Findings and Decision of the Director
of the Division of Oil and Gas

Request for Approval of Transportation Allowances
Redoubt Shoal Unit- Oil Production

Under the Delegation of Authority
From the Commissioner of the State of Alaska
Department of Natural Resources

October 16, 2006

I. INTRODUCTION

Forest Oil Inc. (Forest) in 2002 constructed a 3.752 mile, eight inch diameter pipeline to carry unprocessed well fluids from the Osprey Platform to the on-shore Kustatan Production Facility. Forest also constructed a second eight inch diameter pipeline to carry marketable quality oil from the Kustatan Production Facility to the Cook Inlet Pipeline, a distance of 7.717 miles. These pipelines are not regulated by the Regulatory Commission of Alaska (RCA) or the Federal Energy Regulatory Commission (FERC). Production from the Osprey Platform started in December 2002. In July 2003, Forest contacted the State of Alaska, Department of Natural Resources, Division of Oil and Gas (Division) and said that they were working on a proposal for pipeline fees from the Osprey Oil Platform to the Kustatan Production Facility and from the Kustatan Production Facility to the Cook Inlet Pipeline. In March 2004, the Division requested Forest to provide their proposal to the Division. In July 2004, Forest provided the Division a proposed cost of service (COS) methodology to calculate a transportation deduction for royalty purposes for both pipelines but no proposed transportation allowance rates or cost information. Since the July 2004 meeting, the Division has repeatedly requested Forest to provide actual cost, expense, and proposed pipeline allowances. However, Forest has not provided this information to the Division. Forest has yet to take a transportation deduction from the oil royalty value for either pipeline.

II. FINDING

1. There is no provision in the lease, Alaska Statutes, or Federal precedence that allows a transportation deduction against the State's royalty share for gathering. The platform to shore movement of untreated well fluids from the Osprey platform to the on-shore Kustatan Production Facility primarily involves a gathering function.

    a. The lease explicitly precludes field cost deductions for gathering whether on or off the lease. The Redoubt Shoals Unit consists of five leases: ADL Numbers 378114, 374002, 381003, 381201, and 381203. All five of these leases contain identical language in paragraph 37:

        > Royalty paid in value will be free and clear of all lease expenses (and any portion of those expenses that is incurred away from the leased area) including but not limited to expenses for separating, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area.

b. The lease language implements a1978 legislative mandate that the State's royalty share of oil and gas production should not bear any lease or unit expenses (AS 38.05.180(z):

> [W]henever,... a royalty share is reserved to the State, it shall be delivered in pipeline quality and free of all lease or unit expenses including but not limited to separation, cleaning, dehydration, gathering, salt water disposal, and preparation for transportation off the lease or unit area.

c. Federal offshore precedents do not allow a platform-to-shore deduction.

> In "Nexen Petroleum USA, Inc. v Norton", 2004 WL 722435 WL (E.D.La) the federal district court upheld an IBLA decision that disallowed a charge against the federal government's royalty share for transporting oil from a central accumulation point on one platform to another platform where the oil was treated and put into marketable condition. The IBLA reasoned that a federal oil and gas lessee is responsible for all the expenses of placing oil from federal leases into marketable condition and that "the movement of lease production to the point where treatment took place was gathering and part of placing the oil into marketable condition rather than transportation."

2. The parent company, Forest, is primarily an exploration and production company. As such it faces materially different risks than a more traditional or typical oil pipeline company. Accordingly, it is inappropriate to use the parent company capital structure or return on equity for calculating a weighted average cost of capital. Instead, given the proposed methodology and the resultant risks to Forests' pipeline investment, the weighted average cost of capital and return on equity should be calculated with reference to the risks faced by a typical oil pipeline. The "typical" oil pipeline faces risks that can be reasonably estimated by examining publicly traded companies that are recognized as oil pipeline companies, having stock that is recognized and tracked by an investment information service, and for which pipeline operations constitute a high proportion of the company's business. We follow the FERC in this regard.

   The pipeline from the Kustatan Production Facility to the Cook Inlet Pipeline faces the approximate risks of a "typical" oil pipeline. It faces no competition, unlike many oil pipelines, while the cost of service method significantly shields Forest from throughput risk because rates will be adjusted annually and the pipeline will be depreciated using a unit of throughput depreciation schedule.

3. Forest is the only shipper on its Kustatan to Cook Inlet Pipeline pipeline..

4. Cost of Service (COS) Methodology requested by Forest includes the following provisions:

   a. Operating Expenses = Expenses for operating and maintaining the pipeline (exclusive of depreciation) and an allocated corporate overhead rate. These expenses will be estimated for the coming calendar year.

   b. Depreciation = Recovery of capital invested over the life of the pipeline based on units of throughput (UOT).
      (1) Depreciation formula:
         Gross Depreciable Property – Accumulated Depreciation * UOT factor.
      (2) Gross Depreciable Property = Capital invested in pipeline facilities.
      (3) Accumulated Depreciation = Sum of depreciation to date.
      (4) UOT Factor = Annual Throughput /Remaining Producible Reserves.

   c. Amortization of an Allowance for Funds Used During Construction (AFUDC)
      (1) Amortization formula:
         Amortization of AFUDC = Net AFUDC Balance * UOT factor.
      (2) Net AFUDC = Gross AFUDC – Accumulated Amortization of AFUDC.
      (3) Accumulated amortization = Sum of amortization to date.
      (4) Gross AFUDC (End of Year) = Gross AFUDC (Beginning of year) + Average Construction Work in Progress account) * Weighted Rate of Retrun

   d. Return on Rate Base
      (1) Return on Rate Base Formula:
         Average Depreciated Original Cost (DOC) * Weighted Rate of Return.
      (2) DOC = Net Carried Property + Working Capital – Deferred Taxes.
      (3) Working Capital = Investment in spare parts, line fill, and/or pre-payment of expenses required by commercial operations of the pipeline. Working Capital for 2003 – 2004 was $0.

(4) Weighted Rate of Return (WROR)= (Equity % * Return on Equity) + (Debt % * Cost of Debt)

(a) Equity % = Stockholder Equity/(Stockholder Equity + Long Term Debt). For 2003 the Equity percentage for Forest Oil is 56.05%

(b) Return on Equity = Market Returns for US Oil Pipelines which is approximately 16% for 2003

(c) Long Term Debt = (1.0 – Equity percentage)

(d) Cost of Debt = Average yields for Forest long term debt which for 2003 was 6.03%.

e. Income Tax Allowance: Amount included in the Cost of Service to pay income taxes on taxable items in Cost of Service.

(1). Income Tax Allowance Formula:

Income Tax Allowance = Taxable Items * Income Tax multiplier.

(2). Taxable items = Elements of Cost of Service that are considered income for the purpose of taxation.

(3). Income Tax Multiplier = Tax Rate/ (1-Tax Rate).

f. Net Carryover

(1) Net carryover Formula:

Net Carryover (prior year) = [Rate per Barrel Variance *Actual Throughput] + Interest

(2) Rate per Barrel Variance is the amount by which the estimated Rate per Barrel for the prior year is greater (or less) than the <u>actual</u> Rate per Barrel using actual costs and throughputs.

(3) Net Carryover for the prior year is an adjustment to the Cost of Service for the current year:

(a) If the <u>estimated</u> Rate per Barrel > <u>actual</u> Rate per Barrel for the prior year; then there is a COS Excess and the Net Carryover will be subtracted from Cost of Service for the current year.

(b) If the <u>estimated</u> Rate per Barrel < <u>actual</u> Rate per Barrel; then there is a COS Deficit and the Net Carryover will be added to Cost of Service for the current year

(4) Interest = Short term interest rate such as the three month commercial paper rate published by the Federal Reserve.

g. Rate per Barrel = (Sum of paragraphs II4a through II4f)/expected throughput for the calendar year.

III. DECISION

1. No transportation deduction will be allowed for the pipeline that connects the Osprey platform and the Kustatan Production Facility. This pipeline is a gathering line and deductions for gathering lines are not allowed under the lease terms, Alaska Statutes, or Federal precedence.

2. Reasonable, actual costs of transportation will be allowed as a deduction when calculating the royalties owed the State under the lease. Except as provided in (a) through (e) below, the Cost of Service (COS) methodology proposed by Forest is approved as the method for calculating a transportation deduction for the pipeline that transports marketable pipeline quality oil from the Kustatan Production Facility to the Cook Inlet Pipeline. If the State exercises its option under the leases to take its royalty in kind, Forest agrees to charge the State or purchasers of the State's royalty oil no more than the transportation deduction resulting from the cost of service methodology approved herein to transport royalty oil from the Kustatan Production Facility to the Cook Inlet Pipeline:

    a. No income tax or deferred income tax allowances are authorized since Forest owns the pipeline and is the only shipper. The pipeline generates no income for Forest. Therefore it generates no income tax liability. In such circumstance it is not appropriate to attribute State and Federal corporate income tax as a component of the pipeline's cost of service. In the future, if Forest sells space on the pipeline, in an arm length transaction, Forest may request the State to implement an income tax and deferred income tax allowance components to the Redoubt COS agreement.

    b. Interest on the net carryover balance from the previous year should be based on the 3-month Financial Commercial Paper rate as published in the "Statistical Supplement to the Federal Reserve Bulletin". Given the COS methodology's net carryover provision, this interest rate reasonably corresponds to the period of over or under-recovery of pipeline costs. Since the Federal Reserve reports these interest rates about five month after the actual month, Forest should use a fiscal year (July to June) rate. For example to determine the interest rate on the carried forward balance from 2005 to be incorporated into the cost for 2006, Forest should use the simple average of the monthly 3-month Financial Commercial Paper rates from July 2004 to June 2005 .

    c. Forest must determine a salvage value for the pipeline and subtract that value from the facility capital costs when

determining depreciation. Salvage value must not be less than 10% of the capital cost.

d. Capital Structure

1. When determining an appropriate capital structure for an oil pipeline that lacks its own financing we do not adopt the parent company capital structure. Instead, we follow the FERC and use as a hypothetical capital structure, that being the median capital structure from FERC's oil pipeline proxy group, which today consists of Buckeye Pipeline Partners, L.P.; Enbridge Energy Partners, L.P.; Kinder Morgan Energy Partners, L.P.; and TEPPCO Energy Partners, L.P.. Such a hypothetical capital structure reasonably approximates an appropriate capital structure for an oil pipeline of "typical" risk.

2. For 2003, the proxy group proportion of equity (including common equity) was 45.65%; for 2004 the proportion of equity was 43.55%, and for 2005 it was 42.15%. For 2006 and beyond we adopt the three year average of these capital structures, and permit a 43.79% equity (56.21% debt).

e. Return on Equity

1. We follow FERC and permit the median return on equity of the oil pipeline proxy group. The return on equity for each of the companies is determined using FERC's approved discounted cash flow (DCF) method.

2. Dividend yields are determined by calculating the monthly average stock price of each of the companies in the proxy group by averaging their monthly high and low stock prices for the month. The annual dividend for each company is then divided by the monthly average stock price. The dividend yield (dividend divided by the prior six month average stock price) is then added to the prospective annual growth rate to arrive at a total cost of equity capital for each company. We follow FERC and use a two-stage growth rate, where the near-term growth rate is given a two-third's weight and the longer term growth rate is given a one-third weight. The near-term growth rate is the Institutional Brokers Estimate System median estimate of earnings growth; the long-term growth rate is the gross domestic product forecast, itself obtained from Energy Information Administration, the Social Security Administration, and

Global Insight/DRI-WEFA. Using this method, the median cost of equity is 13.18% for 2004 and 12.16% for 2005. The average of the two rates of return is 12.67%, which we apply as an allowable return on equity

f. Cost of Debt

Forest Oil reports their weighted average cost of debt, at the end of 2003, at 6.04%. This is slightly greater than the cost of debt of the oil pipeline proxy group (which for 2003 averaged 5.88%). Given the relative similarity, and noting that Forest's actual ability to raise capital on favorable terms through debt issuance appears not as strong the members of the proxy group (on average), we permit Forest to use their cost of debt as reported at the end of 2003.

3. To determine the transportation deduction rate for 2002 through 2005, Forest should use reasonable, actual operating and capital expenses. For 2006 and forward, Forest should estimate operating expenses based on reasonable and actual historic costs and estimated through-put based on reservoir performance. For 2007 and forward, these costs and through-put estimates must be provided to the Division by January 20th of the year the estimates are for. Included with the estimated cost and through-put of the next year, Forest must provide the Division a listing of actual capital and operating expenses incurred for the previous year.

4. Within 45 days of the effective date of this Decision, Forest must provide the Division proposed transportation allowances for 2002 through 2006. Forest must provide the Division, with the proposed allowances, listings of all capital costs and all operating expenses for each year for the pipeline connecting the Kustatan Production Facility to the Cook Inlet Pipeline. The Division reserves the right to audit these listings of costs and expenses. Within 30 days of receipt of the proposed transportation allowances, the Division will notify Forest of its concurrence or non-concurrence of the proposed transportation allowances for 2002 through 2006. For the period 2002 through 2006, Forest must file revised royalty reports within 45 days of receiving concurrence of the transportation allowances from the Division. Forest should use an allocation code of "RT" for the transportation allowance as a deduction from the royalty value. If Forest fails to supply the Division with the requested data within 45 days of the date of this Decision or file the revised royalty reports within the specified time period, this Decision becomes null and void and no transportation allowance will be allowed for 2002 to the effective date of this Decision. The Division will not allow interest on the revised reports due to the addition of a transportation allowance for the following reasons: (1) Forest has not requested the Division to approve a transportation allowance but only a Cost of Service Methodology. (2) Forest delayed 18

months in providing the Division a Cost of Service Methodology. (3) Forest has not provided the Division the cost data that the Division repeatedly requested.

5. Reopener. The Division, in its sole discretion, reserves the right to reopen this decision should the purpose, use, or regulatory status of the Redoubt Pipeline change. The Division will give Forest 30 days notice and an opportunity to be heard if the decision is reopened.

III APPEAL

A person affected by this decision may appeal it, in accordance with 11 AAC.02. Any appeal must be received. within 20 calendar days after the date of "issuance" of this decision, as defined in 11 AAC 02.040© and (d), and may be mailed or delivered to Michael L. Menge, Commissioner, Department of Natural Resources, 550 West 7th Avenue, Suite 1400, Anchorage, Alaska 99501; faxed to 1-907-269-8918; or sent by electronic mail to dnr_appeals@dnr.state.ak.us. This decision takes effect immediately. If no appeal is filed by the appeal deadline, this decision becomes a final administrative order and decision of the department on the 31st day after issuance. An eligible person must first appeal this decision in accordance with 11 AAC 02 before appealing this decision to Superior Court. A copy of 11AAC 00 may be obtained from any regional information office of the Department of Natural Resources.

William Van Dyke, Acting Director
Division of Oil and Gas

October 16, 2006
Date