STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

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Senator Hollis French
716 W 4th Ave, Ste 470
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Dear Senator French,

During the Senate Judiciary Committee hearing on April 27, 2012, Mr. William Walker, Mr. Craig Richards, and Dr. Mark Myers raised questions and concerns about the Point Thomson Settlement Agreement ("Agreement"). The concerns raised by Mr. Walker and Mr. Richards echoed the claims asserted in Mr. Walker's April 17, 2012 letter to Department of Natural Resources Commissioner Dan Sullivan, which has been included in the record. The issues raised by Mr. Walker, Mr. Richards, and Dr. Myers are based on a misunderstanding of the Agreement and its background.

The following response explains the context for the Agreement, describes the terms of the Agreement in detail, explains why it is in the public interest, and addresses the issues raised by Dr. Myers and by Mr. Richards on behalf of Mr. Walker. My analysis is focused primarily on the policy concerns raised at the hearing. The Attorney General will address the legal issues raised by Mr. Walker and Mr. Richards in a separate response.

I thank you for this opportunity to provide a response on this important public issue. A table of headings is set forth below for ease of reference.

C. **The Agreement Contains a Firm Development Commitment in the Form of the IPS, and the Penalty of Losing the Unit *and* the Underlying Leases if the IPS is not Completed.**

1. Per the Agreement, the IPS is a Firm Commitment Offering Benefits to the State Far in Excess of the 2009 Conditional Interim Decision.

2. Even if a Major Gas Sale is Sanctioned after Abandonment of the IPS, Previously Contracted Acreage is Forever Lost to the WIOs.

3. If the WIOs Do Not Develop Beyond the IPS, They Will Lose Significant Acreage.

D. **The Agreement Addresses the Next Phase of Development after the IPS by Providing for Additional Development Alternatives that, if Completed, Allow the WIOs to Retain Additional Acreage.**

1. Construction Commitments and Final Investment Decisions Will be Part and Parcel of Sanctioning a Major Gas Sale.

2. Point Thomson Gas Would Be Used for a Major Gas Sale under the Agreement.

3. If the WIOs Abandon the IPS and a Major Gas Sale is Not Sanctioned, DNR May Terminate the Unit and all Point Thomson Leases.

E. **The Agreement Permits DNR to Closely Monitor the WIOs' Development Decisions and Activities and Impose Penalties for Failure to Abide by the Commitments in the Agreement.**

1. Under the Agreement, DNR Retains its POD Powers.

2. The Agreement is Consistent with DNR's Participating Area Regulations.

3. DNR Considered 11 AAC 83.303 Prior to Entering into the Agreement.

4. If a Development path that is Selected by the WIOs is Inconsistent with the Agreement or Law, DNR Has the Right to Oppose the Option.

I. STRATEGIC CONTEXT OF THE POINT THOMSON SETTLEMENT

A. Point Thomson History.

Point Thomson is located 60 miles east of Prudhoe Bay in a remote arctic area.[1] The Point Thomson leases were acquired beginning in 1965.[2] Oil was discovered in 1975, and the Point Thomson Unit ("the Unit") was formed in 1977.[3] Following formation of the Unit, the Point Thomson owners drilled additional wells and discovered large quantities of oil and gas.[4]

The Point Thomson reservoir is a high-pressure retrograde condensate and natural gas reservoir with abnormally-pressured formations.[5] It presents unique engineering challenges with respect to development and production.[6] Since discovery of the field, the Point Thomson owners have drilled 19 exploration / delineation wells in the Point Thomson area.[7]

These wells have demonstrated that Point Thomson is a world class resource.[8] It is the largest undeveloped field in Alaska with one reservoir, the Thomson Sands, holding approximately eight trillion cubic feet of conventional natural gas, which is about 25% of the known North Slope gas reserves, and hundreds of millions of barrels of gas condensate and oil. The field also holds an estimated hundreds of millions of barrels of oil in the Brookian formations, which are geographically separate from the Thomson Sands reservoir.

Under the terms of the Point Thomson Unit Agreement, the Unit was set to expire in 1983 because it was not placed into production. The Department of Natural Resources ("DNR"), however, agreed to remove the automatic termination provision to give the Working Interest Owners ("WIOs") more time to delineate the field's resources and then move into timely production.[9] An unintended consequence of this modification to the Unit Agreement was that the Unit continued for decades without production.[10] Despite its massive resource base, the State has not seen any hydrocarbon production from this important field.

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1 *See* March 29, 2012 Point Thomson Settlement Agreement, Section 1.1 ("Section").

2 *Id.*

3 *Id.*

4 *Id.*

5 *Id.*

6 *Id.*; *see also* http://www.arcticgas.gov/point-thomson-key-gas-field ("But as rich with potential as Point Thomson is, the undeveloped field is also rich with unanswered questions about how to technically produce the gas. . . . Point Thomson is a 'retrograde gas condensate reservoir,' a kind of field that's far more challenging and expensive to engineer into production.").

7 Section 1.1.

8 *See, e.g.*, http://dog.dnr.alaska.gov/Publications/Documents/AnnualReports/Section1_2009.pdf

9 *See* Commissioner Irwin's April 22, 2008 Point Thomson Unit Findings and Decision on Remand From Superior Court at 12.

10 *Id.*

For years, DNR tried to get the WIOs to submit a development plan that would place the Unit into commercial production.[11] All attempts to move the field into production were stymied – the primary reasons offered by the WIOs for refusing to place the Unit into production centered on high costs, engineering challenges, and the fact that no gas pipeline existed to transport the Unit's massive gas reserves.[12]

B. <u>DNR's Default and Termination Decisions and the Ongoing Litigation.</u>

DNR's frustration with the lack of development reached a breaking point in October 2005 when the Director of the Division of Oil and Gas of DNR ("Director") denied approval of the 22nd Plan of Development (a "POD") submitted by the WIOs because they refused to drill wells and put the Unit into production.[13] In this decision, Director Mark Myers placed the Unit into default and informed the WIOs that DNR would terminate the Unit if the WIOs refused to submit a development plan that would put the Unit into timely production.[14]

The WIOs appealed the Director's default decision to DNR Commissioner Menge.[15] This began the lengthy litigation between the State and the WIOs, which lasted for nearly seven years and had the potential to continue for a significant period of time.[16] Because the WIOs insisted on warehousing the Unit's massive reserves, Commissioner Menge affirmed Director Myers's default decision, rejected the WIOs' proposed POD, and terminated the Unit on November 27, 2006.[17] This decision was affirmed upon reconsideration by Acting Commissioner Marty Rutherford on December 27, 2006.[18]

The WIOs appealed the default and termination decisions to the Alaska Superior Court. Judge Gleason affirmed most aspects of DNR's decisions, but vacated the Unit termination decision. Judge Gleason ruled that the WIOs received insufficient notice and were therefore denied an opportunity to be heard on the appropriate remedy for their refusal to place the Unit into production after thirty years. Judge Gleason remanded the matter to DNR.[19]

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11 *Id.* at 9-29, 41-43.

12 *See id.; see also* Brief of Appellant State of Alaska, Department of Natural Resources at 18-20 (May 10, 2011, Supreme Court Case No. S-13730).

13 *See* Commissioner Irwin's April 22, 2008 Point Thomson Unit Findings and Decision on Remand From Superior Court at 27-29.

14 *Id.*

15 *Id.*

16 Section 1.2 – 1.5.

17 *See* Commissioner Irwin's April 22, 2008 Point Thomson Unit Findings and Decision on Remand From Superior Court at 29.

18 *See id.*

19 *See* Brief of Appellant State of Alaska, Department of Natural Resources at 21 (May 10, 2011, Supreme Court Case No. S-13730).

During the remand proceedings, the WIOs submitted a new POD, the 23rd POD. This POD committed to drilling wells and placing the Unit onto production with an initial program that would produce 10,000 barrels per day of gas condensates.[20]

On April 22, 2008, DNR Commissioner Irwin rejected this POD and issued a decision terminating the Unit. Commissioner Irwin rejected the 23rd POD for two main reasons: (i) after years of broken promises to develop the Unit, he did not trust the WIOs to follow through with this development plan; and (ii) even if they did put the Unit into production, the WIOs did not provide a path to full field development or consequences for the failure to move beyond the initial production phase.[21]

After terminating the Unit, Commissioner Irwin issued a three-page "Conditional Interim Decision" in January 2009 that allowed ExxonMobil to drill two wells on two state leases conditioned upon the WIOs' commitment to bring these leases into production.[22] ExxonMobil, the Unit Operator, drilled these two wells and has continued to work on permitting and engineering to move the Unit into production.[23] The Agreement builds on this progress and these work commitments.

Despite the 2009 Conditional Interim Decision, the broader litigation involving the Unit termination continued. The WIOs filed several appeals challenging Commissioner Irwin's 2008 Unit termination decision. On January 11, 2010, after extensive briefing, Judge Gleason reversed DNR's 2008 decision terminating the Unit. [24]

Her ruling was a significant setback for the State. She ruled that the failure to develop known reserves for thirty years and the WIOs' refusal to submit a POD committing to development did not constitute material breach of the Unit Agreement or a violation of state law.[25] The decision also reconstituted the Point Thomson Unit and upended DNR's oversight of Unit development by requiring DNR to conduct a "Section 21" hearing before it could default the Unit.[26] It was a ruling that potentially had far-reaching implications for DNR because it unraveled the "produce or lose" bargain that underlies State oil and gas leases, and it effectively shifted the obligation to develop State leases from lessees to DNR.[27] If this decision was upheld, it conceivably would allow the WIOs to simply sit on the massive Point Thomson resources with no requirement to commercially produce hydrocarbons until a gas pipeline was built.[28]

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20 *See* Commissioner Irwin's April 22, 2008 Point Thomson Unit Findings and Decision on Remand From Superior Court at 29-31.

21 *See id.* at 29-55.

22 January 27, 2009 Commissioner Irwin's Conditional Interim Decision.

23 Section 1.1, 4.1.1.1; http://www.pointthomsonprojecteis.com/.

24 Section 1.4.

25 Decision after Remand (Superior Court Case No. 3AN-06-13751 CI (Consolidated)) January 11, 2010.

26 *Id.* at 23.

27 State of Alaska Petition for Review (Supreme Court Case No. S-13730) at 7-8.

28 *See Id*

Given the significant negative ramifications, the State filed a petition for review of Judge Gleason's decision with the Alaska Supreme Court.[29] The Supreme Court decided to hear the appeal, thereby halting the ongoing Superior Court proceeding. The main issue before the Alaska Supreme Court centered on whether Judge Gleason properly interpreted the applicable law to require a Section 21 hearing.[30] The Court was not asked to address whether DNR properly terminated the Unit.

A ruling from the Alaska Supreme Court on the State's petition for review was still pending as of the Agreement. It is important to understand the procedural context of the case at that time. Any ruling by the Supreme Court – favorable to the State or not – would not have resolved the entire case, it would have merely remanded to the Superior Court to continue with the litigation. Any final decision from the Superior Court would invariably have been appealed back to the Supreme Court. Thus, the litigation surrounding unit termination still had many years before final resolution. Even assuming the State ultimately prevailed in the unit termination litigation, it would have required individual proceedings to terminate the underlying Point Thomson leases. The litigation, in other words, was still far from final resolution.

B. World Oil & Gas Markets: Extreme Price Variability, Declining TAPS Throughput and LNG Opportunities.

The past decade has seen extreme price volatility in global energy markets. Nominal oil prices have bounced from $22 a barrel to $135 to $40 back to nearly $130 and now hover around $100. Natural gas prices have also been volatile – prices in the Lower-48 were as high as $14 per MMBtu in 2008 but dropped below $2 in April 2012. Meanwhile, the price and demand for liquefied natural gas ("LNG") in the Pacific Rim currently remains robust and is increasing due to a number of global factors – although LNG prices are also volatile. With the extreme volatility in energy markets, this much is certain: nobody can say for sure what the future holds in terms of oil and gas prices and profitable hydrocarbon development scenarios.

Another certainty is that the State of Alaska faces an urgent situation that threatens our economic future – the steady decline in oil production through the Trans-Alaska Pipeline System (TAPS). Despite remaining a world-class hydrocarbon basin, Alaska North Slope (ANS) oil production continues to fall. In April 2011, ANS production averaged almost 635,000 barrels per day. One year later, April 2012 production dropped by nearly 50,000 barrels and now averaged 577,000 barrels per day. In the meantime, North Dakota oil production, which sells at approximately a $20 discount compared to Alaska oil, has surged and it has overtaken Alaska as the nation's number two oil producer.[31] Having Point Thomson – one of the State's largest oil and gas fields – remain undeveloped, with no infrastructure connecting it to TAPS, has not helped the State address the TAPS throughput decline challenge.

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29 As a general matter, parties cannot appeal a lower court's decision to the Alaska Supreme Court until the lower court has issued a final order. However, in limited circumstances, the Alaska Supreme Court will take an interlocutory petition for review of an ongoing superior court action if the lower court has issued an interim ruling that needs to be addressed before the lower court's proceedings can continue.

30 *See* State of Alaska Petition for Review at 4.

31 http://www.adn.com/2012/05/15/2465480/n-dakota-passes-alaska-to-become.html

Having Point Thomson remain undeveloped and under a cloud of prolonged litigation also presented an impediment to the State's ability to advance another critically important, long-sought goal: commercializing our massive North Slope gas resources for both in-state use and for export.

Now a window of opportunity has opened for significantly increasing Alaska LNG exports to the Pacific Rim.[32] Demand for natural gas in the Pacific Rim is strong, and there is significant interest in Alaska gas. For the first time, the State's three producers on the North Slope are aligned with a state-backed effort to move forward to commercialize Alaska North Slope (ANS) gas. Before signing the Agreement, BP and ConocoPhillips wanted to increase the probability of transporting Point Thomson gas into a large diameter gas pipeline. It was this desire that launched discussions, for the first time in years, between the three Producers and the State, related to commercializing North Slope gas. Thus, the Agreement catalyzed the alignment among the Producers.

And recently, several reputable studies have shown that Alaska is economically competitive with other LNG projects. For example, in *"Alaskan LNG Exports Competitiveness Study, AGPA, Final Report, July 27, 2011,"* Wood Mackenzie concluded that Alaska is more competitive than Lower 48 and Canadian gas supplies and is on par with Australian LNG projects.[33] Similarly, the Brookings Institution recently released findings from its year-long study on U.S. LNG exports, noting that a large-scale Alaska LNG project to Asia would be in a strong competitive position with respect to other global LNG projects.[34]

This window of opportunity for commercializing North Slope gas will not be open indefinitely. Fortunately, the Agreement puts the WIOs on a clock to develop the Point Thomson resources. But, the State of Alaska is also on a clock. We face fierce competition from many countries and companies vying to meet the growing demand in LNG. Norway, Canada, Australia, Qatar, Russia, and countries in East Africa, in addition to producers in the Lower 48, are all seeking to supply the increased demand for LNG in the Pacific Rim. Indeed, over the past two years, *nine* Australia LNG projects have reached the Final Investment Decision stage.

To capitalize on this opportunity and to make sure Alaska is not left on the sidelines, the Parnell Administration has diligently worked to advance the prospects of a large scale LNG project. We have worked with our AGIA licensee through the Alaska Pipeline Project to move forward on the necessary permitting and engineering work for an LNG project; we have driven the alignment among the three North Slope producers and TransCanada; we are engaged in far reaching discussions with high-ranking federal officials in Washington, D.C. to seek support of a large-scale LNG export project; and we have engaged private sector and government officials from Asia to educate them on the benefits and comparative advantages of Alaska natural gas.

Based on this outreach, we can say that the momentum is building and considerable interest exists in getting ANS gas to Alaskans and world markets.

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32 For over forty years Alaska has exported LNG from Cook Inlet to Asia. Alaska has never, however, exported North Slope gas.

33 http://www.arcticgas.gov/sites/default/files/documents/11-07-alaska-lng-competitiveness-study.pdf

34 http://www.brookings.edu/~/media/Files/rc/reports/2012/0502_lng_exports_ebinger/0502_lng_exports_ebinger.pdf

II. STRATEGIC BENEFITS OF THE POINT THOMSON AGREEMENT

This Agreement significantly advances critical interests for the State of Alaska and its citizens across a number of areas. This section highlights and discusses many of these important areas.

A. Overview: The Point Thomson Settlement Agreement Advances the State's Longstanding Interests Related to This Field.

Before entering into settlement negotiations, the State had four longstanding objectives: (i) secure a commitment to timely production of the Unit's resources[35]; (ii) set out a path to full field development[36]; (iii) leverage Point Thomson development to advance a large scale gas pipeline[37]; and (iv) impose swift consequences if the WIOs failed to follow through on development commitments.

The Agreement achieves all of these goals. First, it provides an unequivocal, binding commitment to drill wells that will delineate resources and place the Unit into production, which will in turn increase TAPS throughput and foster exploration and development in the highly prospective Eastern North Slope.[38] Second, the Agreement lays out a path to full field development. Third, the Agreement advances ANS gas commercialization efforts by:

- Installing infrastructure that can be utilized for gas commercialization;
- Imposing work commitments that will foster gas commercialization;
- Facilitating alignment between the three largest North Slope WIOs and the Alaska Pipeline Project parties;
- Incentivizing a Major Gas Sale "sanction" decision prior to May 2016.

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35 *See* Director Myers's October 27, 2005 Denial of the Proposed Plans for Development of the Point Thomson Unit. In this Decision, Director Myers placed the Unit into default because ExxonMobil refused to provide the State with a development plan. He told the WIOs that they could cure this default by submitting a POD containing "specific commitments to delineate the hydrocarbon accumulations underlying the PTU and develop the unitized substances." Decision at 22.

36 *See* Commissioner Irwin's April 22, 2008 Point Thomson Unit Findings and Decision on Remand From Superior Court. In this Decision, Commissioner Irwin rejected the WIOs' stated commitment to develop the field under a gas cycling pilot program, in part, because while the plan presented a reasonable first step for development, the plan failed to explain how ExxonMobil would continue to expand production as promised and what would happen if they did not expand production. Decision at 31-32. As detailed below, the Agreement addresses all of these issues.

37 Advancing a large scale gas pipeline has been a longstanding goal for the State. *See, e.g.,* the Stranded Gas Development Act (AS 43.82 *et seq.*) and by the Alaska Gasline Inducement Act (AS 43.90 *et seq.*).

38 Sections 1.6 - 1.7, 1.11, 4.1 (noting the benefits under the Agreement and explaining that the IPS work commitments are mandatory). Section 4.1 specifically provides: "The WIOs *shall* put the PTU 15 and PTU 16 wells on production utilizing the IPS by the end of the 2015-2016 winter season and in any event no later than May 1, 2016." (emphasis added).

Finally, the Agreement provides for Unit termination and the return of all Point Thomson leases if the Unit is not placed into production.[39] Similarly, if production only results in the development of some of the Unit's resources, acreage not placed into production will also terminate.[40]

In sum, the Agreement is structured around one key principle that the WIOs must earn their acreage: the more work, investment, and commitments they make, the more acreage they retain. In the 1980s, DNR agreed to revise the Unit Agreement in a manner that while unintentional, effectively took the WIOs off the clock and resulted in warehousing for decades. This Agreement puts the WIOs back on the clock.

B. Continuing with the Status Quo Entailed Inherent Risk for the State.

In evaluating any settlement, it is imperative to judge the settlement against realistic alternatives. The alternative to this settlement was the status quo of continued litigation. Continuing with the ongoing litigation entailed inherent risk to the State. While the State believed it had a strong case, there was no guarantee the State would have ultimately prevailed on every issue. Had the State lost, it might have been stuck with a legal precedent that could have potentially allowed the WIOs to sit on the field without having to move forward with production. And, even had the State ultimately prevailed on all issues in the litigation, it would have taken years to terminate the Unit and litigate the underlying leases to get them back under state control. This potential for additional delay also created risks for the State.

Despite this uncertainty, some have suggested that the State should not have settled the overall litigation, but instead allowed the WIOs to continue with the development plan authorized by Commissioner Irwin in 2009 while continuing to litigate the broader issue of the Unit termination. This view assumes that the WIOs would have proceeded with the development plan through completion. But that was certainly not guaranteed. Judge Gleason's decision re-instated the Point Thomson Unit after the 2009 Conditional Interim Decision, meaning the individual leases were no longer at immediate risk of termination for lack of production. With the Unit reinstated, the WIOs could have chosen to ignore Commissioner Irwin's 2009 decision, and they could have halted all development while the litigation was pending. Given the history of this Unit, such a risk was not insubstantial.

Further, the Agreement has spurred significant progress toward a large scale gas pipeline to move the North Slope gas resources. Indeed, the State agreed to the Agreement, in part, because the Producers committed to work together on a project to Commercialize North Slope gas. Gaining momentum on gas commercialization efforts is critically important given the window of opportunity that currently exists for such a project. These opportunities and benefits would likely not be available if the State had continued to litigate.

Given the fierce competition that the State faces to commercialize ANS gas and the limited opportunity to get ANS gas to the world markets, the progress to commercialize ANS gas could easily be jeopardized by continuing with uncertain litigation. Without this Agreement, there is a heightened risk that ANS gas commercialization efforts would stall – that companies would be less

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39 *See, e.g.*, Sections 1.8; 4.5.2.

40 Sections 1.8; 4.5.3; 4.5.7

likely to invest billions of dollars in a large scale gas pipeline project without greater certainty over the Point Thomson leases and the 25% of ANS gas reserves underlying them.

Finally, continued litigation would have frustrated advancing efforts to increase oil exploration and production from the Eastern North Slope of Alaska. Continuing with litigation would have delayed the activity and investments required by the Settlement, which in turn could have discouraged exploration and development because companies may be less likely to invest in this area without certainty related to Point Thomson development.

C. <u>The Agreement Achieves Significant Near-Term Benefits for the State.</u>

The WIOs must complete the Initial Production System (IPS), which entails drilling two wells (now completed), installing production facilities, and constructing a common carrier liquids pipeline capable of transporting 70,000 barrels of liquids condensate per day.[41] IPS production must begin by the 2015-2016 winter season.[42] The IPS is required to produce 200 million cubic feet a day of natural gas: approximately 10,000 barrels per day of condensate from the gas will be stripped from the gas and sent down TAPS, and the dry gas will be re-injected into the reservoir.[43] Further, the IPS commitments require an additional well to be drilled by 2016-2017 and permitting for two additional wells and another well pad.[44] The WIOs are also obligated to drill additional wells to keep the facilities fully loaded with gas at 200 million cubic feet per day.[45]

A primary function of the IPS Project is to test the viability of gas cycling from both a reservoir and operational perspective by generating reservoir quality and performance information.[46] This will generate critical information to determine the optimum full field development option and facility expansion.[47] The Agreement is structured around an initial cycling development plan that will provide essential data to inform how the field should ultimately be developed.[48]

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41 *See* Sections 1.6, 4.1.

42 Section 4.1.1.2. The original, agreed-upon start-up date of 2014-2015 was pushed back one year because the federal government failed to timely issue the Environmental Impact Statement.

43 Sections 1.6, 4.1.

44 Sections 4.1.2, 4.1.3.

45 Section 4.1.1.3.

46 It appears that there is misunderstanding or minimization of the complexities and uncertainties associated with Point Thomson development – including the scale of the project and challenges associated with the resources, economics, permitting processes, and facility constraints. Certain testimony offered at the Senate Judiciary Committee minimized the IPS and the challenges associated with developing an abnormally high pressured retrograde gas condensate reservoir like Point Thomson. There are very few, if any, retrograde condensate fields that have been cycled at over 10,000 PSI anywhere in the world. By industry standards, the IPS is a "mega-project" – to complete the IPS, the WIOs will have to spend *billions* of dollars. The IPS project requires the WIOs to drill wells, install production facilities, and to build pipelines and roads in a remote arctic environment. In the context of an abnormally high-pressure reservoir, this is an undertaking that requires world-class drilling, production, and execution skills.

47 Sections 1.6, 4.1.1.2.

48 Section 1.6

The contractually binding work commitments set out in the Agreement should finally bring the field into production *in the near future*. Indeed, the Agreement provides the quickest way to bring the Unit into production because it builds on Commissioner Irwin's 2009 decision authorizing Point Thomson development. Once they received DNR's 2009 authorization, the WIOs drilled two production wells. They have also completed most of the necessary engineering and permitting work. If DNR were now to require a different development approach, the WIOs would have to re-start the engineering and permitting process, which would add additional years before the State received the benefits of production from Point Thomson.

A key goal of the Agreement was to bring the Point Thomson field on line as soon as possible and avoid further delays. The requirements of Section 4.1, requiring the WIOs to bring wells into production utilizing the IPS by the end of the 2015-2016 winter season, meet this goal. The IPS gas cycling project will result in approximately 10,000 barrel per day (bpd) production of liquid condensate into TAPS, thus production will create employment opportunities for Alaskans and it will increase TAPS throughput and revenue for state and local governments.

Additionally, to get the field into production, the WIOs will have to invest billions of dollars, which will provide hundreds of jobs for Alaskans.[49] Alaskans can expect more employment in the future because the Agreement also contains a strong Alaska-hire provision.[50]

For decades, much of the highly prospective area between Prudhoe Bay and the Arctic National Wildlife Refuge (ANWR) – the Eastern North Slope – has been dormant, in large part because of its remoteness and the lack of infrastructure. The infrastructure installed under the Agreement, e.g., a 70,000 barrel per day common carrier liquids pipeline, roads, airstrip, and gravel pits, will help open the Eastern North Slope to additional development for other companies both large and small by creating economies of scale that will likely make marginal development more economic.[51] This is an important added benefit for the State.

The Agreement incentivizes full field development by allowing the WIOs to retain acreage that they place into production.[52] It also incentivizes additional development because the WIOs will presumably want to get the best return on their investment in billions of dollars of infrastructure by moving beyond the initial 10,000 barrel per day production.

Despite these advantages, some have argued that even with the Agreement, the WIOs have no intention of following through with its terms and commitments to production – but that they will use the Agreement to further delay development. We do not agree, but even if this is the case, the State is now in a much stronger position legally because the Agreement provides definitive remedies for forfeiture of acreage for the failure to develop within the agreed-upon timelines. The Agreement therefore strengthens the State's litigation position because it provides clear deadlines that the WIOs must meet to move development forward or lose acreage. The Agreement also puts the State on firmer footing to get acreage back if the WIOs delay development because as detailed below, it removes many of the arguments that the WIOs have used in the past to delay development.

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49 Section 1.9.

50 Sections 1.9-1.11, 4.13.

51 Sections 1.10-1.11.

52 Sections 4.3 - 4.4, 4.5.1

Finally, in a significant concession by the WIOS, the Agreement vacated Judge Gleason's decisions, thus permanently eliminating any argument that these decisions restricted DNR's management authority for Point Thomson, or any other unit in the state.[53]

D. **If the WIOs Breach Their Near-Term IPS Commitments, Then the State is Well-Protected Under the Agreement.**

As noted above, the Agreement contains both incentives for the WIOs to undertake work and production commitments, as well as significant consequences if they do not.

The WIOs appear to be intent on meeting their IPS commitments under the Agreement. Their Chief Executive Officers have announced to Alaska and to the world that they are moving forward with the IPS.[54] They have also spent considerable sums drilling wells and securing the necessary permits for this development plan. Further, the WIOs have contracted with over 150 Alaskan companies to fulfill their work commitments.[55]

But even if the WIOs fail to follow through on their commitments, the State is well-protected. In particular, if the WIOs breach the Agreement and abandon the IPS, they will lose significant acreage as early as 2015 under Section 4.2.2.[56] The Unit will automatically terminate by 2019, and unless the WIOs Sanction a Major Gas Sale or submit an acceptable "alternative" Plan of Development (POD) that places the remaining acreage into production they will subsequently lose all remaining Point Thomson leases.[57] DNR's decision to reject this "alternative" POD is at DNR's "sole discretion."[58] This decision cannot be appealed to court, and the WIOs cannot argue that Section 21 of the Unit Agreement applies to the agency's rejection.[59]

After the Unit is terminated, the Agreement takes the extra step of ensuring the underlying leases return to the State in a timely manner. Even leases containing wells capable of producing in paying quantities are subject to swift termination. The WIOs with leases containing such wells (currently there are only two PTU 15 and 16) may only try and avoid lease termination by submitting a Plan of Operations to the Director that commits to placing the capable well on

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53 Section 4.10.

54 *See, e.g.,* http://dnr.alaska.gov/commis/priorities/point_thomson_files/ceo_letter.pdf

55 Section 1.9.

56 Under this provision the amount of acreage returned to the State depends on whether: (1) the WIOs have drilled the West Pad well; and (2) how much money they have spent on Point Thomson development between year end 2007 and the abandonment date. *See* Section 4.2.2. If their total spending on Point Thomson development from 2007 to 2015 does not exceed $2 billion, they will lose the vast majority of the Point Thomson leases automatically in 2015.

57 Sections 4.1.6, 4.6.

58 Section 4.5.2.2.

59 Section 4.5.2.2 provides, in part: "Submittal and approval of the alternative POD shall be subject to the terms of the PTUA including applicable State law. Nonetheless, DNR shall have sole discretion to accept or reject an alternative POD, and a final Commissioner decision on the alternative POD is Without Appeal. For purposes of this paragraph the WIOs agree not to assert that Section 21 of the PTUA applies in any respect to review of or a decision on the proposed alternative POD."

producing status within two years.[60] Moreover, DNR retains the sole discretion to accept the Plan: "Approval or rejection of the Plan of Operation *shall be within the sole discretion of the DNR*. . . . The Commissioner's decision on the Plan of Operation shall be Without Appeal."[61] If the WIOs fail to submit a Plan within sixty days following Unit termination, or the Commissioner denies approval of the Plan, "the leases shall terminate with acreage returning to the State Without Appeal."[62]

Accordingly, pursuant to Section 4.5.2, if there is no IPS and a Major Gas Sale (MGS) is not sanctioned, then the Unit automatically terminates and DNR has the sole discretion to get *all* Point Thomson acreage automatically returned to the State.[63] The WIOs can no longer argue, for example, that Section 21 applies if they refuse to install the IPS or if they refuse to develop the field beyond the IPS.[64] They are now foreclosed from filing a compulsory unitization request with the AOGCC under AS 31.05.110.[65] And they cannot argue that they should retain leases because they are engaged in drilling operations or because the leases contain wells capable of producing in paying

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60 Section 4.5.2.3. Under Alaska law, a lessee may retain any non-producing lease after the primary term if that lease contains a well capable of producing in paying quantities. AS 38.05.180(m).

61 Throughout the Agreement, DNR has insisted that the failure to perform certain activities would result in automatic consequences that are "Without Appeal" – *i.e.,* that cannot be appealed to court. This is a strong provision that protects the State from potential future drawn-out litigation. "Without Appeal" is defined in Section 2.34 to mean:

> the WIOs have waived any rights under the PTUA, individual lease terms, Alaska law and/or the laws of the United States of America, to file an application, petition, administrative appeal, or any cause of action before any administrative tribunal or state or federal court of law, and that the WIOs shall not file any such application, petition, administrative appeal, or cause of action. With regard to acreage that is released to the State Without Appeal under this Agreement, upon the occurrence of the specified event resulting in the release of acreage, that release will occur immediately and automatically.

Section 4.5.2.3 (emphasis added). The WIOs, however, can contest whether the specified event has occurred that triggers the automatic termination – e.g., a WIO can contest whether it did in fact drill a well or whether *force majeure* has prevented them from performing. Section 5.1.4.

62 Section 4.5.2.3. "If the Director or the Commissioner approve the Plan of Operation and the lessees fail to place the well on producing status within two years, the lease shall terminate with acreage returning to the State Without Appeal." *Id.*

63 Section 4.5.2.1 provides: "If IPS Project Start-up has not occurred and a Major Gas Sale has not been Sanctioned by year-end 2019, the following shall occur: (1) subject to Paragraph 4.5.2.2, the Point Thomson Unit and the PTUA shall terminate Without Appeal; (2) except for leases subject to Paragraph 4.5.2.3, each WIO will immediately surrender its leases and all such acreage shall be automatically released Without Appeal to the State; (3) each WIO agrees that it will not apply to form a compulsory unit with the Alaska Oil and Gas Conservation Commission with respect to any lease formerly within the Point Thomson Unit; and (4) this Agreement shall terminate."

64 Sections 2.3.4, 4.5.2.2.

65 *See* Sections 2.3.4, 4.5.2.2, 4.5.2.3.

quantities.[66] The only justification that remains to forestall returning all acreage to the state in 2019 is if the WIOs show that a *force majeure* event prevented timely performance – which is a right that is secured to them under state law.

In sum, the Agreement strips the WIOs of their previously used arguments for refusing to put the Unit into production. The WIOs can no longer argue that Section 21 applies if they refuse to install the IPS or if they refuse to develop the field beyond the IPS.[67] Nor can they argue that they do not need to put the IPS onto production because a reasonably prudent operator would not cycle this field because doing so would be "uneconomic."[68] And the WIOs cannot argue that they get to indefinitely retain all leases with wells capable of producing in paying quantities.[69] Accordingly, the WIOs have relinquished most of the arguments that have been used in the past to prevent the State from terminating the Unit and getting acreage back. If they breach their IPS commitments or Abandon the IPS project, the State will vigorously enforce these provisions of the Agreement, which will limit the WIOs' ability to engage in long, drawn out litigation.

E. <u>The Agreement Provides Long-Term Benefits and the Ability to Optimize Full Field Development.</u>

One reason why Commissioner Irwin rejected POD 23 was because the WIOs failed to address what would happen *after* the IPS was placed on-line.[70] Would the WIOs timely move forward with a full field development plan, or would they force DNR to litigate with them to get more development? Importantly, the Agreement answers the "what next" question because it sets out three full field development alternatives and imposes significant consequences if the WIOs fail to develop beyond the IPS.

1. <u>DNR Retains the Authority to Review Development Plans, and if the WIOs Do Not Commit to or Sanction at Least One Expanded Development Alternative, Significant Acreage Will Contract Out of the Unit.</u>

The Agreement mandates the IPS be put into production. Once the IPS is on-line, the WIOs are presented with the following specifically defined and delineated development paths for the Thomson Sands reservoir which the WIOs must pursue by year-end 2019 or they will lose significant Point Thomson acreage.[71]

- Sanction a Major Gas Sale and begin the process of developing the massive Point Thomson gas reserves to ship down a gas pipeline.[72]

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66 *Id.*

67 Section 2.3.4.

68 *See, e.g.,* Section 4.2.1 ("The economics or costs of the IPS Project cannot be used as a rationale or justification for not completing the IPS Project and do not constitute a factor outside the WIOs' control under Paragraph 4.2.3.").

69 Section 4.5.2.3.

70 *See* Commissioner Irwin's April 22, 2008 Point Thomson Unit Findings and Decision on Remand From Superior Court at 31.

71 *See, e.g.,* Section 4.4.2.

72 *See, e.g.,* Section 4.4.2.

71 *See, e.g.,* Section 4.4.2

- Expand the IPS to cycle more gas and increase condensate production into TAPS; this alternative will result in additional liquids condensate production but leaves the dry gas in the reservoir.[73]

- Produce the Point Thomson gas and condensate, and then transport and inject the dry gas into Prudhoe Bay and send the liquid condensate down TAPS; this alternative will materially increase oil production at Prudhoe Bay, allow for Point Thomson gas to be available for in-state use, and increase condensate production at Point Thomson.[74]

DNR retains the discretion to review these development plans and can reject them if they are inconsistent with the Agreement.[75]

In addition to these post-IPS development alternatives for the Thomson Sands reservoir, the WIOs must develop the Brookian oil accumulations. This is an important component of the Agreement given the estimates of oil in the Brookian accumulations. The WIOs must submit an acceptable development plan that moves the Brookian accumulations into timely production.[76] If they do not submit an acceptable development plan by 2018, they will lose the Brookian acreage.[77] DNR has complete discretion to accept or reject the Brookian POD and its decision to reject the POD will result in the loss of the Brookian acreage, and this decision cannot be appealed to court.[78]

All three development paths can be pursued individually or simultaneously. They will each require billions of dollars of additional investment to complete, thereby providing significant employment opportunities for Alaskans, increasing revenue for the State and local governments, and two of the three will enable Alaskans to finally access large volumes of North Slope gas for in-state use. Each of these alternatives also provide that the WIOs can only fully secure additional Point Thomson acreage once expanded production of hydrocarbons begins.[79]

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72 *See, e.g.,* Section 4.4.2.

73 *See, e.g.,* Sections 4.4.2, 4.5.4, 4.5.5.

74 *See, e.g.,* Section 4.5.5.

75 *See* Section 4.6 (providing that future PODs must be submitted for DNR's approval and must be consistent with Section 10 of the Point Thomson Unit Agreement and the Settlement).

76 Section 4.7.

77 *Id.*

78 Section 4.7 provides: "If the WIOs submit a POD for the Brookian by year-end 2018 that is approved by DNR, the acreage listed in Area F on Exhibit C shall remain in the Point Thomson Unit after any Unit contraction at year-end 2019 and shall be maintained through approved PODs or formation of expanded or new PA(s) in accordance with the PTUA including applicable State law. If the WIOs do not submit a Brookian POD by year-end 2018 or if DNR does not approve the Brookian POD, the acreage listed in Area F on Exhibit C shall be released to the State Without Appeal."

79 Section 4.4.2 (noting that the initial participating area will expand once the WIOs begin expanded production for a Major Gas Sale, IPS Gas Cycling Expansion Project, or the Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project).

2. Given the Importance of a Large Scale Gasline to the State's Interests, the Agreement Focuses on a Major Gas Sale.

Advancing a Major Gas Sale has been a longstanding goal of the State and is therefore a primary goal of the Agreement.[80] The Agreement moves the State closer to a Major Gas Sale in a number of ways.

First, a Major Gas Sale unlocks the potential and resources of the Point Thomson field, which contains approximately 25% of ANS proven gas reserves.

Second, the Agreement provides that in addition to the IPS work, the parties undertake work together to commercialize ANS gas in conjunction with the IPS.[81] The letter to Governor Parnell from the CEOs of BP, ConocoPhillips, and ExxonMobil announced this forward alignment and made public the work that had already begun.[82] The producer alignment is important for a Major Gas Sale – it is also unprecedented when considering their alignment with TransCanada. The Point Thomson Agreement drove the alignment to work together on a single, large-scale, in-state LNG project.

Third, and more specifically, the Agreement incentivizes progress on a Major Gas Sale project. It provides two windows for the producers to Sanction a Major Gas Sale commercial project: (1) from now until 2016, which if chosen, will enable the WIOs to temporarily secure additional Point Thomson acreage; and (2) if a Sanction decision is not made by 2016, then the WIOs will have to do engineering and permitting work on the other full field development alternatives laid out in the Agreement.[83]

And finally, the IPS and full field development alternatives will result in infrastructure and permits required for a Major Gas Sale.[84]

3. The Agreement Provides for Other Full Field Development Alternatives Aimed at Enabling the Optimization of State Resources.

One of the strengths of this Agreement is it provides the State and the WIOs flexibility regarding full field development. The past decade has seen considerable volatility in the global and domestic energy markets. Because nobody can predict the future, it is difficult to know the optimal development path for Point Thomson at present. Although the Agreement places an emphasis on a large scale gas commercialization pipeline project, there is significant value in retaining other paths for how the Point Thomson field should be developed in addition to a Major Gas Sale, which is why the Agreement also has full field cycling as an alternative.

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80 Section 1.11 ("A Major Gas Sale off the North Slope of Alaska is a primary goal of the Parties.").

81 Section 1.7 states: "In parallel with the work on the IPS, Parties and/or their affiliates to this Agreement will, upon execution of this Agreement, undertake work for commercialization of North Slope gas. This work will build on ongoing gas commercialization efforts."

82 http://dnr.alaska.gov/commis/priorities/point_thomson_files/ceo_letter.pdf

83 Section 4.1.6.

84 Section 1.6 – 1.7 (noting that the infrastructure will serve as a "pre-investment" for a Major Gas Sale)

Nevertheless, it has been suggested that full field cycling should be the *only* full field development alternative authorized by the State. We disagree.

First, before committing to full field cycling, the WIOs, and the State, need to better understand, among other things: (i) the operational capability to cycle gas at 10,000 psi; (ii) the efficiency of high pressure separation of condensate from the gas; (iii) the connectivity of the reservoir; (iv) the condensate yield (how much condensate drops out of the gas); and (v) the economic viability of long term gas cycling. There will be much more information on these important aspects once the IPS is online and producing condensates and reinjecting dry gas back into the reservoir.

Second, Point Thomson gas may be needed for a large-scale pipeline. The State therefore does not want to condemn the prospects of a large scale gas pipeline by insisting that Point Thomson gas cannot be made available for North Slope gas commercialization until Point Thomson is fully cycled, which could take 20 to 30 years. Indeed, insisting only on full field cycling could significantly restrict the State's flexibility on advancing a large-scale gas pipeline because full field cycling would deprive the State of the ability to use Point Thomson gas for such a pipeline.

Third, to help advance a large scale gas pipeline, the Agreement encourages the WIOs to sanction a Major Gas Sale by allowing the WIOs to retain the Unit (with the exception of the Brookian, which is subject to a separate process) if a Major Gas Sale goes forward and Point Thomson gas is transported down the gas pipeline.[85]

All three full field development alternatives as set forth and defined in the Agreement are in the public interest because they will provide significant benefits to the State, including increased oil production, billions of dollars in investment, additional revenue to State and local governments, and employment for Alaskans.

Overall, the flexibility related to full field development provided by the Agreement is one of its important strengths. Nobody knows what the future holds. It is in the State's interest to retain all alternatives that would optimize the overall benefit to the State for the development of the Point Thomson resources.

4. <u>Mr. Walker's and Mr. Richard's Views on the Uses of the Point Thomson Reservoir Illustrate Why Full Field Development Alternatives are in the State's Interest.</u>

Given the uncertainty of the future, today's views on the best way to fully-develop Point Thomson may not be tomorrow's. Mr. Walker's and Mr. Richard's changing views on the best uses of the Point Thomson Reservoir illustrate the reasonableness of providing full field development alternatives for the Point Thomson field to promote the State's interests. Mr. Walker asserted in his testimony before the Senate Judiciary Committee on April 27, 2012, and his recent letter to the DNR Commissioner Sullivan, that the only responsible way to develop Point Thomson is through full field cycling of liquids. This position is at odds with the positions he argued for in the written filings and oral testimony he submitted earlier during the pendency of the Point Thomson litigation.[86] There he urged DNR to require a blow down sort of development on the basis that

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[85] *See* Sections 4.4.2.

[86] The Point Thomson record, which serves as the basis for this Agreement, contains over 35,000 pages of documents. Between the 2005 default decision and the 2009 lease termination proceedings held before Commissioner Irwin, DNR held three public hearings related to the issues

Point Thomson provides the "best source of gas" for an LNG project and utilizing Point Thomson gas for a gas pipeline will provide significant benefits for the state. He advocated that DNR needed to get the WIOs to commit their Point Thomson gas reserves into a gas pipeline or, alternatively, terminate the Unit so that it could get another company to develop Point Thomson's gas reserves and put this gas into a gas pipeline.[87]

Similarly, Mr. Richards testified to the Senate Judiciary Committee that the State should only allow for full field cycling of the Point Thomson field. But, in a 2008 brief to DNR, Mr. Richards argued to Commissioner Irwin that he should *reject* the WIOs' plans for field cycling because "Point Thomson is predominately a gas field."[88] A main focus of his brief was to encourage DNR to *forego* gas cycling development, which would keep the gas in the ground at Point Thomson, and terminate the unit so another party could come in and develop the gas reserves for a large scale gas pipeline.[89]

In sum, Mr. Walker's previous statements are diametrically opposed to his current position, articulated before the Senate Judiciary Committee on April 27, 2012. Indeed, previous statements that it is DNR's constitutional duty to develop Point Thomson's gas reserves as soon as possible

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covered in the Agreement. Mr. Walker participated in two of these hearings and submitted hundreds of pages of documents that were considered by DNR before settling this dispute.

87 For example, in 2005 Mr. Walker stated in a court filing that Point Thomson provides the "best source of gas" for an LNG project. [Ex. A at 6] He told DNR that utilizing Point Thomson gas for a gas pipeline will provide significant benefits for the state. [Ex. A at 8-9] Mr. Walker, citing a filing that he submitted to DNR, explained:

- "Natural gas from the PTU is necessary to make a natural gas line project from the North Slope possible. PTU proven gas reserves are sufficient to supply a large diameter gas pipeline at startup."
- "The Authority requires an assured supply of natural gas, such as that found in the PTU, to obtain financing for a gasline project"
- "The Leaseholders are attempting to mothball valuable gas reserves that belong to the State and its citizens. These resources are now more valuable than ever, as a result of increases in the price of natural gas in the past few years. Clearly, it is in the State's best interest, and the best interest of its citizens, to develop these resources sooner rather than later."
- "DNR has a constitutional duty to the State and its citizens to ensure that the Point Thomson gas reserves are developed in a timely manner, and not mothballed as the Leaseholders seek to do."
- "It is in the interest of every citizen that a natural gas Project be built because such a Project will provide needed revenue for many government programs, both at the State and local levels. It is also in the public's interest because a natural gas Project will create jobs and economic activity." [*Id.* at 11]

88 *See* Ex. B at 23.

89 *See* Ex. B at 22-35. Mr. Richards also added: "the Port Authority respectfully submits that the Commissioner would be woefully ignoring his obligations as trustee of our people's resources if he did not focus these termination proceedings on the working interest owners' refusal to market gas from the unit." [Ex. B at 22]

significantly raises questions regarding Mr. Walker's most recent position on Point Thomson development. At a minimum, this demonstrates that even those that follow oil and gas issues closely, such as Mr. Walker, cannot be sure of what the most optimum full field development path is for the state regarding Point Thomson. It also demonstrates the importance of having more than one full field development alternative in the Agreement.

II. DR. MYERS'S, MR. WALKER'S AND MR. RICHARD'S CRITICISMS OF THE AGREEMENT ARE BASED ON MISUNDERSTANDINGS OF ITS TERMS

Dr. Myers, Mr. Walker, and Mr. Richards lay out similar criticisms of the Agreement. As shown below, their reading of the Agreement either misunderstands or misinterprets numerous provisions of the Agreement. Below is a brief summary and response to their claims.

A. Full Field Cycling is One of Several Viable Development Alternatives that Provide Significant Benefits to the State.

The central criticism offered by Dr. Myers, and echoed by Mr. Walker and Mr. Richards, is that the only reasonable development path for Point Thomson is full field cycling, and that the State should not have agreed to any other development option in the Agreement.

As discussed in much more detail below, Dr. Myers, Mr. Walker, and Mr. Richards rely on a misguided application of the 2008 PetroTel study to support their view that full field cycling is the *only* development option that DNR should consider. This study, however, is not a complete guide to determine the feasibility or commercial viability of a full field scale cycling development. The 2008 study was only designed to evaluate the range of proven and potential hydrocarbon resources within the Thomson Sand reservoir and to get a preliminary understanding of the relative impact on potential rate of production and ultimate recovery of hydrocarbons.

It is critical to underscore that these *preliminary* 2008 estimates of technically recoverable resources were made without applying the real-world constraints that would apply to an actual development, such as limitations on the number of wells, restrictions on the placement of drilling pads and other facilities, gas handling limits, or economic metrics. Additionally, since issuance of the report in 2008, new data has been made available to DNR, which allowed the agency to conduct detailed studies and understand more fully the full range of challenges associated with development of the Point Thomson reservoir.

Nonetheless, DNR agrees that full field cycling may be a viable alternative for developing Point Thomson, and that is why the development path is included in the Agreement.[90] Indeed, it should be noted, that the IPS *is* a gas cycling project, and depending on the results of that development, full field cycling might be how the Point Thomson field is optimally developed.[91]

Generally speaking, the primary benefit of full field cycling is that it potentially allows the operator to recover the largest quantity of condensates and oil. But, when evaluating this development option, there are other considerations that cannot be overlooked. For example, the WIOs would not agree to a settlement that demanded only full field cycling; in part because they claim it is not yet known whether full field cycling at Point Thomson is technically feasible. Further, it is far from clear that full field cycling, even if technically feasible, would make economic

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90 Sections 1.7, 2.15, 4.6.2.

91 Sections 1.6 – 1.7

sense to either the State or the WIOs, given that the costs could be much greater than for other development scenarios and the price of oil in the future is not known.[92] And, critically, full field cycling could delay production of natural gas from the reservoir, which in turn has the potential to significantly postpone a large-scale gas pipeline, a critical piece of Alaska's energy future. On the other hand, a market for North Slope natural gas does not currently exist and cannot be assured by the availability of Point Thomson gas. Thus, the public interest is best protected by retaining flexibility to determine the best path for full field development. Indeed, insisting on only one development option overlooks the benefits, discussed above, that accrue to the State by retaining flexibility with full field development.

In sum, the Agreement requires an initial cycling project and then provides for both full field cycling and other alternatives for possible full field development alternatives for Point Thomson. Any of these alternatives will provide considerable value to the State. The Agreement further protects the State because DNR retains the right to reject any development that is inconsistent with the Agreement or state law.[93] And, finally, prior to choosing one of these alternatives, the WIOs will still need to secure AOGCC approval, using data acquired through the IPS, that the development alternative ultimately selected is consistent with the Agreement and with State law.[94]

1. The Difference Between "Gas Cycling" and "Gas Blowdown."

To understand the Agreement, and some of the criticisms, it is worth pausing to discuss the two primary methods to develop a retrograde gas condensate field like Point Thomson.[95]

One development method, gas cycling, produces the natural gas, separates out the gas condensates, ships the condensates to market through a liquids pipeline, and re-injects the gas into the reservoir to maintain reservoir pressure. This is exactly what the IPS will do. In a retrograde condensate field, the reservoir pressure must be maintained above its "dew-point, which at Point Thomson is at a very high pressure," in order to prevent the reservoir's condensates and oil from "dropping out" of the gas phase in the reservoir and being lost to production. The primary benefit of this development method is that it allows the operator to recover the largest quantity of liquid condensates and oil by maintaining reservoir pressure. After recovery of the condensate the re-injected gas (minus the volume used for fuel) can then be produced and sold.

The second development method is gas "blowdown", where natural gas is produced from the reservoir and sold rather than re-injected. The liquid condensates are separated from the gas and

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92 For a detailed overview of the challenges associated with producing this field see http://www.arcticgas.gov/point-thomson-key-gas-field.

93 Sections 5.7, 4.6 (DNR can reject PODs inconsistent with the Settlement Agreement or Section 10 of the Point Thomson Unit Agreement).

94 Section 5.7 provides: "In proceedings before the Alaska Oil and Gas Conservation Commission regarding approvals related to the IPS Project, a Point Thomson Expansion Project, or a Point Thomson project related to a Major Gas Sale, the DNR agrees it will not oppose any such application submitted that is consistent with the terms of this Agreement and applicable State law." Thus, if DNR believes that a development alternative is not consistent with the Settlement or with state law – i.e., the development will result in waste – then DNR can oppose such an alternative before the AOGCC.

95 For a more detailed overview of these issues see http://www.arcticgas.gov/point-thomson-key-gas-field and http://doa.alaska.gov/ogc/Gas/PtThompson_Pool_Rules.pdf

sent to market through a liquids pipeline and the "dry" gas is transported through a gas pipeline. This type of development would allow the WIOs to simultaneously produce gas and liquids, and it would result in a huge rush of production because the Thomson Sands reservoir is highly pressurized. However, it will also result in the potential loss of considerable liquids in the reservoir because reservoir pressure is not maintained.

It should be emphasized that blowing down the Thomson Sands reservoir (the primary resource in the Unit) will have no impact on the ability to recover the significant volumes of oil contained in the shallower Brookian accumulations.

2. The Agreement does not Unconditionally Authorize Gas Blowdown and the AOGCC Must Approve Any Proposed Development.

The main thrust of Dr. Myers' criticism is that the Agreement unconditionally authorizes the waste of significant volumes of oil and gas condensates. This criticism is misplaced because DNR retains the right to reject any development that is inconsistent with the Agreement. Moreover, nothing in the Agreement gives the WIOs an unconditional right to forgo full field cycling and blowdown the field.

Beyond DNR's tools to guide full field development, the Alaska Oil and Gas Conservation Commission ("AOGCC") will adjudicate any development and off-take plan proposed by the operator. The AOGCC is statutorily prohibited from allowing any development plan that will result in waste.[96] And State law provides that it is the AOGCC that must determine whether a particular development plan is wasteful.[97] The Agreement does not alter this relationship or responsibility, and it does not prevent DNR from opposing a development plan that conflicts with the Agreement or with state law.[98]

3. The 2008 PetroTel Study Taken Out of Context Does Not Provide a Realistic Portrait Regarding Full Field Development.

During their testimony before the Senate Judicial Committee on April 27, 2012, the only evidence that Dr. Myers and Mr. Walker cited to support their assertion that blowing down Point Thomson for a large scale pipeline would lead to considerable waste of oil and gas condensates was a 2008 PetroTel study. Based on this study, Dr. Myers and Mr. Walker also claim that the only reasonable development plan for Point Thomson is full field cycling.

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96 AS 31.05.095 provides: "The waste of oil and gas in this state is prohibited." Under AS 31.05.100, an operator must secure AOGCC approval by proving that the development will not result in waste before developing a pool. AS 31.05.170(15) defines waste to mean its "ordinary meaning" and includes "the inefficient, excessive, or improper use of . . . reservoir energy and . . . producing any oil or gas well in a manner which results or tends to result in reducing the quantity of oil or gas to be recovered from a pool[.]"

97 As the AOGCC has stated, "the operator of an oil or gas field applies to the AOGCC for 'Pool Rules.' These are specific rules that stipulate how to develop the reservoir in a way that maximizes oil and gas recovery." http://doa.alaska.gov/ogc/Gas/NS_Gas_Sales.pdf

98 Section 5.7 (DNR can oppose any development application pending before the AOGCC that is inconsistent with state law or the Settlement); Section 4.6 (DNR can reject PODs inconsistent with the Settlement Agreement or Section 10 of the Point Thomson Unit Agreement)

The 2008 PetroTel study should not be used to judge the merits of the IPS and the expanded development alternatives set out in Agreement because the 2008 study was a preliminary analysis and was not designed to evaluate optimal developments scenarios.

In 2007, the Resource Evaluation section of the Division of Oil and Gas contracted with PetroTel, Inc. to perform geologic and engineering evaluation of the Point Thomson Sand reservoir. The study was initiated to provide a technical assessment of the Thomson Sand reservoir. The purpose of the evaluation was to get an independent analysis of the proven and potential hydrocarbon resources contained in the reservoir and gain a better understanding of unique issues associated with development and production of a retrograde gas condensate reservoir.

The scope of the 2008 study did not include optimization of any particular development scenario and it was not designed with the intent of describing a realistic development plan. It is vitally important to note, therefore, that these preliminary 2008 estimates of technically recoverable resource were made without applying the real-world constraints that would apply to an actual development project, such as limitations on the number of wells, regulatory restrictions on the placement of drilling pads and facilities, gas handling limits, or economic metrics.

Here, the 2008 PetroTel study cannot serve as a realistic basis to review a specific development plan precisely because *no consideration was given to these potential restrictions*, i.e., to the location or size of surface infrastructure or facilities, development costs, performance of high pressure facilities, gas handling constraints, or market conditions. Indeed, the 2008 PetroTel study did not consider *any* economic or operational constraints on the number of wells drilled, the amount of gas cycled per day, the volume of gas the facilities could handle, or the associated challenges imposed when permitting a full field development.

In addition, the 2008 study reported that up to 400 million barrels of oil could potentially be recovered from the Thomson Sands oil-rim, which is different from the Brookian resources. This thin oil rim lies between an overlying, highly mobile Thomson Sands gas cap and an underlying water leg. Subsequent modeling runs by DNR and PetroTel, however, indicate that a project to drain the thin oil column of the main Thomson reservoir could face serious challenges because, in part, the wells intended to produce the oil would produce gas instead of oil within a matter of weeks, effectively ending production from the oil rim. Even Dr. Myers conceded during his testimony that the oil rim estimates in the 2008 PetroTel study that he cited in his PowerPoint were likely too optimistic. Thus, the assumption of the 400 million barrels of recoverable oil from the oil rim, in retrospect, appears unrealistic given these challenges, the current state of technology, and development costs.[99]

Put simply, it is not appropriate to use the potentially recoverable reserves reported in the 2008 PetroTel study as the true measure of what will or won't be recovered at Point Thomson.

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[99] Indeed, discounting the recoverability of the oil rim is consistent with the United States Department of Energy's analysis of the Point Thomson reservoir. After reviewing the 2008 PetroTel study, the Department of Energy stated the PetroTel findings "appear to be optimistic and open to question, especially with respect to the recovery predicted for oil from the oil rim." http://www.netl.doe.gov/technologies/oil-gas/publications/AEO/ANS_Potential.pdf at 2-30 Contrary to the 2008 PetroTel study, the DOE concluded that very little of the oil rim oil was recoverable and that "it is conservatively assumed that the gas reserves are 8.0 TCF and the liquids are estimated to be at least 300 MMBC." This number is in stark contrast to the earlier 2008 PetroTel estimates of 620-850 million barrels of petroleum liquids

Ultimately any development at Point Thomson will be a balance (optimization) of not only the potential resource and reservoir characteristics but also the real world development constraints that allow the operator to economically recover the maximum amount of oil and gas over an expected time frame.

4. The 2008 PetroTel Study Does Not Fully Reflect DNR's Current Understanding of the Point Thomson Reservoir.

The 2008 PetroTel study was a preliminary study and does not comport with the Division's current understanding of the challenges in developing the Thomson Sands reservoir. Since this study was issued the Division has learned much more about the reservoir and the challenges associated with development of the resource within. After PetroTel completed the 2008 study, the Division acquired access to ExxonMobil's data room. The Division took the information it learned from the data room and, along with PetroTel, concluded that when comparing similar likely scaled full field developments, the potential liquids lost would be far less than the estimates contained in the 2008 PetroTel study.

More specifically, in September 2008 PetroTel was put under contract to the Alaska Department of Law to provide consulting services and expert testimony to the State of Alaska in connection with the litigation arising from DNR decisions to terminate the Point Thomson Unit. PetroTel performed additional studies and refinements to their earlier modeling efforts in order to advise the State and be in a position to testify in the Point Thomson Unit litigation if the litigation team deemed it appropriate. The work performed by PetroTel on behalf of the Point Thomson Unit litigation team is set forth in detail in Appendix A.

After completing this extensive review, the Division of Oil and Gas concluded that the potential amount of liquid condensate and oil that could be lost if Point Thomson were "blowndown" early for a Major Gas Sale would be significantly less that the estimates found in the 2008 PetroTel study that Dr. Myers and Mr. Walker rely upon. DNR cannot disclose the revised estimate because this information is protected under Alaska law.

This work culminated in a two day briefing by PetroTel and the Division of Oil and Gas for DNR Deputy Commissioner Rutherford and the Point Thomson litigation team in August of 2009. Commissioner Sullivan subsequently received similar briefings from Division staff in 2011. This work was integral to the Agreement and to DNR's decision to support the full field development alternatives authorized by the Agreement.

B. The Major Gas Sale Development Set Forth in the Agreement Contemplates a Large- Scale Gas Pipeline Project Off the North Slope.

Mr. Walker and Mr. Richards have raised questions regarding why the Agreement's definition of Major Gas Sale is a pipeline with capacity greater than 500 million cubic feet per day (mmcfd), as opposed to a larger number, such as the definition of Major Gas Sale in the Prudhoe Bay Unit Operating Agreement. Contrary to Mr. Walker and Mr. Richard's speculation, this definition does not contemplate a small-scale gas pipeline.

The 500 mmcfd threshold was included in the Agreement to reference the exception in AGIA that provides the State may be involved in the finance and construction of a gas pipeline of 500 mmcfd or less without incurring penalties. Requiring the Major Gas Sale to be in excess of 500 mmcfd made clear that any in-state "bullet line" would not qualify as a Major Gas Sale.

It would not be economic to construct a small line as speculated by Mr. Walker and Mr. Richards. In order for a gas pipeline project to make economic sense, the project size would likely need to eventually be well in excess of 500 mmcf per day.

An LNG project will need to be large scale to be economic. Given this, there was no reason to try and specify any minimum pipeline size in the Agreement beyond ensuring the line will be in excess of the 500 mmcfd AGIA limitation because it is not clear today exactly what the initial scope of any LNG project may be. An LNG project may "scale up" over its first few years and the Agreement was designed to provide flexibility to ensure that an arbitrary limitation did not prevent the construction of an economic large-scale gas pipeline project.

C. **The Agreement Contains a Firm Development Commitment in the Form of the IPS, and the Penalty of Losing the Unit *and* the Underlying Leases if the IPS is not Completed.**

1. Per the Agreement, the IPS is a Firm Commitment Offering Benefits to the State Far in Excess of the 2009 Conditional Interim Decision.

Mr. Walker and Mr. Richards argue that the IPS was formerly a firm commitment under DNR's 2009 Conditional Interim Decision and that, under the Agreement, the IPS is now optional and that even if the WIOs Abandon the IPS, they still keep significant acreage.[100] Mr. Walker and Mr. Richards misunderstand the IPS and how it differs from the 2009 decision.

The IPS is not an "option." The Agreement employs binding mandatory language that *requires* the WIOS to complete the IPS. It provides: "The WIOs *shall* put the PTU 15 and PTU 16 wells on production utilizing the IPS by the end of the 2015-2016 winter season and in no event later than May 1, 2016."[101]

In the past when the WIOs have committed to cycling projects at Point Thomson, they have returned to the State and said that cycling is uneconomic. The Agreement takes away this excuse. Under Section 4.2.1, the "economics or costs of the IPS Project cannot be used as a rationale or justification for not completing the IPS Project and do not constitute a factor outside the WIOs' control under Paragraph 4.2.3."

The Agreement also requires the WIOs to "diligently pursue" the completion of the IPS and it provides that the failure to do so constitutes a breach of the Agreement that triggers significant consequences.[102] In particular, if the WIOs breach the Agreement by abandoning the IPS, [103] the

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100 Walker Letter at 5.

101 *See* Section 4.1.1.2 (emphasis added).

102 Section 4.2.1 provides: "The WIOs will have diligently pursued the IPS Project if the project work plans, activities, and pace are undertaken in a manner exemplified by the Point Thomson Provisional Schedule Level 1 work sheet attached as Exhibit E. Moreover, a lack of progress on project work plans, activities, and pace commensurate with the size and scale of the IPS Project over a one-year period is indicia of the WIOs' decision to Abandon the IPS Project."

103 Abandonment is defined in Section 4.2.1, which is quoted above.

WIOs lose significant acreage as soon as 2015,[104] and if there is no Major Gas Sale Sanctioned by 2019, then *all acreage* comes back to the State and the Unit terminates Without Appeal.[105]

The purpose of the Abandonment provision is not, as Mr. Walker suggests, to give the WIOs an "option." Instead, *the State* insisted on including this provision in order to establish predetermined consequences for the WIOs' failure to meet contractual obligations. The alternative, to remain silent on consequences, would likely result in protracted litigation related to the appropriate remedy for the WIOs' failure to meet their binding contractual obligations.

The WIOs' agreement to these consequences for abandonment was a significant concession by the WIOs because, in the past, they have argued that unit and lease termination was not an appropriate remedy for failure to develop the Unit. Now the prospect of losing significant acreage in the near future looms large if the WIOs stop working on the IPS.

Indeed, under the Conditional Interim Decision, there was nothing to prevent the WIOs from stopping work and forcing the State to litigate *for years* on whether they needed to complete the project. This prospect became more likely once Judge Gleason reinstated the Unit, which gave the WIOs the ability to halt their work and wait for the litigation to reach a final resolution.

And contrary to Mr. Walker's contention, the IPS Project described in the Agreement is not in the same as the Conditional Interim Decision.[106] The Agreement goes far beyond the sparse terms of the Conditional Interim Decision. For example, the Agreement sets out a detailed work schedule that the WIOs must abide by; if they do not, then the State has grounds to declare that the IPS Project has been abandoned.[107] The Agreement also obligates the WIOs to keep the IPS fully loaded with gas by drilling additional wells if production falls off and to conduct debottlenecking work to increase liquids recovery.[108] It requires the WIOs to drill the West Pad well by the end of the 2016-2017 winter season[109] and requires the WIOs to pursue permitting of an East Pad, East Pad Well, and a Fifth Well.[110] The Agreement also requires the WIOs to begin working on the next phase of development by submitting a POD for DNR's approval.[111] And as noted above it dispatches with the WIOs' previous excuses for not developing the field.[112]

Accordingly, the IPS Project required by the Agreement differs significantly from the 2009 Conditional Interim Decision because it contains additional mandatory work commitments and provides contractually agreed upon remedies if the WIOs fail to meet their binding obligations.

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104 *See* Section 4.2.2.

105 *See* Section 4.5.2.1.

106 Walker Letter at 4, 5.

107 *See* Section 4.1.1.2; 4.2.1; Ex. E.

108 *See* Section 4.1.1.3; 4.1.1.4.

109 *See* Section 4.1.2.

110 *See* Section 4.1.3.

111 *See* Section 4.1.6, 4.6.

112 *See, e.g.*, Section 4.1.1.2 (the WIOs must complete the IPS – this commitment is not contingent on the outcome of engineering studies), 4.2.1 (the WIOs cannot use economics or costs as an excuse for not completing the project)

2. Even if a Major Gas Sale is Sanctioned after Abandonment of the IPS, Previously Contracted Acreage is Forever Lost to the WIOs.

Mr. Walker and Mr. Richards seem to believe that, if the IPS is Abandoned and acreage is lost as a result, the Sanctioning of a Major Gas Sale will cause previously contracted acreage to come back into the Unit.[113] This is incorrect.

The Agreement is clear that should the WIOs Abandon the IPS but later Sanction a Major Gas Sale, certain acreage that contracts as a result of Abandonment remains contracted.[114] More specifically, if the IPS is Abandoned, Areas E and F contract regardless of the amount of money spent between year-end 2007 and 2015, and if the WIOs spend less than $2 billion and do not drill the West Pad Well, the only acreage that remains in the Unit is Area A.[115]

This acreage will not, as Mr. Walker and Mr. Richards suggest, be reconstituted or recommitted to the Unit if the WIOs later Sanction a Major Gas Sale. The Agreement is explicit on this point: "If IPS Project Start-up has not occurred and a Major Gas Sale is Sanctioned prior to year-end 2019, any acreage that contracts from the Point Thomson Unit under Paragraph 4.2 (the Abandonment provision) of this Agreement *shall not be recommitted to the Point Thomson Unit*."[116]

3. If the WIOs Do Not Develop Beyond the IPS, They Will Lose Significant Acreage.

Mr. Walker and Mr. Richards assert that the WIOs will retain "most, if not all, of Point Thomson in perpetuity" by producing 10,000 barrels per day through the IPS.[117] They are incorrect.

If the WIOs do not move beyond the IPS, then under Sections 4.5.3 and 4.7, Area E and F, and some leases in Area D, will automatically contract out of the PTU. This acreage automatically returns to the State in 2019. The WIOs cannot appeal this decision.[118]

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113 Walker Letter at 7.

114 The State did not insist on getting all of the acreage back in 2015 because the WIOs have, by drilling two wells capable of producing in paying quantities, earned the right to retain some acreage for an additional period of time to place those wells onto production or to Sanction a Major Gas Sale. This provision is also consistent with the central principle of the Settlement: the more work and money the WIOs spend, the more acreage they retain.

115 Under Section 4.2.2.4, only costs that are directly related to Point Thomson Development and that are paid for by the other Point Thomson WIOs can count towards the $2.0 billion number. Point Thomson Development is defined as "work activities" for the IPS and other work activities set out in the Settlement. This means that the WIOs cannot "get credit" for work they have completed on gas pipeline projects or for work completed at other fields (because the Point Thomson WIOs are not going to be billed for this work), nor will legal fees or overhead count because these are not work activities mandated by the Settlement. *See* Section 4.2.2.

116 *See* Section 4.5.7 (emphasis added).

117 Walker Letter at 4.

118 Section 4.5.3.1 provides: "The acreage in Area E and the northern half of ADL 377017 (ADL377017(N) on Exhibit C), without regard to whether this acreage was included in a technical PA application or is included in the PA as the result of a technical PA expansion under Paragraph

Additionally, assuming that the WIOs fail to meet their binding commitment to drill the West Pad Well, then any acreage in Areas B and D that is not contributing to production, i.e., that is not included in the initial participating area, will contract from the unit under Section 4.5.3.2. And even if the WIOs have drilled the West Pad Well, then any acreage in Area D that is not contributing to production will contract from the Unit.

Consequently, by 2019, nearly half of the Point Thomson acreage will automatically return to the State Without Appeal if the WIOs do not expand beyond the IPS. If the WIOs do not move beyond the IPS, the only acreage the WIOs are entitled to hold is Area A. And depending on what else the WIOs have done and the extent of the IPS production, they may keep more leases beyond Area A. The Agreement therefore dramatically restricts the WIOs' ability to keep the State in court for years over their failure to develop the Unit's resources and will result in the automatic return of significant acreage to the State Without Appeal.

This outcome is entirely consistent with State law and the Unit Agreement, both of which provide for retention of acreage as a result of production.[119] The Agreement provides additional protection for the State that does not otherwise exist under the Unit Agreement by specifically tying the retention of additional acreage to undertaking and completing future development projects.[120]

D. <u>The Agreement Addresses the Next Phase of Development after the IPS by Providing for Additional Development Alternatives that, if Completed, Allow the WIOs to Retain Additional Acreage</u>.

1. <u>Construction Commitments and Final Investment Decisions Will be Part and Parcel of Sanctioning a Major Gas Sale</u>.

Mr. Walker and Mr. Richards believe that Sanctioning of a Major Gas Sale could occur in the absence of construction commitments and without final investment decisions,[121] but they misunderstand the definition of Sanction.

The definition of Sanction was carefully crafted to ensure that acreage would not be secured unless a Major Gas Sale project would actually be completed, with a pipeline constructed and gas flowing through the pipeline. The definition of Major Gas Sale mandates a pipeline that delivers gas "off the North Slope of Alaska."[122] The definition of Sanction expressly requires corporate approvals to "proceed with construction of the project to completion."[123] *This is a contractually-*

4.4.3, shall be released to the State Without Appeal. The remaining acreage in Area D shall be subject to the PTUA including applicable State law."

119 *See* Section 11 of the Point Thomson Unit Agreement; AS 38.05.180(m); 11 AAC 83.336.

120 Sections 4.4, 4.5, and 4.7 explicitly discuss when and how acreage is retained and under what circumstances the Point Thomson Unit terminates and acreage returns to the state.

121 Walker Letter at 6-7.

122 *See* Section 2.16.

123 Section 2.28 defines Sanction to mean "formal and explicit approval of a Major Gas Sale. A Major Gas Sale shall be considered "Sanctioned" under this Agreement upon receipt by the State of documentary evidence of: (1) corporate approvals by parties sufficient to proceed with construction of the project to completion; (2) firm transportation service agreements that have been entered into

binding construction commitment to complete a gas pipeline, not a promise to conduct further "studies."

Moreover, a Sanction requires Firm Transportation Service Agreements from customers who will ship gas on the pipeline, and to acquire necessary regulatory approvals, including a Certificate of Public Convenience and Necessity from the Federal Energy Regulatory Commission.[124] These agreements and regulatory approvals represent significant undertakings that will likely cost over a billion dollars and would not occur unless there was a real project.

2. <u>Point Thomson Gas Would Be Used for a Major Gas Sale under the Agreement</u>.

Mr. Walker and Mr. Richards claim if a Major Gas Sale is Sanctioned, the WIOs would retain the Point Thomson Unit without the need to develop Point Thomson gas reserves.[125] This contention is wrong.

If a Major Gas Sale is Sanctioned but the WIOs never produce Point Thomson gas, then they are in breach of the Agreement – assuming they have not pursued one of the other full field development alternatives. Under Section 4.6, the WIOs must submit a POD that complies with Section 10 of the Unit Agreement, which in turn requires the submission of PODs for DNR's approval that timely develop the Unit's resources.[126] Likewise, Section 4.6.1 provides that if a Major Gas Sale is sanctioned, the WIOs "*shall* submit a Future POD that includes works plans and project activities to *develop the Point Thomson Reservoir* for a Major Gas Sale."[127] The Agreement adds that DNR retains the right to reject the proposed POD if it fails to comply with these requirements.[128]

Thus, the Agreement makes very clear that once a Major Gas Sale has been Sanctioned, the WIOs are not relieved from developing the Point Thomson gas reserves – instead they must timely develop the PTU gas unless they decide to pursue another full field development alternative, *e.g.*, full field cycling under Section 4.6.3.

In addition, it provides that the only way to secure Point Thomson acreage after Sanctioning a Major Gas Sale, assuming no other full field development alternative is pursued, is by *producing the gas at Point Thomson.*[129] Section 4.4.2 states that the participating area will *only* expand to include additional Point Thomson acreage "upon Project Start-up of the project *to develop the Point*

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sufficient to proceed with construction of the project to completion; and (3) necessary United States (and, if applicable, Canadian) federal regulatory certificates that have been issued and accepted."

124 Section 2.28.

125 Walker Letter at 7.

126 Section 10 of the PTUA provides, in part, that "Any plan submitted pursuant to this section . . . shall be as complete and adequate as the Director may determine to be necessary for timely development and proper conservation of the oil and gas resources of the unitized area."

127 *See* Section 4.6.1 (emphasis added).

128 *Id.*

129 This critical principle applies to all of the development projects – *e.g.*, acreage is only secured when the IPS is on production (Section 4.3) when additional development

Thomson Reservoir for a Major Gas Sale[.]" Accordingly, Point Thomson gas molecules must be flowing through a gas pipeline off of the North Slope to secure acreage.

The Agreement is also clear that should natural gas production into a gas pipeline never commence from the Unit, then DNR retains the right under Section 2(e) of the Unit Agreement, and applicable state law, to contract non-producing acreage out of the Unit, assuming the Unit has been placed into production.[130] And if a Major Gas Sale has been Sanctioned, but the Unit has never been placed onto production by the IPS, then the State can terminate the Unit under the Unit Agreement and applicable law.[131]

Thus, even if a Major Gas Sale project commences and only uses gas from Prudhoe Bay, the Agreement does not allow the WIOs to permit Point Thomson to lay fallow indefinitely. Moreover, as discussed in detail above, this is one example of how the Agreement has put the WIOs back "on the clock" to get the Unit developed. Accordingly, the contention that the Agreement allows the WIOs "to continue to warehouse Point Thomson resources" is meritless.

3. <u>If the WIOs Abandon the IPS and a Major Gas Sale is Not Sanctioned, DNR May Terminate the Unit and all Point Thomson Leases.</u>

Mr. Walker and Mr. Richards are under the impression that if the IPS is Abandoned and a Major Gas Sale is not Sanctioned, the WIOs have the right to retain the entire Unit by submitting an "Expansion Project POD" by year-end 2019.[132] They misunderstand the Agreement's provisions.[133]

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130 *See* Section 4.5.1 ("If by year-end 2019 a Major Gas Sale has been Sanctioned or the WIOs have Committed to a Point Thomson Expansion Project, acreage to be included in the PA . . . shall remain in the Point Thomson Unit following formation of the Initial PA, and thereafter shall be subject to elimination from the Point Thomson Unit in accordance with the terms of the PTUA including applicable State law, including Section 2(e). If IPS Project Start-up has not occurred and the Initial PA has not been formed, but a Major Gas Sale is Sanctioned, such acreage shall remain in the Point Thomson Unit and shall be subject to elimination from the Point Thomson Unit in accordance with the terms of the PTUA including applicable State law, including Section 2(e), as if the Initial PA had been formed effective May 1, 2016."). Section 2(e) of the Point Thomson Unit Agreement and the applicable State law (11 AAC 83.356) provide that acreage not contributing to production eventually contracts from the Unit. 11 AAC 83.356(b) provides: "ten years after sustained unit production begins, the unit area must be contracted to include only those lands then included in an approved participating area and lands that facilitate production[.]"

131 *See* Section 20(c) of the PTUA and 11 AAC 83.336.

132 Walker Letter at 7.

133 The "Expansion Project POD" does not apply to this situation. Instead, the Expansion Project POD will be submitted *after* the WIOs have begun producing from the IPS and *after* they have completed the necessary work under the "Expansion Planning POD" which the WIOs *must* submit if a Major Gas Sales has not been Sanctioned. Section 4.1.6. The "Expansion Planning POD" requires the WIOs to conduct engineering work and permitting for a Point Thomson Expansion Project: full field cycling or injecting PTU gas into Prudhoe Bay. Section 4.6.2. Once this work is completed, which must occur before year-end 2019, the WIOs must submit an "Expansion Project POD" (or Sanction a Major Gas Sale), or they will lose acreage. *See* Section 4.6.3, 4.5.3. The Agreement further provides that no additional acreage is secured until the expansion project the WIOs have committed to is complete and in production. *See* Section 4.4.2

The Agreement only permits the WIOs to submit an Expansion Project POD *if the IPS project has been completed.* In the absence of completing the IPS, the WIOs must Sanction a Major Gas Sale or the Unit automatically terminates in 2019 and the WIOs lose all of their leases.[134]

The Agreement is clear: DNR has the complete discretion to terminate the Unit in 2019 *and* get all of the leases back Without Appeal if the IPS is not in production or a Major Gas Sale has not been sanctioned. Section 4.5.2.1 provides: "If IPS Project Start-up has not occurred and a Major Gas Sale has not been Sanctioned by year-end 2019, the following shall occur . . . the Point Thomson Unit and the PTUA *shall terminate* Without Appeal . . . *each WIO will immediately surrender its leases and all such acreage shall be automatically released Without Appeal to the State*[.]" (emphasis added).

The Agreement does allow the WIOs to submit one last "alternative" POD[135] or ask DNR for the right to put any wells capable of producing into production in two years.[136] Even so, with both exceptions, DNR has unfettered discretion to deny the request, and the WIOs cannot appeal this determination.[137]

In short, DNR has the full authority, discretion, and contractual right to automatically terminate the Unit in 2019 *and* soon thereafter get all of the leases back Without Appeal if the Unit is not placed into production and a Major Gas Sale has not been Sanctioned. The foregoing provisions provide significant protection for the State because they make clear that if the WIOs fail to follow through on their development commitments, then all acreage comes back to the State. Such clarity is in sharp contrast to the lay of the land that existed under the Unit Agreement following Judge Gleason's decision because, under her decision, there was no assurance that DNR would be able to terminate the Point Thomson Unit or terminate the leases, and get the acreage back.

E. **The Agreement Permits DNR to Closely Monitor the WIOs' Development Decisions and Activities and Impose Penalties for Failure to Abide by the Commitments in the Agreement.**

1. Under the Agreement, DNR Retains its POD Powers.

With respect to PODs, Mr. Walker and Mr. Richards appear to believe that DNR has abrogated its POD review powers and obligations to ensure that future development advances the public interest.[138] They are wrong.

As an initial matter, the Agreement ensures the integrity of the POD review process by vacating Judge Gleason's 2010 decision, thereby permanently foreclosing the WIOs from arguing

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Although such acreage temporarily remains in the Unit after year-end 2019, DNR retains its authority to move to contract the unit if the WIOs are in violation of state law. Section 4.5.1.

134 *See* Section 4.5.2.

135 *See* Section 4.5.2.2. This provision is included because, under State law, a Unit operator *must* submit a Plan of Development. 11 AAC 83.343.

136 *See* Section 4.5.2.3.

137 *See* Section 4.5.2.1.

138 Walker Letter at 6-8; 12-13

that this decision limited DNR's POD review remedies to a Section 21 hearing where DNR had the burden of proof to prove, among other things, that the specific increase in development demanded by DNR satisfies a "good and diligent practices" standard and would not harm the WIOs' interests.[139] Vacating this decision was a significant concession by the WIOs.

The Agreement further expressly preserves DNR's management of State lands under the POD review process. Under DNR's regulations,[140] a unit operator must submit a POD that: (i) commits to diligently developing the unit resources; and (ii) sets out a long-term plan for future work activities. After reviewing the POD and considering the criteria set out in 11 AAC 83.303, DNR has the discretion to approve or deny the POD. If the POD is approved, DNR must monitor activities to ensure that the unit operator is acting in compliance with the POD.

Mr. Walker and Mr. Richards misconstrue how the POD process will work in conjunction with the Agreement.[141] First, the Agreement does not do away with the requirement to have a POD for the IPS; the Agreement *is* the IPS POD.[142] It sets forth the key work activities and timelines that the WIOs must undertake with respect to the IPS, and it has other requirements (such as annual reporting regarding work activities and spend activity) that complement the POD.[143] In addition, before moving forward with the IPS POD and future PODs, the WIOs must secure DNR's approval for their Plan of Operations under 11 AAC 83.158.[144]

For the post-IPS PODs, the WIOs are obligated to submit PODs that comply with Section 10 of the Unit Agreement, and these PODs must contain all information required by 11 AAC 83.343.[145] DNR has the discretion to deny these PODs if they fail to comply with the requirements set out in the Agreement or are inconsistent with Section 10 of the Unit Agreement.[146] Moreover, if the WIOs

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139 Brief of Appellant State of Alaska, Department of Natural Resources at 27-56 (May 10, 2011, Supreme Court Case No. S-13730).

140 11 AAC 83.343.

141 Walker Letter at 8.

142 *See* Section 4.1.

143 The IPS POD complies with the remaining requirements set out in 11 AAC 83.343 because it contains: (i) long-range plans for proposed development (set out in the recitals, 4.1, and 4.6); (ii) and plans for future delineation and exploration (set out in the recitals, 4.1, and 4.6); (iii) details of the proposed operations for one year (set out in Exhibit E); (iv) the surface location of proposed facilities, drill pads, etc, which are set out in submitted and proposed Plan of Operations; (v) under 4.1.5 and 4.2.1 the WIOs must submit annual reports detailing the work completed during the previous year; and (vi) DNR considered criteria consistent with 11 AAC 83.303 before approving this plan. *See* Section 1, 4.1, 4.2.1, 5.8; Ex. E.

144 The Plan of Operations will discuss in more detail the specific environmental impacts of the development plan and the mitigation measures that DNR will require to mitigate these impacts. They will also be subject to public review and comment, and DNR's approval.

145 *See* Section 4.6 ("The WIOs shall prepare plans of further development and operation for the Point Thomson Unit under Section 10 of the PTUA") and Section 4.6.4 l (listing all of the technical data and information required by DNR's regulations).

146 *See* Section 4.6 (providing the DNR retains the right to reject any POD that is inconsistent with the terms of the agreement).

fail to submit a POD that complies with the requirements set out in Section 4.6, this would constitute a breach of the Agreement.[147]

Finally, as discussed above and below, DNR has determined, after considering criteria consistent with 11 AAC 83.303, that the full field development paths set forth and defined in the Agreement are in the public interest.[148] DNR relied on the entire Point Thomson record, spanning over thirty years, to determine that the development paths set forth in the Agreement are acceptable and in the public interest. The WIOs' proposed POD was approved after DNR reviewed voluminous information, including confidential proprietary data in ExxonMobil's data room; engaged in extended discussions with the WIOs related to different development alternatives; and engaged Petrotel to help evaluate various proposed development plans and the economics of these plans.

The Commissioner considered and incorporated regulatory criteria in approving the IPS POD as part of the Agreement and in agreeing to what would constitute acceptable PODs for future development after the IPS. DNR has not relieved the WIOs of the requirement to submit a POD, and DNR has retained the ability to manage state lands under the POD process. Overall, with respect to PODs, Mr. Walker and Mr. Richards fail to recognize that, while the POD process is delineated in the Agreement, the Agreement does not cede the role of PODs in the unit management process, nor does it eliminate DNR's oversight authority.

2. The Agreement is Consistent with DNR's Participating Area Regulations.

Mr. Walker and Mr. Richards mistakenly argue that the Agreement abrogates DNR's unit management authority by eliminating participating area requirements.[149] But the Agreement does not abrogate this important management authority.

Rather, the Agreement works *within* DNR's regulatory framework for the creation of participating areas. DNR's regulations require the creation of a participating area for acreage "reasonably estimated through use of geological, geophysical, or engineering data to be capable of producing or contributing to production of hydrocarbons in paying quantities."[150] Further, the regulations provide that the unit operator must apply for the creation of participating areas "at least 90 days before sustained production."[151]

With participating areas, as with PODs, the Agreement looks to the future and provides that they will be formed if production actually commences at production levels required by the development alternatives. Further, the Agreement requires submission of the same supporting

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147 While Mr. Walker and Mr. Richards note that the WIOs will not be submitting an annual POD, Walker Letter at 8, they overlook the fact that there is not legal requirement for yearly PODS – the Point Thomson Unit Agreement merely requires PODs be submitted from "time to time." They also disregard that PODs are often in multi-year form (Point Thomson has previously operated under multi-year PODs, as has Prudhoe Bay), and they also fail to recognize that the Agreement obviates the need for year-by-year PODs because it clearly specifies work activities for both the IPS Project and delineates the path for future development.

148 *See* Section 5.8.

149 Walker Letter at 12.

150 11 AAC 83.351(a).

151 *Id.*

technical data currently required by DNR regulations. Addressing participating areas in advance of production is consistent with the regulation, which provides that the unit operator must apply for the creation of participating areas "at least 90 days before sustained production."[152] As discussed in detail above, prior to entering into this Agreement, DNR reviewed and analyzed a great deal of technical data, including confidential proprietary data related to reservoir performance. Thus, the participating areas provided for in the Agreement are based on sound technical review and are procedurally consistent with DNR's participating are regulations.

3. DNR Considered 11 AAC 83.303 Prior to Entering into the Agreement.

Mr. Walker and Mr. Richards claim that DNR failed to consider 11 AAC 83.303 and issue a written finding before agreeing to the Agreement.[153] They are wrong.

As an initial matter, there is no requirement that DNR must issue "written" findings under 11 AAC 83.303 before approving the Agreement and the activities authorized by it.[154] Rather, the applicable regulation requires that DNR "consider" the factors set out in 11 AAC 83.303(a) before approving such activities.[155]

Second, consistent with 11 AAC 83.303, DNR did consider the factors set out in 11 AAC 83.303(b) before approving the Agreement and, even though one is not required, it has issued written finding (the Agreement itself) to support its decisions.

More specifically, consistent with 11 AAC 83.303, DNR evaluated due diligence dating back over nearly *a seven year period* and undertook unprecedented action in evaluating all aspects of the Agreement before agreeing to the terms. The Point Thomson litigation began in 2005. DNR conducted three formal public hearings related to the dispute and various proposed development plans. Collectively, these hearings lasted for weeks and involved dozens of witnesses and included the submission of tens of thousands of pages of documentation from the WIOs and the public. After the hearings concluded, the Parties began settlement negotiations in 2008. Throughout this process, DNR spent considerable time and effort to understand all matters covered in the Agreement,

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152 If a participating area is to be formed, the Agreement requires submission of the same supporting technical data that is currently required by DNR regulations. The data enumerated in Exhibit F is taken from DNR's current form for applying for the creation of participating areas, and was expressly approved by DNR's technical staff. *See* Sections 4.4.5 & Ex. F.

153 Walker Letter at 8-9.

154 The only time DNR must issue a written finding is before approving a new unit agreement. 11 AAC 83.303(a). Here, DNR did not approve a new unit agreement – it settled litigation and approved a development plan.

155 11 AAC 83.303(a) provides that when reviewing a POD or a Participating Area application, DNR must consider proposed activity: (1) promotes conservation of all natural resources, including all or part of an oil or gas pool, field, or like area; (2) promotes the prevention of economic and physical waste; and (3) provides 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." 11 AAC 83.303(b).

including the IPS POD, future development plans, and the formation of participating areas. DNR received and analyzed confidential and proprietary data relating to various development options; it spent countless hours with the WIOs, including in ExxonMobil and BP's data rooms, discussing these plans; it assembled a team of over 20 state employees from DNR and the Department of Law, and hired PetroTel and two highly respected law firms to help the State evaluate and analyze matters throughout the settlement negotiations; and it created a record exceeding at least 35,000 pages that support its decision to approve the Agreement

The record supporting the Agreement demonstrates that DNR fully and exhaustively considered all of the criteria set out in 11 AAC 83.303 before concluding that this Agreement is in the public interest.

4. <u>If a Development Path that is Selected by the WIOs is Inconsistent with the Agreement or Law, DNR Has the Right to Oppose It.</u>

Mr. Walker and Mr. Richards assert that the Agreement leaves DNR powerless to oppose the development approach ultimately selected by the WIOs.[156] They are wrong.

Section 5.7 provides that DNR will not oppose any project application submitted to the AOGCC by the WIOs "*that is consistent with the terms of this Agreement and applicable state law.*" This is significant because any development plan submitted to DNR and the AOGCC under the Agreement must comply with AOGCC regulations and DNR regulations (which are applicable state law) and must be consistent with the project definitions in the Agreement (such as the numerous benchmarks regarding a Prudhoe Bay Injection Project).[157] In this way, DNR retains its ability to make a final evaluation of whether any development option chosen and proposed by the WIOs under the Agreement is consistent with the public interest. And, if such a development approach is not consistent with State law or with the terms of the Agreement, then DNR can file an opposition before the AOGCC.

In conclusion, I appreciate this opportunity to supplement the record. DNR fully stands behind the decision to settle the Point Thomson litigation. The Agreement secures the State's goal of settling this protracted and uncertain litigation and moving the field into production, and advances the State's interest in the commercialization of Alaska's natural gas. It is not a perfect settlement – no settlement achieves that standard – but there should be no question that the Agreement is in the public interest. I would be happy to answer any additional questions by the committee.

Sincerely,

Joe Balash
Deputy DNR Commissioner

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156 Walker Letter at 7.

157 *See* Section 2.21

APPENDIX A

The scope of the first phase of the additional PetroTel work addressed in Section III.A.4 was fourfold and dealt primarily with gaining a better understanding of the range of uncertainties in the geologic description of the Point Thomson reservoir.

The first purpose was to generate additional realizations of the static geologic model in order to provide a statistical distribution of the in-place resource within the Point Thomson reservoir from which representative P90 (low-side), P50, and P10 (upside) cases could be extracted. Special consideration was given to creating a "stressed case" geologic description (P99) to capture a possible "worst case" outcome moving forward based upon the existing data from previously drilled wells.

The second purpose was to identify and quantify the uncertainty and potential impact of key variables in the reservoir description, such as reservoir structure, fluid contacts and facies distribution. The third goal was to quantify the expected connectivity of the reservoir within the geo-cellular model for the various descriptions. The final objective was to evaluate different delineation plans which, if executed, would test those key variables and reduce the reservoir uncertainty.

The next phase of work involved reviewing key reservoir data, fluid compositional data and well test data acquired through DNR access to ExxonMobil's confidential Point Thomson data room. The existing dynamic reservoir simulation model was updated based upon this additional information. Special effort was applied to better understand the PVT (pressure/volume/temperature) properties of the gas and refine the equation of state within the model to better match the results of production tests of existing wells and quantify the potential uncertainty in the expected condensate yield from the gas.

Once the dynamic simulator was updated, conceptual development/delineation drilling programs were evaluated and modeled to determine both the optimum and minimum sizing of a pilot project required to determine the validity, within a reasonable time frame, of gas cycling as a recovery mechanism in the Point Thomson reservoir. Variations were run to test the number and location of the wells within the expected physical surface constraints and drilling departure limits imposed by the high pressure reservoir. Each case employed appropriate and realistic facility technology and capacities. The impacts of varying certain aspects of facility design, such as the first stage pressure at which condensate is separated from the produced gas, were explored and quantified. Each cycling pilot case modeled was also run against a primary depletion case (gas blowdown) with the same well configuration to demonstrate the difference in recovery methods.

A methodology for estimating capital and operating costs was then developed beginning with confidential estimates generated by ExxonMobil and their contractors for previous project plans and using industry standards and economic indexes to adjust those estimates to current dollars. Project schedules were also developed based upon ExxonMobil's estimates as well as common practices employed for other large projects located on the North Slope of Alaska.

Ultimately, development scenarios were generated and modeled to evaluate what could be considered a most likely full-field scale development based upon the quantified reservoir risks and uncertainties, as well as the likely facility and surface constraints.

At this point it was decided that the development scenarios would focus primarily on production of the gas and condensate within the gas cap without any dedicated development of the underlying thin oil rim. As mentioned above, previous fine-scale mechanistic modeling of various configurations of dedicated wells targeting production from the oil rim had indicated that production of that resource would likely be very challenging and uncertain due to (i) the close proximity of the large, highly mobile, overlying gas cap, (ii) rapid coning of gas into dedicated oil rim wells that may hamper oil production, (iii) difficulties associated with abnormally pressured directional drilling, and (iv) limitations in the gas handling capacities of facilities. For this reason, oil rim production was not pursued further as part of a likely initial development.[158]

Various development scenarios were then run based on different geologic descriptions to provide production profiles representing a statistical range of outcomes; a P99 stressed case, a P90 low-side, a P50 case, and a P10 upside case. Production and cost profiles were generated for the various cases and provided to the Commercial Section of the Division of Oil and Gas to conduct economic analyses of the different scenarios through the expected life of the project. The analyses incorporated the current ACES tax structure and were run across a range of different assumptions such as commodity price and investment discount rates. This allowed a comparison of the relative economic strength of various development scenarios and outcomes using economic parameters such as Net Present Value (NPV) and Internal Rate of Return (IRR) for both the State and project working interest owners.