## Economic Assessment

Methodology

The economic analysis is the second phase in the assessment of each petroleum province. The first phase of the assessment determines the geologic characteristics and petroleum volumes recoverable by conventional technology. The 2006 assessment uses a new version of the MMS Geologic Resource Assessment Program (GRASP II) that completely integrates the geologic and economic assessment models.

The geologic model generates an inventory of pools in each play, saved as an output file named *ECONVOL*. This file is sampled repeatedly to select pools for the simulations in the economic model. For each modeling trial, a set of hypothetical pools ("simulation pools") are collected using a probability sampling system that replicates the discovery of pools in the province. Engineering parameters are sampled from an array of variables (see Table 1) and assigned to each simulation pool. The collection of pools undergoes a simulation to model the costs and scheduling associated with discovery, development, and production. A discounted cash flow (DCF) analysis is performed for each pool. Pools with positive net present value (NPV) are counted as economic resources for that trial, and those with negative NPV are set to zero resources. The sampling, engineering simulation, and DCF analysis is then repeated. Typically, a full modeling run consists of 10,000 trials with different sets of pools in each trial.

After the modeling run is completed, statistics are aggregated for successful (profitable pools) and unsuccessful (not discovered or negative NPV) simulations. Economic volumes of oil and gas, including associated substances (solution gas in oil, condensate liquids in gas) are compiled and probability levels are calculated. The reported volumes are considered as "risked" because unsuccessful trials are included in the statistics.

The modeling runs are repeated at $2/bbl price increments between $8.00 and $80.00 to produce a spectrum of results under changing economic conditions. The results are compiled on a "price-supply" graph that illustrates the relationship between economically recoverable resources (dependent variable) and commodity prices (independent variable).

The results of the economic assessment are strongly influenced by the preceding geologic assessment, as most of the engineering variables are tied to geologic characteristics. For example: deeper reservoirs have higher well costs; thicker reservoirs have higher well flow rates. Poor geology is accentuated by the economic analysis—not improved by it. This means that provinces with poor geology are likely to have minimal economically recoverable resources.

Improvements in the Engineering Model

A number of revisions were made to the computer model and modeling assumptions to improve the 2006 resource assessment.

- The geologic and engineering models are integrated into the same computer program. This enhances the consistency between the geologic and economic analyses.

- Transportation scenarios are updated to reflect activities expected in the foreseeable future. Oil and gas production is modeled as delivered to U.S. markets. Province-level gathering, processing, and export systems are assumed to be constructed and operated by third-party consortiums with cost-of-service fees modeled as levelized tariffs. Export infrastructure is located at central "hub" facilities that could be utilized by several provinces.
- Current technologies are included in the engineering model. Subsea wells are modeled to gather oil and gas from the margins of large pools and satellite pools to minimize the number of large platforms required for development. High pressure, dense phase pipelines are modeled to carry gas and liquid components in main lines. This improves the cost-efficiency of gas transportation for wet gas.
- Costs for all phases of construction and operations are updated to reflect increased costs under current high-price conditions. Available data from the analogous high-cost regions are used to estimate the costs for operations in offshore Alaska.
- The economic analysis is more sophisticated and more variables are included as engineering inputs (see Table 1). Many engineering parameters are correlated to pool volume to reflect economies of scale, longer development schedules for larger pools, and higher well productivity for larger pools.
- Ranged distributions are used for most of the engineering variables. Look-up cost and scheduling matrices are organized into 3 groups (Arctic, Bering Sea, Pacific margin) to acknowledge the similarities in oceanography, logistics, and required engineering in these sub-regions. Typically, cost and time schedules increase further north in the Alaska OCS. Operations in the Chukchi Sea are the highest cost and operations in the Cook Inlet are the lowest cost.

Engineering Assumptions

The assessment results are strongly influenced by the modeling assumptions for scheduling, costs, and market destinations. In the 2006 assessment, conceptual designs for infrastructure are based on older feasibility studies that were incorporated into previous assessments. Although the studies are somewhat dated, very little work has occurred in offshore Alaska, so these early designs have not been modified through experience. However, all costs are updated, and revised transportation and market scenarios reflect current conditions.

Established conventional technology is assumed for the engineering simulations. No attempt was made to evaluate future technologies with improvements to costs or recovery efficiencies.

Oil and gas production is modeled in all provinces and engineering simulations are biased toward the dominant hydrocarbon type. In oil-prone provinces, oil infrastructure is developed first and gas-prone plays (or associated gas resources) are delayed to utilize oil infrastructure. In gas-prone provinces the situation is reversed, where initial gas development supports later development of smaller oil (crude oil and condensate) pools.

Exploration and development activities in each province are modeled as occurring simultaneously without regard to the activities in other provinces. This level of activity is unprecedented in Alaska, and a realistic timeframe would span many more decades. Consequently, the assessment provides a current view of the petroleum potential, but it does not define a rate at which undiscovered resources will become producing reserves.

The export scenarios are based on one likely and feasible strategy. Alternative scenarios are not evaluated. Existing infrastructure is utilized whenever possible and new export infrastructure is assumed to be built and operated by consortiums. All production in a province, and sometimes several adjacent provinces, shares the same export infrastructure (facilities, pipelines, and transport ships).

The sequence of discovery and development of pools in a play is based on the conventionally recoverable potential of the play. Pools in resource-rich plays are modeled as developed first and cover the costs of initial infrastructure in the province. The development of smaller pools in resource-poor plays is delayed but then produced through existing infrastructure. To approximate this situation, a complicated arrangement of prorated capital costs and cost-of-service fees are input into the simulation model. This procedure approximates a realistic scenario but there is no way to accurately predict the sequence of future activities.

Oil and gas production is delivered by proven conventional systems to existing, ready markets. With the exception of the Cook Inlet, high production rates cannot be absorbed by the demand in Alaska markets, so oil and gas production must be transported to distant markets in the continental U.S. Higher transportation costs reduce the netback value of production and affect the economic viability of all projects in these remote provinces.

Economic Parameters

The economic model replicates the activities of private industry to explore and develop new commercial oil and gas projects. The economic parameters define the value of the income stream from oil and gas production, the associated taxes and royalties due, and the return on investment. The DCF analysis is in constant 2005 dollars (2005$).

Oil and gas is production is sold at delivered (“landed”) prices at the assumed market destinations. Typically, the modeling simulations are run at prices ranging from $8 to $80 ($1.21 to $12.10/Mcf) to represent a spectrum of possible conditions. Oil prices are adjusted for value relative to 32 degree API gravity (lower gravity is worth less, higher gravity is worth more). Gas value is discounted by a factor of 0.85 relative to oil value on a BOE energy equivalency basis (5.62 Mcf/bbl).

A discount rate 0.12 is used as a surrogate for return on investment including cost-of-capital. Simulations NPV greater than zero are considered to be economically viable, as the minimum return on investment capital is met.

An inflation rate of 0.03 is used to adjust costs and income streams to the year actually spent/received in the modeling simulations. The inflation rate is combined with the discount rate to generate discount/deflation factors that are used to adjust future values back to present value (2005$).

Nominal corporate income tax rate is 0.35 and only Federal taxes are considered in the model. State taxes (corporate income and property taxes) associated with onshore operations are covered in the cost-of-service tariffs. Tax treatment for capital expenditures follows the 1986 Tax Reform Act with its definitions of tangible and intangible costs and 8-year depreciation schedule.

Leasing terms and conditions typical of Alaska OCS lease sales are input into the simulations, including: Minimum bid ($25/ac), Annual rental ($5/ac), royalty rate (0.125), and royalty suspension volumes (where applicable).

<u>Economic Assessment Results</u>
A number of caveats should be attached to all resource assessments. Many uncertainties in modeling are unavoidable, but the results could easily be misinterpreted if the following concepts are overlooked.

The economic results span a wide range of possibilities. Given the same geologic endowment, more resources would be economic to produce at higher prices than at lower prices. At the same price level, higher resource volumes could occur at lower probabilities. To accurately portray the results, economic resource potential should always be reported with price and probability qualifiers.

“Resource potential” is not the same as “available reserves” because the modeled oil and gas pools are undiscovered, and many of the Alaska provinces are now closed to leasing and exploration. Without extensive exploration most of the undiscovered resources will remain so. Only confirmed pools (those having a flowing well test) that have positive NPV could become reserves available for future production. Realistically, most of the pools in the hypothetical inventory will never be drilled.

The economic assessment is a very optimistic appraisal of recoverable resource volume because the costs and delays caused by regulatory requirements are not included. However, regulatory restrictions are common in Alaska and are likely to adversely affect many marginal discoveries. Also, some discoveries may not be developed because companies will require a wider profit margin to overcome the financial risks in difficult frontier provinces.

Long distances to market from these remote provinces will require new transportation infrastructure with costs in the tens-of-billions of dollars. Although we assume that the infrastructure is operational when needed, the construction schedule and sponsor groups for this new infrastructure have not been identified. In most cases, a minimum resource base (several large discoveries) will be required to support new export infrastructure in each province. Until this new infrastructure is operational the resources will be stranded.

“Resource potential” is essentially an optimistic appraisal of undiscovered oil and gas. The location and timing of future developments and volumes of petroleum eventually delivered to market cannot be forecast accurately. Although the relative potential of each province is clearly shown in the current assessment, the rate of conversion of undiscovered resources to producing reserves is entirely dependent on the future actions of government and industry.

## Future Work

The 2006 assessment is a refinement of previous MMS assessments. Engineering designs and costs are updated to reflect current conditions, and a DCF analysis for individual pool simulations is more sophisticated than previous assessment models. This suggests that the 2006 petroleum resource assessment is more accurate that previous assessments, even if based largely on the same geologic data. However, the oil and gas resources in offshore Alaska remain undiscovered and there are many uncertainties in the modeling methodology.

In the present assessment we assumed established technologies and existing markets but we did not evaluate alternative scenarios. Future assessments could evaluate different scenarios to determine the most cost-effective strategies to recover petroleum resources from each province. For examples: compressed natural gas (CNG) might be a more cost-effective gas transportation technology than liquefied natural gas (LNG) over short-haul distances; local Alaska markets could supplement distant markets on the U.S. West Coast; offshore processing and export infrastructure could replace long subsea pipelines to onshore facilities.

The results of the 2006 economic assessment suggest that most of the Alaska OCS provinces have marginal resource potential even at high prices. This is partly explained by poor geology, but even the rich provinces are challenged by a lack of infrastructure and high costs compared to other regions. It will require a long-term effort by government and industry, high levels of funding for exploration and technology, and innovative strategies to convert Alaska’s OCS petroleum potential to new supplies of domestic energy.

**Table 1: Input Parameters for Engineering Simulation**

Engineering Variables (scaled to pool volumes)
BOE conversion factor (Mcf/stb)
Initial time delay to exploration discovery
Number of pools developed per year
Percentage of pools unleased in play
Number of development projects for a pool (phased development)
Delay between development projects
Number of OCS tracts overlying a pool
Produced oil gravity (API)
Tract size
Water depth
MD/TVD ratio for development wells
Delay between discovery and development
Delay before production starts (after development drilling)
Delay between exploration wells
Delay between delineation wells
Delay between production wells
Maximum production wells on a platform
Number of exploration wells drilled per pool
Number of delineation wells drilled per platform
Percentage of subsea wells to total wells
TVD depth to reservoir
TVD range of depth to reservoir
Percentage of injection wells
Percentage of dual completions
Length of flowlines between platforms
Oil transportation tariff ($/bbl)
Gas transportation tariff ($/Mcf)
Length of oil gathering line to main pipeline
Length of gas gathering line to main pipeline
Maximum recovery for oil well (Mstb)
Fraction of oil produced before decline
Initial oil production rate (peak rate)
Oil decline factor (exponential decline profile)
Oil decline curve exponent (hyperbolic decline profile)
Maximum recovery for gas well (MMscf)
Fraction of gas produced before decline
Initial gas production rate (peak rate)
Gas decline factor (exponential decline profile)
Gas decline curve exponent (hyperbolic decline profile)
Oil pipeline diameter (scaled to flow rate)
Gas pipeline diameter (scaled to flow rate)

Scheduling Parameters (matrices with dependent variables)
Delay between platform starts (scaled to water depth)
Design, fabrication and installation of platforms (scaled to platform slots)
Number of drilling rigs per platform (scaled to platform slots)
Annual fractions of expenses to built/install platforms (scaled to DFI time)
Days to drill exploration wells (scaled to drilling depth)
Days to drill delineation wells (scaled to drilling depth)
Days to drill production wells (scaled to drilling depth)
Days to drill service wells (scaled to drilling depth)
Days to drill subsea wells (scaled to drilling depth)

Cost Variables (matrices with dependent variables)
Fixed operating costs (per stream)
Variable oil operating costs (per bbl)
Variable gas operating costs (per Mcf)
Exploration (scaled to water and drilling depths)
Delineation (scaled to water and drilling depths)
Production wells (scaled to drilling depth)
Subsea wells (scaled to water and drilling depth)
Single well completions (scaled to drilling depth)
Dual well completions (scaled to drilling depth)
Subsea well completions (scaled to water and drilling depth)
Platform (scaled to well slots and water depth)
Oil production equipment on platform (scaled to production rate)
Gas production equipment on platform (scaled to production rate)
Oil pipeline (scaled to diameter and water depth)
Gas pipeline (scaled to diameter and water depth)
Abandonment (scaled to platform size and water depth)

Economic Parameters
Price adjustment for API oil gravity
Gas price discount factor
Discount rate
Inflation rate
Nominal corporate tax rate
Tangible fractions for infrastructure components
Depreciation schedule (8-year ACRS)
Minimum bid for leasing
Rental for leases
Royalty suspension volumes (scaled to water depth)