SCOMM

#46:35

**AMENDMENT #1 TO SB 309**
**BY SUND**

* Sec. 2. AS 38.05.180 is amended by adding new subsections to read:

Within 90 days after the written request of a lessee of a lease issued under this section, the commissioner shall enter into an agreement with the lessee to use the price for the gas established in the contract between the lessee and a gas or electric utility as the value of the state's royalty share of gas production sold by the lessee under the contract unless the commissioner makes a written finding:

(1) that the contract price is unreasonably low; and

(2) the prospective reduction in royalty receipts would not be balanced by increaseed benefits to in-state gas and electric consumers, and

(3) the lessee and the utility are not related in management, ownership, or other aspect, and

(4) the contract price is not in the best interest of the state.

AMENDMENT #2 TO SB 309
BY SUND

* Sec. 3. AS 38.05.183 is amended by adding a new subsection to read:
The commissioner may enter into a contaract to sell royalty gas in kind to a gas or electric utility at less than market value of the royalty gas if the commissioner makes a written finding that the sale is in the best interest of the state. The commissioner shall consider the consumer benefits, other benefits and detriments of the sale.

# STATE OF ALASKA

POUCH V
JUNEAU, ALASKA 99811
(907) 465-4941

## HOUSE SPECIAL COMMITTEE ON OIL AND GAS

**Sectional Analysis**
**Proposed Oil and Gas Committee Substitute**
**for CSSB 309 (Rules)**

Sec. 1. Findings. It is in the best interest of the state to authorize the commissioner of DNR to establish the in-value royalty for gas sold to a gas or electric utility by using the contract price between the lessee of the state and the utility. This authorization applies only prospectively, and this Act does not apply to state policies regarding the sale of royalty oil.

Sec. 2. The commissioner shall enter into an agreement with a lessee to use the price established in a contract between the lessee and a gas or electric utility as the value of the state's royalty share of gas production, provided that:

a. the lessee and the utility are not related.
b. the agreement is requested in writing by the lessee.
c. the commissioner does not make a written finding that the contract price is unreasonably low and that a prospective reduction in royalty receipts would not be balanced by increased benefits to in-state gas and electric consumers.

This section states that a "gas or electric utility" includes electric cooperatives (such as Chugach, Matanuska, Homer, rural co-ops, and Golden Valley Electric), municipal utilities (such as Anchorage Municipal Light & Power), and gas utilities regulated under AS 42.05 (such as Enstar).

This section also states that, for purposes of this Act, the state's royalty share of gas production does not include gas production from mental health lands or school lands.

Sec. 3. Adds a new subsection to AS 38.05.183, which provides that the commissioner may sell royalty gas taken in-kind to a gas or electric utility at less than market value if the commissioner makes a written finding that the sale is in the best interest of the state. The same definitions for "gas or electric utility" and "royalty gas taken in kind by the state" found in sec. 2 of this legislation are also found in this section.

Sec. 4. Amends AS 38.05.810(a) to make this subsection consistent with the other provisions of the Act.

Sec. 5. Provides that AS 38.05.180(aa), which would be enacted by sec. 2 of this legislation, applies to agreements to establish the in-value royalties on gas production that are sold under a contract entered into, on or after the effective date of the act between the state's lessee and a gas or electric utility.

Sec. 6. Provides for an immediate effective date.

Proposed Amendment to CSSB 309 (Oil & Gas)

Page 2, Line 16

AS 38.05.180(aa)(1) is amended to read:

(1) "gas or electric utility" includes an electric cooperative organized under AS 10.25, a municipal utility, and a gas or electric utility regulated under AS 42.05, provided that if the contract gas is transmitted to consumers through a pipeline and the gas utility either owns the pipeline or is related in ownership to the owner of the pipeline, then the gas utility qualifies as a "gas or electric utility" within the meaning of this subsection only if it is bound or agrees to be bound by the covenants set forth in AS 38.35.120; and

Page 3, Line 3

AS 38.05.183(h) is amended to read:

In this subsection, "gas or electric utility" includes an electric cooperative organized under AS 10.25, a municipal utility, and a gas or electric utility regulated under AS 42.05, provided that if the contract gas is transmitted to consumers through a pipeline and the gas utility either owns the pipeline or is related in ownership to the owner of the pipeline, then the gas utility qualifies as a "gas or electric utility" within the meaning of this subsection only if it is bound or agrees to be bound by the covenants set forth in AS 38.35.120.

Bannister
4/7/86

Original sponsors: Faiks, Kelly
and V.Fischer

1 IN THE SENATE BY THE HOUSE SPECIAL COMMITTEE ON OIL AND GAS

2 CS FOR SENATE BILL NO. 309 (Oil & Gas)

3 IN THE LEGISLATURE OF THE STATE OF ALASKA

4 FOURTEENTH LEGISLATURE - SECOND SESSION

5 A BILL

6 For an Act entitled: "An Act relating to royalty gas contracts; and pro-
7 viding for an effective date."

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

9 * Section 1. FINDINGS. The legislature finds that the best interest of
10 the state will be served if the commissioner of natural resources is au-
11 thorized to establish the in-value royalty for gas sold to a gas or elec-
12 tric utility by using the contract price between the lessee of the state
13 and the utility, whether or not the gas lease establishes a different stan-
14 dard for the valuation and if the lessee and the utility are not related to
15 each other. The legislature finds that this authorization should apply
16 prospectively and does not intend the authorization to apply to the val-
17 uation for royalty purposes of gas sold by a lessee under a gas sales
18 contract entered into before the effective date of this Act. The legisla-
19 ture does not intend this Act to apply to the policies of the state regard-
20 ing the sale of royalty oil.

21 * Sec. 2. AS 38.05.180 is amended by adding new subsections to read:

22 (aa) Within 90 days after the written request of a lessee of a
23 lease issued under this section, unless the commissioner makes a
24 written finding that the contract price is unreasonably low and that a
25 prospective reduction in royalty receipts would not be balanced by
26 increased benefits to in-state gas and electric consumers, the commis-
27 sioner shall enter into an agreement with the lessee to use the price
28 for the gas established in the contract between the lessee and a gas
29 or electric utility, if the lessee and the utility are not related in

1 management, ownership, or other aspect, as the value of the state's
2 royalty share of gas production sold by the lessee under the contract
3 to the utility. In this subsection
4 (1) "gas or electric utility" includes an electric coopera-
5 tive organized under AS 10.25, a municipal utility, and a gas or
6 electric utility regulated under AS 42.05;
7 (2) "price for the gas established in the contract" in-
8 cludes tax reimbursement amounts, deliverability and other charges,
9 and other forms of consideration paid by the gas or electric utility
10 under the contract;
11 (3) "state's royalty share of gas production" does not
12 include the state's royalty share of gas production from land patented
13 to the state under
14 (A) P.L. 84-830, 70 Stat. 709 (Alaska Mental Health
15 Enabling Act);
16 (B) 38 Stat. 1214 (Act of March 4, 1915); or
17 (C) 43 U.S.C. 1635 in settlement of the claims of the
18 state under 38 Stat. 1214.
19 * Sec. 3. AS 38.05.183 is amended by adding a new subsection to read:
20 (h) The commissioner may enter into a contract to sell royalty
21 gas taken in kind by the state to a gas or electric utility at less
22 than the market value of the royalty gas if the commissioner, after
23 considering the consumer benefits, other benefits, and detriments of
24 the sale, makes a written finding that the sale is in the best inter-
25 est of the state. In this subsection,
26 (1) "gas or electric utility" includes an electric coopera-
27 tive organized under AS 10.25, a municipal utility, and a gas or
28 electric utility regulated under AS 42.05;
29 (2) "royalty gas taken in kind by the state" does not

1 include royalty gas taken in kind by the state from gas production on
2 land patented to the state under
3 (A) P.L. 84-830, 70 Stat. 709 (Alaska Mental Health
4 Enabling Act);
5 (B) 38 Stat. 1214 (Act of March 4, 1915); or
6 (C) 43 U.S.C. 1635 in settlement of the claims of the
7 state under 38 Stat. 1214.
8 * Sec. 4. AS 38.05.810(a) is amended to read:
9 (a) Except as otherwise provided in AS 38.05.183(h), the [THE]
10 lease, sale, or other disposal of state land or resources may be made
11 to a state or federal agency or political subdivision, or the lease,
12 sale, or disposal of coal deposits suitable for mining may be made to
13 a utility owned and operated by a government agency or nonprofit
14 cooperative association organized to participate under the Federal
15 Rural Electrification Act for the purpose of generating electric power
16 and energy or the production of process steam, or both, for less than
17 the appraised value as determined by the director and approved by the
18 commissioner to be fair and proper and in the best interests of the
19 public, with due consideration given to the nature of the public
20 services or function rendered by the agency, subdivision, or utility
21 making application, and of the terms of the grant under which the land
22 was acquired by the state.
23 * Sec. 5. AS 38.05.180(aa), enacted by sec. 2 of this Act, applies to
24 agreements to establish for a lease issued under AS 38.05.180 the in-value
25 royalties on gas production that is sold under a contract entered into on
26 or after the effective date of this Act between the state's lessee and a
27 gas or electric utility.
28 * Sec. 6. This Act takes effect immediately in accordance with AS 01.-
29 10.070(c).

# STATE OF ALASKA

POUCH V
JUNEAU, ALASKA 99811
(907) 465-4941

## HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Sectional Analysis
Proposed Oil and Gas Committee Substitute
for CSSB 309

Sec. 1. Findings. It is in the best interest of the state to authorize the commissioner of DNR to establish the in-value royalty for gas sold to a gas or electric utility by using the contract price between the lessee of the state and the utility. This authorization applies only prospectively, and this Act does not apply to state policies regarding the sale of royalty oil.

Sec. 2. The commissioner shall enter into an agreement with a lessee to use the price established in a contract between the lessee and a gas or electric utility as the value of the state's royalty share of gas production, provided that:

a. the lessee and the utility are not related.
b. the agreement is requested in writing by the lessee.
c. the commissioner does not make a written finding that the contract price is unreasonably low and that a prospective reduction in royalty receipts would not be balanced by increased benefits to in-state gas and electric consumers.

This section states that a "gas or electric utility" includes electric cooperatives (such as Chugach, Matanuska, Homer, rural co-ops, and Golden Valley Electric), municipal utilities (such as Anchorage Municipal Light & Power), and gas utilities regulated under AS 42.05 (such as Enstar).

This section also states that, for purposes of this Act, the state's royalty share of gas production does not include gas production from mental health lands or school lands.

Sec. 3. Adds a new subsection to AS 38.05.183, which provides that the commissioner may sell royalty gas taken in-kind to a gas or electric utility at less than market value if the commissioner makes a written finding that the sale is in the best interest of the state. The same definitions for "gas or electric utility" and "royalty gas taken in kind by the state" found in sec. 2 of this legislation are also found in this section.

Sec. 4. Amends AS 38.05.810(a) to make this subsection consistent with the other provisions of the Act.

Sec. 5. Provides that AS 38.05.180(aa), which would be enacted by sec. 2 of this legislation, applies to agreements to establish the in-value royalties on gas production that are sold under a contract entered into, on or after the effective date of the act between the state's lessee and a gas or electric utility.

Sec. 6. Provides for an immediate effective date.

Proposed Amendment to CSSB 309 (Oil & Gas)

AS 38.05.180(aa)(1) is amended to read:

(1) "gas or electric utility" includes an electric cooperative organized under AS 10.25, a municipal utility, and a gas or electric utility regulated under AS 42.05, provided that if the contract gas is transmitted to consumers through a pipeline and the gas utility either owns the pipeline or is related in ownership to the owner of the pipeline, then the gas utility qualifies as a "gas or electric utility" within the meaning of this subsection only if it is bound or agrees to be bound by the covenants set forth in AS 38.35.120; and

AS 38.05.183(h) is amended to read:

In this subsection, "gas or electric utility" includes an electric cooperative organized under AS 10.25, a municipal utility, and a gas or electric utility regulated under AS 42.05, provided that if the contract gas is transmitted to consumers through a pipeline and the gas utility either owns the pipeline or is related in ownership to the owner of the pipeline, then the gas utility qualifies as a "gas or electric utility" within the meaning of this subsection only if it is bound or agrees to be bound by the covenants set forth in AS 38.35.120.

DNR 3-3-86

SUMMARY OF CSSB 309 (RULES)

The Bill will allow the state to provide certainty in royalty gas valuation for Alaska consumer uses and North Slope gas development.

Specifically, the Bill would:

- Authorize the Commissioner of the Department of Natural Resources to accept a contract price between a state lesses (gas producer) and a gas or electric utility as the value of the state's royalty share of production.

- Authorize the Commissioner of the Department of Natural Resources to sell the state's royalty gas to a gas or electric utility at a price below market value. The Legislature reviews long-term sales under existing law.

- Establish a royalty valuation procedure which will facilitate financing for a North Slope gas pipeline.

"Gas or electric utility" includes cooperative electric utilities (such as Chugach, Matanuska, Homer, rural coops, and Golden Valley Electric), municipal utilities (such as Anchorage Municipal Light and Power), and a gas utility regulated under AS 42.05 (such as Enstar).

The Act would apply only to future contracts between a lessee and a purchaser.

A preliminary settlement agreement between the Department of Natural Resources and the Board of Directors of Chugach Electric, which would settle pending litigation over the value of the state's royalty share of Beluga gas now pruchased by Chugach at $0.26/mcf, is contingent on passage of the bill. The preliminary settlement agreement sets the price of Beluga royalty gas under the existing Chugach contract at $0.75/mcf.

Revenue Impact: Section 3 of the Bill, which authorizes the Commissioner to sell royalty gas taken in kind to a gas or electric utility at a price below market value, could result in lower state revenues in the future if this discretionary authority is exercised. The amounts of potential revenue loss cannot be precisely calculated, but would be identified at the time of the sale, when legislative review would occur. The state could also lose or gain revenue by any disparity between contract prices and market values, but this fiscal impact is not predictable.

DNR 3-3-86

Section-by-Section Analysis of CSSB 309 (Rules)

Section 1 of the Bill makes several findings:

- The best interest of the state will be served if the commissioner of Natural Resources is authorized to establish the in value royalty for gas sold to a gas or electric utility by using the contract price between the state lessee and the utility;

- It is in the best interest of the state to give the commissioner explicit discretionary authority to sell in kind royalty gas to a gas or electric utility at a price below market value;

- The proper exercise of discretion conferred by the Act will support and complement the other energy programs of the state;

- The state should adopt a policy for the sale of royalty gas to gas or electric utilities for in-state consumer use and in-state generation of electricity that is fundamentally different from the policies of the state for the sale of royalty oil and for the sale of royalty gas for export from the state or for uses other than in-state consumer use and in-state generation of electricity; and

- It is in the state's best interest to facilitate the financing and construction of a pipeline and increased gas production from the Prudhoe Bay reservoir by establishing a procedure by which the state could commit itself to a royalty valuation methodology for as long as the state takes its royalty share of gas production in value.

Section 2 adds new subsections to AS 38.05.180:

- Subsection (aa) provides that within 90 days after the written request of a lessee, unless the commissioner makes a written finding based on clear and convincing evidence that the contract price is unreasonably low and that a prospective reduction in royalty receipts would not be balanced by increased benefits to in-state gas and electric consumers, the commissioner shall enter into an agreement with the lessee to use the price established in a contract between the lessee and a gas or electric utility as the value of the state's royalty share of gas production, if the lessee and the utility are not related. "Gas or electric utility" includes an electric cooperative organized under AS 10.25, a municipal utility, and a gas or electric utility regulated under AS 42.05.

- Subsection (bb) provides that in the event of a contract between unrelated parties for the sale of gas from the Prudhoe Bay reservoir for delivery through a pipeline for export out of the state, the commissioner shall within 90 days after the written request of a lessee enter into an agreement with the lessee to use the price for gas established in the gas sales contract as the value of the state's royalty share of gas production, unless the

commissioner makes a written finding that the contract price does not assure the maximum benefits to the people of the state in return for the state's gas resources. The lessee shall have the burden of providing all information necessary for the commissioner to make an informed decision, and shall provide clear and convincing evidence that the value of the gas is reflected by the gas sales contract price rather than being attributed to transportation, marketing, or other profit or cost centers.

Section 3 adds a new subsection to AS 38.05.183:

- Subsection (h) provides that the commissioner may sell royalty gas taken in kind to a gas or electric utility at less than the market value of the gas, if the commissioner, after considering the consumer benefits, other benefits, and detriments of the sale, makes a written finding that the sale is in the best interest of the state. "Gas or electric utility" includes an electric cooperative organized under AS 10.25, a municipal utility, and a gas or electric utility regulated under AS 42.05.

Section 4 amends AS 38.05.810(a) to make it consistent with the other provisions of the Act.

Section 5 provides that the proposed AS 38.05.180(aa), which would be enacted by Section 2 of the Act, applies to agreements to establish the in value royalties on gas production that is sold under a contract entered into on or after the effective date of the act between the state's lessee and a gas or electric utility.

Section 6 provides an immediate effective date.

STATE OF ALASKA

**DEPARTMENT OF NATURAL RESOURCES**

*OFFICE OF THE COMMISSIONER*

***BILL SHEFFIELD, GOVERNOR***

*POUCH M*
*JUNEAU, ALASKA 99811*
*PHONE: 907-465-2400*

The Honorable John Sackett
Co-Chair, Finance Committee
Alaska State Senate
Juneau, AK 99811

March 3, 1986

Dear Senator Sackett:

I am responding to your request for more information on the fiscal note and potential fiscal impact of CSSB 309 (Res), now before the Senate as CSSB 309 (Rules).

The fiscal note

The department has submitted a zero fiscal note for the bill, which will not directly affect the state's current royalty gas revenue stream. There are two reasons that it is not possible to identify future costs of the legislation:

- the department is not able to predict how often the new valuation mechanism will be applied in the future, nor can we predict future gas contract prices and quantities; and

- market values for Alaska natural gas (particularly Cook Inlet gas now sold for instate consumer uses and most immediately affected by the proposed statute) are unpredictable, as is the possible disparity (positive or negative) between contract price and market value.

Even though there is no direct fiscal impact that can be assigned to the bill, enactment of the legislation will indirectly affect state royalty income from existing production in Cook Inlet. The state has entered into an agreement with Chugach Electric to value the state's royalty share from Beluga Field production purchased by Chugach under existing contracts at $0.75/mcf if the legislation passes. This value is one-half the state's January offer to settle the pricing dispute at $1.50/mcf, which was rejected by the Beluga producers who sell to Chugach. If the dispute had been settled at $1.50/mcf under existing state law, the

state would have received approximately $1.9 million/year in new royalty income from the Beluga field. Settlement at $0.75/mcf, as will occur if CSSB 309 (Rls) is passed, will increase state royalty revenues from Beluga production by about $810,000/year, according to our calculations, because the state's share of this production is currently valued at $0.21/mcf by the producers. This increase in state royalty revenues is less than would have been expected if 1) the state's $1.50/mcf settlement offer had been accepted, or 2) the state had successfully pursued its legal arguments regarding the value of the state's royalty share under the existing lease terms, based on existing law.

Future costs to the State

As stated above, the department has submitted a zero fiscal note because it is unable to predict future market conditions and contract terms for Alaska natural gas. It is important for the Legislature to consider that market value in the future could either exceed or remain below long-term contract prices for instate consumer gas purchases. The present situation in the Beluga field is an example of how long-term contract prices (Chugach at an adjusted $0.26/mcf and Enstar at an adjusted $2.05/mcf) can be above or below "market value" simultaneously in the same field.

Section 2. The fiscal impacts of Section 2(aa) of CSSB 309 (Rls) will largely depend on future market and contract conditions in Cook Inlet, unless there is a commitment of North Slope natural gas by the producers for instate use. The natural gas market for instate energy use will be affected by the costs of thermal and hydroelectric energy alternatives, including new or expanded coal development; production from new or shut-in gas sources; geothermal development (which has been discussed in connection with Beluga coal development); hydroelectric construction; export projects for coal, gas, or oil; and the price of fuel oil and diesel as alternative fuel sources. There have been some projections of Cook Inlet gas prices by other agencies that this department has disputed on grounds that the Cook Inlet market remains largely controlled by local factors rather than world gas or oil prices or exports. If North Slope natural gas is brought to market its pricing and availability will also become an important factor in the fiscal impact of this bill (Section 2(bb)). Because the eventual marketing arrangements for Prudhoe Bay gas would

probably have to be less diverse and more stable than are marketing arrangements for Cook Inlet gas, it is likely that there would be less disparity between Prudhoe Bay contract price and market value, although the fiscal impact of accepting the contract price as the state's royalty value (given the magnitude of the Prudhoe Bay gas resource) might be larger, either positively or negatively affecting the state's revenues.

Section 3. This section gives the commissioner authority to make below-market-value gas sales for instate energy use. Because the Legislature reviews long-term royalty oil and gas contracts before their implementation by the Department, the fiscal impact of this section will be considered by future Legislatures reviewing such below-market-value gas sales by the state. Without knowledge of how often or at what cost the state will exercise this option, there is no way to estimate the fiscal impact of enacting this statute.

Please contact me if you have any further questions or comments. I am providing copies of this letter to other members of the Senate in anticipation of the floor debate on CSSB 309 (Rls) this morning. Thank you for your interest in this issue.

Sincerely,

Esther C. Wunnicke
Commissioner

cc: All Senators
Dr. Joyce Murphy, Chugach Electric

Work Draft

March 26, 1986

IN THE HOUSE — BY THE HOUSE SPECIAL COMMITTEE ON OIL AND GAS

CS FOR SENATE BILL NO. 309 (RULES)

IN THE LEGISLATURE OF THE STATE OF ALASKA

FOURTEENTH LEGISLATURE - SECOND SESSION

A BILL

For an Act entitled: "An Act relating to royalty gas contracts; and providing for an effective date."

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

* Section 1. FINDINGS. (a) The legislature finds that the best interest of the state will be served if the commissioner of natural resources is authorized to establish the in-value royalty for gas sold to a gas or electric utility by using the contract price between the lessee of the state and the utility, whether or not the gas lease establishes a different standard for the valuation and if the lessee and the utility are not related to each other. The legislature finds that this authorization should apply prospectively and does not intend the authorization to apply to the valuation for royalty purposes of gas sold by a lessee under a gas sales contract entered into before the effective date of this Act. The legislature states that this Act shall not apply to the policies of the state for the sale of royalty oil.

1 (b) The legislature finds that it is in the state's best
2 interest to facilitate the financing and construction of
3 pipelines and increased gas production from state gas leases
4 for industrial and export uses by establishing a procedure by
5 which the state could commit itself to a long-term royalty
6 valuation methodology.

7 * Sec. 2. AS 38.05.180 is amended by adding subsections
8 (aa) and (bb) to read:

9 (aa) Within 90 days after the written request of a lessee
10 of a lease issued under this section, the commissioner may
11 enter into an agreement with the lessee to use the price for
12 the gas established in the contract between the lessee and a
13 gas or electric utility, if the lessee and the utility are not
14 related in management, ownership, or other aspect, as the
15 value of the state's royalty share of gas production sold by
16 the lessee under the contract to the utility. The
17 commissioner may enter into such an agreement after conducting
18 public hearings and making a written determination that the
19 contract price is reasonable and that a prospective reduction
20 in royalty receipts would be balanced by increased benefits to
21 in-state gas and electric consumers. The lessee shall have
22 the burden of providing all information necessary for the
23 commissioner to make an informed decision, and shall provide
24 clear and convincing evidence that the contract price is
25 reasonable and that a prospective reduction in royalty
26 receipts would be balanced by increased benefits to in-state
27 gas and electric consumers.

1 (1) "gas or electric utility" includes an electric
2 cooperative organized under AS 10.25, a municipal utility, and
3 a gas or electric utility regulated under AS 42.05, provided
4 that if the contract gas is transmitted to consumers through a
5 pipeline and the gas utility either owns the pipeline or is
6 related in ownership to the owner of the pipeline, then the
7 gas utility qualifies as a "gas or electric utility" within
8 the meaning of this subsection only if it is bound or agrees
9 to be bound by the covenants set forth in AS 38.35.120; and
10 (2) "price for the gas established in the contract"
11 includes tax reimbursement amounts, deliverability and other
12 charges, and other forms of consideration paid by the gas or
13 electric utility under the contract.
14 (bb) In the event of a contract for the sale of gas from a
15 gas lease issued under this section which does not qualify
16 under subsection (aa), the commissioner may enter into an
17 agreement with the lessee to use the price for the gas
18 established in the gas sales contract as the value of the
19 state's royalty share of gas production sold by the lessee
20 under the gas sales contract. The commissioner may enter into
21 such an agreement after conducting public hearings and making
22 a written determination that the contract price assures the
23 receipt of maximum benefits to the people of the state in
24 return for the state's gas resources. In order to invoke this
25 subsection, a lessee must make its written request no later

1 than 90 days after the first delivery of gas under the gas
2 sales contract. The commissioner shall then act on the
3 request in writing within 120 days. The agreement between the
4 lessee and the commissioner may be for a lesser period of time
5 than that covered by the lessee's gas sales contract, and may
6 provide for a periodic review of the royalty value term by the
7 commissioner. The lessee shall have the burden of providing
8 all information necessary for the commissioner to make an
9 informed decision, and shall provide clear and convincing
10 evidence that the value of the gas is reflected by the gas
11 sales contract price rather than being attributed to
12 transportation, marketing, or other profit or cost centers.
13 The legislature may disapprove an agreement between the
14 commissioner and a lessee under this subsection by passing a
15 resolution within 60 days of the convening of the next regular
16 legislative session. In this subsection, "price for the gas
17 established in the gas sales contract" includes tax
18 reimbursement amounts, deliverability and other charges, and
19 other forms of consideration received by the lessee under the
20 gas sales contract.

21 * Sec. 3. AS 38.05.183 is amended by adding a new
22 subsection (h) to read:

23 (h) The commissioner may enter into a contract to sell
24 royalty gas taken in-kind by the state to a gas or electric
25 utility at less than the market value of the royalty gas if
26 the commissioner, after considering the consumer benefits,
27 other benefits, and detriments of the sale, conducts public

1 hearings and makes a written determination that the sale is in
2 the best interest of the state. In this subsection, "gas or
3 electric utility" includes an electric cooperative organized
4 under AS 10.25, a municipal utility, and a gas or electric
5 utility regulated under AS 42.05, provided that if the
6 contract gas is transmitted to consumers through a pipeline
7 and the gas utility either owns the pipeline or is related in
8 ownership to the owner of the pipeline, then the gas utility
9 qualifies as a "gas or electric utility" within the meaning of
10 this subsection only if it is bound or agrees to be bound by
11 the covenants set forth in AS 38.35.120.
12 * Sec. 4. AS 38.05.810(a) is amended to read:
13 (a) <u>Except as otherwise provided in AS 38.05.183(h), the</u>
14 [The] lease, sale, or other disposal of state land or
15 resources may be made to a state or federal agency or
16 political subdivision, or the lease, sale, or disposal of coal
17 deposits suitable for mining may be made to a utility owned
18 and operated by a government agency or nonprofit cooperative
19 association organized to participate under the Federal Rural
20 Electrification Act for the purpose of generating electric
21 power and energy or the production of process steam or both,
22 for less than the appraised value as determined by the
23 director and approved by the commissioner to be fair and
24 proper and in the best interests of the public, with due
25 consideration given to the nature of the public services or
26 function rendered by the agency, subdivision, or utility
27 making application, and of the terms of the grant under which
28 the land was acquired by the state.

1 * Sec. 5. AS 38.05.180(aa) and (bb), enacted by sec. 2 of
2 this Act, apply to agreements to establish for a lease issued
3 under AS 38.05.180 the in-value royalties on gas production
4 that are sold under a contract entered into, on, or after the
5 effective date of this Act between the state's lessee and a
6 gas or electric utility.
7 * Sec. 6. This Act takes effect immediately in accordance
8 with AS 01.10.070(c).
9 * Sec. 7. This Act does not apply to gas royalties due on
10 production from land patented to the state under the Alaska
11 Mental Health Enabling Act of 1956, P.L. 84-830, 70 Stat. 209
12 (mental health lands), and the Act of March 4, 1915, ch. 181,
13 38 Stat. 1214 and sec. 906(b) of the Alaska National Interest
14 Lands Conservation Act, P.L. 96-487, 94 Stat. 2430 (school
15 lands).

3-25-86

COMMITTEE CS FOR SENATE BILL NO.

309 (Rules) IN THE LEGISLATURE FOR THE

STATE OF ALASKA

FOURTEENTH LEGISLATURE - SECOND SESSION

A BILL

For an Act entitled: "An Act relating to royalty gas contracts; and providing for an effective date."

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

* Section 1. FINDINGS. (a) The legislature finds that the best interest of the state will be served if the commissioner of natural resources is authorized to establish the in-value royalty for gas sold to a gas or electric utility by using the contract price between the lessee of the state and the utility, whether or not the gas lease establishes a different standard for the valuation and if the lessee and the utility are not related to each other. The legislature finds that this authorization should apply prospectively and does not intend the authorization to apply to the valuation for royalty purposes of gas sold by a lessee under a gas sales contract entered into before the effective date of this Act.

(b) The legislature finds that it is also in the best interest of the state to give the commissioner explicit discretionary authority to sell royalty gas received in kind by the state to gas or electric utilities at a price that is below market value.

(c) The legislature finds that the proper exercise of the discretion conferred on the commissioner by this Act would support and complement the other programs that assist the citizens of the state with their long-term gas and electrical needs, including the power cost equalization program under AS 44.83.162 - 44.83.165 and hydroelectric and other programs for the generation of electricity.

(d) The legislature finds that the state should adopt a policy for the sale of royalty gas to gas or electric utilities for in-state consumer use and in-state generation of electricity that is fundamentally different from the policies of the state for the sale of royalty oil and for the sale of royalty gas for export from the state or for uses other than in-state consumer use and in-state generation of electricity.

(e) The legislature finds it is in the state's best interest to facilitate the financing and construction of pipelines and increased gas production from state gas leases for industrial and export uses by establishing a procedure by which the state could commit itself to a royalty valuation methodology for as long as the state takes its royalty share of gas production in value.

* Sec. 2. AS 38.05.180 is amended by adding new subsections to read:

(aa) Within 90 days after the written request of a lessee of a lease issued under this section, unless the commissioner makes a written finding based on clear and

convincing evidence that the contract price is unreasonably low and that a prospective reduction in royalty receipts would not be balanced by increased benefits to instate gas and electric consumers, the commissioner shall enter into an agreement with the lessee to use the price for the gas established in the contract between the lessee and a gas or electric utility, if the lessee and the utility are not related in management, ownership, or other aspect, as the value of the state's royalty share of gas production sold by the lessee under the contract to the utility. In this subsection

(1) "gas or electric utility" includes an electric cooperative organized under AS 10.25, a municipal utility, and a gas or electric utility regulated under AS 42.05, provided that if the contract gas is transmitted to consumers through a pipeline and a gas utility either owns the pipeline or is related in ownership to the owner of the pipeline, then the gas utility qualifies as a "gas or electric utility" within the meaning of this subsection only if it is bound or agrees to be bound by the covenants set forth in AS 38.35.120; and

(2) "price for the gas established in the contract" includes tax reimbursement amounts, deliverability and other charges, and other forms of consideration paid by the gas or electric utility under the contract.

(bb) In the event of a contract for the sale of gas from a gas lease issued under this section that does not qualify under subsection (aa), the commissioner may enter into an agreement with the lessee to use the price for the gas established in the gas sales contract as the value of the state's royalty share of gas production sold by the lessee under the gas sales contract if the commissioner makes a written finding that the contract price assures the receipt of maximum benefits to the people of the state in return for the state's gas resources. In order to invoke this subsection, a lessee must make its written request no later than 90 days after the first delivery of gas under the gas sales contract. The commissioner shall then act on the request in writing within 120 days. The agreement between the lessee and the commissioner may be for a lesser period of time than that covered by the lessee's gas sales contract, and may provide for a periodic review of the royalty value term by the commissioner. The lessee shall have the burden of providing all information necessary for the commissioner to make an informed decision, and shall provide clear and convincing evidence that the value of the gas is reflected by the gas sales contract price rather than being attributed to transportation, marketing, or other profit or cost centers. In this subsection, "price for the gas established in the gas sales contract" includes tax reimbursement amounts, deliverability and other charges, and

other forms of consideration received by the lessee under the gas sales contract. The legislature may disapprove an agreement between the commissioner and a lessee under this subsection by passing legislation within 60 days of the convening of the next legislative session.

* Sec. 3. AS 38.05.183 is amended by adding a new subsection to read:

(h) The commissioner may enter into a contract to sell royalty gas taken in kind by the state to a gas or electric utility at less than the market value of the royalty gas if the commissioner, after considering the consumer benefits, other benefits, and detriments of the sale, makes a written finding that the sale is in the best interest of the state. In this subsection, "gas or electric utility" includes an electric cooperative organized under AS 10.25, a municipal utility, and a gas or electric utility regulated under AS 42.05, provided that if the contract gas is transmitted to consumers through a pipeline and a gas utility either owns the pipeline or is related in ownership to the owner of the pipeline, then the gas utility qualifies as a "gas or electric utility" within the meaning of this subsection only if it is bound or agrees to be bound by the covenants set forth in AS 38.35.120.

* Sec. 4. AS 38.05.810(a) is amended to read:

(a) Except as otherwise provided in AS 38.05.183(h), the [THE] lease, sale, or other disposal of state land or resources may be made to a state or federal agency or political subdivision, or the lease, sale, or disposal of coal deposits suitable for mining may be made to a utility owned and operated by a government agency or nonprofit cooperative association organized to participate under the Federal Rural Electrification Act for the purpose of generating electric power and energy or the production of process steam or both, for less than the appraised value as determined by the director and approved by the commissioner to be fair and proper and in the best interests of the public, with due consideration given to the nature of the public services or function rendered by the agency, subdivision, or utility making application, and of the terms of the grant under which the land was acquired by the state.

* Sec. 5. AS 38.05.180(aa) and AS 38.05.180(bb), enacted by sec. 2 of this Act, applies to agreements to establish for a lease issued under AS 38.05.180 the in-value royalties on gas production that is sold under a gas sales contract entered into on or after the effective date of this Act.

* Sec. 6. This Act takes effect immediately in accordance with AS 01.10.070(c).

* Sec. 7. This act does not apply to gas royalties due on production from land patented to the state under the Alaska Mental Health Enabling Act of 1956, P.L. 84-830,, 70 Stat. 209

(mental health lands), and the Act of March 4, 1915, ch. 181, 38 Stat. 1214 and section 906(b) of the Alaska National Interest Lands Conservation Act, P.L. 96-487, 94 Stat. 2430 (school lands).

# STATE OF ALASKA 1986 LEGISLATIVE SESSION
# FISCAL NOTE

Revision Date: 2/20/86

**REQUEST**

Bill/Resolution No.: CSSB 309 (Res)
Title: Royalty gas contracts

Sponsor: Faiks
Requestor: Senate Resources
Date of Request: 2/19/86

**FISCAL DETAIL**

Agency Affected: Natural Resources
BRU:

Components:

**EXPENDITURES/REVENUES: (Thousands of Dollars)**

| OPERATING | FY 86 | FY 87 | FY 88 | FY 89 | FY 90 | FY 91 |
|---|---|---|---|---|---|---|
| PERSONAL SERVICES | | | | | | |
| TRAVEL | | | | | | |
| CONTRACTUAL | | | | | | |
| SUPPLIES | | | | | | |
| EQUIPMENT | | | | | | |
| LAND & STRUCTURES | | | | | | |
| GRANTS, CLAIMS | | | | | | |
| MISCELLANEOUS | | | | | | |
| TOTAL OPERATING | -0- | -0- | -0- | -0- | -0- | -0- |

| CAPITAL | | | | | | |
|---|---|---|---|---|---|---|

| REVENUE | | | | | | |
|---|---|---|---|---|---|---|

**FUNDING: (Thousands of Dollars)**

| | FY 86 | FY 87 | FY 88 | FY 89 | FY 90 | FY 91 |
|---|---|---|---|---|---|---|
| GENERAL FUND | | | | | | |
| FEDERAL FUNDS | | | | | | |
| OTHER | | | | | | |
| TOTAL | -0- | -0- | -0- | -0- | -0- | -0- |

**POSITIONS:**

| | FY 86 | FY 87 | FY 88 | FY 89 | FY 90 | FY 91 |
|---|---|---|---|---|---|---|
| FULL-TIME | | | | | | |
| PART-TIME | | | | | | |
| TEMPORARY | | | | | | |

**ANALYSIS:** Attach a separate page if necessary

The valuation provisions of this bill will be applied only for future long-term gas contracts, and there is no way to estimate any fiscal impact on the state. Any revenue losses should be balanced by savings in utility costs for consumers, according to the bill.

Prepared by: Ned Farquhar  Phone: 465-2400
Division: Commissioner's Office  Date: 2/20/86

Approved by Commissioner: [signature]  Date: 2/20/86
Agency: Natural Resources

Distribution (by Agency preparing fiscal note):
- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)



10/25/85

RECEIVED APR 2 9 1985

**ENSTAR Natural Gas Company**
3000 Spenard Road
P.O. Box 6288
Anchorage, Alaska 99502
(907) 277-5551

April 25, 1985

Dear Senator Faiks:

The State has announced it intends to increase the price paid for royalty gas which we receive pursuant to a contract entered into in 1960 and last renegotiated in 1974, with Marathon and Union, our suppliers at the Kenai gas field. The Administration says it is compelled to take this action in order to get a fair market value for its royalty gas and stop a "subsidy". The Administration's statements are misleading. The State is receiving fair value. There is no subsidy. There is no requirement for the Administration to take such action. Without proposing regulations, holding hearings, or giving those affected an opportunity to be heard, the Administration would use the State's monopoly power to exact an excessive price from the consumers.

The Fair Value of Gas Committed to a Long-Term Contract
Is The Arm's Length Negotiated Price

Historically, the value of the royalty share of gas committed to a long-term contract has been considered to be the price established by the contract, if that price was set by unrelated parties in arm's length negotiations. Since gas transmission systems require massive capital investments, long-term contracts for production are a characteristic of the business. Without long-term contracts, pipelines would not have been built. In order to assure the marketability of the pipeline's out put, good business practice requires a pricing mechanism that will deliver the product at a competitive price. The free market system basically has dictated the business practices we have followed.

Royalty owners in a number of states have attacked the long followed principle that fair value is determined by arm's length negotiated prices, with mixed results. Courts in Alaska have not ruled on the issue, but ENSTAR believes that the prevailing and equitable view is that fair values are determined by arm's length negotiations, not by bureaucratic edict.

Our Customers Are Not Being Subsidized by the State

The Administration claims there is a subsidy because the price the State is receiving under ENSTAR's long-term contract is less than the price ENSTAR is paying for gas we more recently negotiated to purchase. That purchase covers fifteen years, cannot be terminated, and has known pricing terms. The State's royalty can be terminated on six months notice (and then taken "in kind"). The State maintains it can unilaterally "reprice" its gas at any time while taken as royalty-in-value. No willing buyer would purchase gas from the State under such conditions.

During the 1960's ENSTAR was subjected to criticism in Juneau because some politicians believed ENSTAR paid too much under the very same contract on which DNR now says ENSTAR is paying too little. We (our customers) paid the price necessary to get the commitment of half a trillion cubic feet of gas for 20

years. We (our customers) took the risk that gas prices would go down, not up. The State received what was then considered to be a high price, guaranteed for the life of the contract.

Our customers paid the market price for the risk they took. Gas prices have gone up, not down. Now the State in effect would confiscate the values the consumers paid for. Now the State maintains that without this confiscation, it is subsidizing the consumers. Baloney.

<u>The State is Using Monopoly Power
to Exact an Excessive Price from the Consumers</u>

Alaska is unique in that the Federal and State governments control substantially all royalty. The governments have a monopoly and it is not possible to negotiate royalty valuation terms of lease agreements. Terms are dictated, not negotiated. This is effectively a monopoly action at work, not a free market. DNR admitted in an internal memorandum that its present pricing proposal would "further its relations with the ANCSA corporations... and lend support to current federal royalty litigation...". If business corporations made pricing decisions in concert with or to accommodate other suppliers, they probably would be subject to prosecution.

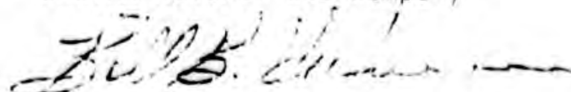
When we, as purchasers, enter into a long-term contract with a producer, we are not assured of the royalty share since the State retains the right to take its gas in kind. Yet we must take the royalty share, no matter what price may be exacted. Obviously, if a free market prevailed, we simply would not purchase State royalty on such terms. The concept of the State receiving fair value for its resources does not mean it can use its monopoly power to squeeze the last bit of revenue from the consumer. It does mean receiving the value that would be arrived at in a free market system. That is exactly what arm's length negotiations do.

For 25 years the State has accepted arm's length negotiated pricing as royalty value. We believe it is unfair and probably unlawful for the State to reverse this acceptance in the present situation, with no regulations, no public hearings, and no court decisions.

We are trying to work with the State Administration and others to develop a legislative or administrative solution to this problem, and are preparing to inform the public as to its scope and effect in the event these efforts are not successful.

Cordially,

ENSTAR Natural Gas Company



Bill B. Hickman
Executive Vice President

BBH/dms

**ENSTAR Natural Gas Company**
3000 Spenard [illegible]
P.O. Box 628[illegible]
Anchorage, Al[illegible] 9950[illegible]
(907) 277-55[illegible]

December 12, 1984

The Honorable Jan Faiks
Alaska State Senator
1024 West 6th Avenue, Suite 202
Anchorage, Alaska 99501

Dear Jan:

I have your September 6 letter and will try to respond in writing, somewhat as to the handout you requested. We have been quite busy through this week, but should have some time after that for the meeting with the Anchorage Caucus if that is still desired. (Jury duty December 16-21).

I will respond in this letter to the "subsidy" allegation, and relate the history of gas in Cook Inlet in a memorandum, attached. The allegation is that our price (and Chugach's) payable to the producers for gas negotiated and contracted many years ago is below the price at which gas would be negotiated at present, and that the price differential, applied to the State's royalty interest in that gas, constitutes a subsidy from State residents who are not users of that gas (or electricity made from it) to those State residents who do use the gas (or electricity made from it).

Those who allege a subsidy appear not to comprehend the character of the natural gas business, and I hope this letter will be of some help in that respect. Natural gas, unlike oil, requires a relatively large investment for delivery to market. The investment is for relatively large pipelines and compressors, (cryogenic processing, storage, and ships in the case of LNG, liquefied natural gas). The investment cannot be made without long term contracts at known pricing, generally well below the then prevailing delivered price of oil in order to assure a market against that competition. Essentially many major users of natural gas can literally switch to oil whenever oil can be obtained for less than gas. The producers run this risk in developing natural gas production, and the pipeline/utility system is exposed to relatively much greater risk because its investment per unit is normally much greater than the producer's. For both, however, long term contracts at known pricing are essential and traditional in the industry. When such contracts are abrogated, as with Canadian production since the early 70's, great distress and severe reaction develops. The experience there is an object lesson for Alaska: Canadian gas was arbitrarily repriced, and lost its market in the Pacific Northwest to OPEC oil. It was followed by depression in both Canada and the Pacific Northwest and by devaluation of Canadian money and in turn the defeat of the decades-old Canadian administration, this year.

Admittedly there has been and will be litigation on the sanctity of contracts and the "rights" of royalty interest owners, as with all controversies both private and public. The State has recently settled with Phillips on North Cook Inlet gas used in its LNG plant, and that in turn has enabled us to gain access to a portion of that gas, for standby purchases in times of high demand.

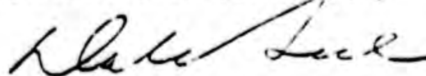
It is my opinion that a majority of Alaskan legislators and the administration and the courts will acknowledge the sanctity of contracts as to our purchase of Cook Inlet gas. In my opinion, the allegations of subsidy of gas ratepayers are advanced in order to justify admitted State subsidy to non-railbelt electric users, as enacted this year and may be increased next year.

It is worth noting that the State's royalty interest in Cook Inlet gas we buy is really rather small (about 1/6th of 1/8th, or 2% of the 26 million mcf annual production). The spread between the price we currently pay and the State's negotiated settlement with Phillips is not nearly as wide as would be inferred from statements by some political figures and other royalty interest owners. It is in the range of $1 million per year, a far cry from the admitted State subsidy to non-railbelt power users.

Jan, I hope the foregoing and the attached memorandum will be of some interest to the Anchorage Caucus. Frankly, I would prefer not to appear before your group at this time, because we are quite likely to become embroiled in the lawsuit involving CIRI, MMS (old USGS) and Union Oil Company. It would be embarrassing to me personally to respond with no comment or otherwise appear evasive, when I would really like to make announcements to the world.

Cordially,

* ENSTAR Natural Gas Company



Dale Teel
President

DT/dms

* The same Anchorage Gas Corporation, Anchorage Natural Gas, Alaska Gas and Service Company, Alaska Pipeline Company, etc. etc.

ENSTAR

ENSTAR Natural Gas Company
COMPANY

# Inter-Company Correspondence

To: File

From: Dale Teel

Location:

Date: December 12, 1984

Subject: History of Cook Inlet Natural Gas
Prepared in Response to Request from Senator Jan Faiks of September 6, 1984

File:

The history of Cook Inlet gas begins, I believe, with the 1959 discovery of the Kenai gas field by Union and Marathon. It was this discovery, I believe, which enabled Anchorage Gas Corporation to win the franchise referendum election in the fall of 1959. I didn't participate in the 1959 negotiations or the franchise campaign and didn't make my first visit to Alaska until January of 1960. I was told however, that the owners of Anchorage Gas Corporation had had in mind to bring me to Alaska (from Honolulu) to organize Anchorage Gas Corporation as an operating company in 1959, even prior to the Kenai discovery, when they were planning to distribute propane or manufactured gas in Anchorage in anticipation of a discovery. The Swanson River oil field had been discovered (1957 or 1958), with gas shows but not commercial quantities. My background then was in propane/butane and manufactured gas, in Hawaii, and I am a graduate chemical engineer.

We built the first marine pipeline in Alaska, across Turnagain Arm, in 1960-61, and turned on gas service in Soldotna and Anchorage in August of 1961. Our first wellhead cost was 32 cents per Mcf (thousand cubic feet), well above the nationally regulated price of 16 cents or so. For a time we believed this cost could compete against coal at Chugach's Knik Arm steam plant (now being moth-balled), and the power/heating plants at Elmendorf and Fort Richardson. Coal was then roughly 55 cents per Mcf equivalent. We were in part relying on the better efficiency and labor cost savings from gas to be competitive with coal. The conversion of these plants, all funded by the federal government, became a hot political issue, and it was not until 1968 that we won out against the politics and the government inertia.

In the meantime, Chevron and Texaco vigorously defended their fuel oil business in Anchorage. They cut their price from 24 cents per gallon to 20 cents per gallon soon after gas became available, and did heavy advertising and took other actions against the introduction of gas. One weekend they hired students to deliver a small bag of peanuts to each house in Anchorage with a flyer saying -- "If you're thinking of converting to gas, think again. Peanuts is all you'll save, so we have decided to give you the peanuts and let you save the cost of conversion." This and many other un-funny competitive actions forced me to appeal to Union and Marathon to cut the Kenai wellhead price to 24 cents (25% reduction) to enable us to remain viable without the large users (power plants) or the large commercial who were burning heavy oil from Chevron.

In 1963 or so the Beluga gas field was discovered, and Chevron and the other producers signed a 20-year contract with Chugach at 16 cents. This fact, and the City's installing its first gas turbine, led me once again to appeal to Union and Marathon for a wellhead price reduction. They agreed that any gas I could sell above 1.6 bcfy (billion cubic feet per year) to the City would be priced at 16 cents, while holding the 24 cents on the remainder. In this way we encouraged the City to add more gas turbines and compete with Chugach.

ENSTAR ENSTAR ENSTAR ENSTAR ENSTAR ENSTAR ENSTAR ENSTAR ENSTAR ENSTAR ENSTAR ENSTAR ENSTAR ENSTAR ENSTAR

Later in 1967 or so, we amended the Kenai wellhead price again, to put the first 8 bcfy at 24 cents and all above 8 bcfy at 16 cents. By this time we had recovered from the 1964 earthquake and found good acceptance in the community. With various sales tools we were rapidly gaining customers and the coal suppliers (Evan Jones) had shut down so that coal was coming from Healy at a much higher price than gas. Until this time Union and Marathon had owned half of our common stock (non-voting), but in 1967 our owners offered a public sale of stock (Alaska Interstate Company) and bought out the Union and Marathon interest.

Our annual gas volume grew rapidly as we displaced coal at all three power plants and the City continued to install gas turbines. In turn, Union/Marathon wanted to raise the wellhead price and dedicate their gas to other markets -- ammonia (Union) and LNG (Marathon). They had made an agreement with Chevron to "rent" Kenai field gas for 8 cents per mcf, but to pay the State royalty at 16 cents, which had become the "market price" via the Beluga sale as well as our negotiations with them. I believe (but do not know) that 8 cents was the wellhead value necessary to make the ammonia and LNG feasible, so pricing the Kenai royalty at 16 cents was a subsidy to the State from Union/Marathon.

In 1967 we renegotiated Kenai gas to 21 cents and scheduled future escalations, in order to get a firm commitment of 550 bcf over a new 20 year term, to 1992, and in 1974 we again negotiated to add a 19.4 cent charge to get firm deliverability through 1985 of 160 million cubic feet per day and 700 psig delivery pressure. Firm deliverability is the right to obtain gas on any day at the contracted level despite a much lower average daily take -- in our case only 72 million cubic feet, or a "swing" of 222%. The federally regulated price at that time was about 40 cents, for 110% "swing". Thus we felt that adding the deliverability charge gave us long term protection and assurance of supply including peak demands. It was well that we did so, because from 1973 or so OPEC began to bring chaos to the price of oil, followed by the embargo and the Iranian actions which took oil (and gas, nationally) to catastrophic levels.

In 1977, again running short of deliverability, we negotiated with the State to buy the State's royalty interest from the North Cook Inlet gas field operated by Phillips. We were aware that this gas price was variable and escalating, but we considered that we could meet the escalating price on condition that we had no obligation to take that gas and would do so only to enable our customers to avoid using oil at an even much higher price. We continued using State royalty gas until we were able to negotiate the needed deliverability from Marathon (at the Beaver Creek gas field). Beaver Creek gas was initially priced at $2.32 and included assured long term deliverability, but is indexed up or down to the price of turbine fuel (oil) at the Tesoro refinery, so that its present price is $2.19. This year we began buying gas from the Lewis River gas field with negligible take or pay, at $1.80.

Clearly, the wellhead value of gas in Alaska does not have a direct correlation to the world price of oil, or even to inflation. There has been, and is, a surplus supply of gas available in the Cook Inlet area, and its real value is determined by negotiations of a willing buyer and a willing seller. We are entrusted by the Alaska Public Utilities Commission with the responsibility to behave prudently in these negotiations and to make the best deals we can for the interest of our custom-

ers and our owners. There is perhaps an art, but very little science, in deciding when to make a deal and on what terms. We have been complimented by many of our associates in the industry, by our customers, and by the APUC. We have been criticized by experts at various times that we have paid too little or too much. But a deal is a deal in the real world, and I am proud of having the lowest gas rates in the country and among the best long term supply. Where we had no customers in 1960, we now serve nearly 70,000 and the benefits extend to all of railbelt Alaska through interconnects of electric power, from Homer and Seward through the Matanuska Valley and soon to Fairbanks. There is no subsidy to our customers, or to these others, although they, in total, are saving hundreds of millions of dollars per year as compared to what they would be spending for oil if we had not developed natural gas in Alaska.

We are aware of efforts by CIRI and MMS (old USGS) to collect retroactive royalty and to set artificial wellhead values for gas used by Union/Marathon in their ammonia-LNG plants. These conditions do not attach to our purchases, all of which were made at arms-length and establish the real market, the only true value of the gas we buy for our customers.

DT/dms

# YUKON PACIFIC CORPORATION

March 18, 1986

Rep. Mike Davis
Pouch V - Mail Stop 3100
Juneau, AK 99811

Re: Position Paper/SB 309

Dear Mr. Davis:

1. Yukon Pacific Corporation is an Alaska-based company working to bring about the Trans Alaska Gas System (TAGS) a pipeline to tidewater for shipment of liquefied natural gas (LNG) to Asian markets.

2. Financing and construction of a multibillion dollar system requires the ability to make long-term contracts with certainty that the state will not later come along and change the price of the State's royalty gas. Pass-through provisions are not possible in the international market.

3. SB 309 in its original form would have addressed the problem by requiring the State to accept the price of the gas under long-term contracts when its royalty share is taken in value. SB 309 as passed by the Senate confirms the State's contention, now being challenged in court, that it does have the right to revalue gas under contract. The bill then makes certain "exceptions" to allow the state's utilities to have the certainty in long-term contract prices they believed they had before the Commissioner's decision in 1985 to raise Beluga in-value prices.

4. Yukon Pacific has sought language in SB 309 that would give it a similar "exception" to allow the Commissioner to agree to long-term contract prices if certain findings are made. The language contained in SB 309 would allow the Commissioner to see to it that producers could keep their price commitments to buyers of North Slope gas if the Commissioner was certain the transaction was both arms-length and did not unfairly diminish the value of the gas by attributing greater profits to transportation or marketing.

5. Yukon Pacific would urge the following changes to the legislation, if the issue is not first settled in court:

P.O. Box 101700 • Anchorage, Alaska 99510 • 907 279-1596 • Telex 25-310 Capt. Cook AHC
515 South Post Oak Road • Suite 225 • Houston, Texas 77027 • 713 960-1880 •

a. The so-called "exception" should be broadened to all new gas contracts so long as the state maintains the ability to prospectively take and sell its gas on an in-kind basis during the life of the contract.

The state may be protected by agreeing to a formula for transportation and for processing charges up front, before the Commissioner makes the findings to go with the contract.

b. The arms length clause in the North Slope contract could prevent a contract price decision by the State if North Slope producers take any interest in a gas pipeline. In ANGTS this was the case and it is likely the case in TAGS.

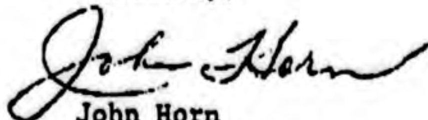
The State is protected by the parallel finding that the market value of the gas is appropriate. Had such a finding been made by the Commissioner before less-than-arms-length transactions were made to construct TAPS, the Phillips-Marathon LNG plant, and the Collier Chemical Plant, it is our belief that expensive and disruptive legal battles on appropriate values of wellhead oil or gas could have been avoided.

6. In conclusion, while Yukon Pacific believes this legislation may not have been necessary if the pending court cases were allowed to come to a conclusion, the company also believes that broadened legislation, removing the proscription on less than arms length transactions, could provide the stability in royalty policy necessary to sign long-term contracts and to finance new projects.

Please pass this information along to the Committee at the hearing on Wednesday, March 19.

With best regards.

Sincerely,



John Horn
Vice Chairman

JH:BH

# MEMORANDUM State of Alaska

TO: Kay Brown, Director
Division of Oil and Gas
and Ned Farquhar, Special Assistant/
Legislative Liaison
Department of Natural Resources

DATE: March 19, 1986

FILE NO:

TELEPHONE NO:

FROM: Harold M. Brown
Attorney General

By: Mark P. Worcester
Assistant Attorney General
Oil, Gas and Mining-Anchorage

SUBJECT: Yukon Pacific's 3/18/86 letter on SB 309

I have the following comments on the Yukon Pacific position paper on SB 309, dated March 18, 1986, and addressed to Representative Mike Davis.

* The letter consistently confuses the terms "price" and "value". When the state takes royalty in value, it receives the value of the gas; when it takes royalty in kind, it receives a price. Accordingly, the state does not "change the price" of royalty on gas production taken in value. Rather, it merely enforces lease provisions which provide that value is not exclusively determined by the price established by the producer's sales contract. This is an essential distinction. For instance, Horn's confusion betweeen "price" and "value" is the predicate for his insinuation that "uncertainty" is attributable to the supposed vagaries of state administration, whereas the critical uncertainty is caused instead by the inability to predict the marketplace over time.

* The letter ignores the fact that Yukon Pacific has always had the ability to obtain "certainty" as to royalty contract "price" through a contract for in kind royalty gas paralleling any sale of working interest gas. Indeed, as indicated above, the only way the state can commit itself not to change a royalty "price" (as opposed to a royalty "value") is in the context of a sale of gas taken in kind.

* The insinuation that the state's legal case is weak is entirely false. If the producers and utilities had thought they had long-term contract prices controlled in value royalties, they would not have had "pass-through" clauses in their sales contracts. More explicitly, had Phillips, Marathon, Union, and Enstar really felt their litigation chances to be so favorable, they would not have all entered into settlements so clearly favorable to the state. Even the Chugach settlement will bring the state three times the amount of royalty that Chugach and the producers asserted was due.

* Up front agreement to a formula for apportioning price among the gas, processing costs and transportation costs for all sales contracts in unrealistic. The state still has not reached final resolution on TAPS charges, and the shipping charge issues for North Slope oil are in litigation in the Amerada Hess case. It took years to resolve these issues with Phillips and Marathon. It would be difficult for the department to make sound decisions on such apportionment "up front" - especially within a 90 day time frame.

* The present bill would not require the department to agree to a formula to apportion a North Slope gas contract price among pipeline, liquefication, shipping and the gas. For instance, the sales contract could be between the producers and Yukon Pacific at the North Slope, with Yukon Pacific marketing the gas in Japan. The bill does not require agreement as to an apportionment formula - only a finding that the value of the gas has not been diverted to transportation or other cost or profit centers.

* The apportionment issue will be a significant issue if the first sale of North Slope gas is directly to the Japanese. Mr. Horn worked with Phillips. Phillips argued in the Cook Inlet LNG litigation that under a "proper" (from Phillips' perspective) netback method, the value should be apportioned according to the <u>amount invested</u> in each segment. Since the pipeline, LNG facility and LNG tankers have great up front costs, this would have resulted in a very low netback value for the gas. In fact, the great profits of the Phillips/Marathon LNG plant came from an increase in the value of the gas: it was economic rent from the fortuitous worldwide escalation of energy prices that created the large profits. I am confident that any formula which Phillips would have proposed "up front" would have been designed to deprive the royalty owner from fully sharing in any fortuitous rise in the value of the gas. Any simple formula would inappropriately attribute rises in the value of the gas to liquification, pipeline and shipping, and would not account for the depreciation of the pipeline, liquefication and shippong facilities.

* It may be worth reiterating that the ability of the state to take its gas is kind is a safeguard of questionable value. The gas market is limited - especially on a day-to-day basis. More importantly, the state is in a very disadvantageous

marketing position. Not only must any contract go through administrative and legislative procedures which discourage potential buyers, but the state, unlike producers, cannot control the volume of gas under any in kind sale, since the state simply takes a percentage of what the amount produced under the lessees' sales contracts.

* The suggestion that "expensive" litigation could have been avoided had SB 309 been on the books sooner is incredible. Certainly, it has been expensive to litigate TAPS and the Phillips LNG cases. However, it has primarily been "expensive" to the oil companies, since they have been required to pay huge sums to the state. Moreover, it is disingenuous to suggest that the Phillips/Marathon LNG disputes could have been avoided if SB 309 had been in place when that project was built. Phillips and Marathon both strenuously argued that the Japan sales price could not be used to determine their royalty obligation. Instead, they argued that their royalty was controlled by the local market price (which they acknowledged could change over time). Union's dispute also could not have been resolved by a SB 309, since it does not sell its gas, but rather transfers it from its production to its chemical division. The only reason that John Horn is touting a netback for Yukon Pacific, after he adamantly opposed a netback when working for Phillips, is because the market is now different, and Yukon Pacific believes the royalty will be lower using a netback from the Japan price (especially if they can manipulate the netback "formula") than it would be if the royalty were controlled by local market values. This illustrates that the most consistent "principle" guiding the industry's stance on royalty policy is that royalties should be minimized.

* It now looks like a real push will be made to amend the (bb) subsection in SB 309 - at least to remove the restriction to arm's-length contracts. I have an additional suggestion on possible amendments. I believe that it would be important that the commissioner have the power to <u>conditionally</u> approve the use of contract price. I think that the power exists now, since a commissioner could reject a proposal, and in the decision accompanying the rejection state the changes which would make the proposal satisfactory. However, it may be difficult for a commissioner to take such actions because of political pressures not to "obstruct" significant projects. It may be easier for a commissioner to insist upon changes to protect the state's

royalty interest if the authorizing statute expressly comprehended that the commissioner's role would go beyond merely taking or leaving an oil company proposal. This kind of authority would be especially important where the proposal called upon the commissioner to agree to apportionment of a destination price among the gas, pipeline, shipping and liquefication segments.

DNR 3-12-86

DISCUSSION POINTS

CSSB 309 (RULES)

- The Bill would benefit Alaska consumers of electricity and natural gas. This way the use of Alaska's royalty gas resources would directly benefit state citizens.

- Although state revenues may be reduced in the future as a result of the Bill, any losses attributable to consumer use would likely be small (compared to oil revenues).

- The Bill would not affect the Legislature's ability to review long-term royalty sales under AS 38.05.183 (See AS 38.06.055).

- The Bill is not a "special interest" rewrite of the state's royalty valuation policy. The benefits that would accrue under the Bill would benefit more than three-fourths of the state's citizens.

- Passage would facilitate financing for a North Slope gas pipeline, which would provide many jobs and boost the state's economy generally. For a project of this magnitude the Legislature may wish to provide "certainty" for valuation of the royalty share.

- The Bill (unlike the original version) provides a proper delineation of the respective roles of the executive and legislative branches.

- The Bill would apply only to future contracts between a lessee and a purchaser, and to future proposed in-kind sales.

- The Administration's reservations about the original bill have been addressed. The Bill allows the conditional settlement agreement with Chugach Electric to take effect, and should be passed promptly.

BY TELECOPY

To: Ned Farquhar
From: Mark P. Worcester
Date: March 7, 1986

RE: Housekeeping amendments to SB 309

We recommend the following amendments to CS for SB 309 (Rules):

Amend Section 1, subsection (e) as follows:
Replace the phrase "the Prudhoe Bay reservoir" with the phrase "Alaska North Slope gas leases";

Amend section 2, subsection (bb) as follows:

(bb) In the event of a contract between parties that are unrelated in management, ownership, or other aspect for the sale of gas from [PRUDHOE BAY RESERVOIR] Alaska North Slope gas leases by means of delivery of the gas through a pipeline for export out of the state, and within 90 days after the written request of a lessee of a lease issued under this section, unless the commissioner makes a written finding that the contract price does not assure the maximum benefits to the people of the state in return for the state's gas resources, the commissioner shall enter into an agreement with the lessee to use the price for the gas established in the gas sales contract as the value of the state's royalty share of gas production sold by the lessee under the gas sales contract. The lessee shall have the burden of providing all information necessary for the commissioner to make an informed decision, and shall provide clear and convincing evidence that the value of the gas is reflected by the gas sales contract price rather than being attributed to transportation, marketing, or other profit or cost centers. In this subsection [,]

(1) "Alaska North Slope gas leases" includes any gas lease issued by the state under this section that lies in whole or part north of 68 degrees north latitude; and

(2) "price for the gas established in the gas sales contract" includes tax reimbursement amounts, deliverability and other charges, and other forms of consideration received by the lessee under the gas sales contract.

Add a new section 7:

This Act does not apply to gas royalties due on production from land patented to the state under the Alaska Mental Health Enabling Act of 1956, P.L. 84-830, 70 Stat. 209 (mental health lands), and the Act of March 4, 1915, ch. 181, 38 Stat. 1214 and section 906(b) of the Alaska National Interest Lands Conservation Act, P.L. 96-487, 94 Stat. 2430 (school lands).

# STATE OF ALASKA

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## HOUSE SPECIAL COMMITTEE ON OIL AND GAS

CSSB 309 (Rules)

Packet Materia!

1. Letter from DNR to Sen. Sackett re: fiscal note
2. Summary of CSSB (Rules)
3. Section-by-Section Analysis
4. Cook Inlet Royalty Gas Valuation Overview - DNR 2/10/86
5. Impacts of State Royalty Gas Increase on Railbelt Consumers - Chugach Electric Association

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

BILL SHEFFIELD, GOVERNOR

POUCH M
JUNEAU, ALASKA 99811
PHONE: 907-465-2400

The Honorable John Sackett
Co-Chair, Finance Committee
Alaska State Senate
Juneau, AK 99811

March 3, 1986

Dear Senator Sackett:

I am responding to your request for more information on the fiscal note and potential fiscal impact of CSSB 309 (Res), now before the Senate as CSSB 309 (Rules).

The fiscal note

The department has submitted a zero fiscal note for the bill, which will not directly affect the state's current royalty gas revenue stream. There are two reasons that it is not possible to identify future costs of the legislation:

- the department is not able to predict how often the new valuation mechanism will be applied in the future, nor can we predict future gas contract prices and quantities; and

- market values for Alaska natural gas (particularly Cook Inlet gas now sold for instate consumer uses and most immediately affected by the proposed statute) are unpredictable, as is the possible disparity (positive or negative) between contract price and market value.

Even though there is no direct fiscal impact that can be assigned to the bill, enactment of the legislation will indirectly affect state royalty income from existing production in Cook Inlet. The state has entered into an agreement with Chugach Electric to value the state's royalty share from Beluga Field production purchased by Chugach under existing contracts at $0.75/mcf if the legislation passes. This value is one-half the state's January offer to settle the pricing dispute at $1.50/mcf, which was rejected by the Beluga producers who sell to Chugach. If the dispute had been settled at $1.50/mcf under existing state law, the

state would have received approximately $1.9 million/year in new royalty income from the Beluga field. Settlement at $0.75/mcf, as will occur if CSSB 309 (Rls) is passed, will increase state royalty revenues from Beluga production by about $810,000/year, according to our calculations, because the state's share of this production is currently valued at $0.21/mcf by the producers. This increase in state royalty revenues is less than would have been expected if 1) the state's $1.50/mcf settlement offer had been accepted, or 2) the state had successfully pursued its legal arguments regarding the value of the state's royalty share under the existing lease terms, based on existing law.

Future costs to the State

As stated above, the department has submitted a zero fiscal note because it is unable to predict future market conditions and contract terms for Alaska natural gas. It is important for the Legislature to consider that market value in the future could either exceed or remain below long-term contract prices for instate consumer gas purchases. The present situation in the Beluga field is an example of how long-term contract prices (Chugach at an adjusted $0.26/mcf and Enstar at an adjusted $2.05/mcf) can be above or below "market value" simultaneously in the same field.

Section 2. The fiscal impacts of Section 2(aa) of CSSB 309 (Rls) will largely depend on future market and contract conditions in Cook Inlet, unless there is a commitment of North Slope natural gas by the producers for instate use. The natural gas market for instate energy use will be affected by the costs of thermal and hydroelectric energy alternatives, including new or expanded coal development; production from new or shut-in gas sources; geothermal development (which has been discussed in connection with Beluga coal development); hydroelectric construction; export projects for coal, gas, or oil; and the price of fuel oil and diesel as alternative fuel sources. There have been some projections of Cook Inlet gas prices by other agencies that this department has disputed on grounds that the Cook Inlet market remains largely controlled by local factors rather than world gas or oil prices or exports. If North Slope natural gas is brought to market its pricing and availability will also become an important factor in the fiscal impact of this bill (Section 2(bb)). Because the eventual marketing arrangements for Prudhoe Bay gas would

probably have to be less diverse and more stable than are marketing arrangements for Cook Inlet gas, it is likely that there would be less disparity between Prudhoe Bay contract price and market value, although the fiscal impact of accepting the contract price as the state's royalty value (given the magnitude of the Prudhoe Bay gas resource) might be larger, either positively or negatively affecting the state's revenues.

Section 3. This section gives the commissioner authority to make below-market-value gas sales for instate energy use. Because the Legislature reviews long-term royalty oil and gas contracts before their implementation by the Department, the fiscal impact of this section will be considered by future Legislatures reviewing such below-market-value gas sales by the state. Without knowledge of how often or at what cost the state will exercise this option, there is no way to estimate the fiscal impact of enacting this statute.

Please contact me if you have any further questions or comments. I am providing copies of this letter to other members of the Senate in anticipation of the floor debate on CSSB 309 (Rls) this morning. Thank you for your interest in this issue.

Sincerely,

Esther C. Wunnicke
Commissioner

cc: All Senators
Dr. Joyce Murphy, Chugach Electric

DNR 3-3-86

## SUMMARY OF CSSB 309 (RULES)

The Bill will allow the state to provide certainty in royalty gas valuation for Alaska consumer uses and North Slope gas development.

Specifically, the Bill would:

- Authorize the Commissioner of the Department of Natural Resources to accept a contract price between a state lesses (gas producer) and a gas or electric utility as the value of the state's royalty share of production.

- Authorize the Commissioner of the Department of Natural Resources to sell the state's royalty gas to a gas or electric utility at a price below market value. The Legislature reviews long-term sales under existing law.

- Establish a royalty valuation procedure which will facilitate financing for a North Slope gas pipeline.

"Gas or electric utility" includes cooperative electric utilities (such as Chugach, Matanuska, Homer, rural coops, and Golden Valley Electric), municipal utilities (such as Anchorage Municipal Light and Power), and a gas utility regulated under AS 42.05 (such as Enstar).

The Act would apply only to future contracts between a lessee and a purchaser.

A preliminary settlement agreement between the Department of Natural Resources and the Board of Directors of Chugach Electric, which would settle pending litigation over the value of the state's royalty share of Beluga gas now pruchased by Chugach at $0.26/mcf, is contingent on passage of the bill. The preliminary settlement agreement sets the price of Beluga royalty gas under the existing Chugach contract at $0.75/mcf.

<u>Revenue Impact</u>: Section 3 of the Bill, which authorizes the Commissioner to sell royalty gas taken in kind to a gas or electric utility at a price below market value, could result in lower state revenues in the future if this discretionary authority is exercised. The amounts of potential revenue loss cannot be precisely calculated, but would be identified at the time of the sale, when legislative review would occur. The state could also lose or gain revenue by any disparity between contract prices and market values, but this fiscal impact is not predictable.

DNR 3-3-86

Section-by-Section Analysis of CSSB 309 (Rules)

Section 1 of the Bill makes several findings:

- The best interest of the state will be served if the commissioner of Natural Resources is authorized to establish the in value royalty for gas sold to a gas or electric utility by using the contract price between the state lessee and the utility;

- It is in the best interest of the state to give the commissioner explicit discretionary authority to sell in kind royalty gas to a gas or electric utility at a price below market value;

- The proper exercise of discretion conferred by the Act will support and complement the other energy programs of the state;

- The state should adopt a policy for the sale of royalty gas to gas or electric utilities for in-state consumer use and in-state generation of electricity that is fundamentally different from the policies of the state for the sale of royalty oil and for the sale of royalty gas for export from the state or for uses other than in-state consumer use and in-state generation of electricity; and

- It is in the state's best interest to facilitate the financing and construction of a pipeline and increased gas production from the Prudhoe Bay reservoir by establishing a procedure by which the state could commit itself to a royalty valuation methodology for as long as the state takes its royalty share of gas production in value.

Section 2 adds new subsections to AS 38.05.180:

- Subsection (aa) provides that within 90 days after the written request of a lessee, unless the commissioner makes a written finding based on clear and convincing evidence that the contract price is unreasonably low and that a prospective reduction in royalty receipts would not be balanced by increased benefits to in-state gas and electric consumers, the commissioner shall enter into an agreement with the lessee to use the price established in a contract between the lessee and a gas or electric utility as the value of the state's royalty share of gas production, if the lessee and the utility are not related. "Gas or electric utility" includes an electric cooperative organized under AS 10.25, a municipal utility, and a gas or electric utility regulated under AS 42.05.

- Subsection (bb) provides that in the event of a contract between unrelated parties for the sale of gas from the Prudhoe Bay reservoir for delivery through a pipeline for export out of the state, the commissioner shall within 90 days after the written request of a lessee enter into an agreement with the lessee to use the price for gas established in the gas sales contract as the value of the state's royalty share of gas production, unless the

commissioner makes a written finding that the contract price does not assure the maximum benefits to the people of the state in return for the state's gas resources. The lessee shall have the burden of providing all information necessary for the commissioner to make an informed decision, and shall provide clear and convincing evidence that the value of the gas is reflected by the gas sales contract price rather than being attributed to transportation, marketing, or other profit or cost centers.

Section 3 adds a new subsection to AS 38.05.183:

- Subsection (h) provides that the commissioner may sell royalty gas taken in kind to a gas or electric utility at less than the market value of the gas, if the commissioner, after considering the consumer benefits, other benefits, and detriments of the sale, makes a written finding that the sale is in the best interest of the state. "Gas or electric utility" includes an electric cooperative organized under AS 10.25, a municipal utility, and a gas or electric utility regulated under AS 42.05.

Section 4 amends AS 38.05.810(a) to make it consistent with the other provisions of the Act.

Section 5 provides that the proposed AS 38.05.180(aa), which would be enacted by Section 2 of the Act, applies to agreements to establish the in value royalties on gas production that is sold under a contract entered into on or after the effective date of the act between the state's lessee and a gas or electric utility.

Section 6 provides an immediate effective date.

# COOK INLET ROYALTY GAS VALUATION: An Overview

A Presentation to the
Senate Resources Committee
by:

Esther C. Wunnicke, Commissioner
Alaska Department of Natural Resources

Kay Brown, Director
Division of Oil and Gas
Alaska Department of Natural Resources

Bill Van Dyke, Petroleum Manager
Division of Oil and Gas
Alaska Department of Natural Resources

Mark Worcester, Assistant Attorney General
Alaska Department of Law

February 10, 1986

2/5/86

## COOK INLET GAS SUMMARY

Lease interpretation: Under the terms of its oil and gas lease contracts with the oil companies, the state is entitled to royalty payments determined by the higher of the price received by an oil company under its sales contract, or the value of the gas at the time of production. This means that the price received under a long-term gas sales contract does not control royalty valuation in those instances where inflation and market forces have caused the current value of the gas to be higher than the contract price.

DNR policy:

(1) As land manager for the citizens of the entire state, it is DNR's responsibility to obtain fair value for the state's oil and gas resources by collecting the full royalties to which the state is entitled under its oil and gas leases.

(2) DNR should not selectively abdicate its responsibility to enforce the royalty terms of the Cook Inlet gas leases just because utility companies have agreed as part of their gas purchase contracts to reimburse the oil companies for royalty collections made by the state. Any consumer subsidy should be the result of an affirmative, direct subsidy by the legislature as part of a comprehensive energy policy.

(3) DNR should not divert from uniform enforcement of the oil and gas leases, since such action could, in addition to directly reducing revenues from any leases from which royalties are not fully collected, also indirectly cause a much larger reduction in state revenues by impairing the state's ability to enforce the royalty provisions of the North Slope leases.

The potential consumer impact result from actions by Chugach, not the state. The risk that gas values might escalate to values in excess of the long-term gas sales price was a circumstance foreseen by the parties to those sales contracts. This is demonstrated by the fact that the contracts between the oil company lessees and Chugach Electric Association, Inc. (Chugach) specifically assign to Chugach the risk of any rise in royalty obligations. The state was not a party to those sales contracts. The contract price, the absence of an adequate price escalator or price reopener, and the assignment to Chugach of the risk of increased royalty obligations were all conditions established by contract between Chugach and the lessees without state participation.

Existing law provides an adequate mechanism for long-term royalty certainty: DNR is sympathetic to the desirability of long-term certainty in royalty matters. However, new statutory authorities are not necessary in order to provide such certainty. Royalty certainty can be attained by negotiation of long-term in kind gas sales contracts which parallel the contracts between the state's

lessees and their gas purchasers. This would allow an opportunity for DNR, the royalty board, and the legislature to evaluate the adequacy of the royalty over the life of the contract. This is preferable to being locked into a long-term royalty value set by prices established by lessees without any notice to or participation from the state.

Litigation: Last March DNR notified the Cook Inlet lessees of its determination to enforce the leases. The notices asserted that the most recent (December 1982) major contracts from the Kenai and Beluga River fields (the "APL II contracts") established the current value. These contracts had a base contract price of $2.05 per mcf in 1985. The state subsequently indicated its readiness to accept a lower royalty value if presented with evidence that the current value of gas in Cook Inlet is less than the price established under the APL II contracts. Union, Marathon, ARCO, Chevron and Shell responded to the notices by suing the state.

Recent Cook Inlet Gas Sales Contracts:

| Date of Contract | Purchaser | Field | Starting Base Price |
|---|---|---|---|
| 1982 | APL (Enstar) | Beluga | $2.32 |
| 1982 | APL (Enstar) | Kenai, Beaver Creek or McArthur River | $2.32 |
| 1983 | Chugach | Cannery Loop | $1.80 |
| 1984 | APL (Enstar) | Lewis River | $1.80 |
| 1985 | Tesoro | Kenai, Beaver Creek or McArthur River | $2.01 |

Settlements achieved: In the last two months of 1985 DNR's royalty enforcement actions achieved significant success. Settlements relating to gas royalties due on production from the Kenai Field, and involving Marathon, Union, Alaska Pipeline Company (Enstar), CIRI, the U.S. Department of the Interior and the state, yielded the state about $4 million in retroactive royalties, and will bring in excess of $6.5 million per year more than the amounts which would have been paid under the lessees' prior reporting practices (including those increases attributable to the state's 90% interest in federal onshore royalties). Under the lessees' theory, the royalties would have been variously between $0.21 and $0.61 per mcf; under the settlement, the lessees will pay $1.95 per mcf during 1986. The $1.95 is squarely within the gas values established by recent Cook Inlet gas sales contracts, as well as the values established by Enstar's pending rates ($2.1854 for Schedule C purchasers - "Large Commercial Service", and from $1.6480 to $2.0158 for sales to power plants). The settlements confirm the soundness of the royalty enforcement action taken last spring.

Remaining disputes: The major remaining dispute relates to the Beluga River field, the primary source of gas for Chugach.

Settlement negotiations during the last six months have failed to produce any resolution. Options explored have included underlifting the state's royalty share, thus delaying the royalty into the future; an in kind sale to Enstar or Chugach; and an in value settlement. The lessees (ARCO, Chevron and Shell) assert that they should not be required to contribute any monies to any settlement, since their sales contract with Chugach requires Chugach to reimburse the lessees for any additional royalty amount the state collects. Chugach, in turn, has been unwilling to agree to an acceptable value, and has indicated that it will seek legislative relief. Recently, the state made a formal offer to its lessees to settle the dispute for $1.50 per mcf. This offer was rejected, but settlement efforts and discussions continue.

Consumer impact. Chugach estimates that a royalty rate of $2.05 per mcf on state leases would increase retail consumer rates only about 2.38%, assuming the lessees were successful in asserting that their contracts with Chugach permitted them to pass the royalty burden on to Chugach, and further assuming that the APUC permitted Chugach to pass the burden on to its consumers. DNR estimates that a $2.05 royalty would increase state revenues by about $2.8 million per year. Under the $1.50 per mcf settlement offer, the increased royalty income would fall to about $2 million per year, and the magnitude of retail consumer impact would be correspondingly reduced to less than 2%. (A two per cent increase on a monthly bill of $30 would be only $0.60).

ATTACHMENT 2

2/5/86

COOK INLET GAS ROYALTY SETTLEMENTS
(State leases and State share of federal royalties)

| Lessee | Scope of Settlement | Retro-active Payment (millions) | Current Monthly Value Under Settlement (per Mcf) | Estimated Additional Royalties per year (millions) |
|---|---|---|---|---|
| Phillips | North Cook Inlet Field gas sold as LNG in Japan | $36.3 | $2.32 | $12.00 |
| Marathon | Kenai field gas sold as LNG in Japan | $ 4.3 | $2.32 | $ 0.75 |
| Union and Marathon | All of Union's Kenai field gas disposition (including the following: urea/ammonia plant, rental gas, Enstar), plus Marathon's dispostions to Enstar under Enstar's 1975 contract | $ 4.1 | $1.95 | 6.90 |
| | Total | $44.7 | | $19.65 |

ATTACHMENT 3

2/5/86

COOK INLET GAS ROYALTY CHRONOLOGY

| Month | Year | Description of Event |
|---|---|---|
| March | 1964 | Foster v. Atlantic Refining Company, 329 F.2d 485 (5th Cir. 1964) holds that long-term contract price does not control royalty valuation when market value rises, even if this is burdensome on the lessee. |
| May | 1965 | Chugach Electric Association, Inc. enters into 20 year contracts with ARCO, Chevron and Shell for Beluga River gas, with an initial price of 15.2 cents per mcf, subject to a volume limit. |
| January | 1973 | Chugach renegotiates its 1965 contracts, extending the term to 1998 (unless the new, higher volume limit is reached earlier). The 1986 base price under those contracts is about 21 cents per mcf. |
| November | 1982 | Chugach obtains supplemental gas deliveries under the 1973 contract at a base price of $1.48 per Mmbtu (approximately equivalent to $1.48 per mcf). |
| December | 1982 | Alaska Pipeline Company (Enstar) signs contracts for gas deliveries from Beluga River (with Shell) and Kenai (with Marathon) at a price of $2.32 per mcf, with annual adjustments based upon fuel price fluctuations (the "APL-II" contracts). This is the first totally new contract for Beluga River gas subsequent to the 1973 Chugach contract under which there were any deliveries. |
| March | 1984 | Piney Woods County Life School v. Shell Oil Company, 726 F.2d 225 (5th Cir. 1984), reh. den. 750 F.2d 69, cert. den. 105 S.Ct. 1868 (1985) reaffirms the soundness and continued validity of the rule in Foster, above. |
| May | 1984 | The state and Phillips settle their dispute concerning the valuation of Cook Inlet gas from state leases which is sold as LNG in Japan, using a formula which initially yields a royalty of $2.40 per mcf. |
| May | 1984 | The federal government informs Union that virtually all gas royalties from the Kenai field, including gas sold under below-current-market, long-term contracts with Enstar, must be valued in accordance with the price under the APL-II contracts. |
| November | 1984 | DNR determines, in consultation with the Department of Law, to enforce the Cook Inlet lease terms requiring payment of gas royalty on the basis of current value. |

| | | |
|---|---|---|
| February | 1985 | U.S. District Judge Fitzgerald rules that Marathon must pay royalties on Kenai Field gas sold as LNG in Japan based upon the Japan sales price, less costs of transportation. Marathon calculates the netback value under the order to be about $3.00 per mcf, while the federal government calculates the value to be about $3.60 per mcf. The accounting remains in dispute in District Court, while the District Court's February 1985 decision is under appeal to the Ninth Circuit. |
| March | 1985 | By written notice, DNR informs its Cook Inlet lessees of its determination to enforce the royalty requirements of the leases. |
| May/June | 1985 | All Cook Inlet gas producers file separate lawsuits seeking judicial declaration of their royalty obligations under the leases. |
| July | 1985 | The state and Marathon settle their dispute concerning the royalty value of Kenai Field gas sold as LNG in Japan in accordance with the terms of the May 1984 Phillips settlement. |
| November | 1985 | The state, federal government and CIRI (all royalty owners in the Kenai field) settle most royalty issues for production from the Kenai field. Most significantly, royalty on gas used in Union's urea and ammonia plant and used to promote greater oil production from the Swanson River oil field, is set at $1.85 per mcf for 1985 and $1.95 per mcf for 1986, with annual adjustments thereafter based upon fluctuations in fuel oil prices. |
| November | 1985 | The Secretary of the Interior issues a definitive order holding that Cook Inlet gas sold by Union and Marathon to Enstar must be valued for royalty purposes according to current market values. |
| December | 1985 | The state, federal government and CIRI enter into a settlement agreement on the value of the royalty on Kenai gas sold to Enstar under long-term contracts. Under this settlement, the royalty owners receive $1.85 per mcf for the part of 1985 at issue, and will receive $1.95 per mcf for 1986 production, with annual adjustment thereafter based upon fluctuations in the oil prices. |
| January | 1986 | The state offers to the producers to settle the dispute concerning the royalty value of gas sold to Chugach. This $1.50 per mcf offer is rejected by the producers, but settlement discussions continue. |

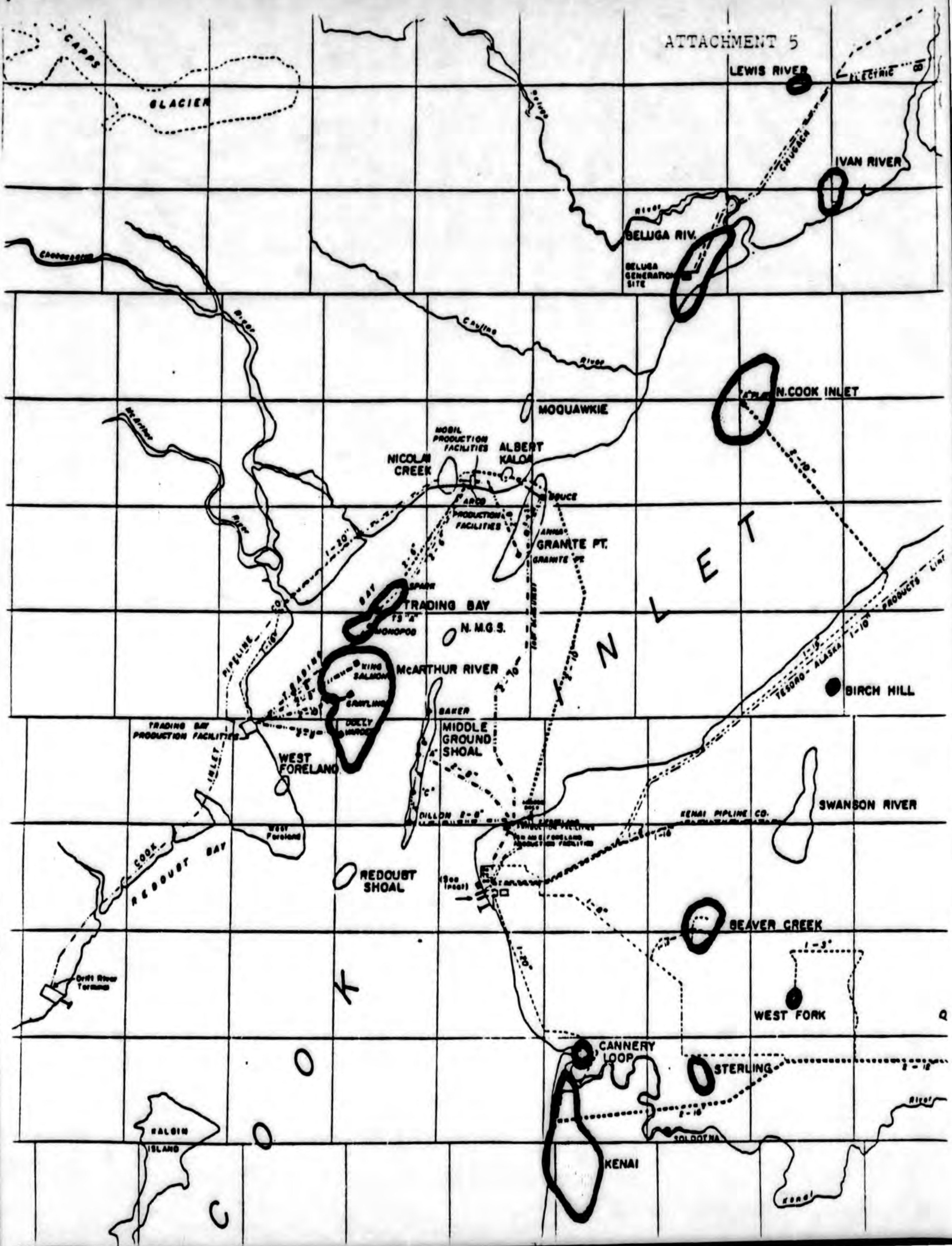
**ALASKA DEPARTMENT OF NATURAL RESOURCES - DIVISION OF OIL AND GAS**
**SUMMARY STATISTICS**
**COOK INLET GAS PRICE DISPUTE**
**AVERAGE MONTHLY SALES VOLUMES - JULY 1984 THROUGH JUNE 1985**

Date:1/14/86

| FIELD Producers (% of field owned) | PURCHASER | % of FIELD on sale by sale basis | SALES VOLUMES (MCF) 1/ | EFFECTIVE ROYALTY INTEREST | ROYALTY VOLUME (MCF) | VALUE REPORTED FOR ROYALTIES 2/ | PRODUCER/ PURCHASER BASE CONTRACT VALUE 2/ 7/ | EFFECTIVE DATE | EXPIRATION DATE | |
|---|---|---|---|---|---|---|---|---|---|---|
| **BELUGA RIVER FIELD** | | | | | | | | | | |
| CHEVRON (33.33%) | ENSTAR | 2.11% | 37,790 | 0.07555 | 2,855 | $1.0000 | $2.0300 9/ | 12/20/82 | 10/1999 | |
| ARCO (33.33%) | ENSTAR | 2.11% | 37,790 | 0.07555 | 2,855 | $1.0000 | $2.0300 9/ | 12/20/82 | 10/1999 | |
| SHELL (33.33%) | ENSTAR | 2.11% | 37,790 | 0.07555 | 2,855 | $1.0000 | $2.0300 9/ | 12/20/82 | 10/1999 | |
| AGEA (100.00%)U-214-35 | ENSTAR | 0.45% | 8,122 | 0.07555 | 614 | $1.0000 | $2.0300 9/ | 12/20/82 | 10/1999 | |
| SUB TOTAL | | 6.77% | 121,492 | | 9,179 | | | | | |
| CHEVRON (33.33%) | CHUGACH | 28.70% | 515,065 | 0.07555 | 38,913 | $0.2103 | $0.2103 | 5/10/65 | 1/1990 | 3/ |
| ARCO (33.33%) | CHUGACH | 28.70% | 515,065 | 0.07555 | 38,913 | $0.2103 | $0.2103 | | | |
| SHELL (33.33%) | CHUGACH | 28.70% | 515,065 | 0.07555 | 38,913 | $0.2103 | $0.2103 | | | |
| AGEA (100.00%)U-214-35 | CHUGACH | 7.13% | 127,863 | 0.07555 | 9,660 | $0.2103 | $0.2103 | | | |
| SUB TOTAL | | 93.23% | 1,673,058 | | 126,400 | | | | | |
| TOTAL BELUGA RIVER FIELD | | 100.00% | 1,794,550 | | 135,578 | | | | | |
| **KENAI FIELD** | | | | | | | | | | |
| UNION (50%) | APL-ANCHORAGE | 10.28% | 843,622 | 0.020600 | 17,494 | $1.9500 8/ | $0.6220 6/ | 5/13/60 | 12/92 | 3/ |
| UNION (50%) | APL-CHEV NIK | 0.19% | 15,888 | 0.020600 | 329 | $1.9500 8/ | $0.6220 | | | |
| UNION (50%) | UNION-CHEV | 0.19% | 15,518 | 0.020600 | 321 | $1.9500 8/ | $0.6220 | 2/5/81 | INDEFINITE | |
| UNION (50%) | CITY OF KENAI | 0.25% | 20,590 | 0.020600 | 426 | $0.3000 | $0.3000 | 5/17/66 | 6/1986 | |
| UNION (50%) | RENTAL GAS | 4.50% | 370,334 | 0.020600 | 7,661 | $1.9500 8/ | $0.0700 | 1/17/66 | 1/1995 | 3/ |
| UNION (50%) | ADDITIONAL RENTAL | 2.37% | 194,901 | 0.020600 | 4,034 | $1.9500 8/ | $0.3000 | | | |
| UNION (50%) | UNION CHEMICAL | 40.73% | 3,352,041 | 0.020600 | 69,347 | $1.9500 8/ | $0.6130 | 11/1/77 | 1990 | |
| TOTAL UNION SHARE | | 58.51% | 4,814,973 | | 99,612 | | | | | |
| MARATHON (50%) | APL-I | 14.38% | 1,183,535 | 0.020600 | 24,485 | $1.9500 8/ | $0.6220 6/ | | 12/1992 | 3/ |
| MARATHON (50%) | APL-II | 4.48% | 368,603 | 0.020600 | 7,626 | $2.0550 | $2.0000 9/ | 12/16/82 | 12/1997 | 3/ |
| MARATHON (50%) | APL-NIKISKI | 0.19% | 15,888 | 0.020600 | 329 | $2.0550 4/ | $0.6220 | | | |
| MARATHON (50%) | CITY OF KENAI | 0.25% | 20,599 | 0.020600 | 426 | $2.0550 4/ | $0.3000 | | 6/1986 | |
| MARATHON (50%) | RENTAL GAS | 4.50% | 370,242 | 0.020600 | 7,640 | $0.2100 | $0.2100 | | 1/1995 | 3/ |
| MARATHON (50%) | ADDITIONAL RENTAL | 2.36% | 194,450 | 0.020600 | 4,023 | $0.3000 | $0.3000 | | | |
| MARATHON (50%) | TOKYO UTILITIES | 15.32% | 1,261,073 | 0.020600 | 26,009 | $2.2795 | $4.7590 5/ | | 6/1/89 | |
| TOTAL MARATHON SHARE | | 41.49% | 3,414,390 | | 70,637 | | | | | |
| TOTAL KENAI FIELD | | 100.00% | 8,229,363 | | 170,249 | | | | | |
| **STERLING FIELD** | | | | | | | | | | |
| UNION (50%) | PENINSULA GREENHOUSE | 50.00% | 736 | 0.015546 | 11 | $0.4000 | $0.4000 | 10/27/61 | | |
| MARATHON (50%) | PENINSULA GREENHOUSE | 50.00% | 736 | 0.015546 | 11 | $2.0550 4/ | $0.4000 | | | |
| TOTAL STERLING FIELD | | 100.00% | 1,472 | | 23 | | | | | |
| **MCARTHUR RIVER FIELD** | | | | | | | | | | |
| UNION/MARATHON (50% each) | | 0.47% | 1,671 | 0.125 | 209 | 0.000 | 0.000 | | | |
| UNION/MARATHON (50% each) | RENTAL GAS | 1.48% | 5,260 | 0.125 | 658 | 0.000 | 0.210 | | | |
| UNION/MARATHON (50% each) | UNION CHEMICAL | 87.56% | 311,215 | 0.125 | 38,902 | 0.000 | 0.613 | | | |
| UNION/MARATHON (50% each) | | 9.39% | 33,375 | 0.125 | 4,172 | 0.000 | 0.000 | | | |
| UNION/MARATHON (50% each) | | 1.10% | 3,910 | 0.125 | 489 | 0.000 | 0.000 | | | |
| TOTAL MCARTHUR RIVER FIELD | | 100.00% | 355,431 | | 44,429 | | | | | |
| **TRADING BAY FIELD** | | | | | | | | | | |
| Marathon 48.66% | | 48.66% | 580 | 0.125 | 73 | 0.000 | 0.000 | | | |
| Union 48.66% | | 48.66% | 580 | 0.125 | 73 | 0.000 | 0.000 | | | |
| Superior 1.34% | | 1.34% | 16 | 0.125 | 2 | 0.000 | 0.000 | | | |
| Texaco 1.34% | | 1.34% | 16 | 0.125 | 2 | 0.000 | 0.000 | | | |
| TOTAL TRADING BAY FIELD | | 100.00% | 1,192 | | 149 | | | | | |

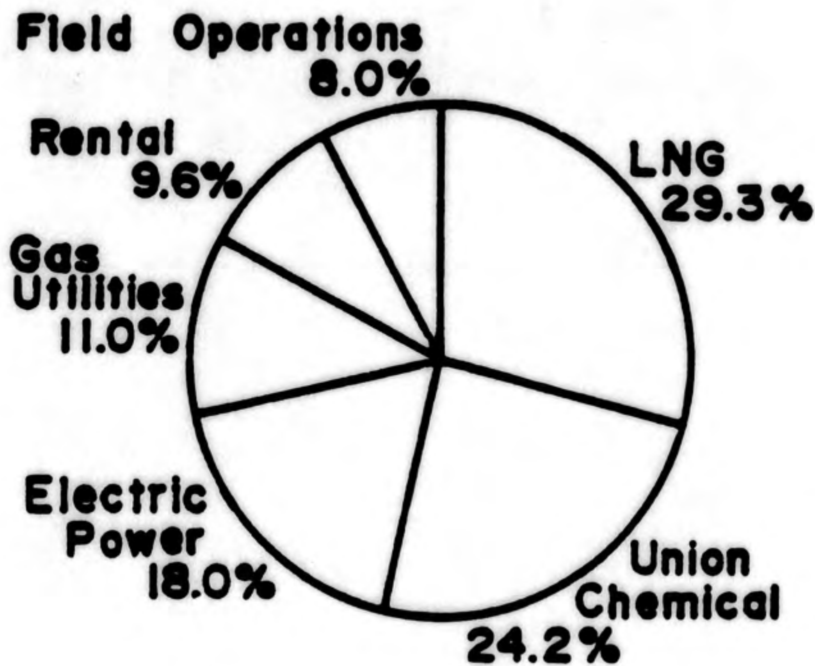
1/ ANNUAL VOLUME DIVIDED BY 12 MONTHS EQUAL AVERAGE MONTHLY VOLUME.
2/ ROYALTY AND CONTRACT VALUES ARE THE MOST CURRENT IN EFFECT AS OF JANUARY 1986. PRODUCTION AND HAVE NOT BEEN ADJUSTED FOR BTU CONTENT.
3/ QUANTITY TERM COULD OPERATE TO EXTEND OR SHORTEN THE CONTRACT PERIOD.
4/ PRICE REPORTED BY MARATHON IS BEING PAID UNDER PROTEST.
5/ CONTRACT PRICE IS A GROSS PRICE BEFORE TRANSPORTATION COSTS.
6/ CONTRACT PRICE TO GO TO $0.27 MCF DURING 1986.
7/ BASE CONTRACT PRICE DOES NOT INCLUDE LESSEE TAX OBLIGATIONS PAID BY THE PURCHASER.
8/ VALUE AGREED TO BY SETTLEMENT.
9/ SPECIAL DELIVERABILITY CHARGE OF $0.35/MCF MAY ALSO BE EFFECTIVE.

ATTACHMENT 4

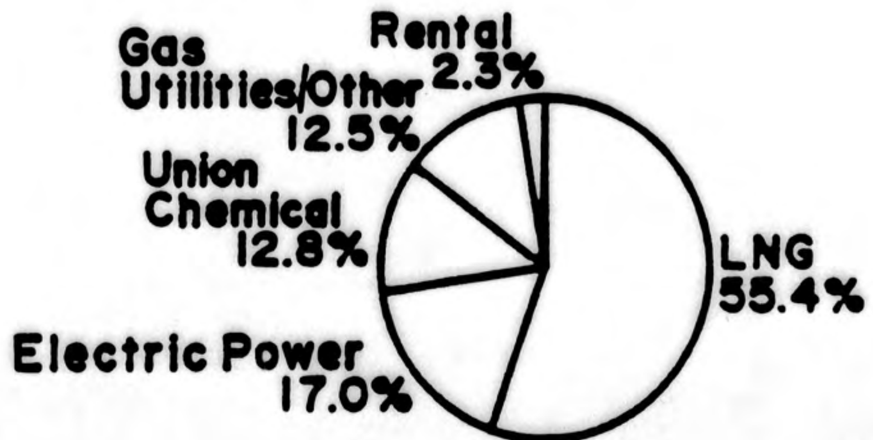

ATTACHMENT 5
CAPPS
GLACIER
LEWIS RIVER
ELECTRIC
CHUGACH
IVAN RIVER
BELUGA RIV.
BELUGA GENERATION SITE
N. COOK INLET
MOQUAWKIE
MOBIL PRODUCTION FACILITIES
ALBERT KALOA
NICOLAI CREEK
ARCO PRODUCTION FACILITIES
GRANITE PT.
TRADING BAY
N.M.G.S.
McARTHUR RIVER
BIRCH HILL
TRADING BAY PRODUCTION FACILITIES
WEST FORELAND
MIDDLE GROUND SHOAL
BAKER
DILLON
KENAI PIPLINE CO.
SWANSON RIVER
TESORO ALASKA
PRODUCTS LINE
REDOUBT SHOAL
REDOUBT BAY
BEAVER CREEK
WEST FORK
Drift River Terminal
CANNERY LOOP
STERLING
KALGIN ISLAND
SOLDOTNA
KENAI
COOK
INLET

# COOK INLET

## Total Sales

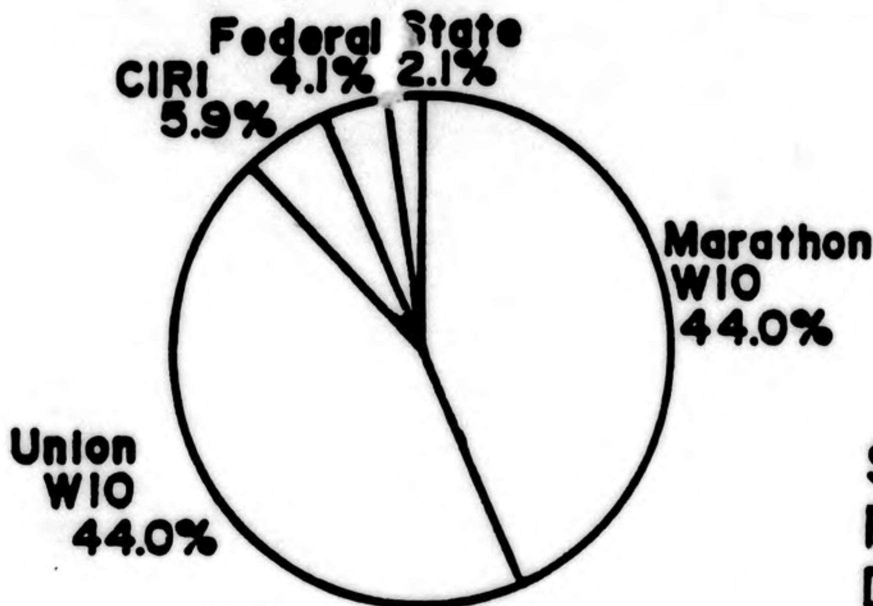



## State Royalty Disposition

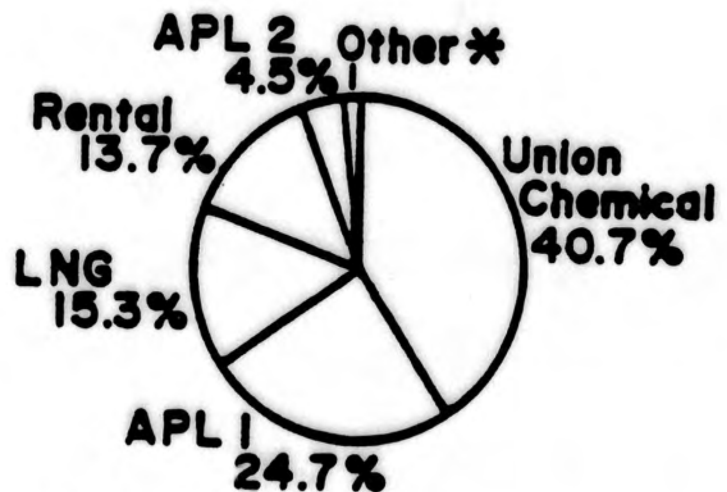


# KENAI FIELD

Royalty And Working Interest Ownership



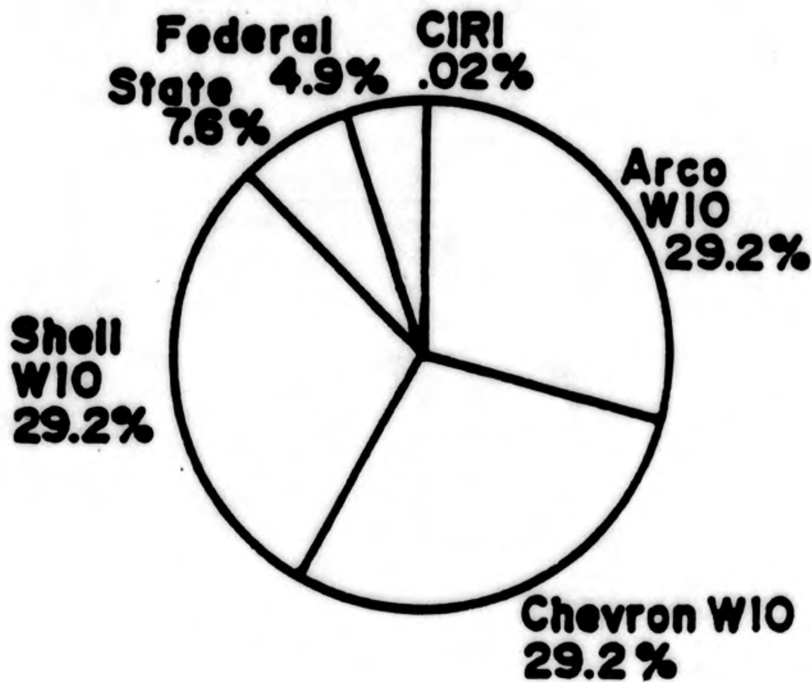

State Royalty Disposition



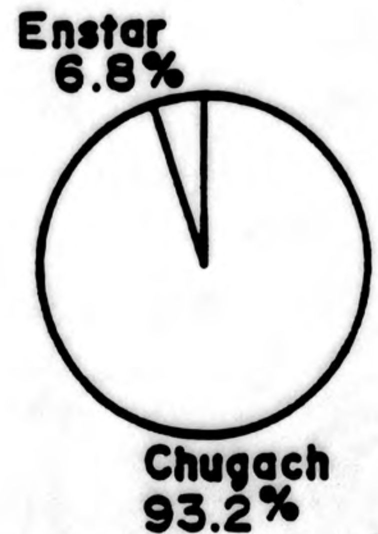

* APL-Nikiski 0.4%
Union-Chevron Exchange 0.2%
City Of Kenai 0.5%

# BELUGA FIELD

**Royalty And Working Interest Ownership**




**State Royalty Disposition**



# COOK INLET GAS PRODUCTION
(For 1984)

| | Total<br>MMCF/Month | State Royalty<br>MMCF/Month |
|---|---|---|
| **Beluga River Field** | | |
| For: Chugach | 1673 | 125 |
| Enstar | 121 | 9 |
| Total | 1794 | 134 |
| **Kenai Field** | | |
| For: APL 1 | 2029 | 42 |
| APL 2 | 369 | 8 |
| APL Nikiski | 31 | 1 |
| APL Kenai | 41 | 1 |
| Union Chevron Ex | 16 | 1 |
| Rental gas | 741 | 15 |
| Rental gas extra | 389 | 8 |
| Ammonia-Urea | 3352 | 67 |
| LNG | 1261 | 25 |
| Total | 8229 | 168 |
| **McArthur River Field** | | |
| For: Rental gas and ammonia-urea | 355 | 44 |
| **Beaver Creek Field** | | |
| For: APL 2 | 789 | 0 |
| **Lewis River Field** | | |
| For: APL 2 | 153 | 19 |
| **North Cook Inlet Field** | | |
| For: LNG | 3932 | 491 |
| GRAND TOTAL | 15,250 | 856 |

**Excerpts from Lease Form DL-1**
**Pertaining to the Pricing of Royalty Products**

11. ROYALTY ON PRODUCTION. Except for oil and gas used on said land for development and production or unavoidably lost, Lessee shall pay Lessor as royalty the following:

(a) On oil 12-1/2 percent in amount or value of the oil produced and saved and removed or sold from said land.

(b) On gas 12-1/2 percent in amount or value of the gas produced and saved and sold or used off said land or used for the extraction of natural gasoline or other products therefrom.

(c) On associated substances 12-1/2 percent in amount or value of such substances produced and saved and removed or sold from said lands.

15. ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts or gross production.

16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or, (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

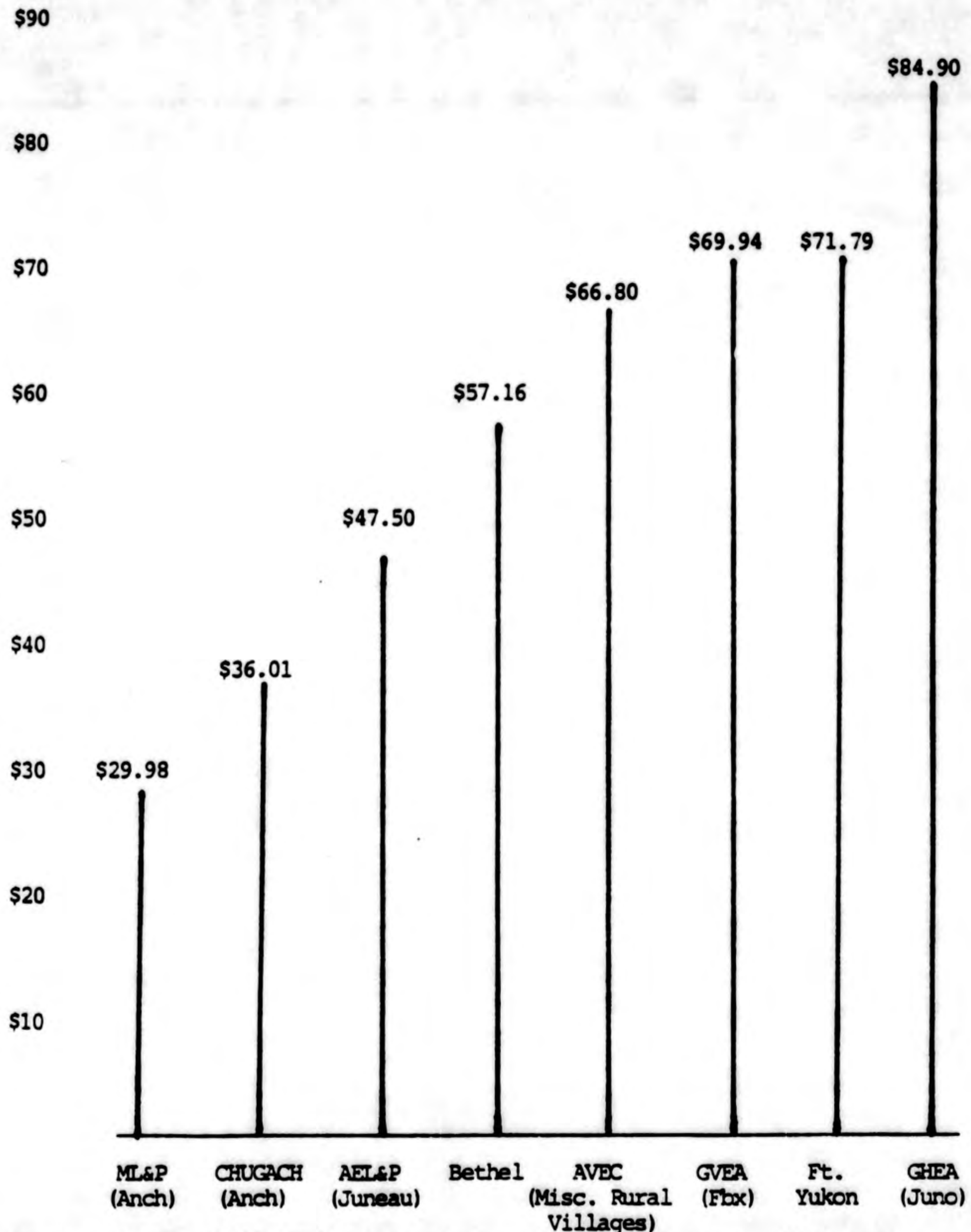
## RECENT CONTRACTS AND PURCHASE AGREEMENTS

| | Purchaser | Field or Seller | Starting Base Price |
|---|---|---|---|
| 1977 | Pac Alaska | Cook Inlet | $1.46 per mcf |
| 1982 | Enstar | Beluga River | $2.32 |
| 1982 | Enstar | Beaver Creek Field | $2.32 |
| 1982-83 | Chugach (Peaking Gas) | Beluga River | $1.40-1.60 |
| 1983 | Chugach | Cannery Loop | $1.80 |
| 1984 | Enstar | Lewis River | $1.80 |
| 1985 | Tesoro | Marathon | $2.01 |
| 1985 | AEG&T (Homer Electric) | Enstar | $2.04 |
| 1985 | ML&P (Anchorage) | Enstar | $1.60 |

February 6, 1986

**Representative Residential Electrical Rates for 500 KWH**

Assumes: Residential rate, non-demand, hot water heater, winter season.
Power Cost Equalization payments have been subtracted.




Source: Alaska Public Utility Commission, except GHEA rates, which were obtained from GHEA.

Chugach Electric

IMPACTS OF STATE ROYALTY GAS INCREASE ON RAILBELT CONSUMERS

Alaskans from Fairbanks to Homer face utility bill increases as a result of the Alaska Department of Natural Resources' decision to drastically raise the price of royalty gas in Cook Inlet. For Chugach Electric Association consumers in the Anchorage area, the impacts will be nearly $3 million a year.

DNR's action was taken with virtually no advance notice to the parties involved, to the public or to the State Legislature. Litigation was initiated by the three producers against DNR on the revaluation in April 1985. Chugach is also involved in the litigation.

There are two major aspects of this issue: The additional costs to utility consumers of DNR's actions and, perhaps more important, the fundamental policy question of how royalty valuation is established.

On March 18, 1985, the Department of Natural Resources (DNR) issued a formal notice to the three Beluga River gas field producers -- ARCO, Shell and Chevron -- informing them that DNR would no longer accept royalty payments based on long-term contract price but would require payments based on the "prevailing market value."

This value was initially determined by DNR to be $2.05 per thousand cubic feet (mcf), based on a Shell-ENSTAR (APL II) contract signed in December 1982. By contrast, Chugach currently pays $.26/mcf for its Beluga gas, under long-term contracts on which the DNR had based its royalty price for the past 17 years.

Based on the $2.05/mcf figure, the annual increase to Chugach retail and wholesale consumers would be approximately $2.8 million -- the equivalent of a rate increase averaging about 3 percent. Even under a recent settlement offer by the state which would value the royalty gas at $1.50/mcf, the impact would be approximately $1.9 million annually -- an equivalent rate increase averaging about 2 percent.

Chugach negotiated its Beluga contracts in good faith and at arms length in 1965, and renegotiated with the producers in 1973. The contracts extend to 1998 or whenever 373 billion cubic feet (bcf) of gas is used, whichever comes first. That means the overall impact of the Beluga royalty revaluation alone could total more than $30 million to consumers.

Additional financial impacts on Chugach consumers have resulted or could result from actions similar to or related to the Beluga royalty revaluation. Those actions are:

- a possible revaluation, identical to the state's, by the other Beluga royalty gas owners (the federal government and Cook Inlet Region, Inc.);

- the recent $8.5 million settlement by ENSTAR relative to royalty gas from the Kenai field (raising ENSTAR's Kenai royalty price from $.66 to $1.95, and including retroactive payments);

- an increase in the cost of power purchased from Anchorage Municipal Light & Power, which was substantially impacted by the ENSTAR increase, and

- a possible increase in state gas severance taxes based on the Beluga royalty gas revaluation.

If all these actions occur, the impact on Chugach consumers would be approximately $6 million annually -- the equivalent of about a 6 percent rate increase. Attachment A details the impacts.

Financial impacts also will be felt in the Fairbanks area, because Chugach has been selling wholesale power to Golden Valley Electric Association and Fairbanks Municipal Utility System over the Anchorage-Fairbanks intertie. ML&P also is selling power to Golden Valley. Golden Valley has estimated that its consumers will save more than $600,000 this winter alone through purchases of power from Chugach and ML&P.

Copper Valley Electric Association also is concerned, because the Glenallen-based cooperative wants its consumers from Glenallen to Valdez to be intertied with the Railbelt utilities and reap the benefits of less expensive power.

Approximately three quarters of the state's estimated 560,000 residents live in the Railbelt between Fairbanks and Homer. Chugach serves nearly half the state's population through sales to its own retail consumers and those of Matanuska Electric Association, Homer Electric Association and the City of Seward. Thus, residents of the Matanuska and Susitna Valleys and on the Kenai Peninsula are directly affected.

In addition to the cost increases associated with the existing gas contracts, there is another major -- and perhaps even more important -- impact of DNR's royalty revaluation decision.

This is what could be called the uncertainty factor. If DNR is ultimately successful in setting royalty prices on what it determines to be the prevailing market value of a resource, utilities, producers and other purchasing parties will have no assurance of what future royalty gas components will be. This injects a real measure of insecurity into long-term gas contracts and, for Chugach at least, into power supply planning and ratemaking.

The uncertainty factor is an important public policy question for the state and is one that may well eclipse the cost-increase aspect of any given royalty lease revaluation. It could be argued that settling the price dispute over a specific revaluation without first resolving the underlying policy question is getting the horse before the cart.

It is important to note that although DNR's gas and oil lease form has given rise to dispute and litigation in many instances over the years, DNR has failed to propose regulations defining important lease terms. Proposed regulations would at least allow for a public discussion of the policy questions.

To resolve the problem raised by the state's royalty gas revaluation, Chugach is supporting passage of S.B. 309, or similar bills H.B. 403 and H.B. 425. Each of these bills would require DNR to tie royalty valuation to long-term contract price, thereby resolving the underlying policy question. A copy of each of the bills is attached.

Uncertainty in long-term price for royalty gas raises problems for Chugach and other utilities both in terms of long-term financing for generation projects and in efforts to ensure electric rate stability. Tying royalty price to long-term contract price allows DNR to continue to manage the state's resources for maximum value, while recognizing that these resources do not have a value independent of long-term contracts. DNR would still be permitted, on only six months' written notice, to take its royalty share in kind and sell it directly to a willing purchaser.

ATTACHMENT A

CHUGACH ELECTRIC ASSOCIATION, INC.
Rate Impacts Due to Market Valuation of Royalty Gas

January 10. 1986

| | Retail: Dollars | Retail: Percent | Wholesale: Dollars | Wholesale: Percent | Total: Dollars | Total: Percent |
|---|---|---|---|---|---|---|
| Current revenues | $63,200,000 | | $35,800,000 | | $99,000,000 | |
| Impacts: | | | | | | |
| The state's Beluga royalty revaluation from $.26/mcf to $2.05/mcf | 1,501,164 | 2.38 | 1,278,769 | 3.57 | 2,779,933 | 2.81 |
| Possible federal/CIRI Beluga revaluation (based on state's $2.05/mcf figure) | 1,000,776 | 1.58 | 852,513 | 2.38 | 1,853,289 | 1.87 |
| ENSTAR settlement | 420,853 | 0.67 | 358,505 | 1.00 | 779,358 | 0.79 |
| ML&P rate increase (resulting from ENSTAR settlement) | 337,500 | 0.53 | 287,500 | 0.80 | 625,000 | 0.63 |
| Possible state gas severance tax increase (based on state's Beluga royalty revaluation) | 87,100 | 0.14 | 74,196 | 0.21 | 161,296 | 0.16 |
| | $3,347,393 | 5.30 | $2,851,483 | 7.97 | $6,198,876 | 6.26 |

JANUARY 13, 1986

TABLE 2.30

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS

ESTIMATED PRODUCTION AND SALES FOR NORTH SLOPE ROYALTY OIL (9)

| | ESTIMATED TOTAL PRODUCTION (BARRELS PER DAY) | | | | | | ESTIMATED ROYALTY (BARRELS PER DAY) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | (1) TOTAL PRUDHOE | (1) TOTAL KUPARUK | (1) TOTAL LISBURNE | (1) TOTAL ENDICOTT | (1) TOTAL MILNE PT. | TOTAL | PRUDHOE ROYALTY | KUPARUK ROYALTY | LISBURNE ROYALTY | ENDICOTT ROYALTY | MILNE PT. ROYALTY | TOTAL ROYALTY |
| 1985 | 1,[illegible],000 | 180,000 | | | 3,000 | 1,733,000 | 193,750 | 22,500 | | | 375 | 216,625 |
| 1986 | 1,[illegible],000 | 220,000 | | | 30,000 | 1,800,000 | 193,750 | 27,500 | | | 3,400 | 226,650 |
| 1987 | 1,[illegible],000 | 220,000 | 30,000 | | 30,000 | 1,850,000 | 193,750 | 27,500 | 6,750 | | 5,400 | 232,900 |
| 1988 | 1,376,000 | 220,000 | 60,000 | 30,000 | 30,000 | 1,736,000 | 172,000 | 27,500 | 7,500 | 7,000 | 5,400 | 219,400 |
| 1989 | 1,183,000 | 220,000 | 70,000 | 100,000 | 25,000 | 1,590,000 | 147,875 | 27,500 | 8,750 | 14,000 | 4,500 | 202,675 |
| 1990 | 1,010,000 | 187,000 | 80,000 | 100,000 | 20,000 | 1,405,000 | 127,250 | 23,375 | 10,000 | 14,000 | 3,600 | 178,225 |
| 1991 | 970,000 | 159,000 | 90,000 | 100,000 | 15,000 | 1,297,000 | 11[illegible],000 | 19,875 | 11,250 | 14,000 | 2,700 | 163,825 |
| 1992 | 846,000 | 135,000 | 100,000 | 100,000 | 15,000 | 1,196,000 | 105,750 | 16,875 | 12,500 | 14,000 | 2,700 | 151,825 |
| 1993 | 772,000 | 122,000 | 100,000 | 85,000 | 10,000 | 1,089,000 | 96,500 | 15,750 | 12,500 | 11,900 | 1,800 | 137,950 |
| 1994 | 706,000 | 109,000 | 100,000 | 75,000 | 10,000 | 1,000,000 | 88,250 | 13,675 | 12,500 | 10,500 | 1,800 | 126,675 |
| 1995 | 646,000 | 98,000 | 90,000 | 70,000 | 10,000 | 914,000 | 80,750 | 12,250 | 11,250 | 9,800 | 1,800 | 115,850 |
| 1996 | 591,000 | 87,000 | 80,000 | 65,000 | 0 | 825,000 | 73,875 | 11,125 | 10,000 | 9,100 | 0 | 104,100 |
| 1997 | 541,000 | 80,000 | 72,000 | 60,000 | 0 | 753,000 | 67,625 | 10,000 | 9,000 | 8,400 | 0 | 95,025 |
| 1998 | 498,000 | 72,000 | 65,000 | 55,000 | 0 | 690,000 | 62,250 | 9,000 | 8,175 | 7,700 | 0 | 87,075 |
| 1999 | 458,000 | 65,000 | 58,000 | 50,000 | 0 | 631,000 | 57,250 | 8,125 | 7,250 | 7,000 | 0 | 79,625 |
| 2000 | 421,000 | 58,000 | 52,000 | 45,000 | 0 | 576,000 | 52,625 | 7,250 | 6,500 | 6,300 | 0 | 72,675 |
| 2001 | 387,000 | 52,000 | 47,000 | 40,000 | 0 | 526,000 | 48,375 | 6,500 | 5,875 | 5,600 | 0 | 66,350 |
| 2002 | 357,000 | 47,000 | 42,000 | 20,000 | 0 | 466,000 | 44,625 | 5,875 | 5,250 | 2,800 | 0 | 58,550 |
| 2003 | 328,000 | 42,000 | 38,000 | 10,000 | 0 | 418,000 | 41,000 | 5,250 | 4,750 | 1,400 | 0 | 52,400 |
| 2004 | 302,000 | 38,000 | 34,000 | 0 | 0 | 374,000 | 37,750 | 4,750 | 4,250 | 0 | 0 | 46,750 |
| 2005 | 278,000 | 34,000 | 31,000 | 0 | 0 | 343,000 | 34,750 | 4,250 | 3,875 | 0 | 0 | 42,875 |
| 2006 | 255,000 | 31,000 | 28,000 | 0 | 0 | 314,000 | 31,875 | 3,875 | 3,500 | 0 | 0 | 39,750 |
| 2007 | 235,000 | 28,000 | 25,000 | 0 | 0 | 288,000 | 29,375 | 3,500 | 3,175 | 0 | 0 | 36,000 |
| 2008 | 216,000 | 25,000 | 20,000 | 0 | 0 | 261,000 | 27,000 | 3,125 | 2,500 | 0 | 0 | 32,625 |
| 2009 | 199,000 | 20,000 | 15,000 | 0 | 0 | 234,000 | 24,875 | 2,500 | 1,875 | 0 | 0 | 29,250 |
| 2010 | 183,000 | 15,000 | 10,000 | 0 | 0 | 208,000 | 22,875 | 1,875 | 1,250 | 0 | 0 | 26,000 |
| 2011 | 168,000 | 10,000 | 0 | 0 | 0 | 178,090 | 21,000 | 1,250 | 0 | 0 | 0 | 22,250 |
| 2012 | 155,000 | 0 | 0 | 0 | 0 | 155,900 | 19,375 | 0 | 0 | 0 | 0 | 19,375 |

| | ESTIMATED SALES OF ROYALTY OIL (BARRELS PER DAY) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| YEAR | ARCO | (2) OWEA | (3) TESORO (OLD) | (4) TESORO (NEW) | (5) CHEVRON | (6) COMPETITIVE SALE 12-11-84 | (7) PETRO/CHEVRON (PROPOSED) | (8) COMPETITIVE SALE 2-4-86 (PROPOSED) | ROYALTY IN VALUE |
| 1985 | 35,000 | 5,167 | 47,533 | 26,867 | 10,600 | 65,000 | | | [illegible] |
| 1986 | 35,000 | 5,167 | 47,533 | 26,867 | 10,600 | 65,000 | 6,000 | 10,000 | [illegible] |
| 1987 | 35,000 | 5,167 | 47,533 | 26,867 | 10,600 | | 6,500 | | [illegible] |
| 1988 | 35,000 | 4,507 | 47,197 | 23,851 | 16,317 | | 6,500 | | [illegible] |
| 1989 | 35,000 | 3,943 | 36,270 | 20,506 | 14,196 | | 6,500 | | [illegible] |
| 1990 | 35,000 | 3,393 | 31,210 | 17,646 | 12,216 | | 5,525 | | [illegible] |
| 1991 | 35,000 | 3,093 | 28,150 | 16,006 | 11,136 | | 4,690 | | [illegible] |
| 1992 | 35,000 | 2,820 | 25,944 | 14,669 | 10,152 | | 3,909 | | [illegible] |
| 1993 | 35,000 | 2,573 | 23,674 | 13,382 | 9,264 | | 3,605 | | [illegible] |
| 1994 | 35,000 | 2,353 | 21,650 | 12,738 | 8,472 | | 3,220 | | 63,701 |
| 1995 | 35,000 | | | | | | 2,875 | | 77,[illegible] |
| 1996 | 35,000 | | | | | | 2,630 | | 66,470 |
| 1997 | 35,000 | | | | | | | | 60,025 |
| 1998 | 35,000 | | | | | | | | 52,075 |
| 1999 | 35,000 | | | | | | | | 44,625 |
| 2000 | 35,000 | | | | | | | | 37,675 |
| 2001 | 35,000 | | | | | | | | 31,350 |
| 2002 | 35,000 | | | | | | | | 23,550 |
| 2003 | 35,000 | | | | | | | | 17,400 |
| 2004 | | | | | | | | | 46,750 |
| 2005 | | | | | | | | | 42,875 |
| 2006 | | | | | | | | | 39,750 |
| 2007 | | | | | | | | | 36,000 |
| 2008 | | | | | | | | | 32,625 |
| 2009 | | | | | | | | | 29,250 |
| 2010 | | | | | | | | | 26,000 |
| 2011 | | | | | | | | | 22,250 |
| 2012 | | | | | | | | | |

(1) DNR ESTIMATE OF FIELD PERFORMANCE, DECEMBER 1985.

(2) OWEA'S TEN-YEAR CONTRACT COMMENCED JULY 1, 1985. QUANTITY IS 2.667% OF DAILY PRUDHOE ROYALTY OIL.

(3) TESORO'S CONTRACT IS CURRENTLY AT ITS MAXIMUM QUANTITY OF 24.533% OF DAILY PRUDHOE ROYALTY OIL. THE CONTRACT EXPIRES JANUARY 1995.

(4) ON OCTOBER 1, 1985 TESORO COMMENCED DELIVERIES UNDER 12/9/83 PRUDHOE CONTRACT WHICH HAS A MAXIMUM QUANTITY OF 13.86% OF DAILY PRUDHOE ROYALTY OIL AND EXPIRES JAN. 1, 1995.

(5) CHEV USA'S CONTRACT CALLS FOR A MAXIMUM QUANTITY OF 9.6% OF DAILY PRUDHOE ROYALTY OIL. THE CONTRACT EXPIRES JANUARY 1, 1995.

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(6) DELIVERIES COMMENCED APRIL, 1985 FOR 50,000 BPD OF PRUDHOE BAY UNIT ROYALTY OIL AND 15,000 BPD OF KUPARUK RIVER UNIT ROYALTY OIL, AND WILL CONTINUE FOR ONE YEAR AS A RESULT OF THE DEC. 11, 1984 COMPETITIVE SALE AND THE SUBSEQUENT KUPARUK SOLICITATION. PRIOR TO THAT TIME THIS OIL REMAINED "IN VALUE."

(7) A PROPOSED PETRO STAR/CHEVRON CONTRACT WILL BE SUBMITTED TO THE LEGISLATURE FOR APPROVAL OF A SALE OF 6,500 BPD ROYALTY OIL FROM THE KUPARUK RIVER UNIT. PETRO STAR/CHEVRON INITIALLY WOULD PURCHASE 6,000 BPD. THE CONTRACT IS EXPECTED TO COMMENCE IN LATE 1986 AND EXPIRE SEPTEMBER 30, 1996.

(8) ON FEBRUARY 4, 1986 THE STATE WILL SELL BY COMPETITIVE BID APPROXIMATELY 10,000 BPD FOR A SIX-MONTH TERM COMMENCING JUNE 1, 1986.

(9) Includes only fields in, or planned for production in the near future.