaskan company such as GCI. Another two BP people will be affected when the toolroom operation is assigned to Fairmont, a contractor who already manages our Prudhoe Bay materials operation. Welding, painting and carpentry will be done in existing VECO workshops, affecting an additional six BP employees. We do expect that there will be additional impacts to our contractor workforce, but do not yet have detailed information.

Roughly half of these employees are members of the Oil, Chemical and Atomic Workers Union (OCAW) and so, as agreed to by OCAW in their labor agreement with the company, we have given 60 days notice of our intention to outsource and are prepared to enter into discussions with the union on alternatives and effects.

We are well aware of the unfortunate reality that any change such as this does affect current workers and we have always tried to minimize the impacts of such changes through generous severance terms, benefits extension, outplacement help and other assistance programs. Our intent is to help the North Slope employees who will be affected by our proposed changes, within the limitations imposed by the labor agreement with OCAW. However, we recognize that those affected employees and others are concerned and that they may be expressing that concern by questioning our commitment to hire Alaskans.

I want to assure you that our commitment to maintaining and improving the oil industry's role in hiring Alaskans is a sincere one which we take very seriously. Last week, BP and representatives from 19 other oil industry companies unveiled an Alaska hire initiative which outlines specific actions we will take toward realizing this commitment. They include examining our internal policies and practices, working with the state to ensure an adequately trained and available workforce, looking closely at our recruitment and hiring efforts, and setting goals and measuring performance against them.

However, it is important to recognize that the greatest opportunity to increase jobs for Alaskans is through new development and new development can only occur if we remain globally competitive, both with respect to new investment opportunities and in our base business.

I hope that the information I have provided is helpful to you. Please know that BP welcomes the opportunity to discuss this and other issues which come before you. Thank you for your time and concern.

Sincerely,

A handwritten signature in black ink, appearing to read "John C. Morgan". The signature is written in a cursive style with a prominent initial "J" and a long, sweeping underline.

John C. Morgan