

AK LEGISLATURE SPECIAL COMMITTEE FILES SCOMM 148 32159

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

Presentation two

Last Updated: March 13th, 2007



The Alaska Gasline Inducement Act

Introduction

State value for the \$500M (Part 2)
Evaluation Criteria and Process
Increasing Predictability for Producers
Getting Gas for the Pipeline



The Alaska Gasline Inducement Act

State Value for \$500 million

Presentation 1:

- Project moves forward faster**
- Lower tariffs**
- Expansion Commitments**
- Rolled-in rates**

Presentation 2:

- In-State Use**

State Value for \$500 million



In-State Use

- **5 off-take points**
- **Distance sensitive rates**
- **Expansion provisions**

Distance sensitive rates



The Alaska Gasline Inducement Act

Hypothetical: Gas Off-take in Fairbanks

- Off-take volume to meet heating needs only
 - Main pipeline sized at 4.3 BCF/D delivered to Alberta
 - Main pipeline cost \$20.5B
 - Main Pipeline has 70% debt financing at 14% ROE
-

Full Tariff from NS to AK/Canada border = 72¢

Mileage-based rate from NS to Fairbanks = 46¢

Distance sensitive rates



Fairbanks Gas Prices if capacity acquired at initial or subsequent Open Season

With distance sensitive rates:

\$5.50 Alberta Gas price
minus \$2.14 pipeline (Alaskan + Canadian) and GTP costs
= \$3.36 North Slope netback value
+ 49¢ GTP fee
+ 47¢ tariff to Fairbanks
= \$4.32 Fairbanks price

Without distance sensitive rates:

\$3.35 North Slope netback value
+ 49¢ GTP fee
+ 72¢ tariff to Fairbanks
= \$4.62 Fairbanks price

Distance sensitive rates



The Alaska Gasline Inducement Act

Fairbanks Gas Prices if no capacity available through expansion

If in-state entities are not ready to subscribe for capacity in the initial open season, and if there are no expansions, then benefits of distance sensitive rates are not enjoyed.

Illustration:

\$5.50 Alberta Gas price
- \$2.14 pipeline and GTP costs
= \$3.36 North Slope netback value
+ \$2.14 pipeline and GTP costs
= \$5.50 Fairbanks gas price

Evaluation Criteria



Value to State:

- Timing
- Cost overrun mitigation
- Favorable tariffs
- Initial capacity and expansion
- State match after open season

Likelihood of Success:

- Feasibility of work plan and budget
- Financial strength
- Technical expertise
- Track Record

Evaluation Process



- 1) Applications made public**
- 2) Public review and comment - 60 days**
- 3) Commissioners select licensee and make findings.**
- 4) Legislative review, opportunity to disapprove**
 - Review of published applications**
 - Review of Commissioners' finding- 30 days₉**

Increasing Predictability for Producers

1. Royalty predictability

- **“Higher-of” Provision**
- **RIV vs. RIK**

2. Production tax exemption

- **Description of tax exemption structure**
- **Constitutionality**

Increasing Predictability for Producers



Royalty Predictability

- **Minimize retroactive adjustments**
- **Use public price indices**
- **RIK/RIV switching**

Increasing Predictability for Producers



Production tax predictability

- **Tax Exemption = gas production tax obligation (current year) minus gas production tax obligation (open season year)**
- **Available only on gas shipped in capacity acquired in first binding open season**
- **Available first ten years of gas flow**

**Increasing Predictability
for Producers**



Production tax exemption

Constitutionality

Increasing Predictability for Producers



Constitution of Alaska

Article 9 - Finance and Taxation

§ 1. Taxing Power

The power of taxation shall never be surrendered. This power shall not be suspended or contracted away, except as provided in this article.

Increasing Predictability for Producers



Constitution of Alaska

Article 9 - § 4. Exemptions

The real and personal property of the State or its political subdivisions shall be exempt from taxation [P]roperty used exclusively for non-profit religious, charitable, cemetery, or educational purposes, ... shall be exempt from taxation. Other exemptions of like or different kind may be granted by general law. All valid existing exemptions shall be retained until otherwise provided by law.

Getting Gas for the Pipeline

- How Much is Needed?
- Prudhoe Bay
 - AOGCC off-take study
- Point Thomson
- New exploration

(c) Contents of notice. Notice of the open season required in paragraph (a) of this section, shall contain at least the following information; however, to the extent that any item of such information is not known or determined at the time the notice is issued, the prospective applicant shall make a good faith estimate based on the best information available of all such unknown or undetermined items of required information and further, must identify the source of information relied on, explain why such information is not presently known, and update the information when and if it is later determined during the open season period:

(8) Based on the In-State Study and the delivery points within the State of Alaska identified in paragraph (c)(1) of this section, there must be an estimated transportation rate for such deliveries, based on the amount of in-state needs shown in the study. Such estimated transportation rate must be based on the costs to make such in-state deliveries and shall not include costs to make deliveries outside the State of Alaska;

Code of Federal Regulations Currentness

Title 18. Conservation of Power and Water Resources

Chapter I. Federal Energy Regulatory Commission, Department of Energy

Subchapter E. Regulations Under Natural Gas Act

Part 157. Applications for Certificates of Public Convenience and Necessity and for Orders Permitting and Approving Abandonment Under Section 7 of the Natural Gas Act (Refs & Annos)**Subpart B.** Open Seasons for Alaska Natural Gas Transportation Projects (Refs & Annos)**§ 157.30 Purpose.**

This subpart establishes the procedures for conducting open seasons for the purpose of making binding commitments for the acquisition of initial or voluntary expansion capacity on Alaska natural gas transportation projects, as defined herein.

§ 157.31 Definitions.

(a) "Alaska natural gas transportation project" means any natural gas pipeline system that carries Alaska natural gas to the international border between Alaska and Canada (including related facilities subject to the jurisdiction of the Commission) that is authorized under the Alaska Natural Gas Transportation Act of 1976 or section 103 of the Alaska Natural Gas Pipeline Act.

(b) "Commission" means the Federal Energy Regulatory Commission.

(c) "Voluntary expansion" means any expansion in capacity of an Alaska natural gas transportation project above the initial certificated capacity, including any increase in mainline capacity, any extension of mainline pipeline facilities, and any lateral pipeline facilities beyond those certificated in the initial certificate order, voluntarily made by the pipeline. An expansion done pursuant to section 105 of the Alaska Natural Gas Pipeline Act is not a vol-

untary expansion.

§ 157.32 Applicability.

These regulations shall apply to any application to the Commission for a certificate of public convenience and necessity or other authorization for an Alaska natural gas transportation project, whether filed pursuant to the Natural Gas Act, the Alaska Natural Gas Transportation Act of 1976, or the Alaska Natural Gas Pipeline Act, and to applications for expansion of such projects. Absent a Commission order to the contrary, these regulations are not applicable in the case of an expansion ordered by the Commission pursuant to section 105 of the Alaska Natural Gas Pipeline Act.

§ 157.33 Requirement for open season.

(a) Any application for a certificate of public convenience and necessity or other authorization for a proposed Alaska natural gas transportation project must include a demonstration that the applicant has conducted an open season for capacity on its proposed project, in accordance with the requirements of this subpart. Failure to provide the requisite demonstration will result in an application being rejected as incomplete.

(b) Initial capacity on a proposed Alaska natural gas transportation project may be acquired prior to an open season through pre-subscription agreements, provided that in any open season as required in paragraph (a) of this section, capacity is offered to all prospective bidders at the same rates and on the same terms and conditions as contained in the pre-subscription agreements. All pre-subscription agreements shall be made public by posting on Internet websites and press releases within ten days of their execution. In the event there is more than one such agreement, all prospective bidders shall be allowed the option of selecting among the several agreements all of the rates, terms and conditions contained in any one such agreement.

§ 157.34 Notice of open season.

(a) Notice. A prospective applicant must provide reasonable public notice of an open season through methods including postings on Internet Web sites, press releases, direct mail solicitations, and other advertising. In addition, a prospective applicant must provide actual notice of an open season to the State of Alaska and to the Federal Coordinator for Alaska Natural Gas Transportation Projects.

(b) In-State Needs Study. A prospective applicant must conduct or adopt a study of gas consumption needs and prospective points of delivery within the State of Alaska and rely upon such study to develop the contents of the notice required in paragraph (a) of this section. Such study shall be identified in the notice and if practicable, shall include or consist of a study conducted, approved, or otherwise sanctioned by an appropriate governmental agency, office or commission of the State of Alaska. In its open season proposal, a prospective applicant shall include an estimate based upon the study, of how much capacity will be used in-state.

(c) Contents of notice. Notice of the open season required in paragraph (a) of this section, shall contain at least the following information; however, to the extent that any item of such information is not known or determined at the time the notice is issued, the prospective applicant shall make a good faith estimate based on the best information available of all such unknown or undetermined items of required information and further, must identify the source of information relied on, explain why such information is not presently known, and update the information when and if it is later determined during the open season period:

(1) The general route of the proposed project, including receipt and delivery points, and any alternative routes under consideration; delivery points must include those within the State of Alaska as determined by the In-State Study in paragraph (b) of this section.

(2) Size and design capacity (including proposed certificate capacity at the delivery points named in paragraph (c)(1) of this section to the extent that it differs from design capacity), a description

of possible designs for expanded capacity beyond initial capacity, together with any estimated date when such expansions designs may be considered;

(3) Maximum allowable operating pressure and expected actual operating pressure;

(4) Delivery pressure at all delivery points named in paragraph (c)(1) of this section;

(5) Projected in-service date;

(6) An estimated unbundled transportation rate for each delivery point named in paragraph (c)(1) of this section, stated on a volumetric or thermal basis, for each service offered, including reservation rates for pipeline capacity, interruptible transportation rates, usage rates, fuel retention percentages, and other applicable charges, or surcharges, such as the Annual Charge Adjustment (ACA); (if rates are estimated on a volumetric basis then the notice must inform bidders that final pro forma service agreements and the sponsor's proposed FERC tariff will have to be submitted with rates based on a thermal basis.)

(7) The estimated cost of service (i.e., estimated cost of facilities, depreciation, rate of return and capitalization, taxes and operational and maintenance expenses), and estimated cost allocations, rate design volumes and rate design;

(8) Based on the In-State Study and the delivery points within the State of Alaska identified in paragraph (c)(1) of this section, there must be an estimated transportation rate for such deliveries, based on the amount of in-state needs shown in the study. Such estimated transportation rate must be based on the costs to make such in-state deliveries and shall not include costs to make deliveries outside the State of Alaska;

(9) Negotiated rate and other rate options under consideration, including any rates and terms of any precedent agreements with prospective anchor shippers that have been negotiated or agreed to outside of the open season process prescribed in this section;

(10) Quality specifications and any other requirements applicable to gas to be delivered to the project; provided that a prospective applicant shall not require that potential shippers process or treat their gas at any designated plant or facility;

(11) Terms and conditions for each service offered;

(12) Creditworthiness standards to be applied to, and any collateral requirements for, prospective shippers;

(13) The date, if any, by which potential shippers and the prospective applicant must execute precedent agreements;

(14) A detailed methodology for determining the value of bids for deliveries within the State of Alaska and for deliveries outside the State of Alaska;

(15) The methodology by which capacity will be awarded, in the case of over-subscription, clearly stating all terms that will be considered, except that if any capacity is acquired through pre-subscription agreements as provided in § 157.33(b) and the prospective applicant does not redesign the project to accommodate all capacity requests, only that capacity that was acquired through pre-subscription or was bid in the open season on the same rates, terms, and conditions as any one of the pre-subscription agreements shall be allocated on a pro rata basis and no other capacity acquired through the open season shall be allocated.

(16) Required bid information, whether bids are binding or non-binding, receipt and delivery point requirements, the form of a precedent agreement and time of execution of the precedent agreement, definition and treatment of non-conforming bids;

(17) The projected date for filing an application with the Commission;

(18) All information that the prospective applic-

ant has in its possession pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, or that the prospective applicant has made available to, or obtained from, any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season;

(19) A list of the names and addresses of the prospective applicant's affiliated sales and marketing units and Energy Affiliates involved in the production of natural gas in the State of Alaska. Affiliated unit means "Affiliate" as applicably defined in § 358.3(b) of this chapter. Energy Affiliate means "Energy Affiliate" as applicably defined in § 358.3(d) of this chapter;

(20) A comprehensive organizational charts showing:

(i) The organizational structure of the prospective applicant's parent corporation(s) with the relative position in the corporate structure of marketing and sales units and any Energy Affiliates involved in the production of natural gas in the State of Alaska.

(ii) The job titles and descriptions, and chain of command for all officers and directors of the prospective applicant's marketing and sales units and any Energy Affiliates involved in the production of natural gas in the State of Alaska; and

(21) A statement that any officers and directors of the of the prospective applicant's affiliated sales and marketing units and Energy Affiliates involved in the production of natural gas in the State of Alaska named in paragraph (c)(19) of this section will be prohibited from obtaining information about the conduct of the open season or allocation of capacity that is not posted on the "open season" Internet website or that is not otherwise also available to the general public or other participants in the open season.

(d) Timing.

(1) A prospective applicant must provide prospective shippers at least 90 days from the date on which notice of the open season is given within which to submit requests for transportation services. No bid shall be rejected because a prospective shipper has submitted another bid in another open season conducted under this subpart.

(2) A prospective applicant must consider any bids tendered after the expiration of the open season by qualifying bidders and may reject them only if they cannot be accommodated due to economic, engineering, design, capacity or operational constraints, or accommodating the request would otherwise adversely impact the timely development of the project, and a detailed explanation must accompany the rejection. Any bids tendered after the expiration of the open season must contain a good faith showing, including a statement of the circumstances which prevented the late bidder from tendering a timely bid and how those circumstances have changed. If a prospective applicant determines at any time that, based on the criteria stated in this paragraph, no further late bids for capacity can be accommodated, it may request Commission approval to summarily reject any further requests.

(3) Within 10 days after precedent agreements have been executed for capacity allocated in the open season, the prospective applicant shall make public on the Internet and through press releases the results of the open season, at least including the name of the prospective shipper, amount of capacity awarded, and term of agreement.

(4) Within 20 days after precedent agreements have been executed for capacity allocated in the open season, the prospective applicant must submit copies of all such precedent agreements to the Commission and copies of any relevant correspondence with bidders for capacity who were not allocated capacity that identifies why such bids were not accepted (all documents identified in this paragraph (d)(4) may be filed under confidential treatment pursuant to § 388.112 of this

chapter if desired.

§ 157.35 Undue discrimination or preference.

(a) All binding open seasons shall be conducted without undue discrimination or preference in the rates, terms or conditions of service and all capacity allocated as a result of any open season shall be awarded without undue discrimination or preference of any kind.

(b) Any complaint filed pursuant to § 385.206 of this chapter alleging non-compliance with any of the requirements of this subpart shall be processed under the Commission's Fast Track Processing procedures contained in § 385.206(h).

(c) Each prospective applicant conducting an open season under this subpart must function independent of the other divisions of the prospective applicant as well as the prospective applicant's Marketing and Energy affiliates as those terms are defined in § 358.3(d) and (k) of the Commission's regulations. In instances in which the prospective applicant is not an entity created specifically to conduct an open season under this subpart, the prospective applicant must create or designate a unit or division to conduct the open season that must function independent of the other divisions of the project applicant as well as the project applicant's Marketing and Energy affiliates as those terms are defined in § 358.3(d) and (k) of the Commission's regulations.

(d) Each project applicant conducting an open season under this subpart that is not otherwise subject to the provisions of part 358 of this chapter must comply with the following sections of that part: Sections 358.4(a)(1) and (3); 358.4(e)(3), (4), (5), and (6); 358.5(a), (b), (c)(3) and (5); and 358.5(d). The exemptions from § 358.4(a)(1) and (3) set forth in § 358.4(a)(4), (5), and (6) of this chapter also apply to each project applicant conducting an open season under this subpart.

§ 157.36 Open seasons for expansions.

Any open season for capacity exceeding the initial capacity of an Alaska natural gas transportation project must provide the opportunity for the trans-

portation of gas other than Prudhoe Bay or Point Thomson production. In considering a proposed voluntary expansion of an Alaska natural gas pipeline project, the Commission will consider the extent to which the expansion will be utilized by shippers other than those who are the initial shippers on the project and, in order to promote competition and open access to the project, may require design changes to ensure that some portion of the expansion capacity be allocated to new shippers willing to sign long-term firm transportation contracts, including shippers seeking to transport natural gas from areas other than Prudhoe Bay and Point Thomson.

§ 157.37 Project design.

In reviewing any application for an Alaska natural gas pipeline project, the Commission will consider the extent to which a proposed project has been designed to accommodate the needs of shippers who have made conforming bids during an open season, as well as the extent to which the project can accommodate low-cost expansion, and may require changes in project design necessary to promote competition and offer a reasonable opportunity for access to the project.

§ 157.38 Pre-approval procedures.

No later than 90 days prior to providing the notice of open season required by § 157.34(a), a prospective applicant must file, for Commission approval, a detailed plan for conducting an open season in conformance with this subpart. The prospective applicant's plan shall include the proposed notice of open season. Upon receipt of a request for such a determination, the Secretary of the Commission shall issue a notice of the request, which will then be published in the Federal Register. The notice shall establish a date on which comments from interested persons are due and a date, which shall be within 60 days of receipt of the prospective applicant's request unless otherwise directed by the Commission, by which the Commission will act on the proposed plan.

§ 157.39 Rate treatment of pipeline expansions.

There shall be a rebuttable presumption that rates for any expansion of an Alaska natural gas transportation

project shall be determined on a rolled-in basis.

Current through February 22, 2007; 72 FR 7933
END OF DOCUMENT

18 C.F.R. § 157.21

C**Effective: November 17, 2005**Code of Federal Regulations Currentness

Title 18. Conservation of Power and Water Resources

Chapter I. Federal Energy Regulatory Commission, Department of Energy

Subchapter E. Regulations Under Natural Gas Act

Part 157. Applications for Certificates of Public Convenience and Necessity and for Orders Permitting and Approving Abandonment Under Section 7 of the Natural Gas Act (Refs & Annos)

Subpart A. Applications for Certificates of Public Convenience and Necessity and for Orders Permitting and Approving Abandonment Under Section 7 of the Natural Gas Act, as Amended, Concerning Any Operation, Sales, Service, Construction, Extension, Acquisition or Abandonment

→ § 157.21 Pre-filing procedures and review process for LNG terminal facilities and other natural gas facilities prior to filing of applications.

(a) LNG terminal facilities and related jurisdictional natural gas facilities. A prospective applicant for authorization to site, construct and operate facilities included within the definition of "LNG terminal," as defined in § 153.2(d), and any prospective applicant for related jurisdictional natural gas facilities must comply with this section's pre-filing procedures and review process. These mandatory pre-filing procedures also shall apply when the Director finds in accordance with paragraph (e)(2) of this section that prospective modifications to an existing LNG terminal are modifications that involve significant state and local safety considerations that have not been previously addressed. Examples of such modifications include, but are not limited to, the addition of LNG storage tanks; increasing throughput requiring additional tanker arrivals or the use of larger vessels; or

changing the purpose of the facility from peaking to base load. When a prospective applicant is required by this paragraph to comply with this section's pre-filing procedures:

(1) The prospective applicant must make a filing containing the material identified in paragraph (d) of this section and concurrently file a Letter of Intent pursuant to 33 U.S.C. 127.007, and a Preliminary Waterway Suitability Assessment (WSA) with the U.S. Coast Guard (Captain of the Port/Federal Maritime Security Coordinator). The latest information concerning the documents to be filed with the Coast Guard should be requested from the U.S. Coast Guard. For modifications to an existing or approved LNG terminal, this requirement can be satisfied by the prospective applicant's certifying that the U.S. Coast Guard did not require such information.

(2) An application:

(i) Shall not be filed until at least 180 days after the date that the Director issues notice pursuant to paragraph (e) of this section of the commencement of the prospective applicant's pre-filing process; and

(ii) Shall contain all the information specified by the Commission staff after reviewing the draft materials filed by the prospective applicant during the pre-filing process, including required environmental material in accordance with the provisions of part 380 of this chapter, "Regulations Implementing the National Environmental Policy Act."

(3) The prospective applicant must provide sufficient information for the pre-filing review of any pipeline or other natural gas facilities, including facilities not subject to the Commission's Natural Gas Act jurisdiction, which are necessary to transport regassified LNG from the subject LNG terminal facilities to the existing natural gas pipeline infrastructure.

(b) Other natural gas facilities. When a prospective

applicant for authorization for natural gas facilities is not required by paragraph (a) of this section to comply with this section's pre-filing procedures, the prospective applicant may file a request seeking approval to use the pre-filing procedures.

(1) A request to use the pre-filing procedures must contain the material identified in paragraph (d) of this section unless otherwise specified by the Director as a result of the Initial Consultation required pursuant to paragraph (c) of this subsection; and

(2) If a prospective applicant for non-LNG terminal facilities is approved to use this section's pre-filing procedures:

(i) The application will normally not be filed until at least 180 days after the date that the Director issues notice pursuant to paragraph (e)(3) of this section approving the prospective applicant's request to use the pre-filing procedures under this section and commencing the prospective applicant's pre-filing process. However, a prospective applicant approved by the Director pursuant to paragraph (e)(3) of this section to undertake the pre-filing process is not prohibited from filing an application at an earlier date, if necessary; and

(ii) The application shall contain all the information specified by the Commission staff after reviewing the draft materials filed by the prospective applicant during the pre-filing process, including required environmental material in accordance with the provisions of part 380 of this chapter, "Regulations Implementing the National Environmental Policy Act."

(c) Initial consultation. A prospective applicant required or potentially required or requesting to use the pre-filing process must first consult with the Director on the nature of the project, the content of the pre-filing request, and the status of the prospective applicant's progress toward obtaining the information required for the pre-filing request described in paragraph (d) of this section. This consultation will also include discussion of the specifications for the applic-

ant's solicitation for prospective third-party contractors to prepare the environmental documentation for the project, and whether a third-party contractor is likely to be needed for the project.

(d) Contents of the initial filing. A prospective applicant's initial filing pursuant to paragraph (a)(1) of the section for LNG terminal facilities and related jurisdictional natural gas facilities or paragraph (b)(1) of this section for other natural gas facilities shall include the following information:

(1) A description of the schedule desired for the project including the expected application filing date and the desired date for Commission approval.

(2) For LNG terminal facilities, a description of the zoning and availability of the proposed site and marine facility location.

(3) For natural gas facilities other than LNG terminal facilities and related jurisdictional natural gas facilities, an explanation of why the prospective applicant is requesting to use the pre-filing process under this section.

(4) A detailed description of the project, including location maps and plot plans to scale showing all major plant components, that will serve as the initial discussion point for stakeholder review.

(5) A list of the relevant federal and state agencies in the project area with permitting requirements. For LNG terminal facilities, the list shall identify the agency designated by the governor of the state in which the project will be located to consult with the Commission regarding state and local safety considerations. The filing shall include a statement indicating:

(i) That those agencies are aware of the prospective applicant's intention to use the pre-filing process (including contact names and telephone numbers);

(ii) Whether the agencies have agreed to participate in the process;

(iii) How the applicant has accounted for agency schedules for issuance of federal authorizations; and

(iv) When the applicant proposes to file with these agencies for their respective permits or other authorizations.

(6) A list and description of the interest of other persons and organizations who have been contacted about the project (including contact names and telephone numbers).

(7) A description of what work has already been done, e.g., contacting stakeholders, agency consultations, project engineering, route planning, environmental and engineering contractor engagement, environmental surveys/studies, and open houses. This description shall also include the identification of the environmental and engineering firms and sub-contractors under contract to develop the project.

(8) For LNG terminal projects, proposals for at least three prospective third-party contractors from which Commission staff may make a selection to assist in the preparation of the requisite NEPA document.

(9) For natural gas facilities other than LNG terminal facilities and related jurisdictional natural gas facilities, proposals for at least three prospective third-party contractors from which Commission staff may make a selection to assist in the preparation of the requisite NEPA document, or a proposal for the submission of an applicant-prepared draft Environmental Assessment as determined during the initial consultation described in paragraph (c) of this section.

(10) Acknowledgement that a complete Environmental Report and complete application are required at the time of filing.

(11) A description of a Public Participation Plan which identifies specific tools and actions to facilitate stakeholder communications and public information, including a project website and a single point of contact. This plan shall also de-

scribe how the applicant intends to respond to requests for information from federal and state permitting agencies, including, if applicable, the governor's designated agency for consultation regarding state and local safety considerations with respect to LNG facilities.

(12) Certification that a Letter of Intent and a Preliminary WSA have been submitted to the U.S. Coast Guard or, for modifications to an existing or approved LNG terminal, that the U.S. Coast Guard did not require such information.

(e) Director's notices.

(1) When the Director finds that a prospective applicant for authority to site and construct a new LNG terminal has adequately addressed the requirements of paragraphs (a), (c) and (d) of this section, the Director shall issue a notice of such finding. Such notice shall designate the third-party contractor. The pre-filing process shall be deemed to have commenced on the date of the Director's notice, and the date of such notice shall be used in determining whether the date an application is filed is at least 180 days after commencement of the pre-filing process.

(2) When the Director finds that a prospective applicant for authority to make modifications to an existing or approved LNG terminal has adequately addressed the requirements of paragraphs (a), (c) and (d) of this section, the Director shall issue a notice making a determination whether prospective modifications to an existing LNG terminal shall be subject to this section's pre-filing procedures and review process. Such notice shall designate the third-party contractor, if appropriate. If the Director determines that the prospective modifications are significant modifications that involve state and local safety considerations, the Director's notice will state that the pre-filing procedures shall apply, and the pre-filing process shall be deemed to have commenced on the date of the Director's notice in determining whether the date an application is filed is at least 180 days after commencement of the pre-filing process.

(3) When a prospective applicant requests to use this section's pre-filing procedures and review for facilities not potentially subject to this section's mandatory requirements, the Director shall issue a notice approving or disapproving use of the pre-filing procedures of this section and determining whether the prospective applicant has adequately addressed the requirements of paragraphs (b), (c) and (d) of this section. Such notice shall designate the third-party contractor, if appropriate. The pre-filing process shall be deemed to have commenced on the date of the Director's notice, and the date of such notice shall be used in determining whether the date an application is filed is at least 180 days after commencement of the pre-filing process.

(f) Upon the Director's issuance of a notice commencing a prospective applicant's pre-filing process, the prospective applicant must:

(1) Within seven days and after consultation with Commission staff, establish the dates and locations at which the prospective applicant will conduct open houses and meetings with stakeholders (including agencies) and Commission staff.

(2) Within 14 days, conclude the contract with the selected third-party contractor.

(3) Within 14 days, contact all stakeholders not already informed about the project, including all affected landowners as defined in paragraph § 157.6(d)(2) of this section.

(4) Within 30 days, submit a stakeholder mailing list to Commission staff.

(5) Within 30 days, file a draft of Resource Report 1, in accordance with § 380.12(c), and a summary of the alternatives considered or under consideration.

(6) On a monthly basis, file status reports detailing the applicant's project activities including surveys, stakeholder communications, and agency meetings.

(7) Be prepared to provide a description of the

proposed project and to answer questions from the public at the scoping meetings held by OEP staff.

(8) Be prepared to attend site visits and other stakeholder and agency meetings arranged by the Commission staff, as required.

(9) Within 14 days of the end of the scoping comment period, respond to issues raised during scoping.

(10) Within 60 days of the end of the scoping comment period, file draft Resource Reports 1 through 12.

(11) At least 60 days prior to filing an application, file revised draft Resource Reports 1 through 12, if requested by Commission staff.

(12) At least 90 days prior to filing an application, file draft Resource Report 13 (for LNG terminal facilities).

(13) Certify that a Follow-on WSA will be submitted to the U.S. Coast Guard no later than the filing of an application with the Commission (for LNG terminal facilities and modifications thereto, if appropriate). The applicant shall certify that the U.S. Coast Guard has indicated that a Follow-On WSA is not required, if appropriate.

(g) Commission staff and third-party contractor involvement during the pre-filing process will be designed to fit each project and will include some or all of the following:

(1) Assisting the prospective applicant in developing initial information about the proposal and identifying affected parties (including landowners, agencies, and other interested parties).

(2) Issuing an environmental scoping notice and conducting such scoping for the proposal.

(3) Facilitating issue identification and resolution.

(4) Conducting site visits, examining alternatives, meeting with agencies and stakeholders,

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and participating in the prospective applicant's public information meetings.

(5) Reviewing draft Resource Reports.

(6) Initiating the preparation of a preliminary Environmental Assessment or Draft Environmental Impact Statement, the preparation of which may involve cooperating agency review.

(h) A prospective applicant using the pre-filing procedures of this section shall comply with the procedures in § 388.112 for the submission of documents containing critical energy infrastructure information, as defined in § 388.113.

[Order 665, 70 FR 60440, Oct. 18, 2005]

SOURCE: 50 FR 42487, Oct. 18, 1985; 51 FR 9186, March 7, 1986; 51 FR 22218, June 18, 1986; 52 FR 47910, Dec. 17, 1987; 53 FR 4133, Feb. 12, 1988; 53 FR 15028, April 27, 1988; 53 FR 15381, April 29, 1988; 56 FR 50245, Oct. 4, 1991; 57 FR 21893, May 26, 1992; Order 2005-A, 70 FR 35026, June 16, 2005, unless otherwise noted.

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18 C. F. R. § 157.21, 18 CFR § 157.21

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IN THE SUPERIOR COURT FOR THE STATE OF ALASKA
FIRST JUDICIAL DISTRICT AT JUNEAU

STATE OF ALASKA,)
)
Plaintiff,) Civil Action
) No. 77-847
COMMISSIONER OF NATURAL RESOURCES,)
and DIRECTOR OF THE DIVISION OF)
LANDS, STATE OF ALASKA,)
)
Involuntary Plaintiffs,)
)
vs.) SETTLEMENT AGREEMENT
)
AMERADA HESS CORPORATION; ATLANTIC)
RICHFIELD COMPANY; BP ALASKA INC.;)
BP ALASKA EXPLORATION INC.; EXXON)
CORPORATION; GETTY OIL COMPANY;)
HUNT INDUSTRIES; CAROLINE HUNT)
TRUST ESTATE; LAMAR HUNT TRUST)
ESTATE; WILLIAM HERBERT HUNT TRUST)
ESTATE; N. B. HUNT; THE LOUISIANA)
LAND AND EXPLORATION COMPANY;)
MARATHON OIL COMPANY; MOBIL OIL)
CORPORATION; SOHIO PETROLEUM)
COMPANY; CHEVRON U.S.A. INC.;)
PLACID OIL COMPANY; and PHILLIPS)
PETROLEUM COMPANY,)
)
Defendants.)

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EXHIBIT A

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1 THIS AGREEMENT, dated April 1, 1980, for reference
2 purposes only, entered into by and among the STATE OF ALASKA,
3 acting by and through its Attorney General under the authority
4 conferred by AS 44.23.020, AS 09.50.300, AS 22.20.050(a) and
5 common law, the COMMISSIONER OF NATURAL RESOURCES, STATE OF ALASKA
6 (the "Commissioner") and the DIRECTOR OF THE DIVISION OF LANDS,
7 STATE OF ALASKA (the "Director") (the foregoing parties being
8 hereinafter collectively referred to as the "State" except where
9 otherwise indicated), and each of the following defendants in
10 the above-entitled action:

11
12 AMERADA HESS CORPORATION,

13
14 ATLANTIC RICHFIELD COMPANY,

15
16 BP ALASKA INC.,

17
18 BP ALASKA EXPLORATION INC.,

19
20 EXXON CORPORATION,

21
22 GETTY OIL COMPANY,

23
24 HUNT INDUSTRIES,

25
26 CAROLINE HUNT TRUST ESTATE,

27
28 LAMAR HUNT TRUST ESTATE,

29
30 WILLIAM HERBERT HUNT TRUST ESTATE,

31
32 N. B. HUNT,

1 THE LOUISIANA LAND AND EXPLORATION COMPANY,

2
3 MARATHON OIL COMPANY,

4
5 MOBIL OIL CORPORATION,

6
7 SOHIO ALASKA PETROLEUM COMPANY, formerly known as
8 Sohio Petroleum Company,

9
10 CHEVRON U.S.A. INC.,

11
12 PLACID OIL COMPANY,

13
14 and

15
16 PHILLIPS PETROLEUM COMPANY

17
18 (said defendants being hereinafter referred to as the "Lessees"
19 except where otherwise indicated),

20
21 W I T N E S S E T H

22
23 THAT, WHEREAS, the Lessees are the present holders of
24 certain oil and gas leases (said leases being hereinafter referred
25 to as the "Leases") issued by the State covering those certain
26 lands, in the vicinity of Prudhoe Bay, more particularly described
27 in Exhibit A to the Prudhoe Bay Unit Agreement (said agreement,
28 as amended from time to time, being hereinafter referred to as
29 the "Unit Agreement"); and

1 WHEREAS, the Lessees entered into the Unit Agreement
2 effective as of April 1, 1977, with the agreement and approval
3 of the State; and
4

5 WHEREAS, several disputes have arisen between the State
6 and the Lessees concerning their respective rights and duties
7 under the provisions of AS 38.05.180(a), AS 31.05.110, the Leases
8 and the Unit Agreement; and
9

10 WHEREAS, the State, on September 2, 1977, commenced the
11 above-captioned action in the Superior Court for the State of
12 Alaska, First Judicial District at Juneau (hereinafter, the
13 "Court"), seeking a judgment declaring the rights and duties
14 of the parties with respect to "in value" royalty payments to
15 the State on oil produced from lands governed by the Unit Agree-
16 ment; and
17

18 WHEREAS, the Lessees, on October 13, 1977, answered
19 the State's complaint and filed a counterclaim seeking a judg-
20 ment declaring the rights and duties of the parties with respect
21 to both "in value" and "in kind" royalty payments to the State
22 on both oil and gas produced from lands governed by the Unit
23 Agreement; and
24

25 WHEREAS, the State and the Lessees, recognizing that
26 there is substantial doubt as to the ultimate outcome of this
27 litigation, and considering the many difficulties and delays
28 inherent in this highly complex litigation, agree that the continu-
29 ing economic uncertainty, great expense and other detriment to
30 all parties which would result from the prolongation of this
31 litigation are undesirable; and
32

1 WHEREAS, the State and each of the Lessees have there-
2 fore concluded that a settlement of this litigation in the manner
3 and upon the terms and conditions hereinafter set forth is in
4 the best interests of all parties; and

5
6 WHEREAS, the Commissioner has determined that the settle-
7 ment of this litigation upon the terms and conditions set forth
8 in this Agreement is necessary and proper to secure the proper
9 protection of the public interest by, among other things, facili-
10 tating the exercise by the State of its option under the Leases
11 and under the Unit Agreement to take its royalty "in kind."

12
13 NOW, THEREFORE, in consideration of the foregoing and
14 in consideration of the various covenants hereinafter contained,
15 the State and each of the Lessees agree and covenant as follows:

16
17 ARTICLE 1: DEFINITIONS

18
19 As used in this Agreement:

20
21 1.1 Previously Defined Terms. Each of the terms "Commis-
22 sioner," "Director," "State," "Lessees," "Leases," "Unit Agreement"
23 and "Court" shall have the meaning given to it on the preceding
24 pages.

25
26 1.2 Effective Date shall have the meaning given to
27 it in Section 5.2.

28
29 1.3 Field Cost Allowance shall mean:

30
31 (a) with respect to Royalty Oil, the amount per barrel
32 thereof determined in accordance with Section 2.6.

1 (b) with respect to Royalty Gas, the amount per MCF
2 thereof determined in accordance with Section 3.7.

3
4 1.4 Interim PPI for a particular year shall have the
5 meaning given to it in Section 1.5.

6
7 1.5 PPI for a particular calendar month shall mean the
8 Producer Price Index for Industrial Commodities (or its successor
9 index) for said month as determined and reported by the U.S.
10 Department of Labor, or by such other agency of the United States
11 government as may, from time to time, determine and report such
12 index if the U.S. Department of Labor ceases to do so. If the
13 method by which the PPI is determined or the base thereof is
14 changed, the successor index or base shall, to the extent prac-
15 ticable, be correlated with the previously applicable index or
16 base so that the amounts determined by the formulae hereinafter
17 set forth shall not be changed by reason of the substitution of
18 such successor index or base. References herein to the PPI for
19 a particular year shall mean the PPI for the month of December of
20 that year. Unless otherwise specified, all calculations hereunder
21 which require use of the PPI shall be made using the PPI as finally
22 determined and reported; provided, however, that if the PPI for a
23 particular year has not been finally determined and reported prior
24 to the date on which a particular calculation pursuant to Subsection
25 2.6.2, Subsection 3.7.2, or Subsection 3.8.3 must be made, then
26 such calculation shall be made, and the amounts of all payments
27 or deductions based on such calculation shall be determined, using
28 the PPI for said year as then most recently determined and reported
29 (such index being hereinafter referred to as the "Interim PPI" for
30 said year), subject, however, to the provisions of Sections 2.7
31 and 3.14. The parties agree that the Producer Price Index for
32 Industrial Commodities (1967 = 100.0 base) for June 1977 is 194.7.

1.6 RIK Gas shall mean any Royalty Gas taken by the State "in kind."

1.7 RIK Oil shall mean any Royalty Oil taken by the State "in kind."

1.8 RIV Gas shall mean any Royalty Gas for which the State is to be compensated "in value."

1.9 RIV Oil shall mean any Royalty Oil for which the State is to be compensated "in value."

1.10 Royalty Gas shall mean any gas, other than gas which is conditioned in the Field Fuel Gas Unit (a part of Shared Group 19, as defined in Exhibit 32A of the Prudhoe Bay Unit Operating Agreement), included in the State's royalty share of gas produced from the Unit Area, regardless of the condition or form (e.g., wet gas, sales quality residue gas, gas plant liquids, et cetera) in which said gas may exist at the point of taking, in the case of RIK Gas, or at the Intermediate Valuation Point (as defined in Subsection 3.2.15), in the case of RIV Gas.

1.11 Royalty Oil shall mean any oil included in the State's royalty share of oil produced from the Unit Area, regardless of the condition or form in which said oil may exist at the point of taking, in the case of RIK Oil, or at the LACT Meter (as defined in Subsection 2.2.2), in the case of RIV Oil.

1.12 TAPS shall mean the Trans Alaska Pipeline System.

1.13 Unit Area shall mean the land described by Tracts in Exhibit A to the Unit Agreement and shown on Exhibit B to the

Unit Agreement as of the Effective Date of this Agreement and, in addition, all other land to which the Unit Agreement may hereafter be extended as therein provided (it being expressly understood and agreed that the term "Unit Area" shall encompass, at any particular time, all land as to which the Unit Agreement has previously become effective, regardless of whether the Unit Agreement then remains effective as to such land).

1.14 Upstream Cost Allowance shall mean the amount per MCF of Royalty Gas determined in accordance with Section 3.6.

1.15 Year Of Production shall mean, with respect to particular oil or gas, the calendar year during which the volume of said oil or gas is measured for royalty purposes.

ARTICLE 2: SETTLEMENT OF OIL ROYALTY ISSUES

2.1 Scope. The provisions of this Article are applicable to all royalties accruing to the State on oil produced from the Unit Area on or after June 20, 1977, the date of first production into TAPS.

2.2 Definitions. As used in this Article and Article 4:

2.2.1 Field Costs shall mean, with respect to particular Royalty Oil, any and all costs (including, without limiting the generality of the foregoing, gathering, separation, cleaning, dehydration and other field handling costs) incurred by the Lessees with respect to such oil upstream of the LACT Meter for such oil, other than costs (including, but not limited to, chilling costs) incurred by the Lessees with respect to such oil downstream of a Separation Facility

(as defined in the Prudhoe Bay Unit Operating Agreement)
in order to blend with such oil any liquid hydrocarbons
extracted from gas for the purpose of transporting said
gas liquids off the North Slope of Alaska with said oil
(the latter type of costs being hereinafter referred to
as "Oil-NGL Blending Costs").

2.2.2 LACT Meter shall mean, with respect to particular oil, the particular meter at which the volume of said oil is initially measured for royalty purposes. (At the date of this Agreement, with respect to all oil other than that taken by a Lessee at the Arco/Exxon Prudhoe Bay Crude Oil Topping Plant, "LACT Meter" means the custody transfer meters into TAPS.)

2.2.3 LACT Meter Value shall mean, with respect to particular Royalty Oil, the value of said oil at the LACT meters into TAPS. With respect to particular Royalty Oil measured for royalty purposes at a LACT Meter other than a LACT meter into TAPS, LACT Meter Value shall mean the value at the LACT meters into TAPS of oil of like grade and gravity (e.g., with respect to Royalty Oil taken by a Lessee at the Arco/Exxon Prudhoe Bay Crude Oil Topping Plant, the value at the LACT meters into TAPS of oil of the same grade and gravity as oil at the inlet LACT meter to said plant).

2.3 Settled RIK Oil Taking Issue. As used herein, the term "Settled RIK Oil Taking Issue" shall mean the issue of where and in what condition the Lessees are obligated to deliver RIK Oil to the State. In full and final settlement of the respective claims and contentions of the State and each of the Lessees with

respect to the Settled RIK Oil Taking Issue, the State and each
of the Lessees agree that all RIK Oil taken as royalty from a
particular Lessee at a particular time shall be delivered to the
State at the custody transfer meters into TAPS in the same condition
as oil generally available for taking or other disposition by said
Lessee at said point at the time at which said RIK Oil is taken
by the State.

2.4 Settled Upstream RIK Oil Issue. As used herein,
the term "Settled Upstream RIK Oil Issue" shall mean the issue
of whether, with respect to RIK Oil taken by the State as royalty
from a particular Lessee, the State is liable to each Lessee for
reimbursement of all or any portion of the Field Costs incurred
by said Lessee with respect to said oil. In full and final settle-
ment of the respective claims and contentions of the State and
each of the Lessees with respect to the Settled Upstream RIK Oil
Issue, the State and each of the Lessees agree that with respect
to each barrel of RIK Oil taken as royalty from a particular Les-
see the State shall be liable to that Lessee for an amount equal
to the Field Cost Allowance with respect to said oil, determined
in accordance with Section 2.6.

2.5 Settled Upstream RIV Oil Issue. As used herein,
the term "Settled Upstream RIV Oil Issue" shall mean the issue
of whether, in computing the value of Royalty Oil for the purpose
of making royalty payments "in value" on oil produced from the
Unit Area, each Lessee may deduct from the LACT Meter Value of
said oil all or any portion of the Field Costs incurred by said
Lessee with respect to said oil. In full and final settlement
of the respective claims and contentions of the State and each
of the Lessees with respect to the Settled Upstream RIV Oil Issue,
the State and each of the Lessees agree that, in computing the

value for royalty purposes of each barrel of RIV Oil for which
a particular Lessee makes settlement; said Lessee may deduct
from the LACT Meter Value of said oil an amount equal to the
Field Cost Allowance with respect to said oil, determined in
accordance with Section 2.6.

2.6 Field Cost Allowance for Royalty Oil. Each Lessee
shall be entitled to a Field Cost Allowance with respect to Royalty
Oil, determined as follows:

2.6.1 Pre-1980. With respect to Royalty Oil measured
for royalty purposes on or before December 31, 1979, the
Field Cost Allowance shall be 42 cents per barrel.

2.6.2 Thereafter. With respect to Royalty Oil measured
for royalty purposes on or after January 1, 1980, the Field
Cost Allowance shall be the amount determined by using the
following formula:

Field Cost Allowance = 42 cents x $\frac{\text{PPI for the year prior to the Year Of Production}}{\text{PPI for June 1977.}}$
per barrel

2.7 Payment of PPI Adjustment Differential. If, in
accordance with Section 1.5, the Field Cost Allowance for particular
Royalty Oil is calculated using the Interim PPI for the year
prior to the Year Of Production for said oil and, as a result,
any Lessee:

(i) receives an amount pursuant to Section 2.4 with respect
to said oil, if said oil is RIK Oil, or

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(ii) deducts an amount pursuant to Section 2.5 with respect to said oil, if said oil is RIV Oil

(such amount so received, if RIK Oil, or deducted, if RIV Oil, being referred to in this Section as the "Interim Amount" for said oil), which amount is greater than or less than the amount that would have been so received or deducted by said Lessee with respect to said oil had said allowance been calculated using the PPI for said year as finally determined and reported (such amount calculated using said finally determined PPI being referred to in this Section as the "Redetermined Amount" for said oil), then:

(a) Refund to State. If the Interim Amount received or deducted with respect to said oil is greater than the Redetermined Amount for said oil, said Lessee shall pay to the State, within sixty days after the PPI for said year is finally determined and reported, an amount equal to the difference between said Interim Amount and said Redetermined Amount.

(b) Payment of Balance Due Lessee. If the Interim Amount deducted or received with respect to said oil is less than the Redetermined Amount for said oil, the State shall pay to said Lessee an amount equal to the difference between said Redetermined Amount and said Interim Amount. Such payment shall be made promptly (within sixty days, if possible) after receipt by the State of said Lessee's invoice therefor.

2.8 Payment of Pre-Effective Date Oil Royalties Differential. To the extent that any Lessee, prior to the Effective Date, has taken a greater or lesser deduction in computing

the value of particular RIV Oil, or has received a greater or
1 lesser amount as compensation for Field Costs incurred with respect
2 to particular RIX Oil, than the Field Cost Allowance for such
3 oil determined in accordance with Section 2.6, such Lessee, in
4 the case of a greater deduction or amount, or the State, in the
5 case of a lesser deduction or amount, shall pay the difference
6 to the party entitled thereto, together with interest thereon,
7 computed with respect to said oil from the last day of the calendar
8 month following the calendar month during which said oil was
9 measured for royalty purposes until the date said difference
10 is paid, at the rate of eight percent (8%) per annum (which the
11 parties agree is the legal rate of prejudgment and post-judgment
12 interest to which the prevailing party would have been entitled
13 had the above entitled action been litigated to its conclusion).
14 Each Lessee from whom the State is entitled to receive payment
15 pursuant to this Section shall pay such sum to the State within
16 sixty days after the Effective Date, such payment to be made
17 by wire transfer if in excess of \$50,000. Any obligation of
18 the State to make payment to any Lessee pursuant to this Section
19 shall be satisfied by offsetting the amount owed to said Lessee
20 by the State against amounts then or thereafter due from said
21 Lessee to the State as royalty on RIV Oil; provided, however,
22 that any amount not so offset within six months after the Ef-
23 fective Date shall be paid to said Lessee by the State promptly
24 (within thirty days, if possible) after receipt by the State
25 of an invoice therefor.

26 27 ARTICLE 3: SETTLEMENT OF GAS ROYALTY ISSUES

28
29 3.1 Scope. The provisions of this Article are appli-
30 able to all royalties accruing to the State on gas produced from
31 the Unit Area and measured for royalty purposes after Major Gas
32

1 sale other than royalties, if any, on gas which is conditioned
2 in the Field Fuel Gas Unit (a part of Shared Group 19, as defined
3 in Exhibit 32A of the Unit Operating Agreement).

4 3.2 Definitions. As used in this Article, Article 4
5 and in the Exhibits to this Agreement:

6
7 3.2.1 Affiliate of a particular Lessee shall mean any
8 company that is owned or controlled by that Lessee. For
9 the purpose of this definition, ownership or control of
10 any company exists if fifty percent (50%) or more of the
11 stock of such company that has the right to vote for direc-
12 tors is owned or controlled, directly or indirectly, by the
13 particular Lessee. The stock owned or controlled by a Lessee
14 shall be deemed to include all stock owned or controlled,
15 directly or indirectly, by any other company that is owned
16 or controlled by that Lessee. Affiliate of a particular
17 Lessee also includes any parent company that owns or controls,
18 directly or indirectly, fifty percent (50%) or more of the
19 stock having the right to vote for directors of such Lessee,
20 and any company of which said parent company owns or controls,
21 directly or indirectly, more than fifty percent (50%) of
22 the stock having the right to vote for directors of such
23 company.

24
25 3.2.2 Base Amount shall mean, with respect to a particular
26 Gas Conditioning Plant, the amount per MCF of Royalty Gas
27 determined in accordance with Subsection 3.8.2 for said plant.

28
29 3.2.3 Base Period shall mean, with respect to a particular
30 Gas Conditioning Plant, the calendar year following the
31 Initial Period for said plant.
32

1 3.2.4 Calculated Conditioning Cost shall mean, with
2 respect to a particular Gas Conditioning Plant and particu-
3 lar Royalty Gas, the amount per MCF of said gas determined
4 in accordance with Section 3.8 for said plant and gas.

5 3.2.5 Conditioning (or "to Condition," "to cause to
6 be Conditioned," et cetera) shall refer to the conditioning
7 or treating of gas to meet sales gas specifications of a
8 major gas pipeline for transportation off the North Slope
9 of Alaska, the disposal of byproducts of such conditioning.
10 or treating, and any transportation of conditioned gas to
11 said pipeline. Conditioning shall include, without limiting
12 the generality of the foregoing, hydrocarbon dewpoint control,
13 NGL fractionation, water dewpoint control, CO₂ removal,
14 compression and chilling; but shall include neither (i)
15 any conditioning or treating which occurs in a Separation
16 Facility (as defined in the Unit Operating Agreement), nor
17 (ii) the blending, with oil, of liquid hydrocarbons extracted
18 from gas for the purpose of transporting said gas liquids
19 off the North Slope of Alaska with such oil. If part, but
20 not all, of the process of Conditioning occurs in a particular
21 Gas Conditioning Plant, the term "Conditioning," with respect
22 to that plant, refers to the portion of the entire Conditioning
23 process that occurs in said plant (including the disposal
24 of byproducts therefrom, whether or not such disposal occurs
25 in said plant).

26
27 3.2.6 Divided Plant shall have the meaning given to
28 it in Subsection 3.9.1.

29
30 3.2.7 Downstream Conditioning Allowance shall mean,
31 with respect to a particular Lessee, Gas Conditioning Plant
32

1 and calendar month, the amount per MCF of Royalty Gas deter-
2 mined in accordance with Subsection 3.11.2 for said Lessee,
3 plant and month.

4 3.2.8 Effective Rate Of Interest for a specified calendar
5 month shall mean a monthly rate of interest equal to one
6 hundred twenty-five percent (125%) of one-twelfth of the
7 Citibank, N.A. (or its successors) annual base interest rate
8 in effect for substantial, responsible commercial borrowers
9 (commonly referred to as the "prime rate") on the first
10 day of such month. Effective Rate Of Interest for a period
11 longer than one month shall mean the product of (i) the
12 arithmetic average of the Effective Rate Of Interest for
13 each calendar month occurring during said period, multiplied
14 by (ii) the number of calendar months in said period.
15

16 3.2.9 Field Costs shall mean, with respect to partic-
17 ular Royalty Gas, any and all costs (including, without
18 limiting the generality of the foregoing, gathering, separa-
19 tion, cleaning, dehydration, compression and other field
20 handling costs) incurred by the Lessees with respect to
21 such gas upstream of the Intermediate Valuation Point for
22 such gas, in the case of RIV Gas, and upstream of the point
23 of taking, in the case of RIK Gas, other than (i) costs
24 incurred by the Lessees in Conditioning such gas, and (ii)
25 costs incurred by the Lessees with respect to such gas in
26 an extraction plant, the primary purpose of which is to
27 extract liquid hydrocarbons from gas that is injected back
28 into any formation underlying the Unit Area (such costs
29 incurred in such a plant being hereinafter referred to as
30 "Cycling Plant Costs").
31
32

1 3.2.10 Gas Conditioning Plant shall mean an assemblage
2 of facilities, located in or near the Unit Area and owned in
3 common by one or more persons, which facilities are designed
4 or used (i) to Condition gas produced from the Unit Area, or
5 (ii) to support, directly or indirectly, the construction or
6 operations of facilities designed or used to Condition such
7 gas; provided, however, that in the case of a Unit Plant,
8 the term "Gas Conditioning Plant" shall not include Support
9 Facilities. If any gas produced from the Unit Area is Condi-
10 tioned in one such assemblage prior to further Conditioning
11 in another such assemblage, then each such assemblage shall
12 be deemed to be a separate Gas Conditioning Plant. If Support
13 Facilities are used in connection with the construction or
14 operation of a Unit Plant, a portion of the costs attributable
15 to such Support Facilities shall be included in computing
16 certain costs with respect to said Gas Conditioning Plant,
17 as more particularly provided in Subsection 3.2.24. For
18 purposes of illustration only, a functional description of
19 one possible design for a Gas Conditioning Plant is contained
20 in Exhibit A. A Gas Conditioning Plant may ultimately be
21 constructed which differs from that described in Exhibit A.
22

23 3.2.11 Heating Value of particular gas shall mean
24 the gross number of BTU's per standard cubic foot of said
25 gas at a pressure of 14.65 psia and a temperature of 60°
26 Fahrenheit.
27

28 3.2.12 Initial Amount shall mean, with respect to
29 a particular Gas Conditioning Plant, the amount per MCF
30 of Royalty Gas determined in accordance with Subsection
31 3.8.1.
32

1 3.2.13 Initial Period, except as provided in Subsection
2 3.8.4, shall mean, with respect to a particular Gas Condition-
3 ing Plant, the period beginning at 12:01 A.M. on the first day
4 of the calendar month following the calendar month during
5 which Major Gas Sale occurs and ending at the end of the
6 calendar year following the calendar year during which Major
7 Gas Sale occurs. For example, if Major Gas Sale occurs
8 on January 15, 1985, the term "Initial Period" (except as
9 provided in Subsection 3.8.4) shall mean the period beginning
10 on February 1, 1985, and ending on December 31, 1986.

11
12 3.2.14 Interest During Construction shall mean, with
13 respect to a particular Gas Conditioning Plant, the cumula-
14 tive total of all Construction Interest calculations for said
15 plant. "Construction Interest" for each Gas Conditioning
16 Plant shall be calculated for each calendar month starting
17 with the month during which the Federal Energy Regulatory
18 Commission issues a final certificate of public convenience
19 and necessity with respect to a major gas pipeline for trans-
20 porting gas off the North Slope of Alaska (or, if no such
21 certificate is required, starting with the month during
22 which the final permit, certificate or approval necessary
23 to begin construction of such a pipeline is obtained) and
24 ending with the month during which Major Gas Sale occurs.
25 "Construction Interest" for a particular Gas Conditioning
26 Plant shall be determined by multiplying the Relevant Sum
27 for said plant for a particular calendar month by the Effective
28 Rate Of Interest for that month. The "Relevant Sum" for a
29 particular Gas Conditioning Plant for a particular calendar
30 month shall be the cumulative total amount of Investments
31 for said plant (excluding expenditures attributable to Support
32 Facilities) paid and recorded or approved for payment through

1 the last day of that month, plus the cumulative total of
2 all previous Construction Interest calculations for said
3 plant.
4

5 3.2.15 Intermediate Valuation Point shall mean:
6

7 (a) with respect to RIV Gas delivered for Conditioning
8 to a Unit Plant, the outlet of said plant.
9

10 (b) with respect to RIV Gas delivered for Condition-
11 ing to a Non-Unit Plant (other than RIV Gas described in
12 Paragraph 3.2.15(a)), the inlet of said plant. If particular
13 RIV Gas produced from the Unit Area is first Conditioned
14 in a Non-Unit Plant prior to further Conditioning in another
15 Non-Unit Plant, the Intermediate Valuation Point for such
16 gas shall be the inlet of the first such Non-Unit Plant.
17

18 (c) with respect to RIV Gas never delivered to a Gas
19 Conditioning Plant for Conditioning, the meter at which
20 the volume of said gas is measured for royalty purposes.
21

22 3.2.16 Intermediate Value shall mean, with respect
23 to particular Royalty Gas, the value of said gas at the
24 Intermediate Valuation Point for said gas.
25

26 3.2.17 Investments shall mean, with respect to a par-
27 ticular Gas Conditioning Plant, the total of all costs, in
28 dollars actually spent (not escalated), attributable to the
29 engineering, design, acquisition, construction, transportation,
30 erection, expansion, alteration, start-up, commissioning and
31 replacement (including unreimbursed costs associated with
32 a catastrophic loss) of said Gas Conditioning Plant, minus

1 the salvage value of equipment removed from said plant if
2 the cost of such equipment was previously included in Invest-
3 ments. "Investments" for said plant shall also include a
4 portion of the total of such types of costs, in dollars
5 actually spent (not escalated), incurred with respect to
6 Support Facilities, if any, for said plant, allocated on
7 the basis set forth in Subsection 3.2.24, but shall not
8 include any expenditure made after Major Gas Sale which is
9 attributable to the Conditioning of gas produced from outside
10 the Unit Area. If all or any portion of the facilities
11 presently constituting the Central Injection Plant (a part
12 of Non-Shared Group C, as defined in Exhibit 32B of the
13 Unit Operating Agreement) are used to provide sales boost
14 compression for said Gas Conditioning Plant (and thus con-
15 stitute a part of said Gas Conditioning Plant), but said
16 facilities remain available for the injection of gas back
17 into the Unit Area when not being used for sales boost com-
18 pression, "Investments" for said plant shall include ninety-
19 eight percent (98%) of all of the aforesaid types of costs,
20 in dollars actually spent (not escalated), incurred with
21 respect to those Central Injection Plant facilities capable
22 of being used both for sales boost compression and for gas
23 injection.

24
25 3.2.18 Major Gas Sale shall mean 12:01 A.M. on the
26 day on which the first delivery of gas produced from the
27 Unit Area is made to a major gas pipeline for transportation
28 off the North Slope of Alaska for any purpose other than,
29 or in addition to, use or consumption as fuel for TAPS.

30
31 3.2.19 Majority Owned Plant shall have the meaning
32 given to it in Subsection 3.9.2.

1 3.2.20 Minority Owned Plant shall have the meaning
2 given to it in Subsection 3.9.3.

3
4 3.2.21 Non-Unit Plant shall mean a Gas Conditioning
5 Plant that is not Unit Equipment.

6
7 3.2.22 Plant Investment Costs shall mean, with respect
8 to a particular Gas Conditioning Plant, the sum of Investments
9 for said plant plus Interest During Construction for said
10 plant.

11
12 3.2.23 Regulated Plant shall have the meaning given
13 to it in Subsection 3.9.4.

14
15 3.2.24 Support Facilities shall mean those items of
16 Unit Equipment which are used both (i) to support (whether
17 directly or indirectly) the construction or operations of
18 a Unit Plant and (ii) to support other Unit Operations;
19 provided, however, that Support Facilities shall not include
20 such portion, if any, of those facilities presently consti-
21 tuting the Central Injection Plant (a part of Non-Shared
22 Group C, as defined in Exhibit 32B of the Unit Operating
23 Agreement) as are used to provide sales boost compression
24 for said Gas Conditioning Plant. Support Facilities may
25 include, but are not limited to, facilities of the types
26 listed in Exhibit B. Except as otherwise expressly provided
27 in this Agreement, in computing Investments, Plant O&M Costs
28 (as defined in Subparagraph 3.8.1(a)(2)) and Ad Valorem
29 Taxes (as defined in Subparagraph 3.8.1(a)(1)) for the purpose
30 of calculating the Calculated Conditioning Cost for said
31 plant, an allocated portion of, respectively, the investment
32 costs, operating and maintenance costs and ad valorem taxes

1 attributable to the Support Facilities, if any, for said
2 plant shall also be included in such computations as though
3 such allocated portion were incurred directly with respect
4 to said plant. The basis for allocating to said plant a
5 portion of such costs attributable to certain types of Support
6 Facilities is shown in Exhibit B. As used in Exhibit B,
7 allocation by "Investment Ratio" shall mean allocation in
8 the same proportion as the ratio of total Plant Investment
9 Costs for said plant (excluding costs attributable to Support
10 Facilities) to total investment costs in the Unit (excluding
11 costs attributable to Support Facilities) at the end of
12 the Initial Period; and allocation by "Percentage Based
13 on Usage" shall mean allocation in the same proportion as
14 the ratio of usage of the particular facility by or in support
15 of said plant to total usage of the facility during the
16 Initial Period. If Support Facilities of a type not shown
17 in Exhibit B are used to support said plant, the investment
18 costs, operating and maintenance costs and ad valorem taxes
19 attributable thereto shall be allocated between said plant
20 and the other facilities supported by such Support Facilities
21 in accordance with generally accepted accounting principles.

22
23 3.2.25 Total Plant Throughput for a particular period
24 shall mean:

25
26 (a) with respect to a particular Unit Plant, the total
27 volume (measured at the outlet of said plant and expressed
28 in MCF) of all tailgate residue gas, and other products and
29 byproducts discharged from said plant during that period
30 minus any portion of said total volume that is Used In Unit
31 Operations.
32

1 (b) with respect to a particular Non-Unit Plant, the
2 total volume (measured at the inlet of said plant and ex-
3 pressed in MCF) of all gas produced from the Unit Area and
4 delivered to said plant during that period (hereinafter,
5 "Delivered Gas") minus the volume determined by multiplying
6 (i) the total volume (measured at the outlet of said plant
7 and expressed in MCF) of any portion of the tailgate residue
8 gas and other products and byproducts yielded from Deli-
9 vered Gas that is Used In Unit Operations (hereinafter,
10 "Returned Gas"), by (ii) the ratio determined by dividing
11 (A) the volume weighted average Heating Value (measured
12 at the outlet of said plant) of Returned Gas, by (B) the
13 volume weighted average Heating Value (measured at the inlet
14 of said plant) of Delivered Gas.
15

16 3.2.26 Unit Equipment shall have the meaning given
17 to it in the Unit Agreement.
18

19 3.2.27 Unit Operating Agreement shall have the meaning
20 given to it in the Unit Agreement.
21

22 3.2.28 Unit Operations shall have the meaning given
23 to it in the Unit Agreement.
24

25 3.2.29 Unit Partial Conditioning Plant shall mean
26 a Unit Plant in which gas produced from the Unit Area is
27 Conditioned prior to further Conditioning in a Non-Unit
28 Plant.
29

30 3.2.30 Unit Plant shall mean a Gas Conditioning Plant
31 that is Unit Equipment.
32

1 3.2.31 Used In Unit Operations shall have the meaning
2 given to it in Subsection 3.15.1.
3

4 3.3 Settled RIK Gas Taking Issue. As used herein, the
5 term "Settled RIK Gas Taking Issue" shall mean the issue of where
6 and in what condition the Lessees are obligated to deliver RIK
7 Gas to the State. In full and final settlement of the respective
8 claims and contentions of the State and each of the Lessees with
9 respect to the Settled RIK Gas Taking Issue, the State and each
10 of the Lessees agree as follows:
11

12 3.3.1 Unit Plant. If there is a Unit Plant, then
13 all RIK Gas shall be taken by the State at the outlet of
14 said plant.
15

16 3.3.2 Non-Unit Plant. If there is a Non-Unit Plant
17 and there is no Unit Plant, then all RIK Gas shall be taken
18 by the State upstream of said Non-Unit Plant at a single
19 point located within the Unit Area and mutually agreed upon
20 by the State and the Lessees.
21

22 3.3.3 No Plant. If there is no Gas Conditioning Plant,
23 then all RIK Gas shall be taken by the State at a single
24 point located within the Unit Area and mutually agreed upon
25 by the State and the Lessees.
26

27 3.3.4 Condition at Point of Taking. All RIK Gas taken
28 as royalty from a particular Lessee at a particular time
29 shall be delivered to the State in the same condition as
30 gas generally available for taking or other disposition
31 by said Lessee at the time and point at which said RIK Gas
32 is taken by the State.

1 3.4 Settled Upstream RIK Gas Issue. As used herein,
2 the term "Settled Upstream RIK Gas Issue" shall mean the issue
3 of whether, with respect to RIK Gas taken by the State as royalty
4 from a particular Lessee, the State is liable to said Lessee
5 for reimbursement of (i) all or any portion of the Field Costs
6 incurred by said Lessee with respect to said gas, and (ii) all
7 or any portion of any Conditioning costs incurred by said Lessee
8 with respect to said gas upstream of the point of taking. In
9 full and final settlement of the respective claims and contentions
10 of the State and each of the Lessees with respect to the Settled
11 Upstream RIK Gas Issue, the State and each of the Lessees agree
12 that, with respect to each MCF of RIK Gas taken as royalty from
13 a particular Lessee, the State shall be liable to that Lessee
14 for an amount equal to the Upstream Cost Allowance with respect
15 to said gas, determined in accordance with Section 3.6.

16
17 3.5 Settled Upstream RIV Gas Issue. As used herein,
18 the term "Settled Upstream RIV Gas Issue" shall mean the issue
19 of whether, in computing the value of Royalty Gas for the purpose
20 of making royalty payments "in value" on gas produced from the
21 Unit Area, each Lessee may deduct from the Intermediate Value
22 of said gas (i) all or any portion of the Field Costs incurred
23 by said Lessee with respect to said gas, and (ii) all or any
24 portion of any Conditioning costs incurred by said Lessee with
25 respect to said gas in a Gas Conditioning Plant located upstream
26 of the Intermediate Valuation Point for said gas. In full and
27 final settlement of the respective claims and contentions of
28 the State and each of the Lessees with respect to the Settled
29 Upstream RIV Gas Issue, the State and each of the Lessees agree
30 that, in computing the value for royalty purposes of each MCF
31 of RIV Gas for which a particular Lessee makes settlement, said
32 Lessee may deduct from the Intermediate Value of said gas an

1 amount equal to the Upstream Cost Allowance with respect to said
2 gas, determined in accordance with Section 3.6.

3
4 3.6 Upstream Cost Allowance. Each Lessee shall be
5 entitled to an Upstream Cost Allowance with respect to Royalty
6 Gas, determined as follows:

7
8 3.6.1 Gas Conditioned by Unit Plant. The Upstream
9 Cost Allowance for Royalty Gas that is discharged from a
10 Unit Plant and measured for royalty purposes during a par-
11 ticular calendar month shall be an amount per MCF (measured
12 at the outlet of said plant) equal to the sum of: (i) the
13 Field Cost Allowance determined for said month in accordance
14 with Section 3.7, plus (ii) the Calculated Conditioning
15 Cost determined for said plant and said gas in accordance
16 with Section 3.8.

17
18 3.6.2 Other Royalty Gas. The Upstream Cost Allowance
19 for Royalty Gas measured for royalty purposes during a parti-
20 cular calendar month, other than Royalty Gas described in
21 Subsection 3.6.1, shall be an amount per MCF (measured at
22 the point of taking in the case of RIK Gas and at the Inter-
23 mediate Valuation Point in the case of RIV Gas) equal to the
24 Field Cost Allowance determined for said month in accordance
25 with Section 3.7, whether or not there is a Unit Plant.

26
27 3.7 Field Cost Allowance. The Field Cost Allowance
28 for Royalty Gas shall be determined as follows:

29
30 3.7.1 Pre-1986. The Field Cost Allowance with respect
31 to Royalty Gas, if any, measured for royalty purposes after
32

Major Gas Sale and on or before December 31, 1985, shall be 15.5 cents per MCF.

3.7.2 Thereafter. The Field Cost Allowance with respect to Royalty Gas measured for royalty purposes after Major Gas Sale and on or after January 1, 1986, shall be the amount per MCF determined by using the following formula:

$$\begin{array}{lcl} \text{Field Cost} & & \text{PPI for the year} \\ \text{Allowance} & = & \text{prior to the Year} \\ \text{per MCF} & = & 15.5 \text{ cents} \quad \times \quad \frac{\text{Of Production}}{\text{PPI for 1984.}} \end{array}$$

3.7.3 Upstream Gas Facilities. A functional description of facilities used to clean, dehydrate and transport gas is contained in Exhibit C.

3.8 Calculated Conditioning Cost. The Calculated Conditioning Cost for a particular Gas Conditioning Plant and particular Royalty Gas shall be determined as follows:

3.8.1 Initial Amount

(a) Formula. With respect to Royalty Gas measured for royalty purposes during a particular calendar month after Major Gas Sale and prior to the end of the calendar month during which the Commissioner is notified of the Base Amount pursuant to Paragraph 3.8.2(b), the Calculated Conditioning Cost shall be the amount per MCF (hereinafter, the "Initial Amount") determined by using the following formula:

$$\begin{array}{lcl} \text{Initial Amount} & & \text{An estimate of} \\ \text{per MCF} & = & \text{the Base Investment} + \text{An estimate} \\ & & \text{Component} \quad \quad \quad \text{of the Base} \\ & & \quad \quad \quad \text{O\&M Component,} \end{array}$$

1 where:

2
3 (1) "Base Investment Component" is the per MCF amount
4 determined by adding:

5
6 (i) "Interest on Plant Investment Costs" (the
7 amount determined by multiplying Plant Investment
8 Costs as of the end of the Initial Period by the
9 Effective Rate Of Interest for the Initial Period);
10 plus

11
12 (ii) "Depreciation" (the amount determined by
13 dividing Plant Investment Costs as of the end
14 of the Initial Period by 300 and then multiplying
15 by the number of months in the Initial Period)
16 (this represents depreciation calculated on a
17 25-year straight line basis); plus

18
19 (iii) "Ad Valorem Taxes" (the amount determined
20 by multiplying one-twelfth of all ad valorem taxes
21 applicable to the Gas Conditioning Plant for the
22 last calendar year of the Initial Period, plus
23 a portion of the total of all ad valorem taxes
24 applicable to all Support Facilities for such
25 calendar year (allocated on the basis set forth
26 in Subsection 3.2.24) by the number of calendar
27 months in the Initial Period);

28
29 and then dividing said sum by Total Plant Throughput
30 for the Initial Period; and
31
32