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TO: Representative Tuck
Chair, Legislative Budget & Audit Committee

FROM: Mr. Rich Ruggiero, IN3nergy; Ms. Christina Ruggiero, IN3nergy

DATE: February 25, 2020

RE: Request on Analysis of the Ballot Initiative 19OGTX

On February 10th you requested[1] a review and analysis of ballot initiative 19OGTX entitled: "An Act relating to the oil and gas production tax, tax payments, and tax credits" or by its simple title of the "Fair Share Act" (the "Initiative"). You specifically asked that:

- We thoroughly respond to the questions raised in the attached letter from the presiding officers of the Legislature; and

- At the request of House Resources Committee Co-chair, Representative Lincoln, include potential impacts to [tax] revenue, Alaska production, and potential future investment in our analysis of the Initiative.

The letter from the presiding officers[2], Senator Giessel and Representative Edgmon, contains a number of specific requests related to a detailed review of the Initiative. Their requests for an initial review of the Initiative include:

- Review the language from a holistic perspective;

- Describe the Initiative and how it would change the current oil and gas fiscal regime;

- Questions raised by the Initiative, the answers to which would materially impact future analysis of the Initiative's impacts;

- Provisions to which the contractors, as they undertake modeling and analysis of the impacts, may need to interpret or receive direction on how to interpret;

- Identify provisions which may affect generally investment in the North Slope basin, such as the disclosure of previously confidential taxpayer information; and

[1] Attached hereto as Appendix 1
[2] Attached hereto as Appendix 2

- Articulate any impacts to the Middle Earth and Cook Inlet basins, including to investment behavior.

- Isolate the components which will likely result in variable fiscal analysis depending on how those components are interpreted; for example, but not limited to:
  - How is “field” defined?
  - How is “Offsets” defined? Does the term include the gross value reduction?
  - How are lease expenditures attributable to gas handled?
  - How will carry-forward lease expenditures be treated for new developments outside the major fields, by companies with production in the major fields? Will those carry-forward lease expenditures be subject to the 10% value reduction per year after 10 years?
  - To what tax is the ‘additional’ production tax to be additional to?
  - Whether the new tax applies to oil only or to oil and gas?

There is a degree of overlap in the multiple requests received concerning an analysis of the Initiative. This report addresses the various inquiries first with a thorough holistic review of the Initiative based only on its content, supplemented by additional comments on each of the questions asked.

By request of the presiding officers, the following analysis has purposefully ignored any other interpretations by the administration, by the Initiative’s sponsors and other interested parties.

Upon reading this report, some viewers may look at some of the issues discussed as being minor or not worth highlighting. The considerable ambiguity contained in the Initiative needs to be viewed as a whole for a number of potential future scenarios: determining whether or not the Legislature could pass ‘substantially similar’ language, discussing amendments should the Initiative pass, and understanding the cause of disputes on how to define regulations for the Initiative should the Initiative pass. Defining what is intended by the wording of the Initiative will likely be problematic and contentious.

HOLISTIC REVIEW OF 19OGTX

There has been much debate over the years as to what Alaska’s fair share of petroleum revenues should be. Beginning with ELF in the late 1970s, several pieces of legislation have been passed to try and achieve the right level of state take from oil production that still ensures continued oil company investment in growth opportunities. A number of concerned citizens, believing that the current state share under today’s oil price levels is insufficient, have put together a ballot initiative in hopes of achieving a greater share of oil revenue for the state.

It appears the Initiative intends to increase the production taxes paid on the largest legacy oil producing assets on Alaska’s North Slope and to separate, or ringfence, those assets such that the positive cash flows could not be used to immediately recover costs from other North Slope assets. By requiring ringfencing and new taxes, the Initiative appears to try and isolate these large fields from the rest of the state in the petroleum tax framework.

The Initiative fails to deliver language that is clear, concise and in the key areas, unambiguous. Without such clarity and specificity, many different interpretations are possible. If the voters approve it, there will be an extended period of uncertainty and business disruption as all interested parties attempt to interpret exactly what it will mean in practice.

Even as experienced practitioners in petroleum fiscal policy, looking only at the language of the Initiative, we found it impossible to ascertain exactly what the sponsors intended. This uncertainty will make it difficult for the Legislature, if it chooses to do so, from coming up with 'substantially similar' language.

The following paragraphs provide a summary sectional analysis supplemented with observation of issues and questions raised. Where possible, alternative interpretations are noted and discussed.

Section 1

Titled the "Fair Share Act", the Initiative does not contain any statement to define what would constitute a "fair share" of certain oil revenues to the State of Alaska. Without such language, and with many of the following sections open to interpretation, any interpretation of the Initiative could be pursued as the correct "fair share" interpretation.

The most important aspect of this first section is the statement, "Notwithstanding Any Other Statutory Provision to the Contrary the Oil and Gas Production Tax in AS 43.55 Shall Be Amended As Follows". From our perspective, the inclusion of the term "Notwithstanding" means the language of the Initiative is intended to override production tax terms contained in AS 43.55 that would otherwise govern the taxation of the oil assets meeting the criteria in Section 2.

Other than this statement in Section 1, the only other direct reference to altering a particular part of AS 43.55 is Section 4 paragraph (a) in relation to the per barrel credits in AS 43.55.024 (i) and (j). Sections 3 and 4, without any other specific reference to sections of AS 43.55 appear to change the gross and net tax on production. Determining the actual tax due and payable involves more than just the gross and net tax calculations in Sections 3 and 4 as there are a number of credits, allowances and carried forward items within the language of AS 43.55 that appear not to have been changed.

Section 2

Section 2 appears to identify which oil operations on Alaska's North Slope are to be impacted. Section 2 states that the tax provisions in Sections 3 and 4 "only apply to **oil** [emphasis added] produced from *fields, units and nonunitized reservoirs* [*emphasis added*] north of 68 degrees north latitude that have produced in excess of 40,000 barrels of oil per day in the previous calendar year **and** [*emphasis added*] in excess of 400,000,000 barrels of total cumulative oil production." It further states that all other oil production and the production taxes related thereto remain unchanged.

As discussed below, in AS 43.55 the term(s) "fields, units and nonunitized reservoirs" is not used. While there is a definition for 'units' there are no definitions for 'field' or for 'nonunitized reservoirs'. In order to not show any prejudice toward one interpretation or another of what each of those terms means, "fields, units, and nonunitized reservoirs" qualifying under Section 2 of the Initiative will be referred to as a "40/400 Asset".

Section 2 language is unclear and will require significant interpretation to implement. While the description appears to be an attempt to isolate the three largest 'fields' from the rest of the slope, the Initiative wording leads to a number of varying observations and questions.

1. Today, all North Slope operations, except for gas used in the state, are treated as part of one ringfence for tax purposes (AS 43.55.160 (a) (i) (A)). Taxes are assessed by producer, or taxpayer.

2. AS 43.55 generally uses the term "leases and properties" throughout AS 43.55 to refer to oil and gas operations in the state. We did not find any usage of the phrase "fields, units or nonunitized reservoirs" in any statute or regulation governing the taxation of oil and gas. We are unable to discern why terms not common to AS 43.55 would be chosen to define assets to be assessed against the qualification criteria.

3. Without defining language, it is not clear whether "fields, units and nonunitized reservoirs" defines three separate types of groupings, i.e. a field, a unit or a nonunitized reservoir, or whether the term is meant to be used collectively as a singular grouping. There is no language to assist in any way to determine what the intended definition(s) is (are) for fields, units and nonunitized reservoirs.

4. With respect to oil and gas taxation, aside from the modification of ELF in 1989 to add a field test, taxes payable have been on a well basis or a broad geographical basis; i.e. North Slope, Cook Inlet and Middle Earth. Data and information published online by DNR and AOGCC address groupings of wells by lease, participating area, area, pool, field and unit. In the case of Prudhoe Bay for example, the terms unit and field are sometimes used interchangeably while other times they are referred to separately and uniquely as the Prudhoe Bay field and Prudhoe Bay satellites that collectively comprise the Prudhoe Bay unit.

5. The term 'field' is very common in the oil and gas industry. Generally, it is defined as an area of oil and gas production with at least one common reservoir for the entire area.[3] "Field" is not defined in AS 43.55, the petroleum tax statute.

6. Field is defined elsewhere in statute and regulation, but for purposes other than taxation. One example, for operations under AS 31.05.170 AOGCC provides that "field" means a general area which is underlain or appears to be underlain by at least one pool, and includes the underground

[3] https://www.mineralweb.com/library/oil-and-gas-terms/oil-gas-field-definition/

reservoir containing oil or gas; and the words “pool” and “field” mean the same thing when only one underground reservoir is involved, but “field” unlike “pool” may relate to two or more pools.

7. Neither AS 43.55 nor the Initiative provide any guidance on what type or size grouping of wells or pools constitute a field. A narrow definition for field will lead to issues noted later when a Section 2 qualifying field is also part of a unit.

8. The term “unit” is defined under AS 43.55.900. A “unit” means a group of tracts of land that is subject to a cooperative or a unit plan of development or operation that has been certified by the commissioner of natural resources under AS 38.05.180(p). The North Slope contains a number of “units”. Each of the North Slope units appear to contain a number of pools and fields.

9. It appears there are two primary ways to initially qualify as a 40/400 Asset: (1) the combined daily production and the combined cumulative production of a bunch of ‘small’ pools in a unit meet the two threshold levels, or (2) a single ‘field’ meets the two threshold levels which by definition means the entire ‘unit’ that field is a part of would also qualify as a 40/400 Asset. In this latter case there could be both a ‘field’ qualifying as a 40/400 Asset as well as a unit qualifying as a 40/400 Asset.

10. The fields or pools, whether narrowly or broadly defined, that meet the criteria are Alpine, Kuparuk and Prudhoe Bay which then by the language of Section 2 could also mean that the Colville River Unit, Kuparuk River Unit and Prudhoe Bay Unit, respectively, meet the qualifications.[4] All would be 40/400 Assets.

11. We were unable to find any definition for ‘nonunitized reservoir” in statute or regulation. One interpretation is that any reservoir, and the wells producing from that reservoir, that are not part of a single reservoir unitization agreement could by default be part of a nonunitized reservoir. In AS 43.55.025 there is a definition for “reservoir” which means an oil and gas accumulation, discovered and evaluated by testing, that is separate from any other accumulation of oil and gas.

12. In petroleum practice, a reservoir can cover large geographic areas. In the Lower 48, the Chase reservoir in the Hugoton field covers an area in three states in excess of 7500 square miles. Each of the three states break the reservoir into defined fields or units for regulatory purposes; however, the ‘reservoir’ is not unitized. Generally speaking, the Chase is a good example of a nonunitized reservoir.

13. Using the AS 43.55 definition for reservoir, any well or pool of wells that produce from the same formation could be viewed as a “nonunitized reservoir”. According to AOGCC’s North Slope Stratigraphic Column, there are numerous pools/fields that possibly produce from the same

[4] On the AOGCC website (http://aogweb.state.ak.us/poolstatistics/annual/current/poolStatisticsCurrent.html) under Commerce/AOGCC/Pool Statistics/Current Oil & Gas Pool Statistics

reservoir.[5] Even though parts of the same reservoir are part of different operational units, combined they could represent a nonunitized reservoir. Generally speaking, unit and unitization are not the same thing.

14. The purpose of discussing this at length is to show that depending on the definition agreed for pools, fields, units and reservoirs, it is possible that assets other than just the Prudhoe Bay, Kuparuk and Alpine 'fields' could qualify as 40/400 Assets.

15. For new production coming online, best practices would have new producing areas using existing facilities on the slope where they can. For the North Slope, this would generally mean using facilities from fields or units qualifying as 40/400 Assets. If the Initiative were to pass, and if new production was defined or forced to be combined with a 40/400 Asset, then the new production would become a 40/400 Asset with the first barrel produced. There will be many issues to consider in defining and applying definitions for fields, units and nonunitized reservoirs.

16. Section 2 states that the provisions in Sections 3 and 4 "**only** apply to oil" [emphasis added]. This would appear to mean the Initiative is only covering oil. But Section 3 uses "For oil production" dropping the 'only' modifier. Section 4 "For production" dropping any reference to oil and opening the possibility that production refers to oil and gas. Finally, Section 5 uses "for oil and for gas". In these four sections the Initiative goes from exclusively oil to definitely oil and gas. Whether it is oil only or oil and gas, the interpretations are numerous and varied.

17. For Sections 3 and 4 to apply, the 40/400 Assets must "have produced in excess of 40,000 bopd in the previous calendar year" [emphasis added]. It is unclear as to whether that means production over the entire previous calendar year averaged in excess of 40,000 bopd or that the fields, units and nonunitized reservoirs merely needed to produce in excess of 40,000 bopd on one single day in the previous calendar year. The use of language such as "**averaged** in excess of 40,000" or "produced **on any day** in excess of 40,000" would have easily provided clarity.

18. Once operations meet the two production criteria, the Initiative is not clear when the other sections of the Initiative apply. Looking first to the daily production criteria, do the new taxes and ringfencing requirements apply beginning with the month of January in the year following the year of qualifying production? Do they apply for the entire subsequent calendar year? Do the new taxes still apply if in the calendar year after having produced in excess of 40,000 bopd the production falls below 40,000 bopd?

19. A second possible situation (in the future for new developments) is where the field, unit or nonunitized reservoir has been producing consistently above 40,000 bopd but has not yet reached the cumulative criteria of 400,000,000 barrels. In this case, do the new taxes in Sections 3 and 4 begin to apply the month in which the cumulative production exceeds 400,000,000 barrels? Or, do they apply starting January 1st of the following year? The Initiative does not

[5] http://aogweb.state.ak.us/poolstatistics/annual/current/OIL/Prudhoe_Bay,Prudhoe_Oil/Illustration_Strat_Col.pdf

include any effective date language for the cumulative criteria to clearly understand when the new taxes under the Initiative would be applied in this second possible situation.

20. There is no language in the Initiative on where the qualifying oil production is to be measured. Is it total barrels sold into the market? Total barrels delivered to TAPS? Or, is it referring to total barrels produced at the wellhead? These three production values are always different and can be significantly different over time. For example, a 5% difference between wellhead barrels and sold barrels is +/- a 20,000,000 barrel difference relative to a 400,000,000 target, or the equivalent of 40,000 bopd for 500 days.

21. Another issue related to production is whether the qualification criteria in Section 2 relate to total barrels or to taxable barrels? Taxes under AS 43.55 are assessed against revenues based on taxable barrels. These two values generally will differ by the quantity of royalty barrels or +/- 12%, a considerable difference. This difference between total barrels and taxable barrels would also translate into significantly different time periods when operations would be qualified as a 40/400 Asset.

22. There can be a considerable amount of energy used in support of production operations. The Initiative does not address whether or not for the purposes of Section 2 if lease use of produced oil and gas is to be considered as production.

23. While the intent may have been to only have Alpine, Kuparuk and Prudhoe Bay 'fields' to be 40/400 Assets, the use of "units and nonunitized reservoirs" could cause all of the pools of oil that form the Colville River, Kuparuk and Prudhoe Bay Units to be qualified as 40/400 Assets as well. Depending on a chosen definition of "nonunitized reservoir" many more pools and wells could also be defined as 40/400 Assets.

Section 3 Alternative Gross Minimum Tax

This section defines a **monthly** alternative gross minimum tax ("AGMT") for oil produced from 40/400 Assets. The AGMT would appear to replace the current gross minimum tax that ranges from 0% to a maximum of 4%[6] of the gross value at the point of production ("GVPP") with a new gross tax ranging from 10% to as much as 15% of the GVPP.

The AGMT increases from a base of 10% of GVPP when the average monthly price for Alaska North Slope crude oil for sale on the United States West Coast (La. Basin) ("ANSWC") is less than $50/bbl, increasing "an additional 1%" of the GVPP "for each $5 increment" in the ANSWC price above $50/bbl. The AGMT increases until reaching a maximum rate of 15% which is applicable for all monthly average ANSWC prices equal to or greater than $70/bbl.

[6] AS 43.55.011(f)

The Initiative in Section 3 includes a paragraph (c) that states "No credits, carried forward lease expenditures, including operating losses, or other offsets may reduce the amount of tax below the amounts calculated in this section." Under AS 43.55 there currently are no provisions for adjusting the GVPP, through the use of credits, net operating losses ("NOLs") or otherwise, in the calculation of the gross minimum tax due. However, there are a number of allowed deductions from the GVPP in the calculation of the Production Tax Value ("PTV") for purposes of calculating a net tax.

1. The AGMT rate is to be assessed on the GVPP. The Initiative does not contain any language to alter the definition of GVPP from how it is defined in current statute. This Section 3 creates new higher gross minimum tax rates at new ANSWC trigger prices for 40/400 Assets.

2. The Initiative defines the applicable trigger price as the "Alaska North Slope crude oil for sale on the United States West Coast **(La. Basin)"** [emphasis added]. Current statutes do not include the parenthetical when referring to the price of Alaskan crude. There is nothing in the language of the Initiative to explain the deviation from standard AS 43.55 wording. The inclusion of the parenthetical is deliberate; however, we were unable to ascertain how this might change or redefine the trigger prices for the Initiative.

3. The calculation to determine GVPP has never included deductions for credits, lease expenditures or offsets. The only expenditures and offsets in the GVPP calculation relate to midstream activities downstream of the unit boundary, such as TAPS tariffs and shipping costs. For determining the gross tax payable, under AS 43.55 today the gross tax rate is multiplied by the GVPP without any further deductions for upstream activities.

4. With the inclusion of paragraph (c), not in Section 4 where it would appear to more appropriately belong, it is not possible to discern what is intended by the inclusion of paragraph (c) in this section.

5. The language is not clear if the 1% gross minimum tax increase at prices above $50 per barrel is in $5 step increments or if the increase is continuous at the rate of 1% per $5 (e.g. at $53 ANSWC is the applicable tax rate 11% [10%+1% >$50 but<$55] or 10.6% [10%+1%*($3/$5)]). A step function would be consistent with current gross minimum tax language. This could have been made clear and unambiguous had the sponsors chosen to reference the step language used in AS 43.55.

6. While credits, carried-forward lease expenditures and operating losses are terms used often in AS 43.55, the term 'offsets' is not. Without any defining language in the Initiative it is unclear what is meant by the term 'offsets'. One possible interpretation is that it is a catch-all term that could be defined to be as broad or as narrow as needed now or in the future to prevent reduction of the amounts upon which tax calculations are based.

Section 4 Tax on Production Tax Value

This section appears to define a new net tax calculation to be applied against the Production Tax Value ("PTV") as defined in AS 43.55.

Paragraph (a) clearly and explicitly states that the credits now allowed in AS 43.55.024 (i) and (j) shall not be used for 40/400 Assets. These two credits are the fixed $5 per barrel credit for GVR eligible fields and the sliding scale (from $0 to $8) per barrel credit for all other fields on the North Slope. We note here how in this case the specific references to the current statutes are used to make clear which of the several credits allowed under AS 43.55 would no longer apply.

The second paragraph (b) describes "An additional production tax" that shall be paid each month when the producer's average PTV of taxable oil is equal to or more than $50. The tax is calculated by subtracting $50 from the monthly average PTV of a barrel of oil, then multiplying that difference by the total barrels of taxable oil, and further multiplying that number by 15%.

Whether intentional or not, the unclear drafting raises several issues.

1. It is clear that the existing per barrel tax credits do not apply to 40/400 Assets. By the use of specific references to AS 43.55 alternative interpretations are eliminated.

2. Under current AS 43.55 language the gross minimum tax on GVPP and the net tax on PTV are both treated as and referred to as "production tax".

3. As both a gross tax on GVPP and a net tax on PTV are a production tax, it is unclear from the language, "An additional production tax", if the proposed new Section 4 tax is (1) another production tax in addition to the Section 3 tax; or (2) an additional net tax on PTV on top of other taxes in AS 43.55.

4. Referring back to the use of "Notwithstanding" in Section 1, one very plausible interpretation is that this new Section 4 tax is a production tax in addition to the new gross minimum tax in Section 3 thus replacing the current taxes under AS 43.55 otherwise applicable to 40/400 Assets.

5. If this new tax was intended to be in addition to the current 35% net tax on PTV it would have been very simple to have included language to that effect, such as "**In addition to the tax in AS 43.55.011(e)(2)**, an additional production tax…." Even though simple and specific language was used to make clear which credits no longer applied, such specific language was not used for paragraph (b). This was easily avoidable ambiguity.

6. Paragraph (b) states that the additional tax shall be paid when the "average monthly Production Tax Value of taxable oil is equal to or more than $50". PTV "of taxable oil" defines the gross taxable income. It is a revenue and not a unit value. In reality, the PTV of taxable oil, or the monthly gross taxable income, will always be greater than $50 for every 40/400 Asset.

7. In AS 43.55 trigger prices are typically defined as PTV "**<u>per barrel of</u>**" taxable oil. This provides a unit value which may or may not be more than $50 in any given month. It is unclear why the 'per barrel of' language was not used in determining when the additional tax applies.

8. In the second sentence of paragraph (b), however, the wording switches to use of PTV on a per barrel basis. The inclusion or exclusion of the 'per barrel' modifier greatly changes the meaning as noted in the prior two paragraphs.

9. Also, throughout AS 43.55, when referring to PTV on a per barrel basis it is always referred to as PTV per **taxable** barrel. In our discussion on Section 2 above we noted the significant difference between barrels and taxable barrels. Notwithstanding that AS 43.55 always refers to PTV per barrel of taxable oil, this paragraph (b) uses the language "PTV per barrel". By definition, there are always more barrels than taxable barrels, so PTV per barrel will always be a smaller number than PTV per taxable barrel. Leaving out the modifier 'taxable' makes a +/- 12% difference in one part of the calculation and will result in a significantly lower tax than we believe was intended.

Section 5 Separate Treatment

This section defines how taxes are to be calculated by each producer. It states that the taxes in Sections 3 and 4 are to be calculated separately for oil and gas, by calendar month, and that eligible lease expenditures be calculated, deducted and carried forward separately for each of the fields, units and nonunitized reservoirs.

1. Section 2 states that the taxes in Sections 3 and 4 only apply to oil. Section 5 now states the taxes in Sections 3 and 4 also pertain to gas in some way. Both cannot be true. The addition of gas here in Section 5 opens the door to any number of interpretations.

2. If you take the position that the inclusion of gas was intentional to cause a change to the status quo, one possible interpretation is that gas from each 40/400 Asset would be ringfenced from each other and from other North Slope gas.

3. As the language of the Initiative lacks any instructions related to gas, one could assume that gas and oil related lease expenditures will continue to be combined and deducted against the PTV for oil as is their current treatment.

4. Paragraph (b) notes that taxes are to be calculated and paid for each calendar month. It follows then that there will be no producer annual tax return for 40/400 Assets. This differs from the present AS 43.55 language where various estimates are used to calculate and pay monthly tax installments followed by a single annual tax return filing reconciling the installment payments.

5. Paragraph (b) states the monthly allowed lease expenditures are equal to the annual lease expenditures divided by 12. While mathematically this is not hard to do, administratively this will

be burdensome for both the producers and the Department of Revenue. Essentially, when the year is complete and all lease expenditure amounts are finalized for the year, it's our understanding that the producers will need to file 12 amended tax returns, one for each month, for every 40/400 Asset versus today when they file one tax return for the year for all of the North Slope combined.

6. While paragraph (b) addresses how lease expenditures are to be treated, it is silent on how carried forward losses and other eligible credits that are routinely deducted from GVPP to determine PTV should be handled. Will they be allowed to be used to the maximum extent to minimize monthly taxes or will they be subjected to a 1/12th rule as well? It should be expected that as for-profit entities, taxpayers will choose to use any eligible deduction in a manner to minimize overall tax payments. The lack of instructions covering the handling of all deductions will very likely lead to multiple interpretations.

7. Existing carried forward losses and credits have been created from a taxpayer's collective North Slope operations, not from a specific field or unit. No language has been offered to suggest how these aggregated amounts are to be disaggregated into the new individual field and unit ringfences. Resolving this, depending on the amounts at stake, could be highly contentious.

8. Paragraph (c) states that expenses must be calculated, deducted and carried forward separately for each of the fields, units and nonunitized reservoirs that meet the conditions of Section 2. What Section 5 does not say is that taxes must be calculated separately for each field, unit or nonunitized reservoir. Why would the Initiative require expenses to be separated by each 40/400 Asset but not explicitly require a separate tax return for each 40/400 Asset? Again, the language of Section 5 creates a situation that would allow for multiple interpretations.

    a. If the reason for accounting for expenses separately for each 40/400 Asset is that each producer of a 40/400 Asset must file a separate tax return per 40/400 Asset, taxes would need to be calculated separately for each qualifying field as well as the for unit containing the field(s), e.g. both for the Prudhoe Bay field and the Prudhoe Bay Unit. This could lead to double taxation.

    b. Along the same line of thinking, would each of the other pools that may not be part of the Prudhoe Bay field but are part of the qualifying Prudhoe Bay Unit have to file separate tax returns as well?

    c. Realistically, you either have to ringfence the unit and do one tax return for the unit or you need to ringfence each field within a qualifying unit, but not both. The language of the Initiative does not provide any guidance in this matter.

9. Section 5 appears to create a multiplicity of new tax returns that will require significant staffing to complete, review and audit. The multiple tax returns will also require extensive rules to define how the costs of any common use facilities are to be distributed among the various ringfenced

40/400 Assets and all other non-qualifying leases that use the same facilities. This is a significant undertaking for both the producers and the administration.

Section 6 Greater of

Section 6 is a short, simple and unambiguous statement, "For each producer, for each calendar month and for each of the fields, units and nonunitized reservoirs the tax due is the greater of the taxes calculated under Section 3 or Section 4."

1. We noted that the language of Section 5, while calling for different things to be handled separately, failed to explicitly call for separate tax returns for each of the 40/400 Assets. The "each of" reference in Section 6 could be interpreted to mean that each of the fields*,* each of the units *and* each of the nonunitized reservoirs is ringfenced separately for tax purposes. If so, it raises the possibility of double taxation as noted earlier with both a qualifying field and the unit it is part of having to file separate tax returns.

2. The above language is explicit in that the tax due from a producer for a 40/400 Asset is the greater of the tax calculated under Section 3 and Section 4 of the Initiative. There is no reference, direct or implied, to any other taxes, including those in AS 43.55, being applicable to a 40/400 Asset.

3. Whereas Section 4 is noted as "an additional production tax", Section 6 only references the tax calculated as per Sections 3 and 4. The wording does not leave open any possibility that the new Section 4 tax was in addition to some other tax, unless that other tax was the new tax in Section 3.

4. Given the tax is only to be the greater of taxes defined by the Initiative in Section 3 or Section 4, the 10% to 15% gross tax on GVPP in Section 3 will always be greater than the 15% net tax on PTV in excess of $50 per taxable barrel in Section 4. While this may not be what was intended, this is the only conclusion that can be reached based on the very specific wording of Section 6.

Section 7 Public Records

This section would make the tax returns, along with supporting material, for each of the fields*,* units and nonunitized reservoirs a matter of public record. What is uncertain, and what the Initiative did not make clear is that they should be treated as non-confidential. If the intent was for them to be made available to the public, the Initiative did not make that clear.

1. The language used in this section fails to actually change anything as it is our understanding that tax returns and supporting material, as well as a whole host of other producer supplied data, are already a matter of public record but because of their content they are treated as confidential and not subject to public disclosure.

2. The inclusion of Section 7 appears to be trying to make all 40/400 Asset tax returns and all the data associated with those returns non-confidential public information. The following two points raise issues with public release of tax returns.

3. Where other countries require producers to publicly release taxpayer information, it is usually just the total amount of tax paid. We are not aware of any other oil and gas regime requiring the public release of all supporting and back up data associated with taxes paid.

4. "All filings and supporting information" could be interpreted as not only supplying documents and data for the initial filing of the return but also all amended returns and all audits. This could be further interpreted to include all information associated with negotiation of tax settlements which could ultimately have Alaska government documents included in the disclosure.

5. Section 7 references the "Department". Throughout AS 43.55 the Department of Revenue is referred to as the "department" (lower case). We are not able to discern any reason why the Initiative would choose to use the upper case Department or what the implications, if any, it implies.

Section 8 Scope of Initiative

This section places no restriction on the Legislature for use of the funds raised by this Initiative and explicitly allows for the revenues generated to be used to pay permanent fund dividends.

Section 9 Severability

This is a typical clause that states if any part of the Act is found to be invalid all the other parts remain unaffected. Given all the ambiguity contained in the Initiative, and the many different interpretations possible, it is hard, but not impossible, to imagine any particular aspect being invalid as opposed to the entire Initiative being invalid.

<u>PRESIDING OFFICERS REQUESTS</u>

A. *Identify provisions [of the Initiative] which may affect generally investment in the North Slope basin, such as the disclosure of previously confidential taxpayer information.*

    a. The biggest impact, negatively, will be the ringfencing of the largest, profitable fields thus not allowing for the timely deduction of capital and operating costs associated with other investments, in particular investments in new fields. Instead of a quick recovery of costs, those costs would need to be carried forward and recovered from production many years into the future. This is a significant reduction of project economics from the producer perspective.

b. Producers have a choice as to where they can invest their capital. With many countries competing for capital, the risks associated with a public disclosure of all the backup data and information used to determine taxes would in our view create a barrier to new companies from coming to Alaska and may cause existing players to reconsider their commitment to Alaska. Even though the Initiative looks to cover the larger fields there would always be the risk that it could one day be applied to all operations in the state.

B. *Articulate any impacts to the Middle Earth and Cook Inlet basins, including to investment behavior.*

a. The current wording of the Initiative makes no changes to operations or tax returns for Middle Earth or the Cook Inlet. The only impact we perceive to non-North Slope areas is the uncertainty that is created and the ensuing debates that will take place on how to interpret the Initiative. This risk will likely cause current and prospective producers to take a pause in their investment considerations while implementation details are sorted.

b. Where a producer has operations outside the North Slope, the requirement to make public all data associated with a return could cause some data from Middle Earth or Cook Inlet operations to be exposed (e.g. allocation of overhead expenses).

C. *Isolate the components which will likely result in variable fiscal analysis depending on how those components are interpreted; for example, but not limited to:*

a. *How is "field" defined?*
Field is not currently defined under AS 43.55; however, it is defined elsewhere in statute and regulation. Using the definitions for field and pool in the discussion of Section 2 above, a field can be comprised of one or more pools. As described earlier, depending on the definitions adopted, there could be just a few assets qualified as 40/400 Assets or there could be numerous operations on the North Slope qualified as 40/400 Assets.

b. *How is "Offsets" defined? Does the term include the gross value reduction?*
Offsets is not defined in the Initiative or in AS 43.55, although offset is used in other Alaska statutes. It is generally defined as any allowable deduction from revenues to determine taxable income. This would include the gross value reduction allowed in AS 43.55. Its inclusion in the language of the Initiative would allow for an interpretation to be anything that is a current deduction to be disallowed.

c. *How are lease expenditures attributable to gas handled?*
Under current statute gas expenses are combined with those from oil and the combined total is deducted in the calculation of oil production taxes. Section 5 calls for a separate tax return for gas for 40/400 Assets but provides zero guidance on how the expenses related thereto are to be handled.

d. *How will carry-forward lease expenditures be treated for new developments outside the major fields, by companies with production in the major fields? Will those carry-forward lease expenditures be subject to the 10% value reduction per year after 10 years?*
   The Initiative does not contain any language about changes to AS 43.55 for assets that do not qualify under Section 2. Given the lack of any language to the contrary, the current language regarding the carry forward of losses, and the value reduction after certain amount of time, would remain unchanged for new developments.

e. *To what tax is the 'additional' production tax to be additional to?*
   As noted in the sectional discussion of the Initiative, while Section 4 refers to "an additional tax" Section 6 makes it clear the tax in Section 4 stands alone as the only net tax for 40/400 Assets.

f. *Whether the new tax applies to oil only or to oil and gas?*
   The language of Sections 2, 3 and 4 make clear the taxes in Sections 3 and 4 only apply to oil. However, in Section 5 it calls for the taxes in Sections 3 and 4 to be calculated separately for oil and for gas. It is unclear what Section 5 means relative to gas and many different interpretations could be made.

g. *Potential impact to revenues, Alaska production and potential future investments.*
   When looking to invest in a location or a project, producers will conduct both an economic review as well as a risk review of the potential investment. Should it pass, the wording of the Initiative creates a high degree of uncertainty as to economics and would be viewed as extremely risky given the many different possible interpretations. This high degree of uncertainty would very likely lead to a reluctance to commit any funds until clarity is achieved, which we suspect would take a year or two to achieve given the large dollar difference of different interpretations.

   Additionally, the uncertainty surrounding what exactly the Initiative is calling for could slow discretionary maintenance or workover spending. Without this spending, production levels will decline faster than expected. The greater the number of fields or pools qualified under Section 2, the greater the negative impact on production.

   The Initiative uncertainty is one problem impacting investment. Another issue is the intent of the Initiative to isolate the North Slope's largest legacy fields from the rest of the slope. For any of the producers with ownership in those legacy fields, they will no longer be able to deduct expenses associated with other fields or with new developments from the revenues of those large fields. This ringfencing will greatly increase the perceived costs and negatively impact the economics of any satellite operations or possible new developments. The negative impact to economics could push the many new developments being actively pursued below the corporate funding level. With passage of the Initiative we doubt any new players would choose to pursue opportunities in Alaska until decisions are made on how the Initiative is to be implemented.

SUMMARY

With a few simple word changes or additions, the wording of the Initiative could easily have been more exact, negating the need for any interpretation. If passed, the ambiguity of the Initiative would create an extended period of business uncertainty which will likely negatively impact investment, operations and production.

Basically, the Initiative will cause a number of producing assets on the North Slope to be individually ringfenced for tax purposes. Those assets will then be subject to a new gross tax to be calculated and paid monthly. The details on how that is to happen will be the subject of much debate.

Alaska State Legislature
Legislative Budget and Audit Committee

Chair:

Rep. Chris Tuck

Vice Chair:

Sen. Click Bishop

House Members:

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Rep. Andy Josephson
Rep. Ivy Spohnholz
Rep. Mark Neuman
Rep. Jennifer Johnston – alt

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Sen. Lyman Hoffman
Sen. Bill Wielechowski – alt

Committee Contact:

State Capitol
Room 24
Juneau, Alaska 99801-1182
(907) 465-2095

Committee Aide:

Aurora Hauke
(907) 465-5051

To: Rich Ruggiero, IN3nergy
Christine Ruggiero, IN3nergy

From: Representative Chris Tuck
Chair, Legislative Budget and Audit Committee

C.T.

Re: Work Plan: An analysis of the ballot initiative, 19OGTX

Date: February 10, 2020

Please complete an analysis of the ballot initiative, 19OGTX, An act relating to the oil and gas production tax, tax payments, and tax credits. The written report(s) should follow these guidelines:

1. Please see the attached memo from the presiding officers, Senator Giessel and Representative Edgmon, and thoroughly respond to their request.

2. Per a request from House Resources Committee Co-chair Representative Lincoln's office, please include an analysis of the ballot initiative that describes, "potential impact to revenues, Alaska production, and potential future investment." It is anticipated that this content will be included in a presentation to the House Resources Committee.

Please let me know if you have questions or would like any additional clarification.

Attached: "Request for analysis of Initiative 19OGTX" memo from Senator Giessel and Speaker Edgmon.

Alaska State Legislature

SENATOR
CATHY GIESSEL

Senate President

State Capitol
Juneau, Alaska 99801-1182

REPRESENTATIVE
BRYCE EDGMON

Speaker of the House

State Capitol
Juneau, Alaska 99801-1182

DATE: Feb. 5, 2020

TO: Representative Chris Tuck
Chair, Legislative Budget & Audit Committee

RE: Request for analysis of Initiative 19OGTX titled "An Act relating to the oil and gas production tax, tax payments, and tax credits"

Dear Representative Tuck,

On behalf of the House and Senate of the 31st Legislature, we request LB&A engage contractors IN3NERGY and Gaffney, Cline & Associates in analysis of Initiative 19OGTX, 'An Act relating to the oil and gas production tax, tax payments, and tax credits.' (www.elections.alaska.gov/Core/initiativepetitionlist.php#19OGTX)

Pending certification by the Division of Elections, this initiative is scheduled to appear before statewide voters later this year.

We are requesting initial and subsequent analysis. The initial analysis will support a hearing(s) of the Legislature reviewing the content of the initiative. The subsequent analysis (request pending) will support committee inquiries into the implications of the initiative. House and Senate committees hearing the initiative will likely request additional, specific analysis at a future time.

Our initial request is as follows:

- Please review the initiative language from a holistic perspective. Describe the initiative; how it would change the current oil and gas fiscal regime; questions raised by the initiative, the answers to which would materially impact future analysis of the initiative impacts; and provisions to which the contractors, as they undertake modeling and analysis of the impacts, may need to interpret or receive direction on how to interpret.

- Identify provisions which may affect generally investment in the North Slope basin, such as the disclosure of previously confidential taxpayer information.

- Articulate any impacts to the Middle Earth and Cook Inlet basins, including to investment behavior.

- Isolate the initiative components which will likely result in variable fiscal analysis depending on how those components are interpreted; for example, but not limited to:
    - How is 'field' defined?
    - How is 'offsets' defined? Does the term include the gross value reduction?
    - How are lease expenditures attributable to gas handled?
    - How will carry-forward lease expenditures be treated for new developments outside the major fields, by companies with production in the major fields? Will those carry-forward lease expenditures be subject to the 10% value reduction per year after 10 years?
    - To what tax is the 'additional' production tax to be additional to?
    - Whether the new tax applies to oil only or to oil and gas

- This analysis may take the form of a written report to LB&A.

It is our expectation that the contractors, as they conduct this analysis, will consider the initiative itself but will not consider legislation that is based off any individual's interpretation of the initiative.

Thank you,

Senate President Cathy Giessel

House Speaker Bryce

Edgmon