STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

COMMISSIONER'S FINDINGS AND DECISION ON REMAND FROM SUPERIOR COURT POINT THOMSON UNIT

APRIL 22, 2008

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This is my Decision in the remedy proceeding held as directed by Judge Sharon Gleason in her December 26, 2007 Decision on Appeal ("Gleason Decision"). The Gleason Decision affirmed the State of Alaska, Department of Natural Resources' ("DNR") decision rejecting the 22nd Plan of Development ("POD") for the Point Thomson Unit ("PTU"). Judge Gleason also found that the due process rights of ExxonMobil Corporation, Operator of the Point Thomson Unit ("ExxonMobil"); BP Exploration (Alaska) Inc., ("BPXA"), Chevron U.S.A., Inc. ("Chevron"); and ConocoPhillips Alaska, Inc. ("Conoco") (collectively, "Appellants") were violated because they did not have adequate notice that DNR would invoke the remedy of unit termination if it did not approve the 22nd POD. Judge Gleason directed DNR to conduct proceedings to allow Appellants to present and support alternative remedies to unit termination in light of the rejection of the 22nd POD.

To afford Appellants the opportunity to present their alternatives to unit termination, I invited written proposals.[1] Appellants submitted a 23rd POD on February 19, 2008 as the proposed remedy for DNR's rejection of the 22nd POD.[2] I conducted an administrative hearing March 3 through 7, 2008 to allow Appellants to explain and support their proposed remedy. Appellants submitted additional written materials after the hearing. This record, including the materials designated as the PTU record in the case before Judge Gleason, was the basis for my decision.

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[1] Letter dated January 3, 2008 [R. 30505-6] The record of this remedy proceeding was numbered as part of the PTU record, beginning with the number 30,000. In this Decision, both the hearing exhibit and the PTU record numbers are used as references. "R." is a record cite. "Tr. at" is a hearing transcript page number reference. "HE" stands for hearing exhibit.

[2] [HE 5, R. 30000-30019]

In Section I of this Decision, I summarize the background of the remand proceeding and the Point Thomson Unit's checkered history. In Section II, I review and analyze the 23rd POD that Appellants proposed as an alternative remedy to unit termination. In Section III, I discuss the legal issues raised during the proceeding, including why Section 21 of the Point Thomson Unit Agreement ("PTUA") does not apply to this proceeding. Section IV is a summary of my Decision.

I. BACKGROUND

A. Procedural History of Remedy Proceeding

The factual and procedural background of the cases appealed to Judge Gleason is detailed in the first sixteen pages of the Gleason Decision and is not repeated here. After the Gleason Decision was issued, I wrote to Appellants and set a schedule for submission of alternative remedies.[3] Appellants responded, describing their view of the appropriate procedures for the proceeding.[4] Judge Gleason entered another order retaining jurisdiction over the case and setting June 15 as the deadline for completion of the remand proceeding.[5] I again wrote to Appellants, appointing a hearing officer, setting deadlines for filing witness lists and briefs on the issues raised in their correspondence, and setting a hearing date.[6] The hearing officer convened a prehearing conference on February 27, 2008 to resolve procedural issues in advance of the hearing to maximize the time available to Appellants.

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[3] January 3, 2008 letter. [R. 30505-6]
[4] January 18, 2008 and February 8, 2008 letters to Commissioner Irwin. [R. 30507-12; 30516-18; 30519-20]
[5] Gleason order, January 15, 2008.
[6] January 28, 2008 letter. [R. 30513-15]

The Alaska Gasline Port Authority ("AGPA") requested permission to offer a fifteen-minute opening statement at the hearing and to submit a post-hearing brief.[7] AGPA's request was granted because AGPA submitted an *amicus* brief in the underlying proceeding, AGPA's participation for fifteen minutes during the hearing would not impede Appellants' opportunity to present their proposed remedy, and its arguments might enhance my understanding of the record. Appellants requested and were granted the opportunity to file a brief in response to AGPA's post-hearing brief.[8]

I made thirty hours of hearing time available to Appellants. Appellants called fourteen witnesses to testify at the hearing. To ensure that Appellants were able to fully present their proposed remedy, they were invited to submit any testimony that could not be presented at the hearing by affidavit after the hearing, and they did. Appellants offered 256 hearing exhibits, all of which were made part of the record in this case.[9]

Public comment was filed on March 5, 2008 by W. Findlay Abbott, and on March 7, 2008 by Tom Lokosh. Mr. Lokosh's comments were made a part of the record.[10] Mr. Abbott's public comments were not made a part of the record in this case because they were not relevant to the issues in this remand remedy hearing. Mr. Abbott also filed a Motion for Leave to File Amicus Curiae Brief on April 2, 2008, after the deadline for post-hearing briefs.[11] The contents of Mr. Abbott's original public comments were entirely included within his proposed *amicus* brief. Mr. Abbott's filings were numbered

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[7] February 20, 2008 letter. [R. 30864-5]
[8] [R. 31388]
[9] [R. 30000-30345; 30400-30412; 30500-30504]
[10] [R. 30910-11]
[11] The Motion included a certificate of service showing that Appellants were served.

as part of the record, but not considered in making this Decision because to consider them I would have needed to allow Appellants the opportunity to respond.[12] I am operating in this case under the timeline imposed by Judge Gleason's January 15, 2008 Order and would not be able to fully consider the comments and Appellants' response and timely issue my Decision. Thus, Mr. Abbott's Motion for Leave to File Amicus Brief is denied.

The hearing began on March 3, 2008 with initial testimony from Appellants (except Conoco) in support of the 23rd POD. ExxonMobil presented testimony from Craig Haymes, ExxonMobil Alaska Production Manager. Mr. Haymes introduced the 23rd POD and testified about his company's commitment to it.[13] He stated that this was the first time the PTU working interest owners ("WIOs") had committed to put the field into production.[14] He laid the foundation for the technical witnesses who followed and described the work that had been done by the WIOs since the rejection of the 22nd POD.[15]

John Zager, General Manager of Chevron's Alaska Operations, expressed Chevron's support for the 23rd POD. He noted that 85 percent of Chevron's North Slope gas resources were in the Point Thomson Unit.[16] Mr. Zager, citing the current WIOs' expertise, asserted that the State would see production soonest by approving the 23rd POD.[17] He asserted that the recent changes in voting provisions of the Unit Operating

[12] [R. 31335-31359]
[13] Mr. Haymes offered essentially the same testimony three times during the hearing [Tr. at 88, 680 and 1011], and again in his post-hearing affidavit. [R. 31033-31077]
[14] [Tr. at 92]
[15] [Tr. at 93-4]
[16] [Tr. at 208]
[17] [Tr. at 208]

Agreement ("UOA") would have the effect of removing the ability of any of the WIOs individually to veto unit development actions.[18]

Kevin Brown, Manager of Alaska Gas Business Development for BPXA, testified next in support of the 23rd POD. He noted that informal discussions with the Alaska Oil and Gas Conservation Commission ("AOGCC") suggested that it supported the plan for reservoir development described in the 23rd POD.[19]

Robert L. Brusenham, Land Manager for Leede Operating Company, testified in support of the 23rd POD on behalf of approximately three-quarters of the independents who collectively own about a 1 percent working interest ownership in the PTU.[20] Leede acquired an interest in one of the leases that later became part of the original unit in 1977. Mr. Brusenham acknowledged that he was frustrated at times with the pace of development progress in this unit.[21] When asked what conduct by the unit operator would cause him to support removal of the unit operator, Mr. Brusenham testified that if the unit operator acted negligently, knowingly doing things that should not be done, removal would be appropriate.[22]

Beginning on the second day of the hearing, ExxonMobil offered the testimony of several witnesses to support the technical aspects of the 23rd POD. Because their testimony was based on data classified as confidential under AS 38.05.035(a)(9), almost

[18] [Tr. at 216] The State is not a party to the UOA.

[19] [Tr. at 253-4] I discuss the AOGCC's role in review of Point Thomson area development plans below in footnote 141.

[20] [Tr. at 299] He represented Leede Operating Company and L.L.S. Neidert; J.P. Searls; J.A. Searls, Dec., Susan Collier, Executor; Chap-KDL, Ltd., Jack L. Russell, General Partner; United Oil & Minerals Limited Partnership; Richard Donnelly; R. Searls Jr., Trust, Susan Collier; S.J.S. Collier; Kingdon R. Hughes, Hughes Family Limited Partnership and Samson Resources Company. [R. 31384-7]

[21] [Tr. at 309]

[22] [Tr. at 309]

all of this portion of the hearing was not open to the public. ExxonMobil's geoscientist Elizabeth Elkington offered testimony about the hydrocarbon resources within the Point Thomson area. Dennis O'Brien, a reservoir engineer, testified from an engineering perspective about how the Point Thomson resources could be produced. He described the results of the models ExxonMobil used to plan the recovery of hydrocarbons.

On the morning of the third day the hearing was again open to the public. William Meeks, a drilling engineer with experience working in high-pressure wells, explained that ExxonMobil had contracted for a drilling rig that could be used to drill the wells described in the 23rd POD.[23] He said that all of the wells in the 23rd POD could be completed with a single rig in advance of construction of the facilities required for processing produced fluids.[24]

Craig Pruitt, development planner for ExxonMobil, offered testimony about the design of the facilities described in the 23rd POD. He explained that a phased approach enabled the WIOs to use the results from the first five wells to determine how the gas resources in the unit could best be produced.[25] He testified that the Initial Production System ("IPS") facilities were designed modularly so that they could be expanded to accommodate additional volumes of production or moved to another location.[26]

ExxonMobil next offered testimony from an economist associated with Cambridge Energy Research Associates ("CERA"), David Hobbs. Mr. Hobbs supported a phased

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[23] [Tr. at 593]
[24] [Tr. at 596]
[25] [Tr. at 628-9]
[26] [Tr. at 639, 641]

approach to development, using several case studies from other developments in the world to explain how the project economics would be enhanced if the development progressed as reservoir risks were resolved.[27]

On the fourth day of the hearing BPXA offered the testimony of four witnesses. Bill Bredar testified about BPXA's view of the 23rd POD. While BPXA's geologic interpretations of the reservoir were not totally aligned with ExxonMobil's, BPXA fully supported the 23rd POD.[28] Gary Gustafson detailed the permits that would be required and the time needed to obtain them.[29] Kevin Brown returned to the stand and characterized the differences among the WIOs on reservoir interpretation as "creative tension."[30] He cited the changes to the UOA as "a demonstration of commitment."[31]

Ken Boyd, an independent consultant who was the Director of DNR's Division of Oil and Gas from 1995 to 2001, supported the 23rd POD but suggested that DNR should consider requiring relinquishment of the leases if the WIOs failed to perform the commitments made in the 23rd POD.[32] Witnesses Brown and Gustafson also submitted testimony after the hearing by affidavit.[33]

On the last day of the hearing, Chevron offered three witnesses. James Webb, the project manager for Chevron's interests in Point Thomson, stated Chevron's support for the 23rd POD and acknowledged that Chevron had some different interpretations of the

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[27] [Tr. at 703-720]
[28] [Tr. at 734-5]
[29] [HE 210; Tr. at 810-25]
[30] [Tr. at 841]
[31] [Tr. at 850]
[32] [Tr. at 914]
[33] [R. 30914-24; 30925-27]

geologic data.[34] Dr. Richard Strickland, a consultant in petroleum engineering, offered his opinion that the 23rd POD was the quickest path to production of the Point Thomson resources.[35] John Zager returned to the stand to state Chevron's commitment to advance the project.[36]

Mr. Haymes returned during the final session of the hearing. He responded to questions, deferring answers to several of the subsequently filed affidavits.[37]

Appellants were invited to submit by affidavit, no later than March 14, 2008, any additional testimony that they were unable to present during the hearing. After the hearing, BP witnesses Brown and Gustafson supplemented their earlier testimony.

ExxonMobil submitted testimony from six witnesses by affidavit. Professor Patrick Martin, Professor of Law from Louisiana State University, was offered as an authority on pooling and unitization law. He stated that unit termination would result in litigation that would delay development.[38] Frank X. Siroky, former lead, LNG Project, American Transportation and Regulatory, ExxonMobil, offered testimony to rebut the suggestion made in AGPA's opening statement that ExxonMobil had refused to negotiate the sale of Point Thomson gas.[39] Paul Pike, ExxonMobil's Project Manager for Alaska Gas, offered confidential testimony addressing several geoscience questions asked during the hearing.[40] Finally, Anil Kholsa, an ExxonMobil Economic Advisor, stated that the

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[34] [Tr. at 941]
[35] [Tr. at 981]
[36] [Tr. at 1001]
[37] [Tr. at 1011-51]
[38] [R. 30978]
[39] [R. 30995-1001]
[40] [R. 31078-88]

23rd POD did not make economic sense as a stand-alone project, but was viable as the first phase of full field development.[41] Mr. Haynes and Mr. Hobbs supplemented their earlier testimony.[42]

Conoco submitted testimony by affidavit after the hearing from two witnesses. Mark Ireland, the North Slope Gas Upstream Manager for Conoco supported the 23rd POD.[43] Peter Frost, Director of Regulatory Affairs, Gas & Power Marketing Group of Conoco, testified about how gas pipelines operate.[44]

Appellants were also invited to file post-hearing briefs. The hearing officer identified two specific legal issues for briefing, but invited Appellants to brief any additional issues they wanted to call to my attention. Appellants filed a joint post-hearing brief, along with a [Proposed] Agreed Final Judgment and Order.[45] AGPA also filed a post-hearing brief. After the post-hearing briefs were filed, Appellants asked for the opportunity to file a brief in response to AGPA's brief. Their request was granted and Appellants filed a final brief on April 4, 2008.[46]

B. Unit History

The lengthy history of this unit is contained in the record. During the hearing, Appellants argued that they should not be criticized for the lack of development of the leases in the PTU because they had operated under approved PODs and honored all of the commitments they made in those plans. The record does not support Appellants' view of

41 [R. 31090-1]
42 [R. 31033-77, 30931-52]
43 [R. 31110-21]
44 [R. 31103-9]
45 [R. 31157-89, 31151-6]
46 [R. 31388, 31362-83]

history. Because Appellants' credibility and willingness to follow through on approved commitments are central issues in this proceeding, I am detailing the unit's history in this Decision. The record shows that the WIOs were repeatedly advised that failure to develop the leases in the Point Thomson Unit could result in unit termination. The record also shows that after the 5th POD ended in 1982, the unit operator did not drill another unit well, despite the fact that the drilling during the first five years of the unit's existence identified valuable hydrocarbon reserves. Appellants were repeatedly told that DNR wanted them to develop these leases. When Appellants wanted to expand the unit, they offered drilling commitments in 1984 and 2001. DNR accepted the commitments made in Appellants' PODs and Expansion Agreements in good faith and relied on them in approving Appellants' PODs and expansion applications. Appellants reiterated these drilling commitments to justify some of the PODs. However, Appellants did not honor any of their drilling commitments.

Credibility is most persuasively established by actions, not words. Appellants' historical actions can be judged objectively: whether they fulfilled their obligations under the leases and unit agreements; and whether they performed the actions they committed to perform in the PODs and Expansion Agreements approved by DNR. DNR approved those PODs and Expansion Agreements based on the belief that Appellants were making commitments in good faith that they were willing and able to honor.

The clear pattern established by the history of this unit is of broken development commitments, recalcitrance and repeated efforts to delay rather than bring the substantial hydrocarbon resources in this area to market. It appears that Appellants made the decision in 1983 to treat the unit as a gas reservoir and hold it until they believed it served their interests to produce and market the gas. The unit history after 1983 reveals a constant shell game where Appellants induce DNR to approve PODs and Expansion Agreements only to consistently renege on commitments, allowing Appellants to warehouse this vast resource. The testimony offered in this remedy proceeding did not persuade me to find that the proposed 23rd POD will change that pattern or that the WIOs will fulfill the commitments in the 23rd POD.[47] This pattern, established over the last twenty-five years, is an objective reason for me to believe that these WIOs will not perform the work to which they have committed in the 23rd POD.[48]

1. Early Years: Exploration Drilling 1977 to 1982

ExxonMobil, as unit operator, drilled exploration wells during PODs 1 through 5 from 1977 through 1982. During this period, Appellants drilled exploration wells that tapped large hydrocarbon deposits, discovered oil and gas in paying quantities, and conducted studies.[49]

Appellants' 1st POD said that "[i]f oil is discovered in sufficient quantities to warrant future development, the Prudhoe Bay to Valdez oil pipeline will be the probable marketing outlet for the area."[50]

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[47] Their credibility was further undermined by the view expressed by several at the hearing, but most persistently by Mr. Haymes, that they had done everything they promised DNR they would do throughout the history of the unit. [R. 31044-51; Tr. at 220, 265] The credibility issue is more fully discussed in Section II.C.8(c.) of this Decision.

[48] On Page 16 of their Post-hearing Brief Appellants argue that "There is simply no objective reason to believe that the WIOs will not perform." [R. 31176] I find that the history of this unit is such an objective reason.

[49] [R. 11360-70, 11340-41, 11306-07, 11292-95, 11272-74]

[50] [R. 11366]

Appellants discovered oil, but they have never produced it.[51] After the 1st POD, Appellants continued to drill exploration wells from 1979 to 1982 in the 2nd - 5th PODs.

2. Middle Years: Studies and First Expansion Agreement 1983-1993

After the 5th POD expired in 1982, Appellants drilled no more unit wells. Beginning with the 6th POD in 1983, the unit history records a pattern of DNR attempting to get Appellants to develop the unit and Appellants responding by making development commitments to win unit POD approval or unit expansion approval, and then failing to honor those commitments. Because Appellants discovered valuable hydrocarbon deposits, the Point Thomson Unit Agreement ("PTUA") required them to form a participating area ("PA")[52] or the unit would terminate.[53] Instead of forming a PA, Appellants convinced DNR to amend the PTUA to eliminate the PA formation requirement. What in hindsight was an unwise decision by DNR may have been reasonable in 1983 because the WIOs diligently explored the unit area during its first five years. When Director Brown permitted elimination of the PA formation requirement, DNR expected that development would continue apace and production would begin in the late 1980s.[54] However, the PTUA amendment was interpreted by Appellants to remove development pressure.

[51] The 23rd POD continues this refusal: "The potential production contribution from the oil rim is uncertain. . . . The Brookian reservoirs have substantial risks and uncertainties[.]" [HE 5, R. 30005, 30008] Since 1983, DNR has repeatedly requested that ExxonMobil drill the delineation wells necessary to resolve the uncertainty, but Appellants have either refused or made unfulfilled promises to drill more wells.

[52] Participating areas are formed before production to allocate the volume of produced resource amongst leases. Unit Agreements required formation of a participating area within a specific number of years after unit formation to ensure timely development.

[53] Point Thomson Unit Agreement ("PTUA"), Articles 9 and 20(c). [R. 9496, 9504]

[54] [R. 9463]

In the 1983 6th POD, Appellants proposed geotechnical and environmental studies.[55] DNR approved the POD, but asked Appellants to do more delineation and development work:

> . . . [T]he Department feels that the activities proposed for the time period covered do not significantly contribute to the further delineation and understanding of the reservoir(s) and unit area as required in 11 AAC 83.343 (a)(1), and in the Unit Agreement.
>
> The primary interests of the department in reviewing and approving unit plans of development and operation are to ensure that the engineering and geologic studies characterizing the underlying reservoir(s) are progressing, and that orderly and timely development of commercial hydrocarbon reservoirs occurs. [R. 11258]

Instead of responding to DNR's concerns regarding the lack of proposed development, Appellants proposed in the 1984 7th POD a five-year plan to conduct studies without drilling or substantial delineation work. ExxonMobil explained that Appellants had expended more than $700 million on the unit and that "[s]ufficient drilling has been accomplished to establish within reason the area and potential commerciality of the field. Further development prior to commencement of construction of a pipeline to market would constitute economic waste[.]"[56]

[55] [R. 296-98, 11261-8]

[56] [R. 297] DNR did not agree that sufficient drilling had been accomplished to understand the commerciality of the reservoir. In October 1985, Director Brown told Exxon: ". . . it has been and remains the intent of the division that the required well shall be one that will supply data about the as-yet poorly understood Thomson Sands characteristics. . . ." [R. 10022] Director Eason re-affirmed this position in January 1988. [R. 11555] Further, a "pipeline to market" was not necessary. The trans-Alaska pipeline, which could have transported the oil and gas condensates known to exist in the PTU to market, began operating in 1977. The 60 miles between Point Thomson and Prudhoe Bay was the only missing piece. All but the last 22 miles of that gap was filled when the Badami pipeline was built. [HE 10, R. 30024] ExxonMobil now apparently agrees that more drilling is necessary because the 23rd POD proposes five wells to obtain more geologic information to aid in designing a full field development plan. [HE 5, R. 30000, 30004]

This was the first of numerous times that ExxonMobil argued that funds already expended should excuse their obligation for future development. Neither the unit agreement nor the leases require Appellants to expend funds. Instead, they require development. More than twenty years later, when ExxonMobil tried to convince DNR to approve the 22nd POD, it argued that Appellants had spent $800 million.[57] The fact that Appellants had spent $700 million by 1983 and only $100 million more during the subsequent twenty-five years is further evidence that efforts to develop these lands virtually stopped.

While DNR conditionally approved the 7th POD on November 29, 1983, DNR's decision provided that POD approval did not relieve Appellants of any drilling or other work commitment "that may be attached to the lease as a condition for approval of an expansion of the Point Thomson Unit to include the lease in the unit area."[58] During DNR's review of the 7th POD, Appellants were also negotiating with DNR to approve a unit expansion agreement.[59]

Four months after approval of the 7th POD, DNR approved unit expansion based on Appellants' commitment to drill wells in 1985 and 1990, and on the understanding that Appellants would create a common database.[60] The WIOs had not yet merged their geologic information to create a common understanding of the reservoir.[61]

[57] [R. 850, 891-2]
[58] [R. 299]
[59] [R. 10121-3]
[60] [R. 10040-1, 10060, 10019-20]
[61] WIOs normally pool their data so that it can be merged to produce a comprehensive description of the reservoir that enables them to more knowledgeably plan development and production.

DNR approved the wells and the database because they would facilitate unit development.[62] Director Brown considered the wells to be an important component of the PTU development: "I consider meeting the requirements of the March 26, 1984 [Expansion] Decision and Findings a priority and a remaining obligation."[63]

Ultimately, Appellants failed to meet any of these commitments. They did not drill the 1985 well and did not prepare the common database as represented.[64] Nevertheless, Appellants continued to tout these commitments in order to create the perception that they were moving the unit toward timely exploration and development. ExxonMobil stated that it was "making preparations to be in a position to commence a well in the 1985/1986 winter season" for the purpose of confirming reservoir commerciality.[65] ExxonMobil also reiterated that the goal of the drilling program was to begin a gas cycling project by 1992:

> As discussed with you, current plans call for establishment of a participating area and start-up of production for a gas cycling / condensate recovery development as early as 1992 . . . . [R. 10023–4]

When Appellants filed their 8th POD in 1988, they incorporated the 1984 Expansion Agreement commitment to drill the second well by 1990 into the POD. Appellants' 8th POD requested a three-year POD to do the following: acquire more 3-D seismic; drill the promised expansion agreement PTU well #5 by 1990; and conduct

[62] [R. 10019-20, 10037, 10040-1] Again, the 7th POD decision stated that POD approval did not relieve Appellants of the drilling commitments contained in the proposed expansion agreement. [R. 299]

[63] [R. 10022]

[64] [R. 10026, 10018]

[65] [R. 100023]

reservoir well mapping studies.[66] DNR approved the POD.[67] A year later, Appellants informed DNR that they were not going to drill the promised well because the economics had changed.[68] Appellants also failed to complete the reservoir mapping study first proposed in the 8th POD.

In the 1991 9th POD, ExxonMobil proposed to continue the reservoir mapping study.[69] DNR responded:

> [T]he Eighth Plan of Development for the PTU, approved by the division on October 6, 1988 for a three year period, anticipated the preparation of unit consensus maps for each of the currently known reservoirs (Pre-Mississippian, Thomson, and Flaxman [Brookian]). The consensus maps were to be prepared during the period of the Eighth Plan and were to assist in the assessment of the unit's development potential and contribute to the further delineation and understanding of the reservoir(s) and unit area as required in 11 AAC 83.343(a)(1), and in the Unit Agreement.
>
> The consensus mapping by the unit owners was not accomplished as proposed during the term of the Eighth Plan, and the division remains concerned with some of the rational [sic] given for delaying consensus mapping program. (*See* September 25, 1991 correspondence). The division is further concerned with the length of time to accomplish the mapping program and the adverse impacts of this delay for making the detailed technical analysis for the orderly and timely development of the hydrocarbons in the Point Thomson Area. [R. 11404–5]

The mapping project became the primary focus of the 1993 10th POD.[70]

The 1994 11th POD proposed to continue reservoir characterization and other studies.[71] DNR reluctantly approved the POD, but warned Appellants that DNR was considering unit contraction due to the lack of unit exploration and development.

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[66] [R. 11529–34]

[67] [R. 11528, 11537, 11554]

[68] [R. 11463, 11457]

[69] [R. 11452–54a, 11469]

[70] [R. 11386–96] The 10th POD also proposed initiation of a multi-year "Consensus Reservoir Characterization Study" and a "Conceptual Planning Schedule." [R. 11387]

> I am informing Exxon, the PTU operator, of my intent to contract the unit boundary effective January 1, 1995 . . . .
>
> No explicit exploration work was conducted under the tenth plan nor is any contemplated under the eleventh plan. . . . Absent significant and actual on-the-ground exploratory activity on the tracts identified in Attachment # 1 on or before December 31, 1994, pursuant to 11 AAC 83.356(e) and 11 AAC 83.343(b), I plan at this time to contract the unit boundary effective January 1, 1995. [R. 11735-6]

3. Later Years: DNR Struggles to Elicit Development Commitments 1994-2004

Director Eason also said that DNR would not accept the 12th POD if it did not contain substantial delineation work and a discussion of Appellants' efforts to market hydrocarbons.[72] When Appellants submitted their proposed 1995 12th POD, DNR rejected it because it did not include substantial exploration activities and did not include a discussion of Appellants' effort to market.[73] Director Eason did, however, initially agree to extend the due date for the POD to give Appellants additional time to commit to substantial unit development.[74] Nonetheless, DNR never approved a 12th POD.

By 1995, when the 13th POD was submitted, there was a new Director of the Division of Oil and Gas, Ken Boyd. Appellants ignored Director Eason's statements that the next POD must include substantial commitments to delineate and develop the PTU reservoirs. Instead, the 13th POD maintained that PTU development was uneconomic.

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[71] [R. 11738-43]

[72] [R. 11735-6]

[73] [R. 10479-80] The unit operator responded that no market existed and denied marketing responsibility stating it is an individual lessee's duty. [R. 10480-1]

[74] On Dec. 22, 1994, Director Eason wrote ExxonMobil: "As discussed this morning, this is to acknowledge our agreement to extend the 11th POD . . . until April 30, 1995. The decision to extend is intended to provide an opportunity for both of us to review the discussions and the documents exchanged to date regarding our perspective views on contraction of the unit area and on diligent further exploration and development of the PTU acreage." [R. 10479]

Appellants, therefore, committed to conducting studies.[75]

Director Boyd responded by backing off the former Director's unit contraction warning and approved the 13th POD because Appellants had represented that they would endeavor to develop the unit through farmout agreements;[76] BPXA and ARCO might explore the western portion of the Point Thomson Sands; and Appellants were now considering "any synergistic benefits between the PTU and Badami and/or any other potential accumulations, e.g., Flaxman, ANWR, etc."[77]

Despite approval, Director Boyd expressed his displeasure with Appellants' lack of cooperation among themselves[78] and urged them to fully delineate and develop the unit in a timely manner.[79] Director Boyd concluded:

> The division remains concerned about the lack of exploration and development work that has been conducted in the PTU. The division has stepped back from its intent to contract the unit to allow the partners to find new opportunities, including farm-in agreements, to evaluate the area outside the known Pt. Thomson sands accumulation. The division wants the acreage within or immediately adjacent to the unit explored and evaluated. To that end, the division wants the working interest owners to share data pertaining to the acreage within or immediately adjacent to the unit. The division wants the unit to function as a unit rather than as separate leases. Most importantly the division wants a fair and honest attempt to get this acreage explored and to be appraised of efforts to develop and produce the Pt. Thomson sands accumulation itself. [R. 321]

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[75] [R. 314-8]

[76] A farmout agreement is an agreement to assign an interest in leased land in exchange for a drilling commitment on that land. Williams and Meyers, *Manual of Oil and Gas Terms*, 11th Edition (2000).

[77] [R. 4303, 14936-7, 14371-2, 14961, 14926]

[78] For example, according to BPXA, ExxonMobil had rejected its offer to drill wells. BPXA and Chevron also complained about ExxonMobil's lack of cooperation with sharing data and with the unit's slow pace of development. [R. 14419]

[79] [R. 321]

In the 1997 14th POD, Appellants sought approval by reporting that they played a role in passage of the Stranded Gas Development Act ("SGDA").[80] ExxonMobil cited the non-unit Sourdough No. 3 well drilled by BPXA and Chevron in 1994, even though that well was not drilled as a unit operation.[81] In ExxonMobil's POD request, it conceded that it did not complete all of the tasks promised in the 13th POD.[82] The POD also offered more studies Appellants said were necessary for a gas cycling project, and Appellants again said they were attempting to farmout the western portion of the unit.[83] DNR approved the POD because BPXA and Chevron drilled a well in the PTU during the term of the 13th POD.

The 1998 15th POD again proposed the creation and evaluation of a common PTU database.[84] DNR rejected the POD because it failed to include an evaluation of the Thomson oil rim; did not include a plan to estimate the recoverable oil; and did not attempt to delineate and develop the Brookian and Thomson oil.[85] Director Boyd concluded:

> . . . BP and Chevron publicly announced a discovery with an estimated 100 mmb of recoverable oil from the Sourdough prospect within the . . . unit . . . . ExxonMobil's A-1 well discovered the Flaxman oil accumulation . . . . The proposed POD did not include plans for developing either of these known prospects or exploration for additional reservoirs within the unit . . . . The unit Plan of Development must include a schedule to evaluate the geology of the multiple reservoirs in the entire

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80 [R. 348–50; 11650]

81 In 1996, BPXA and Chevron followed up on the 1994 Sourdough discovery in the Brookian with a second 1996 well, Sourdough No. 3, which was also drilled as a non-unit well.

82 [R. 14926-7]

83 [R. 14928, 14860, 11648–52]

84 [R. 15350] The common database was initially promised by Appellants in 1984 and was to be completed by September 1986. [R. 10018-19]

85 [R. 324]

> unit area and perform an integrated economic analysis of the unit. This evaluation should at a minimum incorporate the Thomson condensate, oil rim, Upper Cretaceous through Eocene turbidites, and fractured basement potential. [R. 324]

DNR requested that Appellants drill an exploration well in the unit by 1999. Appellants refused, continuing to insist that they had drilled enough wells to understand the reservoir:

> While the Owners acknowledge the DNR's desire for additional exploration within the PTU, the requests for an exploratory well in 1999 is not appropriate given the substantial exploration effort heretofore undertaken by the Owners. A total of 17 exploration well and/or delineation wells have been drilled in or around the PTU. Collectively these wells have encountered and to some extent tested all of the known prospective formations common to the PTU...." [R. 332][86]

Appellants denied DNR's request for them to disclose to the State the unit studies that had been performed and said the 15th POD should be approved as submitted.[87]

DNR responded to Appellants' proposal by threatening unit default.[88] On December 16, 1997, DNR and Appellants met to resolve this dispute and discuss DNR's rejection of the 15th POD. ExxonMobil claimed it could not submit a POD delineating all of the reservoirs because Appellants were not sharing all the results of their respective exploratory efforts; acknowledging that they could not produce an integrated development plan due to Appellants' varied interests, even though the unit had existed for 20 years.[89]

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[86] At the recent hearing, Appellants cited the same seventeen wells as evidence of their diligence. [HE 11, R. 300251]
[87] [R. 332-4]
[88] [R. 327-30]
[89] [R. 11604-5]

DNR eventually approved an interim six-month POD that required, among other things, that the next proposed POD include a plan to delineate all of the reservoirs within the unit area. The POD also needed to set out a plan to develop the oil reserves.[90] The requirements of this interim POD were fulfilled.[91] Appellants submitted a new 15th POD on May 14, 1998.[92] DNR approved the 15th POD with certain conditions, including that Appellants: share all available data with each other; create a common database; develop a consensus map of all of the potential PTU reservoirs; further delineate the Thomson and Brookian reservoirs; complete development planning studies; and explore potential synergies between oil and gas development.[93]

The 2000 16th POD characterized Appellants' PTU development view as considering the cycling of gas liquids while waiting for a gas pipeline.[94] The Appellants were planning the following development:

> Drill eight gas producers from two onshore drill sites to produce one billion cubic feet per day (GCF/D) of wet gas. One drill site will be located on the east end of the field with the other on the west side. The location and number of wells and the project off take rate are subject to optimization. Both higher and lower off take rates will be considered.
>
> Separate condensate from gas production for export to TAPS Pump Station #1. The resulting initial condensate rate will be dependent upon final determination of fluid composition and the cycling pattern but may vary from 50 to 70 thousand barrels per day (KB/D). [R. 11761]

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[90] [R. 11604-5, 11614-6, 11829]
[91] [R. 11830]
[92] [R. 11571]
[93] [R. 11829-30] During this time, ExxonMobil also filed an application to expand the PTU by adding an additional lease. DNR rejected ExxonMobil's request because, in part, the lack of exploration and development work completed by Appellants. [R. 13380-3]
[94] [R. 11759-60]

The 16th POD represented that the gas cycling project could be economic, but that Appellants would have to complete more studies.[95] After initially rejecting a draft 16th POD, DNR conditionally approved a revised 16th POD because it described a path progressing toward development. Appellants promised to complete the studies needed to support the cycling project and to evaluate the necessity of additional delineation wells.[96]

The 2001 17th POD was approved because it included preparation of a base case development plan for the Thomson Sand to move the unit into production.[97] The POD concluded that neither additional seismic nor drilling were required to evaluate the Thomson Sand.[98] DNR required Appellants to select a base case development plan and do a preliminary analysis of the gas cycling project's commercial viability.[99]

In 2001, Appellants proposed the 18th POD and also filed an application to expand the unit. Appellants made the following representations regarding the development they proposed in return for unit expansion:

> The Owners have endeavored in the attached response <u>to unambiguously demonstrate our commitment to the development</u> of the Point Thomson Unit. We are committing to aggressive work program and the expenditure of substantial funds that will put us in a position to initiate project execution activities as early as possible. (emphasis added) [R. 1502]

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[95] [R. 11787]

[96] [R. 11757, 11763, 11772-3]

[97] [R. 1459-61] ExxonMobil also promised that Appellants would finalize the revisions to the UOA, which was initially promised in the 16th POD. ExxonMobil, however, did not complete this commitment. [R. 1512] In fact, the commitment to finalize the revisions to the UOA, initially promised in the 16th POD, was still not completed by the time ExxonMobil proposed the 22nd POD. [R. 752]

[98] [R. 1464] In contrast, the evidence offered during the remand hearing emphasized that wells needed to be drilled to resolve considerable uncertainty that exists in this reservoir. [HE 5, R. 30005; HE 108-156, R. 30122-30170; HE 5, R. 30017; Tr. at 113-9, 185, 248, 282, 354, 365, 559-61, 706-12, 745-56, 837, 859, 883, 973 and 1050]

[99] [R. 1464]

The ExxonMobil letter goes on to state Appellants are "unambiguously committed" to expedited permitting; to accelerated engineering studies; and to drilling a new well or re-drilling the Red Dog well[100] by 2002-03 winter season and to spending $300 million on a development drilling program beginning in 2006, if the project were viable.[101] The proposed project consisted of an exploration well by 2003, a production well by 2006, and seven production wells by 2008.[102] ExxonMobil told DNR that this work should lead to gas cycling or gas sales production: "Carrying out these work commitments will provide the Owners the flexibility to either independently develop the Point Thomson for gas cycling ... or provide for early gas sales[.]"[103] Thus, Appellants created the impression these work commitments were necessary for either a gas cycling or gas sales project.

DNR approved the 2001 Expansion Agreement based on ExxonMobil's stated "unambiguous commitment" to explore, to bring the unit into production, and also on the assumption that these commitments would be incorporated in future PODs.[104] The language ExxonMobil used to describe the level of its commitment, and its subsequent non-performance, undermine the testimony of Mr. Haymes that the 23rd POD was the first time ExxonMobil had seriously promised to develop the unit.[105] In the 2002 18th POD, Appellants committed, in part, to select a location for the Expansion Agreement

[100] The Red Dog Well is outside the PTU. It was an exploration well drilled in 1999 by BPXA, Chevron, and Conoco (then ARCO). [HE 11, R. 30025]
[101] [R. 1502]
[102] [R. 380, 632, 12761-6]
[103] [R. 1502]
[104] [R. 1561, 12757-66, 12736-42]
[105] [R. 31056-8]

well, develop a drilling plan, and contract for a drill rig "in preparation to drill the well through the Thomson Sands . . . during the 2002-2003 winter season."[106] DNR approved the 18th POD based on Appellants' promises to develop the unit by doing this preliminary work and to pursue expedited permitting and engineering work for a gas cycling project.[107] DNR stated: "I am pleased to see concrete plans put into motion for the development of PTU reserves. During the 18th POD, ExxonMobil plans to select a location for delineation well and contract for a rig by June 2002."[108]

After DNR approved the 18th POD, Appellants abandoned their commitment to drill the first well promised in the 2001 Expansion Agreement and did not perform the work associated with that well as promised in the 18th POD.[109]

In the 2003 19th POD, Appellants proposed additional studies and permitting for a gas cycling project, and notified DNR that they would not drill the well due in 2003 and touted in the 18th POD.[110] Nonetheless, DNR approved the POD because the permitting and studies were necessary for the proposed Thomson Sand wells promised in 2006 and 2008.[111]

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[106] [R. 1514]
[107] [R. 365–72, 641]
[108] [R. 11928]
[109] [R. 374–75, 377–78, 385]
[110] [R. 383–91, 1552] A central purpose of the 19th POD was an assessment of the gas cycling projects commercial viability. [R. 4399] Appellants, however, failed to complete this task, reportedly because of rising cost estimates, revised resource assessment, and the failure to complete the necessary permit stipulations. [R. 4401] Appellants also failed to meet their commitment to complete a new unit operating agreement, which was initially made in the 16th POD. [R. 4401]
[111] [R. 393–400, 414-17, 1561–2, 4418]

In the 20th POD, Appellants committed primarily to pursue major permits and complete studies needed for development and construction of the gas cycling project.[112] DNR approved the 20th POD with the understanding that during the 20th POD, Appellants would proceed "on two parallel paths to meet the next commitments in the Unit Expansion Approval. They promised to commence development drilling by June 15, 2006, and complete seven development wells by June 15, 2008."[113]

After DNR approved the 20th POD, Appellants stopped much of the 20th POD work, including the development permitting and investigation of the Pre-Mississippian reservoir.[114] On December 18, 2003, Appellants notified DNR that a gas cycling project was uneconomic and that Appellants intended to investigate a gas blow-down (major gas sales) project.[115] Appellants had not completed many of the work commitments made in the 2001 Expansion Agreement[116] or incorporated into the 18th, 19th, and 20th PODs.[117] Instead, Appellants decided they needed to begin new studies to support a gas blow-down project.[118]

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[112] [R. 4402]

[113] [R. 4653] With the 20th POD, Appellants requested that DNR defer the remaining expansion agreement commitments. [R. 4652] DNR did grant extensions, but rejected Appellants' request to extend the deadline for the 2006 and 2008 production wells by two years. [R. 4652-53]

[114] During the 20th POD, Appellants also failed to secure approval for a new unit operating agreement, which, again, was initially promised in the 16th POD, during the 20th POD. [R. 422]

[115] [R. 632–33]

[116] When Appellants failed to drill in 2003, two leases reverted to the State and Appellants paid the state $950,000. [R. 377–78, 380]

[117] For example, Appellants promised to pursue project permitting, but these activities were suspended due to project scope, design, and feasibility uncertainties. [R. 1908] The planned Pre-Mississippian evaluation promised in the 20th POD was also not done because Appellants concluded that the gas injection project was not commercially viable. [R. 1909, 1914] Appellants also failed to complete negotiations on a new operating agreement as promised in every POD since the 16th POD. [R. 1910]

[118] [R. 632–33] This contention is inconsistent with the representations ExxonMobil had previously made when it asked DNR to approve the 2001 expansion that the work commitments could be applied to gas cycling or blow-down projects. [R. 1502]

In the 2004 21st POD, Appellants shifted their focus to a gas sales project, but continued to work on a gas cycling project even though they had "not been able to identify an economically viable Gas Injection Project under current fiscal terms."[119] DNR requested copies of Appellants' reservoir data and the various PTU studies they had conducted in order to evaluate Appellants' claim that gas cycling was not commercially viable. DNR needed the data and studies to verify ExxonMobil's claims. Appellants denied DNR's request.

While Appellants' insistence that the 22nd POD's primary focus on gas sales was a logical extension of the 21st POD, DNR has never agreed that the only way PTU can be developed is by gas blow-down project:

> The Division must determine if the proposed 21st POD is in the public interest. The 21st POD focuses on gas sales, which may not be the best alternative, especially considering the unknown timing of a gas sales pipeline. A prudent unit operator should evaluate all alternatives to develop the unitized substances including: gas injection followed by gas sales, gas sales followed by gas injection, simultaneous gas sales and gas injection projects, and the combined economics of developing gas and oil from the Thomson Reservoir along with oil from the Pre-Mississippian and Brookian reservoirs within the PTU. The Division cannot adequately review the proposed plan without the technical data, assumptions, and interpretations that went into the PTU Owners' evaluation of the Gas Injection Project. Article 10 of the PTU Agreement, Plan of Further Development and Operations, supports the Division's data request as follows:
>
>> Any plan submitted pursuant to this section shall provide for the exploration of the unitized area and for the diligent drilling necessary for determination of the area or areas thereof capable of producing unitized substances in paying quantities in each and every productive formation and shall be as complete and adequate as the Director may determine to be

[119] [R. 420]

> necessary for timely development and proper conservation of the oil and gas resources of the unitized area . . . . [R. 427]

DNR issued a decision conditionally approving the 21st POD and gave Appellants thirty days to provide the requested information or the unit would be in default.[120] ExxonMobil appealed the conditional approval of the 21st POD to the Commissioner. In that appeal, I affirmed Director Mark Myers' decision and notified Appellants that they must address the 2006 and 2008 drilling commitments in the 22nd POD.[121] Appellants provided the requested information and did not appeal my decision to superior court.[122]

Despite the focus on gas sales, DNR approved the 21st POD because Appellants agreed to evaluate oil production from the Thomson and Brookian reservoirs, promised to work on alternative development scenarios, and provided the requested information.[123] The Director reminded Appellants that they would still be expected to drill the well due in 2006 and the seven production wells due in 2008.[124]

4. Consideration and Rejection of the 22nd POD-2005

In a 2005 draft 22nd POD, Appellants initially proposed to do more studies until a gas pipeline was constructed.[125] Director Myers responded by asking Appellants to drill one exploratory well to resolve reservoir uncertainties that prevented them from

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[120] [R. 428]

[121] [R. 12278-79] In that decision, I wrote: "the Division was reluctant to expand the PTU . . . given that no development had occurred in the unit during the preceding 24 years, and the PTU owners had no plans to develop the known reserves underlying the PTU in the foreseeable future. . . . The commitments contained in the 2nd Expansion are integrated into the long-term plan of development for the PTU. And, given the timeline to fulfill the drilling commitments, it is appropriate that the Division give Exxon notice that the drilling plan must be addressed in the 22nd POD." [R. 12279]

[122] [R. 12268–80]

[123] [R. 1943]

[124] [R. 1916]

[125] [R. 12217-25]

committing to the production of oil and gas liquids.[126] If Appellants agreed to drill, DNR would approve the POD, extend the Expansion Agreement drilling deadlines, and concede that a gas blow-down project was the best alternative if the well data supported this conclusion.[127]

But Appellants refused to drill.[128] A subsequent draft 22nd POD stated the unit would not be developed without a gas pipeline.[129] Appellants also requested to be relieved of the commitments they had made in return for approval of the 2001 expansion and PODs 18 through 21. Appellants argued that their efforts to negotiate a fiscal contract under the SGDA should relieve them of the Expansion Agreement drilling commitments so long as the SGDA negotiations were pending.[130]

Director Myers denied the request to substitute SGDA negotiations for the work commitments.[131] After negotiations and reviewing drafts, he disapproved the 22nd POD, put the unit in default, and provided Appellants with an opportunity to cure the default by filing a POD that delineated the reservoirs and committed to development.[132] Director Myers also stated the unit was subject to termination if Appellants did not cure, and he explained why termination would be justified given the unit's history.[133]

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[126] [R. 1958-60]
[127] [R. 1958-60]
[128] [R. 12190]
[129] [R. 628]
[130] [R. 200-3, 206–14]
[131] [R. 200-03, 1958-60]
[132] [R. 200-03, 644, 648, 1958-60]
[133] [R. 643-649] The AOGCC supported the Director's decision, stating that Appellants had not been cooperating with the AOGCC. Appellants had not complied with requests to provide information needed to establish PTU pool rules. Appellants had also refused AOGCC requests for PTU gas cycling documents. [R. 5605–13]

Appellants appealed Director Myers' decision to Commissioner Michael Menge and continued to insist, despite so many unknowns surrounding the Point Thomson reservoirs, that development of the PTU must await a gas pipeline.[134] Appellants' appeal also asked the Commissioner to substitute SGDA negotiations for the Expansion Agreement drilling commitments, offered to pay $20 million and return 20,000 acres of PTU leases to the State. [135] Appellants' proposal to return less and different acreage; i.e., acreage with no or marginal hydrocarbon prospects, for failure to comply with their drilling commitments, was unacceptable to DNR.[136]

Commissioner Menge affirmed the Director's decision, disapproved the revised 22nd POD, disapproved the proposal to relieve Appellants of the drilling commitments, and terminated the unit.[137] Acting Commissioner Marty Rutherford affirmed on reconsideration.[138]

II. REVIEW OF THE 23RD PLAN OF DEVELOPMENT, APPELLANTS' PROPOSED REMEDY

Appellants have proposed a 23rd POD[139] as their remedy for DNR's rejection of the 22nd POD. They have also provided me with amendments to the UOA that they say will significantly reduce barriers to unit development. The question before me is whether accepting Appellants' proposed 23rd POD is an adequate remedy or whether some other course of action (for example, unit termination, unit contraction, monetary penalties, a

[134] [R. 666, 669]
[135] [R. 682-84]
[136] [R. 5756-58, 5766]
[137] [R. 5756-58, 5766]
[138] [R. 9286-90]
[139] [HB 5, R. 30000-19]

POD with strict benchmarks and non-performance penalties, etc.) is in the public interest.[140] In making this Decision, I am mindful of DNR's legislatively delegated constitutional duty to ensure the development of Alaska's resources for the benefit of all Alaskans. *See* AS 44.37.020(a) (providing that DNR is charged with the responsibility of administering State programs for the conservation and development of natural resources); AS 38.05.180(a)(1) (policy of the State to encourage the development of natural resources to maximize economic and physical recovery); AS 38.05.020(b)(4) (the commissioner may exercise the powers and do the acts necessary to carry out the provisions and objective of the Alaska Land Act). As discussed in detail below, when I apply State law and regulations to this record and consider the public interest, the 23rd POD is an inadequate remedy.

In the 23rd POD, Appellants promise to spend $1.3 billion by 2014. The plan proposes to drill up to five wells.[141] It describes the location of three wells, two that will be drilled to test reservoir connectivity and that can later be converted to production wells and a disposal well. It also provides that two more wells will be drilled to test Pre-Mississippian or Brookian accumulations. [*Id.*] The plan commits to the construction of production and processing infrastructure and to a modest production of a minimum of 10,000 barrels a day of gas condensate from the Thomson Sands beginning in 2014. [*Id.*] Finally, the plan commits to development work for initiating gas sales. [*Id.*]

[140] *See Kachemak Bay Conservation Soc'y v. State, DNR*, 6 P.3d 270, 276 (Alaska 2000) ("the legislature delegated to DNR much of its authority to ensure that such leasing of state land or interests in state land is consistent with the public interest.").

[141] [HE 5; R. 30000-19, Tr. at 170-2]

The plan describes how Appellants intend to test the reservoir and construct an initial production facility between now and 2014. Despite the fact that the plan may present a technically reasonable first step for developing these lands from a conservation perspective,[142] it is an inappropriate remedy because I find no basis in this record to conclude that I can be assured that it will be completed as promised; or that if the 23rd POD is completed, that Appellants will continue to expand production as promised. Additionally, some of the plan's provisions, as detailed below, do not meet the public interest criteria and the factors I considered under AAC 83.303.[143] I cannot risk the continued delays in development of this valuable state resource by these WIOs with this history of unfulfilled commitments.

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[142] AOGCC Commissioner Foerster's comments to the press about the 23rd POD were cited by Appellants. [Tr. at 254-5] Her comments should be viewed in the context of her statutory responsibility. The AOGCC is responsible for ensuring that hydrocarbons are not wasted. AS 31.05.030(b). There is no waste when there is no production. The AOGCC's responsibilities do not include managing the State's mineral resources to collect royalty revenues for the State. DNR balances responsible reservoir development with economic considerations that are not within the scope of the AOGCC's review. Commissioner Foerster expressed support for the 23rd POD but acknowledged that whether it was enforceable was the remaining question. The AOGCC issued a statement on November 3, 2006 expressing its concern with the pace of development of "the largest proven accumulation of oil and gas in the State that is still undeveloped." [R. 5605-13]

[143] Under 11 AAC 83.303 a POD must: (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. In evaluating the above criteria, the commissioner will consider (1) the environmental costs and benefits; (2) the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir; (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 . . . the commissioner determines necessary or advisable to protect the public interest.

A. Appellants' Proposed 23rd POD Must Be Evaluated as Appellants' Only Proposed Remedy for Failure to Submit an Adequate POD, Not Merely as the Next POD

Appellants have treated this remedy proceeding like it is an extension of the POD submission and approval process. It is not. The initial 22nd POD was rejected, and a revised 22nd POD was submitted and reviewed and also rejected. The unit was terminated with the second rejection, and Appellants appealed to the superior court. This is a remand from the superior court to provide Appellants an opportunity to propose an alternative remedy to unit termination, not a continuation of the normal unit administration process.

Appellants' revised 22nd POD did not include a plan to delineate all of the resources in the PTU and put it into production. That act exhausted DNR's patience and led to its decision to terminate the unit. Appellants now argue that the only remedy for their long-standing failure to put the unit into production and for their failure to submit an acceptable POD is for DNR to accept yet another POD with "firm commitments" similar to those broken in the past.[144] The history of this unit demonstrates that is there is no effective way to ensure the WIO's performance.

Appellants have already had three chances to submit an acceptable 22nd POD – a draft submitted July 1, 2005 which Director Myers rejected[145]; the 22nd POD itself rejected by Myers, who then placed the unit in default[146]; and the modified 22nd POD

[144] Appellants submitted a [Proposed] Agreed Final Judgment and Order as assurance of performance. [R. 31151-6] As explained below in Section III. D., it does not provide sufficient assurance of performance.
[145] [R. 11208]
[146] [R. 12190]

rejected by Commissioner Menge.[147]

Despite multiple opportunities to submit an acceptable POD, Appellants have argued in their briefing that not only is another POD an appropriate remedy here, it is the only remedy DNR can consider. Appellants assert that DNR must accept the 23rd POD because it meets all the requirements for a valid POD that would have been accepted had it been offered as a cure to the 2005 Director's decision rejecting the 22nd POD.[148]

Appellants also contend that DNR cannot reject the 23rd POD unless DNR proves that Appellants must do something more under Section 21 of the PTUA and the reasonably prudent operator standard. Finally, despite Judge Gleason's finding that DNR had the authority to terminate the unit, Appellants imply that even if DNR finds a POD to be unacceptable, that does not constitute grounds for termination. Appellants suggest that rejection of a POD only leads to negotiation between Appellants and DNR regarding an appropriate POD and if DNR wishes to alter the level of exploration or production, it must hold a hearing under Section 21.[149]

The central issue, however, is not whether DNR can show under Section 21 that sound engineering practices would require Appellants to do more or that a reasonably prudent operator would do more than Appellants have offered in the 23rd POD. The issue and the standard are clear: whether it is in the public interest to accept the 23rd POD or to terminate the unit. Appellants chose to ignore the record showing that DNR already

[147] [R. 12933]
[148] Appellants did not explain why they did not submit the 23rd POD in response to Director Myers' rejection of their first proposed 22nd POD.
[149] [Post-Hearing Br. at 2-4, 13; R. 31162-4, 31173]

engaged in a dialogue with Appellants regarding the rejected 22nd POD.[150] In addition, Appellants ignore that DNR's approval of the 21st POD was conditioned in part on a demand that the unit operator abide by its commitment to drill certain exploration wells in 2006.[151] In this Decision, I exercise my expertise in the management of the State's resources to ensure that the public interest is protected.

B. Applicable State Law Governs My Evaluation of Whether Appellants' Proposed Remedy in the Form of the 23rd POD is in the Public Interest.

In order to evaluate whether Appellants' proposed remedy satisfies the public interest, I turn to applicable State law. The Gleason Decision[152] found that the "public interest" was the standard for whether unitization should be approved under the applicable statute[153] and regulations[154] in effect in 1977 when the unit was formed.[155] She also found that current regulation, 11 AAC 83.303, "is not inconsistent with Section 10 of the PTUA or the former regulations." [*Id.*] I find that the subsection 303 criteria should be considered as part of my review of Appellants' proposed remedy. Further, Section 10 of the PTUA requires that PODs be "complete and adequate as the Director may determine necessary for timely development and proper conservation of the oil and gas resources of the unitized area."[156]

[150] [R. 12208]
[151] [Post-Hearing Br. at 2-4, 13; R. 31162-4, 31173]
[152] December 26, 2007 Decision on Appeal In *ExxonMobil et al. v. State*, 3AN-06-13751 Civil.
[153] Gleason Decision at 5-6, citing former AS 38.05.180(m).
[154] Gleason Decision at 4-5, citing former 11 AAC 83.340, former 11 AAC 83.345.
[155] Gleason Decision at 22.
[156] [R. 9496-7]

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The credibility of the commitment being made in the 23rd POD by the WIOs is a crucial factor in evaluating whether Appellants' proposed remedy is in the public interest. As I explained to Appellants at the outset of the hearing, I need to understand why DNR should believe that the WIOs will bring the reservoirs in the PTU into production and its resources to market now when it has failed to do so during the first thirty-one years of unit operations and when it has a record stretching back over twenty years of walking away from commitments.[157]

C. Analysis of Factors Set Forth in 11 AAC 83.303

To make the determination that Appellants' proposed remedy is necessary and advisable to protect the public interest under 11 AAC 83.303, I must find that it will (1) promote conservation, (2) promote the prevention of economic and physical waste, and (3) provide protection for all the parties of interest, including the State. 11 AAC 83.303(a).

In evaluating these criteria, I will consider (1) environmental costs and benefits, (2) geological and engineering characteristics of the reservoir, (3) exploration activities in the PTU, (4) the economic costs and benefits to the State, and (5) other relevant factors, including Appellants' failure to diligently develop the unit over the past thirty-one years. 11 AAC 83.303(b).

What follows is my discussion of the factors set out in subsection .303(b), as they apply to the 23rd POD, followed by my findings under subsection .303(a), including my finding that the 23rd POD is not necessary or advisable to protect the public interest.

[157] [Tr. at 67-68]

1. Environmental Costs and Benefits

Environmental costs of development are generally minimized through unitized development of the PTU resources as opposed to individual lease development. The 23rd POD is consistent with this. But PTU termination does not preclude the formation of new units and the State can still realize the benefits of unitized development of the PTU reservoirs.

2. Geologic and Engineering Characteristics and Hydrocarbon Potential

The PTU contains hydrocarbons in the following reservoirs: Thomson Sand and Pre-Mississippian metasedimentary strata with approximately 8 trillion cubic feet of gas and several hundred million barrels of gas liquids in place in the form of a retrograde condensate. In addition to the gas and associated condensate, hundreds of millions of barrels of potential oil reserves are present in the oil rim of the Thomson reservoir and also in multiple shallower, overlying Brookian reservoirs.[158] The Thomson Sand reservoir is under very high pressure, exceeding 10,000 PSI.[159]

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[158] [R. 639-40, 824; HE 55, R. 30069(confidential); HE 171, R. 30187(confidential); R. 16479(confidential)]

[159] [R. 639–40] Hydrocarbons can occur in the forms of gases, liquids or solids. When they exist as oil, gas, and gas condensate, they are all producible, valuable resources. A gas condensate reservoir is one in which the fluids under initial reservoir pressure and temperature conditions exist in a single phase (all gas). The dense gas that occurs there originally has liquid in varying amounts dissolved in it, depending upon the geologic conditions of deposition and upon pressure and temperature conditions in the reservoir. It generally is believed that the fluids exist initially at or near dew point in the reservoir and that components in certain proportions begin to condense to liquid in the reservoir when reservoir pressure declines. The formation of liquids from mixtures when pressure decreases at constant temperature is called retrograde condensation. When liquid condenses in the reservoir, it "wets" the formation, adheres to the rock particles, and may not come out with the gas that is produced. It follows that if conditions of pressure, temperature, and composition can be maintained in a natural gas-condensate reservoir so that all the liquid fractions remain in solution in the gas until the gas reaches the surface, substantially all of them can be removed. Liquids recovered from gas at the surface in mechanical separators are crude oil that can be transported to market in an oil pipeline. If, however, conditions are induced in the natural reservoir that permit liquids to condense in the sand or porous limestone and "wet" the formation, a large proportion of the liquids will not be extracted by any ordinary means. Injection of gas, water or other fluids to maintain pressure or retard pressure

In a high-pressure retrograde condensate reservoir with suspended hydrocarbon liquids like the Thomson Sand, a considerable portion of the liquids will fall out of suspension (condense) in the reservoir and become unrecoverable when reservoir pressure drops.[160] This loss can be mitigated by maintaining reservoir pressure while producing liquids. This is accomplished by initially producing the high-pressure reservoir with a gas cycling project.[161]

In a cycling or injection operation, gas and liquids are initially produced together. Then liquids are stripped and the gas is re-injected to maintain reservoir pressure until an optimum amount of liquids have been recovered. In a gas blow-down project (primary depletion), produced gas is not injected into the reservoir to maintain pressure. As a result, a significant amount of gas condensate will be left in the reservoir and production from the Point Thomson oil rim will be impaired. Primary depletion as a gas field is the least efficient and results in the lowest hydrocarbon recovery.[162] The 23rd POD proposes a minimal, nominal cycling project of the high-pressure Thomson Sand gas reservoir.

Under the plan, Appellants propose to initially drill one production, one injection, and one disposal well. They also propose to construct facilities that would be capable of producing 10,000 barrels a day of gas condensate beginning in 2014 from the single producing well in the Thomson Sand gas reservoir.[163] Appellants suggest that they will also drill two more wells to learn more about one or more of the other reservoirs in the

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is one method of combating this loss. See, generally, Williams and Meyers, *Manual of Oil and Gas Terms*, 11th Edition (2000).

[160] [R. 5611-2]

[161] [R. 5612]

[162] [R. 5612]

[163] [HE 5, R. 30000-9]

unit; the Brookian oil reservoirs; the oil leg of the Thomson Sand reservoir; or the Pre-Mississippian reservoir below the Thomson Sand.[164] Under the proposed POD, the facilities could be expanded later to produce from more reservoirs than the Thomson Sand.[165]

The 23rd POD is a modest commitment to temporary production of the Thomson Sand gas condensate beginning in six years. Appellants make no pretense that the 23rd POD will put the Thomson Sand reservoir into production at anywhere near its potential. Appellants say that they will expand the facilities and production if the new data obtained from the 23rd POD work indicates that further development would be appropriate.[166] There is also no commitment to produce the unit's considerable oil reserves.[167] The Brookian accumulations; including Flaxman, which tested more than 2,500 barrels of oil/day in the Alaska State A-1 well; and Sourdough, which BPXA announced in a 1997 press release as a discovery with 100 MMBO of recoverable oil; contain hundreds of millions of barrels of oil. The 23rd POD sets out no plans for production of oil from any of these reservoirs or resources.[168]

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[164] [R. 30007-8] It is unclear how Appellants are treating the expansion leases in the proposed 23rd POD. I asked at the remedy hearing whether the 23rd POD assumes the inclusion of any of the expansion leases, and the response was unclear, but included the comment that Appellants would like to engage in a discussion with DNR as to the status of those leases. [Tr. at 158] The November 27, 2006 Commissioner's Decision made it clear that Appellants had breached the Expansion Agreement and that the State was entitled to have the expansion leases contract out of the PTU and to receive payment for the breach. The penalty due under the Expansion Agreement was paid at the end of June 2007. The expired expansion leases, following their contraction out of the PTU, were 27721-887] Thus, it would be inappropriate for Appellants to include any of these leases in the proposed 23rd POD.

[165] [HE 5, R. 3011-14]

[166] [HE 5, R. 3011-14]

[167] [HE 5, R. 30008, 30013; HE 55, R. 30069(confidential)]

[168] [R. 824, 11761, 30069, Tr. at 317-8, 366, 519(confidential)]

3. Prior Exploration

The discussion of the unit exploration activities in Director Myers' decision is incorporated here by reference.[169] No exploration activities have occurred since that decision was written in 2005. Section I of this Decision sets out the unit history regarding various plans and agreements to develop and explore the unit and the dispute between Appellants and DNR over these activities, or the lack thereof.

By 1982, Appellants had drilled sufficient exploration wells to confirm that the PTU was underlain by very large hydrocarbon deposits. No unit wells have been drilled since 1982. In 1983, ExxonMobil stated that sufficient drilling had been accomplished to establish within reason the area and potential commerciality of the field, and any further development activity would constitute economic waste.[170] Appellants have conducted many studies of the unit area since 1982, and they have obtained seismic over the entire unit area.[171]

4. Economic Costs and Benefits to the State

The State will economically benefit from development of the Point Thomson acreage. The State will receive royalties and taxes on whatever production that occurs. The IPS facilities and the additional geologic, engineering and other data described in the 23rd POD could be used to advance development. Implementation of the plan may add jobs to our economy.

169 [R. 639-42]
170 [R. 296-98]
171 [R. 177, 179]

The cost estimate for the 23rd POD is $1.3 billion.[172] Appellants state that the resulting facility is not economic, will not result in a profit, and can only be justified as a reservoir test facility that may lead to further development of the unit.[173]

The State will also incur significant costs under the 23rd POD. The State will have to wait until the end of 2014 for what is essentially nominal and may be temporary production of gas condensates from the Thomson Sands.[174] Delayed production is potentially a significant cost to the State.[175] There is no commitment in the 23rd POD to produce all of the unit's oil and gas resources or to maximize ultimate hydrocarbon recovery.

5. Other Relevant Factors

a. Commitment of Gas in First Open Season

In the cover letter submitted with the 23rd POD, ExxonMobil made a conditioned offer to commit to ship its gas during the first open season. "ExxonMobil, as an individual owner, will fully participate in and make commitments for its Point Thomson gas in an open season for a gas pipeline (producer owned, third-party owned or some other combination) in that pipeline's open season on terms and conditions no less favorable to ExxonMobil than those upon which other shipping commitments are made."[176] During the hearing, ExxonMobil was asked to define those terms and explain

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172 [HB 5, R. 30001, 30004]
173 [R. 31091]
174 [R. 31093-5]
175 [Tr. at 1025]
176 [HE 5, R. 30000-1]

the nature of this commitment.[177] Mr. Haymes provided further testimony on this issue in his post-hearing affidavit, stating essentially that ExxonMobil would commit to ship its gas if it could be assured that the commercial terms were comparable to the best deal offered to any other shipper.[178] This testimony did not define this commitment adequately enough for DNR to be able to rely on it. It requires the State to bear the risk that ExxonMobil will be able to successfully negotiate tariff terms with the pipeline owner. While it may be commercially reasonable for ExxonMobil to couch its offer in terms that preserve its future ability to negotiate tariff conditions with the pipeline owner, the choice to not define its commitment eliminates its value to the State.

b. Failure to Diligently Develop

My evaluation of the 23rd POD is informed by the unit's history, which is discussed in detail above. In the face of this history, all Appellants, except Mr. Brusenham, testified that they are pleased with the pace of development to date.[179] They also claim that by approving their past PODs, DNR has condoned their rates of exploration and development.[180] This argument is not supported by the record.

As documented in this Decision, the failure to adequately explore and delineate the Point Thomson resources – as promised in many PODs – and the failure to commit to production has been the cause of DNR's frustration with Appellants since 1983. These failures played a central role in DNR's (1) decision to contract leases out of the unit in 1985 and 1990, (2) threat to contract the unit in 1993-1995, (3) conditional approval of

177 [Tr. at 1021-1023]
178 [R. 31059-60]
179 [Tr. at 220, 265-6; R. 31045]
180 Appellants' Post-Hearing Brief at 11 [R. 31170]

many PODs, (4) refusal to approve the 12th POD, (5) rejection of the 15th and 16th PODs, (6) threat to default the unit in 1997, (7) refusal to approve the 1998 Expansion Agreement; and (8) reluctance to approve the 2001 Expansion Agreement. It was also the basis for Director Myers' default decision in 2005, as well as for Commissioner Menge's and Acting Commissioner Rutherford's termination decisions in 2006.

Moreover, DNR approved two Expansion Agreements and several PODs expecting that Appellants would drill wells that ultimately were never drilled. Appellants promised to drill a 1985 well, a 1990 well, a 2002-2003 season well, and a 2006 well. They induced DNR to approve Expansion Agreements and PODs with commitments to drill those wells. Yet, Appellants did not drill any of these wells.

These facts have influenced my evaluation of the 23rd POD because past performance indicates a pattern that I can reasonably determine will be repeated absent clear evidence that the pattern has changed. In light of this history, I find that the 23rd POD is not adequate to insure timely development as Section 10 of the PTUA requires.

The lack of drilling directly impacted Appellants' ability to timely produce this resource. Appellants asserted during the hearing that, because the unit has not been adequately explored, many unknowns remain and they cannot commit to more robust production of the Thomson Sands reservoir and cannot commit to produce the Thomson Oil Rim and Brookian reservoirs.[181] These statements, coupled with the unit history discussed above, establish that Appellants have not exercised reasonable diligence in exploring and developing the leases in this unit. Further, given that an unreasonable

[181] [Tr. at 113, 185, 248, 282, 706-710, 748-765, 858]

amount of time has passed without adequate exploration and development since Appellants first acquired leases in 1965, since the unit was formed in 1977, and since massive quantities of oil and gas were discovered in the early 1980s, it also serves as a basis for terminating the unit.

c. Unit Operating Agreement

Appellants claim that I can be assured they will abide by the commitments made in the 23rd POD because they have proposed amendments to their agreements subjecting decisions regarding unit operations to majority vote, thus removing a "one party veto." Specifically, they propose amending Article 14.2 of the UOA so that matters subject to vote under this section will be approved by simple majority vote, and amending Article 15 of the UOA to modify when ExxonMobil can be removed as unit operator.[182] The amendments are not effective until Conoco agrees. For this reason, BPXA, Chevron and ExxonMobil have signed an interim voting protocol in which an affirmative vote of any two of the three is binding.[183]

Appellants portrayed the amendments and the protocol as eliminating barriers to development. But these representations are not supported by the case presented by Appellants, by the amendments themselves, or by the terms of the applicable agreements. Under the UOA and the PTUA, the WIOs assign their right to explore and produce to the unit operator, ExxonMobil.[184] The amendments do not modify ExxonMobil's exclusive powers and responsibilities as unit operator under the UOA and PTUA to conduct unit

182 [R. 30846-60]
183 [HE 218A, R. 30308A]
184 [PTUA Sec. 4, R. 9493; UOA Art. 8, R. 9932]

exploration and development operations. Rather, the only effect of the amendment on the unit operating agreement is to change the percentage required to supervise and control the unit operator in an operation from 67 percent to simple majority.

This amendment might improve the chances of unit development if ExxonMobil was the only barrier to development. But BPXA and Chevron said they were satisfied with ExxonMobil's performance as unit operator and that they approved the PODs that had been submitted.[185] At the hearing, Appellants were asked what would constitute adequate grounds for removal of the unit operator if having DNR terminate the unit for failure to submit an adequate POD was not adequate grounds.[186] With the exception of Mr. Brusenham, all of the WIOs answered ambiguously.[187] Given this testimony, it does not make sense to conclude that the amendments will alter the pace of unit development.

Moreover, Appellants would have me ignore that the PTUA and UOA have at all times granted Appellants other tools to accelerate exploration and development, if they had so desired.[188] An individual lessee has always had the right to unilaterally force a well to be drilled so long as it was willing to bear the cost. Further, individual lessees have always had the power to drill a well on any lease in which they hold a majority interest so long as the unit operator declines to drill after ninety days notice and DNR approves the well.[189]

185 [Tr. at 220, 265]
186 [Tr. at 880, 1020]
187 [Tr. at 882, 1020]
188 [R. 9500 (PTUA Sec. 13), 9930, 9932 (UOA Art. 4, 8 and 9)]
189 PTUA Section 13 [R. 9500]

Not all voting matters in the past were governed by the 67 percent voting arrangement Appellants seek to amend here. Rather, the parties chargeable with the costs of a certain operation are permitted to vote in proportion to their cost obligation. Thus, the WIOs who are responsible for the majority of costs of an operation have always had the right to control and supervise the unit operator in the performance of that operation.[190] The proposed amendment does not change this cost voting arrangement.

Thus, despite having these tools at their disposal, there is nothing in the record that indicates Appellants attempted to use these provisions to force ExxonMobil to initiate exploration and development. This may be explained by the fact that they have always been satisfied with ExxonMobil's decisions regarding the pace of exploration and development. Or it may be explained by the fact that these provisions were insufficient to trump ExxonMobil's general powers as unit operator. Finally, it may be that other lessees lacked the will to challenge the decisions of the unit operator. For whatever reason, this history gives no indication that the proposed amendment will do anything to change the status quo.

Another point not addressed by Appellants but evident from a close reading of the record was that the document amending UOA Article 14.2 also creates a new UOA Article 15.8 addressing removal of the unit operator that appears to conflict with the unit agreement. Under Section 5 of the PTUA, ExxonMobil can be removed as unit operator for default or a failure to perform its duties.[191] The proposed UOA amendment sets a

[190] [UOA Sec. 14.1 and 14.2; R. 9937]
[191] [R. 9494]

much higher standard for removal of ExxonMobil which could only be removed for a substantial breach of a material condition.[192] At best, these amendments, apparently done hastily in an attempt to assuage DNR's concerns about how ineffectively the unit had been managed, have the potential to create legal issues among the WIOs.[193]

In summary, notwithstanding Appellants' representations to me, it does not appear that the proposed amendments to the UOA would materially change the way the unit will be operated. Moreover, the testimony of BPXA and Chevron contradicts the way they portrayed the probable effect of the amendments. If BPXA and Chevron are pleased with ExxonMobil's performance and the PODs it has submitted, there is no reason to believe that their ability to "supervise" ExxonMobil will make a significant difference in the approach taken thus far to PTU development. Further, BPXA, Chevron, and Conoco may have had tools at their disposal to "supervise" ExxonMobil earlier in this unit's history and simply chosen not to use them. There was no credible evidence offered during this proceeding that they will use this "new" tool of majority control to alter the status quo.

6. Conservation

The 23rd POD would promote a modest level of unitized development, which theoretically promotes conservation because of shared development goals among the WIOs. This effect has not been evident in the PTU to date. But, by terminating the unit and re-offering the leases, DNR could allow new WIOs to have the opportunity to

[192] [R. 30856]

[193] This conclusion is not altered by the amendment of the 2000 alignment agreements Appellants referenced on remand. Regardless of the implication of Appellants' view of the amendment, this document does not override or otherwise alter the UOA or PTUA.

actively work toward production.

7. Prevention of Waste

The concept of waste includes both physical and economic waste. Physical waste is loss of hydrocarbons resulting from the method of production. The AOGCC has the statutory responsibility to guard against physical waste. DNR has both responsibilities. With the 23rd POD, the Appellants provided a plan that commits to a small-scale pilot project. They also stated that "[w]e continue to believe that gas sales from PTU resources will generate the maximum benefit for the state."[194] Appellants' plan does not adequately address the potential waste of gas condensates and the potential waste of leaving the Thomson Sands and Brookian oil reserves in the ground.

Designing production facilities on a small scale initially and expanding them once the best method of producing a reservoir is known may effectively prevent economic waste.[195]

8. Protection of All Parties of Interest

a. Appellants' Interests

The 23rd POD protects Appellants' interests by allowing them to retain the unit without putting it into full production. Appellants assert that they will spend $1.3 billion over the next six years. While this is a considerable sum, it is a nominal investment from their perspective relative to the value of the resources in the unit area. In the recent Chukchi Sea lease sale, $2.7 billion was spent to acquire leases over an area for which

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194 [HE 5, R. 30000]
195 [Tr. at 703-20]

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there was considerably less geologic, geophysical and engineering knowledge and that is hundreds of miles away from production infrastructure.

b. State's Interests

The State's interests are not protected by this POD. The State's primary interest is in responsible production of the hydrocarbon resources in its lands. This plan fails to commit to investigate and develop all of the hydrocarbon resources: oil; gas; and gas condensates. After thirty years of unitization, a nominal commitment to gas condensate production six years hence is insufficient to fulfill Appellants' development obligations. The State's interests are better served by unit termination.

Appellants assure me that they will expand production after this POD is completed provided they are satisfied with what they learn about the reservoir between now and 2014. The unit history, however, reveals a clear pattern of DNR relying on what is assumed to be good faith commitments to complete PODs with promises to drill wells or perform other activities, only to abandon these commitments once a POD is approved. As described elsewhere in this Decision, I am not persuaded that this long-standing pattern of broken commitments will change. The risk of non-performance of both the 23rd POD itself, and the promises Appellants make in support of the 23rd POD, as assessed on this record, lead me to conclude that approving the 23rd POD will not protect the State's interests. The State's interests are better served by unit termination.

It is also not in the State's interest to approve the 23rd POD because (1) it appears that Appellants have not undertaken the necessary development studies and permit planning to ensure that they can, or will, complete the project as promised; (2) the term of the 23rd POD is too long; and (3) it includes no meaningful performance benchmarks.

i. Permitting Risks

During DNR's review of the proposed 22nd PODs, Appellants asserted that without completing necessary studies and permit planning, they could not commit to major development projects. ExxonMobil explained that it could not receive project approval without completing screening studies, Conceptual Engineering studies, and Front End Engineering Design ("FEED") studies.[196] Once a project progresses beyond the FEED stage it enters the final Detail Design phase and, according to ExxonMobil, it is then eligible to be considered for funding or sanctioning.[197]

ExxonMobil concluded that a reasonably prudent operator would not commit to a project without completing these stages of project review: "Systematic and comprehensive planning and analysis is essential to achieving a successful project. . . ."[198] ExxonMobil elaborated:

> Prudent project management and engineering requires that certain work products be in place before making a sanction decision and those products

[196] BPXA and ExxonMobil have previously cited the comprehensive screening process a project undergoes before obtaining company approval as a primary reason for why they could not commit to production through gas cycling in their 22nd POD. BP stated that the first project phase or stage is screening, which analyzes preliminary data to determine economic projects. [R. 692] After screening, the best projects are reviewed at the Conceptual Engineering stage. [R. 692] At this phase of project review, the preliminary design work is completed for each project that has been advanced. [R. 692] This stage yields more rigorous, detailed, and realistic cost estimates. Once the Conceptual Engineering phase is completed, proposed projects can move to the FEED stage, which entails experts selecting the optimal design for the identified project, adding greater design detail, identifying vendors, and obtaining quotes for major equipment components. [R. 692] The result of this work becomes the design basis for purchase orders issued for major production equipment and for environmental assessments and permitting. [R. 765] According to ExxonMobil, after FEED is completed the project can move to the last stage: Detailed Design. [R. 766]

[197] [R. 766]

[198] [R. 764] BPXA also relied on this argument in its briefing to Commissioner Menge. [R. 692, 870, 895] BPXA maintained "the systematic procedures most likely to result in a successful project do not provide for sanction until after FEED is completed." [R. 896] BPXA went on to explain that because a new gas cycling project had not completed FEED, it was unreasonable for Director Myers to insist in 2005 that a gas cycling project have approval within one year. [R. 896]

> must be produced in a logical sequence. The work plans and activities set forth in the Modified [22nd] POD for progressing gas sales development and for undertaking evaluation of alternative development scenarios reflect this sequential progression of a project. [R. 743]

BPXA has also emphasized the importance of planning to any successful project:

> A reasonable, prudent operator does not commit to development of a major project without first completing substantial study to define a project that is likely to succeed. Any development project at PTU will be what planners characterize as a 'mega-project'. . . Systematic and comprehensive planning is essential to increase the odds of a project succeeding.
>
> Mega-projects should not be schedule driven, <u>because schedule driven mega-projects almost always fail.</u> Costs increase, and quality decreases. Despite pressure to adhere to a schedule, the final product may be delayed because of the lack of adequate planning. Moreover, without sufficient planning, the project may not work as intended. (Emphasis added) [R. 905]

In the proposed 22nd POD, Exxon Mobil also explained that because of reservoir uncertainty, potential gas cycling projects were stuck in the Conceptual Engineering phase and could not progress beyond this stage without having reviewed results from the next well tests.[199] Without having completed these critical studies, Appellants concluded in November 2006 that they could not possibly commit to a gas cycling project.[200]

However, in the 23rd POD, Appellants are apparently willing to skip the necessary project review phases (i.e., Conceptual Engineering, FEED, and Detailed Design) and

[199] [R. 748] ExxonMobil maintained that it needs to begin a new Conceptual Engineering (CE) study for potential gas sales projects and that it would not begin this process until after a new well was drilled. [R. 748]

[200] [R. 743-48] BPXA argued: "It would be irresponsible and inconsistent with the RPO Standard to skip the planning stages and to sanction a major [development] project within the time period [i.e., five years] of the Modified POD." [R. 888] BPXA concluded: "By no stretch of the imagination could a reasonable, prudent operator of the PTU in 2005 commit to be in production in four years." [R. 896]

commit to a major production project costing approximately $1.3 billion.[201] This commitment to production through a gas cycling project is inconsistent with Appellants' previous statements that prudent oil field practices require the completion of Conceptual Engineering and FEED studies before project sanction. The current "firm commitments" also appear to conflict with Appellants' past history of walking away from gas cycling projects due to the latest cost studies or reservoir modeling studies.[202] Over the history of the PTU, ExxonMobil has made commitments to gas cycling prior to completing studies, only to tell the State that they could no longer fulfill their promise to produce hydrocarbons after reviewing the results of these studies.[203] The State cannot risk having another project promised by ExxonMobil cancelled because the completion of a FEED study in 2010 "shows" that production is no longer economic.

Representations during the remedy hearing regarding the permitting process also lead me to disapprove of Appellants' proposed remedy. In support of its proposed 22nd POD, ExxonMobil argued: "A development project at PTU will require a large number of

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[201] Under the 23rd POD, the Conceptual Engineering phase will be completed in December 2008. [R. 30011] This appears to conflict with Exxon's previous statement that it could not complete this development phase until it drills a new well and reviews the results from the well test. [R. 748] Under the 23rd POD, however, new wells and the FEED stage will not be completed until 2010. [R. 30011]

[202] For example, in BPXA's October 2006 brief to Commissioner Menge, it explained that initial indications showed that a gas cycling project was on the margin of being commercially viable after devoting "substantial resources to attempting to manage the risks and to design a reasonably prudent gas cycling project. [But] as the gas cycling project was advanced into the Front End Engineering Design (FEED), newly available data forced re-evaluation of the project. The newest, most reliable models . . . increased the likelihood that the reservoir is more disconnected than was previously believed. .... Around the same time . . . the estimated costs for constructing a gas cycling project has increased by approximately 30%. Between the decreasing estimates of production and the increasing estimates of costs, the per unit cost of development doubled." [R. 863-5] BPXA then concluded that the FEED study showed that the gas cycling project was not commercially viable and not a project that a reasonable, prudent operator would pursue. [R. 865, 897] However, during the remand hearing, Appellants said there was significant uncertainty regarding the reservoirs. It is unclear how they could make such definitive statements regarding the viability of liquids production in 2006, and then in 2007 say they really don't know how much oil or condensates exist in the unit. This testimony further undermines their credibility.

[203] [R. 631–3, 864-5]

permits from multiple levels of governmental authority. . . . To obtain necessary permits in a timely manner so development can proceed on schedule requires substantial advance planning."[204] ExxonMobil discussed how National Environmental Policy Act review requirements and Alaska Coastal Management Program consistency review process have to be completed before permits can be issued.[205] ExxonMobil explained that it could not plan for these permits because the ". . . environmental review process cannot begin until the project is adequately designed. . . ."[206] ExxonMobil concluded:

> Permitting for a development project can be a key risk because of the uncertainty in the schedule of project approvals and the conditions that may be placed on project permits. This risk can be managed and reduced by devoting time and to planning the permitting process. . . .
>
> Much of the planning for permitting depends on particular details of the project, so it is not possible to complete the permit planning until Conceptual Engineering is concluded and generally it is not practical to apply for permits until FEED is underway or completed. Sound project management requires that a permitting plan be in place before major expenditures on engineering. [R. 754-55]

I agree that obtaining the required permits from the federal and state agencies is likely to be a complex and time-consuming process in light of how little of the engineering and technical work necessary to develop this unit has been done to date. The 23rd POD requires the State to bear this considerable risk.

The 23rd POD project was agreed upon by Appellants several weeks before the hearing.[207] Under the 23rd POD, Conceptual Engineering will not be completed until December 2008, which is the earliest stage that Appellants suggest that they begin their

[204] [R. 754]
[205] [R. 753]
[206] [R. 753]
[207] [Tr. at 782]

permit planning.[208] Given how permitting for a development project can be a key risk, it makes little sense to approve a POD that, according to ExxonMobil's past representations, cannot adequately complete permit planning. Further, given ExxonMobil's narrow interpretation of its commitments made to the State, the State runs a considerable risk of seeing ExxonMobil fail to satisfy benchmarks because of "permitting delays"[209] that are largely within Appellants' control. Approval of this plan merely serves as an invitation for ExxonMobil to abandon this project under the guise of permitting delays or denials.

ii. Term of POD

The full term of the proposed 23rd POD extends from October 1, 2005 to December 31, 2014, a little more than nine years.[210] The six-year remaining term of the 23rd POD does not protect the State's interest. It is in the State's interest to require PODs to be submitted annually with identifiable benchmarks to be achieved each year. This nine-year term can be divided into two components, a three-year retroactive period and a six-year prospective period.

It is common during the early years after unitization to approve five- or six-year plans to accommodate facilities construction schedules. For units that have existed for more than ten years, PODs that are one or two years long are common.

A unit operator's obligation to submit a POD comes from Section 10 of the unit agreement. DNR monitors WIOs' progress toward meeting the commitments made in

208 [R. 754-5]
209 [R. 384-7, 12179-80]
210 [HE 5, R. 30004-5]

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the leases and unit agreement to develop the resources and bring them to market by reviewing PODs. Because the term of the leases and unit agreements are determined by continued progress toward that goal, PODs are an important tool in the management of the State's resources.

The purpose of submitting a retroactive POD is to create the illusion that the WIOs have operated continuously with DNR's approval. Mr. Haymes testified that ExxonMobil saw a retroactive term of this POD as appropriate because they continued to study the reservoir after the 22nd POD was rejected.[211] Retroactive approval of a POD is not appropriate. This unit operator has not operated with the continuous approval of DNR. There have been no approved unit activities since the 21st POD expired on September 30, 2005. It is nonsensical to approve a *plan* that covers a time period that has already expired.

The remaining six-year term is also inconsistent with the State's interests because it does not include meaningful benchmarks and is inconsistent with DNR's practice in managing units. In its post-hearing brief, the parties offered performance benchmarks throughout the six-year remaining term of the POD. The explanation offered at the hearing was that the long term was necessary because "if the POD was of shorter duration that creates a lot more uncertainty."[212] While a six-year term might create more certainty for the WIOs, it would create uncertainty for the State. A long term without benchmarks increases the risk of non-performance during the term and does not allow for

[211] [R. 93-4]
[212] [Tr. at 1049]

interim adjustments.

BPXA suggested that DNR should impose benchmarks in its order.[213] The parties were asked to file briefs detailing their perspective on DNR's authority. They argued that DNR could impose benchmarks only with their consent. Regardless of whether that position is correct as a matter of law, it suggests another issue that Appellants may litigate.

Specific, meaningful performance benchmarks within the 23rd POD might have resolved this issue. Appellants could have offered to voluntarily dissolve the unit and relinquish the leases if they failed to complete the promised activities in the 23rd POD. They could have made their commitment to put all of the unit's resources into production more credible by offering to contract the unit to the boundaries of the existing participating areas at the end of this POD, or to contract the unit now to the area included in this POD. They could have offered financial penalties to compensate the State for delayed production and lost lease sales revenue. Appellants argue that I have no authority to impose these penalties, that only they have the ability to offer them, yet they do not.[214]

c. Public Interest

I have a constitutional and statutory obligation to ensure that development plans are in the public interest. Based on the subsection .303 analysis above, I find that it is not necessary or advisable or in the public interest to accept the 23rd POD as a remedy in this

[213] [Tr. at 866-867]
[214] [Post-Hearing *Brief* at 15-22, R. 31175-82]

proceeding. Additionally, DNR has serious doubts, based on the unit's history and the credibility of witnesses testifying at the remand hearing, that the promises made in the POD will ever be kept. In Section I of this Decision, I detailed the numerous instances where Appellants failed to follow through on what appeared to be unequivocal commitments to develop and produce resources from the PTU. In light of this history, I made it very clear to Appellants that they needed to convince me that they could be trusted to follow through on the commitments set forth in the proposed 23rd POD. At the beginning of the hearing, I told Appellants that "I need to understand how, in light of the history of this unit, DNR can be assured that the commitments made in the 23rd POD will be met."[215] I also said that "I need to understand why you think it is reasonable for DNR to approve a plan of development that continues for six more years and does not appear to have any intervening enforcement benchmarks."[216] I told Appellants that "I need to understand your view on what will happen if any of the commitments in the 23rd Plan of Development are not timely performed."[217] Finally, I warned Appellants that it was absolutely critical to convince me that they would follow through on the 23rd POD:

> Now, let me be very clear; I've looked through the history of the unit and a clear pattern emerges. DNR's patience was exhausted when a decision was made to reject the 22nd Plan of Development. Your job is to convince me that the pattern has been changed .... [Tr. at 68]

Thus, at the outset of the hearing, I communicated to Appellants that I was concerned about whether DNR could trust a commitment by them to follow through on the 23rd

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[215] [Tr. at 67]

[216] [Tr. at 67]

[217] [Tr. at 67–68]

POD, and I highlighted the lack of enforcement mechanisms in the plan as a major area of concern.[218]

During this proceeding, I was very troubled by testimony that Appellants believed they had always followed through with commitments made in prior PODs and with commitments made in the course of convincing DNR to accept these prior PODs.[219] Even in the face of the evidence discussed above, the major WIOs apparently believe that they have lived up to their obligations to DNR.[220] This perception of compliance should have been destroyed with the rejection of the 22nd POD, if not earlier. Overall, the refusal or inability of the witnesses to acknowledge Appellants' past failures and the manner in which they betrayed DNR's trust weighed very heavily against them and significantly compromised their credibility. If Appellants do not recognize that they have failed to follow through on commitments in the past, I cannot trust them when they promise to follow through on commitments in the future. And if Appellants truly believe that they have always followed through on promises to DNR, whether in the form of approved PODs or otherwise, then they lack the ability to understand what a commitment is and I cannot trust them to responsibly develop Point Thomson's resources.

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[218] One of the measures DNR traditionally applies to evaluate the strength of any developers' intention is to ask for proof of the commitment of financial resources by the corporation. Because the 23rd POD was only recently offered by Appellants to DNR and describes work to be performed between now and 2014, none of the companies offered evidence that the project had been sanctioned by their boards of directors, or that Authorizations For Expenditures had been signed. They did offer, however, evidence that funding would be provided. [Tr. at 1005-6, 166-8, 263, R. 31122]

[219] [R. 31052-78]

[220] Mr. Brusenham was the only witness who testified credibly on this issue. He acknowledged frustration with the pace of development. [Tr. 308-9]

I found several important witnesses to be not credible. At the hearing, Craig Haymes testified three times on behalf of ExxonMobil.[221] He is the company's Alaska Production Manager.[222] He stated, many times, that ExxonMobil was committed to following through on the 23rd POD.[223] Mr. Haymes was an important witness for all of the Appellants, since ExxonMobil is the unit operator, but I did not find Mr. Haymes to be a credible witness. At times, his answers were contradicted by the record established in this proceeding. For example, Mr. Haymes stated that "[w]e've been very active in progressing Point Thomson since – throughout the entire period of Point Thomson ...."[224] The record severely undercuts this statement. Frequently, Mr. Haymes' answers were not straightforward.[225] For example, I asked the following question:

> Q: Do you think there's ever a time when the operator should not be given another chance to submit another plan of development? And if so, when?
> A: Commissioner Irwin, I think the way I'd look at that is the plans of development that have been submitted over the years and other time lines have been approved. The recent POD modified 22 POD that was rejected was based on – on a number of reasons. And so what we've done is looked at those reasons. We've done substantial work throughout this period when there's uncertainty and brought forward a plan of development that is substantially greater in terms of the production commitment relative to what we had in the POD 22. And we've done that to ensure we maximize the resource recovery of Point Thomson in a timely manner both for the State and the owners.
> Q: I guess I'd still re-ask though, is there ever a time when an operator should not be given another chance . . . . . [Tr. at 144-5]

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[221] [Tr. at 88, 680, 1011]

[222] [Tr. at 89]

[223] [See, for example: Tr. at 90-2, 156-7, 159, 162-3, 166, 169 and 690-692]

[224] [Tr. at 93]

[225] [Tr. at 146-8, 153-4, 193-4]

At times, Mr. Haymes responded to simple questions by offering an answer in the form of multiple, rhetorical questions that were largely non-responsive to the question asked.[226] Finally, his general demeanor was that of a witness primed to reiterate, rather robotically, Appellants' commitment to the 23rd POD.

The credibility of Mr. Haymes was also undercut by his testimony regarding assurances. Specifically, he suggested that the lack of "off-ramps" (i.e., circumstances where leases contracted out of the unit and/or penalty payments were due for non-performance) greatly enhanced the credibility of the proposed POD.[227] This position, particularly in light of my comments at the beginning of the hearing with respect to assurances, was not credible. Such "off-ramps" in the context of the 2001 Expansion Agreement provided compensation to the State for value lost when the unit operator

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[226] "Q: But this is – the fact is and it was confirmed at the hearing this last week, there has been no new well data since 1985, some of it's been reinterpreted recently, but nothing's changed with regard to the geology of this unit. What seems to have promoted this plan of development is the fact that the 22nd was rejected and the unit terminated. Is that at all a factor in the fact that in – affecting your decision to come forward with this 23rd plan?
A: Your Honor, the 23rd Plan of Development is based on a foundation of objective, technical work. Yes, it's based on the 14 wells that have penetrated the resource, the learnings from the 19 wells that have been drilled in the unit or in the vicinity of the unit. Yes, it's based on the integration of eight 3D seismic programs, it's based on the fluid samples we've got. There has[sic] been many different interpretations of that data over the years and the various model outputs you can get can be very different. As you saw we've run hundreds thousands of runs to come up with our current resource estimate. So that's been a factor. The other factors are that when you look back in time there was definitely a focus in the 2001 time frame on a large scale gas cycling project. And some of those risks were recognized, perhaps later than you would have liked, but they were recognized at a point in time and that caused everybody to agree that it wasn't prudent to pursue. And then at that time we were active fiscal negotiations for the gas contract. And so that shifted the focus to a gas development and Point Thomson is predominately gas. And then obviously the POD 22 was rejected by the DNR. We thought it was prudent with respect to the circumstances we're in and so that's led us to step back and think about this plan of development. And clearly you heard that the need or the timely need for liquids production so we're taking that into account. We've considered the need to delineate. We've used the last 18 months of technical work to determine what our plan of development is and come up with this plan based on a lot of input from the owners. So has it been a factor? Yes. Is it the only factor? No. Is this plan of development based on a foundation of technical work? Absolutely. Can we do it? Yes. Is it prudent in managing the risks? Absolutely it is. Does it follow good oil and gas field practices? Yes, it does. Does it set up Point Thomson for the future? Yes, it does. Does it set it up for expansion? Yes. Does it set it up given the uncertainties for us to go in many different ways, a larger cycling project, a blow down, a major gas sales or combinations?" [Tr. at 1035-7, See also Tr. at 1048, 165–6, 168–9]

[227] [Tr. at 166, 684; R. 31057-60]

failed to perform, and they also ensured that valuable leases would automatically revert to the State for re-letting and eventual development. In addition, Mr. Haymes focused solely on "off-ramps," which he characterized as a type of option; i.e., where the unit operator had the choice to complete a particular task or essentially opt for the penalty in lieu of performance. Those provisions of the Expansion Agreement were penalties, not options. His testimony persuaded me that penalties would be essential if I were to approve the 23rd POD, but as long as ExxonMobil regards penalties as "off ramps" any penalty would only be a payment to preserve ExxonMobil's option to further delay development. Overall, ExxonMobil's testimony with respect to "off-ramps" and assurances was unconvincing and therefore compromised their credibility.

As with Mr. Haymes, John Zager with Chevron also had difficulty answering simple questions in a straightforward manner:

> Q: Since your company has been involved with Point Thomson have you been satisfied with the progress and development of the project to date?
> A: Commissioner Irwin, yes, we've been involved with this project, you know, from the inception and have been consulted as each and every POD was submitted and approved by the Department of Natural Resources. So, you know, we kind of are where we are at this point in time and progress has been made and – and it's, I thin [SIC] now time to move forward with this next major plan of development.
> Q: That's not quite what I asked. Are you satisfied with the progress made to date since your company's been involved with Point Thomson . . .
> A: I guess in a nut shell the answer would be yes, sir.
> [Tr. at 219–220]

Mr. Zager did not wish to answer the question asked of him, which negatively impacted his credibility.

Despite the fact that I alerted Appellants to DNR's concern over the lack of enforcement mechanisms in the proposed POD, they could not reach a consensus at the hearing about whether imposition of enforcement mechanisms would be an appropriate way of addressing DNR's concern. Specifically, Mr. Brown of BPXA testified that it would be "open" to meaningful enforcement mechanisms:

> Q: Speaking for BP, would BP be open to additional forms of assurance if the Commissioner thought they were appropriate?
> A: Yes, BP would. BP is.
> ...
> Q: Speaking for BP, what additional types of commitments would BP be open to considering or using if the Commissioner thought it appropriate?
> A: Well, Commissioner, if you're looking for consequences . . . BP would be open to things from financial penalties, relinquishment and those sorts of things. [Tr. at 866–7, 874, 928-30]

Chevron, on the other hand, was not prepared to agree to assurances or performance mechanisms.[228] ExxonMobil essentially testified that such assurances were not necessary because the State "has sufficient, robust regulations to pursue unit termination and lease termination if we do not comply with the commitments we outline in this plan of development."[229] ExxonMobil stated that it would be "willing to talk with the State further about what other assurances they believe may be necessary or prudent."[230]

[228] [Tr. at 1008]
[229] [Tr. at 1043]
[230] [Tr. at 1043-4]

In conjunction with their post-hearing filings, Appellants (with the exception of Conoco[231]) were able to agree that termination for failure to meet certain milestones (albeit with caveats and conditions) would be agreeable to them, but only in the form of a judgment and only on their terms. However, as discussed below, the [Proposed] Agreed Final Judgment and Order does not adequately address my concerns. It also troubled me that, despite the obvious importance of the issue of trust and an acceptable working relationship among themselves, Appellants' testimony about penalties was not consistent during the hearing. And while the submission of a [Proposed] Agreed Final Judgment and Order after the hearing was a step in the right direction, Conoco refused to join the other Appellants in its submission.

Normally, I would not be concerned that Appellants had different perspectives with respect to a particular topic; indeed, such disagreement can often be a sign that they are comfortable taking positions that differ from one another, and that they are fully evaluating the issue at hand. But in this remedy proceeding, I emphasized that enforcement mechanisms were a critical issue bearing on whether I could trust Appellants to follow through on the commitments outlined in the proposed POD. When Appellants failed to agree on whether assurances were appropriate, that strongly signaled to me that Appellants' commitment varied in strength and conviction.

Finally, throughout the hearing, witnesses testified that development at Point Thomson would occur more quickly if DNR approved the 23rd POD instead of

[231] Conoco declined to join in the proposal because it did not believe the proposal was "relevant to any remedy that DNR may lawfully impose." [R. 31177] Instead, it offered to "enter into a settlement agreement of the type proposed by the other WIOs outside of the remand proceeding process." [*Id.*]

terminating the unit because it would take years for new lessees to essentially "get up to speed" on Point Thomson and be in a position to develop it. This argument assumes, of course, that Appellants would meet all of their commitments and follow through on the POD. As discussed in this section, I have serious doubts that they would do so. Critically, if Appellants did not complete the POD in a timely manner, the State is in a worse position than ever, having wasted any number of years on a gamble that Appellants would finally put Point Thomson into production. Given the history of this unit and the credibility of the witnesses presented at the hearing, I will not take such a gamble with the public's Point Thomson resources.

III. LEGAL ISSUES

A. Section 21

Judge Gleason directed me to consider the import of Section 21[232] of the PTUA in connection with this remand proceeding. Appellants contend that DNR cannot reject the

[232] Section 21 provides: "RATE OF PROSPECTING, DEVELOPMENT AND PRODUCTION. The Director is hereby vested with authority to alter or modify from time to time in his discretion the quantity and rate of production under this agreement when such quantity and rate is not fixed pursuant to state law or does not conform to any statewide voluntary conservation or allocation program which is established, recognized and generally adhered to by the majority of operators in such state, such authority being hereby limited to alternation or modification in the public interest, the purpose thereof and the public interest to be served thereby to be stated in the order of alteration or modification. Without regard to the foregoing, the Director is also hereby vested with authority to alter or modify from time to time at his discretion the rate of prospecting and development and the quantity and rate of production under this agreement when such alteration or modification is in the interest of attaining the conservation objectives stated in this agreement and is not in violation of any applicable state law.[R. 9305]

Powers in this section vested in the Director shall only be exercised after notice to Unit Operator and opportunity for hearing to be held not less than thirty (30) days from notice, and shall not be exercised in a manner that would (i) require any increase in the rate of prospecting, development or production in excess of that required under good and diligent oil and gas engineering and production practices; or (ii) alter or modify the rates of production from the rates provided in the approved plan of development and operations then in effect or, in any case, curtail rates of production to an unreasonable extent, considering unit productive capacity, transportation facilities available, and conservation objectives; or (iii) prevent this agreement from serving its purpose of adequately protecting all parties in interest hereunder, subject to applicable conservation laws and regulations. [R. 9448]

23rd POD unless it holds a Section 21 hearing and proves that a reasonably prudent operator would accelerate the rates of prospecting, development, or production. Appellants also argue that if DNR finds a POD unacceptable, it cannot terminate the unit.[233] Instead, Appellants argue that DNR must negotiate an acceptable POD with them or, if DNR seeks to alter the rate of prospecting and development, then DNR must comply with Section 21.[234]

Section 21 does not apply to my evaluation of Appellants' proposed remedy. Section 21 only applies where there is ongoing prospecting, development, or production operations. In this case, there are no ongoing operations. Section I above details the history of this unit. The most recent drilling activity by the unit operator was in 1982, twenty-six years ago.[235] The last seismic data was gathered almost a decade ago, in 1999.[236] Thus, Section 21 is not implicated because there is currently no prospecting, development or production. This construction is most consistent with the PTUA as a whole and also appears to be consistent with Conoco's argument before Judge Gleason that Section 21 does not apply where there are no ongoing unit operations.[237]

Moreover, Section 21 does not supersede the applicable statutes and regulations which authorize unitization only when it is in the public interest. It also does not trump Section 10 and the regulations, which give DNR the discretion to determine the adequacy of a proposed POD. Thus, Appellants' argument that if DNR rejects the 23rd POD,

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[233] [R. 30534-6]
[234] [R. 30524]
[235] [R. 37, 11272-3]
[236] [R. 179]
[237] *See* Conoco's Opening Brief at 47-50.

Section 21 shifts the responsibility to DNR to design an acceptable POD is inappropriate as a matter of public policy and inconsistent with DNR's authority.

The application of Section 21 to this proceeding would violate good public policy. The burden should not be shifted to DNR to define how the reservoir should be developed. State law and the PTUA assign the responsibility to the unit operator and give DNR an oversight role to protect the State's interests.[238]

Appellants' attempt to have this hearing conducted under Section 21 seems to be an effort to shift the consequences of their failure to DNR. By shifting the burden of proof to DNR under Section 21, Appellants seek to relieve themselves of the obligation created in Section 10 of the PTUA to submit an acceptable POD. They also wish to shift the focus to Section 21 to avoid the fact that this is a remedy proceeding.

B. Due Process

The Gleason Decision determined that due process dictated that Appellants were entitled to a clear written notice that DNR was considering the remedy of termination when it rejected the 22nd POD, and that Appellants should have had the opportunity to be heard with respect to the appropriate remedy when the modified 22nd POD was rejected. Judge Gleason remanded the matter to DNR for such notice and hearing on the issue of remedy. DNR provided that notice in my January 3, 2008 letter to Appellants. [239] Appellants were provided the opportunity to be heard on the remedy issue at the hearing which commenced on March 3, 2008.

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[238] AS 44.37.020, 38.05.020 and .180.
[239] [R. 30505-6]

PTU REC_31456

Exc. 000725

Appellants objected to the process afforded them at the remedy hearing. In their letter dated January 18, 2008, Appellants asserted that DNR should appoint an independent hearing officer for the remedy hearing, DNR staff should be required to submit briefing and evidence at the hearing, and DNR staff should be subject to cross-examination at the remedy hearing.[240] I responded to each of these objections in my letters to Appellants dated January 28, 2008[241] and February 14, 2008[242] and explained that Appellants provided no basis for DNR to depart from its standard administrative process, a process that has repeatedly been upheld by the Alaska Supreme Court.[243] Appellants' objections to my acting as decision-maker are not well taken given that it is my duty to manage the State's resources in the public interest. Appellants have made no credible showing of bias. Rather, Appellants object to my acting as decision-maker because DNR is a party to the PTUA. But Appellants ignore that the Alaska courts have repeatedly upheld DNR's authority to issue administrative decisions regarding State oil and gas leases.[244] The Alaska Supreme Court has specifically rejected the distinction that Appellants urge here, that DNR's duty to administer State oil and gas resources is separate from DNR's status as a party to the State's oil and gas leases.[245]

Appellants were afforded the process they were due in this remedy proceeding.

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[240] [R. 30507-12]
[241] [R. 30513-15]
[242] [R. 30521-22]
[243] See, e.g., *State Dept. of Natural Resources v. Arctic Slope Regional Corp.*, 834 P.2d 134, 143 (Alaska 1991).
[244] The Commissioner's Decision affirming the rejection of the revised 22nd POD was issued administratively and Judge Gleason did not rule that there was a due process violation in connection with the rejection of the revised 22nd POD.
[245] See *State Dept. of Natural Resources v. Arctic Slope Regional Corp.*, 834 P.2d 134, 143 (Alaska 1991); see also *University of Alaska v. National Aircraft Leasing, Ltd.*, 536 P.2d 121, 128-129 (Alaska 1975) (rejecting any distinction between an agency's "proprietary" and "governmental" activities); *ConocoPhillips v. State Dept. of Natural Resources*, 109 P.3d 914 (Alaska 2005) (DNR permitted to adjudicate royalty dispute).

Appellants were given specific notice that the remedy of termination was being considered for the failure to submit an acceptable 22nd POD. Appellants were afforded a full and fair opportunity to be heard on what remedy was appropriate in this matter. Additionally, Appellants were given specific notice before, during, and at the end of the hearing regarding the issues DNR deemed important in addressing the appropriate remedy here. They submitted testimony, exhibits and briefs for my consideration. Due process requires nothing more.

C. Material Breach

Appellants argued in the remedy proceeding that the failure to submit an acceptable 22nd POD and the failure to submit an acceptable revised 22nd POD cannot be considered a breach of the PTUA. Appellants further argued that DNR never asserted before Judge Gleason that Appellants had breached the PTUA. However, DNR made precisely this argument to Judge Gleason[246], asserting that the failure to submit an acceptable POD was a material breach of the PTUA because submission of an acceptable POD was a material condition of performance under the PTUA and applicable regulations.[247] There clearly was a material breach of the PTUA in this case when Appellants failed to submit an acceptable POD for the PTU. The question before me in this remedy proceeding was whether their proposed remedy, the 23rd POD, was an

[246] *See* Brief of Appellee in 3AN-06-13751 CI (consolidated) filed July 23, 2007 at 58.

[247] Appellants go as far as to argue that Judge Gleason found that failure to submit an acceptable POD was not a "default" here and thus Appellants are not in breach of contract. [R. 31161] Appellants misread Judge Gleason's decision. Judge Gleason found that Appellants' conduct here did not qualify as one of the types of default listed in 11 AAC 83.374(a). But subsection .374(a) does not list all of the incidences of default under the unit agreement. In other words, 374(a) only lists a limited universe of circumstances constituting "default" that, in turn, impose certain procedural obligations on DNR.

appropriate alternative to unit termination.

In addition to Appellants' failure to submit an acceptable POD, Director Myers' October 27, 2005 decision found that the history of non-development and delay served as a basis for terminating the unit.[248] Commissioner Menge's 2006 termination decision agreed with Director Myers and found that the failure to diligently explore, develop, and produce justified termination.[249] Commissioner Menge also found that an unreasonable amount of time had passed without production and this fact was also a basis for termination of the PTU.[250] Acting Commissioner Rutherford agreed and stated these reasons supported her decision to affirm.[251] These failures also constitute a material breach of the PTUA and support termination.

D. [Proposed] Agreed Final Judgment and Order

Appellants' [Proposed] Agreed Final Judgment and Order is unacceptable for several reasons. It requires me to cede statutorily assigned duties to the court and does not provide adequate assurance of performance.

The appropriate resolution of this administrative proceeding is for me to issue a decision on remedy for failure to submit an acceptable POD. Appellants' proposed

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[248] [R. 646, 649]

[249] [R. 5686] Commissioner Menge found: "The critical facts underlying this decision are that the unit is made up of leases beyond their primary term and in many cases decades beyond their primary term. The unit has been in existence for nearly 30 years. Massive PTU reserves were found in the early 1980s. The unit has never been put into production. A PTU production well has never been drilled. . . . The unitization scheme is intended to cause state leases to be developed efficiently. It is not intended to allow appellants to simply hold oil and gas leases indefinitely[.]" [R. 5686]

[250] [R. 5686]

[251] [R. 9290] Acting Commissioner Rutherford found: ". . . DNR is entitled to terminate a unit which has been known to contain massive hydrocarbon reserves for more than 30 years, but which has never been put into production . . . . Units are not formed for the purpose of simply holding properties until such time as Appellants think production will be profitable enough to commence. On these facts, when Appellants say they cannot put the unit into production, DNR can terminate the unit as a matter of law." [R. 9290]

judgment asks that I cede to the court the responsibility to decide whether Appellants have complied with the terms of the 23rd POD. The remedy also "withdraws" the prior administrative decisions in this matter. History cannot be erased. Those administrative decisions are valid determinations and comprise part of the history of the unit. The only reason for Appellants to ask that these decisions be withdrawn is a desire to escape the consequences of their past actions and failures to act. Withdrawing these decisions could harm the State in future disputes with Appellants by creating significant holes in the record.

It is inappropriate for the court to determine, in the first instance, whether POD milestones have been achieved and, second, whether such failure is excused by Section 25 of the PTUA. It is DNR's responsibility to manage State resources. DNR has expertise and experience in managing oil and gas resources and ceding jurisdiction to the court on this issue would be inappropriate. Any decision regarding the failure to meet a milestone will involve issues within DNR's unique expertise. DNR must therefore retain the authority to make the initial decision on these issues pursuant to standard administrative procedures.

Again, the unit history and Appellants' credibility eliminate the value of their proposal. Appellants' past commitments to stipulated penalties have not been honored. DNR and Appellants entered into an agreement whereby DNR approved an expansion of the PTU on the condition that Appellants perform certain items of work and put the unit into production.[252] The unambiguous terms of the 2001 Expansion Agreement provided that the failure to begin development drilling by June 15, 2006 would result in the automatic termination of all expansion leases beyond their primary terms. "Development drilling in the PTU must begin by June 15, 2006, or all of the expansion acreage will automatically contract out of the PTU effective that date[.]"[253] The Expansion Agreement further provided that the lessees "waive the extension provision of 11 AAC 83.140 and acknowledge that the notice and hearing provisions of 11 AAC 83.374 shall not be applicable to leases contracted out of the PTU Area beyond their primary term, since the [WIOs] will automatically surrender the contracted leases, with surrender and lease expiration effective the day the leases contract out of the PTU and no default will occur."[254] Appellants agreed to these terms.[255]

Despite this clear drill or pay penalty, Appellants tried to modify the Expansion Agreement in 2006 by proposing to drop all well requirements and to reduce and modify the acreage that would be relinquished as a result of the failure to meet the explicit drilling requirements.[256] The Commissioner denied the modification request and found Appellants in breach of the Expansion Agreement.[257] This meant that the entire expansion acreage (29,000 acres) contracted out of the PTU and Appellants owed $20 million to the State.[258]

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[252] [R. 1521-48]
[253] [R. 12762]
[254] [R. 12765]
[255] [R. 12767]
[256] [R. 665-81]
[257] [R. 5670-89]
[258] [R. 5688-89]

Remarkably, despite Appellants' explicit contractual obligation to drill or have the leases automatically contract from the unit, Appellants appealed the Commissioner's decision denying their request to modify the Expansion Agreement. There was no legal basis for such an appeal, as evidenced by the fact that Appellants eventually failed to brief this point on appeal, resulting in Judge Gleason's decision that claims concerning the Expansion Agreement were expressly abandoned and thus dismissed.

More importantly, Appellants also failed to abide by the terms of the Expansion Agreement by appealing Director Kevin Banks' decisions terminating the expansion leases despite their promise not to appeal the termination. Moreover, ExxonMobil filed an original action for injunctive relief to prevent, in part, DNR from terminating the expansion leases and also filed an application with the AOGCC to compulsorily unitize the expansion leases or acreage from the unit.

What I conclude from this history eliminates the value of Appellants' offer. Even when the parties have negotiated unequivocal penalties for failure to meet milestones, Appellants have ultimately refused to accept or abide by them without resorting to litigation. For this reason, DNR is exceedingly wary of relying on penalties or other types of assurances as a means of ensuring that Appellants will perform or adequately compensate the State for failure to do so.

IV. DECISION

Appellants proposed a new POD, the 23rd, as an alternative remedy to unit termination. They all supported the 23rd POD with testimony, affidavits, and exhibits. For the reasons explained in detail in this Decision, I do not approve the 23rd POD as an alternative remedy for unit termination upon rejection of the proposed 22nd POD. I find that important portions of the testimony and evidence offered in support of the 23rd POD was either unpersuasive or incredible and that approval of the 23rd POD would not protect the State or public interests.

The history of the unit and the evidence offered by Appellants have convinced me that approving the 23rd POD will not result in timely development of these valuable State lands. As I stated early in this decision, credibility is most persuasively established by actions, not words. This unit's history presents a pattern of commitments that were not honored. I identified this pattern as an issue when the hearing began. Rather than persuading me that the pattern had changed, the evidence offered in support of the 23rd POD suggested that the pattern would continue if I approved the 23rd POD. The WIOs stated that they were satisfied with the pace of unit development to date. They characterized their past payments of non-performance penalties as exercising options, rather than paying penalties. The 23rd POD did not include benchmarks or non-performance penalties to assure DNR that Appellants would complete it as promised, or to compensate the State for the potential loss of value if they failed to perform. On this record, Appellants' "firm commitment' is not enough.

The 23rd POD fails to meet several of the criteria of 11 AAC 83.303. It does not adequately develop all of the known hydrocarbon resources in the unit area. The delayed production schedule described could have a significant economic cost to the state. Its promise to commit gas from this unit during the first open season of a gas pipeline is of no value to the State because the attached condition is undefined. The amendments to the Unit Operating Agreement did not clearly enhance the other WIOs' ability to supervise ExxonMobil's actions as unit operator. Because each of the major WIOs testified that they were satisfied with ExxonMobil's performance as unit operator to date when the record shows that this operator has delayed, rather than facilitated, development, I do not believe that the amendments will ensure timely development. Further, the amendments made to the UOA may not be effective because they appear to conflict with provisions of the PTUA. The permitting risks associated with this project are considerable, mostly because so little work has been done to date. The proposed prospective term of the POD, six more years, does not protect the state's interests because it does not permit the state to adequately monitor this unit's progress. Approving a retroactive term of the POD would not serve the State's interests because approving Appellants' non-performance in the past may reduce DNR's ability to ensure future performance.

Most importantly, the public's interest would not be protected if I approve the 23rd POD because I do not believe, based on this record, that Appellants will perform as promised this time. Nothing I heard during the hearing or read in the subsequent filings convinced me that the long-established pattern of not honoring commitments would change. Allowing these Appellants another opportunity to delay development of this valuable state resource is too risky.

The [Proposed] Agreed Final Judgment and Order is not acceptable because it would require DNR to cede some of its authority to manage development of State lands to the court, and does not include any provisions to compensate the State for its losses if Appellants fail to perform.

The 23rd POD proposed by Appellants as the remedy for rejection of the 22nd POD does not meet the standards in 11 AAC 83.303 and does not serve the public interest. It is not adequate to insure timely development as required by Section 10 of the PTUA. The Point Thomson Unit is terminated.

Commissioner Tom Irwin, April 22, 2008

A person affected by this decision may request reconsideration, in accordance with 11 AAC 02. Any reconsideration request 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 Tom 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@alaska.gov. Failure of the commissioner to act on a request for reconsideration within 30 days after issuance of this decision is a denial of reconsideration and is a final administrative order and Decision for purposes of an appeal to Superior Court. The decision may then be appealed to Superior Court within a further 30 days in accordance with the rules of the court, and to the extent permitted by applicable law. An eligible person must first request reconsideration of this decision in accordance with 11 AAC 02 before appealing this decision to Superior Court.

CERTIFICATE OF SERVICE

I hereby certify that on the 22 day of April, 2008, I caused a true and correct copy of the foregoing document to be served on:

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