

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

1022 SCOMM 28: JOINT GAS PIPELINE COMMITTEE, 1981-82 / 022

1 taxable oil produced shall be paid by the state out of its royalties
2 from the oil whenever payment by the state is required under the revenue-
3 sharing provisions of sec. 9 of the Alaska Native Claims Settlement Act
4 (P.L. 92-203, 85 Stat. 688, 43 U.S.C. 1601 et seq.) into the Alaska
5 Native Fund, until all amounts paid in the fund equal \$500,000,000.

6 Sec. 43.55.012. ADJUSTMENTS IN TAX RATES. (a) The amounts set
7 out in sec. 11(c) and sec. 16(c) of this chapter shall be increased or
8 decreased by a percentage equal to the percentage of change in the Gross
9 National Product Deflator published by the Bureau of Economic Analysis
10 of the United States Department of Commerce, or 7.5 per cent per year,
11 whichever is the lesser of the two. Changes in tax rates will be com-
12 puted based on changes in the Gross National Product Deflator from that
13 of the First Quarter 1977 Gross National Product Deflator. The depart-
14 ment shall post the changes in the tax rates periodically and shall
15 notify every person producing oil in the state of the changes.

16 (b) The cents-per-barrel amount set out in sec. 11(c) of this
17 chapter applies to oil of 27 degrees API gravity. For each degree of
18 API gravity less than 27 degrees the cents-per-barrel amount shall be
19 reduced by \$.005 and for each degree of API gravity greater than 27
20 degrees the cents-per-barrel amount shall be increased by \$.005 except
21 that oil above 40 degrees API gravity shall be taxed as 40 degree oil.
22 In applying the gravity adjustment under this subsection, fractional
23 degrees of API gravity shall be disregarded.

24 Sec. 43.55.013. ECONOMIC LIMIT FACTOR. (a) The economic limit
25 factor for oil production of a lease or property equals

26
$$(1 - [PEL/TP]) \exp ([300 \times WD]/PEL)$$

27 Where: PEL = the production rate at the economic limit;

28 TP = total production during the month for which the tax
29 is to be paid;

1 WD = the total number of well days in the month for which
2 the tax is to be paid; and

3 Where "exp" indicates that the expression following it is an exponent.

4 (b) The economic limit factor for gas production of a lease or
5 property equals one minus the ratio of the monthly production rate at
6 the economic limit to the production during the month for which the tax
7 is to be paid.

8 (c) The monthly production rate at the economic limit for a lease
9 or property is presumed to be 100 barrels times the number of well days
10 for the lease or property during the month for which the tax is to be
11 paid. The taxpayer may rebut this presumption at a formal hearing
12 under AS 43.05.420 by providing clear and convincing evidence of a
13 different monthly production rate at the economic limit for the lease or
14 property. The hearing shall be held before February 15 of the year or
15 within six months after commencement of oil production for a lease or
16 property. The monthly production rate at the economic limit for the
17 lease or property based upon the clear and convincing evidence of the
18 taxpayer shall be calculated by dividing the value determined under (e)
19 of this section into the average monthly direct operating cost deter-
20 mined under (d) of this section and shall be used for purposes of this
21 section for all oil production during that calendar year from the lease
22 or property.

23 (d) The average monthly direct operating cost for oil production
24 operations of the lease or property shall be determined based on the
25 number of months operated during the preceding 12-month period. The
26 direct operating costs include production supplies, purchased fuel,
27 routine maintenance, and wages and benefits of employees working on the
28 production operations. The direct operating costs do not include
29 capital expenditures, tangible or intangible drilling expenses, costs of

1 well workovers, costs for replacement or repairs (other than routine
2 maintenance), depreciation or amortization, taxes, insurance, overhead,
3 money paid or set aside (or booked as being paid or set aside) to cover
4 the cost of terminating the oil production operations of the lease or
5 property, or any other cost not directly related to the oil production
6 operations of the lease or property.

7 (e) For the purposes of this chapter, the gross value of oil shall
8 be calculated as provided in sec. 150 of this chapter, and the gross
9 value of gas shall be calculated as provided in (h) of this section.

10 (f) Before February 15 of each year or within six months after
11 commencement of gas production for a lease or property, the department
12 shall notify the producer of gas of the monthly production rate at the
13 economic limit for each lease or property in the state for that year.
14 The monthly production rate at the economic limit for a lease or property
15 shall be determined at a formal hearing under AS 43.05.240 and must be
16 established by clear and convincing evidence presented by the taxpayer
17 at that hearing. The monthly production rate at the economic limit for
18 the lease or property based upon the clear and convincing evidence of
19 the taxpayer shall be calculated by dividing the value determined under
20 (h) of this section into the average monthly direct operating cost
21 determined under (g) of this section.

22 (g) The average monthly direct operating cost for gas production
23 operations of the lease or property shall be determined based on the
24 number of months operated during the preceding 12-month period. The
25 direct operating costs include drilling supplies, fuel, routine maintenance,
26 and wages and benefits of employees working on the production
27 operations. The direct operating costs do not include capital expenditures,
28 tangible or intangible drilling expenses, costs of well workovers,
29 costs for replacement or repairs (other than routine maintenance),

1 depreciation or amortization, taxes, insurance, overhead, money paid or
2 set aside (or booked as being paid or set aside) to cover the cost of
3 terminating the gas production operations of the lease or property, or
4 any other cost not directly related to the gas production operations of
5 the lease or property.

6 (h) The value at the point of production of gas produced from the
7 lease or property shall be determined on the basis of the highest price
8 paid for gas of like quality and pressure in the same field.

9 (i) The department may aggregate two or more leases or properties
10 (or portions of them), for purposes of determining economic limit
11 factors under this section and applying them to sec. 11 of this chapter,
12 when economically interdependent oil or gas production operations are
13 not confined to a single lease or property. The department may also
14 segregate a lease or property into two or more parts, for purposes of
15 determining economic limit factors under this section and applying them
16 under sec. 11 of this chapter, when two or more economically independent
17 oil or gas production operations are being conducted on it.

18 (j) A determination of the monthly production rate at the economic
19 limit for a lease or property is retroactive to January 1 of the current
20 year. For production of a lease or property commencing after January 1,
21 the determination of the monthly production rate at the economic limit
22 for that lease or property made within six months after the commencement
23 of production is retroactive to the commencement of production.

24 Sec. 43.55.016. GAS PRODUCTION TAX. (a) There is levied upon the
25 producer of gas a tax for all gas produced from each lease or property
26 in the state, less any gas the ownership or right to which is exempt
27 from taxation. The tax is equal to either the percentage-of-value
28 amount calculated under (b) of this section or the cents-per-Mcf amount
29 calculated under (c) of this section, whichever is greater, multiplied

1 by the economic limit factor determined for gas production of the lease
2 or property under sec. 13 of this chapter. If the amounts calculated
3 under (b) and (c) of this section are equal, the amount calculated under
4 (b) of this section shall be treated as if it were the greater for
5 purposes of this section.

6 (b) The percentage-of-value amount equals 10 per cent of the gross
7 value at the point of production of the taxable gas produced from the
8 lease or property.

9 (c) The cents-per-Mcf amount equals \$.064 per thousand cubic feet
10 of taxable gas produced from the lease or property as adjusted by sec.
11 12 of this chapter.

12 Sec. 43.55.017. RELATION TO OTHER TAXES. (a) Except as provided
13 in this chapter and in ch. 58 of this title, the taxes imposed by this
14 chapter are in place of all taxes now imposed by the state or any of its
15 municipalities, and neither the state nor a municipality may impose a
16 tax upon

17 (1) producing oil or gas leases;
18 (2) oil or gas produced or extracted in the state;
19 (3) the value of intangible drilling and exploration ex-
20 penses.

21 (b) The taxes imposed by this chapter are in place of all taxes
22 imposed by a municipality upon oil or gas in place or nonproducing oil
23 or gas leases or properties.

24 (c) The taxes imposed by this chapter are not in place of the tax
25 imposed by ch. 57 of this title or income taxes, franchise taxes or
26 taxes upon the retail sale of oil or gas products.

27 * Sec. 2. AS 43.55.020(a) is amended to read:

28 (a) The gross production tax on oil or gas shall be paid monthly.
29 The tax is due on the 20th [LAST] day of each calendar month on oil or

1 gas produced [REMOVED OR SOLD] from each lease or property during the
2 preceding month. If the tax is not paid before the end of the month in
3 which it becomes due, the tax becomes delinquent.

4 * Sec. 3. AS 43.55.030(a)(1) is amended to read:

5 (1) a description of the lease or property from which the oil
6 or gas was produced [REMOVED OR SOLD], by name, legal description, lease
7 number or by accounting code numbers assigned to the department;

8 * Sec. 4. AS 43.55.030(a)(3) is amended to read:

9 (3) the gross amount of oil or gas produced [REMOVED OR SOLD]
10 from the lease or property, and the percentage of the gross amount owned
11 by each producer for whom the tax is paid;

12 * Sec. 5. AS 43.55.030(a)(4) is amended to read:

13 (4) the total value of the oil or gas produced [REMOVED OR
14 SOLD] from the lease or property owned by each producer for whom the tax
15 is paid; and

16 * Sec. 6. AS 43.55.140 is amended by adding a new paragraph to read:

17 (12) "well days" means the number of days in which a well is
18 operating during a month.

19 * Sec. 7. AS 43.55.010, 43.55.015 and 43.55.140(10) and (11) are re-
20 pealed.

21 * Sec. 8. This Act takes effect July 1, 1977 and applies to production
22 during the month of July, 1977, and succeeding months.

Original sponsor: Rules Committee by
request of the Governor

Offered: 5/2/77
Referred: Finance

1 IN THE SENATE

BY THE RESOURCES COMMITTEE

2 CS FOR SENATE BILL NO. 238 am

3 IN THE LEGISLATURE OF THE STATE OF ALASKA

4 TENTH LEGISLATURE - FIRST SESSION

5 A BILL

6 For an Act entitled: "An Act relating to the oil and gas properties produc-
7 tion tax; and providing for an effective date."

8 BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

9 * Section 1. AS 43.55 is amended by adding new sections to read:

10 Sec. 43.55.011. OIL PRODUCTION TAX. (a) There is levied upon the
11 producer of oil a tax for all oil produced from each lease or property
12 in the state, less any oil the ownership or right to which is exempt
13 from taxation. The tax is equal to either the percentage-of-value
14 amount calculated under (b) of this section or the cents-per-barrel
15 amount calculated under (c) of this section, whichever is greater,
16 multiplied by the economic limit factor determined for the oil produc-
17 tion of the lease or property under sec. 13 of this chapter. If the
18 amounts calculated under (b) and (c) of this section are equal, the
19 amount calculated under (b) of this section shall be treated as if it
20 were the greater for purposes of this section.

21 (b) The percentage-of-value amount equals 11.5 per cent of the
22 gross value at the point of production of taxable oil produced from the
23 lease or property.

24 (c) The cents-per-barrel amount equals \$.75 per barrel of taxable
25 oil produced from the lease or property, as adjusted by sec. 12 of this
26 chapter.

27 (d) When the cents-per-barrel amount calculated under (c) of this
28 section is greater than the percentage-of-value amount calculated under
29 (b) of this section, an amount not less than \$.05 for each barrel of

1 taxable oil produced shall be paid by the state out of its royalties
2 from the oil whenever payment by the state is required under the revenue-
3 sharing provisions of sec. 9 of the Alaska Native Claims Settlement Act
4 (P.L. 92-203, 85 Stat. 688, 43 U.S.C. 1601 et seq.) into the Alaska
5 Native Fund, until all amounts paid in the fund equal \$500,000,000.

6 Sec. 43.55.012. ADJUSTMENTS IN TAX RATES. The cents-per-barrel
7 amount set out in sec. 11(c) of this chapter applies to oil of 27
8 degrees API gravity. For each degree of API gravity less than 27
9 degrees the cents-per-barrel amount shall be reduced by \$.005 and for
10 each degree of API gravity greater than 27 degrees the cents-per-
11 barrel amount shall be increased by \$.005 except that oil above 40
12 degrees API gravity shall be taxed as 40 degree oil. In applying the
13 gravity adjustment under this subsection, fractional degrees of API
14 gravity shall be disregarded.

15 Sec. 43.55.013. ECONOMIC LIMIT FACTOR. (a) The economic limit
16 factor for oil production of a lease or property equals

17
$$(1 - [PEL/TP]) \exp ([750 \times WD]/PEL)$$

18 Where: PEL = the production rate at the economic limit;

19 TP = total production during the month for which the tax
20 is to be paid;

21 WD = the total number of well days in the month for which
22 the tax is to be paid; and

23 Where "exp" indicates that the expression following it is an exponent.

24 (b) The economic limit factor for gas production of a lease or
25 property equals one minus the ratio of the monthly production rate at
26 the economic limit to the production during the month for which the tax
27 is to be paid.

28 (c) The monthly production rate at the economic limit for a lease
29 or property is presumed to be 100 barrels times the number of well days

1 for the lease or property during the month for which the tax is to be
2 paid. The taxpayer may rebut this presumption at a formal hearing
3 under AS 43.05.420 by providing clear and convincing evidence of a
4 different monthly production rate at the economic limit for the lease or
5 property. The hearing shall be held before February 15 of the year or
6 within six months after commencement of oil production for a lease or
7 property. The monthly production rate at the economic limit for the
8 lease or property based upon the clear and convincing evidence of the
9 taxpayer shall be calculated by dividing the value determined under (e)
10 of this section into the average monthly direct operating cost deter-
11 mined under (d) of this section and shall be used for purposes of this
12 section for all oil production during that calendar year from the lease
13 or property.

14 (d) The average monthly direct operating cost for oil production
15 operations of the lease or property shall be determined based on the
16 number of months operated during the preceding 12-month period. The
17 direct operating costs include production supplies, purchased fuel,
18 routine maintenance, and wages and benefits of employees working on the
19 production operations. The direct operating costs do not include
20 capital expenditures, tangible or intangible drilling expenses, costs of
21 well workovers, costs for replacement or repairs (other than routine
22 maintenance), depreciation or amortization, taxes, insurance, overhead,
23 money paid or set aside (or booked as being paid or set aside) to cover
24 the cost of terminating the oil production operations of the lease or
25 property, or any other cost not directly related to the oil production
26 operations of the lease or property.

27 (e) The value at the point of production of oil produced from
28 the lease or property shall be determined on the basis of the acqui-
29 sition cost C.I.F. at West Coast refineries for imported oil of like

1 quality, minus the reasonable cost of transportation between the point
2 of production of the oil from the lease or property and those West
3 Coast refineries.

4 (f) Before February 15 of each year or within six months after
5 commencement of gas production for a lease or property, the department
6 shall notify the producer of gas of the monthly production rate at the
7 economic limit for each lease or property in the state for that year.
8 The monthly production rate at the economic limit for a lease or property
9 shall be determined at a formal hearing under AS 43.05.240 and must be
10 established by clear and convincing evidence presented by the taxpayer
11 at that hearing. The monthly production rate at the economic limit for
12 the lease or property based upon the clear and convincing evidence of
13 the taxpayer shall be calculated by dividing the value determined under
14 (h) of this section into the average monthly direct operating cost
15 determined under (g) of this section.

16 (g) The average monthly direct operating cost for gas production
17 operations of the lease or property shall be determined based on the
18 number of months operated during the preceding 12-month period. The
19 direct operating costs include drilling supplies, fuel, routine maintenance,
20 and wages and benefits of employees working on the production
21 operations. The direct operating costs do not include capital expenditures,
22 tangible or intangible drilling expenses, costs of well work-
23 overs, costs for replacement or repairs (other than routine maintenance),
24 depreciation or amortization, taxes, insurance, overhead, money paid or
25 set aside (or booked as being paid or set aside) to cover the cost of
26 terminating the gas production operations of the lease or property, or
27 any other cost not directly related to the gas production operations of
28 the lease or property.

29 (h) The value at the point of production of gas produced from the

1 lease or property shall be determined on the basis of the highest price
2 paid for gas of like quality and pressure in the same field.

3 (i) The department may aggregate two or more leases or properties
4 (or portions of them), for purposes of determining economic limit
5 factors under this section and applying them to sec. 11 of this chapter,
6 when economically interdependent oil or gas production operations are
7 not confined to a single lease or property. The department may also
8 segregate a lease or property into two or more parts, for purposes of
9 determining economic limit factors under this section and applying them
10 under sec. 11 of this chapter, when two or more economically independent
11 oil or gas production operations are being conducted on it.

12 (j) A determination of the monthly production rate at the economic
13 limit for a lease or property is retroactive to January 1 of the current
14 year. For production of a lease or property commencing after January 1,
15 the determination of the monthly production rate at the economic limit
16 for that lease or property made within six months after the commencement
17 of production is retroactive to the commencement of production.

18 Sec. 43.55.016. GAS PRODUCTION TAX. (a) There is levied upon the
19 producer of gas a tax for all gas produced from each lease or property
20 in the state, less any gas the ownership or right to which is exempt
21 from taxation. The tax is equal to either the percentage-of-value
22 amount calculated under (b) of this section or the cents-per-Mcf amount
23 calculated under (c) of this section, whichever is greater, multiplied
24 by the economic limit factor determined for gas production of the lease
25 or property under sec. 13 of this chapter. If the amounts calculated
26 under (b) and (c) of this section are equal, the amount calculated under
27 (b) of this section shall be treated as if it were the greater for
28 purposes of this section.

29 (b) The percentage-of-value amount equals 10 per cent of the gross

1 value at the point of production of the taxable gas produced from the
2 lease or property.

3 (c) The cents-per-Mcf amount equals \$.064 per thousand cubic feet
4 of taxable gas produced from the lease or property as adjusted by sec.
5 12 of this chapter.

6 Sec. 43.55.017. RELATION TO OTHER TAXES. (a) Except as provided
7 in this chapter and in ch. 58 of this title, the taxes imposed by this
8 chapter are in place of all taxes now imposed by the state or any of its
9 municipalities, and neither the state nor a municipality may impose a
10 tax upon

11 (1) producing oil or gas leases;
12 (2) oil or gas produced or extracted in the state;
13 (3) the value of intangible drilling and exploration ex-
14 penses.

15 (b) The taxes imposed by this chapter are in place of all taxes
16 imposed by a municipality upon oil or gas in place or nonproducing oil
17 or gas leases or properties.

18 (c) The taxes imposed by this chapter are not in place of the tax
19 imposed by ch. 57 of this title or income taxes, franchise taxes or
20 taxes upon the retail sale of oil or gas products.

21 * Sec. 2. AS 43.55.020(a) is amended to read:

22 (a) The gross production tax on oil or gas shall be paid monthly.
23 The tax is due on the 20th [LAST] day of each calendar month on oil or
24 gas produced [REMOVED OR SOLD] from each lease or property during the
25 preceding month. If the tax is not paid before the end of the month in
26 which it becomes due, the tax becomes delinquent.

27 * Sec. 3. AS 43.55.030(a)(1) is amended to read:

28 (1) a description of the lease or property from which the oil
29 or gas was produced [REMOVED OR SOLD], by name, legal description, lease

1 number or by accounting code numbers assigned to the department;

2 * Sec. 4. AS 43.55.030(a)(3) is amended to read:

3 (3) the gross amount of oil or gas produced [REMOVED OR SOLD]
4 from the lease or property, and the percentage of the gross amount owned
5 by each producer for whom the tax is paid;

6 * Sec. 5. AS 43.55.030(a)(4) is amended to read:

7 (4) the total value of the oil or gas produced [REMOVED OR
8 SOLD] from the lease or property owned by each producer for whom the tax
9 is paid; and

10 * Sec. 6. AS 43.55.140 is amended by adding a new paragraph to read:

11 (12) "well days" means the number of days in which a well is
12 operating during a month.

13 * Sec. 7. AS 43.55.010, 43.55.015 and 43.55.140(10) and (11) are re-
14 pealed.

15 * Sec. 8. This Act takes effect July 1, 1977 and applies to production
16 during the month of July, 1977, and succeeding months.

Original sponsor: Rules Committee by request
of the Governor

Offered: 5/7/77
For Today's Calendar

IN THE SENATE

BY THE FINANCE COMMITTEE

HOUSE CS FOR CS FOR SENATE BILL NO. 238

IN THE LEGISLATURE OF THE STATE OF ALASKA

TENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act relating to the oil and gas properties production tax; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. AS 43.55 is amended by adding new sections to read:

Sec. 43.55.011. OIL PRODUCTION TAX. (a) There is levied upon the producer of oil a tax for all oil produced from each lease or property in the state, less any oil the ownership or right to which is exempt from taxation. The tax is equal to either the percentage-of-value amount calculated under (b) of this section or the cents-per-barrel amount calculated under (c) of this section, whichever is greater, multiplied by the economic limit factor determined for the oil production of the lease or property under sec. 13 of this chapter. If the amounts calculated under (b) and (c) of this section are equal, the amount calculated under (b) of this section shall be treated as if it were the greater for purposes of this section.

(b) The percentage-of-value amount equals 12.5 per cent of the gross value at the point of production of taxable oil produced from the lease or property.

(c) The cents-per-barrel amount equals \$.9375 per barrel of taxable oil produced from the lease or property, as adjusted by sec. 12 of this chapter.

(d) When the cents-per-barrel amount calculated under (c) of this section is greater than the percentage-of-value amount calculated under (b) of this section, and payment by the state to the Alaska Native fund

1 out of the state's royalties on that oil is required under the revenue
2 sharing provisions of sec. 9 of the Alaska Native Claims Settlement Act
3 (P.L. 92-203, 85 Stat. 688, 43 U.S.C. 1601 et seq.), that payment shall
4 be not less than \$.05 for each taxable barrel of oil produced until all
5 amounts paid in the fund equal \$500,000,000.

6 Sec. 43.55.012. ADJUSTMENTS IN TAX RATES. (a) The amounts set
7 out in sec. 11(c) and sec. 16(c) of this chapter shall be increased or
8 decreased by a percentage equal to the percentage of change in the Gross
9 National Product Deflator published by Bureau of Economic Analysis of
10 the United States Department of Commerce. Changes in tax rates will be
11 computed based on changes in the Gross National Product Deflator from
12 that of the First Quarter 1977 Gross National Product Deflator. The
13 department shall post the changes in the tax rates periodically and
14 shall notify every person producing oil within the state of the changes.

15 (b) The cents-per-barrel amount set out in sec. 11(c) of this
16 chapter as adjusted by (a) of this section applies to oil of 27 degrees
17 API gravity. For each degree of API gravity less than 27 degrees the
18 cents-per-barrel amount shall be reduced by \$.005 and for each degree of
19 API gravity greater than 27 degrees the cents-per-barrel amount shall be
20 increased by \$.005 except that oil above 40 degrees API gravity shall be
21 taxed as 40 degree oil. In applying the gravity adjustment under this
22 subsection, fractional degrees of API gravity shall be disregarded.

23 Sec. 43.55.013. ECONOMIC LIMIT FACTOR. (a) The economic limit
24 factor for oil production of a lease or property equals

25
$$(1 - [PEL/TP]) \exp ([300 \times WD]/PEL)$$

26 where: PEL = the production rate at the economic limit;

27 TP = total production during the month for which the tax
28 is to be paid;

29 WD = the total number of well days in the month for which

1 the tax is to be paid; and
2 where "exp" indicates that the expression following it is an exponent.

3 (b) The economic limit factor for gas production of a lease or
4 property equals one minus the ratio of the monthly production rate at
5 the economic limit to the production during the month for which the tax
6 is to be paid.

7 (c) The monthly production rate at the economic limit for a lease
8 or property is presumed to be 300 barrels times the number of well days
9 for the lease or property during the month for which the tax is to be
10 paid. The taxpayer may rebut this presumption at a formal hearing under
11 AS 43.05.240 by providing clear and convincing evidence of a different
12 monthly production rate at the economic limit for the lease or property.
13 The hearing shall be held before February 15 of the year or within six
14 months after commencement of oil production for a lease or property.
15 The monthly production rate at the economic limit for the lease or pro-
16 perty based upon the clear and convincing evidence of the taxpayer shall
17 be calculated by dividing the value determined under (e) of this section
18 into the average monthly direct operating cost determined under (d) of
19 this section and shall be used for purposes of this section for all oil
20 production during that calendar year from the lease or property.

21 (d) The average monthly direct operating cost for oil production
22 operations of the lease or property shall be determined based on a
23 period of not less than four consecutive months. The direct operating
24 costs include only royalty, production supplies, purchased fuel, routine
25 maintenance, and wages and benefits of employees working on the produc-
26 tion operations. Additional direct operating costs not listed in this
27 section may be included only after their inclusion in a regulation
28 adopted by the department. The direct operating costs do not include
29 capital expenditures, tangible or intangible drilling expenses, costs of

1 well workovers, costs for replacement or repairs (other than routine
2 maintenance), depreciation or amortization, taxes, insurance, overhead,
3 money paid or set aside (or booked as being paid or set aside) to cover
4 the cost of terminating the oil production operations of the lease or
5 property, or any other cost not directly related to the oil production
6 operations of the lease or property.

7 (e) For the purpose of calculating the economic limit, the value
8 at the point of production of oil produced from the lease or property
9 shall be determined on the basis of the acquisition cost C.I.F. at West
10 Coast refineries for imported oil of like quality, minus the reasonable
11 cost of transportation between the point of production of the oil from
12 the lease or property and those West Coast refineries.

13 (f) Before February 15 of each year or within six months after
14 commencement of production for a lease or property the department shall
15 notify the producer of gas of the monthly production rate at the eco-
16 nomic limit for each lease or property within the state for that year.
17 The monthly production rate at the economic limit for a lease or pro-
18 perty shall be determined at a formal hearing under AS 43.05.240 and
19 must be established by clear and convincing evidence presented by the
20 taxpayer at that hearing. The monthly production rate at the economic
21 limit for the lease or property based upon the clear and convincing
22 evidence of the taxpayer shall be calculated by dividing the value
23 determined under (h) of this section into the average monthly direct
24 operating cost determined under (g) of this section.

25 (g) The average monthly direct operating cost for gas production
26 operations of the lease or property shall be determined based on a
27 period of not less than four consecutive months. The direct operating
28 costs include only royalty, production supplies, purchased fuel, routine
29 maintenance, and wages and benefits of employees working on the

1 production operations. Additional direct operating costs not listed in
2 this section may be included only after their inclusion in a regulation
3 adopted by the department. The direct operating costs do not include
4 capital expenditures, tangible or intangible drilling expenses, costs of
5 well workovers, costs for replacement or repairs (other than routine
6 maintenance), depreciation or amortization, taxes, insurance, overhead,
7 monies paid or set aside (or booked as being paid or set aside) to cover
8 the cost of terminating the gas production operations of the lease or
9 property, or any other cost not directly related to the gas production
10 operations of the lease or property.

11 (h) For the purpose of calculating the economic limit, the value
12 at the point of production of gas produced from the lease or property
13 shall be determined on the basis of the highest price paid for gas of
14 like quality and pressure in the same field or some other field within
15 100 miles in the state.

16 (i) The department may aggregate two or more leases or properties
17 (or portions of them), for purposes of determining economic limit factors
18 under this section and applying them to sec. 11 or sec. 16 of this chap-
19 ter, when economically interdependent oil or gas production operations
20 are not confined to a single lease or property. The department may also
21 segregate a lease or property into two or more parts, for purposes of
22 determining economic limit factors under this section and applying them
23 under sec. 11 or sec. 16 of this chapter, when two or more economically
24 independent oil or gas production operations are being conducted on it.

25 (j) A determination of the monthly production rate at the economic
26 limit for a lease or property is retroactive to January 1 of the current
27 year. For production of a lease or property commencing after January 1,
28 the determination of the monthly production rate at the economic limit
29 for that lease or property made within six months after the commencement

of production is retroactive to the commencement of production.

Sec. 43.55.016. GAS PRODUCTION TAX. (a) There is levied upon the producer of gas a tax for all gas produced from each lease or property in the state, less any gas the ownership or right to which is exempt from taxation. The tax is equal to either the percentage-of-value amount calculated under (b) of this section or the cents-per-Mcf amount calculated under (c) of this section, whichever is greater, multiplied by the economic limit factor determined for gas production of the lease or property under sec. 13 of this chapter. If the amounts calculated under (b) and (c) of this section are equal, the amount calculated under (b) of this section shall be treated as if it were the greater for purposes of this section.

(b) The percentage-of-value amount equals 10 per cent of the gross value at the point of production of the taxable gas produced from the lease or property.

(c) The cents-per-Mcf amount equals \$.064 per thousand cubic feet of taxable gas produced from the lease or property as adjusted by sec. 12 of this chapter.

Sec. 43.55.017. RELATION TO OTHER TAXES. (a) Except as provided in this chapter and in ch. 58 of this title, the taxes imposed by this chapter are in place of all taxes now imposed by the state or any of its municipalities, and neither the state nor a municipality may impose a tax upon

- (1) producing oil or gas leases;
- (2) oil or gas produced or extracted in the state;
- (3) the value of intangible drilling and exploration expenses.

(b) The taxes imposed by this chapter are in place of all taxes imposed by a municipality upon oil or gas in place or nonproducing oil

1 or gas leases or properties.

2 (c) The taxes imposed by this chapter are not in place of the tax
3 imposed by ch. 57 of this title or income taxes, franchise taxes or
4 taxes upon the retail sale of oil or gas products.

5 * Sec. 2. AS 43.55.020(a) is amended to read:

6 (a) The gross production tax on oil or gas shall be paid monthly.
7 The tax is due on the 20th [LAST] day of each calendar month on oil or
8 gas produced [REMOVED OR SOLD] from each lease or property during the
9 preceding month. If the tax is not paid before the end of the month in
10 which it becomes due, the tax becomes delinquent.

11 * Sec. 3. AS 43.55.020(e) is amended to read:

12 (e) Gas produced in excess of that needed for safety purposes
13 [AND USED], except gas used in the operation of a lease or property in
14 drilling for or producing oil or gas, or for repressuring, is considered,
15 for the purpose of this chapter and in the amount used, as gas produced
16 [REMOVED OR SOLD] from a lease or property. Gas flared beyond the
17 amount authorized for safety by the Department of Natural Resources
18 under AS 31.05.170(11)(H) is considered as gas produced, except that it
19 is subject to a penalty equal to the tax computed under sec. 16 of this
20 chapter as adjusted by sec. 12 of this chapter per thousand cubic feet
21 of gas for the month in which the gas was flared.

22 * Sec. 4. AS 43.55.030(a)(1) is amended to read:

23 (1) a description of the lease or property from which the oil
24 or gas was produced [REMOVED OR SOLD], by name, legal description, lease
25 number or by accounting code numbers assigned by the department;

26 * Sec. 5. AS 43.55.030(a)(3) is amended to read:

27 (3) the gross amount of oil or gas produced [REMOVED OR SOLD]
28 from the lease or property, and the percentage of the gross amount owned
29 by each producer for whom the tax is paid;

1 * Sec. 6. AS 43.55.030(a)(4) is amended to read:

2 (4) the total value of the oil or gas produced [REMOVED OR
3 SOLD] from the lease or property owned by each producer for whom the tax
4 is paid; and

5 * Sec. 7. AS 43.55.140 is amended by adding new paragraphs to read:

6 (12) "gross value at the point of production" means

7 (A) for oil, the value of the oil at the point where it
8 is metered or measured (by automatic custody transfer meter, tank
9 gauge, or other method approved by the commissioner) in a condition
10 of pipeline quality on the premises of the lease or property from
11 which it is recovered; however, if the oil is not of pipeline
12 quality when it is removed from the premises of the lease or pro-
13 perty from which it is recovered, or if the oil recovered from a
14 lease or property is not metered or measured (by automatic custody
15 transfer meter, tank gauge, or other method approved by the com-
16 missioner) on the premises of the lease or property from which it
17 is recovered, then the gross value at the point of production is
18 the value of that oil at the off-premises location where the oil is
19 first metered or measured (by automatic custody transfer meter,
20 tank gauge, or other method approved by the commissioner) in a
21 condition of pipeline quality;

22 (B) for gas recovered from or in association with oil,
23 the value of the gas at the point where it is accurately metered or
24 measured after separation from the oil; for gas run through a gas
25 processing plant, the gross value at the point of production is the
26 full consideration received by the producer for the gas if sold in
27 an arm's length transaction or, in the absence of an arm's length
28 transaction, is the sum of the value of the liquids extracted from
29 the gas at the plant and the value of the residue gas, less a

1 reasonable allowance for processing the gas at the plant and for
2 transporting the gas to the plant from the premises upon which the
3 oil production operation is conducted; and

4 (C) for gas not recovered from or in association with
5 oil, the value of the gas at the point where it is accurately
6 metered or measured or the value of the gas at the point of sale,
7 if any, on the premises of the lease or property from which the gas
8 is recovered, whichever is the higher value; for gas run through a
9 gas processing plant, the gross value at the point of production is
10 the full consideration received by the producer for the gas if sold
11 in an arm's length transaction or, in the absence of an arm's
12 length transaction, is the sum of the value of the liquids ex-
13 tracted from the gas at the plant and the value of the residue gas,
14 less a reasonable allowance for processing the gas at the plant and
15 for transporting the gas to the plant from the point where it was
16 accurately metered or measured;

17 (13) "oil production operation" means the operation by which
18 oil is recovered from a lease or property and rendered into oil of
19 pipeline quality, and includes any gathering done before the oil is
20 finally rendered into oil of pipeline quality;

21 (14) "pipeline quality" means good and merchantable condi-
22 tion;

23 (15) "well days" means the number of days in which a well is
24 operating during a month.

25 * Sec. 8. AS 43.55.010, 43.55.015 and 43.55.140(10) and (11) are re-
26 pealed.

27 * Sec. 9. This Act takes effect July 1, 1977 and applies to production
28 during the month of July 1977 and succeeding months.

Original sponsor: Rules Committee by request
of the Governor

Offered: 5/23/77

1 IN THE SENATE

BY THE FREE CONFERENCE COMMITTEE

2 FREE CONFERENCE CS FOR HOUSE CS FOR CS FOR SENATE BILL NO. 238

3 IN THE LEGISLATURE OF THE STATE OF ALASKA

4 TENTH LEGISLATURE - FIRST SESSION

5 A BILL

6 For an Act entitled: "An Act relating to oil and gas taxation; and providing
7 for an effective date."

8 BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

9 * Section 1. AS 43.55 is amended by adding new sections to read:

10 Sec. 43.55.011. OIL PRODUCTION TAX. (a) There is levied upon the
11 producer of oil a tax for all oil produced from each lease or property
12 in the state, less any oil the ownership or right to which is exempt
13 from taxation. The tax is equal to either the percentage-of-value
14 amount calculated under (b) of this section or the cents-per-barrel
15 amount calculated under (c) of this section, whichever is greater,
16 multiplied by the economic limit factor determined for the oil produc-
17 tion of the lease or property under sec. 13 of this chapter. If the
18 amounts calculated under (b) and (c) of this section are equal, the
19 amount calculated under (b) of this section shall be treated as if it
20 were the greater for purposes of this section.

21 (b) The percentage-of-value amount equals 12.25 per cent of the
22 gross value at the point of production of taxable oil produced from the
23 lease or property.

24 (c) The cents-per-barrel amount equals \$0.60 per barrel of taxable
25 old crude oil produced from the lease or property, and \$0.80 per barrel
26 for all other taxable oil produced from the lease or property, both as
27 adjusted by sec. 12 of this chapter.

28 (d) When the cents-per-barrel amount calculated under (c) of this
29 section is greater than the percentage-of-value amount calculated under

(b) of this section, and payment by the state to the Alaska Native fund out of the state's royalties on that oil is required under the revenue sharing provisions of sec. 9 of the Alaska Native Claims Settlement Act (P.L. 92-203, 85 Stat. 688, 43 U.S.C. 1601 et seq.), that payment shall be not less than \$.05 for each taxable barrel of oil produced until all amounts paid in the fund equal \$500,000,000.

Sec. 43.55.012. ADJUSTMENT IN TAX RATES. (a) Before January 1 of each year the department shall review the prices received for crude oil or gas produced in Alaska, the value of that oil or gas, and the general level of prices in Alaska and the nation, and submit a written report of this review to the governor with the department's recommendations for changes in the amounts set out in sec. 11(c) and 16(c) of this chapter. The governor shall, within 30 days of receiving the department's report, submit the proposed changes to the amounts in sec. 11(c) and 16(c) of this chapter to the legislature.

(b) The cents-per-barrel amount set out in sec. 11(c) of this chapter as adjusted by (a) of this section applies to oil of 27 degrees API gravity. For each degree of API gravity less than 27 degrees the cents-per-barrel amount shall be reduced by \$.005 and for each degree of API gravity greater than 27 degrees the cents-per-barrel amount shall be increased by \$.005 except that oil above 40 degrees API gravity shall be taxed as 40 degree oil. In applying the gravity adjustment under this subsection, fractional degrees of API gravity shall be disregarded.

Sec. 43.55.013. ECONOMIC LIMIT FACTOR. (a) The economic limit factor for old crude oil production of a lease or property equals one minus the ratio of the monthly production rate at the economic limit to the production during the month for which the tax is to be paid.

(b) The economic limit factor for oil production of a lease or property other than old crude oil equals:

1 $(1-[PEL/TP]) \exp ([460 \times WD]/PEL)$

2 where: PEL = the monthly production rate at the economic limit;

3 TP = total production during the month for which the tax
4 is to be paid;

5 WD = the total number of well days in the month for which
6 the tax is to be paid; and

7 where "exp" indicates that the expression following it is an exponent.

8 (c) The economic limit factor for gas production of a lease or
9 property equals one minus the ratio of the monthly production rate at
10 the economic limit to the production during the month for which the tax
11 is to be paid.

12 (d) The monthly production rate at the economic limit for a lease
13 or property is presumed to be 300 barrels times the number of well days
14 for the lease or property during the month for which the tax is to be
15 paid. The taxpayer may rebut this presumption at a formal hearing under
16 AS 43.05.240 by providing clear and convincing evidence of a different
17 monthly production rate at the economic limit for the lease or property.
18 The hearing shall be held before February 15 of the year or within six
19 months after commencement of oil production for a lease or property.
20 The monthly production rate at the economic limit for the lease or pro-
21 perty based upon the clear and convincing evidence of the taxpayer shall
22 be calculated by dividing the value determined under (f) of this section
23 into the average monthly direct operating cost determined under (e) of
24 this section and shall be used for purposes of this section for all oil
25 production during that calendar year from the lease or property.

26 (e) The average monthly direct operating cost for oil production
27 operations of the lease or property shall be determined based on a
28 period of not less than four consecutive months. The direct operating
29 costs include only royalty, production supplies, purchased fuel, routine

1 maintenance, and wages and benefits of employees working on the produc-
2 tion operations. Additional direct operating costs not listed in this
3 section may be included only after their inclusion in a regulation
4 adopted by the department. The direct operating costs do not include
5 capital expenditures, tangible or intangible drilling expenses, costs of
6 well workovers, costs for replacement or repairs (other than routine
7 maintenance), depreciation or amortization, taxes, insurance, overhead,
8 money paid or set aside (or booked as being paid or set aside) to cover
9 the cost of terminating the oil production operations of the lease or
10 property, or any other cost not directly related to the oil production
11 operations of the lease or property.

12 (f) For the purpose of calculating the economic limit, the value
13 at the point of production of oil produced from the lease or property
14 shall be determined on the basis of the acquisition cost C.I.F. at West
15 Coast refineries for imported oil of like quality, minus the reasonable
16 cost of transportation between the point of production of the oil from
17 the lease or property and those West Coast refineries.

18 (g) Before February 15 of each year or within six months after
19 commencement of production for a lease or property the department shall
20 notify the producer of gas of the monthly production rate at the eco-
21 nomic limit for each lease or property within the state for that year.
22 The monthly production rate at the economic limit for a lease or pro-
23 perty shall be determined at a formal hearing under AS 43.05.240 and
24 must be established by clear and convincing evidence presented by the
25 taxpayer at that hearing. The monthly production rate at the economic
26 limit for the lease or property based upon the clear and convincing
27 evidence of the taxpayer shall be calculated by dividing the value
28 determined under (i) of this section into the average monthly direct
29 operating cost determined under (h) of this section.

1 (h) The average monthly direct operating cost for gas production
2 operations of the lease or property shall be determined based on a
3 period of not less than four consecutive months. The direct operating
4 costs include only royalty, production supplies, purchased fuel, routine
5 maintenance, and wages and benefits of employees working on the
6 production operations. Additional direct operating costs not listed in
7 this section may be included only after their inclusion in a regulation
8 adopted by the department. The direct operating costs do not include
9 capital expenditures, tangible or intangible drilling expenses, costs of
10 well workovers, costs for replacement or repairs (other than routine
11 maintenance), depreciation or amortization, taxes, insurance, overhead,
12 monies paid or set aside (or booked as being paid or set aside) to cover
13 the cost of terminating the gas production operations of the lease or
14 property, or any other cost not directly related to the gas production
15 operations of the lease or property.

16 (i) For the purpose of calculating the economic limit, the value
17 at the point of production of gas produced from the lease or property
18 shall be determined on the basis of the highest price paid for gas of
19 like quality and pressure in the same field.

20 (j) The department may aggregate two or more leases or properties
21 (or portions of them), for purposes of determining economic limit factors
22 under this section and applying them to sec. 11 or sec. 16 of this chap-
23 ter, when economically interdependent oil or gas production operations
24 are not confined to a single lease or property. The department may also
25 segregate a lease or property into two or more parts, for purposes of
26 determining economic limit factors under this section and applying them
27 under sec. 11 or sec. 16 of this chapter, when two or more economically
28 independent oil or gas production operations are being conducted on it,
29 or when old crude oil is produced from the same lease or property as

1 other oil.

2 (k) A determination of the monthly production rate at the economic
3 limit for a lease or property is retroactive to January 1 of the current
4 year. For production of a lease or property commencing after January 1,
5 the determination of the monthly production rate at the economic limit
6 for that lease or property made within six months after the commencement
7 of production is retroactive to the commencement of production.

8 Sec. 43.55.016. GAS PRODUCTION TAX. (a) There is levied upon the
9 producer of gas a tax for all gas produced from each lease or property
10 in the state, less any gas the ownership or right to which is exempt
11 from taxation. The tax is equal to either the percentage-of-value
12 amount calculated under (b) of this section or the cents-per-Mcf amount
13 calculated under (c) of this section, whichever is greater, multiplied
14 by the economic limit factor determined for gas production of the lease
15 or property under sec. 13 of this chapter. If the amounts calculated
16 under (b) and (c) of this section are equal, the amount calculated under
17 (b) of this section shall be treated as if it were the greater for
18 purposes of this section.

19 (b) The percentage-of-value amount equals 10 per cent of the gross
20 value at the point of production of the taxable gas produced from the
21 lease or property.

22 (c) The cents-per-Mcf amount equals \$.064 per thousand cubic feet
23 of taxable gas produced from the lease or property as adjusted by sec.
24 12 of this chapter.

25 Sec. 43.55.017. RELATION TO OTHER TAXES. (a) Except as provided
26 in this chapter and in ch. 58 of this title, the taxes imposed by this
27 chapter are in place of all taxes now imposed by the state or any of its
28 municipalities, and neither the state nor a municipality may impose a
29 tax upon

1 (1) producing oil or gas leases;
2 (2) oil or gas produced or extracted in the state;
3 (3) the value of intangible drilling and exploration expen-
4 ses.

5 (b) The taxes imposed by this chapter are in place of all taxes
6 imposed by a municipality upon oil or gas in place or nonproducing oil
7 or gas leases or properties.

8 (c) The taxes imposed by this chapter are not in place of the tax
9 imposed by ch. 57 of this title or income taxes, franchise taxes or
10 taxes upon the retail sale of oil or gas products.

11 * Sec. 2. AS 43.55.020(a) is amended to read:

12 (a) The gross production tax on oil or gas shall be paid monthly.
13 The tax is due on the 20th [LAST] day of each calendar month on oil or
14 gas produced [REMOVED OR SOLD] from each lease or property during the
15 preceding month. If the tax is not paid before the end of the month in
16 which it becomes due, the tax becomes delinquent.

17 * Sec. 3. AS 43.55.020(e) is amended to read:

18 (e) Gas produced in excess of that needed for safety purposes
19 [AND USED], except gas used in the operation of a lease or property in
20 drilling for or producing oil or gas, or for repressuring, is considered,
21 for the purpose of this chapter and in the amount used, as gas produced
22 [REMOVED OR SOLD] from a lease or property. Gas flared beyond the
23 amount authorized for safety by the Department of Natural Resources
24 under AS 31.05.170(11)(H) is considered as gas produced, except that it
25 is subject to a penalty equal to the tax computed under sec. 16 of this
26 chapter as adjusted by sec. 12 of this chapter per thousand cubic feet
27 of gas for the month in which the gas was flared.

28 * Sec. 4. AS 43.55.030(a)(1) is amended to read:

29 (1) a description of the lease or property from which the oil

1 or gas was produced [REMOVED OR SOLD], by name, legal description, lease
2 number or by accounting code numbers assigned by the department;

3 * Sec. 5. AS 43.55.030(a)(3) is amended to read:

4 (3) the gross amount of oil or gas produced [REMOVED OR SOLD]
5 from the lease or property, and the percentage of the gross amount owned
6 by each producer for whom the tax is paid;

7 * Sec. 6. AS 43.55.030(a)(4) is amended to read:

8 (4) the total value of the oil or gas produced [REMOVED OR
9 SOLD] from the lease or property owned by each producer for whom the tax
10 is paid; and

11 * Sec. 7. AS 43.55.140 is amended by adding new paragraphs to read:

12 (12) "gross value at the point of production" means

13 (A) for oil, the value of the oil at the point where it
14 is metered or measured (by automatic custody transfer meter, tank
15 gauge, or other method approved by the commissioner) in a condition
16 of pipeline quality on the premises of the lease or property from
17 which it is recovered; however, if the oil is not of pipeline
18 quality when it is removed from the premises of the lease or pro-
19 perty from which it is recovered, or if the oil recovered from a
20 lease or property is not metered or measured (by automatic custody
21 transfer meter, tank gauge, or other method approved by the com-
22 missioner) on the premises of the lease or property from which it
23 is recovered, then the gross value at the point of production is
24 the value of that oil at the off-premises location where the oil is
25 first metered or measured (by automatic custody transfer meter,
26 tank gauge, or other method approved by the commissioner) in a
27 condition of pipeline quality;

28 (B) for gas recovered from or in association with oil,
29 the value of the gas at the point where it is accurately metered or

1 measured after separation from the oil; for gas run through a gas
2 processing plant, the gross value at the point of production is the
3 full consideration received by the producer for the gas if sold in
4 an arm's length transaction or, in the absence of an arm's length
5 transaction, is the sum of the value of the liquids extracted from
6 the gas at the plant and the value of the residue gas, less a
7 reasonable allowance for processing the gas at the plant and for
8 transporting the gas to the plant from the premises upon which the
9 oil production operation is conducted; and

10 (C) for gas not recovered from or in association with
11 oil, the value of the gas at the point where it is accurately
12 metered or measured or the value of the gas at the point of sale,
13 if any, on the premises of the lease or property from which the gas
14 is recovered, whichever is the higher value; for gas run through a
15 gas processing plant, the gross value at the point of production is
16 the full consideration received by the producer for the gas if sold
17 in an arm's length transaction or, in the absence of an arm's
18 length transaction, is the sum of the value of the liquids ex-
19 tracted from the gas at the plant and the value of the residue gas,
20 less a reasonable allowance for processing the gas at the plant and
21 for transporting the gas to the plant from the point where it was
22 accurately metered or measured;

23 (13) "oil production operation" means the operation by which
24 oil is recovered from a lease or property and rendered into oil of
25 pipeline quality, and includes any gathering done before the oil is
26 finally rendered into oil of pipeline quality;

27 (14) "pipeline quality" means good and merchantable condi-
28 tion;

29 (15) "well days" means the number of days in which a well is

operating during a month;

(16) "old crude oil" means crude oil production classified as "old crude oil" in 10 CFR Chapter II Part 212-72 on May 1, 1977, and which is also classified as "old crude oil" on the date of production.

* Sec. 8. AS 43.56.210(6) is amended to read:

(6) "taxable property" means real and tangible personal property used or committed by contract or other agreement for use within this state primarily in the exploration for, production of, or pipeline transportation of gas or unrefined oil (except for property used solely for the retail distribution or liquefaction of natural gas), or in the operation or maintenance of facilities used in the exploration for, production of, or pipeline transportation of gas or unrefined oil, including machinery, appliances, supplies, equipment, drilling rigs, wells (whether producing or not), gathering lines and transmission lines, pumping stations, compressor stations, power plants, topping plants, processing units, roads, tank farms, tanker terminals, docks and other port facilities, air strips and communication equipment and facilities, maintenance equipment and facilities, and maintenance camps and other related facilities; "taxable property" does not include permanent residences, office buildings requiring substantial local government services, or oil and gas pipeline systems owned and operated by a certificated public utility [AS UTILITIES AND] regulated by the Alaska Public Utilities Commission;

* Sec. 9. AS 43.55.010, 43.55.015 and 43.55.140(10) and (11) are repealed.

* Sec. 10. (a) If a court of competent jurisdiction invalidates the differential economic limit factor computation under AS 43.55.013(a) and (b), the economic limit factor contained in (b) of that section shall be used for computation of the economic limit for all oil.

1 (b) If a court of competent jurisdiction invalidates the differential
2 cents-per-barrel amounts set out in AS 43.55.011(c), then the cents-per-
3 barrel amount under that section shall be \$0.80 per barrel for all crude oil.

4 * Sec. 11. This Act applies to production during the month of July, 1977
5 and succeeding months.

6 * Sec. 12. This Act takes effect July 1, 1977.
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Introduced: 1/31/77
Referred: Resources and Finance

BY THE RULES COMMITTEE BY
REQUEST OF THE LEGISLATIVE
COUNCIL (for the Subcommittee
on Oil and Gas Leasing and
Taxing Policies)

1 IN THE SENATE

2 SENATE BILL NO. 105

3 IN THE LEGISLATURE OF THE STATE OF ALASKA

4 TENTH LEGISLATURE - FIRST SESSION

5 A BILL

6 For an Act entitled: "An Act relating to the Alaska net income tax; and
7 providing for an effective date."

8 BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

9 * Section 1. LESIGLATIVE FINDINGS AND INTENT. The legislature finds and
10 declares that the method of apportioning income for tax purposes under the
11 "Uniform Division of Income for Tax Purposes" formula embodied in the Multi-
12 State Tax Compact (AS 43.19) and AS 43.20.065 does not fairly represent the
13 extent of the business activities in this state of multi-state corporations
14 engaged in the production and pipeline transportation of crude oil and
15 natural gas in Alaska. The legislature therefore intends that the provisions
16 of section 18 of article IV of the Multi-State Tax Compact (AS 43.19) which
17 allow separate accounting of income shall be adopted for the determination of
18 corporate income tax liability on income derived from the production and
19 pipeline transportation of oil and gas and related activities. The legisla-
20 ture further intends that separate accounting shall result in the assessment
21 of tax against multi-state corporations so that the tax paid by these cor-
22 porations will be commensurate with the tax that would be paid by corporations
23 owning and operating only the Alaskan assets of these multi-state corpora-
24 tions.

25 * Sec. 2. AS 43.20.011 is amended by adding a new subsection to read:

26 (f) For purposes of determining taxable income under (e) of this
27 section that part of income of any corporation derived in Alaska from
28 oil or natural gas production or the transportation of crude oil or
29 natural gas by pipeline, including income from royalties on oil and gas

production, shall, notwithstanding sec. 65 of this chapter, be determined by separate accounting in accordance with section 18 of article IV of the Multi-State Compact (AS 43.19.010) and secs. 12 - 14 of this chapter.

* Sec. 3. AS 43.20 is amended by adding new sections to read:

Sec. 43.20.012. DETERMINATION OF OIL AND NATURAL GAS PRODUCTION INCOME. (a) The determination of taxable income attributable to oil and natural gas production, as required under secs. 11(e) and (f) of this chapter, shall be based on a separate accounting of costs and revenues associated with the production.

(b) Gross revenue from oil and gas production shall be the well-head value as established for purposes of the oil and gas properties production tax, in accordance with the provisions of ch. 55 of this title.

(c) Deductions from gross revenue for the purposes of determining taxable production income shall include:

(1) royalties actually paid whether in kind or in value;

(2) severance taxes actually paid;

(3) property taxes actually paid by the corporation taxpayer on the producing property and the facilities directly associated with it, including facilities for the gathering, treating and preparing of the oil or gas for shipment;

(4) the costs incurred by the corporation taxpayer in operating the oil or gas field, including the costs of gathering, treating and preparing the oil or gas for shipment, but net of any payments received for those services;

(5) depreciation on investments which are associated with the production, gathering, treating and preparing for shipment of the oil or gas, and which are located in or adjacent to the site of production, in-

1 cluding depreciation on capitalized interest, lease acquisition payments
2 and property taxes paid before the commencement of production on the
3 leasehold, facilities or investment associated with it;

4 (6) interest expense not capitalized and capitalizable, to
5 the extent that it does not exceed a portion of total interest paid by
6 the corporation, its subsidiaries and affiliates, determined by multi-
7 plying total interest paid by a fraction, the numerator of which is the
8 book value of the corporation's fixed assets in and associated with the
9 field, and the denominator of which is the book value of all fixed
10 assets held by the corporation, its subsidiaries and affiliates;

11 (7) expenses incurred after December 31, 1976 of unsuccessful
12 exploration efforts for oil and gas in Alaska, including the acquisition
13 costs of properties abandoned, dry hole costs, and the costs of geologic
14 and geophysical exploration on or related to those properties.

15 (d) The department shall establish regulations covering the calcu-
16 lation of depreciation costs, the allocation of interest costs, the
17 definition of facilities associated with the production, gathering,
18 treating and preparing for shipment of oil and gas, and other matters
19 necessary to implement this section.

20 Sec. 43.20.013. DETERMINATION OF CRUDE OIL AND NATURAL GAS PIPE-
21 LINE TRANSPORTATION INCOME. - (a) Except as provided in (b) and (c) of
22 this section, annual taxable income from the pipeline transportation of
23 crude oil in Alaska in interstate commerce in facilities devoted wholly
24 to interstate commerce shall be eight per cent of the valuation of the
25 pipeline facility as determined by or in accordance with principles
26 established by the Interstate Commerce Commission (ICC).

27 (b) If no ICC valuation has been made of an interstate oil pipe-
28 line facility or if the oil pipeline facilities are engaged wholly or
29 partially in intrastate commerce, net income shall be determined in

1 accordance with regulations established by the Alaska Pipeline Commis-
2 sion under AS 42.06.041. A tax return reporting this income shall be
3 accompanied by a certification from the Alaska Pipeline Commission to
4 the effect that to the best of the commission's knowledge and belief the
5 income calculation has been made in accordance with the principles
6 established in regulations adopted by the commission, or, if the income
7 is not, in the opinion of the commission, reported in accordance with
8 its regulations, then a statement to that effect, identifying the
9 deficiencies in the report and, if possible, providing a reporting of
10 the true and correct income.

11 (c) A corporation operating an oil pipeline facility engaged
12 solely in interstate commerce may elect to have the taxable income from
13 that facility determined in accordance with (b) of this section, rather
14 than (a) of this section if it complies with all applicable regulations
15 and orders of the Alaska Pipeline Commission concerning accounting
16 methods and reports, and properly files all reports or other information
17 required by Alaska Pipeline Commission regulations.

18 (d) A corporation's taxable income from the transportation of
19 natural gas shall be determined for interstate natural gas pipelines in
20 conformance with the reporting procedures established by the Federal
21 Power Commission, and for intrastate pipelines in conformance with pro-
22 cedures established by the Alaska Public Utilities Commission. A tax
23 return reporting income from the intrastate transportation of natural
24 gas by pipeline shall be accompanied by a certification from the Alaska
25 Public Utilities Commission to the effect that to the best of the com-
26 mission's knowledge and belief the income calculation has been made in
27 accordance with the principles established in regulations adopted by the
28 commission, or, if the income is not, in the opinion of the commission,
29 reported in accordance with its regulations, then a statement to that

1 effect, identifying the deficiencies in the report and, if possible,
2 providing a reporting of the true and correct income.

3 (e) The certifications of the Alaska Pipeline Commission and the
4 Alaska Public Utilities Commission submitted in accordance with this
5 section shall not prejudice any future action by the respective commis-
6 sion nor shall it prevent the respective commission from submitting a
7 revised certification within three years of the due date of the tax
8 return in support of which it was originally filed.

9 (f) Nothing in this section or in sec. 12 of this chapter shall
10 limit a corporate taxpayer's right to appeal or the taxpayer remedies
11 provided under ch. 5 of this title.

12 Sec. 43.20.014. DETERMINATION OF INCOME FROM OTHER ACTIVITIES OF
13 CORPORATIONS ENGAGED IN OIL OR NATURAL GAS PRODUCTION OR TRANSPORTATION.
14 Taxable income from activities other than oil or natural gas production
15 or pipeline transportation shall be determined by subtracting the income
16 as determined under secs. 12 and 13 of this chapter from the corpora-
17 tion's consolidated net income and applying the allocation formula
18 required under the provisions of sec. 65 of this chapter, except that
19 the property factor and the payroll factor shall be calculated without
20 reference to payroll or property related to production or pipeline
21 transportation activity the income from which is taxable in accordance
22 with secs. 12 and 13 of this chapter.

23 Sec. 43.20.015. PUBLIC REPORTING. Notwithstanding the provisions
24 of AS 43.05.230, the commissioner of revenue shall compile and transmit
25 to the legislature an annual consolidated report of state revenues and
26 taxation policies under this chapter. This report shall include total
27 Alaska income tax paid by firms and individuals covered under this
28 chapter, itemized deductions by category and the tax cost of these de-
29 ductions. For purposes of this section, "tax cost" means the amount of

1 revenue which the state would have collected had not a specific deduc-
2 tion been allowed. Also included in the report shall be a summary of
3 each corporate tax return filed which shows income from the production
4 of oil or natural gas, showing the total amount of oil and gas produced
5 by or for each taxpayer, the taxable income of the corporation from
6 production as reported in accordance with sec. 12 of this chapter, from
7 pipeline transportation as reported in accordance with sec. 13 of this
8 chapter, from other income allocated to the state under sec. 14 of this
9 chapter, and the tax due.

10 * Sec. 4. AS 43.20.330 is amended by adding new subsections to read:

11 (f) Any person who improperly influences, or attempts to improper-
12 ly influence, by means of payment or offer of payment or other valuable
13 consideration, any state official in his determination of values and
14 apportionments under this chapter shall be guilty of bribery and punish-
15 able under AS 11.30.040.

16 (g) Any person who knowingly and wilfully makes false statements
17 or representations, or who knowingly allows false statements or repre-
18 sentations to be made on his behalf in the case of corporations, with a
19 purpose of avoiding the corporate tax imposed under this chapter is
20 guilty of wilful tax avoidance and is punishable upon conviction by a
21 fine of three times the amount of the tax that would have been unpaid
22 had the false statement been undetected, and by imprisonment for not
23 less than 10 days nor more than one year.

24 * Sec. 5. AS 42.06.140 is amended by adding a new paragraph to read:

25 (11) shall provide all reasonable assistance to the Depart-
26 ment of Revenue in determining the net income from oil pipeline facili-
27 ties.

28 * Sec. 6. AS 42.06 is amended by adding a new section to read:

29 Sec. 42.06.041. CERTIFICATION OF INCOME TO DEPARTMENT OF REVENUE.

1 (a) Upon request of a pipeline carrier the commission shall review the
2 accounts of that carrier and provide a certification to the Department
3 of Revenue either stating that to the best of the commission's knowledge
4 and belief the report of net pipeline income submitted by the carrier
5 under AS 43.20.013 is in accordance with the commission's regulations
6 governing the accounting of income, or that it is not so in accordance,
7 in which case the commission shall identify the deficiencies in the
8 report and, if possible, provide a reporting of the true and correct in-
9 come.

10 (b) The commission shall provide the certification of compliance
11 or deficiency in reporting within 45 days of the date on which the pipe-
12 line carrier requests it, but all certifications remain subject to
13 amendment by the commission for a period of three years after the due
14 date of the tax return which they accompany.

15 (c) The commission may by regulation establish accounting pro-
16 cedures and definitions as may be necessary to define net income for tax
17 purposes, but net income so defined shall coincide as nearly as possible
18 with the net income definition used by the commission in establishing
19 rates and measuring rate of return, and shall be derived before any
20 deductions for income taxes accrued or paid.

21 * Sec. 7. AS 42.05.141 is amended to read:

22 Sec. 42.05.141. GENERAL POWERS AND DUTIES OF THE COMMISSION. The
23 Alaska Public Utilities Commission [MAY]

24 (1) may regulate every public utility engaged or proposing to
25 engage in such a business inside the state, except to the extent ex-
26 empted by sec. 711 of this chapter and the powers of the commission
27 shall be liberally construed to accomplish its stated purposes;

28 (2) may investigate, upon complaint or upon its own motion,
29 the rates, classifications, rules, regulations, practices, services and

1 facilities of a public utility and hold hearings on them;

2 (3) may make or require just, fair and reasonable rates,
3 classifications, regulations, practices, services and facilities for a
4 public utility;

5 (4) may prescribe the system of accounts and regulate the
6 service and safety of operations of a public utility;

7 (5) may require a public utility to file reports and other
8 information and data;

9 (6) may appear personally or by counsel and represent the
10 interests and welfare of the state in all matters and proceedings in-
11 volving a public utility pending before an officer, department, board,
12 commission or court of the state or of another state or the United
13 States and to intervene in, protest, resist, or advocate the granting,
14 denial or modification of any petition, application, complaint or other
15 proceeding;

16 (7) may examine witnesses and offer evidence in any proceed-
17 ing affecting the state and initiate or participate in judicial pro-
18 ceedings to the extent necessary to protect and promote the interests of
19 the state;

20 (8) shall provide all reasonable assistance to the Department
21 of Revenue in determining the net income from natural gas pipeline
22 facilities.

23 * Sec. 8. AS 42.05 is amended by adding a new section to read:

24 Sec. AS 42.05.502. CERTIFICATION OF INCOME TO DEPARTMENT OF
25 REVENUE. (a) Upon request of a pipeline carrier the commission shall
26 review the accounts of that carrier and provide a certification to the
27 Department of Revenue either stating that to the best of the commission's
28 knowledge and belief the report of net pipeline income submitted by the
29 carrier under AS 43.20.013 is in accordance with the commission's regu-

1 lations governing the accounting of income, or that it is not so in
2 accordance, in which case the commission shall identify the deficiencies
3 in the report and, if possible, provide a reporting of the true and
4 correct income.

5 (b) The commission shall provide the certification of compliance
6 or deficiency in reporting within 45 days of the date on which the pipe-
7 line carrier requests it, but all certifications remain subject to
8 amendment by the commission for a period of three years after the due
9 date of the tax return which they accompany.

10 (c) The commission may by regulation establish accounting proce-
11 dures and definitions as may be necessary to define net income for tax
12 purposes, but net income so defined shall coincide as nearly as possible
13 with the net income definition used by the commission in establishing
14 rates and measuring rate of return, and shall be derived before any
15 deductions for income taxes accrued or paid.

16 * Sec. 9. This Act relates only to income earned or received after
17 December 31, 1976.

18 * Sec. 10. This Act takes effect January 1, 1978.
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Original sponsor: Rules Committee
by request of the Legislative Council
(for the Subcommittee on Oil and Gas
Leasing and Taxing Policies)

Offered: 4/27/77
Referred: Finance

1 IN THE SENATE

BY THE RESOURCES COMMITTEE

2 CS FOR SENATE BILL NO. 105

3 IN THE LEGISLATURE OF THE STATE OF ALASKA

4 TENTH LEGISLATURE - FIRST SESSION

5 A BILL

6 For an Act entitled: "An Act relating to the Alaska net income tax; and
7 providing for an effective date."

8 BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

9 * Section 1. LEGISLATIVE FINDINGS AND INTENT. The legislature finds and
10 declares that the method of apportioning income for tax purposes under the
11 "Uniform Division of Income for Tax Purposes" formula embodied in the Multi-
12 State Tax Compact (AS 43.19) and AS 43.20.065 does not fairly represent the
13 extent of the business activities in this state of multi-state corporations
14 engaged in the production and pipeline transportation of crude oil and
15 natural gas in Alaska. The legislature therefore intends that the provisions
16 of section 18 of article IV of the Multi-State Tax Compact (AS 43.19) which
17 allow separate accounting of income shall be adopted for the determination of
18 corporate income tax liability on income derived from the production and
19 pipeline transportation of oil and gas and related activities. The legisla-
20 ture further intends that separate accounting shall result in the assessment
21 of tax against multi-state corporations so that the tax paid by these cor-
22 porations will be commensurate with the tax that would be paid by corpora-
23 tions owning and operating only the Alaskan assets of these multi-state
24 corporations.

25 * Sec. 2. AS 43.20.011 is amended by adding a new subsection to read:

26 (f) For purposes of determining taxable income under (e) of this
27 section that part of income of any corporation derived in Alaska from
28 oil or natural gas production or the transportation of crude oil or
29 natural gas by pipeline, including income from royalties on oil and gas

1 production, shall, notwithstanding sec. 65 of this chapter, be deter-
2 mined by separate accounting under the authority of section 18 of
3 article IV of the Multi-State Compact (AS 43.19.010) and in accordance
4 with secs. 67 - 69 of this chapter.

5 * Sec. 3. AS 43.20 is amended by adding new sections to read:

6 Sec. 43.20.067. DETERMINATION OF OIL AND NATURAL GAS PRODUCTION
7 INCOME. (a) The determination of taxable income attributable to oil
8 and natural gas production in Alaska, as required under sec. 11(f) of
9 this chapter, shall be calculated using gross income and deductions from
10 gross income as defined in this section.

11 (b) Gross income from oil and gas production in Alaska shall be
12 the value of oil and gas produced as established for purposes of the oil
13 and gas properties production tax, in accordance with the provisions of
14 ch. 55 of this title.

15 (c) Deductions from gross income for the purposes of determining
16 taxable production income shall include:

- 17 (1) royalties actually paid whether in kind or in value;
18 (2) severance taxes actually paid for which no prior deduc-
19 tion has been claimed for income tax purposes;
20 (3) property taxes actually paid by the corporation taxpayer
21 on producing property and facilities directly associated with producing
22 property, including facilities for the gathering, treating and preparing
23 of the oil or gas for shipment, provided the payments are made after the
24 date of initial production of the property with which they are associated;
25 (4) the direct costs incurred by the corporation taxpayer in
26 operating oil or gas fields, including the costs of gathering, treating
27 and preparing oil or gas for shipment, but net of any payments received
28 for those services and not including indirect costs and overhead except
29 as provided in (6) of this subsection;

1 (5) depreciation on investments which are associated with the
2 production, gathering, treating and preparing for shipment of the oil or
3 gas, and which are located in or adjacent to the site of production,
4 including depreciation on interest capitalized at a rate not to exceed
5 the average cost of borrowed capital to the corporation taxpayer during
6 the year in which it is capitalized and also including the amortization
7 of lease acquisition payments and property taxes paid for or on pro-
8 ducing properties before the commencement of production on the lease-
9 hold, facilities or investment associated with it;

10 (6) interest expense not capitalized, to the extent that it
11 does not exceed a portion of total interest paid by the corporation, its
12 subsidiaries and affiliates, determined by multiplying total interest
13 paid by a fraction, the numerator of which is the book value of the
14 corporation's fixed assets in and associated with the producing proper-
15 ties in Alaska and the denominator of which is the book value of all
16 fixed assets held by the corporation, its subsidiaries and affiliates;

17 (7) expenses incurred after December 31, 1976 of unsuccessful
18 exploration efforts for oil and gas in Alaska, including the acquisition
19 costs of properties abandoned, dry hole costs, and the costs of geologic
20 and geophysical exploration on or related to those properties.

21 (d) The department shall establish regulations covering the calcu-
22 lation of depreciation costs, the allocation of interest costs, the
23 definition of facilities associated with the production, gathering,
24 treating and preparing for shipment of oil and gas, and other matters
25 necessary to implement this section.

26 (e) Deductions from gross income under this section shall not
27 include expenses previously deducted on a return filed under this
28 chapter.

29 Sec. 43.20.068. DETERMINATION OF CRUDE OIL AND NATURAL GAS

1 PIPELINE TRANSPORTATION INCOME. (a) Taxable income attributable to the
2 transportation of crude oil in interstate commerce in Alaska shall be
3 the sum of the amount reported to the Interstate Commerce Commission
4 under the category "net balance transferred from income" as specified as
5 of January 1, 1977 in 49 CFR 10 Part 1204, account 700 and of federal
6 income taxes paid as specified as of January 1, 1977 in 49 CFR 10 Part
7 1204, accounts 670 and 695, and of taxes actually paid under sec. 11(e)
8 of this chapter. A tax return reporting that income shall be accompanied
9 by a certification from the Alaska Pipeline Commission to the effect
10 that to the best of the commission's knowledge and belief the income
11 calculation has been made in accordance with the principles established
12 by the Interstate Commerce Commission, or, if in the opinion of the
13 commission, the income is not reported in accordance with the regulations
14 of the Interstate Commerce Commission, then a statement to that effect,
15 identifying the deficiencies of the report and, if possible, providing a
16 reporting of the true and correct income.

17 (b) Taxable income attributable to the transportation of natural
18 gas in interstate commerce in Alaska shall be the sum of the amount
19 reported to the Federal Power Commission under the category "balance
20 transferred from income" as specified in 18 CFR 1, Part 201, account
21 433 and of federal income taxes paid as specified as of January 1, 1977
22 in 18 CFR 1, Part 201, accounts 409, 409.1, 409.2 and 409.3, and of
23 taxes actually paid under sec. 11(e) of this chapter. A tax return
24 reporting that income shall be accompanied by a certification from the
25 Alaska Public Utilities Commission to the effect that to the best of the
26 commission's knowledge and belief the income calculation has been made
27 in accordance with the principles established by the Federal Power
28 Commission, or, if in the opinion of the commission, the income is not
29 reported in accordance with the regulations of the Federal Power
30

1 Commission, then a statement to that effect, identifying the deficiencies
2 of the report and, if possible, providing a reporting of the true and
3 correct income.

4 (c) Taxable income attributable to the transportation of crude oil
5 in Alaska of any corporation not under Interstate Commerce Commission
6 jurisdiction, or of a corporation under the Interstate Commerce Commis-
7 sion but not reporting the operation of pipelines in Alaska separately
8 from the operation of pipelines elsewhere, shall be an amount equal to
9 that which would have been reported to the Interstate Commerce Commission
10 under (a) of this section had the corporation been, in fact, under
11 Interstate Commerce Commission jurisdiction for the taxable year and
12 required to report on the operation of Alaska pipelines separately from
13 the operation of pipelines elsewhere. A tax return reporting that
14 income shall be accompanied by a certification from the Alaska Pipeline
15 Commission to the effect that to the best of the commission's knowledge
16 and belief the income calculation has been made in accordance with the
17 principles established by the Interstate Commerce Commission, or, if in
18 the opinion of the commission, the income is not reported in accordance
19 with the regulations of the Interstate Commerce Commission, then a
20 statement to that effect, identifying the deficiencies of the report
21 and, if possible, providing a reporting of the true and correct income.

22 (d) Taxable income attributable to the transportation of natural
23 gas in Alaska by any corporation not under the jurisdiction of the
24 Federal Power Commission, or of a corporation under Federal Power Commis-
25 sion jurisdiction but not reporting the operation of Alaska pipelines
26 separately from the operation of pipelines elsewhere, shall be an amount
27 equal to that which would have been reported to the Federal Power Commis-
28 sion under (b) of this section had the corporation been, in fact, under
29 Federal Power Commission jurisdiction for the taxable year and required

1 to report on the operation of Alaska pipelines separately from the opera-
2 tion of pipelines elsewhere. A tax return reporting that income shall
3 be accompanied by a certification from the Alaska Public Utility Commis-
4 sion to the effect that to the best of the commission's knowledge and
5 belief the income calculation has been made in accordance with the
6 principles established by the Federal Power Commission, or, if in the
7 opinion of the commission, the income is not reported in accordance with
8 the regulations of the Federal Power Commission, then a statement to
9 that effect, identifying the deficiencies of the report and, if possible,
10 providing a reporting of the true and correct income.

11 (e) The certifications of the Alaska Pipeline Commission and the
12 Alaska Public Utilities Commission submitted in accordance with this
13 section do not prejudice any future action by the respective commission
14 nor prevent the respective commission from submitting a revised certi-
15 fication within three years of the due date of the tax return in support
16 of which it was originally filed.

17 (f) Nothing in this section or in sec. 67 of this chapter limits a
18 corporate taxpayer's right to appeal or the taxpayer remedies provided
19 under ch. 5 of this title.

20 Sec. 43.20.069. DETERMINATION OF INCOME FROM OTHER ACTIVITIES OF
21 CORPORATIONS ENGAGED IN OIL OR NATURAL GAS PRODUCTION OR TRANSPORTATION.
22 Taxable income from activities other than oil or natural gas production
23 or pipeline transportation shall be determined by subtracting the income
24 as determined under secs. 67 and 68 of this chapter from the corpora-
25 tion's combined net income and applying the apportionment formula
26 required under the provisions of sec. 65 of this chapter, except that
27 both the numerator and the denominator of the property factor and the
28 payroll factor shall be calculated without reference to payroll or
29 property related to crude oil or natural gas production or pipeline

1 transportation activity in Alaska, and the sales factor shall not be
2 used in the calculation.

3 Sec. 43.20.070. PUBLIC REPORTING. Notwithstanding the provisions
4 of AS 43.05.230, the commissioner of revenue shall compile and transmit
5 to the legislature an annual consolidated report of state revenues and
6 taxation policies under this chapter. This report shall include total
7 Alaska income tax paid by firms and individuals covered under this
8 chapter and itemized deductions by category.

9 * Sec. 4. AS 43.20 is amended by adding a new section to read:

10 Sec. 43.20.075. BOOKS AND RECORDS. The department may provide by
11 regulation the manner in which books and records must be kept and main-
12 tained for purposes of determining gross income and deductions from
13 gross income under secs. 67 - 69 of this chapter.

14 * Sec. 5. AS 43.20.335 is amended by adding new subsections to read:

15 (k) Any person who improperly influences, or attempts to improper-
16 ly influence, by means of payment or offer of payment or other valuable
17 consideration, any state official in his determination of values and
18 apportionments under this chapter is guilty of bribery and punishable
19 under AS 11.30.040.

20 (l) Any person who knowingly and wilfully makes false statements
21 or representations, or who knowingly allows false statements or repre-
22 sentations to be made on his behalf in the case of corporations, with a
23 purpose of avoiding the corporate tax imposed under this chapter is
24 guilty of wilful tax avoidance and is punishable upon conviction by a
25 fine of three times the amount of the tax that would have been unpaid
26 had the false statement been undetected, and by imprisonment for not
27 less than 10 days nor more than one year.

28 * Sec. 6. AS 42.06.140 is amended by adding a new paragraph to read:

29 (11) shall provide all reasonable assistance to the

1 Department of Revenue in determining the net income from oil pipeline
2 facilities.

3 * Sec. 7. AS 42.06 is amended by adding a new section to read:

4 Sec. 42.06.041. CERTIFICATION OF INCOME TO DEPARTMENT OF REVENUE.

5 (a) Upon request of a pipeline carrier the commission shall review the
6 accounts of that carrier and provide a certification to the Department
7 of Revenue either stating that to the best of the commission's knowledge
8 and belief the report of net pipeline income submitted by the carrier
9 under AS 43.20.069 is in accordance with the commission's regulations
10 governing the accounting of income, or that it is not so in accordance,
11 in which case the commission shall identify the deficiencies in the
12 report and, if possible, provide a reporting of the true and correct in-
13 come.

14 (b) The commission shall provide the certification of compliance
15 or deficiency in reporting within 45 days of the date on which the pipe-
16 line carrier requests it, but all certifications remain subject to
17 amendment by the commission for a period of three years after the due
18 date of the tax return which they accompany.

19 (c) The commission may by regulation establish accounting pro-
20 cedures and definitions as may be necessary to define net income for tax
21 purposes, but net income so defined shall coincide as nearly as possible
22 with the net income definition used by the commission in establishing
23 rates and measuring rate of return, and shall be derived before any
24 deductions for income taxes accrued or paid.

25 * Sec. 8. AS 42.05.141 is amended to read:

26 Sec. 42.05.141. GENERAL POWERS AND DUTIES OF THE COMMISSION. The
27 Alaska Public Utilities Commission [MAY]

28 (1) may regulate every public utility engaged or proposing to
29 engage in such a business inside the state, except to the extent

1 exempted by sec. 711 of this chapter and the powers of the commission
2 shall be liberally construed to accomplish its stated purposes;

3 (2) may investigate, upon complaint or upon its own motion,
4 the rates, classifications, rules, regulations, practices, services and
5 facilities of a public utility and hold hearings on them;

6 (3) may make or require just, fair and reasonable rates,
7 classifications, regulations, practices, services and facilities for a
8 public utility;

9 (4) may prescribe the system of accounts and regulate the
10 service and safety of operations of a public utility;

11 (5) may require a public utility to file reports and other
12 information and data;

13 (6) may appear personally or by counsel and represent the
14 interests and welfare of the state in all matters and proceedings in-
15 volving a public utility pending before an officer, department, board,
16 commission or court of the state or of another state or the United
17 States and to intervene in, protest, resist, or advocate the granting,
18 denial or modification of any petition, application, complaint or other
19 proceeding;

20 (7) may examine witnesses and offer evidence in any proceed-
21 ing affecting the state and initiate or participate in judicial pro-
22 ceedings to the extent necessary to protect and promote the interests of
23 the state;

24 (8) shall provide all reasonable assistance to the Department
25 of Revenue in determining the net income from natural gas pipeline
26 facilities.

27 * Sec. 9. AS 42.05 is amended by adding a new section to read:

28 Sec. 42.05.502. CERTIFICATION OF INCOME TO DEPARTMENT OF REVENUE.

29 (a) Upon request of a pipeline carrier the commission shall review the

1 accounts of that carrier and provide a certification to the Department
2 of Revenue either stating that to the best of the commission's knowledge
3 and belief the report of net pipeline income submitted by the carrier
4 under AS 43.20.069 is in accordance with the commission's regulations
5 governing the accounting of income, or that it is not so in accordance,
6 in which case the commission shall identify the deficiencies in the
7 report and, if possible, provide a reporting of the true and correct
8 income.

9 (b) The commission shall provide the certification of compliance
10 or deficiency in reporting within 45 days of the date on which the pipe-
11 line carrier requests it, but all certifications remain subject to
12 amendment by the commission for a period of three years after the due
13 date of the tax return which they accompany.

14 (c) The commission may by regulation establish accounting proce-
15 dures and definitions as may be necessary to define net income for tax
16 purposes, but net income so defined shall coincide as nearly as possible
17 with the net income definition used by the commission in establishing
18 rates and measuring rate of return, and shall be derived before any
19 deductions for income taxes accrued or paid.

20 * Sec. 10. This Act relates only to income earned or received after
21 December 31, 1976.

22 * Sec. 11. This Act takes effect January 1, 1978.
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LAWS OF ALASKA

1978

Source

Chapter No.

SCS CSHB 322 (Resources)

110

AN ACT

Establishing an oil and gas corporate income tax; and providing for an effective date.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. LEGISLATIVE FINDINGS AND INTENT. The legislature finds and declares that the method of apportioning income for tax purposes under the "Uniform Division of Income for Tax Purposes" formula embodied in the Multistate Tax Compact (AS 43.19) and AS 43.20.065 does not fairly represent the extent of the business activities in this state of multistate corporations engaged in the production and pipeline transportation of crude oil and natural gas in Alaska. The legislature therefore intends that, in accordance with the provisions of art. IV, sec. 18 of the Multistate Tax Compact (AS 43.19), the income tax of all corporations engaged in the production or pipeline transportation of oil or natural gas in or directly associated with this state shall be assessed by the tax administrator under this Act. The legislature further intends that the assessment of income tax against a multistate corporation engaged in the production or pipeline transportation of oil or natural gas shall be commensurate with the tax that would be assessed against a corporation owning and operating only those assets of the multistate corporation which are in or directly associated with this state.

* Sec. 2. AS 43.20.011(e) amended to read:

(e) There is imposed for each taxable year upon the entire taxable income of every corporation derived from sources within the state a tax consisting of a normal tax equal to 5.4 per cent of taxable income, and a surtax which is equal to 4.0 per cent of taxable income. For purposes of this chapter the surtax exemption for a taxable year follows secs. 1561 and 1563 of the Internal Revenue Code. The tax of a corporation engaged in the production or transportation of crude oil or natural gas shall be determined and paid in accordance with ch. 21 of this title.

* Sec. 3. AS 43 is amended by adding a new chapter to read:

CHAPTER 21. OIL AND GAS CORPORATE INCOME TAX.

Sec. 43.21.010. APPLICATION. This chapter applies to every corporation doing business in the state which derives income from the production of oil or gas from a lease or property in or directly associated with the state, or from the pipeline transportation of oil or gas in the state. The tax calculated under this chapter is measured by the total taxable income of the corporation as defined in secs. 20 - 40 of this chapter and is determined at the rates established under AS 43.20.011(e).

Sec. 43.21.020. DETERMINATION OF TAXABLE INCOME FROM OIL AND GAS PRODUCTION. (a) The taxable income of a corporation from the production of oil and gas from a lease or property in the state shall be the corporation's net income as calculated by the department in accordance with this section.

(b) Gross income of a corporation from oil and gas production shall be the gross value at the point of production of oil or gas produced from a lease or property in the state. The department shall by regulation determine a uniform method of establishing the gross value at the point of production. In making its determination the department may use the actual prices or values received for the oil or gas, the posted prices for the oil or gas in the same field, or the prevailing prices or values of oil or gas in the same field. In addition, in its determination of gross value at the point of production of oil or gas produced from a lease or property, the department shall determine the reasonable costs of transportation from the point of sale to the point of production of the oil or gas. Transportation costs set by a tariff properly on file with the Alaska Pipeline Commission or other regulatory agency shall be considered prima facie reasonable, but if a tariff properly on file with a regulatory agency is subsequently amended, changed, or overturned retroactively, the reasonable costs of transportation shall be recomputed for that period using the newly determined tariff.

(c) Net income from oil and gas production shall be determined by the department by deducting from gross income the following:

(1) royalties paid in kind or in value;

(2) taxes imposed under AS 43.55 and AS 43.57 which are actually paid by the corporation on the production from a lease or property in the state;

(3) taxes imposed under AS 43.56 and AS 29.53 which are actually paid by the corporation on property used directly in the production of oil or gas from a lease or property in the state, including property used in production, gathering, treatment or preparation of the oil or gas for pipeline transportation, but only if those property tax payments were due and payable only after the date of commercial production from the lease or property with which the property was associated;

(4) the direct costs incurred by or for the corporation in operating the lease or property, including the direct costs of producing, gathering, treating or preparing the oil or gas for pipeline transportation, but net of any payments received for those activities and not including any indirect cost or overhead expense;

(5) depreciation (using the unit of production method or such other reasonable methods as the department may by regulation establish) on property used directly in the production, gathering, treatment or preparation of the oil or gas for pipeline transportation including amortization of capitalized interest for investments in this property at a rate not to exceed the average cost of borrowed capital to the taxpayer during the year in which it is capitalized;

(6) the amortization of lease acquisition payments and taxes paid under AS 43.56 and AS 29.53 (including capitalized interest on both) for or on producing properties before the commencement of commercial production from the lease or property for which the property is being used;

(7) interest expense not capitalized of the corporation, to the extent that it does not exceed that portion of the total interest paid by the consolidated business of which the corporation is a part, determined by multiplying the total interest (reduced by intercompany transactions within the consolidated business) by a fraction, the numerator of which is the value of the corporation's real and tangible personal property used directly in the production of oil or gas from a lease or property in the state and the denominator of which is the value of all real and tangible personal property of the consolidated business;

(8) expenses incurred by the corporation after December 31, 1977 of unsuccessful exploration of oil or gas in the state including the acquisition costs of abandoned properties, dry hole costs and the costs of geologic and geophysical exploration related to those abandoned properties;

(9) general overhead or administrative expense incurred by the corporation attributable to the production of oil or gas from a lease or property in the state to the extent that it does not exceed the lesser of:

(A) that portion of the total general overhead or administrative expense incurred by the consolidated business of which the corporation is a part, determined by multiplying the total general overhead or administrative expense by a fraction, the numerator of which is the value of the corporation's real and tangible personal property used directly in the production of oil or gas from a lease or property in the state and the denominator of which is the value of all real and tangible personal property of the consolidated business, or

(B) the sum of \$0.12 for each barrel of oil and \$0.02 for each thousand cubic feet of gas produced from a lease or property in the state.

(d) Deductions from gross income under this section shall not include expenses previously deducted on a return filed under AS 43.20.

(e) Where a corporation subject to this chapter shares the production or proceeds of the production from a lease or property through a working interest, royalty interest, overriding royalty interest, production payment, net profit interest, joint venture or other agreement, the department shall allocate the deductions from gross income between the corporation and the persons with whom it has such an agreement in accordance with the terms of the agreement.

Sec. 43.21.030. DETERMINATION OF INCOME FROM OIL AND GAS PIPELINE TRANSPORTATION. (a) Except as provided in (c) of this section, taxable income attributable to the transportation of oil in a pipeline engaged in interstate commerce in Alaska shall be determined by the department and shall be the amount reported or that would be required to be reported to the Federal Energy Regulatory Commission or its successors as net operating income, less those portions of interest and general administrative expense attributable to the pipeline transportation of oil in the state, except that taxable income shall also include taxes on or measured by income. The department shall establish regulations governing the determination of interest and general administrative expense attributable to pipeline transportation of oil in the state.

(b) Except as provided in (c) of this section, taxable income attributable to the transportation of natural gas in a pipeline engaged in interstate commerce in Alaska shall be determined by the department and shall be the amount reported or that would be required to be reported to the Federal Energy Regulatory Commission as net operating income less that portion of interest and general administrative expense attributable to pipeline transportation in the state, except that the taxable income shall also include taxes on or measured by income. The department shall establish regulations governing the determination of interest and general administrative expense attributable to pipeline transportation of natural gas in the state.

(c) Taxable income attributable to the transportation of oil or natural gas in Alaska of any corporation not under the Federal Energy Regulatory Commission jurisdiction, or of a corporation under the jurisdiction of the Federal Energy Regulatory Commission but not reporting the operation of pipelines in Alaska separately from the operation of pipelines elsewhere, shall be determined by the department and shall be based upon an amount equal to that which would have been reported to the Federal Energy Regulatory Commission under (a) of this section in the case of oil pipelines, or (b) of this section in the case of natural gas pipelines, had the corporation been, in fact, under Federal Energy Regulatory Commission jurisdiction for the taxable year and required to report on the operation of Alaska pipelines separately from the operation of pipelines elsewhere.

Sec. 43.21.040. DETERMINATION OF INCOME FROM ACTIVITIES OTHER THAN OIL AND GAS PRODUCTION OR PIPELINE TRANS-

PORTATION. (a) Taxable income of a corporation subject to this chapter from activities in this state other than the production of oil or gas from a lease or property in the state or the pipeline transportation of oil or gas in the state shall be determined in accordance with the method established in art. IV of AS 43.19.010 and in AS 43.20.071, as modified by (b) - (e) of this section.

(b) The total taxable income of the consolidated business shall be the net income determined and certified by an independent certified public accountant for the purposes of a report to shareholders covering its earnings and profits for the taxable year (calculated without regard to any taxes on or measured by net income), less the taxable income of the corporation as determined under secs. 20 and 30 of this chapter.

(c) The numerator and denominator of the property factor, of the payroll factor and of the sales factor shall be calculated without reference to that portion of property, payroll or sales directly related to the production of oil or gas from a lease of property in the state or the pipeline transportation of oil or gas in the state.

(d) Compensation earned by employees of the consolidated business who are employed in the United States but not in any state shall be included in the numerator of the payroll factor if the employees are directly supplied from a base of operations maintained in this state.

(e) The value of oil or gas production facilities or other properties of the consolidated business which are located in the United States but not in any state shall be included in the numerator of the property factor if the property is serviced or supplied from a base of operations maintained in the state or if that property relies on onshore facilities in this state for storage of the oil or gas produced.

Sec. 43.21.050. ASSESSMENT OF INCOME AND TAX. (a) The department shall assess taxable income and the amount of tax payable on that taxable income.

(b) On or before August 15 of each year the department shall send to every corporation taxable under this chapter a notice of assessment showing the amount of income taxable under this chapter for the previous year and the amount of tax payable on that taxable income.

(c) For purposes of this chapter the department may combine taxable incomes of corporations subject to tax under this chapter who are part of the same consolidated business.

Sec. 43.21.060. RETURNS. On or before April 15 of each year, a corporation subject to tax under this chapter shall submit a return in a form prescribed by the department setting out information required by the department to determine taxable income. For purposes of this chapter, the department may require corporations subject to tax under this chapter who are part of the same consolidated business to file a single return.

Chapter 110

Sec. 43.21.070. PAYMENT OF TAX. The tax levied under this chapter is payable to the department on or before September 30 of each year or in installments at the times and under the conditions the department may by regulation require. This tax is payable on the due date set out in this section even though the assessment is under appeal or the validity, enforceability or application of this chapter or any provision of this chapter is challenged before the department or in the courts.

Sec. 43.21.080. TRANSITIONAL RULES. The department shall provide by regulation transition rules for corporations subject to tax under ch. 20 of this title before the effective date of this Act to avoid double taxation of the same income or double deduction of the same expense of those corporations as a result of becoming subject to tax under this chapter.

Sec. 43.21.090. REGULATIONS. The department may adopt regulations in accordance with the Administrative Procedure Act (AS 44.62) as appropriate to administer and enforce this chapter.

Sec. 43.21.100. PENALTIES. The penalties established in ch. 20 of this title apply to this chapter.

Sec. 43.21.110. PUBLIC REPORTING. (a) The commissioner of revenue shall compile and transmit to the legislature an annual consolidated report of state revenues and taxation policies under this chapter. This report shall include total aggregate income tax paid by corporations covered under this chapter and aggregate income and deductions by category, so classified as to prevent the identification of particular returns or reports.

(b) The legislative auditor shall transmit to the legislature an annual report reviewing the actions of the department in administering this chapter.

Sec. 43.21.120. DEFINITIONS. Unless the context requires otherwise the definitions contained in AS 43.55.-140 are applicable to this chapter. In addition, in this chapter

(1) "base of operations" means the closest point on land to the offshore oil or gas production operations from which goods, services and supplies flow to those offshore oil or gas production operations;

(2) "consolidated business" means a corporation or group of corporations having at least 50 per cent common ownership, direct or indirect, or a group of corporations in which there is common control either direct or indirect as evidenced by any arrangement, contract or agreement.

* Sec. 4. This Act applies to taxable income earned or received after December 31, 1977.

* Sec. 5. The Act takes effect immediately in accordance with AS 01.10.070(c).

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Approved by the Governor: July 8, 1978
Actual Effective Date: July 9, 1978



LAWS OF ALASKA

1978

Source

HCSSB 601

Chapter No.

111

AN ACT

Making special appropriations to the power project revolving fund and the Department of Revenue; and providing for an effective date.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. The sum of ~~\$6,000,000~~ ^{\$500,000} is appropriated from the general fund to the power project revolving fund (AS 44.56.170) to be used for loans for reconnaissance studies, design, modification, expansion and preconstruction engineering for water supply and hydroelectric projects.

* Sec. 2. The sum of ~~\$10,600,000~~ ^{\$7,000,000} is appropriated from the general fund to the Department of Revenue for a loan to the municipality of Sitka for continuing design, federal licensing, and commencing construction of the Green Lake hydroelectric project; the terms and conditions of the loan are to be determined by the commissioner of revenue in consultation with the commissioner of transportation and public facilities.

* Sec. 3. This Act takes effect immediately in accordance with AS 01.10.070(c).

Approved by the Governor: July 8, 1978
Actual Effective Date: July 9, 1978

SCOMM

28:7

TAPS SETTLEMENT ANALYSIS MATERIALS

PREPARED BY

THE ATTORNEY GENERAL

FOR

THE GOVERNOR

AND

THE LEGISLATURE

APRIL 12, 1982

MEMORANDUM

State of Alaska

TO: The Honorable Jay S. Hammond
Governor
State of Alaska

DATE: April 9, 1982

FILE NO:

TELEPHONE NO:

FROM: Wilson L. Condon
Attorney General

SUBJECT: TAPS Settlement
Analysis Materials
For Distribution To
The Legislature

Attached to this memorandum is a package of materials which I recommend should be made available to the Legislature and its staff or consultants to assist them in their evaluation of the proposed TAPS Settlement with B.P. Pipeline Company. This package includes the following documents:

1. My memorandum to the File dated March 30, 1982, entitled "The Pros and Cons" of Settlement.
2. My Memorandum to the File dated April 9, 1982, summarizing the 10 major features of the Proposed Settlement Agreement between the State and B.P. Pipeline Company.
3. A copy of the April 5, 1982, Draft Settlement Agreement, which is substantially the entire document, subject only to minor technical revisions.
4. My Memorandum to the File dated March 1, 1982, entitled "TAPS STATUS REPORT".
5. Copies of your letters to me dated December 9, 1981, and January 28, 1982, directing my negotiations and memorializing your desire and intent to confer with Legislative leadership before committing to any settlement proposal.

Twenty bound sets of these materials are currently available for distribution as you direct.

As you are aware, there are numerous other documents I have had prepared in connection with our settlement efforts in the TAPS case. These documents, which are privileged attorney-client communication, include supporting material for the conclusions and analysis set forth in the three memoranda to my file itemized above. I recommend that we allow people

The Honorable Jay S. Hammond
Governor

April 9, 1982
Page 2

who may wish to read any of these documents to do so, subject to the provision that no copies of these documents may be made or publicly distributed until after a complete settlement embracing all eight of the TAPS owner companies is consummated.

It has recently become quite likely that we will be able to achieve such a settlement. B.P. has all but committed to the terms of the settlement agreement, and we believe that they will bring Sohio with them. Our intelligence is that Exxon is 90% likely to join, perceiving that an outcome substantially identical to the settlement will be thrust upon them in any event should they oppose it. We believe that ARCO is at least 80% likely to join if Exxon and Sohio do. Finally the remaining four owners, holding in aggregate less than 10% of the TAPS system, will be hard pressed not to join if the four major owners have.

Nevertheless, there does remain a real possibility of our failing to consummate a complete settlement with all of the TAPS owners. In the absence of an all-embracing settlement, the State's litigation efforts will probably continue. There are passages in some of our background analyses which, if quoted out of context, are susceptible to being mischaracterized as expressions of private disagreement with our publicly advocated litigation position. On the assumption that any document we release without restriction could be used against us in ongoing litigation, I believe that we should maintain strict security over any document that could in any way be twisted to the jeopardy of our litigation posture.

By making these materials available, even for reading, we open the door for their possible use against us. However, I believe it is worth taking this risk to ensure that interested legislators and members of the public can fully review the process by which we have reached our recommendation.

WLC:vrh

MEMORANDUM

State of Alaska

CONFIDENTIAL - ADVICE OF COUNSEL

to Memo to the File

DATE April 9, 1982

FILE NO:

TELEPHONE NO:

FROM Wilson L. Condon
Attorney General

SUBJECT Outline of Proposed
TAPS Settlement
Agreement between
State of Alaska and
BP Pipeline Company

Here, in summary form, is a catalogue of the features contained in the proposed Settlement Agreement with B.P. Pipeline Company:

1. Initial 1982 Tariff: \$4.625 per barrel.
2. Reimbursement of State's litigation expenses: B. P. will reimburse the State for its proportional 1/6 share of the \$20 million the State has spent on the TAPS litigation from its inception to the effective date of the settlement.
3. Rate Base reduction: in settlement of our Phase II case on construction cost overruns, the rate base will be reduced by \$400,000,000. If the other TAPS owner companies do not join in the settlement, B. P. will stipulate to a larger rate base reduction totalling \$500,000,000.
4. Inflation escalator: the \$4.625/barrel base tariff will escalate annually by 40% of the rate of inflation as determined with reference to the Federal Gross National Product Deflator (the "GNP" index). If inflation exceeds 12% for any annual period, the escalator percentage increases, but only enough so that the discounted average value of the tariff over the settlement period remains constant (stated in 1982 present value dollars).

CONFIDENTIAL - ADVICE OF COUNSEL

Memo to the File

April 9, 1982

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5. Rate reductions for increased throughput:
Rates will be lowered for increases in throughput under the following adjustment formula:

New Rate = existing rate

$$x \frac{1.6 \text{ mbd}}{[\frac{1}{2} (\text{new throughput less } 1.6 \text{ mbd}) + 1.6 \text{ mbd}]}$$

For example, if throughput increases from the current level of 1.6 mbd to 2.0 mbd and the existing rate is \$4.625/barrel, the new rate will be \$4.111/barrel. If throughput falls off during the life of the settlement, the tariff will increase under this same formula.

6. Adjustment for changes in tax rates:
Rates will be increased or decreased to pass along any material increases or decreases in federal or state income tax rates or in ad valorem taxes.
7. Adjustment for expensive disaster: Rates may be increased in the event of disasters costing more than \$50,000,000 to repair. The amount required in excess of \$50,000,000 will be recovered over 5 years, including a financing cost allowance approximately equal to the prime rate of interest. The companies will absorb the first \$50,000,000.
8. Adjustment for pumpability of other crude oil stocks. Rates may be increased or decreased for crude oils other than from the Sadlerochit field to reflect variations in pumpability characteristics.
9. Effective date and duration of settlement arrangement: The settlement arrangement will last for 10 years from the effective date of the FERC's approval of the settlement. At the end of the settlement period we may either extend or renegotiate the settlement or apply to the then appropriate regulatory body for a rate determination.

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Memo to the File

April 9, 1982

Page 3

10. Waiver of claim for refund: In exchange for B.P.'s (and other agreeable pipeline companies') agreeing to these terms and foregoing their claims for higher TAPS tariffs, the State agrees to waive its claims for refunds for past years during which the rates, of course, exceeded the \$4.625/barrel settlement figure.

WLC:vrh

MEMORANDUM

State of Alaska

CONFIDENTIAL - ADVICE OF COUNSEL

TO: To File

DATE: March 30, 1982

FILE NO:

TELEPHONE NO:

FROM: Wilson L. Condon
Attorney General

SUBJECT: Pros and cons of
settlement

This is a revised version of the memorandum originally prepared on March 1, 1982. It incorporates a number of revisions to the computations shown on pages 11, 12 and 15 below. In general, these revisions reflect assumed levels of success from litigation that are higher than the projections that were used in the earlier memorandum. In other words, this memorandum is deliberately calculated to make the settlement proposal look less favorable than it would appear to be from the March 1, 1982 memorandum.

The motivation for my undertaking this exercise is the reactions of some of the State's TAPS litigation counsel to the probability assumptions set forth in the earlier memorandum. In the past four weeks, it has come to my attention that there are differences of opinion regarding the probabilities of success that the State could expect in the event the litigation should continue. While I stand firmly behind the assumptions spelled out in the March 1 memorandum, I felt it would be a worthwhile exercise to compute the outcome that follows from a set of probabilities that assume greater likelihood of success from litigation.

Qualitatively, these revised calculations and the

modified assumptions upon which they are based do not alter the conclusion of the March 1 memorandum that the proposed settlement of \$4.625/40% escalating is superior to the arithmetically-achieved expected value of continuing the litigation. However, the margin of superiority has been reduced from 8 cents per barrel to 4 cents per barrel.

THE PROS AND CONS OF SETTLEMENT

Introduction.

I have reached an understanding with representatives of B.P. Pipeline Company regarding a possible settlement of their part of the TAPS tariff litigation. B.P. has indicated a willingness to stipulate to a 1982 tariff of \$4.625 per barrel, 40% of which would escalate with the rate of inflation. The settlement period would last for 10 years. In addition, they would be relieved of refund liability for the years 1978 to the settlement date, during which they have collected \$6.35 per barrel. However, they would reimburse the State for \$3 million of the \$18 million which the State has incurred to date as litigation expenses in the TAPS proceeding. This reimbursement figure is based on B.P.'s approximately one-sixth ownership interest in the TAPS facilities.

I see three inter-related questions to address in assessing whether this proposal is a deal the State should want to take. The first goes to the multiparty procedural setting

of the TAPS case: should we settle with B.P. alone? The second goes to timing: should we settle now or wait? The third goes to the fundamentals of the proposal: is the \$4.625/40% escalating proposal a fair deal for the State?

None of these questions is open-and-shut. There are several pros and cons associated with settling in general and this settlement in particular. On balance, I think the pros outweigh the cons. Accordingly, it is my judgment that the State should stipulate with B.P. to this proposal. Here are the considerations as I see them.

1. Should we settle with B.P. alone?

Pluses	Minuses
+ Increased likelihood of total resolution of TAPS litigation.	- Risk of undermining our best possible outcome if total resolution not achieved.
+ At minimum, moderate reduction in scope of litigation.	

At present, the only way to resolve the TAPS litigation by settlement is to start by settling with B.P. separately. None of the other major TAPS owners have made any proposals that would be remotely acceptable to the State. But if B.P. publically accepts a \$4.625/40% arrangement the other companies will be hard-pressed to justify 1982 tariffs in the

range of \$5.30 (with at least 40% escalators). ^{1/} Even if a separate settlement with B.P. does not force the other companies into a substantially similar arrangement, it will reduce the number of parties litigating against us and the number of issues to be resolved. This in turn would mean at least modest savings in the cost of continued litigation.

On the minus side, we would risk undermining our best possible outcome if a separate settlement with B.P. does not precipitate an overall resolution. Once we have publicly agreed to a \$4.625/40% arrangement with B.P., we will find it hard to justify rates substantially lower. The crux of this consideration is whether the \$4.625/40% proposal is a reasonable settlement. For the reasons discussed on pages 6-13 below, I think that it is. Therefore, I think this risk is worth taking.

2. Should we settle now or wait?

Pluses	Minuses
+ Timing propitious for settlement	- FERC decision on Phase I or in <u>Williams Brothers</u> might improve our negotiation position

1/ The weighted average of the settlement proposal advanced in May, 1981, by representatives of ARCO, B.P., Exxon and Sohio, was a 1982 tariff of \$5.32 per barrel, 40% of which would escalate with inflation. In late December, 1981, Exxon filed for a rate reduction from their initial rate of \$6.27 to a new rate of \$5.30. Exxon's action was motivated by the constraining effect of the 1941 antitrust consent decree, which currently acts as a ceiling on oil pipeline rates, but which may soon be dissolved on the motion of the Antitrust Division of the Department of Justice.

MEMORANDUM
To the File

March 30, 1982
Page #5

The Phase II cost of construction hearings have just begun, and by all expectations will continue for several months in the absence of settlement. Settlement now would have the generally beneficial effect of minimizing legal expenses for all parties. In addition, the cost of construction case is the single largest and most emotionally charged issue in the entire TAPS litigation. Psychological factors favor settling now, before the cost of construction hearings have gotten too heated and the parties have gotten irrevocably committed to their litigation postures.

If we don't settle shortly, the psychological factors will soon turn against settlement for the indeterminate future. Once the parties have become publicly committed to their litigation positions, they are less likely to be favorably disposed to compromise. A lengthy period of emotional run-off will probably be required to get people back to the bargaining table. Countering this consideration, however, are the assurances we have received from B.P.'s representatives that the cost of construction hearings will not polarize their position.

On the minus side, if we settle now we risk losing the potential benefits of a FERC decision either on the appeals from Judge Kane's Phase I decision or in the Williams Brothers case. Williams Brothers is the companion case to TAPS. The FERC's promised rulings on Judge Kane's decision and in Williams Brothers, either of which could establish the definitive

oil pipeline rate-making formula, are both long overdue. The worst case scenario would have us settling with B.P. days before the FERC announces a rate-making precedent which would yield substantially lower rates than we have agreed to.

For several reasons I think this risk is worth taking. First, we have no guarantee that either decision is imminent. Our best intelligence is that the FERC has suspended all consideration of the TAPS Phase I decision pending the outcome of settlement discussions. As for the Williams Brothers case, it has been pending at the FERC, upon remand from the courts, since November, 1978. When the FERC intervened in the court proceedings in the Spring of 1978, its counsel gave oral assurances that the agency would move the case with "dispatch." In any event, the FERC has never shown itself to be capable of swift decision-making on major policy questions.

Second, a major policy pronouncement in Williams Brothers would not necessarily apply to TAPS. Two ratemaking formulas have been advocated on the Williams Brothers record that were not addressed in TAPS. If the FERC were to adopt either, then Phase I of TAPS would have to be reopened before these formulas could be applied in our case.

Third, the Williams Brothers decision could go against us. Four of the five formulas advocated in Williams Brothers are potentially less favorable to us than the formula we advocated in TAPS. Reporting on a most-significant recent

development, a December, 1981 Foster Oil Pipeline Report indicates that John David Hughes, the FERC Commissioner most sympathetic to the State's position, is giving serious consideration to one of these less favorable formulas. This apparent shift in Commissioner Hughes' position significantly alters my estimation of the chances of a FERC precedent going against us. Back in November, 1981, my best judgment was a 50-50 chance of the FERC's adopting either a variation of our advocated formula or a variation of a far less favorable formula. My best judgment now is that the probabilities have tipped to 60-40 against us.

In my judgment, there is not likely to be a better time for settling for the foreseeable future.

3. Is \$4.625/40% a fair deal for the State?

Pluses	Minuses
<u>Financial Considerations</u>	
+ Seal off exposure to worse outcomes	- Loss of opportunity for better outcomes
+ Lower than can be justified under technical analysis	
+ Immediate increase in State revenues	- No refunds
+ Save projected litigation expenses	
<u>Policy Considerations</u>	
+ Certainty of tariffs for 10 years	- Increased risk of TAPS being deregulated
+ Eliminate potential adverse impact on ANGTS	- Loss of rate-making precedent

Financial Considerations

The chief reason for settling any dispute is to buy certainty. The advantage of settlement is that it seals off exposure to any worse result. The corresponding disadvantage is that it costs the opportunity for any better result. After extensive fact-gathering and detailed technical analysis, I have concluded that the \$4.625/40% escalating proposal is significantly better than the net present value of the sum of our most likely best and worst case probabilities, even after allowing for the possibility of the State's ultimately winning refunds plus interest.

The concept of net present value is simple enough. The value of a set of choices is merely the sum of the products of the various pay-offs multiplied by their respective probabilities. Take, for a simple example, a two-choice lottery in which there is a 60% chance of winning \$4.00 and a 40% chance of losing \$5.00. The value of this set of choices is \$.40, computed as follows: $[(.60 \times \$4)] + [(.40 \times -\$5)] = \$2.40 - \$2.00 = \$.40$. This method of analysis is helpful in assessing the \$4.625/40% escalating TAPS tariff proposal.

In my view, these are the relevant possibilities and probabilities which cover the 10 year settlement period: I judge there to be a 25% probability that the FERC will simply avoid making any decision on the TAPS tariffs. (For my reasoning, see the discussion in the TAPS Briefing Paper at pages

67-69 and pages 74-75). Within this range, I have been advised by our special counsel handling the consent decree proceeding that there is a 50% probability that the consent decree will have been vacated. In this case, B.P. can be expected to leave its rate at its current tariff level of \$6.35/barrel -- increasing it periodically to keep it at this level in constant dollars. Correspondingly, I believe there is a 50% probability that the consent decree ceiling will be left in place pending a FERC decision on proper oil pipeline rate making methodology. In that case, B.P. would likely follow the other TAPS owners and lower its 1982 rate to the consent decree area of \$5.43/40% escalating (which is equal to \$4.47 stated in constant 1982 dollars).

As for the remaining 75% probabilities, Commissioner Hughes' recent pronouncements (see p. 7) have caused me to reassess the likelihood of the FERC's staying with the utility-formula advocated by the State and adopted by Judge Kane in his Phase I decision. Although I now believe that the odds are 40% for the utility formula and 60% that the Commission will adopt some variation of the trended original cost formula, to downplay the settlement proposal I have based my computations on a 50% probability for the utility formula. As calculated by our technical consultants, the utility-formula variation I think most likely is equal to \$3.07 in constant dollars over the settlement period, but this figure does not allow for the possi-

bility of our reducing rates in the Phase II cost of construction and cost of service cases. Accordingly, I have further lowered this outcome to a 10 year tariff of \$2.79 in constant dollars. (This assumes a success level of approximately 40% in Phase II. ^{2/}) As for the TOC variations, I have considered the possibilities of the FERC's choosing a low, a medium, and a medium-high real rate of return coupled with a major rate-base reduction, to allow for a reasonable level of success in the cost of construction case. All of these possibilities and probabilities reduce to the following matrix:

1. FERC AVOIDS DECISION = 25% overall probability	<u>Net present value</u>
A. Tariff stays at \$6.35 (constant dollars) x 12.5% =	\$0.7938
B. Tariff goes to \$4.47 (constant dollars) x 12.5% =	0.5588

2/ If we were 100% successful in both our Phase I cost of construction and cost of service cases, the effect would be to reduce the tariffs by \$.97 per barrel. Discounting this figure at an 8% assumed rate of inflation over 10 years yields a present value equivalent of \$.708 per barrel reduction per year in constant (1982) dollars. A 40% success level would thus mean a net reduction of \$.283 cents per barrel. In other words, I have assumed a 40% probability of our being completely successful in all of our Phase II litigation, which is arithmetically the equivalent of a 100% probability of our achieving 40% of our maximum potential rate reduction. In my judgment, this is a reasonable, but quite optimistic, probability of success in light of what we know about the sympathies and leanings of the current panel of FERC commissioners.

2. FERC DECIDES TARIFFS AND
METHODOLOGY = 75% overall probability

- A. Modified Kane methodology + 40%
success in Phase II:

Tariff goes to \$2.79 (constant
dollars) x 37.5% = 1.0425

- B. TOC with 5% real rate of return:

Tariff goes to \$3.64 (constant
dollars) x 3.75% = 0.1365

- C. TOC with 6.5% real rate of return

Tariff goes to \$4.40 (constant
dollars) x 22.5% = 0.9900

- D. TOC with 7.0% real rate of return

Tariff goes to \$4.56 (constant
dollars) x 11.25% = .5130

TOTAL = Net Expected Value of tariff (in present value dollars)
over settlement period = \$4.0346

Since the \$4.625/40% proposal is the equivalent of only \$3.802 in present value dollars, it is clearly lower than the net expected value tariff of \$4.0346.

However, the settlement proposal requires the State to forego the possibility of refunds, so some allowance must be made for that. Once again, the net present value analysis enables us to compute the expected value of the refund. In the 25% probability that the FERC ducks a decision on TAPS, there would be no refund possibility at all. As for the remaining 75%, for the reasons discussed on pages 61 and 67 of the TAPS Briefing Paper, I think it is rather unlikely that the FERC

will require refunds, whatever methodology it might choose. My judgment sets the odds of refund -- should the FERC decide methodology -- at only 40%. ^{3/} Nevertheless, to be conservative and to downplay the proposed settlement, I have estimated the gross probability of refund at 50% for purposes of the following computations. The net probability of refund, then, is 50% of 75%, which equals 37.5%.

Within this 37.5% probability, the refunds could be very large or rather small, depending upon the methodology adopted. (Parenthetically, it should be remembered that the State's interest is only about 24% of each dollar of any owner company's refund exposure. Since the State's interest is a constant per cent, however, no special computations need to

3/ This is a very difficult judgment call because the choice of either the utility formula or the trended original cost formula would logically seem to require the FERC to address and decide the question of refunds. Especially under the time path of the TOC approach, where rates are lowest in the early years and highest in the later, the companies' refund exposure would be enormous.

There are, to my mind however, several ways for the FERC to side-step the consequences of "methodological purity." Since both the utility and the TOC formulas are untried methodologies as far as oil pipeline rates are concerned (and TOC has never been used to set rates of any kind), it seems highly likely that the FERC would adopt some sort of transition arrangement to ease the shift from the ICC valuation approach to any other ratemaking methodology. I would expect the present body of FERC commissioners to seize upon this device of "the transition" as the means of vastly ameliorating the companies' refund exposure which would otherwise be an apparent requirement of deciding the case.

made in computing the net present value of any owner company's refund exposure.)

The key variable is the time path associated with each methodology. Under the TOC methodology, tariffs are lowest in the early years and highest in the later years. By contrast, under the utility-methodology, rates are highest in the early years and lowest in the later years. B.P.'s refund exposure turns on the difference between \$6.35, the rate it is currently charging, and the rate determined for the years up to 1982. Accordingly, its refund exposure is greatest under the TOC scenarios.

It is my best judgment that under the revised Kane methodology, the resultant rates for 1978 and 1979 would be at least as high as B.P.'s current rate of \$6.35. Consequently, there would be no refund exposure for these years. As a best estimate for B.P.'s refund exposure for the years 1980 and 1981, I have taken Judge Kane's unmodified 1978 and 1979 rates for B.P. and applied them against B.P.'s throughput for 1980 and 1981. For the TOC scenarios, our consultants have computed the rates from 1978 forward, so the determination of B.P.'s refund exposure is much easier. For all scenarios, I have also allowed for interest compounding at 6.25% per year up to 1982. This is the current legal rate of interest on rate refunds awarded by the FERC.

Once again, I have assessed the probability of the

FERC's using the modified Kane methodology at 50% and the probability of the FERC's using a TOC methodology at an aggregate of 50%. I have also allowed for the possibility of a low, medium, and medium-high real rate of return with the TOC methodology. The computations are available on separate work papers. Here is the resultant matrix:

Net Probability of refund = 37.5%

A.	B.P.'s exposure under modified Kane (utility-type approach) \$237,576,000 x 50% =	\$118,788,000
B.	B.P.'s exposure under TOC, 5% Real ROR \$1,194,983,000 x 5% =	59,749,000
C.	B.P.'s exposure under TOC, 6.5% Real ROR \$736,489,000 x 30% =	220,947,000
D.	B.P.'s exposure under TOC, 7% real ROR \$660,108,000 x 15% =	<u>\$99,016,000</u>
TOTAL = gross present value of B.P.'s refund exposure, assuming there are refunds. =		\$498,500,000
<u>x 37.5% net probability of refunds</u>		<u>x .375</u>
Net present value of B.P.'s refund exposure =		\$186,938,000

The bottom-line of these calculations is that B.P. faces a likely refund exposure of \$186,938,000 if we reject the settlement. At its effective rate of 24%, the State's refund interest has an expected value of \$44,865,000

On the other hand, since the constant dollar net

present value tariff is larger than the constant dollar value of the settlement, B.P. will have likely foregone future revenues if we accept the settlement. The magnitude of this revenue loss is the difference between the constant dollar values of the NEV tariff and the settlement tariff, multiplied by the throughput over the 10 year settlement period.

Assuming an annual throughput of 1.6 million barrels per day for TAPS as a whole and a one-sixth share for B.P., B.P.'s 10-year throughput equals 973,330,000 barrels. Multiplied by the 23.26 cent difference between the NEV tariff and the settlement figure yields a 10-year revenue loss of \$226,397,000 in constant 1982 dollars. Since this figure is \$39,459,000 larger than B.P.'s net present value refund exposure, the conclusion which follows from this analysis is that the settlement clearly favors the State, even after allowance is made for the possibility of our receiving refunds plus interest if we choose to reject this settlement.

In fact, when the \$39,459,000 NEV revenue shortfall is divided by the 10-year projected throughput of 973,330,000 barrels, the result is a constant dollar value margin of 4 cents per barrel by which the settlement favors the State. Translated back into a 1982 tariff escalating at 40%, this means a settlement figure as high as $\$4.675/40\%$ would appear to equalize the value of B.P.'s present refund exposure and future revenue loss.

It should also be noted that no allowance has been made for the non-quantifiable benefits associated with settlement.

Aside from B.P., I am not aware of anyone who has analyzed the case as thoroughly or as carefully as we have. I am aware of other opinions to the effect that a mid-way split between our best and worst case probabilities would be much lower than \$4.625/40%. I believe that these opinions may be sincerely held, but I do not share them.

The remaining financial considerations focus on the revenue impact of settlement on the State. On the plus side, settling with B.P. at \$4.625/40% will mean an immediate annual increase in State royalty and severance tax income of approximately \$35 million. In addition, the State would also receive an immediate one-time payment of \$3 million, representing B.P.'s reimbursement of its proportional share of the State's TAPS litigation expenditures.

If settlement with B.P. should precipitate settling with the remaining TAPS owners on substantially similar terms, the annual increase in State royalty and severance tax revenues would grow to approximately \$200 million and the State would recover the balance of the \$18 million it has spent on TAPS to date. As an additional plus, if settlement with B.P. precipitates a general settlement, the State would thereby save another \$15.6 million, which represents the projected cost of liti-

gating the case to a conclusion.

On the minus side, settlement means foregoing any refunds. I do not regard this as a great sacrifice for several reasons. First, as pointed out in the technical analysis above, I think there is a low overall probability of the FERC's ordering refunds under any circumstances. Second, even if FERC should order refunds, the likelihood is that such an order would be stayed pending appeal. The current interest rate on FERC refunds is 6.25%, so the State would be losing considerable time-value on whatever refunds it might ultimately receive. At best, the receipt of refunds is a very speculative contingency which will not be realized, if ever, until some time in the indeterminate future. Finally, as the technical analysis has shown, the settlement is better for the State than the net present value tariff even after allowing for the possibility of the State's receiving a refund plus interest.

One concluding comment is in order as regards the foregone possibilities of refunds and/or lower tariffs. At stake here is the public's money. The crucial issue is to define the extent to which better results should be sought at the risk of realizing substantially worse outcomes. In my judgment, a more conservative philosophy is required when handling the public's money than when an individual is handling his own. I believe that the responsible course is first to minimize the down-side risks to the fullest practicable extent and only then

to endeavor to maximize speculative gains on the up-side. In my opinion, the \$4.625/40% settlement is fully consistent with this philosophy and still achieves a better result than can be justified on purely probabilistic analysis.

Policy Considerations.

As a policy matter, settlement carries the twin advantages of bringing certainty to TAPS tariffs for at least the 10-year settlement period and reducing uncertainties in several related areas. As long as the TAPS litigation continues, uncertainties will be prolonged in the areas of royalty revenue projections, severance tax revenue projections and state income tax projections. This in turn causes difficulties in fiscal and permanent fund planning.

Those who pay or collect these taxes and prepare or audit the returns face additional uncertainties associated with computation and reporting. Under the new apportionment formulas that have just gone into effect on January 1, 1982, it will be impossible to make final State income tax computations until TAPS tariffs are finally established. Amended returns will have to be filed (and audited) for all of the years during which TAPS tariffs will have been litigated.

Another policy advantage to settlement is the elimination of potentially adverse impacts on the financing and construction of the Alaska Natural Gas Transmission System

(ANGTS). The very strength of our cost of construction case could convince potential investors that the risks of constructing the ANGTS are far greater than presently perceived. Similarly, the strength of our cost of service case could convince investors that the ANGTS is potentially far less profitable than presently perceived.

On the minus side, a settlement of any kind could increase the likelihood of TAPS' being deregulated by Congressional action, and could kill any incentive the FERC has to devise a satisfactory oil pipeline rate-making formula. In other words, while settlement would increase certainty for the next 10 years, it could mean greater uncertainty as to what will happen to TAPS tariffs at the conclusion of the settlement period.

These risks are significant, but I think they are worth taking. In this inflationary period in which we live, everyone's time-horizons have shortened considerably. Few people are willing to commit themselves to any major financial arrangement for more than 10 years. TAPS might be deregulated even if we do not settle. The owner companies are fighting hard for deregulation right now. If we do not settle and TAPS is deregulated, we lose all of the benefits of settlement. Meanwhile, a lot can happen in 10 years. Even if today's Congress were to agree to deregulate TAPS at the end of the settlement period, changed circumstances might persuade a 1990's

Congress to reinstitute regulatory controls. .

As for the precedent value of TAPS, I share the opinion that the case has grown beyond the ability of the FERC to manage or decide. A precedent-setting decision, if it comes at all, is as likely to come from Congress as from the FERC. Even if FERC should issue a landmark ruling, I anticipate years of appellate litigation challenging it. And when the appellate process has run its course, changed circumstances in the 1990's could conceivably undermine the applicability of whatever precedent remains.

Conclusion

There is a significant likelihood that TAPS will not be resolved by litigation. At best litigation will be costly and enormously protracted. Settlement is the best way to resolve the issue of TAPS tariffs. Settlement minimizes to the fullest practicable extent the significant possibilities of the State's realizing a far worse outcome if the litigation process continues. Settlement with B.P. is the only apparent device for bringing about a general settlement.

Now is the most favorable time for settling that we are likely to see for the foreseeable future. A tariff of \$4.625 per barrel, commencing in 1982, 40% of which would escalate with inflation, is a very fair settlement for the State. It is 4 cents per barrel better than the result that can be

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To the File

March 30, 1982
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justified under purely technical analysis, even allowing for the possibility of refund plus interest. It is my professional judgment that it should be accepted.

WLC:pjg:RS