The oil and gas supply module (OGSM) consists of a series of process submodules that project the availability of:

- Domestic crude oil production and dry natural gas production from onshore, offshore, and Alaskan reservoirs
- Imported pipeline–quality gas from Mexico and Canada
- Imported liquefied natural gas.

The OGSM regions are shown in Figure 12.

The driving assumption of OGSM is that domestic oil and gas exploration and development are undertaken if the discounted present value of the recovered resources at least covers the present value of taxes and the cost of capital, exploration, development, and production. Crude oil is transported to refineries, which are simulated in the petroleum market module, for conversion and blending into refined petroleum products. The individual submodules of the oil and gas supply module are solved independently, with feedbacks achieved through NEMS solution iterations (Figure 13).

Technological progress is represented in OGSM through annual increases in the finding rates and success rates, as well as annual decreases in costs. For conventional onshore, a time trend was used in econometrically estimated equations as a proxy for technology. Reserve additions per well (or finding rates) are projected through a set of equations that distinquish between new field discoveries and discoveries (extensions) and revisions in known fields. The finding rate equations capture the impacts of technology, prices, and declining resources. Another representation of technology is in the success rate equations. Success rates capture the impact of technology and saturation of the area through cumulative drilling. Technology is further represented in the determination of drilling, lease equipment and operating costs. Technological progress puts downward pressure on the drilling, lease equipment, and operating cost projections. For unconventional gas, a series of eleven different technology groups are represented by time–dependent adjustments to factors which influence finding rates, success rates, and costs.

Lower 48 Onshore and Shallow Offshore Supply Submodule

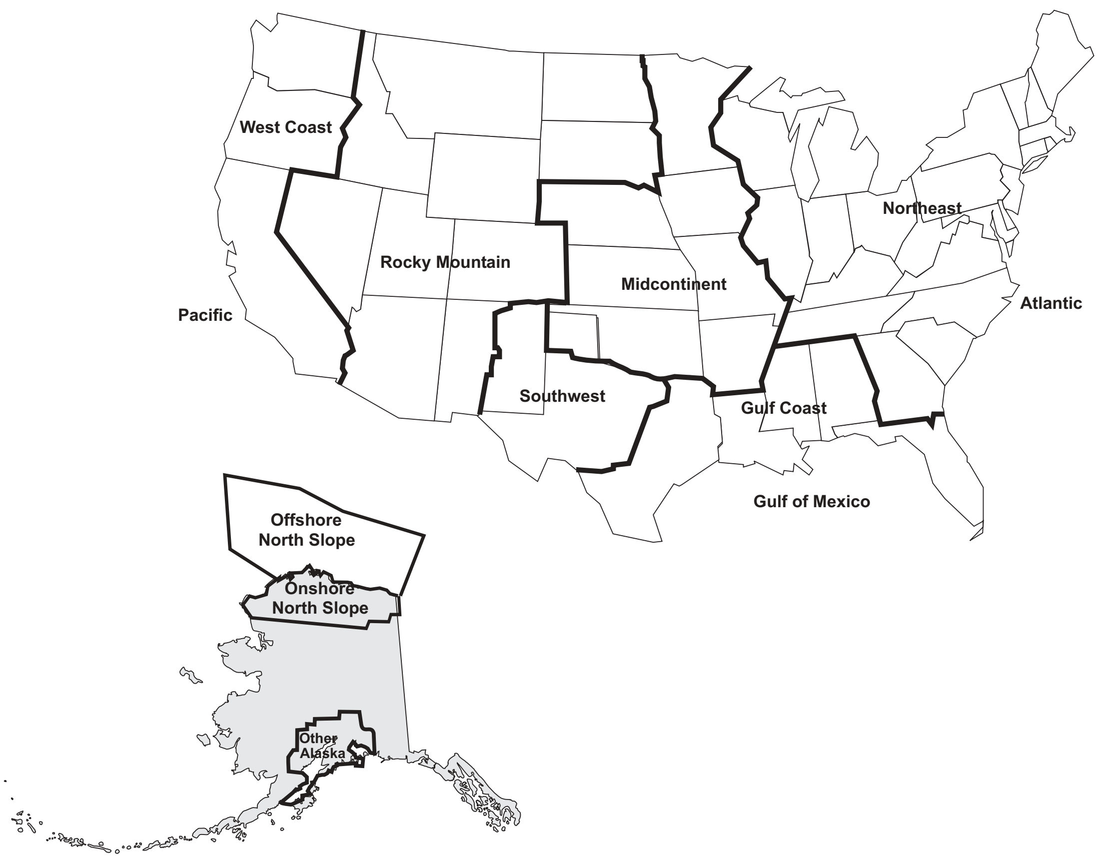
The lower 48 onshore supply submodule projects crude oil and natural gas production from conventional recovery techniques. This submodule accounts for drilling, reserve additions, total reserves, production-to-reserves ratios for each lower 48 onshore supply region.

The basic procedure is as follows:

- First, the prospective costs of a representative drilling project for a given fuel category and well class within a given region are computed. Costs are a function of the levels of drilling activity, average well depth, rig availability and the effects of technological progress.
- Second, the present value of the discounted cash flows (DCF) associated with the representative project is computed. These cash flows include both the capital and operating costs of the project, including royalties and taxes, and the revenues derived from a declining well production profile, computed after taking into account the progressive effects of resource depletion and valued at constant real prices as of the year of initial valuation.
- Third, drilling levels are calculated as a function of projected profitability as measured by the projected DCF levels for each project and national level cashflow.

OGSM Outputs	Inputs from NEMS	Exogenous Inputs
Crude oil production Domestic and Canadian nonassociated natural gas supply curves Mexican and liquefied natural gas imports and exports Cogeneration from oil and gas production Reserves and reserve additions Drilling levels Associated-dissolved gas production	Domestic and Canadian natural gas production and wellhead prices Crude oil demand World oil price Electricity price Gross Domestic Product Inflation Rate	Resource levels Initial finding rate parameters and costs Production profiles Tax parameters Mexican natural gas consumption and capacities Liquefied natural gas costs and capacities

Figure 12. Oil and Gas Supply Module Regions



- Fourth, regional finding rate equations are used to forecast new field discoveries from new field wildcats, new pools and extensions from other exploratory drilling, and reserve revisions from development drilling.

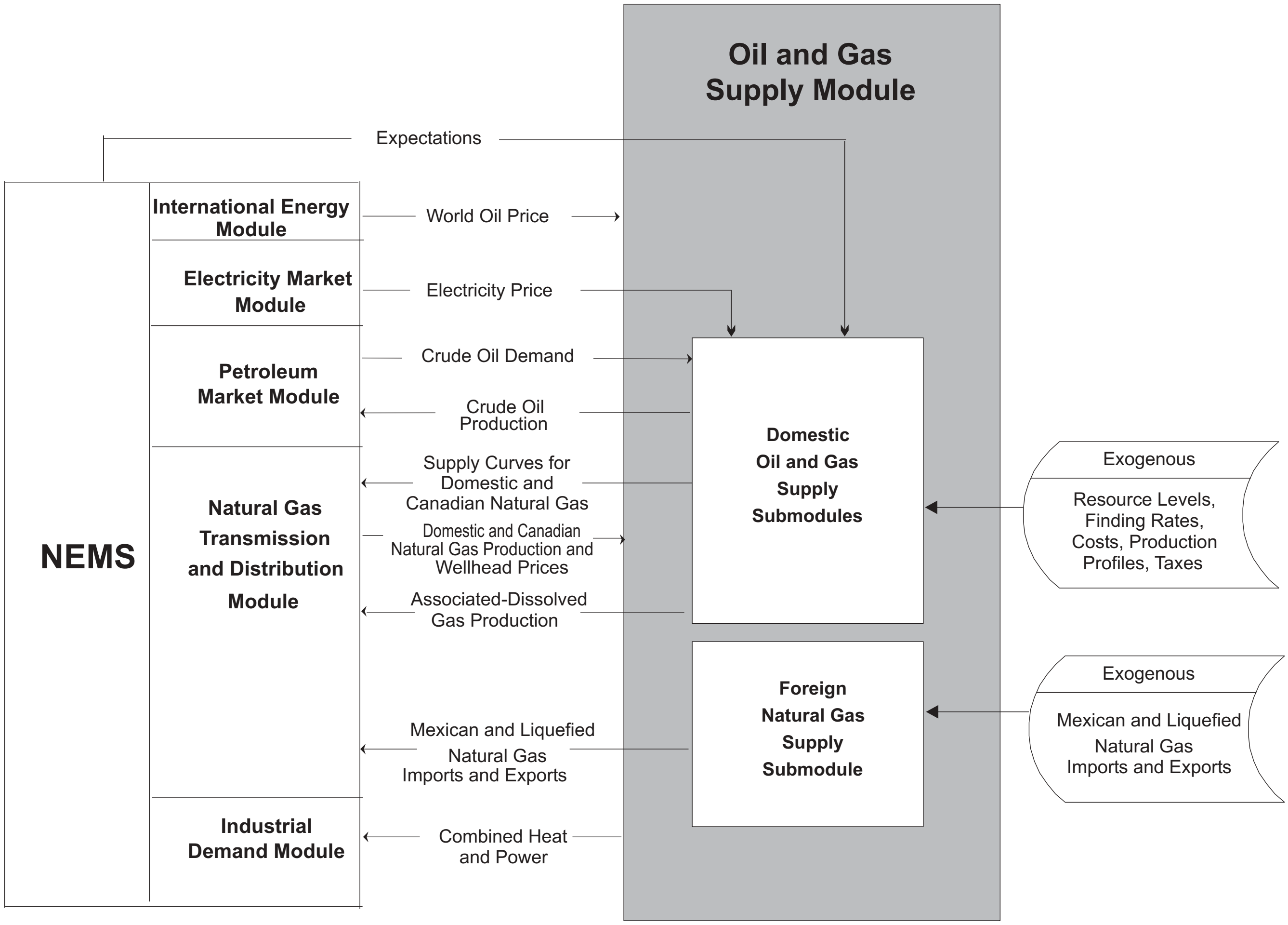
- Fifth, production is determined on the basis of reserves, including new reserve additions, previous productive capacity, flow from new wells, and, in the case of natural gas, fuel demands. This occurs within the market equilibration of the natural gas transmission and distribution module (NGTDM) for natural gas and within OGSM for oil.

Unconventional Gas Recovery Supply Submodule

Unconventional gas is defined as gas produced from nonconventional geologic formations, as opposed to conventional (sandstones) and carbonate rock formations. The three nonconventional geologic formations considered are low–permeability or tight sandstones, gas shales, and coalbed methane.

For unconventional gas, a play–level model calculates the economic feasibility of individual plays based on locally specific wellhead prices and costs, resource quantity and quality, and the various effects of technology on both resources and costs. In each year, an initial resource characterization determines the expected ultimate recovery (EUR) for the wells drilled in a particular play. Resource profiles are adjusted to reflect assumed technological impacts on the size, availability, and industry knowledge of the resources in the play. Subsequently, prices received from NGTDM and endogenously determined costs adjusted to reflect technological progress are utilized to calculate the economic profitability (or lack thereof) for the play. If the play is profitable, drilling occurs according to an assumed schedule, which is adjusted annually to account for technological improvements, as well as varying economic conditions. This drilling results in reserve additions, the quantities of which are directly related to the EURs for the wells in that play. Given these reserve additions, reserve levels and expected production–to–reserves (P/R) ratios are calculated at both the OGSM and the NGTDM region level. The resultant values are aggregated with similar values from

Figure 13. Oil and Gas Supply Module Structure



the conventional onshore and offshore submodules. The aggregate P/R ratios and reserve levels are then passed to NGTDM, which determines the prices and production for the following year through market equilibration.

Offshore Supply Submodule

This submodule uses a field–based engineering and economic analysis approach to project reserve additions and production from resources in the shallow and deep water offshore Gulf of Mexico Outer Continental Shelf and Pacific regions. Two structural components make up the offshore supply submodule, an exogenous price/supply data generation routine and an endogenous reserves and production timing algorithm.

The price/supply data generation methodology employs a rigorous field–based DCF approach. This offline model utilizes key field properties data, algorithms to determine key technology components, algorithms to determine the exploration, development and production costs, and computes a minimum acceptable supply price (MASP) at which the discounted net present value of an individual prospect equals zero. The MASP and the recoverable resources for the different fields are aggregated by planning region and by resource type to generate resource–specific price–supply curves. In addition to the overall supply price and reserves, costs components for exploration, development drilling, production platform, and operating expenses, as well as exploration and development well requirements, are also carried over to the endogenous component.

After the exogenous price/supply curves have been developed, they are transmitted to an endogenous algorithm. This algorithm makes choices for field exploration and development based on relative economics of the project profitability compared with the equilibrium crude oil and natural gas prices determined by the petroleum market module and natural gas transmission and distribution module. Development of economically recoverable resources into proved reserves is constrained by drilling activity. Proved reserves are translated into production based on a P/R ratio. The drilling activity and the P/R ratio are both determined by extrapolating the historical information.

Alaska Oil and Gas Submodule

This submodule projects the crude oil and natural gas produced in Alaska. The Alaskan oil submodule is divided into three sections: new field discoveries, development projects, and producing fields. Oil transportation costs to lower 48 facilities are used in conjunction with the relevant market price of oil to calculate the estimated net price received at the wellhead, sometimes called the netback price. A discounted cash flow method is used to determine the economic viability of each project at the netback price.

Alaskan oil supplies are modeled on the basis of discrete projects, in contrast to the onshore lower 48 conventional oil and gas supplies, which are modeled on an aggregate level. The continuation of the exploration and development of multiyear projects, as well as the discovery of new fields, is dependent on profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, historical production patterns, and announced plans for currently producing fields.

Alaskan gas production is set separately for any gas targeted to flow through a pipeline to the lower 48 States and gas produced for consumption in the State and for export to Japan. The latter is set based on a forecast of Alaskan consumption in the NGTDM and an exogenous specification of exports. North Slope production for the pipeline is dependent on construction of the pipeline, set to commence if the lower 48 average wellhead price is maintained at a level exceeding the established comparable cost of delivery to the lower 48 States.

Foreign Natural Gas Supply Submodule

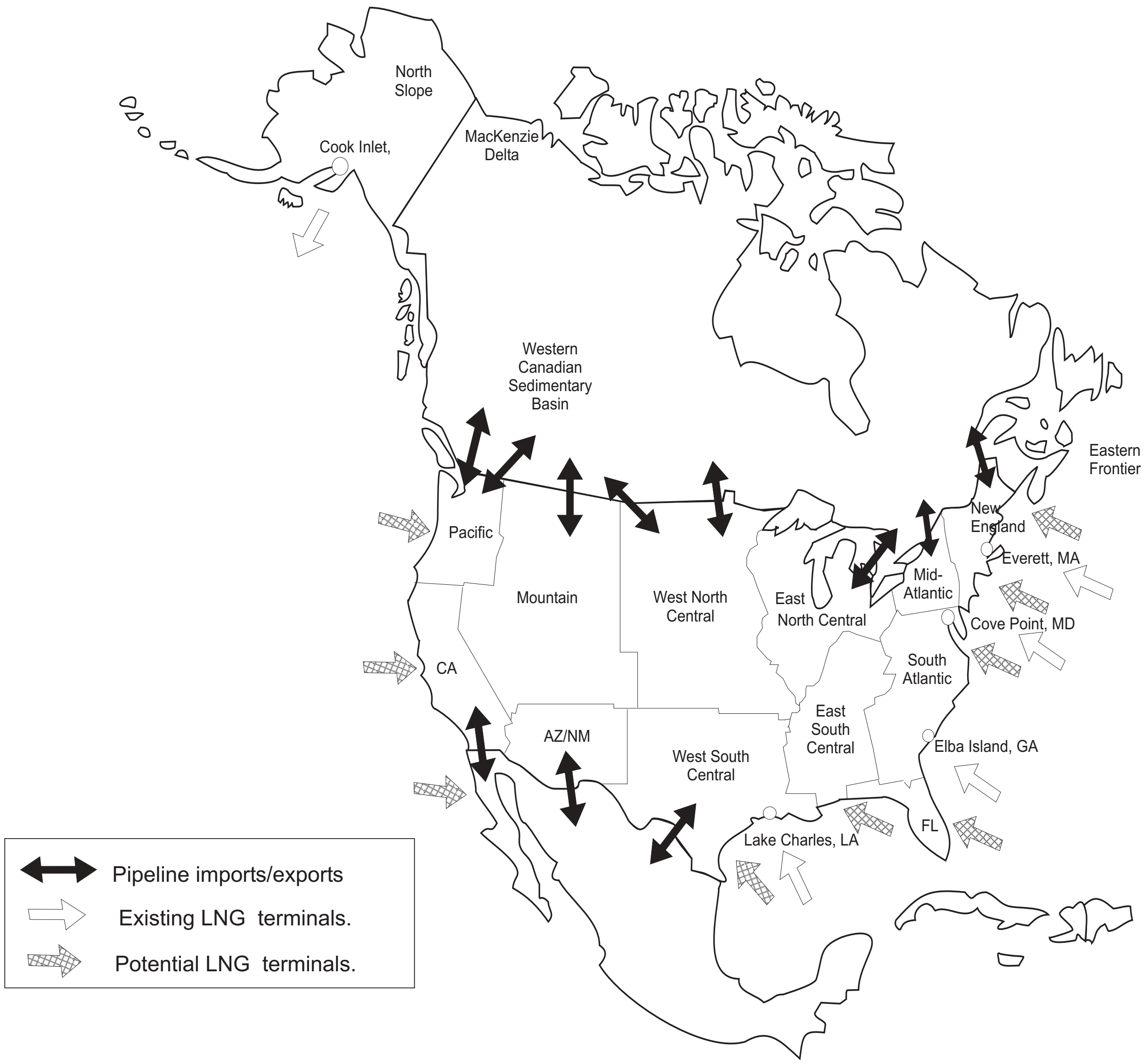
The foreign natural gas supply submodule (FNGSS) establishes production in the Western Canadian Sedimentary Basin (WCSB) and Eastern Canada, natural gas trade via pipeline with Mexico, as well as liquefied natural gas (LNG) trade. The receiving regions for foreign gas supplies correspond to those of the natural gas integrating framework established for NGTDM. Within NGTDM, pipeline natural gas imports flow from two sources: Canada and Mexico. U.S. natural gas trade with Canada is represented by seven entry/exit points, and trade with Mexico is represented by three entry/exit points (Figure 14).

OGSM provides NGTDM with the beginning–of–year natural gas proved reserves from the WCSB and an associated expected production–to–reserve ratio. NGTDM uses this information to establish a short–term supply curve for the region. Along with exogenously specified forecasts for exports of gas to Canada, other Canadian supplies, and Canadian consumption, this supply curve is used to determine the wellhead gas production and price in the WCSB and the level and price of imports from Canada at the seven border crossings. Based on the WCSB gas wellhead price, OGSM forecasts drilling activity in the WCSB using an econometrically derived equation, along with the associated reserve additions. The finding rate is set using an assumed exponential decline function which responds to the drilling activity. The reserve additions are added to the beginning-of-year proved reserves from the current forecast year, after the forecasted production levels are subtracted, to establish the beginning–of–year proved reserves for the next forecast year. Construction is set to commence on a pipeline to bring natural gas from the MacKenzie Delta to market after the lower 48 average wellhead price is maintained at a level exceeding the established comparable cost.

Mexican gas trade is a highly complex issue. A range of noneconomic factors influences, if not determines, flows of gas between the United States and Mexico. The uncertainty is so great that not only is the magnitude of flow for any future year in doubt, but also the direction of flow. Reasonable scenarios have been developed and defended in which Mexico may be either a net importer or exporter of hundreds of billions of cubic feet of gas by 2025 or sooner.

Despite the uncertainty and the significant influence of noneconomic factors that influence Mexican gas trade with the United States, a methodology to anticipate the path of future Mexican imports and exports has been incorporated into FNGSS. This outlook is generated using assumptions regarding regional supply and regional/sectoral demand growth for natural gas in Mexico that have been developed from an assessment of current and expected industry and market circumstances as indicated in industry announcements, or articles or reports in relevant publications. Excess supply is assumed to be available for export to the United States, and any short-

Figure 14. Foreign Natural Gas Trade via Pipeline and Liquefied Natural Gas Terminals



fall is assumed to be met by imports from the United States. The importation of liquefied natural gas into Baja, Mexico is expected to commence when the market price, established as a netback from the price in California, exceeds the assumed cost.

Liquefaction is a process whereby natural gas is cooled to minus 260 degrees Fahrenheit, causing it to be converted from a gas to a liquid. This also reduces its volume significantly, making it possible to transport to distant markets. This allows stranded gas, or gas that would otherwise be inaccessible due either to lack of nearby markets or lack of pipeline infrastructure to deliver it to local markets, to be monetized.

Costs of producing, liquefying, transporting, and re-gasifying the gas for delivery via pipeline to end-users are input to the FNGSS. The summations of these values for each location serve as economic thresholds that must be achieved before investment in expansion at an existing, or construction of a new, LNG project occurs. Imported LNG costs compete with the purchase price of gas prevailing in the vicinity of the import terminal. This is a significant element in evaluating the competitiveness of LNG supplies, since LNG terminals vary greatly in their proximity to domestic producing areas. Terminals close to major consuming markets and far from competing producing areas may provide a sufficient economic advantage to make LNG a competitive gas supply source in some markets.

In addition to costs, extensive operational assumptions are required to determine LNG imports. Dominant general factors affecting the outlook include expected developments with respect to the use of existing capacity, expansion at existing sites, and construction at additional locations. The LNG forecast also requires the specification of a combination of factors: available gasification capacity, schedules for and lags between constructing and opening a facility, tanker availability, expected utilization rates, and worldwide liquefaction capacity. For inactive terminals, it is necessary to determine the length of time required to restart operations, normally between 12 and 18 months. These considerations are taken into account when the economic viability of LNG supplies is determined.

The algorithm for representing LNG regasification capacity expansion in the United States compares estimated costs for bringing LNG into various regions in the United States with the average market price in the region over the previous three years of the forecast. If the market price has been sustained above the estimated cost, construction of additional regasification capacity is expected to occur. The regions represented are: New England Census Division, Middle Atlantic Census Division, South Atlantic Census Division (excluding Florida), Florida, East South Central Census Division, West South Central Census Division, California, and Washington/Oregon. The incremental expansion volumes are specified exogenously, along with the expected utilization of the capacity across time. Under special circumstances (e.g., rapid consumption growth) these utilization rates are adjusted endogenously. The assumed costs for bringing LNG into the United States reflect the least cost aggregation of cost estimates for production, liquefaction, transportation, and regasification from potential supply sources to each of the coastal regions of the United States. Build decisions occur under various restrictions, such as the limitation that new capacity can not be added in a region until existing capacity has been expanded to a specified limit and all of this capacity is fully utilized within the region. In deciding upon capacity expansion, the model does not attempt to anticipate future market situations, factor in regional demand for LNG (except through its indirect impact on prices), nor select between potential regasification sites. The model accounts for LNG exports to Japan from Alaska using an exogenously–specified forecast.