



THE STATE
of **ALASKA**
GOVERNOR MIKE DUNLEAVY

Department of Revenue

COMMISSIONER'S OFFICE

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June 2, 2026

The Honorable Neal Foster
House Finance Committee, Co-Chair
Alaska State Legislature
State Capitol, Room 511
Juneau, AK 99801

The Honorable Andy Josephson
House Finance Committee, Co-Chair
Alaska State Legislature
State Capitol, Room 505
Juneau, AK 99801

The Honorable Calvin Schrage
House Finance Committee, Co-Chair
Alaska State Legislature
State Capitol, Room 410
Juneau, AK 99801

Dear Co-Chairs Foster, Josephson, and Schrage,

The purpose of this letter is to provide you with responses to the questions posed to the Department of Revenue (DOR) regarding House Bill 381 (HB 381) on May 14 and May 21, 2026. Please see the questions in italics and our responses immediately below the questions.

Note, this response is preliminary and was prepared under an accelerated timeline, and thus future analysis may result in different results.

Also note, the provisions regarding spreading Fairbanks spur line costs among all Alaska customers were not fully incorporated into modeling of HB 381. The modeling has spread those costs across all customers. DOR plans to update this for future analyses and can provide revised slides for past analyses if requested. Under HB 381 version T, the effective impact would be an increase to break-even cost of supply of about \$0.20 per thousand cubic feet (mcf) for in-state customers, in the full project scenario. There would be no change to the Phase 1 only analyses.

- 1. If the municipalities enter an AVT arrangement and the state later disagrees with it, could the state simply remove that authority from the municipalities and impose its own tax scheme?**

We recommend asking this question to the Department of Law.

- 2. What are the revenue figures for the state and municipalities at AVT rates of 6 cents, 12 cents, and 15 cents per MCF?**

The enclosed slides provide comparisons of state and municipal revenues under alternative pipeline AVT rates of 6 cents, 12 cents, and 15 cents per thousand cubic feet (mcf). Slides 2-4 provide cumulative cash flow summaries and cost-of-supply tables for each scenario. Slides 5-7 provide annual state revenue charts for each scenario.

Average annual state revenues during the first ten years of full project operations (2033-2042) are approximately \$17 million under a 6 cent per mcf pipeline AVT, \$33 million under a 12 cent per mcf pipeline AVT, and \$42 million under the 15 cent per mcf pipeline AVT reflected in CSHB 381(RES) version T. Average annual municipal revenues over the same period are approximately \$71 million under a 6 cent per mcf pipeline AVT, \$143 million under a 12 cent per mcf pipeline AVT, and \$178 million under a 15 cent per mcf pipeline AVT.

Under the assumptions used in DOR's modeling, the alternative volumetric tax (AVT) under CSHB 381(RES) version T applies only to the gas pipeline component of the project. Because future municipal elections under the bill's optionality provisions are unknown, the analysis assumes that municipalities retain current-law property tax treatment for the gas treatment plant and liquefied natural gas facility components.

- 3. Can DOR share its detailed assumptions on 45Q credit values and upstream operating costs, so the committee can assess the economic interplay between the carbon capture/reinjection activity and the overall project lift costs?**

The federal section 45Q tax credit for carbon capture allows entities involved in carbon capture for the purposes of utilization or sequestration to claim a credit for 12 years after the carbon capture equipment is placed into service. This credit is eligible for "elective pay" allowing tax-exempt and governmental entities to claim the credit benefits. If the CO₂ is sequestered in geological storage or used in enhanced oil recovery, and the entity meets other requirements, the credit is earned at a rate of \$85 per ton of CO₂ sequestered. This rate increases with inflation beginning 2027.

Over the first 12 years of Alaska LNG project operations approximately 68 million tons of CO₂ are anticipated to be injected, earning \$7.4 billion of 45Q credits. CO₂ injection is anticipated to continue beyond this 12-year period totaling 232 million tons through 2062.

Costs associated with extracting the CO₂ in the Gas Treatment Plant are included in DOR's operating expenses assumption of \$331 million per year in real 2026 dollars. Costs associated with injection and long-term monitoring associated with the CO₂ usage are not directly included in our analysis, but may overlap or offset with projected status quo or incremental upstream costs.

We assume approximately \$1.9 billion in incremental upstream operating costs associated with the Alaska LNG project over the first 12 years of operations where 45Q credits would be earned. Upstream incremental operating costs over the modeled period total \$6.5 billion through 2062. The upstream investment assumptions were developed by DOR in collaboration with DNR in 2018-2019 based on publicly available information, have not been validated by the producers, and have a range of uncertainty.

4. *Please provide modeling showing the estimated impact to in-state consumers of spreading the Fairbanks spur line cost across only Alaska in-state ratepayers, including the approximate added \$/mcf cost to consumers.*

Based on the AVT provisions in HB 381 version T, the Cost of Supply for in-state utilities would total \$4.75 per mcf without a Fairbanks spur line, and approximately \$4.95 per mcf with a Fairbanks spur line costing \$194 million. This \$0.20 per mcf impact represents an initial estimate, as updates to the DOR model are still ongoing to separate those pipeline costs that would be passed to all gas buyers from those of the Fairbanks spur that under HB 381 version T would only be passed to in-state buyers.

The provisions regarding spreading Fairbanks spur line costs among all Alaska customers were not fully incorporated into modeling of HB 381. The modeling presented has spread those costs across all customers. DOR plans to update this for future analyses and can provide revised slides for past analyses if requested.

These cost of supply estimates are based on the baseline AKLNG model assumptions and assume the full project goes forward, including LNG exports. These rates may differ depending on the construction costs and property tax associated with the Fairbanks spur line.

5. *Please provide the administration's position or recommendation regarding how municipalities should address increased service demands and infrastructure impacts associated with the project, given the modeled reduction in municipal revenues under the governor's proposal.*

House Bill 2001, introduced by the Governor on May 21st, reflects more recent discussions with the communities and legislators to address increased service demands and infrastructure impacts through the Community Impact Grant Program and the Alaska Liquefied Natural Gas Project Mitigation Fund. These funds would be received by communities in addition to any Alternative Volumetric Tax they would collect as a result of this project.

6. Please provide the June 2023 BRG analysis prepared for ENSTAR regarding LNG import options and associated cost estimates referenced during testimony.

The June 2023 Berkeley Research Group (BRG) “Cook Inlet Gas Supply Project (CIGSP) Phase I Assessment” was prepared for the Alaska Utilities Working Group led by ENSTAR. The report evaluates potential options to address anticipated Cook Inlet gas supply shortfalls, including LNG import options, an in-state gas pipeline, Cook Inlet supply development scenarios, and related indicative cost estimates. The report also recommended additional work under a potential Phase II analysis to further refine and evaluate supply options; however, DOR’s understanding is that this additional study was not commissioned by ENSTAR or the working group.

The report can be found here:

<https://www.enstarnaturalgas.com/wp-content/uploads/2023/06/CIGSP-Phase-I-Report-BRG-28June2023.pdf>

7. Provide updated Phase 1-only heat maps / sensitivity matrices for Version T of the bill, similar to the analyses previously presented to Senate Resources in late April.

The enclosed slides provide updated Phase 1-only sensitivity matrices for current law, HB 381 as introduced, and CSHB 381(RES) version T. Slide 8 summarizes the model assumptions specific to a Phase 1 project with no LNG exports. Slides 9 and 10 present estimated in-state break-even prices under varying upstream gas price assumptions and capital expenditure assumptions for the Phase 1 in-state pipeline scenario.

Under DOR’s baseline assumption of a \$1.50 per thousand cubic feet upstream gas price, the estimated weighted average nominal in-state break-even prices in 2033 are approximately \$14.55/mcf under current law, \$12.45/mcf under HB 381 as introduced, and \$12.65/mcf under CSHB 381(RES) version T. These weighted average prices include an assumption of a baseload industrial consumer paying \$6/mcf and a higher cost for utilities.

The estimated nominal in-state break-even prices for Southcentral utilities in 2033 are approximately \$22.70/mcf under current law, \$18.60/mcf under HB 381 as introduced, and \$18.99/mcf under CSHB 381(RES) version T.

The Phase 1 analysis assumes an in-state pipeline scenario without LNG exports or an LNG facility.

8. Does the Regulatory Commission of Alaska (RCA) have authority over gas sales from the project?

As stated in our response to this question during the bill hearing, the pipeline itself will be regulated by FERC. However to clarify further, our understanding is that ENSTAR and the other Southcentral utilities will be required to gain approval from the RCA for any gas sales

agreement with the project, so there is some RCA role in the project. We recommend that the committee consult with the RCA and impacted utilities directly for further information on the process for RCA approvals and on the current status of negotiations for gas supply.

9. Please provide opportunity-cost modeling or analysis comparing potential state equity investment returns against alternative uses of funds, including comparison to Permanent Fund-style returns.

A decision to invest in the AKLNG project would depend on expected project rate of return, on expected risk, and on expected benefits to the state not included in the rate of return.

DOR modeling of the project assumes a 10% pre-tax rate of return, which would compare favorably to the expected rate of return for the Permanent Fund of 7.6% over the short term and 7.3% over the long term. The Permanent Fund is chosen since it is a large source of funds that effectively serves as the marginal source of revenue and savings for the state. However, this comparison ignores the different level of risk for the Permanent Fund or other diversified baskets of investment. Until more information is available on project costs, potential returns, and risk, it is unclear whether the state should choose to invest.

Under DOR's baseline assumptions, the estimated cost of investing for a 5% share of the project is \$880 million, representing 1.0% of the current total value of the Permanent Fund, while the estimated cost of investing for a 25% share of the project is \$4.42 billion, or 5.0% of the Permanent Fund. In general, such a large single investment would reduce the diversification of the state's investment portfolio and hence could increase investment risk. For reference, under the Alaska Permanent Fund Corporation (APFC) Investment Policy, board approval is required for any investment in Alaska of more than 1% of the fund in order to maintain diversification.

State investment in the project could be justified if expected returns are high enough to overcome concerns about the impact on state portfolio diversification, or if state investment is necessary to ensure the project goes forward and achieves the other expected benefits to the state, including lower energy prices and increased employment.

While DOR can provide a basic overview, it is recommended to contact the Treasury Division for more in-depth information, or APFC for information relating to investment by the Permanent Fund.

Under HB2001, introduced by the Governor for the special session, DOR would be required to assist the legislature with understanding funding options and evaluating state equity investment decision. More sophisticated and in-depth evaluation of opportunity costs and potential funding options including Permanent Fund would be part of this workload.

10. What would be a comparable AVT rate to the current property taxes of the North Slope Borough and Kenai Peninsula Borough.

If the Alaska LNG project were to proceed under current tax law the CY 2033 property tax collections from the GTP and Pipeline to the North Slope Borough are estimated to total \$288 million under the baseline AKLNG assumptions including a \$46.2 billion project capital cost in real 2026 dollars. The equivalent AVT rate to generate that revenue in CY 2033 based on the throughput definition in HB 381 version T is approximately \$0.24 per mcf.

Similarly, if the Alaska LNG project were to proceed under current tax law the CY 2033 property tax collections from the Pipeline and LNG Plant to the Kenai Peninsula Borough are projected to total \$178 million. The equivalent AVT rate to generate that revenue in CY 2033 based on the throughput definition in HB 381 version T is approximately \$0.15 per mcf.

Please let me know if the department can be of further assistance.

Sincerely,



Janelle L. Earls
Commissioner

Enclosure: Slides for select questions

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