Findings and Decision of the Director
of the Division of Oil and Gas

APPROVAL OF THE

SAG RIVER PARTICIPATING AREA

WITHIN THE MILNE POINT UNIT

Under a Delegation of Authority
from the Commissioner of the State Of Alaska
Department of Natural Resources

May 11, 2005

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Introduction and Background

The Milne Point Unit (MPU) is located on the North Slope of Alaska. It is northwest of the Prudhoe Bay Unit, north of the Kuparuk River Unit, and southeast of the Nikaitchuq Unit. The Alaska Department of Natural Resources, Division of Oil and Gas (the DNR or the Division as appropriate) approved the MPU on October 29, 1979, effective retroactively to September 28, 1979.

The MPU currently has two participating areas, the Kuparuk Participating Area (KPA) and the Schrader Bluff Participating Area (SBPA). The Division approved the initial KPA on April 20, 1982, effective retroactively to April 15, 1980. There have been eleven revisions to the KPA since its formation. The Division approved the eleventh revision of the KPA on November 24, 1999, effective retroactively to March 1, 1998.

The Division approved the initial SBPA on March 29, 1991, effective March 23, 1991. There have been two revisions to the SBPA since its formation. The Division approved the latest revision on July 17, 2003, effective retroactively to April 1, 2003.

BP Exploration (Alaska) Inc. (BP), the MPU operator, applied to form the Sag River Participating Area (SRPA) within the unit area. All the lands proposed for inclusion in the SRPA are currently within either the KPA or the SBPA. The KPA includes all acreage in the proposed SRPA, except one part of ADL 25516 (T13N R10E Section 22). The SBPA overlaps the southwest half of the proposed SRPA and includes the area not covered by the KPA, see Attachment 1 and Attachment 2.

The Division approves BP's application to form the SRPA within the MPU. The SRPA encompasses an area that is "reasonably known to be underlain by hydrocarbons and known or reasonably estimated ... to be capable of producing or contributing to production of hydrocarbons in paying quantities." 11 AAC 53.351(a). The Division also approves Exhibit B for the SRPA to the MPU Agreement (Tract Allocation Schedule), dated March 3, 2005 (Attachment 3 to this Decision). The SRPA is effective retroactively to February 1, 2005.

I. Historical Timeline of the Application Process

BP submitted the SRPA Application (First Application) on June 10, 2002, in accordance with 11 AAC 83.351 and Article 11 of the MPU Agreement (the Agreement). On June 14, 2002, the Division met with BP to review the First Application. Following the meeting, the Division granted BP permission to begin injection in the Sag River formation using well F-73A and notified BP that a written decision would be not be issued until additional documentation was submitted. The Division also requested additional data related to a full field simulation model. BP was unable to locate the simulation reports but the Alaska Oil and Gas Conservation Commission (AOGCC) had them on record as part of the Sag River Pool Rules. The Division finished its preliminary review of the technical data BP submitted to the AOGCC on June 27, 2002, and finalized its preliminary review of the First Application on July 25, 2002, pending receipt of revised exhibits and some of the requested data.

On September 9, 2002, BP notified the Division that the SRPA project manager left the company and the new project manager (Second Project Manager) requested a meeting to review the application and determine a plan forward. On October 1, 2002, BP submitted the 22nd MPU Plan of Development (22nd POD) and met with the Division to review the First Application. On October 8, 2002, BP renewed its commitment to amend the First Application and, the Division approved the 22nd POD on October 28, 2002.

On April 4, 2003, BP notified the Division that the Sag River Production wells (F-33A and C-23) had failed shortly after the October 1, 2002 meeting and BP deferred its plans to amend the First Application. Simultaneously, BP notified the Division that it had completed a workover on F-33A and requested permission to restart production from F-33A and injection in F-73A for a period of six months, contingent upon submission of an amended participating area application. In April of 2003, the Division granted BP's request to restart injection and production through October 4, 2003, with the understanding that BP planned to submit an amended First Application by June 1, 2003, as stated in its letter dated April 4, 2003.

On October 1, 2003, BP submitted the 23rd Plan of Development (23rd POD) for approval and on October 3, 2003, the Division notified BP that the 23rd POD should include its plan to amend the First Application and a request to extend the tract operations approval which was about to expire. On November 3, 2003, BP applied for approval to continue test production from the F-33A well and continue injection into the F-73A well, but did not supply the status report needed to support its request. On November 5, 2003, the Division requested an update of the production/injection history and a review of the waterflood response. The Division approved the 23rd POD on November 17, 2003, under the assumption that BP was preparing a review of the waterflood response.

On January 12, 2004, BP provided production/injection data, but no analysis of the waterflood response. On January 26, 2004, the Division clarified that it expected a review of the waterflood response, not just the raw data, before it would grant another extension.

On August 24, 2004, BP notified the Division that the Second Project Manager had been reassigned and a new project manager (Third Project Manager) had been assigned. On September 2, 2004, the Division granted approval to continue test production of the F-33A with injection support from F-73A, until November 1, 2004, to allow the new team time to evaluate the reservoir and amend the First Application.

On September 24, 2004, BP's new SRPA team met with the Division to discuss its plan forward and on September 30, 2004, BP submitted the 24th Plan of Development (24th POD) for approval. On October 12, 2004, BP notified the Division that another project manager (Forth Project Manager) was taking over the SRPA project and the Division met with the new team on October 21, 2004.

On November 15, 2004, representatives from BP and the Division met to review a status report of the waterflood response in the F-Pad area and the Second Application for the Formation of the Sag River Participating Area (2nd Application) that BP had submitted on November 1, 2004.

On December 22, 2004, after receiving additional supporting documentation, the Division approved the 24th POD. On February 9, 2005, the Division completed its review of the economic impacts and accepted the terms of the 2nd Application. This Decision documents the terms agreed to by the Division and BP for approval of the 2nd Application.

On March 3, 2005, BP amended the 2nd Application with revisions to the tract participation schedule to reflect a February 1, 2005 effective date. BP based the final tract participation percentages on the recoverable reserves remaining on each tract as of February 1, 2005.

II. Application for the Formation of the Sag River Participating Area

The 2nd Application included the following exhibits to the Unit Agreement: Exhibit A, a map of the MPU; Exhibit B, a schedule allocating unitized substances and expenses within the SRPA; a map of the SRPA; Exhibit E, Sag River Allocation of Participating Area Expense; a geologic description of the Sag River Formation; a Sag River Type Log; Sag River production and injection data; and an Amendment to the 24th POD to include development of the SRPA.

The proposed SRPA encompasses approximately 6,538 acres, including portions of seven State oil and gas leases: ADL 355017 (Tract 15), ADL 355018 (Tract 16), ADL 25509 (Tract 10), ADL 47434 (Tract 3), ADL 47437 (Tract 5), ADL 25516 (Tract 4), and ADL 47433 (Tract 2). The DNR issued oil and gas leases ADL 25516 and ADL 25509 following North Slope Sale 13 held on September 10, 1964, on State lease form DL-1 October 1963. The DNR issued oil and gas leases ADL 47433, ADL 47434 and ADL 47437 following North Slope Sale 23 held on September 10, 1969, on State lease form DL-1 October 1963. All seven leases had a 10-year primary term and retained 12.5% royalty to the State of Alaska.

III. Analysis of the Application for the Formation of the SRPA

The Commissioner of the DNR (the Commissioner) reviews unit-related applications, including unit expansions and the formation of participating areas, under AS 38.05.180(p) and 11 AAC 83.301—11 AAC 83.395. The State statute and DNR regulations set out the standards and criteria for formation of a participating area. The Commissioner or his designee[1] may approve the formation of a participating area if he determines it is necessary or advisable in the public interest[2]. This Finding and Decision evaluates the 2nd Application based on the six criteria set out in 11 AAC 83.303 (b).

1. Geological and Engineering Characteristics of the Reservoir

The MPU contains four producing formations: the Kuparuk River, the Ugnu, the Schrader Bluff, and the Sagavanirktok River (Sag River) formations. The Kuparuk River formation, present at a

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

2 The proposed unit action must be necessary or advisable in the public interest: "To conserve the natural resources of all or part of an oil or gas pool, field, or like area, the lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or unit plan of development or operation of the pool, field, or like area, or part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest." AS 38.05.180(p).

depth of approximately 7,500 feet true vertical depth subsea (tvdss), is the major producer in the MPU. The Ugnu and Schrader Bluff formations produce viscous ("heavy") oil at approximately 4,000 feet tvdss. The Sag River is the deepest of the producing formations in the MPU. Within the proposed MPU SRPA, the depth of the Sag River varies from 8,500 feet tvdss in the northwest to 9,500 feet tvdss in the southeastern part of the field.

The primary trapping mechanism in the Sag River oil pool is structural, consisting of three-way northwest-trending anticlinal closures sealed against the downthrown side of faults with throws generally exceeding 50 feet. An orthogonal fault pattern segments the oil column into three separate accumulations in the SRPA area. Numerous northwest-trending faults isolate the Sag River reservoir into separate oil-water segments. The known oil-water contacts in the MPU SRPA are 8,950 feet tvdss in the F-pad fault block based on Milne B-01 DST results, and 9,050 feet tvdss in the L-pad and C-pad fault blocks.

The Sag River is late Triassic to early Jurassic in age and consists primarily of thin, marine-shelf sand intervals found throughout the central portion of the North Slope. BP defined the Sag River oil pool in the May 6, 1998 AOGCC pool rules hearing as the accumulation of hydrocarbons common to and correlating with the interval between the measured depths of 8,810 feet and 8,884 feet in the Milne Point Unit No. A-01 well. BP subdivided the Sag River within the MPU into four laterally extensive sub-zones, A through D, which are fairly uniform in thickness and have similar reservoir properties.

Zone A is the basal Sag River sandstone unit that unconformably overlies the Shublik formation. The Zone A interval in the proposed project area is composed almost entirely of non-reservoir sandstone with porosity as high as 18 percent, permeability as great as 1.2 millidarcies and an average gross thickness of about 16 feet.

Zone B is the primary Sag River reservoir interval with porosity as great as 21 percent, permeability as high as 23 millidarcies and an average gross thickness of 30 feet. Zone B generally ranges between 22 feet and 36 feet. Permeability in core samples recovered from Zone B range between 0.1-10 millidarcies with a mean value of 2.8 millidarcies. Average porosities vary from 8–21 percent with a mean of 18 percent.

Zone C is the uppermost Sag River sandstone interval. Zone C is generally non-reservoir with porosity has great as 17 percent, permeability as high as 2.9 millidarcies and an average gross thickness of 10 feet.

Zone D, the uppermost zone in the Sag River, is also non-reservoir with an average thickness about 21 feet of siltstone and shale.

The combination of moderate-to-good porosity and poor permeability observed in zones A through C results from two processes; bioturbation and diagenesis. Core data show extensive carbonate cementation and greater grain densities in Zones A and C than in Zone B.

Sag River crude oil properties are: gravity 39.2 degree API, solution gas-oil ratio 974 SCF/STB, formation volume factor 1.56 RB/STB, viscosity 0.277 centipoise, gas gravity 0.8, and bubble point pressure 3,513 psi. BP recorded an initial reservoir pressure of 4,425 psi and a temperature of 235 ° F at an 8,750 feet tvdss datum.

In 1998, BP estimated the original oil-in-place (OOIP) in the Sag River formation to be 62 MMBO with a reservoir area of about 8,500 acres. At that time, BP estimated that primary recovery would be about 15 percent of the OOIP, assuming solution gas drive with some limited aquifer pressure support.

2. Prior Exploration and Development Activities

MPU Sag River production began in 1995 from conventional wells produced by subsurface electric submersible pumps. Plagued by frequent pump failure, artificial lift problems, high gas-oil ratios and high decline rates, continued Sag River production became marginally economic. Eventually, BP suspended or abandoned most of the Sag River wells or re-completed them in the Kuparuk River formation.

In 2001, BP improved productivity by completing two horizontal coiled tubing sidetracks and installing submersible jet pumps. On April 23, 2002, the AOGCC authorized the injection of fluids for enhanced oil recovery in the Sag River oil pool.

There are currently two production wells, F-33A and C-23, and one injector F-73A within the SRPA. The F-73A is a horizontal injection well that supports the F-33A horizontal producer in the northern end of the proposed SRPA. Cumulative Sag River production from the F-33 and F-33A wells is approximately 720,000 barrels of oil. The C-23 well, a conventional producer located in the center of the proposed SRPA with no injection support, is currently shut-in due to pump failure. The C-23 well produced 378,012 barrels of oil; 356,905 MCF of gas; and 11,050 barrels of water from May 1996 through September 1998 and from February 2001 through April 2002.

3. The Applicant's Plan of Development for the SRPA

BP is currently working on a Development Options Study that will evaluate the production response in F-33A due to injection in F-73A, alternative well designs, and various development schemes. If these issues can be resolved, BP estimates that it will need approximately six injector/producer well pairs to develop the proposed area. BP plans to drill a horizontal sidetrack from C-23 followed by a new injection well to support C-23 production, but would like to maintain the flexibility to utilize other wells that it determines are better candidates as they become available.

To provide the operator operational flexibility, the initial SRPA includes a relatively large area with specific milestones to develop the entire area. The Division and the operator agreed to the following conditions for the approval of the 2nd Application:

1. Definition of SRPA wells (SRPA Wells):
    a. Wells that are drilled, completed, and placed on production or injection by the milestone dates in Item 2 below and are part of the

approved SRPA POD.

b. The F-33A and F-73A wells are approved SRPA Wells.
c. Multilateral or other unconventional well configurations may count as multiple SRPA Wells, if the operator obtains the Division's written agreement as such before drilling the well.
d. Wells drilled outside of the approved SRPA may count as a SRPA Well, if the operator obtains the Division's written approval before drilling the well.

2. The operator must drill, sidetrack, or recomplete:
   a. at least two SRPA Wells by December 31, 2006;
   b. at least two additional SRPA Wells by December 31, 2008; and
   c. additional SRPA Wells in the last six locations by December 31, 2010.

3. Failure to fulfill the drilling commitments will result in automatic contraction of the SRPA based on the following rules, unless otherwise agreed by the Director:
   a. The operator will base the revised area of SRPA on:
      i. 160-acre well spacing around each of the active wells;
      ii. paying quantities;
      iii. engineering/geologic/geophysical data; and
      iv. any commitments to prove up undrilled areas.

      remove this
   b. The operator will submit a proposed tract participation schedule and map for the SRPA by March 1st of the year following an automatic contraction.
      i. The operator will base the new tract participation schedule on the remaining recoverable reserves in the revised SRPA.
      ii. Approval of a revised SRPA and the new tract participation schedule will be effective retroactive to January 1st of the year following the automatic contraction.
   c. For example, if there are only five SRPA wells on December 31, 2008, the SRPA will automatically contract on December 31, 2008, a new Exhibit B is due by March 1, 2009 and the new Exhibit B is effective on January 1, 2009.

4. If the operator drills an approved SRPA Well to the Sag River formation that does not produce hydrocarbons in paying quantities or contribute to the production of hydrocarbons in paying quantities (Dry Hole), the Dry Hole will count toward the well commitment, but the SRPA will automatically contract to exclude the nonproductive area from the SRPA on the following December 31st.

5. An approved SRPA Well that has a mechanical failure, such as a failed pump, will count toward the well commitments, if the well has produced in paying quantities.

6. If the operator plans any activity that does not conform to the approved MPU POD, operator will comply with 11 AAC 83.343(c).

4. The Economic Costs and Benefits to the State

Approval of the proposed SRPA and the amended 24th POD will result in both short-term and long-term economic benefits to the State. The long-term goal is to maximize the physical and economic recovery of hydrocarbons from the SRPA. Development and production from the SRPA will provide royalty and tax revenues to the State over the life of the field. The lessees may reinvest revenues in new exploration and development in the State. Royalty, tax, and employment benefits derived from production and economic development will far exceed any additional administrative burdens associated with permitting SRPA facilities, administering the unit leases, or collecting royalties on production.

The Division has reviewed the proposed tract participation schedule and plan of development. BP has demonstrated that it is in all parties' best interests to approve the tract participation schedule with no retroactive allocations of past Sag River capital expenses, operating expense, or production for Net Profit Share (NPS) and royalty purposes. BP will not reallocate Sag River capital expenses, operating expenses, and production that occurred prior to February 1, 2005, to the SRPA but will report those expenses and production to the leases where they occurred. BP shall allocate capital expenses, operating expenses, and production that occurred or occurs after February 1, 2005 to the new SRPA based on the approved SRPA tract participation schedule.

The Division maintains its authority to audit all NPS Lease and royalty reports. No one shall construe anything in this Decision to circumvent the right of the State to inspect, audit, and redetermine any NPS Lease calculations. If, as a result of an inspection of records under 11 AAC 83.245(e) or an audit under 11 AAC 83.245(f), the Commissioner determines that the method of allocating costs and production to an NPS Lease is improper, there is an error or an improper cost claimed in a NPS lease account, or there is an error in the NPS due to the State, the Commissioner will redetermine the net profit, recalculate the NPS payment due to the State, and notify BP of the redetermination. 11 AAC 83.247

The tract participation percentage for each tract in the SRPA is based on the remaining recoverable reserves within the tract as a percentage of the total remaining recoverable reserves in the SRPA. The approved tract participation percentages set forth in Exhibit B are effective February 1, 2005.

Allocation of operating and capital costs to the SRPA NPS leases shall be done in a manner consistent with the MPU Net Profit Share Leases Agreement, as amended from time to time. A copy of this agreement is included as Attachment 5.

As of February 1, 2005, based on the available knowledge and information, the Division's approval of the SRPA is in the best interest of all parties. The Documents and Division analysis supporting this Decision are stored in the Division's confidential files.

In summary, the economic benefits outweigh the costs. The working interest owners made meaningful commitments to develop the participating area and the State will receive taxes, royalties, and increased economic activity. Therefore, DNR's evaluation of the section .303(b)(5) economic criteria supports approval of the Application.

5. The Environmental Costs and Benefits

Alaska statutes require DNR to give public notice and issue a written finding before disposal of the state's oil and gas resources. AS 38.05.035(e); AS 38.05.945. DNR develops lease stipulations, or mitigation measures, through the lease sale process to mitigate the potential environmental impacts from oil and gas activity. In preparing a written finding before an oil and gas lease sale, the Commissioner may impose additional conditions or limitations beyond those imposed by law. AS 38.05.035(e).

DNR includes mitigation measures in oil and gas leases. The existing MPU leases contain stipulations designed to protect the environment and address concerns regarding impacts to the area's fish and wildlife species, habitat and subsistence activities, and cultural resources and privacy. They address such issues as the protection of primary waterfowl areas, site restoration, construction of pipelines, seasonal restrictions on operations, public access to, or use of, the leased lands, and avoidance of seismic hazards. All lease operations after unitization are subject to a coastal zone consistency determination, and must comply with the terms of both the state and North Slope Borough coastal zone management plans.

Ongoing mitigation measures, such as seasonal restrictions on specific activities in certain areas, can reduce the impact on bird, fish, and mammal populations. For example, DNR requires consolidation of facilities to minimize surface disturbances. With these mitigation measures, the anticipated exploration and development related activity is not likely to significantly impact bird, fish, and mammal populations. Area residents use the unit area for subsistence hunting and fishing. Oil and gas activity may affect some wildlife habitat, and some subsistence activity. The environmental impact will depend on the level of development activity, the effectiveness of mitigation measures and the availability of alternative habitat and subsistence areas. In any case, the anticipated activity under the plan of development will affect habitat and subsistence activity less than if the lessees developed the leases individually because unitized exploration, development, and production will minimize surface impact. The SRPA will provide for a plan of development governing that production that will help avoid unnecessary duplication of development efforts on and under the surface. Facilities can be located to maximize recovery and to minimize environmental impacts, without regard for individual lease ownership.

The approval of the SRPA itself has no environmental impact. The approval does not entail any environmental costs in addition to those that may occur when permits to conduct lease-by-lease exploration or development are issued. The Commissioner's approval of the SRPA is an administrative action that does not convey any authority to conduct any operations on the surface within the unit area. Unitization does not waive or reduce the effectiveness of the mitigation measures that condition the lessee's right to conduct operations on these leases. DNR's approval of the Unit Plan of Development is only one-step in the process of obtaining permission to drill a well or wells or develop the known reservoirs within the unit area. The Unit Operator must still obtain approval of a Plan of Operations from the state, and permits from various agencies on state leases before drilling a well or wells or initiating development activities to produce known reservoirs within the unit area.

IV. Findings

1. Promote the Conservation of all Natural Resources

The SRPA will promote the conservation of both surface and subsurface resources through unitized (rather than lease-by-lease) development. Approval of the Application will reduce both the number of facilities required to explore for and develop reserves and the aerial extent or the footprint required to accommodate those facilities.

The formation of oil and gas units, as well as the formation of participating areas within units, generally conserves hydrocarbons. Formation of the SRPA will provide for efficient, integrated development of the Sag River reservoir within the MPU. A comprehensive operating agreement and plan of development governing the area will help avoid duplicative development efforts on and beneath the surface.

There will be environmental impacts associated with reservoir development. However, all unit development must proceed according to an approved plan of development. Additionally, before undertaking any specific operations on State land, the Division must approve a Unit Plan of Operations. DNR may condition its approval of a Unit Plan of Operations and other permits on performance of the mitigation measures developed for the most recent North Slope Areawide lease sale in addition to those in the leases. Compliance with mitigation measures will minimize, reduce, or avoid adverse environmental impacts.

Creating the SRPA will help maximize oil and gas recovery, while minimizing negative impacts on other natural resources. This reduction in environmental impacts and conservation of hydrocarbon resources is in the public interest.

2. Promote the Prevention of Economic and Physical Waste

Forming a participating area prevents economic and physical waste by eliminating redundant expenditures for a given level of production, and by avoiding loss of ultimate recovery with the adoption of a unified reservoir management plan. Marginally economic reserves, which otherwise would not be produced on a lease-by-lease basis, can be produced from the SRPA in combination with more productive leases. Facility consolidation lowers capital costs and promotes optimal reservoir management. Pressure maintenance and secondary recovery procedures are easier to design and achieve through joint, unitized efforts than would otherwise be possible. In combination, these factors allow the unit operator to develop and produce less profitable areas of a reservoir in the interest of all parties, including the State.

Reducing costs and environmental impacts through unitized operations will expedite development of reserves and will promote greater ultimate recovery of oil and gas from the unit area. This may increase and extend the State's income stream from production taxes and royalties.

Formation of the SRPA will facilitate the equitable division of costs and allocation of the hydrocarbon shares, and provide for a diligent development plan that helps to maximize hydrocarbon recovery from the reservoir. Further, the formation of a participating area, which enables commingled production, facility sharing opportunities, and adoption of a unified reservoir management strategy, may allow for the development of economically marginal hydrocarbon accumulations.

3. Provide for the Protection of all Parties of Interest, Including the State

The SRPA protects the economic interests of the State and a unified plan will be more likely to maximize hydrocarbon recovery. Formation of the SRPA advances the efficient evaluation and development of the hydrocarbon resources while minimizing impacts to the area's cultural, biological, and environmental resources.

Formation of the SRPA protects the economic interests of the working interest owners and royalty owners of a common reservoir. The approved production allocation schedule ensures an equitable allocation of revenue to the lessors commensurate with the value of their leases.

The SRPA will not diminish access to public and navigable waters beyond those limitations imposed by law or already contained in the oil and gas leases covered by the Agreement. The Agreement provides for future expansions and contractions of the participating area, as warranted by data obtained by exploration or otherwise. The SRPA and the Agreement thereby protect the public interest, the rights of the parties, and the correlative rights of adjacent landowners.

V. Decision

The Division reviewed the statutes, oil and gas unitization regulations, the MPU Agreement, and materials supplied by BP in support of the Application. The Division finds that formation of the SRPA within the MPU will promote the conservation of all natural resources, promote the prevention of economic and physical waste, and provide for the protection of all parties in interest including the State. The Application adequately and equitably protects the public interest, is in the State's best interest, and it meets the requirements of AS 38.05.180(p) and 11 AAC 83.303. Therefore, the Application is approved under 11 AAC 83.351(b).

The SRPA encompasses all unitized substances in the Sag River Reservoir within the boundary of the approved participating area.

The allocations of production for the tracts within the SRPA are approved as shown on Attachment 3 dated March 3, 2005 and allocation of costs are approved as documented in Attachment 5, signed by the Director on February 27, 2001. DNR assigned Accounting Code "MPSR" to the SRPA for royalty accounting purposes, which BP shall reference on monthly operator and royalty reports.

The Amended Plan of Development is approved for the period from February 1, 2005 through December 31, 2005.

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

Mark D Myers
Division of Oil and Gas

5-11-05
Date

cc: Christopher A. Ruff, Petroleum Land Manager

Attachment 1.	Exhibit A, Map of the MPU Boundary
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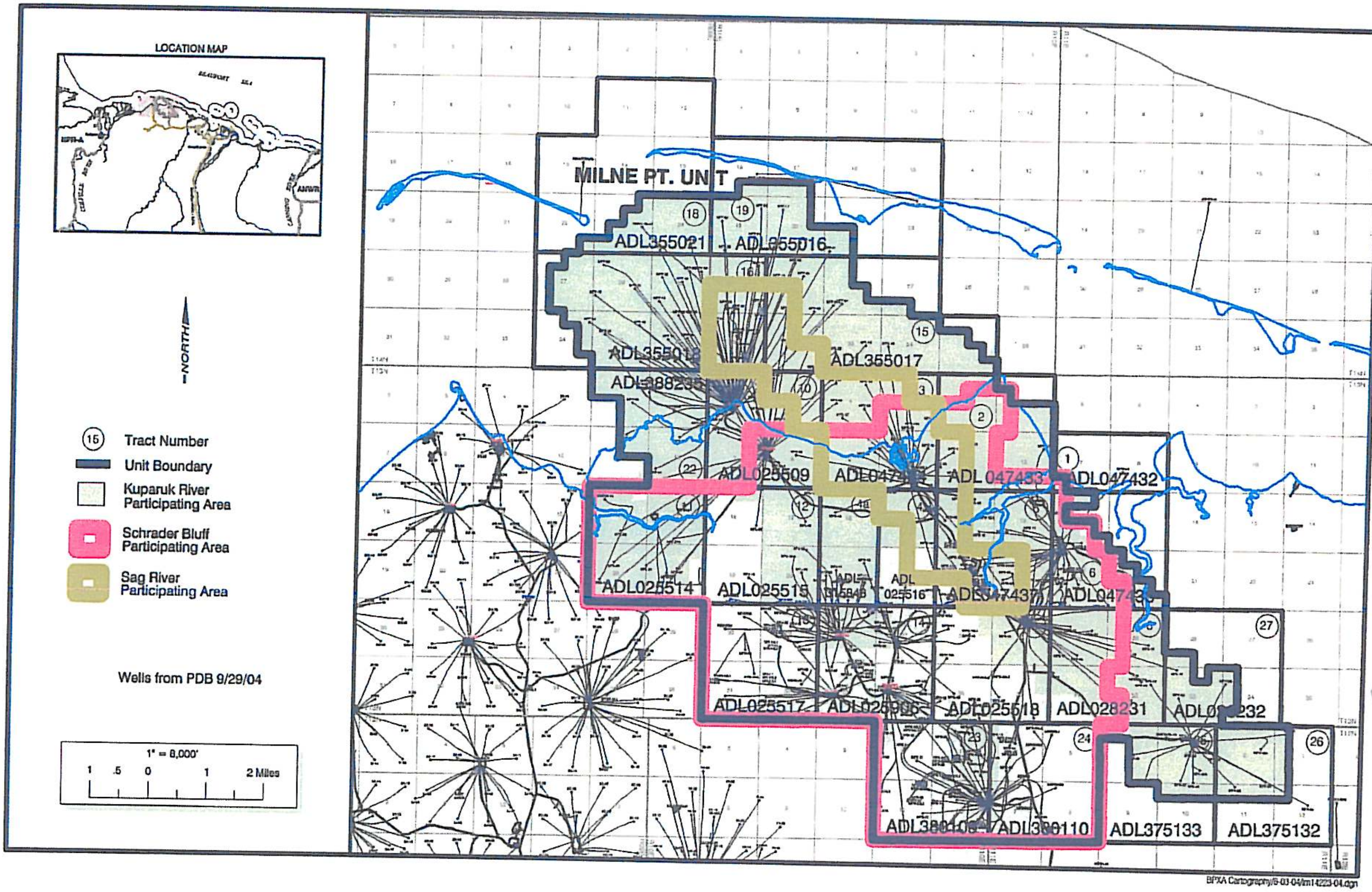
[redacted]

Milne Point Unit (Exhibit A) including Sag River Participating Area



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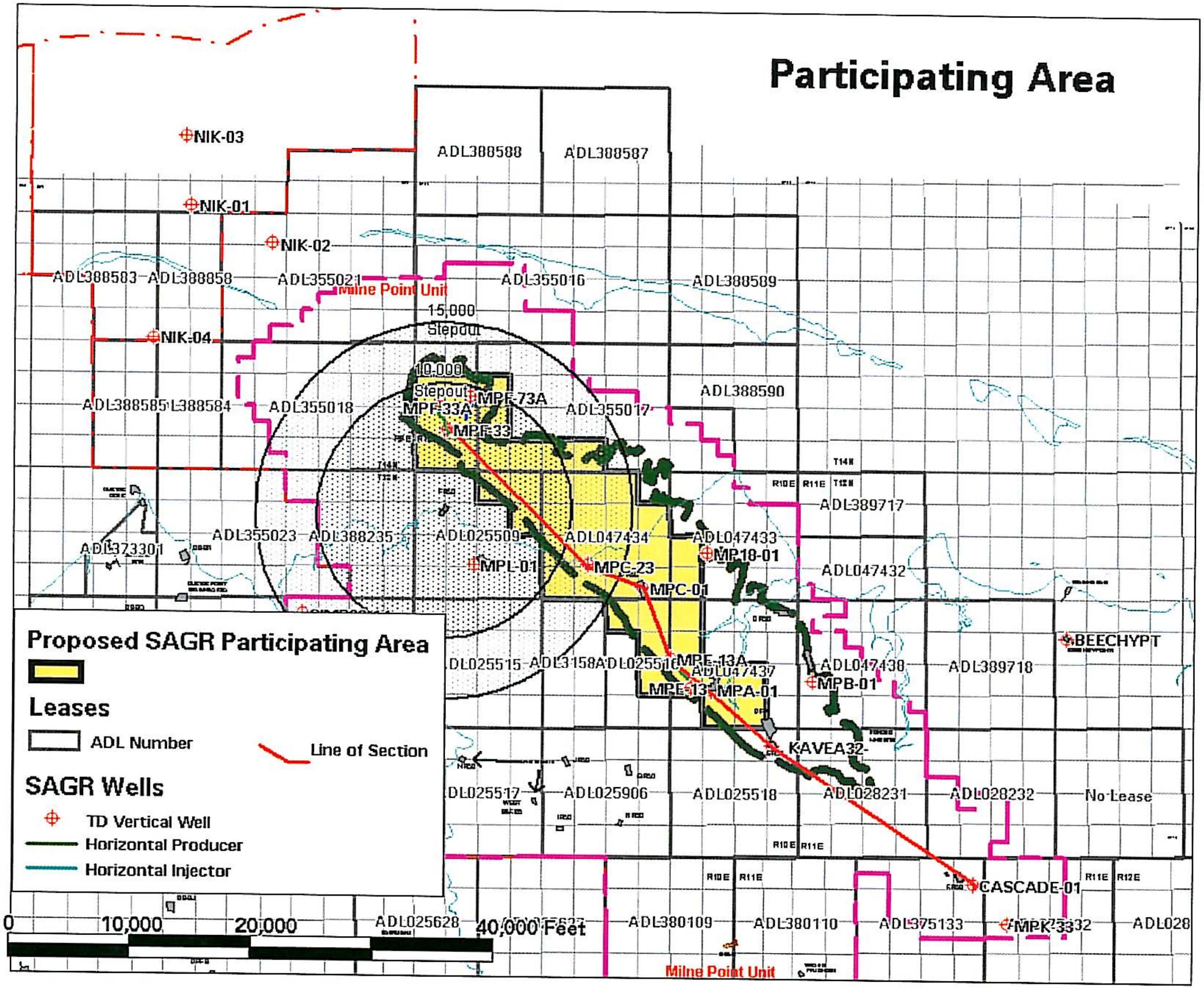
Attachment 1

Attachment 2



BP Confidential

[redacted] MILNE POINT UNIT – EXHIBIT B
SAG RIVER PARTICIPATING AREA
Schedule of Lease Ownership and Unit Tract Allocations
(Submitted March 3, 2005)
Not Based on Area, Original Oil in Place, or Original Reserves but on Remaining Reserves at February 1, 2005. See Att. 16 - Confidential

Unit Tract No.	ADL Lease No.	Legal Description of Acreage in Sag River Participating Area (all in Umiat Meridian, Alaska)		Unit Tract Acreage In Sag River P. A.	Unit Tract Allocation (%)	Royalty (%)	NPSL	Working Interest Owner and Ownership (%)		Overriding Royalty Interest Owner and Ownership (%)	
2	047433	T13N, R10E			4.79	20.00	0.00	BPXA	100.000	Ashland	0.2500000
		Sec. 11:	W½	320.00				Total WI	100.000	ORYX	1.1666500
				320.00						Black Stone Acq. Part 1	0.4500000
										Total ORRI	1.8666500
3	047434	T13N, R10E			38.53	20.00	0.00	BPXA	100.000		
		Sec. 3:	S½, NW¼	480.00				Total WI	100.000		
		Sec. 4:	All	640.00							
		Sec. 9:	All	640.00							
		Sec. 10:	All	640.00							
				2,400.00							
4	025516	T13N, R10E			5.47	12.50	0.00	BPXA	100.000		
		Sec. 15:	NW¼, NE¼, SE¼	480.00				Total WI	100.000		
		Sec. 22:	NE¼	160.00							
				640.00							
5	047437	T13N, R10E			15.67	20.00	0.00	BPXA	100.000	Black Stone Acq. Part 1	0.4500000
		Sec. 14:	W½	320.00				Total WI	100.000	ORYX	1.2500000
		Sec. 23:	N½, SE¼	480.00						Total ORRI	1.7000000
		Sec. 24:	W½	320.00							
				1,120.00							
10	25509	T13N, R10E									
		Sec. 5:	NW¼, NE¼, SE¼	480.00	7.99	12.50	0.00	BPXA	100.000		
				480.00				Total WI	100.000		

ATTACHMENT 3

Unit Tract No.	ADL Lease No.	Legal Description of Acreage in Sag River Participating Area (all in Umiat Meridian, Alaska)		Unit Tract Acreage In Sag River P. A.	Unit Tract Allocation (%)	Royalty (%)	NPSL	Working Interest Owner and Ownership (%)		Overriding Royalty Interest Owner and Ownership (%)
15	355017	T14N, R10E			11.53	12.50	40.00	BPXA	100.000	
		Sec. 29:	SW¼	160.00				Total WI	100.000	
		Sec. 32:	NW¼, SW¼, SE¼	480.00						
				640.00						
16	355018	T14N, R10E			16.02	12.50	30.00	BPXA	100.000	
		Sec. 30:	S½	315.00				Total WI	100.000	
		Sec. 31:	All	623.00						
				938.00						
TOTAL SAG RIVER PARTICIPATING AREA ACREAGE				6,538.00	100.00					

Note: All overriding royalty interests are described as a percentage of gross production.

ATTACHMENT 4

[redacted]

Amendment to Milne Point Unit
Plan of Development
(January 1, 2005 through December 31, 2005)

Overview of Sag River Activity

In prior years, BP drilled conventional producers in the Sag River Formation to test economic and development potential. These wells were completed with electric submersible pumps (ESP) and were unable to produce for long periods of time due to high temperatures, high gas/oil ratios and poor pump performance. BP determined that primary production alone with conventional producers using ESPs was not economically viable. All but two of the wells that penetrated the Sag River Formation have been completed back to the Kuparuk River Formation or have been suspended or abandoned.

In 2001, BP sidetracked the existing Sag River producing well (MPF-33A) and an idle Kuparuk River producing well (MPF-73A) using coiled tubing drilling techniques. Both wells were placed on production initially to test the productivity of horizontal wells in the Sag River Formation. In addition, the wells were both produced with jet pumps instead of ESPs as jet pumps are not susceptible to the same temperature and GOR limitations. Results from MPF-33A were particularly favorable, and DNR granted temporary approval to commence injection support in MPF-73A, pending final approval of a Sag River PA. Cumulative production from F-33 and F-33A is approximately 720,000 bbl, with the last two years production being more cyclical, as it was affected by jet pump scaling, nozzle chipping, and corrosion.

Development Plans for Sag River

Current plans for the F-pad include continuing monitoring pressure and production response in F-33A from offset injector F-73A, as well as pressure in injector F-73A. These results will be incorporated into the 2005 development options study.

If secondary support between the two wells in the Northern Area is evident and production from MPF-33A can be stabilized at a reasonable rate, or if an economically viable alternative well design and development scheme comes out of the 2005 study, BP may develop additional fault blocks in the PA. These additional fault blocks currently map out large enough to support five producer-injector pairs for a total of 10 locations. Development in the PA faces several challenges, including waterflood support, high grass roots well costs and facilities constraints. If these issues can be overcome, development would probably begin with a horizontal sidetrack from an existing well (C-23) and probable drilling of a new injector. By 1/1/2007, a minimum of two locations are planned to be drilled and completed. By 1/1/2011, an additional eight locations are planned to have been drilled and completed. Some of the locations will most likely have to be developed with new wells, increasing the total development cost significantly. Other locations may be accessible via sidetracking old Kuparuk Formation wells, which will reduce well cost and benefit economics. Fewer than 10 separate wells may be required, as multi-lateral drilling techniques associated with improving drilling technology may allow multiple reservoir penetrations from a single mother wellbore to improve economic viability.

ATTACHMENTS

Milne Point Unit
Net Profit Share Leases (NPSL)
Agreement

I. Recitals

The parties to this Agreement are the State of Alaska ("State"), BP Exploration (Alaska) Inc. ("BPXA") and BP Exploration and Oil ("BPXO"). BPXA and BPXO are referred to collectively as "BP". BP owns working interests in the following Net Profit Share Leases (NPSLs) in the Milne Point Unit (MPU): ADL 355016, ADL 355017, ADL 355018, ADL 355021, and ADL 388235 (MPU NPSLs) which it acquired at various times from Chevron, Conoco, ARCO and Oxy. The assignments from Oxy to BP have not yet been approved by DNR. The State of Alaska ("State") and BP are entering into this Agreement in an effort to minimize uncertainty in BP's NPSL reporting.

II. Agreement

The intent of this Agreement is to establish starting balances for the MPU NPSL development accounts, operating and capital cost allocation methodologies for the period 1994 through 1998, conditions for changing the operating and capital cost allocation methodologies for the period 1999 forward, a capital access fee, the starting date for BP reporting on the MPU NPSLs BP purchased from Oxy, and procedures for re-filing of NPS reports.

A. NPSL Development Account Balances

1. The January 1, 1994 beginning development account balance for each MPU NPSL interest BP acquired from Chevron and Conoco is as follows:

a) ADL 355016	$ 170,604.15
b) ADL 355017	$2,879,545.76
c) ADL 355018	$ 204,885.50
d) ADL 355021	$6,259,886.99
e) ADL 388235	zero

2. The November 1, 1996 beginning development account balance for the MPU NPSL interest BP acquired from ARCO is as follows:

a) ADL 388235	$ 57,777.98

3. The April 1, 2000 beginning conditional development account balance for each MPU NPSL interest BP acquired from Oxy is as follows:

a) ADL 355016	$ 668,788.04
b) ADL 355017	$4,571,078.24
c) ADL 355018	$1,873,062.67
d) ADL 355021	$ 929,058.72
e) ADL 388235	zero

4. The OXY development account balances may be adjusted due to audit or as a result of settlement of any portion of an audit from January 1, 1994 forward.

B. Operating and Capital Cost Allocation Methodology

1. January 1, 1994 through December 31, 1998 cost allocation methodology

a. PA or UT specific operating costs

Participating area (PA) and unitized tract well operation (UT) specific operating costs will be allocated to the PA or UT to which they are attributed.

ii. The costs will be applied to the leases within a PA according to the PA tract factors set forth on Exhibit C to the MP Unit Agreement.

b. MPU shared operating costs

i. Operating costs attributable to the MPU generally will be allocated to each PA and UT based on the ratio of the -Total Liquids Production for each PA or UT to the Total Liquids Production for the entire MPU. [(Total MPU Shared Operating Costs) X (Total Liquids Production for PA or UT / Total Liquids Production for MPU)].

ii. The operating costs allocated to each PA will then be allocated to each lease according to the tract factors shown on Exhibit C to the MP Unit Agreement.

iii. "Total Liquids Production" will be determined according to the Monthly Production Total Liquids (Oil and Water) Report and the Monthly Production Summary Report for the MPU that allocates the total MPU production volume to each MPU PA and UT based on the calculated well production for a PA or UT. "Total Liquids Production" will exclude load diesel and Prince Creek Formation water.

BP will reallocate costs to the extent amendments to the Monthly Production Reports, costs or tract factors are approved by DNR.

c. PA or UT specific capital costs

i. PA and UT specific capital costs will be allocated to the PA or UT to which they are attributed.

ii. Capital costs for each PA will then be allocated to each lease within the PA according to the PA tract factors shown on Exhibit C to the MP Unit Agreement.

d. MPU shared capital costs

Capital costs attributable to the MPU generally will be allocated to each PA based on the ratio of Total Liquid Hydrocarbon Reserves for each PA to the Total Liquid Hydrocarbon Reserves of the entire MPU. [(Total MPU Shared Capital Costs) X (Total Liquid Hydrocarbon Reserves for the PA / Total MPU Liquid Hydrocarbon Reserves)].

ii. Shared capital costs allocated to each PA will then be allocated to each lease according to PA tract factors shown on Exhibit C to the MP Unit Agreement.

iii. Shared capital costs for UT operations will be determined on a case by case basis using allocation methods consistent with the above principles.

iv. "Total Liquid Hydrocarbon Reserves" is defined as the reserves used to determine the tract allocation percentages for Exhibit C of the MPU Agreement.

2. January 1, 1999 forward: Until changed as described below, BP will use the cost allocation methodology described above in paragraph II.B.1.

a. The State may change the cost allocation methodology by written notice to BP.

b. If the State gives BP written notice of a change in cost allocation methodology prior to March 31, 2002, the State may request that the new methodology be retroactive to the production period beginning January 1, 1999.

c. If the State gives BP written notice of change in cost allocation methodology on or after March 31, 2002, the State may request that the methodology be retroactive to the first day of the production month in which notice was given.

C. Capital Access Fee

1 BP and the State agree that BP will be allowed to charge a capital access fee of $0.96 per barrel of oil produced from MPU effective December 1, 2000 for the NPSL interests BP acquired from Oxy and January 1, 1994 on all other BP NPSL interests.

2. The per barrel capital access fee charge is in lieu of an allocation of capital costs to the MPU NPSL Development Accounts for facilities in existence prior to January 1, 1994.

3. The capital access fee will be debited to the applicable development account as a capital cost for NPSL reporting purposes.

D. Reporting on Oxy NPSLs

1 Beginning December 1, 2000 (December production month) BP will include the NPS leases it acquired from Oxy in its royalty and NPSL reports even though the assignment of the leases from Oxy to BP had not been approved by that date.

2. BP will also file any revisions back to December 1, 2000 for Oxy.

E. BPXA Re-filing of NPSL reports

On or before December 31, 2001, BP will re-file its NPSL reports for the production periods January 1, 1994 through December 31, 2000 to make them consistent with this Agreement.

2. The re-filing will also include adjustments for royalty and production tax settlements that affect BP's NPSL reports.

3. The re-filing will consolidate both BPXA and BPXO entities as a single filing. BPXO lease assignments to BPXA were effective with the February 1998 production month.

F. Determination of production revenue

Production revenue for the production period January 1, 1994 through December 31, 1999, shall be determined in accordance with sections III, C, 1 and 3 of that certain agreement entitled "Settlement Agreement Including the Fourth Amendment to the 1991 Royalty Settlement Agreement, Agreement to Terminate Pending Reopener, and Agreement to Settle Royalties for 1993 through 1999" executed by BP and the state on December 27, 2000.

G. DNR Audit Rights Not Affected

1. This Agreement does not limit the State's audit authority including but not limited to the right to validate NPSL costs and to separately audit Oxy NPSL costs for the years 1994 through 2000.

2. Notwithstanding the state's right to audit, this Agreement establishes the starting NPSL development account balances for the MPU leases stated in Section II.A., the methodology for allocating operating and capital costs for the period January 1, 1994 through December 31, 1998, and a capital access fee.

H. Combined PAs

This Agreement in no way limits any existing right of the state to combine, eliminate, modify or otherwise change the PA or UT configuration of the MPU or the MPU itself or binds the State to approve agreements between members of the MPU.

I. Binding Effect

This Agreement shall be binding on the parties, their principals, officers and employees, and their successors and assigns.

J. Governing Law and Venue

This Agreement shall be interpreted under the laws of the State of Alaska, and all disputes about this Agreement shall be resolved in the courts of the State of Alaska.

K. Warranty of Authority

Each of the persons signing below on behalf of a corporate party represents and warrants that he has the authority to execute this Agreement on behalf of the party for which he signs. Each of the persons signing below on behalf of the State represents and warrants that he holds the office shown and is authorized to exercise the powers of that office on behalf of the party for which he signs. In addition, BP specifically warrants and represents that it is fully authorized and able to make, and to ensure the performance of, the commitments made herein.

L. Effective Date

Except where a different effective date has been specified for a particular provision, the effective date for this Agreement is February 1, 2001.

BP Exploration (Alaska) Inc.

Dated: 3/1/01 By: Geoffrey E Stein

TAX + ROYALTY OFFICER

BP Exploration and Oil, Inc.

Dated 3/1/01 By: Geoffrey E. Stein

ATTORNEY-IN-FACT

State of Alaska

Dated: 2-27-01 By: Mark D. Myers

Mark D. Myers
Director of Oil and Gas
Department of Natural Resources