THE STATE of ALASKA
GOVERNOR BILL WALKER

**Department of Natural Resources**

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August 3, 2018

Senator Cathy Giessel
Chair, Alaska Senate Resources Committee
State Capitol, Room 427
Juneau, AK 99801-1182

Re: Senate Resources Questions to DNR regarding Alaska LNG

Dear Senator Giessel:

Thank you for the questions you provided to us on July 16, 2018 as follow up to the joint House and Senate Resources Committee hearing of July 11. Set forth below are DNR's responses.

*1. What level of stream crossing disturbances will the DNR tolerate for AKLNG? Will the same standard of disturbance to anadromous fish habitat used by DNR on the proposed Pebble Mine in western Alaska be use for AKLNG?*

> Concerning the construction of a pipeline for both projects, similar standards will apply to both Alaska LNG and to Pebble, and will be evaluated on a case by case basis. Both temporary and permanent disturbance of streams, including anadromous streams, may be permitted. Mitigations will be made part of the authorizations issued by DNR and ADF&G, such as the method for construction or seasonal restrictions. A minimum requirement is that the pipeline ROW be kept in good repair, and constructed in a manner as to prevent erosion and fish blockage. Pipeline crossings at all fish streams on both the proposed Alaska LNG and Pebble pipelines will be evaluated on a case by case basis by ADF&G and will require a separate Title 16 Fish Habitat Permit. ADF&G Habitat biologists will look at various factors such as fish species present and if spawning is known or likely to occur in the vicinity of the crossing. Construction timing windows or alternative crossing techniques such as horizontal directional drilling may be required for crossings at sensitive areas. The committee may want to direct related follow up questions directly to ADF&G.

*2. Does the DNR plan on any legislative changes to relevant statutes for the next legislative session that is considered necessary for the progress of AKLNG? If so, are those changes significant, either in the number of the changes or the magnitude of the changes?*

> DNR does not currently plan on proposing legislation to the Governor's Office related to Alaska LNG.

*3. Can DNR summarize the status of its Best Interest Finding (BIF) process evaluating a Royalty-In-Kind (RIK) or Royalty-In-Value (RIV) determination? What are the hurdles to completing the BIF? Are the private producer parties on the Alaska North Slope (ANS) advocating for one royalty form or another? If so, what is their reasoning? Is AGDC advocating for one royalty form or another? If so, what is its reasoning?*

There are several BIFs that DNR may issue related to RIV and RIK: (1) a BIF determining to take royalty as RIV instead of RIK; (2) if RIK, a BIF determining whether to proceed as a competitive or noncompetitive sale; (3) if RIK, a BIF approving a specific RIK contract; and (4) if amending leases under AS 38.05.180(hh), such as to modify the State's ability to switch between RIV and RIK on six months' notice, a BIF finding that the amendment is supported by evidence and in the state's best interest. This question appears to be focused on the first of these BIFs.

In keeping with the State's constitutional obligation to develop natural resources "for the maximum benefit of its people," the legislature has charged DNR with evaluating whether taking royalty in value on any state lease would be in the State's best interest. Alaska courts have stated that this best interest consideration involves determining whether the State would receive the same or greater value from RIV as it would from RIK.

DNR is currently considering whether to take gas from the Prudhoe Bay and Point Thomson Units as RIV or RIK in the event of a major gas sale as part of the proposed Alaska LNG project. This involves evaluating the potential benefits to the State under RIV and RIK scenarios for leases in both units. As part of this evaluation, DNR is discussing potential RIK terms with AGDC to get a better sense of the RIK scenarios. These discussions cannot at this point result in a binding agreement because DNR has not yet determined whether to take RIV or RIK. Nor has DNR determined, if taking RIK, whether to proceed with a competitive or noncompetitive sale. Uncertainties and lack of information about potential AGDC gas sales agreements and sales purchase agreements remain a significant hurdle to evaluating RIV and RIK scenarios.

The RIV and RIK scenarios could also be impacted by lease amendments under AS 38.05.180(hh), so another uncertainty is what leases, if any, can or will be amended and what those amendments might entail. Exxon, BP, and Conoco have expressed interest in amending yet to be specified leases to lock in an RIV or RIK selection for an extended period of time. But there are several potential difficulties.

First, not all leases are subject to AS 38.05.180(hh), which was adopted in 2014 as part of SB 138. In general, DL-1 leases are subject to statutes and regulations adopted at the time the lease was entered, whereas New Form leases are subject to later-adopted statutes and regulations. Most unit agreements modify DL-1 leases to make them subject to later-adopted statutes and regulations. The Point Thomson Unit Agreement makes the DL-1 leases in that unit subject to AS 38.05.180(hh); the Prudhoe Bay Unit Agreement does not. In addition, the Prudhoe Bay Unit Agreement itself includes provisions allowing the

State to switch between RIV and RIK. Thus, before the State could modify its rights to switch, the State and the Prudhoe Bay lessees would need to amend the Unit Agreement to make all the leases subject to AS 38.05.180(hh) and to modify the Unit Agreement provisions regarding switching.

Second, before the State can approve a lease amendment under AS 38.05.180(hh), all co-lessees for a particular lease must agree to the same amendment. The leases in PBU and PTU have between four and seventeen co-lessees each.

Third, AS 38.05.180(ii) requires DNR to make multiple findings before it can approve a lease amendment. These include a finding that gas production into the pipeline during the initial project term will originate from a particular lease. DNR will need additional information from the Prudhoe and Point Thomson operators before it can determine which leases might be eligible for amendment.

DNR is taking into account these and other uncertainties about potential lease amendments as part of its evaluation of RIV and RIK scenarios.

DNR has spoken with Exxon, BP, and Conoco, but has not yet communicated with other Prudhoe Bay or Point Thomson lessees. All three indicated a preference to amend leases to lock in RIV or RIK. AGDC has similarly indicated a preference for DNR to lock in RIV or RIK. AGDC, Exxon, BP, and Conoco have each acknowledged that it will be up to DNR to determine whether the State takes RIV or RIK.

*4. To the extent permitted, what is the status of DNR's stance on Field Cost Allowances (FCAs) on the ANS, and their potential impact to the state's royalty revenues?*

DL-1 leases (issued before 1980) specify that if a lessee cleans or dehydrates RIK oil or gas, the lessee can deduct those costs. These are what are referred to as "Field Costs" or a "Field Cost Allowance" (FCA). The DL-1 leases do not include this language for RIV. In the 1970s, the State filed the *Amerada Hess* lawsuit against several ANS producers, including a claim that the producers should not be deducting field costs for RIV. The superior court agreed, holding on summary adjudication that the oil and gas leasing statute "prohibits the field costs deductions . . . when royalty is taken 'in value'" and that "the Commissioner is prohibited from collecting royalty 'in kind' if the amount realized would be less than if taken 'in value.'" The parties later settled the entire case, and as part of that settlement agreed to a Field Cost Allowance for certain leases that applies to both RIV and RIK. That settlement was the first of several Royalty Settlement Agreements (RSAs). Each RSA has different terms, different parties, and applies to different leases, and some govern only oil or only gas. Most, but not all, of the Prudhoe Bay Unit is under an RSA for both oil and gas. Some leases in the Point Thomson Unit are subject to an RSA. For gas, BP and Conoco have RSAs applicable to certain Point Thomson leases that include provisions for an FCA under certain circumstances. The oil

RSAs applicable to Point Thomson do not specify an FCA different from what is provided in the leases themselves.

New Form leases (issued 1980 and later) specifically prohibit any FCA, in accordance with AS 38.05.180(f)(2).

Point Thomson began producing condensate (which under the lease terms is oil) in April 2016. The State currently takes all of its royalty on this production in value. In May 2016, Exxon sent a letter to the DNR Division of Oil and Gas, pointing out that the DL-1 leases in Point Thomson were not subject to an agreed FCA, and stating its intent to deduct its “actual field costs associated with producing condensate.” On July 6, 2017, the Director issued a decision stating that no FCA was permissible on RIV from Point Thomson DL-1 leases. Exxon, Conoco, and BP appealed that decision to the DNR Commissioner. These appeals remain pending before the Commissioner. Thus, there is no final agency decision. Any references to the “State’s position” or “DNR’s stance” on FCA refers to the DNR Division of Oil and Gas Director’s position in her July 6, 2017 decision. The Commissioner will consider the arguments of Exxon, Conoco, and BP, including procedural arguments and requests, and issue a decision in due course.

Please let us know if you have any further questions.

Sincerely,

Andrew T. Mack

Andrew T. Mack
Commissioner