APPENDIX C

ECONOMIC MODEL

C.1 Model Description

A commercially available financial software package[a] is used to develop the Alaska economic model. This software allows the easy creation of a financial model, has extensive features for querying the model, construction of "what if" scenarios, and goal-seeking features. The economic model was previously described in *Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?* (DOE, 1991). The previous model is refined and modified for the current study.

C.1.1 Model Parameters

A discounted cash flow petroleum accounting model is used to evaluate the historical and projected economics of arctic Alaska oil resources. The model is constructed so the appropriate level of detail for the currently producing and known undeveloped fields can be used depending on the available information. Producing fields and known undeveloped fields are analyzed using historical and projected production and investment schedules reflecting the information known about these fields.

Geologic, geophysical, and lease acquisition costs are assumed to be sunk costs, and are excluded from economic calculations. All costs, oil prices, inflation, and discounting are calculated at the mid-year. Project capital is assumed to be 100% equity with no debt financing or leverage considered.

C.1.1.1 Resource Parameters. OOIP and ultimate hydrocarbon recovery factors are primary inputs. Historical and projected production schedules are directly entered into the model.

A percent water cut versus percent predicted ultimate recovery relationship is used to calculate water production. The water and oil production are summed to give total fluid production. This feature is used to calculate production operating costs on a per barrel of fluid lifted basis for some fields.

The number of development wells drilled is calculated using the development drilling investment

a. Interactive Financial Planning System, (IFPS). *The use of a commercial product neither implies endorsement or recommendation.*

schedule and the cost per development well. Actual development well cost is used when available, otherwise the cost is estimated by average well-depth look-up table. Development wells are either producing wells or injection wells. The number of producing wells is determined as a percentage of total development wells. As a field nears depletion, the number of active producers is reduced as a specified function of ultimate recovery. This procedure simulates the late-life operations of a producing field, as individual uneconomic wells are shut-in. The average well production rate is calculated by dividing the total field production rate by the number of active producers. This allows calculation of production based severance tax, as discussed below. Field oil production terminates when the specified reserves are depleted.

C.1.1.2 Capital Investments. Project investments include exploration, delineation, and development well costs and production facilities. All investment costs are input as 1/1/95 dollars and inflated to mid-year then current dollars using the applicable inflation category:

- Historical and projected well costs, counts, and timing are directly entered for the producing and known undeveloped fields.
- Historical and projected facilities cost are directly entered.
- Offshore production platforms are directly entered for all cases.

C.1.1.2.1 Costs. Project costs are either tangible or intangible and treated differently for tax purposes. Tangible costs are assumed to be 100% of production facilities and 30% of development well costs. The balance is considered to be intangible.

C.1.1.2.2 Timing. The scheduling of the exploration, delineation, and development drilling programs is estimated and directly entered into the model. The actual project timing is determined by institutional, regulatory, economic, and environmental factors.

C.1.1.3 Operating Costs. Total field operating costs are calculated using a combination of cost components based on total fluid lifted, well workover cost, facilities cost-sharing fee, and MI. For each case studied, the actual cost components used varied. **Table C.1** shows which cost components are used for each field.

A percent water cut versus percent of ultimate predicted recovery relationship is used to estimate water production. Historical reservoir water-cut performance is extrapolated for the projected cases using

Table C.1. Cost components used for each field.

Field	Total Fluid Lifted	Well Workover	Facilities Cost Sharing	Miscible Injectant
Prudhoe Bay	Yes	No	No	No
Kuparuk River	Yes	No	No	No
Lisburne	Yes	No	No	No
Endicott	Yes	No	No	No
Milne Point	Yes	No	No	No
Point McIntyre	Yes	Yes	Yes	No
Niakuk	Yes	No	Yes	No
Schrader Bluff	Yes	Yes	Yes	No
Northwest Milne Point	Yes	Yes	Yes	No

the actual reported production history, while the known undeveloped cases use an analogous water-cut curve based on the estimated size of the resource and producing formation. Where pilot test or reservoir study data is available, this information is used. The oil production rate and recovery at any point in time is used to calculate the water production. The oil production rate and water production rate are summed for total fluid production rate. This approach incorporates historical and expected reservoir performance in the determination of operating cost based on total fluid production.

C.1.1.4 Inflation Adjustment. All costs are inflated to then current dollars from a 1/1/95 base using a mid-year inflation. Four types of inflation can be used:

- General inflation - assumed to be related to the Gross Domestic Product (GDP) implicit price deflator
- A transportation inflation factor
- A drilling inflation factor
- An oil inflation factor that consists of general inflation plus real oil price growth.

The historical annual percent change in the GDP price deflator is shown in **Figure B.8**.

C.1.1.5 Tax Calculations. The determination of the undepreciated state and federal balances and property tax base is required to estimate future income for the currently producing fields. Historical cases are run for Prudhoe Bay, Kuparuk River, Lisburne, Endicott, Milne Point, Point McIntyre, and Niakuk using the best available information for historical and announced oil prices, production rates, and investment schedules and categories. The historical runs are made to year-end 1994 to provide an overlap for the forecast models. Year-end 1994 federal undepreciated balances, as calculated in the historical runs, are added to the depreciation for new investments starting in 1995. The year-end 1994 undepreciated balance depreciated for various time lengths to provide the best match of the 1994 to 1995 historical overlap time periods. While not exactly matching the historical depreciation schedule, the total values are in very good agreement. There is a minor affect for the first 3 to 4 years of the forecast economic runs. Unamortized IDC balances are treated in a similar fashion.

C.1.1.5.1 Tax Calculation Definitions

(1) **Gross Revenue** = Field Production Volume of Oil and Gas x Well Head Price.

(2) **Royalty** = [Royalty Interest Rate x Gross Revenue] - [Oil Processing Fee x Field Production Volume x Royalty Interest Rate].

(3) **Ad Valorem Property Tax Base** = [Previous Year Ad Valorem Property Tax Base - (Previous Year Ad Valorem Property Tax Base/Remaining Project Life)] x (Inflation Rate) + Previous Year Tangible Investment.

(4) **Conservation Tax** = (Conservation Tax Rate + Conservation Surtax Rate) x Field Production Volume x (1 - Royalty Interest Rate).

(5) **Income Before State and Federal Taxes** = Gross Revenue - Operating Costs - Royalty - Severance Tax - Ad Valorem Tax - Conservation Tax.

(6) **State Income Tax** = (Income Before State and Federal Taxes - State Income Tax Depreciation) x State Income Tax Rate.

(7) **State Income Tax Depreciation (Straight Line Basis)** = Cumulative Total Capital/Project Life.

(8) **State Income Tax Depreciation (Units of Production Basis)** = State Income Tax Depreciation Factor x State Income Tax Depreciation Basis.

(9) **State Income Tax Depreciation Factor** = Current Year Total Field Production/Current Year End Remaining Reserves.

(10) **State Depreciation Basis** = Previous Year State Depreciation Basis + Current Year Total Capital - Previous Year State Income Tax Depreciation.

(11) **Federal Income Tax** = (Income Before State and Federal Taxes - Federal Income Tax Deduction - State Income Tax) x Federal Income Tax Rate.

(12) **Federal Income Tax Deduction** = Federal Income Tax Depreciation + Amortized intangible drilling cost (IDC) + Expensed IDC.

(13) **Federal Income Tax Depreciation (Oilfield Equipment)** = 1.5 x [(Current Year Tangible Capital + Previous Year Book Value) Depreciated on a 7-year 150% continuous declining balance basis].

(14) **Federal Income Tax Depreciation (Gas-To-Liquids Conversion Plants)** = 1.5 x [(Current Year Tangible Capital + Previous Year Book Value) Depreciated on a 10-year 150% continuous declining balance basis].

(15) **Federal Income Tax Depreciation (Gas Pipeline, LNG Plant, and LNG Tankers)** = 1.5 x [(Current Year Tangible Capital + Previous Year Book Value) Depreciated on a 15-year 150% continuous declining balance basis].

(16) **Book Value** = Cumulative Tangible Investment - Cumulative Tax Depreciation.

(17) **Tangible Capital** = Plant Capital + 0.30 x Drilling Capital.

(18) **Intangible Capital** = 0.70 x Drilling Capital.

(19) **Expensed IDC** = 0.70 x Intangible Drilling Capital.

(20) **Amortized IDC** = (Current Year Unexpensed Drilling Capital + Previous Year Unamortized IDC); amortized on a 5-year straight line basis.

(21) **Total Capital** = Plant capital + Drilling Capital.

(22) **Plant Capital** = 100% Tangible.

(23) **Drilling Capital** = 30% Tangible + 70% Intangible.

(24) **Operating Cash Flow** = Income Before State and Federal Income Taxes - Federal Income Tax - State Income Tax.

(25) **Industry Cash Flow** = Income Before State and Federal Income Tax - Federal Income Tax - State Income Tax - Total Capital.

(26) **State Revenue** = Royalty + Severance Tax + Ad Valorem Tax + Conservation Tax + State Income Tax.

(27) **Federal Revenue** = Federal Income Tax.

C.1.1.6 State of Alaska Taxes. A major improvement in this model relative to the previous study is the incorporation of Alaska tax law for the treatment of state depreciation, property tax, severance tax with an ELF for both oil and gas, conservation tax and surtax, royalty processing fees, and state income tax. State taxes are calculated before federal income tax and are a deduction in determining federal taxable income. One major change from the previous study was the incorporation of a state income tax loss carry-forward provision. No state income taxes are paid until all previous state income tax losses had been offset. This study focuses on project specific economics and does not attempt to take into account individual companies tax position. Two different approaches can be used, tax loss to offset other company income or to treat a tax loss as zero taxes with no offsetting effect. The tax loss carry-forward approach is essentially intermediate to the other two options.

C.1.1.6.1 Depreciation--The state of Alaska calculates depreciation on a units-of-production basis on the total investment (tangible and intangible) once the asset has been placed in service. A units-of-production depreciation factor is calculated using the yearly production divided by the year-end remaining reserves. The depreciable basis is the cumulative total investment less cumulative depreciation. The state depreciation is the product of the state depreciation factor and the depreciation basis. This amount is deducted as a non-cash expense.

C.1.1.6.2 Property Tax (Ad Valorem)--The state property tax base is calculated using the inflation adjusted cumulative tangible investment, less the previous year's property tax base divided by the remaining project life. This value is adjusted by the general inflation rate plus previous year tangible investment. The property tax (or ad valorem tax) is 2% of the current year property tax base.

C.1.1.6.3 Severance Tax--The state oil severance tax is calculated at 12.25% of the net wellhead value (i.e., less royalty oil) for the first 5 years of production and 15% thereafter, multiplied by the oil ELF with a minimum tax of $0.80 (unescalated) per net barrel of production. Net production is defined as oil production less royalty. Similarly, the state gas severance tax is calculated at 10.0% of the net wellhead value, multiplied by the gas ELF, with a minimum tax of $0.064/MCF.

C.1.1.6.3.1 Oil ELF. The oil ELF calculation used is the post-1989 formula, which is:

$$\text{Oil ELF} = [1 - 300/\text{Daily Average Well Rate (BOPD)}]^{x}$$

where:

$$x = [150{,}000/\text{Average Daily Field Rate (BOPD)}]^{1.5333}.$$

C.1.1.6.3.2 Gas ELF. The gas ELF calculation is:

$$\text{Gas ELF} = [1 - 3{,}000/\text{Daily Average Well Rate, (MCF/day)}]$$

C.1.1.6.3.3 Future Producing Well Determination. The number of future active wells on an annual basis is required in severance tax calculations. The method developed in the 1991 DOE publication (1991) to project the future active producers is adopted for use. Two sets of equations were developed to determine the future active producers in two different project sizes. The first set, for projects similar to PBU, is:

Set A - For the production period between 80% and 98% of ultimate recovery the current number of active producers is:

- Producers = [{181.1011 - 1.0112 (% of ultimate recovery)} x maximum number of active producers] ÷ 100.

For the production period after 98% of ultimate recovery, the current number of active producers is:

- Producers = [1845.3988 - 17.9939 (% of ultimate recovery)] x maximum active producers] ÷ 100.

The second set, for projects closer in size or smaller than the Kuparuk River Unit (KRU), is:

Set B - For the production period between 60% and 95% of ultimate recovery, the current number of active producers is:

- Producers = [{124.5528 - 0.4065 (% of ultimate recovery)} x maximum active producers] ÷ 100.

For the production period after 95% of ultimate recovery, the current number of active producers is:

- Producers = [{458.3330 - 4.3330 (% of ultimate recovery)} x maximum active producers] ÷ 100.

Maximum active producers is assumed as the total cumulative producers drilled with no allowance for shutdown wells unless complete segments of the project are abandoned.

C.1.1.6.4 Conservation Tax--The conservation tax rate is \$0.004/BBL of net production and the conservation surtax is \$0.05/BBL of net production.

C.1.1.6.5 Income Tax Calculation--The state income tax rate is calculated as follows:

$$\textit{State Income Tax Rate} = 9.4\% \times \frac{1}{3} \times \left(\frac{\textit{Alaska Sales}}{\textit{Worldwide Sales}} + \frac{\textit{Alaska Production}}{\textit{Worldwide Production}} + \frac{\textit{Alaska Assets}}{\textit{Worldwide Assets}} \right.$$

Because it is difficult to independently determine any company's worldwide sales, production, and assets, a nominal effective state tax rate of 3% is used. This value compares favorably with the implicit effective rate from Deakin (1989). An effective rate of 1.5% to 3% is used by the ADR for revenue forecasting.[a]

The state income tax is calculated as follows:

- **Net Revenue** = Gross Revenue - (Royalty - Processing Fee)

- **Net Before State Income Tax** = Net Revenue - Total Operating Cost - Severance Tax - Conservation Tax - Conservation Surtax - State Property Tax - State Depreciation

- **Net After State Income Tax** = Net Before State Income Tax - State Income Tax + State Depreciation.

The state depreciation is added back for the calculation of federal taxes.

C.1.1.7 Federal Taxes. Federal income taxes are calculated after the state of Alaska tax calculations, with state taxes treated as a deduction from federal income. The federal income calculations involve the treatment of IDCs, depreciation, and federal income tax. One major change from the previous study is the incorporation of a federal income tax loss carry-forward provision. No federal income taxes are paid until all previous federal income tax losses have been offset. This study focuses on project specific economics and does not take into individual companies tax position. Two different approaches could be used, tax loss to offset other company income or to treat a tax loss as zero taxes with no offsetting effect.

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a. Alaska Department of Revenue, personal communication, May 1990.

The tax loss carry-forward approach is essentially intermediate to the other two options.

C.1.1.7.1 Federal Amortization of IDCs--Federal tax law allows IDCs to be expensed and amortized and permits a more favorable treatment of depreciation. Current tax law permits 70% of the IDCs to be expensed in the year incurred and the balance amortized over 60 months. The model assumes that IDCs are 90% of exploration and delineation well costs and 70% of development well costs.

C.1.1.7.2 Federal Depreciation (producing facilities)--Federal depreciation is calculated using a 7-year, 150% declining balance of the tangible investment with no switchover. This method is consistent with the approach used by the Alaska Department of Revenue. The tangible assets are assumed to have no salvage value at the end of the project. Federal law allows the choice of depreciation methods such as Accelerated Cost Recovery System (ACRS), straight line, declining balance, units of production, and sum-of-the-years digits with a switchover before the end of the depreciation life. No depletion allowance is used for the recovery of exploration and lease acquisition costs; these costs are assumed to be sunk costs.

C.1.1.7.3 Federal Depreciation (gas-to-liquids conversion plants)--The federal income tax depreciation is calculated by multiplying 1.5 X [(current year tangible capital + previous year book value) depreciated on a 10-year, 150% continuous declining balance basis].

C.1.1.7.4 Federal Depreciation (gas pipeline, LNG plant, and LNG tankers) -- The federal income tax depreciation is calculated by multiplying 1.5 X [(current year tangible capital + previous year book value) depreciated on a 15-year, 150% continuous declining balance]

C.1.1.7.5 Federal Income Tax Calculation--The federal income tax rate is 34% of the federal taxable income. Non-cash deductions are added back to net income for the determination of cash flow.

The federal income tax, net income, and operating and total cash flows are calculated as follows:

- **Net Income Before Federal Income Tax** = Net After State Income Tax - Expensed IDC - Amortized IDC - Federal Depreciation
- **Net Income** = Net Income Before Federal Income Tax - Federal Income Tax

- **Operating Cash Flow** = Net Income + Federal Depreciation + Amortized IDC + Expensed Intangible Investment
- **Total Cash Flow** = Operating Cash Flow - Total Investment.

C.1.1.8 Economic Determination. The yearly total cash flow is discounted to determine the present worth of the future total cash flow. The base year for discussing constant dollars is as of January 1, 1995. The economic limit is defined as the year operating cash flow is negative (after payout of the project). A nominal discount rate of 10% is used. The real discount rate is related to the nominal discount rate by the following equation from Stermole (1982).

$$[1/(1+i_n)]^n = [1/(1+f)]^n \times [1/(1+i_r)]^n$$

where

n = time periods

i_n = nominal discount rate

f = inflation rate

i_r = real discount rate.

With an inflation rate of 2.2% and a 32 year time period, the real discount rate for a nominal discount rate of 10% is 7.6%.

The yearly present values are summed to determine the cumulative net present value of each case considered. The model does not directly calculate the internal rate of return (IRR), but the IRR can be determined by solving for the nominal discount rate that results in a cumulative net present value of zero at the end of the project.

C.2 Model Validation

The economic model was previously validated (DOE 1991) by comparison with the Young (1986) and the Deakin (1989) studies. For a discussion of the model validation see the above referenced study.