THE STATE of ALASKA
GOVERNOR MIKE DUNLEAVY

Department of Revenue

COMMISSIONER'S OFFICE

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April 28, 2026

The Honorable Cathy Giessel
Senate Resources Committee, Chair
Alaska State Legislature
State Capitol, Room 121
Juneau, AK 99801

Dear Chair Giessel,

The purpose of this letter is to provide you with responses to the questions asked of the Department of Revenue (DOR) during the Senate Bill 280 presentations to the Senate Resources Committee on April 13 and 14, 2026. Please see the questions in bold and italics and our responses immediately below the questions.

1. ***Provide percentage split of state vs local revenues from the 2015 Municipal Advisory Gas Project Review Board report assumptions (including PILT and property tax amounts).***

   The 2015 Municipal Advisory Gas Project Review Board (MAGPRB) report did not establish a fixed percentage split between state and municipal revenues. Instead, the report identified estimated total payments in lieu of property tax and proposed an allocation methodology between the state and municipalities.

   The report estimated Construction Payments in Lieu of Taxes (CPILT) of approximately $800 million over the construction period and Operations Payments in Lieu of Taxes (OPILT) totaling approximately $15.7 billion over the first 25 years of operations. It was proposed that CPILT and OPILT payments would be made at the project level in lieu of traditional property tax, with revenues distributed by the state to municipalities using a formula-based methodology reflecting the physical location of project infrastructure (such as the gas treatment plant, pipeline, and LNG facilities), as well as potential statewide distribution components intended to allow broader participation in project benefits. Final allocation percentages between the state and municipalities were not specified in the report and were expected to be determined through legislation and project agreements.

   The 2015 MAGPRB report can be referenced here: https://dor.alaska.gov/docs/default-source/magpb/magp-board-annual-report-2015---final-2_5_16.pdf?sfvrsn=283c525_3.

2. At what mill rate (between 2 mills and 20 mills) would the Department assume the project would no longer move forward?

The DOR fiscal note for SB 280 as introduced showed positive revenue impact, based on the modeling assumption that the AKLNG project would not proceed without tax relief. This was a modeling assumption and fiscal note presentation decision, not a definitive prediction on a project FID. This modeling assumption was based on informal discussions with AGDC, the project's history of not advancing under the current tax regime, and modeled LNG prices indicating the project is economically marginal absent cost overruns.

The marginal economics of the project per modeled assumptions, means that DOR cannot say with reasonable certainty what level of taxation and regulation will trigger a binary FID decision. That is a question best directed to the project developer.

As a result, future fiscal notes for this legislation will likely be indeterminate to more properly represent the uncertainty. Material new information could change that.

Of course, tax rates are only one (important) aspect of the AKLNG project. Additional provisions in subsequent bill versions, as well as unfolding national and global events, will also impact project attractiveness.

3. Provide year-by-year state property tax revenue under current law vs AVT scenario (like slide 18 breakout, except for current law).

Please see slide 5 in the attached presentation. The provided tables present modeled revenue for current law and SB 280 as introduced through FY 2036. Beyond FY 2036, current law is assumed to be the same in subsequent years while the AVT in SB 280 as introduced would increase by one percent annually.

4. Provide documentation supporting assumption of zero oil production impact for Prudhoe Bay due to gas commercialization (likely AOGCC filing or order).

The Alaska Gasline Development Corporation (AGDC) has provided an assumption of zero oil production impact at Prudhoe Bay associated with gas commercialization, based on analysis presented in 2015 by British Petroleum (BP) to the Alaska Oil and Gas Conservation Commission (AOGCC) indicating cumulative oil impacts from Major Gas Sales of less than 300 million barrels. An attachment is included documenting this information from BP.

Thus, in 2015, BP was advocating in favor of major gas sales and making the case that there would not be a large impact on oil production. In consultation with AGDC, DOR used the information from BP as a basis for a baseline assumption of no impact to Prudhoe Bay oil production.

Detailed reservoir modeling and analysis, or information from the field operator, could yield different assumptions. Gas sales could decrease oil volumes by reducing reservoir pressure and overall oil recovery. Conversely, gas sales could increase oil volumes by removing production constraints and extending the economic life of wells and the field overall. While a precise model of economic limits, fluid dynamics, and reservoir performance is extremely complex, DOR does have the ability to prepare illustrative scenarios with higher or lower oil production from Prudhoe Bay.

5. The dotted lines on the charts in slides 30 and 32 are confusing, please update these.

Revised charts have been provided in the attached presentation (slides 7 and 8), corresponding to previously presented slides 30 and 32, with the LNG sales line removed in response to concerns that the dotted line could be misinterpreted. The intent of the LNG sales line was to illustrate project timing and throughput for context. The updated charts present only state revenue, as requested.

6. Please provide an estimate of the producers' profit per mcf.

Estimated producer profit from gas sales per our baseline AKLNG modeling assumptions is approximately $1.05 per thousand cubic feet (mcf) over the full 2023–2062 modeled period. This estimate assumes a $1.50 per mcf sales price and accounts for all incremental revenue and incremental upstream costs.

Estimated producer profit is approximately $0.82 per mcf over the modeled period when excluding modeled oil and condensate revenue impacts associated with new liquid production. The second measure is provided to better isolate the upstream value attributable to gas sales alone.

All values presented above are in real 2026 dollars.

Both of these numbers assume zero oil production impacts at Prudhoe Bay, do not account for previously incurred development costs, and include simplified tax assumptions for production tax, property tax, and corporate tax.

7. What profit do you estimate the upstream owners are getting from the revenues shown in slide 31?

Estimated upstream owner returns are approximately 83 percent internal rate of return (IRR) based on incremental after-tax producer cash flows under the baseline assumptions. Excluding oil and condensate revenue impacts associated with new liquid production, estimated upstream owner returns are approximately 54 percent IRR. These estimates reflect incremental revenues associated with expanded oil and gas production.

Both of these numbers assume zero oil production impacts at Prudhoe Bay, do not account for previously incurred development costs, and include simplified tax assumptions for production tax, property tax, and corporate tax.

8. Provide a chart showing the amount of lease expenditures deductions to the state per year for this project and the "loss of revenue to the state" associated with those lease expenditures.

Charts showing modeled incremental lease expenditures and the tax impact of those lease expenditures on production tax revenues are provided in slides 11-12 of the attached presentation. Production tax is calculated net of capital and operating lease expenditures; accordingly, the impacts shown reflect the reduction in production tax resulting from these deductions. Over the 40-year modeled period, modeling assumes a total of $11.3 billion of incremental upstream lease expenditures generating a tax offset of approximately $3.3 billion (nominal).

Note, the overall production tax impact is still positive due to the increased production of oil and gas, totaling approximately $10.0 billion over the modeled period. Annual incremental production tax impacts are illustrated on slide 13 of the attached presentation, alongside the official Spring 2026 production tax forecast.

Note also, the impacts of lease expenditures on production tax revenue reflect the reduction in production tax associated with incremental AKLNG-related lease expenditures, without regard to whether those would be deemed oil or gas related (as contemplated in the Senate Resources Committee Substitute version G) and assuming no change to baseline allowable lease expenditures per Spring 2026 forecast.

9. What is the per mcf price for the consumer, looking at slides 33-35.

The gas price paid by the consumer will be different for residential customers, industrial customers and electric utilities. It will also vary based on the gas provider.

To address this question, DOR looked at ENSTAR as they have readily available information regarding cost of service and are a major gas supplier in Southcentral. For ENSTAR customers, the gas price consists of the gas commodity charge added to the cost of natural gas delivery service. No markup is made on the gas commodity charge; ENSTAR earns a regulated return on their transmission system and other delivery costs. The delivery cost is currently $3.67 per thousand cubic feet (mcf) in 2026 dollars for the average residential customer. Assuming 2.5 percent long-term inflation, this implies that adding approximately $4.36 per mcf to utility cost values, such as those found on slide 20 of the attached presentation, provides an estimate of the gas price for a residential consumer.

Further information about current ENSTAR residential rates can be seen here: https://www.enstarnaturalgas.com/enstar-rate-case-overview-faqs/.

10. Provide estimate of change in state revenue and in cost of supply for in-state and LNG export if: 1. all upstream producers pay state CIT, or 2. midstream pays state CIT.

Estimated impacts to state revenue and cost of supply under the requested scenarios are provided in slide 15 of the attachment, reflecting cases where (1) all upstream producers pay state corporate income tax (SCIT), (2) midstream entities pay SCIT, and (3) both. Under these assumptions, no change in cost of supply is observed across scenarios, as the gas commodity charge is held constant in DOR modeling. While not reflected in the model, upstream producers could require a higher price for gas to offset higher tax liabilities. The midstream operator could also require a higher delivered cost of gas to achieve a given rate of return.

Currently about two-thirds of upstream producers are assumed to be subject to SCIT. Extending this to all producers would add an estimated $0.9 billion of tax over the modeled project life. Note, this estimate represents only the impact from incremental project-related cash flows and not the impact from extending such a tax to oil and gas companies more broadly.

Currently the midstream operator is assumed not to be subject to SCIT. Extending the tax to the midstream operator would add an estimated $7.4 billion of tax over the modeled project life in the baseline (current law) scenario, holding all else equal.

Finally, extending SCIT to both upstream producers and the midstream operator would add an estimated $8.3 billion of tax over the modeled project life.

11. Provide sensitivity matrix for in-state gas for Phase 1 development only.

Sensitivity matrices for in-state gas under Phase 1 development, under current law and SB 280 as introduced, are provided in slides 16-20 of the attachment. These include an overview of updated Phase 1 modeling assumptions, as well as sensitivity tables showing weighted

average in-state break-even prices for the developer and break-even prices for utilities under both scenarios.

The Phase 1 modeling reflects updated assumptions to align with the Spring 2026 modeling, including a gas supply source other than Prudhoe Bay and incorporation of associated gas treatment costs.

Note, the Phase 1-only modeling assumes an industrial "anchor customer" which will pay a lower rate for gas than utility and residential customers. The lower rate – assumed to be $6 per mcf in 2026 dollars – is required to make an industrial anchor an economic proposition. While utilities and consumers would pay a higher price relatively, they would pay a lower price than would otherwise be the case without an anchor customer.

Please let me know if I can be of further assistance.

Sincerely,

Janelle L. Earls
Acting Commissioner

Enclosures: Response Presentation
BPXA Redacted Confidential Presentation to AOGCC 27 Aug 2025

cc: Jordan Shilling, Legislative Director, Office of the Governor
Lacey Sanders, Director, Office of Management and Budget