POINT THOMSON UNIT

APPROVAL OF THE
INITIAL PARTICIPATING AREA
FORMATION

Findings and Decision of the Director
of the Division of Oil and Gas
Under Delegation of Authority
from the Commissioner of the State of Alaska
Department of Natural Resources

November 9, 2015

Table of Contents

I. INTRODUCTION AND DECISION SUMMARY

This is the decision of the State of Alaska, Department of Natural Resources (DNR), Director of the Division of Oil and Gas (Division), pursuant to a September 30, 1999, delegation of authority from the DNR Commissioner on the application of ExxonMobil Alaska Production Inc. (ExxonMobil) to form the Point Thomson Initial Participating Area (PTIPA). On August 18, 2015, supplemented by a later submission, ExxonMobil, as Operator of Point Thomson Unit (PTU), and on behalf of PTU working interest owners, applied to form the PTIPA within the PTU on state leases issued by the DNR (Application).

The Division finds that the formation of the PTIPA promotes conservation of all natural resources, promotes the prevention of economic and physical waste, and provides for the protection of all parties of interest, including the State. DNR approves the Application in accordance with the criteria under 11 AAC 83.303. The approved effective date of the PTIPA is the date of Initial Production System (IPS) Project Start-up with first production through the IPS Project with delivery into Trans Alaska Pipeline System (TAPS).

II. APPLICATION FOR AND HISTORY OF PROPOSED AREA

The Point Thomson leases were acquired beginning in 1965. Oil was first discovered in 1975 in the Lower Tertiary age Canning Formation, and the PTU was formed in 1977 after the PTU-1 well discovered hydrocarbons in the older, early Cretaceous Thomson sand. The field is located approximately 60 miles east of Prudhoe Bay along Alaska's northern coastline. The Point Thomson reservoir is an abnormally-pressured retrograde condensate reservoir with an oil rim. Including the discovery wells, the Point Thomson owners have drilled a total of 19 exploration/delineation wells within and immediately adjacent to the Point Thomson Unit. In recent years, they drilled and completed two of those wells, PTU-15 and PTU-16, to initiate gas cycling condensate recovery from the PTU, which is expected to start up in 2016.

During 2005, the Division denied approval of the 22nd Plan of Development (POD) and placed PTU in default. That denial was appealed to the Commissioner, and the Commissioner affirmed the default decision by terminating the PTU on November 27, 2006, which in turn was affirmed upon reconsideration by the Commissioner on December 27, 2006. The Commissioner's decision was appealed to the Superior Court of the State of Alaska, and the court on December 26, 2007, affirmed in part, reversed in part, and the termination of PTU was vacated and the matter was remanded to the Commissioner. On April 22, 2008, the Commissioner issued another decision terminating the PTU, which was affirmed upon reconsideration on June 11, 2008. On August 4, 2008, DNR issued lease expiration decisions for leases within the PTU.

The working interest owners of the PTU appealed and challenged the Commissioner's decisions to the Superior Court. On January 11, 2010, the Superior Court reversed DNR's decision terminating the PTU. Thereafter, DNR filed in the Supreme Court of the State of Alaska a petition for review of the Superior Court's decision, which was granted by the Supreme Court on May 28, 2010. On March 29, 2012, DNR and the working interest owners of the PTU decided to resolve all pending litigation and administrative proceedings between them related to the PTU by and through terms and conditions as set forth in the Settlement Agreement (Settlement).

The Settlement defines the Initial Participating Area (IPA) as "the first participating area for the PTU" and contains the leases listed as the IPA on Exhibit C. Settlement Paragraph 4.3.1. Exhibit C lists state leases in Area A, IPA, which consist of ADL Nos. 47557, 47558, 47559, 47560, 47570, 47571, 47572, 50983, and 377020. Exhibit C also lists leases contained in Area B, West Pad Area, which include ADL Nos. 47561, 51667, and 312862. The Settlement directs that at least 90 days before the date of first production through the IPA Project, the PTU Operator shall submit documentation regarding the IPA as prescribed by Settlement Paragraph 4.4.5, including tract allocations for each lease in the IPA. Settlement Paragraph 4.3.1. The information to be submitted to DNR under the Settlement Paragraphs 4.3.1 (IPA), 4.4.1 (Area B Expansion), and 4.4.2 (PA Expansion to Entire Unit) is set forth in Exhibit F (attached) to the Settlement. Settlement Paragraph 4.4.5.

Settlement Paragraph 4.3.1 further provides: "The Initial PA shall be formed and is approved upon IPS Project Start-up effective the date of first production through the IPS with delivery into TAPS. Within twenty (20) days following the month of first production through the IPS Project with delivery into TAPS, the Unit Operator shall provide notice to DNR of the date of first production through the IPS Project with delivery into TAPS." The "Initial Production System" or "IPS" is further defined as, "the gas cycling facilities designed with capacity to produce and re-inject (cycle) 200 million cubic feet of gas per day [MMCFD] utilizing reciprocal compression and with the objective of a minimum of 10,000 barrels per day [BPD] of condensate for delivery into the Trans Alaska Pipeline System (TAPS)." Settlement Paragraph 2.13. The IPS Project includes construction and installation of the IPS, and also includes a 12-inch liquid hydrocarbon pipeline from Point Thomson to an interconnection with the Badami Field liquid hydrocarbon pipeline. Settlement Paragraph 2.14.

ExxonMobil submitted confidential and public information with the Application. ExxonMobil requested that certain portions of the information submitted with the Application and marked "confidential" be kept confidential pursuant to the PTU agreement, AS 38.05.035(a)(8), 11 AAC 82.810, and AS 45.50.910 *et seq.* The confidential geological, geophysical, and engineering data support the Application and indicate that all the State leases proposed for inclusion in the PTIPA could contribute in paying quantities to production of hydrocarbons.

ExxonMobil submitted with the Application revised Exhibits C and D for the PTU Agreement. Exhibit C and Table 1 below display the unit tract numbers, legal descriptions, lease numbers, working interest ownership, royalty interest ownership, overriding royalty interest ownership, and unit tract participations for the PTIPA. Exhibit D is a map of the PTIPA.

Table 1. Leases for Proposed PTU Initial Participating Area (PTIPA), Area A

Tract No.	ADL No.	Description	Acres	Royalty %	Working Interest Owner	Working Interest Percent	PA Tract Allocation
1	47557	T10N-R24E. UM Sec. 31, All, 623 acres	623.00	12½	ExxonMobil BP COP	62.674000% 32.326000% 5.000000%	4.541974%
2	47558	T10N-R23E, UM Sec. 25, All, 640 acres Sec. 26, All, 640 acres Sec. 35, All, 640 acres	2,560.00	12½	ExxonMobil BP COP	62.674000% 32.326000% 5.000000%	10.322896%

Tract No.	ADL No.	Description	Acres	Royalty %	Working Interest Owner	Working Interest Percent	PA Tract Allocation
		Sec. 36, All, 640 acres					
3	47559	T10N-R23E, UM	2,560.00	12½	ExxonMobil	62.674000%	19.988177%
		Ses. 27, All, 640 acres			BP	32.326000%	
		Sec. 28, All, 640 acres			COP	5.000000%	
		Sec. 33, All, 640 acres					
		Sec. 34, All, 640 acres					
4	47560	T10N-R23E, UM	640.00	12½	ExxonMobil	46.266043%	3.872682%
		Sec. 32, All, 640 acres			BP	22.691275%	
					Colt Alaska	11.612196%	
					Pacific	5.000000%	
					Hughes	3.600000%	
					COP	3.509756%	
					Chap-KDL,	2.271950%	
					Searls,	1.135975%	
					Eastland Oil	0.757318%	
					Pinta Real	0.504879%	
					Donnelly,	0.504878%	
					Donnelly,	0.504878%	
					O'Neill, Jan	0.504878%	
					Collier,	0.473322%	
					Searls, J.P.	0.473322%	
					Niedert,	0.189330%	
					Eastland	1.514635%	
					Donnelly, R.	0.378659%	
					Donnelly,	0.378659%	
5	47561	T10N-R22E, UM	2,560.00	12½	ExxonMobil	62.674000%	11.470133%
		Sec. 25, All, 640 acres			BP	32.326000%	
		Sec. 26, All, 640 acres			COP	5.000000%	
		Sec. 35, All, 640 acres					
		Sec. 36, All, 640 acres					
14	47570	T9N-R23E, UM	2,560.00	12½	ExxonMobil	62.674000%	7.106642%
		Ses. 3, All, 640 acres			BP	32.326000%	
		Sec. 4, All, 640 acres			COP	5.000000%	
		Sec. 9, All, 640 acres					
		Sec. 10, All, 640 acres					
15	47571	T9N-R23E, UM	2,560.00	12½	ExxonMobil	62.674000%	9.818136%
		Sec. 1, All, 640 acres			BP	32.326000%	
		Sec. 2, All, 640 acres			COP	5.000000%	
		Sec. 11, All, 640 acres					
		Sec. 12, All, 640 acres					
16	47572	T9N-R24E, UM	1,253.00	12½	ExxonMobil	62.674000%	8.500339%
		Sec. 6, All, 625 acres			BP	32.326000%	
		Sec. 7, All, 628 acres			COP	5.000000%	
17	50983	T10N-R23E, UM	640.00	12½	ExxonMobil	62.674000%	6.361276%
		Sec. 29, All, 640 acres			BP	32.326000%	
					COP	5.000000%	
18	51667	T10N-R23E, UM	1,243.00	12½	ExxonMobil	62.674000%	8.115255%
		Sec. 30, All, 620 acres			BP	32.326000%	
		Sec. 31, All, 623 acres			COP	5.000000%	

Tract No.	ADL No.	Description	Acres	Royalty %	Working Interest Owner	Percent	PA Tract Allocation
27	312862	T10N-R22&23E, UM TRACT C30-110 (BF-110): A PORTION OF BLOCKS 753 AND 797 AS SHOWN ON THE "LEASING AND NOMINATION MAP" FOR THE FEDERAL/STATE BEAUFORT SEA OIL AND GAS LEASE SALE, DATED 1/30/79, MORE PARTICULARLY DESCRIBED AS FOLLOWS: THOSE LANDS LOCATED IN THE S1/2 OF BLOCK 753, BEING A PORTION OF BLOCK 753 ON THE AFORESAID LEASING AND NOMINATION MAP, CONTAINING 1152.00 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T10N, R22E; U.M., AK., AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T10N, R23E; U.M., AK., IN BLOCK 797 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL O.C.S. BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1133.95 HECTARES, LESS AND EXCEPT THE NORTH HALF OF THE AFOREMENTIONED TRACT.	2,824.34	Sliding Scale 20-65	ExxonMobil BP COP	62.674000% 32.326000% 5.000000%	5.790316%
33	377020	T10N-R23E, UM That portion of Tract 65-020. "TRACT 65-020 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 754 OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/79, CONTAINING 1152 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, 22 AND 23, T. 10N., R. 23E., UMIAT MERIDIAN, ALASKA IN BLOCK 798 (BEING IN THE NORTHERLY PORTION), LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1109.94 HECTARES." lying southerly of Sections 14, 15, 16 and 17, T. 10 N., R. 23 E., U.M., Alaska in OCS Block 798.	1,909.74	20	ExxonMobil BP COP	62.674000% 32.326000% 5.000000%	4.112174%
		Total IPA	**21,933.08**				**100.000000%**

III. APPROACHES TO FULL FIELD DEVELOPMENT OF POINT THOMSON UNIT AS PROVIDED BY THE SETTLEMENT AGREEMENT

A. General Background

Point Thomson is located east of Prudhoe Bay and adjacent to the Arctic National Wildlife Refuge. Oil was discovered in lower Tertiary deepwater sandstones of the Brookian sequence in 1975 and gas-condensate and associated oil were discovered in the Lower Cretaceous Thomson sand (informal unit of local usage) in 1977. The Point Thomson Unit contains 38 state leases on approximately 93,000 acres of state land. The unit encompasses the Thomson sand reservoir consisting of a large condensate-gas cap underlain by a thin viscous oil rim. It is estimated that the Thomson sand contains approximately 8 trillion cubic feet (TCF) of gas-in-place, with an oil rim that has approximately 160 million barrels of original oil-in-place (OOIP). The unit also contains smaller, separate oil accumulations in younger Brookian strata.

B. Settlement Agreement

Under the Settlement there are several stages to the development of the Point Thomson Field. As a part of the firsts step, the working interest owners have committed to completion of the IPS, which is designed to produce 10,000 BPD of condensate and cycle natural gas on an annualized average of approximately 200 MMCFD. Settlement Paragraph 4.1.1.3. To install the IPS, the working interest owners were to drill PTU-15 and PTU-16 wells from the Central Pad and construct facilities and install a 22-mile common carrier pipeline from Point Thomson Field to connect to TAPS. Settlement Paragraphs 2.14, 4.1.2. The pipeline is designed to transport up to 70,000 BPD from Point Thomson to an existing connection with the Badami pipeline, which will provide for final delivery of Point Thomson liquid hydrocarbons into TAPS. Settlement Paragraph 1.6. The facilities and other infrastructure needed for the IPS will also be needed in the event of full-field development and will provide critical information for the next phases of the development of the PTU.

The "Initial PA" may be expanded as prescribed in the Settlement. Area B expansion is permitted under the following terms and conditions (i) a West Pad is drilled as provided in Settlement Paragraph 4.1.2 and casing is set across the Thomson sand, and (ii) an Authorization for Expenditure (AFE) for gathering line to the West Pad is approved, then the "Initial PA" shall "automatically expand to include the West Pad Area (Area B) acreage listed on Exhibit C." Settlement Paragraph 4.4.1.

Within 20 days of following the month in which last of the two conditions have been satisfied, the Unit Operator is required to submit appropriate documentation, including PA tract allocations for each lease in the PA and notice confirming that the conditions have been met, including signed AFEs, a Permit to Drill for PT-17 the West Pad well, as provided in Settlement Paragraph 4.1.2 and casing has been set across the Thomson sand and copies of appropriate signed AFEs for a gathering line to the West Pad approved by the working interest owners, including ExxonMobil, BP, and ConocoPhillips. Upon completion of these acts by the Unit Operator, the Initial PA formed as provided in 4.3 shall automatically expand to include the West Pad (Area B) to include Area B acreage listed on Exhibit C (attached) to the Settlement. Settlement Paragraphs 4.2.2, 4.3.3 Agreement.

The working interest owners "shall put the PTU- 15 and PTU 16 wells on production" utilizing the IPS "by the end of the 2015-2016 winter season," and in any event "no later than May 1, 2016." Settlement Paragraph 4.1.1.2. The work plan and activities associated with the IPS project are set forth in Exhibit E of the Settlement. The PTU-15 and PTU-16 wells must be placed in "Continuous Operations" either under production or gas injection. *Id*. The term "Continuous Operations" in the context of IPS project means "continuing operation of wells and facilities to produce oil or gas from the Thomson Reservoir into a pipeline…" Settlement Paragraph 2.5,. Moreover, the working interest owners are required to drill "a Thomson sand well from the West Pad by the end of the 2016-2017 winter season" and in any event "no later than May 1, 2017." Settlement Paragraph 4.1.2. The working interest owners are also required to continue permitting for East Pad, an East Pad Well, and a fifth well, with permitted location of the fifth well to be determined by the working interest owners based on prior results.

On September 24, 2015, ExxonMobil submitted to the Division additional information relevant to the Application for the inclusion of Area B into the IPA, including supporting evidence of effort to drill West Pad and a copy of an AFE for a gathering line to the West Pad as specified in Settlement Paragraph 4.4.1. Upon testing the PTU-15 and PTU-16 wells, ExxonMobil reported a concentration of hydrogen sulfide (H_2S) that was higher than anticipated, which resulted in reducing the size of the production tubing from 7 inch outer diameter (OD) to 5 inch OD. Due to the reduced production tubing diameter, it was incapable of meeting the annualized average 200 MMCFD cycling requirement. Due to the Operator's desire to obtain additional data from West Pad at the earliest moment as well as to accommodate the minimum cycling requirement, ExxonMobil decided to accelerate the start-up of West Pad, PTU-17, to early 2016. The West Pad will have proper metallurgy and completion size (7 inch OD tubing) to accommodate 200 MMCFD of gas production.

In March 2015, ExxonMobil completed the 22-mile liquid hydrocarbon pipeline that has capacity to transport approximately 70,000 BPD of condensate from Point Thomson to a pipeline interconnect at Badami. There is existing pipeline infrastructure from Badami to TAPS.

In addition to the IPS production commitments and timeline, the Settlement created certain pathways, incentives, and benchmarks for work in connection with a full field development of the Point Thomson reservoir. The work will build upon ongoing gas commercialization efforts. Under the Settlement there are three alternatives to full-field development.

C. Three Alternatives to Full-Development of Point Thomson Unit

After IPS comes on production, anticipated to be first quarter of 2016 but no later than May 1, 2016, the Settlement provides for three alternatives to the full-field development of the PTU: Alternative A-Major Gas Sale; Alternative B-Expanded Liquid Production into TAPS; and Alternative C-Expanded Liquid Production into TAPS, Enhanced Prudhoe Bay, and Gas for In-State Use. Settlement Paragraphs 1.7, 2.15, 2.16, 2.21, 4.1.1.2. The term "Major Gas Sale" (MGS) means "a large-scale pipeline project having a design throughput of more than 500 MMCFD that results in delivery of gas off the North Slope of Alaska." Settlement Paragraph 2.16.

Under Alternative A, a primary goal of the settlement is to incentivize commercialization of North Slope gas/MGS and provides flexibility to allow different MGS alternatives. Settlement Paragraph 1.11. There are two windows in which to "sanction" a MGS: (1) from the date of settlement to 2016 and (2) from 2016 to 2019. The word "sanction" in the context of MGS means that all required state and federal gas line permits have been issued and the pipeline sponsors have secured all necessary financing and corporate approval to proceed with pipeline construction. Settlement Paragraph 2.28.

If an MGS is sanctioned prior to year-end of 2016, the working interest owners will begin work on a Point Thomson project associated with the MGS. On the other hand, if MGS is not sanctioned by June 2016, the producers of PTU must begin engineering and permitting for a Point Thomson Expansion Project, Alternatives B or C. Settlement Paragraphs 1.7, 4.1.6.2. An expanded cycling project would result in additional condensate production, totaling approximately 20,000 to 30,000 BPD into TAPS. Settlement Paragraph 4.4. If an MGS is not sanctioned by year-end of 2019, the producers of PTU must commit to Alternative B or Alternative C or lose significant acreage from the PTU.

Certain acreage within the PTU is secured or expanded when specified activities are completed (e.g., MGS is sanctioned or the producers' commitment to Point Thomson Gas Development/Prudhoe Bay Enhanced Recovery Project or IPS Cycling Expansion Project). Settlement Paragraphs 2.20, 4.5.2. Likewise, the Settlement provides for automatic release of certain acreage to the State if the IPS is not completed or if certain key commitments or decisions are not made. Settlement Paragraph 1.8. Depending upon the work activities that occur, the PTU will remain in effect, contract, expand, or may terminate. *Id*.

Alternative B expands the IPS cycling capacity and increases production to a minimum of an additional 20,000 BPD of liquids into TAPS. Settlement Paragraphs 2.21, 4.5.5. The producers must expand cycling by 2019. Any expansion of less than an additional 20,000 BPD of condensate will result in automatic contraction of certain acreage within the PTU. Alternative B will require additional wells and larger gas processing and production facilities.

Alternative C requires complex reservoir integration between Prudhoe Bay and PTU. Condensate produced from PTU would continue to be transported to TAPS, but the PTU gas stripped of condensate would instead be injected into the Prudhoe Bay reservoir, which would increase oil recovery from Prudhoe Bay. Settlement Paragraphs 2.21, 4.6.3. Major investment, infrastructure and hydrocarbon pre-positioning would be required for this Alternative to facilitate North Slope gas commercialization. Alternative C also requires that a significant volume of gas be available for in-state use from Prudhoe Bay no later than 2019.

As part of the settlement, an MGS is the primary goal of the parties. To that end, the paths under the three principal development options (Alternatives A, B, and C) would allow the parties to pursue their goals independently or in conjunction with an MGS and at the same time continue progress on permitting, regulatory, and engineering activities toward an MGS. Settlement Paragraph 1.11.

IV. STATUTE, REGULATIONS, AND PTU AGREEMENT PROVISIONS RELEVANT TO EVALUATION OF THE APPLICATION

This portion of the decision sets out the provisions of statute, regulations, and PTU provisions relevant to this decision.

A. Statute

Legislative intent regarding the State oil and gas leasing program is set out in AS 38.05.180(a). It provides:

AS 38.05.180. Oil and Gas and Gas Only Leasing

(a) The legislature finds that:

(1) the people of Alaska have an interest in the development of the State's oil and gas resources to

(A) maximize the economic and physical recovery of the resources;

(B) maximize competition among parties seeking to explore and develop the resources;

(C) maximize use of Alaska's human resources in the development of the resources;

B. Regulations

State Regulation 11 AAC 83.303 sets out decision criteria for deciding whether to grant an application to form a participating area. It provides:

11 AAC 83.303. Criteria

(a) The commissioner will approve a proposed unit agreement for state oil and gas leases if he makes a written finding that the agreement is necessary or advisable to protect the public interest considering the provisions of AS 38.05.180 (p) and this section. The commissioner will approve a proposed unit agreement upon a written finding that it will

(1) promote conservation of all natural resources, including all or part of an oil or gas pool, field, or like area;

(2) promote the prevention of economic and physical waste; and

(3) provide for the protection of all parties of interest, including the state.

(b) In evaluating the above criteria, the commissioner will consider

(1) the environmental costs and benefits of unitized exploration or development;

(2) the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir proposed for unitization;

(3) prior exploration activities in the proposed unit area;

(4) the applicant's plans for exploration or development of the unit area;

(5) the economic costs and benefits to the State; and

(6) any other relevant factors, including measures to mitigate impacts identified above, the commissioner determines necessary or advisable to protect the public interest.

(c) The commissioner will consider the criteria in (a) and (b) of this section when evaluating each requested authorization or approval under 11 AAC 83.301 - 11 AAC 83.395, including

(1) an approval of a unit agreement;

(2) an extension or amendment of a unit agreement;

(3) a plan or amendment of a plan of exploration, development or operations;

(4) a participating area; or

(5) a proposed or revised production or cost allocation formula.

The following regulations should also be considered in connection with the Application.

11 AAC 83.351. Participating Area

(a) At least 90 days before sustained unit production from a reservoir, the unit operator shall submit to the commissioner for approval a description of the proposed participating area, based on subdivisions of the public land or its aliquot parts. The participating area may include only the land reasonably known to be underlain by hydrocarbons and known or reasonably estimated through use of geological, geophysical, or engineering data to be capable of producing or contributing to production of hydrocarbons in paying quantities. If any portion of a lease is included in a participating area formed under a unit agreement, the entire leased land will be committed to the unit and the lease will not be severed. Under 11 AAC 83.371(a), the unit operator also shall submit to the commissioner for approval of a proposed division of interest or formula setting out the percentage of production and costs to be allocated to each lease or portion of lease within the participating area. Upon approval by the commissioner, the area of productivity constitutes a participating area.

(b) A separate participating area must be established as provided in (a) of this section for each reservoir delineated, except that with the consent of the commissioner and all working interest owners, any two or more reservoirs or participating areas within the unit may be combined into one participating area. Separate participating areas may be established to distinguish between an oil rim and a gas cap within the same reservoir.

(c) A participating area must be expanded to include acreage reasonably estimated through use of geological, geophysical, or engineering data to be capable of producing or contributing to the production of hydrocarbons in paying quantities, and must be contracted to exclude acreage reasonably proven through use of geological, geophysical, or engineering data to be incapable of producing hydrocarbons in paying quantities, subject to approval by the commissioner. A revised division of interest or formula allocating production and costs must be submitted for approval under 11 AAC 83.371 at the time of expansion or contraction of a participating area.

11 AAC 83.356. Unit Area; contraction and expansion

(a) A unit must encompass the minimum area required to include all or part of one or more oil or gas reservoirs, or all or part of one or more potential hydrocarbon accumulations.

(b) 10 years after sustained unit production begins, the unit area must be contracted to include only those lands then included in an approved participating area and lands that facilitate production including the immediately adjacent lands necessary for secondary or tertiary recovery, pressure maintenance, reinjection, or cycling operations. The commissioner will, at the commissioner's discretion, after considering the provisions of 11 AAC 83.303, delay contraction of the unit area if the circumstances of a particular unit warrant such an approach. If any portion of a lease is included in the participating area, the portion of the lease outside the participating area will neither be severed nor will it continue to be subject to the terms and conditions of the unit. The portion of the lease outside the participating area will continue in full force and effect so long as production is allocated to the unitized portion of the lease and the lessee satisfies the remaining terms and conditions of the lease.

(c) Any expansion or contraction of the unit area must be based on legal subdivisions of land as defined in 11 AAC 88.185.

(d) No land will be excluded from a unit area due to the depletion of hydrocarbons.

(e) Not sooner than 10 years after the effective date of the unit agreement, the commissioner will, in the commissioner's discretion, contract the unit area to include only that land covered by an approved unit plan of exploration or development, or that area underlain by one or more oil or gas reservoirs or one or more potential hydrocarbon accumulations and lands that facilitate production as set out in (b) of this section. Before any contraction of the unit area under this subsection, the commissioner will give the unit operator, the working interest owners, and the royalty owners of the leases or portions of leases being excluded reasonable notice and an opportunity to be heard.

11 AAC 83.395. Definitions

Unless the context clearly requires a different meaning, in 11 AAC 83.301 - 11 AAC 83.395 and in the applicable unit agreements:

(1) "conservation of the natural resources of all or part of an oil or gas pool, field or like area" means maximizing the efficient recovery of oil and gas and minimizing the adverse impacts on the surface and other resources;

(9) "sustained unit production" means continuing production of oil or gas from a reservoir in the unit area into a pipeline or other means of transportation to market, but does not include testing, evaluation or pilot production.

11 AAC 83.343. Unit plan of development

(a) A unit plan of development must be filed for approval as an exhibit to the unit agreement if a participating area is proposed for the unit area under 11 AAC 83.351, or when a reservoir has become sufficiently delineated so that a prudent operator would initiate development activities in that reservoir. All development operations must be conducted under an approved plan of development. A unit plan of development must contain sufficient information for the commissioner to determine whether the plan is consistent with the provisions of 11 AAC 83.303. The plan must include a description of the proposed development activities based on data reasonably available at the time the plan is submitted for approval as well as plans for the exploration or delineation of any land in the unit not included in a participating area. The plan must include, to the extent available information exists:

(1) long-range proposed development activities for the unit, including plans to delineate all underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established;

(2) plans for the exploration or delineation of any land in the unit not included in a participating area;

(3) details of the proposed operations for at least one year following submission of the plan; and

(4) the surface location of proposed facilities, drill pads, roads, docks, causeways, material sites, base camps, waste disposal sites, water supplies, airstrips, and any other operation or facility necessary for unit operations.

C. Point Thomson Unit Agreement

The PTU Unit Agreement Sections 11 and 16 provide, in their relevant parts:

Section 11. Participation After Discovery

"At least ninety (90) days prior to commencement of production of unitized substances into pipeline or other means of transportation to market, the Unit Operator shall submit for approval by the Director a schedule based on subdivisions of the public land survey or aliquot parts thereof of all unitized land then regarded as reasonably proved to be productive of unitized substances in paying quantities; all lands in said schedule on approval of the Director are to constitute a participating area, effective as of the date such production commences or the effective date of the unit agreement, whichever is later… Said schedule, which will be attached as Exhibit C to this agreement, shall also: (a) set forth the percentage of unitized substances to be allocated as provided in this agreement to each unitized tract with a royalty of other than one-eighth or net profit share lease tract in the participating areas so established and shall govern the allocation of production for the purpose of calculating royalty and net profit payments for said tracts; (b) set forth the percentage of costs to be allocated to each net profit share lease tract in the participating are so established and shall govern the allocation of costs for the sole purpose calculating net profit payments for said tracts; and (c) set forth the percentage of unitized substances and costs to be allocated to all other tracts."

"A separate participating area shall be established in like manner for each separate pool or deposit of unitized substances or for any group thereof produced as a single pool or zone, and any two or more participating areas so established may be combined into one with the consent of the owners of all working interest in the lands within the participating areas so to be combined, on approval of the Director. The participating area or areas so established shall be revised from time to time, subject to like approval, whenever such action appears proper as a result of further drilling operations or otherwise to include additional land then regarded as reasonably proved to be productive in paying quantities, or to exclude land then regarded as reasonably proved not to be productive in paying quantities and the percentage of allocation shall also be revised accordingly."

Section 16. Conservation

"Operations hereunder and production of unitized substances shall be conducted to provide for the most economical and efficient recovery of said substances without waste, as defined by or pursuant to law or regulation."

V. DECISION CRITERIA DISCUSSION

The Division's review of the Application is based on the criteria set out in state regulations including but not limited to 11 AAC 83.303 (a) and (b), which are the decision criteria for units, and 11 AAC 83.351, which is the decision criteria for participating areas. A discussion of the subsection (b) criteria is followed by a discussion of the subsection (a) criteria. Analysis and discussion of subsection (b) requirements precedes and supports the findings under subsection (a).

A. Decision Criteria Considered Under 11 AAC 83.303(b)

1. The Environmental Costs and Benefits of Unitized Exploration or Development

ExxonMobil anticipates initial production from the reservoir underlying the proposed PTIPA no later than May 1, 2016. Formation of the PTIPA will enable ExxonMobil to continue unitized development and operations of the proposed PTIPA area by ensuring production operations conforming to state regulations that require a participating area be formed for producing unit areas. 11 AAC 83.351. Unitized development and operations provide an environmental benefit because they enable multiple leases to be developed through common facilities thereby reducing the impact on the environment. This decision does not, however, authorize any specific activity or operation; ExxonMobil must obtain additional permits and authorizations as necessary before conducting specific operations in the unit area.

A unit operator must obtain approval of a plan of operations from the State as prescribed in the regulations and the Settlement Agreement, and other permits from various agencies, before drilling a well or wells or initiating development activities. DNR considered environmental issues during the lease sale process, PTU formation, and PTU expansion. ExxonMobil has obtained the required permits for the current PTIPA wells and is operating under an approved plan of operations.

ExxonMobil has designed the development of the Point Thomson sand within the PTU to minimize the amount of surface impact from the facilities necessary to develop using existing compact drill-site and existing PTU infrastructure. Formation of the PTIPA will promote efficient development of the State's resources, while minimizing impacts to the region's cultural, biological, and environmental resources.

2. Geological and Engineering Characteristics of the Reservoir

A participating area "may include only the land reasonably known to be underlain by hydrocarbons and known or reasonably estimated through use of geological, geophysical, or engineering data to be capable of producing or contributing to the production of hydrocarbons in paying quantities." 11 AAC 83.351(a). ExxonMobil has drilled wells, is currently completing commissioning activities in the proposed PTIPA, and production is anticipated from Area A and Area B of Point Thomson beginning in 2016.

Data and information submitted by ExxonMobil to the Division in support of its Application to form the PTIPA included interpretive geologic maps and cross sections, analyses of well logs, production test data, core and fluid analysis data, and regional structure maps. Some of the information and data ExxonMobil submitted in support of its Application is confidential under AS 38.05.035(a)(8)(C) and 11 AAC 96.220, but the ExxonMobil data indicates the proposed PTIPA area is underlain by hydrocarbons and will contribute to production.

On August 25, 2015, AOGCC issued Area Injection Order No. 38, Docket No. AIO-15-017 (AIO 38) with regard to the Point Thomson Field, PTU, and Thomson Sand Undefined Pool. The hearing was on July 7, 2015 and testimony was provided by ExxonMobil Corporation representatives. In the decision, in the absence of a conservation order from the AOGCC formally defining a pool at that time, the accumulation of condensate and oil within the Thomson Sand of the PTU was termed the Thomson Sand Undefined Oil Pool, and governed by the statewide rules of 20 AAC 25. AIO 38, Findings Paragraph 2. In conjunction with AIO 38, ExxonMobil submitted relevant geological and geophysical, engineering information relevant to the Point Thomson Field.

On October 15, 2015, AOGCC issued Conservation Order No. 719 (CO 719), under which an Order was issued for classification of a new pool and prescribed pool rules for development of the Thomson Oil Pool within the Point Thomson Field, PTU, East Harrison Bay, Beaufort Sea, Alaska. The Pool Rules characterize and define the hydrocarbon accumulation within the Thomson Sand reservoir as an oil pool because, although the accumulation consists of a large condensate-gas cap underlain by a thin viscous oil rim, well tests conducted on the Thomson Sand reservoir have shown Gas-Oil Ratio (GOR) values that range from about 850 to 15,750 Standard Cubic Feet of Gas per Stock Tank Barrel of condensate produced (SCF/STB). Because the expected GOR values from wells producing from the Thomson Sand reservoir is expected to be less than 100,000 SCF/STB, AOGCC regulation 20 AAC 25.990(45) requires classification as an oil pool and the development wells as "oil wells". Exxon requested and was granted waiver by the AOGCC to operate the Thomson Oil Pool above the GOR limits of state regulation 20 AAC 25.240(a).

Geology of the Point Thomson Interval

The Thomson Sand Oil Pool comprises the Lower Cretaceous Thomson sand, which is common to, and correlates with the interval between 16,126 and 16,377 feet measured depth (MD) in reference well PTU-15 (equivalent to -12,614 and -12,828 feet true vertical depth subsea [TVDSS]). AOGCC CO 719, p. 4.

Within the Point Thomson Unit, the hydrocarbon accumulation trapped in the Thomson Sand comprises a nearly 500 foot-thick, high-pressure, condensate gas cap overlying a 37 foot-thick column of viscous oil. Well log and seismic information indicate that the extent of the hydrocarbon accumulation is influenced by both structural and stratigraphic elements. The PTU accumulation is bounded by a four-way anticlinal closure. The broad, east-southeast-trending, shale-capped anticlinal closure provides primary control for the accumulation. Facies changes within the Thomson sand strongly influence the reservoir quality, especially in the southwestern portions of the PTU.

The Thomson sand consists of conglomerate, sandstone, and siltstone derived from an area of pre-Mississippian basement rocks comprising dolomite, argillite, quartzite, and phyllite that were exposed during Early Cretaceous time in the northern and northeastern portion of the Point Thomson Unit. At that time, these exposed basement rocks were bordered to the southwest by a sea. Sediments eroded from this exposed source area were transported down-gradient to the southwest and deposited in alluvial fan, fan-delta, and shallow marine shoreface environments. Wave and current activity reworked these sediments and distributed them in southeast-trending bands subparallel to the existing shoreline. In general, coarser-grained, proximal lithologies are dominated by carbonate clasts, with finer-grained quartz and ductile grains increasingly more prominent in the more distal areas to the southwest.

ExxonMobil divides the Thomson sand into six distinct petrofacies based on grain size, sorting, cementation, and ductile gain content: (1) cemented conglomerate and breccia, (2) open-framework conglomerate, (3) bimodal conglomerate, (4) clean sandstone, (5) silty sandstone, and (6) siltstone. Each petrofacies occupies a well-defined area on a plot of core porosity versus core permeability and can be identified by unique signature from the well logs. These petrofacies are used to distribute the different facies and rock properties between the wells for the purpose of reservoir modeling. Within the Thomson sand reservoir, porosity ranges from about 5% to 34%, and averages about 14%. Permeability ranges from 0.01 millidarcys in some samples of cemented conglomerate and breccia to 50 darcys in some samples of open-framework conglomerate; *See* Table, AOGCC CO 719, pp.5-6.

Within the Thomson Sand, ExxonMobil has also identified and mapped a flooding surface that informally divides the interval into upper and lower members that reflect changes in relative sea level and rate of sedimentation. The lower member is dominantly progradational, whereas the upper member is dominantly retrogradational.

The Thomson Sand lies unconformable atop pre-Mississippian basement comprising phyllite, argillite, quartzite, and dolomite. Although matrix porosity of these carbonate and low grade metamorphic strata is extremely low, fractured and/or karsted dolomite in the northern part of the field may serve as a minor secondary reservoir in communication with the Thomson Sand.

The Thomson Sand is overlain by siltstone, mudstone, and shale assigned to the Highly Radioactive Zone (HRZ), Hue Shale, and Canning Formation, in ascending stratigraphic order. These intervals provide the top seal for the hydrocarbon accumulation in the Thomson Sand reservoir. In the northern and northeastern parts of the PTU, where the HRZ and Hue Shale intervals are absent or very thin, mudstone and siltstone of the lower Canning Formation provides the top seal.

The structure of the Thomson Sand is a gently dipping, four-way anticlinal closure. Based on well- and 3-D seismic control, the top of the reservoir lies about -12,500 feet TVDSS within the PTU area. The anticlinal closure is cut by several, north- and north-northeast trending normal faults, but none of these faults appear to completely offset the Thomson Sand or create isolated reservoir compartments within it.

The gas-oil contact within the Thomson Sand is -12,975 feet TVDSS determined from Modular Dynamic Tester (MDT) pressure measurements and fluid samples obtained in PTU-16. The oil-water contact is -13,012 feet TVDSS based on well tests and well log data from a well that is subject to extended confidentiality under 11 AAC 83.153. These fluid contacts are believed to be of constant elevation throughout the area and the entire Thomson Sand reservoir is considered to be in pressure communication. Average reservoir pressure is approximately 10,100 psi at the datum of -12,700 feet TVDSS. Reservoir temperatures ranges from about 220° to 230° F.

Flow tests of PTU-15 and PTU-16 indicate the API gravity of the condensate is 38°. Condensate yield is dependent on the separation pressure. Test results suggest an initial condensate yield from test separators of approximately 65 Stock Tank Barrels of condensate liquids per Million Standard Cubic Feet (STB/MMSCF) of gas. ExxonMobil estimates that condensate yield from the production separator will be approximately 50 STB/MMSCF due to the higher outlet pressure of the IPS. The API gravity of the black oil in the oil rim reportedly varies from approximately 10 to 18° with a viscosity of about two centipoise at reservoir conditions. The lower portion of the oil rim consists of an oil-water transition zone, where both oil and water are partially mobile. Concentrations of hydrogen sulfide up to 30 parts per million (ppm) were encountered in both PTU-15 and PTU-16 during well tests; H_2S had not been previously identified in the reservoir.

ExxonMobil's geologic and reservoir model estimates that the original gas-in-place for the PTU is about 8 TCF. The 37-foot thick, viscous-oil rim is estimated to contain about 160 million barrels of OOIP. AOGCC CO 719, Findings, Paragraph 11.

3. Prior Exploration Activities in the Unit Area

Hydrocarbons were first discovered in the Point Thomson area in 1975 in the Alaska State A-1 well, which tested 23° API gravity oil at a rate of over 2,500 Barrels of Oil per Day (BOPD) from the lower Tertiary Flaxman Sand (informal unit of local usage) of the Canning Formation. The Lower Cretaceous Thomson sand reservoir was discovered in 1977 by the PTU-1 well. Since that time, an additional 15 wells have penetrated the Thomson Sand or its equivalent subsurface horizon in the PTU area. Data from these wells and from seven overlapping, 3-D seismic surveys were used to determine the geologic structure of the Thomson sand reservoir. Production tests, drillstem tests, downhole sampling, core, and well log data were used to establish reservoir properties, fluid properties, and the gas-oil and oil-water contacts for this reservoir.

Additional oil was discovered in the Tertiary Canning Formation with the drilling of the Sourdough 2 and Sourdough 3 wells in 1994 and 1996 by BP. BP indicated in 1997 that the Sourdough prospect could possibly contain 100 Million Barrels of Oil (MMBO) of recoverable oil. Future development of these and other Brookian oil accumulations in the area may benefit from the infrastructure associated with development and commercialization of the hydrocarbons in the main Thomson sand reservoir.

PTU-15 and PTU-16 were drilled in 2009 and 2010 and are the most recent wells drilled through the Thomson sand interval. After logging and testing, both of these wells were suspended and later re-completed to be the first development wells in the field upon start-up of the planned IPS in 2016.

4. The Applicant's Plans for Development of the Unit Area

ExxonMobil's planned operations, termed IPS, will produce and sell condensate liquids from the reservoir and then re-inject the dry gas as the enhanced recovery mechanism (informally termed as "gas cycling"). Production will commence using two wells: PTU-15, the initial gas producer, and PTU-16, a gas injector, both of which are located on the Central Pad. ExxonMobil will drill one additional well, PTU-17 from the West Pad during the 2015/2016 winter season and complete it as a gas producer. Upon completion of PTU-17, PTU-15 will be switched from a producer to an injector, and PTU-16 will remain an injector. The onshore, 55-acre Central Pad, located in Section 34, Township 10N, Range 23E, Umiat Meridian, is the location of the separation and injection facilities, operation camps, dock, and fuel and material storage. The West Pad will occupy approximately 17 acres within Section 36, Township 10N, Range 23E, Umiat Meridian. Gathering lines will transport gas produced from PTU-17 back to the Central Pad for separation and re-injection.

Condensate production and gas re-injection through the IPS is scheduled to begin during the first quarter of 2016. All facility modules are on-site and physical tie-ins are complete, ExxonMobil is currently installing electronic and communication systems such that final testing and commissioning can proceed. The IPS is designed to produce (approximately) an annualized average gas rate of 200 Million Standard Cubic Feet per Day (MMSCFD) via surface flow line to PTU production processing facility at Central Pad. Approximately 10,000 Barrels of Condensate per Day (BCPD) will be extracted from the gas and transported from the Central Pad through the Badami, Endicott, and TAPS common carrier pipelines. After separation of the gas condensate, approximately 194 MMSCFD will be re-injected into the Thomson sand reservoir. Injection pressures are expected to average approximately 9,800 to 10,000 psi at the wellhead, and will be limited to a maximum injection pressure of 11,025 psi. Re-injection of the residual dry gas will maintain reservoir voidage at a ratio of about 0.97:1, which will help to maintain reservoir pressure to facilitate additional condensate recovery and also preserve gas for future sales.

As noted previously, the 37-foot thick, viscous-oil rim is estimated to contain about 160 million barrels of OOIP. Exxon Mobil currently has no plans to target development of the oil rim. Production from the relatively thin interval would be extremely difficult, even using horizontal wells and the latest technology. Reservoir simulation modeling indicates that the high viscosity oil would yield minimal oil production prior to breakthrough of overlying gas, underlying water, or both. Ultimate oil recovery would be very low, and would require separate facilities to process the viscous oil.

The work plan and activities in connection with the IPS Project are set forth in Exhibit E attached to the Settlement Agreement. During the first year of production following the IPS Project Start-up, the working interest owners will collect data and information regarding production, well and reversion performance, and transportation system operation to aid in further development planning and decisions. Settlement Paragraph 4.1.1.2.

Additional wells will be drilled and placed on production as needed to keep the IPS fully loaded with gas to sustain the objective of a minimum of 10,000 BCPD until the Thomson sand reservoir is no longer able to sustain that objective. Settlement Paragraph 4.1.1.3. Due to a change in circumstances regarding the presence of higher concentration of H_2S and a desire to attain additional data from the West Pad sooner, the working interest owners will drill a Thomson sand well from the West Pad beginning in the fall of 2015 and anticipated to be completed during the first quarter of 2016. In addition to the West Pad, the working interest owners will continue permitting for the East Pad, an East Pad well, and a fifth well, with the permitted location of the fifth well determined by the working interest owners based on prior well results. Settlement Paragraph 4.1.3.

5. The Economic Costs and Benefits to the State and Other Relevant Factors

The PTIPA will provide economic benefits to the State through royalty and tax payments on production. The initial allocation methodology provides an equitable production allocation between the leases. ExxonMobil submitted tract participation schedules for the leases in the proposed PTIPA as required under 11 AAC 83.351. The proposed allocation distributes expenses and production among the tracts and leases on the basis of Exhibit C to the Settlement Agreement. A review of the relevant technical information shows the proposed tract factors adequately protect the State's interest.

Allocation of Production and Costs

Section 12 of the Settlement states that "[a]ll unitized substances produced from each participating area established under this agreement," with exception of that used in connection with operations as specified, "shall be deemed to be produced on the basis prescribed in Exhibit C." If there is any allocation different than from Exhibit C not approved by the Director, then such allocation methodology must be submitted to the Director. The PTU agreement also provides that, "production of unitized substances from participating area shall be allocated as provided in Exhibit C of this agreement regardless of whether any wells are drilled on any particular part or tract of said participating area." The agreement also provides an ordering rule for the gas produced from the participating area and reinjected into the participating area for repressuring or recycling purposes.

6. Any Other Relevant Factors, including the Protection of the Public Interest

The approval of the PTIPA promotes and maximizes the efficient recovery of oil and gas resources within the State. Additionally, it protects the fiscal interests of the State by consideration of alternative projects to fully develop the Point Thomson reservoir, including an alternative expansion project for the condensate production, an alternative project to deliver Point Thomson gas to the Prudhoe Bay for injection for the purpose of enhanced oil recovery process, and an alternative potential MGS project.

B. Decision Criteria Considered Under 11 AAC 83.303(a)

1. Promote Conservation of All Natural Resources

The unitization of oil and gas reservoirs and the formation of participating area within unit areas to develop hydrocarbon-bearing reservoirs are well-accepted means of hydrocarbon conservation. Formation of an initial participating area within an existing unit, with development occurring under the terms of a unit agreement, promotes efficient evaluation and development of the State's resources, and minimizes impacts to the area's cultural, biological, and environmental resources.

2. Promote the Prevention of Economic and Physical Waste

Approval of the formation of the PTIPA promotes prevention of economic and physical waste. Approval of the PTIPA does not result in economic waste given the current well spacing, market demand, and anticipated production rates. Annual approval of the PTIPA development activities as described in the future plans of development must also provide for the prevention of economic and physical waste. Using the existing and developing infrastructure and facilities eliminates the need to construct stand-alone facilities to process production from the Point Thomson Reservoir; optimizing production while preventing economic and physical waste protects all parties.

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

Formation of the PTIPA protects the economic interests of all parties. Combining interests and operating under the terms of the PTU Agreement and PTU Operating Agreement provides each individual WIO an equitable allocation of costs and revenues commensurate with the resources of its leases. Operating under the PTU Agreement ensures accurate reporting and record keeping, state approval of plans of exploration and development and operating procedures, royalty settlement, in-kind taking, and emergency storage of oil and gas, all of which will further the State's interest.

The people of Alaska have an interest in the development of the State's oil and gas resources to maximize the economic and physical recovery of the resources. AS 38.05.180(a). Diligent exploration and development under a single approved unit plan without the complications of competing leasehold interests promotes the State's interest. Approval of the PTIPA as prescribed under the Settlement (Paragraph 4.6 *et seq.*) and future annually approved plans of development as provided by the PTU Agreement provides for continued review and approval of ExxonMobil's plans to develop the PTIPA in a manner which will maximize economic and physical recovery of the resources.

The formation of the PTIPA advances the efficient evaluation and development of the State's resources, minimizes impacts to the area's cultural, biological, and environmental resources which protect the State's interest.

VI. DECISION

The Conservation of All Natural Resources

1. The approval of the PTIPA promotes conservation of the natural resources of all or part of an oil or gas pool, field, or like area by maximizing the efficient recovery of oil and gas and minimizing the adverse impacts on the surface and other resources.

2. The development and operation of these leases under the PTU Agreement and the PTIPA reduces the occurrences of disturbances to wildlife habitat that would otherwise be disrupted by individual lease development. This reduction in environmental impacts and preservation of subsistence access is in the public interest.

3. All unit plans and development must proceed according to permits, commitments, approvals, conditions, and deadlines, schedules and other requirements as set forth in the

Settlement. The State, Division, and local agencies have issued various approvals for PTU development. Future operations will require similar review and approval. DNR may condition its approval of a future unit Plan of Operations or permits on performance of mitigation measures. Compliance with mitigation measures will minimize, reduce or completely avoid adverse environmental impacts.

The Prevention of Economic and Physical Waste

With the approval of the IPS condensate production commitments and time line, the Settlement creates pathways, incentives, and bench marks for full-field development of the Point Thomson reservoir. The Division considered the prevention of economic and physical waste criteria under 11 AAC 83.303(a)(2). The PTIPA development activities must be conducted in line with development schedule and terms as prescribed in the Settlement, which will provide for the future promotion of prevention of economic and physical waste.

The Protection of All Parties in Interest, Including the State

1. The formation of the PTIPA meets the requirements of 11 AAC 83.351 for participating area formation because the proposed participating area will be in production as described herein, and 11 AAC 83.371 because the proposed allocation of production is consistent with the data and adequately and equitably protects the public interest. Formation of the PTIPA is in the State's best interest.

2. The geological and engineering data provided reasonably justify the inclusion of the proposed acreage within the PTIPA under the terms of the applicable regulations governing formation and operation of oil and gas units (11 AAC 83.301 – 11 AAC 83.395). The terms and conditions under which these lands were leased from the state also justify inclusion because ExxonMobil has worked to develop the unit in accordance with the Settlement and the proposed PTIPA.

3. The Thomson Oil Pool comprises the Lower Cretaceous Thomson sand, which lies between 16,126 and 16,377 feet MD in reference well PTU-15 (equivalent to -12,614 and -12,828 TVDSS).

4. The Settlement provides that within 20 days following the month of first production through the IPS Project with delivery into TAPS, the Unit Operator shall provide notice to DNR of the date of first production through the IPS Project with delivery into TAPS. Settlement Paragraph 4.3.1. ExxonMobil is hereby directed to furnish that notice as prescribed herein after the delivery into the TAPS.

5. The Division approves the PTIPA tract allocation schedule effective May 1, 2016, or the date of first production through the IPS Project with delivery into TAPS, whichever is the earlier, for allocating production and costs among the leases in the PTIPA. ExxonMobil will report production from the PTIPA to royalty accounting unit code PTTR.

For the reasons discussed in this Findings and Decision, the formation of the PTIPA is formed and approved upon "IPS Project start-up effective the date of first production through the IPS project with delivery into TAPS." Further, upon receipt of the notification that a West Pad is drilled and casing set across the Thomson sand, Area B expansion of the PTIPA is approved effective the first day of the month in which the last of conditions (i) and (ii) as set forth in Settlement Paragraph 4.4.1 was met.

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 Mark Myers, Commissioner, Department of Natural Resources, 550 W. 7th Avenue, Suite 1400, Anchorage, Alaska 99501; faxed to (907) 269-8918, or sent by electronic mail to dnr.appeals@alaska.gov. This decision takes effect immediately. 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.

If you have any questions regarding this decision, please contact Hak Dickenson with the Division at (907) 269-8799 or by email at hak.dickenson@alaska.gov.

Corri A. Feige

Corri A. Feige, Director
Division of Oil and Gas

9 Nov. 15
Date

VII. ATTACHMENTS

1. Exhibit C, PTIPA Tracts and Tract Participations
2. Exhibit D, Map of the PTIPA within the Point Thomson Unit Boundary
3. Exhibit F, from March 29, 2012, Settlement Agreement

Attachment 1. Exhibit C, Tracts and Tract Participations

Exhibit C
Point Thomson Unit Agreement
Tracts and Tract Participations for the Initial Participating Area

Initial Participating Area Leases

Tract No.	ADL No.	Description	Acres	Royalty %	Working Interest Ownership: Owner	Working Interest Ownership: Percent	Initial PA Tract Allocation
1	47557	T10N-R24E, UM	623.00	12½	ExxonMobil	62.674000%	4.541974%
		Sec. 31, All, 623 acres			BP	32.326000%	
					COP	5.000000%	
2	47558	T10N-R23E, UM	2,560.00	12½	ExxonMobil	62.674000%	10.322896%
		Sec. 25, All, 640 acres			BP	32.326000%	
		Sec. 26, All, 640 acres			COP	5.000000%	
		Sec. 35, All, 640 acres					
		Sec. 36, All, 640 acres					
3	47559	T10N-R23E, UM	2,560.00	12½	ExxonMobil	62.674000%	19.988177%
		Ses. 27, All, 640 acres			BP	32.326000%	
		Sec. 28, All, 640 acres			COP	5.000000%	
		Sec. 33, All, 640 acres					
		Sec. 34, All, 640 acres					
4	47560	T10N-R23E, UM	640.00	12½	ExxonMobil	46.266043%	3.872682%
		Sec. 32, All, 640 acres			BP	22.691275%	
					Colt Alaska LLC	11.612196%	
					Pacific Lighting	5.000000%	
					Hughes K.R., LP	3.600000%	
					COP	3.509756%	
					Chap-KDL, Ltd.	2.271950%	
					Searls, Estate	1.135975%	
					Eastland Oil Co.	0.757318%	
					Pinta Real Dev	0.504879%	
					Donnelly, G.	0.504878%	
					Donnelly, R.R.	0.504878%	
					O'Neill, Jan D.	0.504878%	
					Collier, S.J.S.	0.473322%	
					Searls, J.P.	0.473322%	
					Niedert, L.L.S.	0.189330%	
					Eastland P&M*	1.514635%	
					Donnelly, R. Jr.*	0.378659%	
					Donnelly, D.P.*	0.378659%	
5	47561	T10N-R22E, UM	2,560.00	12½	ExxonMobil	62.674000%	11.470133%
		Sec. 25, All, 640 acres			BP	32.326000%	
		Sec. 26, All, 640 acres			COP	5.000000%	
		Sec. 35, All, 640 acres					
		Sec. 36, All, 640 acres					
14	47570	T9N-R23E, UM	2,560.00	12½	ExxonMobil	62.674000%	7.106642%
		Ses. 3, All, 640 acres			BP	32.326000%	
		Sec. 4, All, 640 acres			COP	5.000000%	
		Sec. 9, All, 640 acres					
		Sec. 10, All, 640 acres					
15	47571	T9N-R23E, UM	2,560.00	12½	ExxonMobil	62.674000%	9.818136%
		Sec. 1, All, 640 acres			BP	32.326000%	
		Sec. 2, All, 640 acres			COP	5.000000%	
		Sec. 11, All, 640 acres					
		Sec. 12, All, 640 acres					
16	47572	T9N-R24E, UM	1,253.00	12½	ExxonMobil	62.674000%	8.500339%
		Sec. 6, All, 625 acres			BP	32.326000%	
		Sec. 7, All, 628 acres			COP	5.000000%	
17	50983	T10N-R23E, UM	640.00	12½	ExxonMobil	62.674000%	6.361276%
		Sec. 29, All, 640 acres			BP	32.326000%	
					COP	5.000000%	
18	51667	T10N-R23E, UM	1,243.00	12½	ExxonMobil	62.674000%	8.115255%
		Sec. 30, All, 620 acres			BP	32.326000%	

Exhibit C
Point Thomson Unit Agreement
Tracts and Tract Participations for the Initial Participating Area

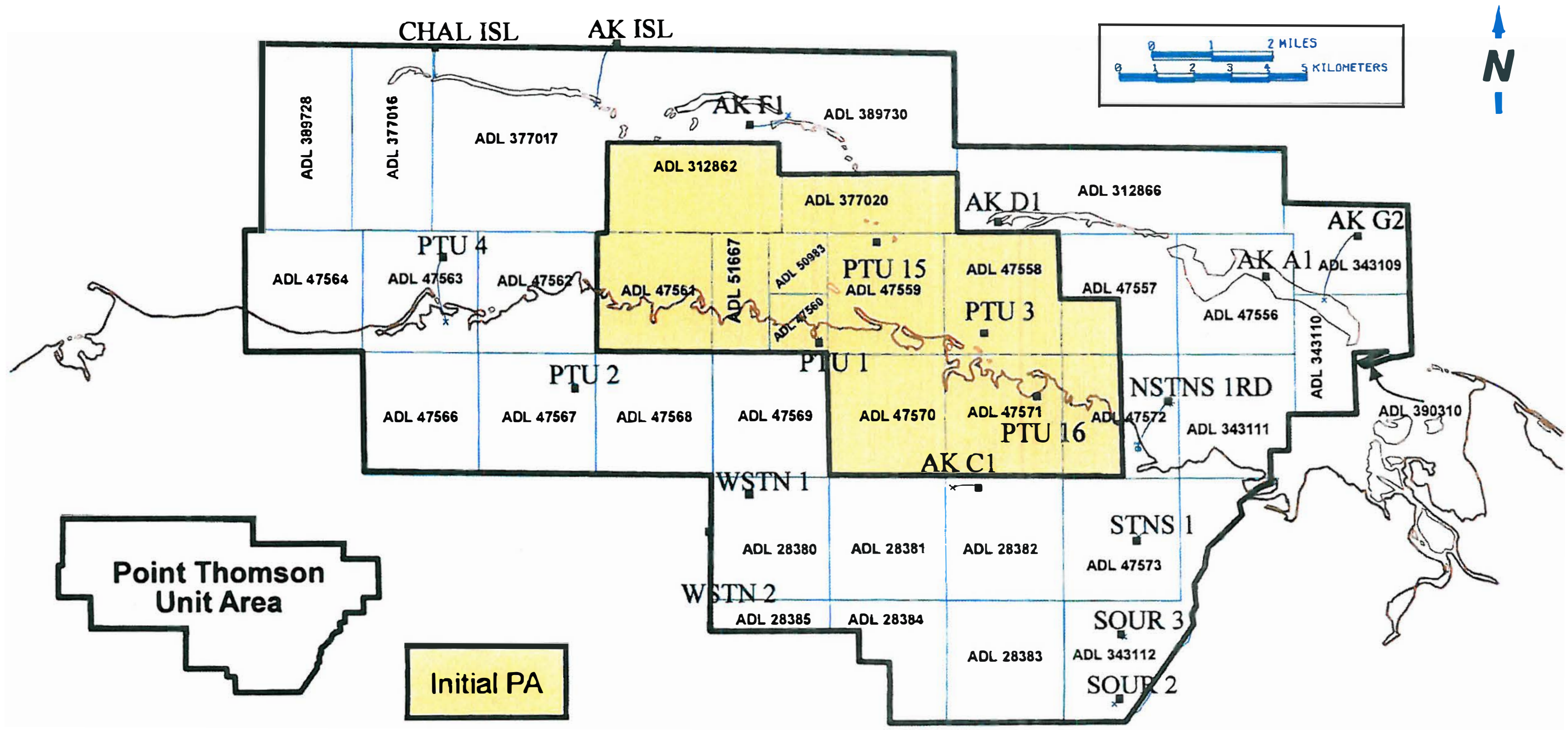
Initial Participating Area Leases

Tract No.	ADL No.	Description	Acres	Royalty %	Working Interest Ownership: Owner	Working Interest Ownership: Percent	Initial PA Tract Allocation
		Sec. 31, All, 623 acres			COP	5.000000%	
27	312862	T10N-R22&23E UM TRACT C30-110 (BF-110): A PORTION OF BLOCKS 753 AND 797 AS SHOWN ON THE "LEASING AND NOMINATION MAP" FOR THE FEDERAL/STATE BEAUFORT SEA OIL AND GAS LEASE SALE, DATED 1/30/79, MORE PARTICULARLY DESCRIBED AS FOLLOWS: THOSE LANDS LOCATED IN THE S1/2 OF BLOCK 753, BEING A PORTION OF BLOCK 753 ON THE AFORESAID LEASING AND NOMINATION MAP, CONTAINING 1152.00 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T10N, R22E; U.M., AK., AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T10N, R23E; U.M., AK., IN BLOCK 797 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL O.C.S. BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1133.95 HECTARES, LESS AND EXCEPT THE NORTH HALF OF THE AFOREMENTIONED TRACT.	2,824.34	Sliding Scale 20-65	ExxonMobil BP COP	62.674000% 32.326000% 5.000000%	5.790316%
33	377020	T10N-R23E, UM That portion of Tract 65-020, "TRACT65-020 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 754 OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/79, CONTAINING 1152 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, 22 AND 23, T. 10N., R. 23E., UMIAT MERIDIAN, ALASKA IN BLOCK 798 (BEING IN THE NORTHERLY PORTION), LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1109.94 HECTARES." lying southerly of Sections 14, 15, 16 and 17, T. 10 N., R. 23 E., U.M., Alaska in OCS Block 798.	1,909.74	20	ExxonMobil BP COP	62.674000% 32.326000% 5.000000%	4.112174%
		Total IPA	**21,933.08**				**100.000000%**

Attachment 2. Exhibit D, Map of the PTIPA within the Point Thomson Unit Boundary

EXHIBIT D

Boundaries of the Initial Participating Area



Attachment 3. Exhibit F, from March 29, 2012, Settlement Agreement

Exhibit F

PA DOCUMENTATION

DNR will keep information submitted in a PA application confidential as provided in AS 38.05.035(a)(8) and its applicable regulations. In accordance with AS 38.05.035(a)(8)(C), in order for geological, geophysical and engineering data to be held confidential, the Unit Operator must request confidentiality at the time the data is submitted by indicating "CONFIDENTIAL" on all confidential data items.

1. Depth Structure Maps and digital grids (including faults) for each producing horizon.

2. Gross Isochore Maps and digital grids for each producing horizon

3. Hydrocarbon Net Pay Maps and digital grids for each producing horizon. Also include any fluid contact maps and digital grids used in creation of the hydrocarbon net pay maps.

4. Average Porosity and Hydrocarbon Saturation Maps and digital grids for each producing horizon.

5. Hydrocarbon Pore Feet Maps and digital grids for each producing horizon.

6. Paper and digital copies of representative seismic lines to support the applied for action. Data submitted should include both strike and dip oriented lines, include picked horizons for all mapped surfaces, mapped faults, and wells demonstrating time-depth ties to well log formation picks. Lines should be clearly annotated with seismic survey

ID, seismic volume, line number, picked horizon and well names. Map clearly showing location of all seismic and well sections provided.

7. Paper and digital copies of representative stratigraphic and structural well-log cross-sections. Cross-sections should include, log correlations for all mapped horizons, mapped faults, identified fluid contacts and deepest "oil down to" (ODT) and shallowest "water up to" (WUT) picks. Cross-sections should be of an appropriate scale that all annotations, picks, log curves and scales are clearly legible.

8. Hydrocarbon formation volume factors (B_o, B_g) applied to each reservoir.

9. Oil Gravity and/or Viscosity Maps and digital grids for each producing horizon.

10. Digital file (ascii or Excel spreadsheet) of formation picks in measured depth (MD) and sub-sea true vertical depth (sstvd) for each well, including all plug backs and pilot holes. Picks should include top and base of each producing interval, all known fluid contacts and deepest "oil down to" (ODT) and shallowest "water up to" (WUT) picks.

11. Digital files of calculated curve data from log analysis used in determining reservoir properties and in-place hydrocarbon volumes. Curve data should include total and/or effective porosity, water saturation, permeability, clay volume, and bulk volume water.

12. Criteria /cutoffs (i.e. porosity, saturation, volume shale, permeability) used to determine net pay in each producing horizon.

13. Digital file (ascii or Excel spreadsheet) of calculated rock properties of each producing interval for every well. Data to include, top and base depth of interval in measured

depth and sstvd, gross interval thickness (tvt), net sand thickness, net hydrocarbon pay thickness, net to gross ratio, average reservoir porosity, average reservoir water saturation (Sw), average permeability, permeability height (kh), and hydrocarbon pore feet

14. Location Map clearly showing all existing production, injection and planned wells. Horizontal wells should be shown as a line highlighting the existing and planned productive interval length. In addition, a digital file (ascii or Excel spreadsheet) provided with target x y coordinates for planned wells. For horizontal wells, x y coordinates for heel and toe locations should be provided for both existing and planned wells.

15. Summary of all oil and gas (including non-hydrocarbon constituents) compositional analyses, including gravity and viscosity data.

16. Paper and digital copies of all pressure build-up PTA and fluid PVT analyses.

17. Relative permeability curves for oil/water, gas/oil, and gas/water.

18. Paper and digital copies of all capillary pressure analyses, where available.

19. Calculated original oil and/or gas in place (OOIP and/or OGIP) volumes

20. Estimated ultimate recovery (EUR).

21. Proposed reservoir depletion plan set forth in the current POD.

22. Production forecast.